Energy Tidbits

Did US Defense Secretary Austin Signal A Softening of US Position on Iran Just Before JCPOA Restarts?

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November 21, 2021

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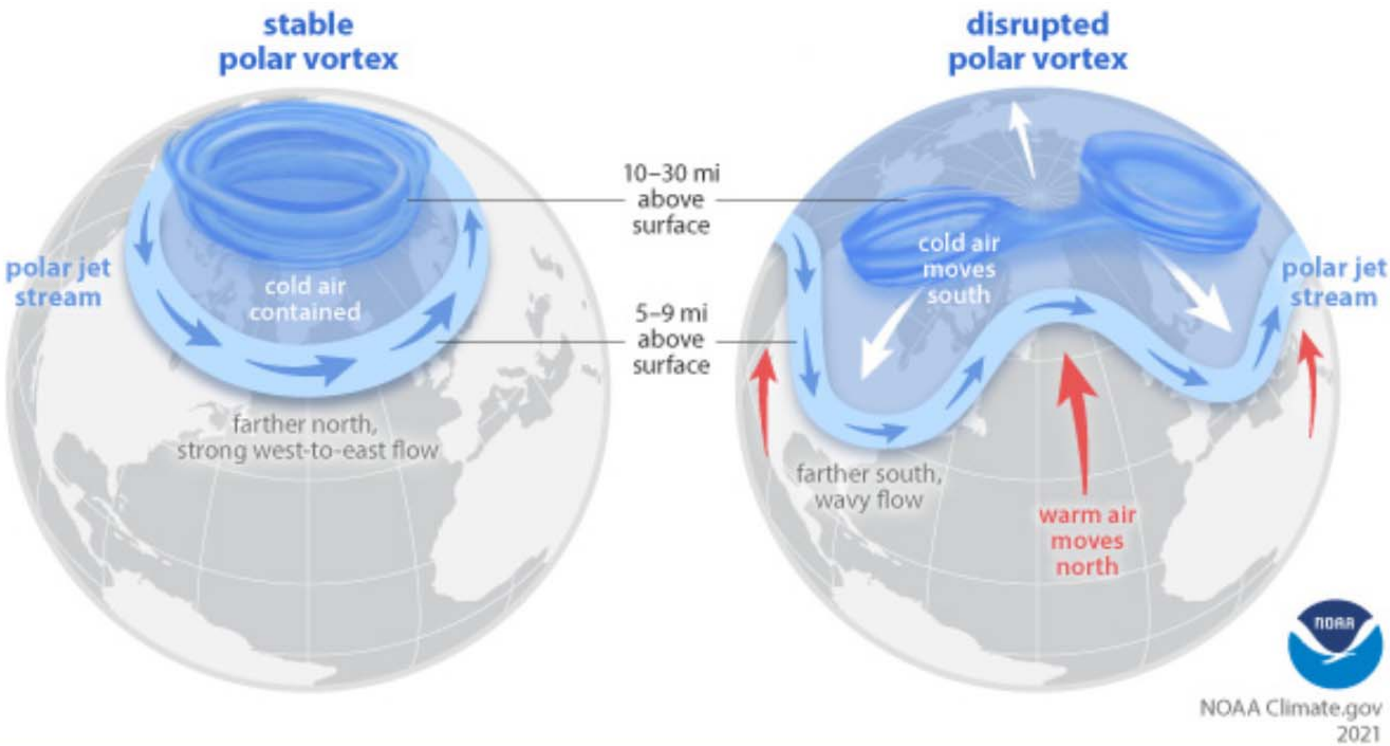
https://twitter.com/NOAAClimate/status/1369679820246970373/photo/1

Understanding the polar vortex

The Arctic polar vortex is a strong band of winds in the stratosphere, surrounding the North Pole 10–30 miles above the surface.

The polar vortex is far above and typically does not interact with the polar jet stream, the flow of winds in the troposphere 5–9 miles above the surface. But when the polar vortex is especially strong and stable, the jet stream stays farther north and has fewer "kinks." This keeps cold air contained over the Arctic and the mid-latitudes warmer than usual.

Every other year or so, the Arctic polar vortex dramatically weakens. The vortex can be pushed off the pole or split into two. Sometimes the polar jet stream mirrors this stratospheric upheaval, becoming weaker or wavy. At the surface, cold air is pushed southward to the mid-latitudes, and warm air is drawn up into the Arctic.



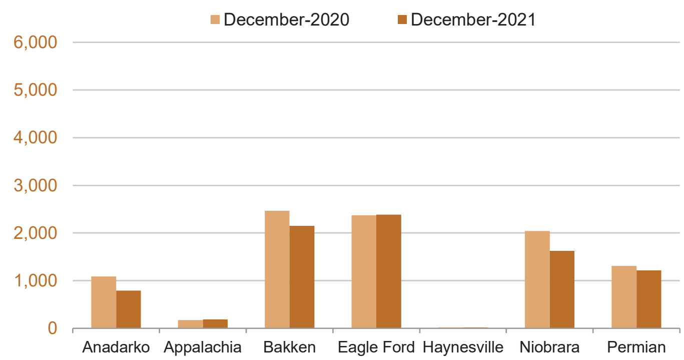
Year-over-year summary

November 2021

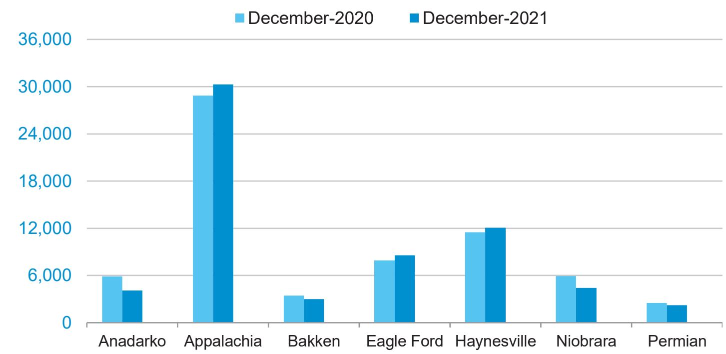
Drilling Productivity Report

drilling data through October
projected production through December

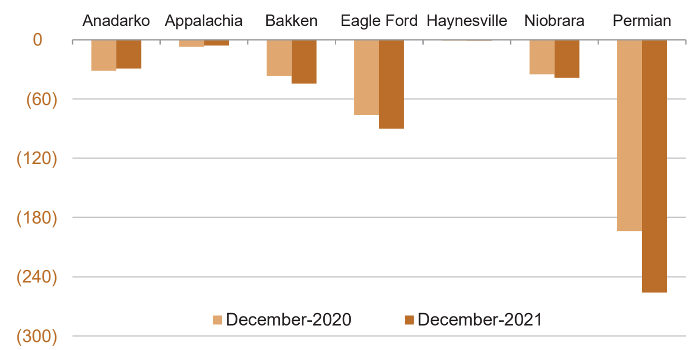
New-well oil production per rig
barrels/day



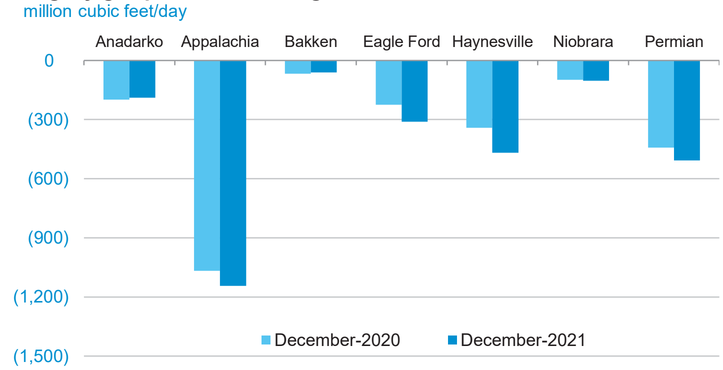
New-well gas production per rig
thousand cubic feet/day



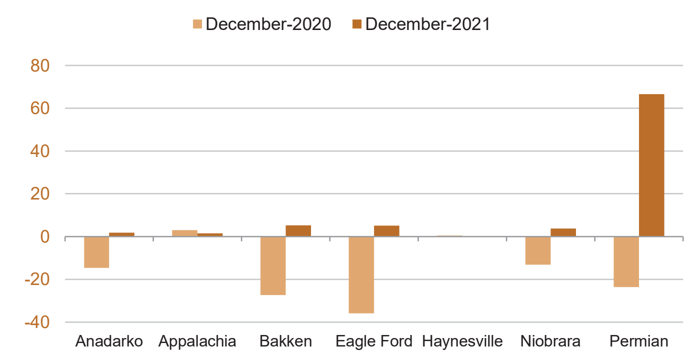
Legacy oil production change
thousand barrels/day



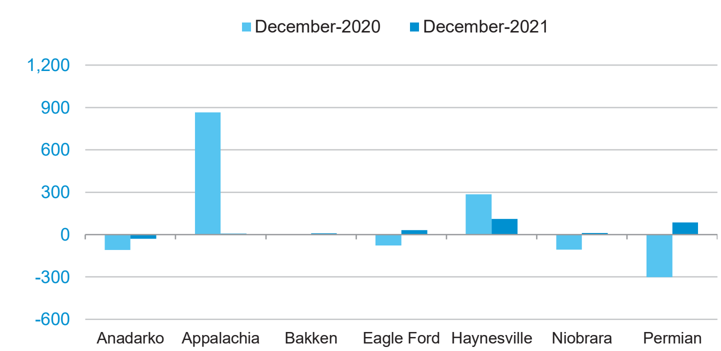
Legacy gas production change
million cubic feet/day



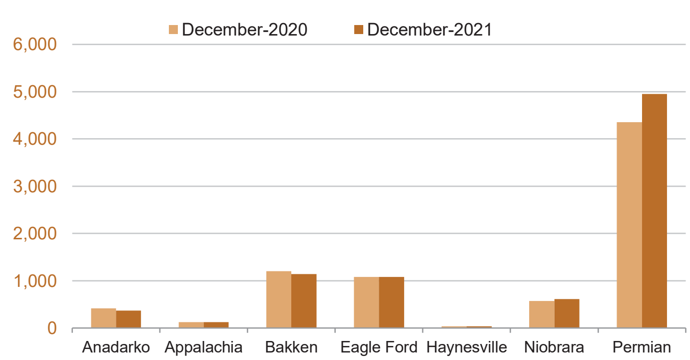
Indicated monthly change in oil production (Dec vs. Nov)
thousand barrels/day



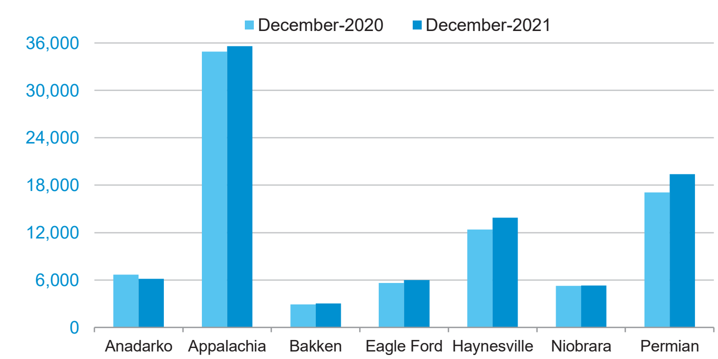
Indicated monthly change in gas production (Dec vs. Nov)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

November 2021

drilling data through October
projected production through December

Oil
-50
barrels/day
month over month

795 *December*
845 *November*
barrels/day

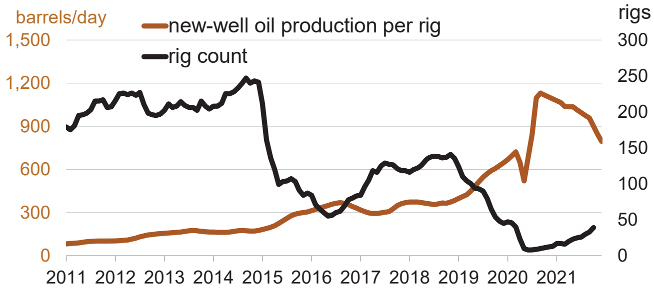
Monthly additions from one average rig

December **4,086**
November **4,540**
thousand cubic feet/day

Gas
-454
thousand cubic feet/day
month over month

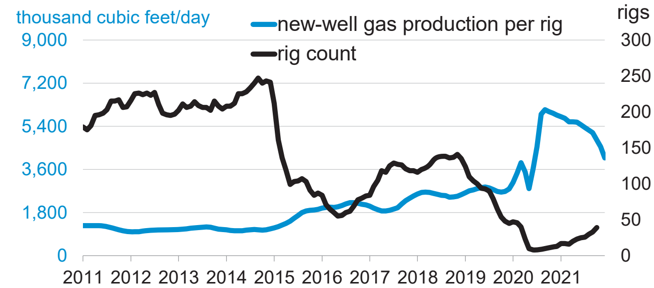
Anadarko Region
New-well oil production per rig

Rig count

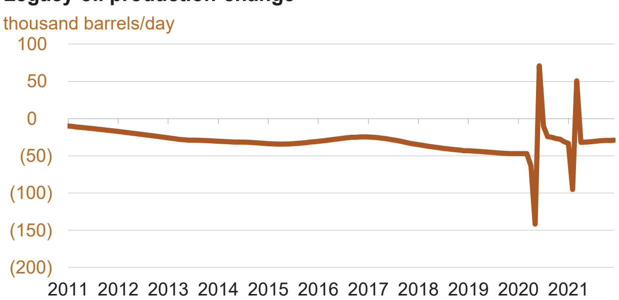


Anadarko Region
New-well gas production per rig

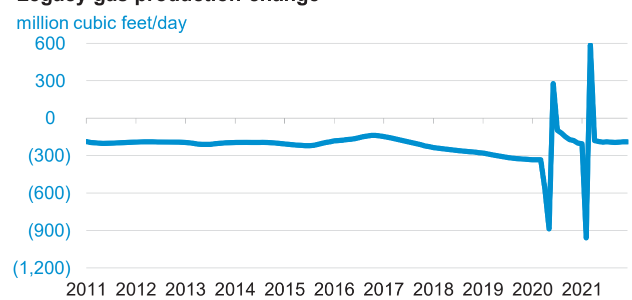
Rig count



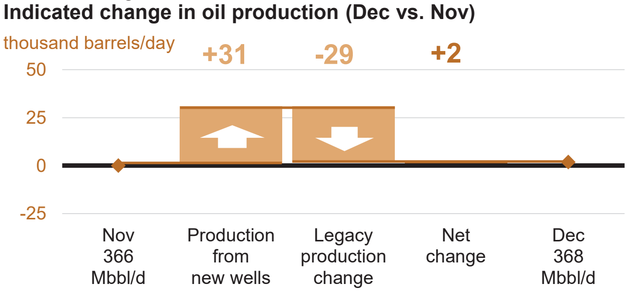
Anadarko Region
Legacy oil production change



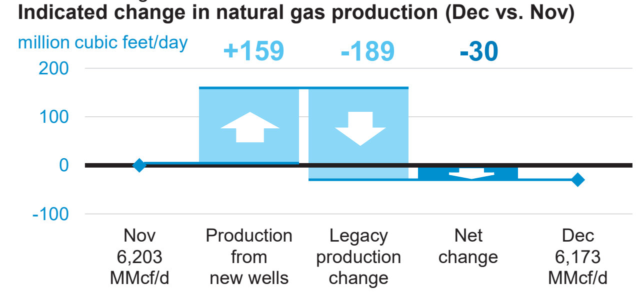
Anadarko Region
Legacy gas production change



Anadarko Region
Indicated change in oil production (Dec vs. Nov)

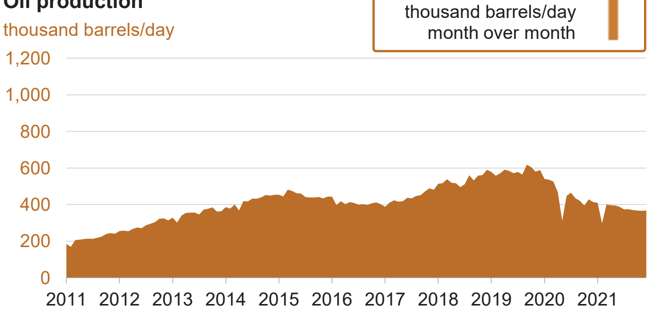


Anadarko Region
Indicated change in natural gas production (Dec vs. Nov)



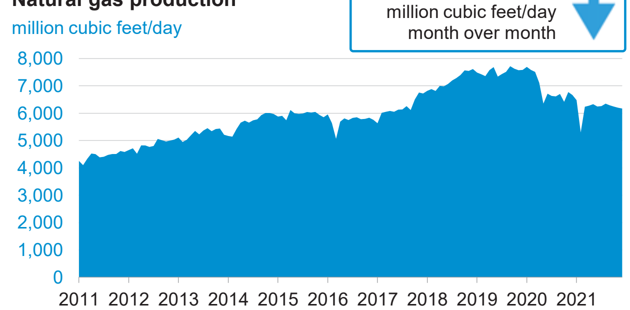
Anadarko Region
Oil production

Oil +2
thousand barrels/day
month over month



Anadarko Region
Natural gas production

Gas -30
million cubic feet/day
month over month



Appalachia Region

Drilling Productivity Report

November 2021

drilling data through October
projected production through December

Oil
0
barrels/day
month over month

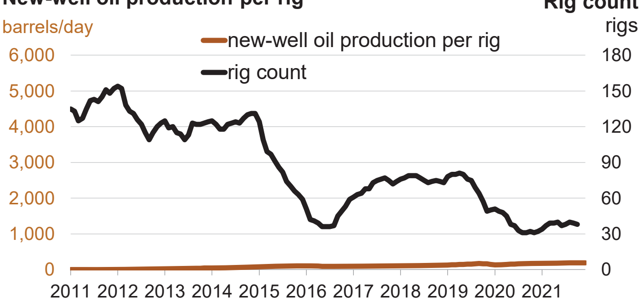
187 *December*
187 *November*
barrels/day

Monthly additions from one average rig

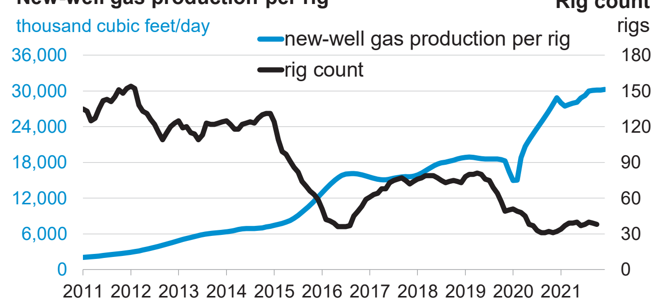
December **30,284**
November **30,133**
thousand cubic feet/day

Gas
+151
thousand cubic feet/day
month over month

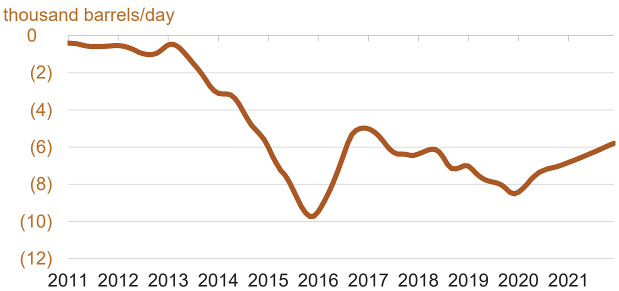
Appalachia Region
New-well oil production per rig



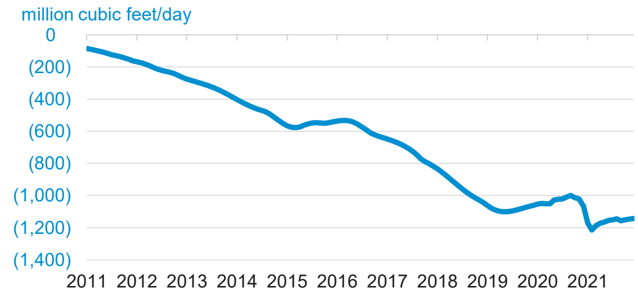
Appalachia Region
New-well gas production per rig



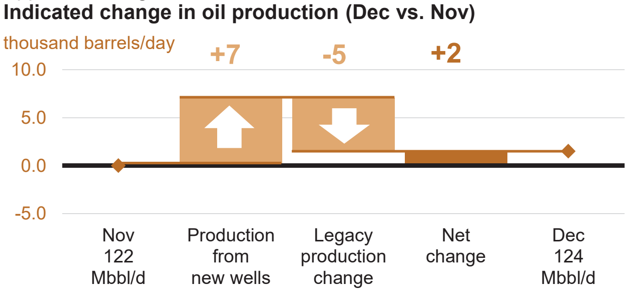
Appalachia Region
Legacy oil production change



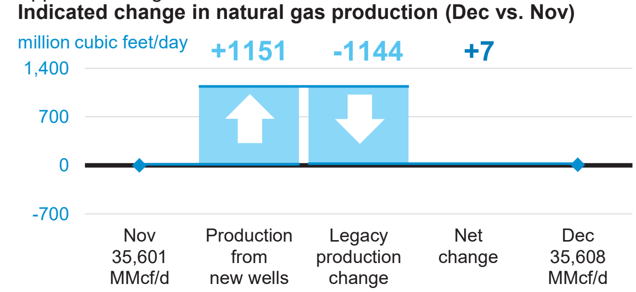
Appalachia Region
Legacy gas production change



Appalachia Region
Indicated change in oil production (Dec vs. Nov)

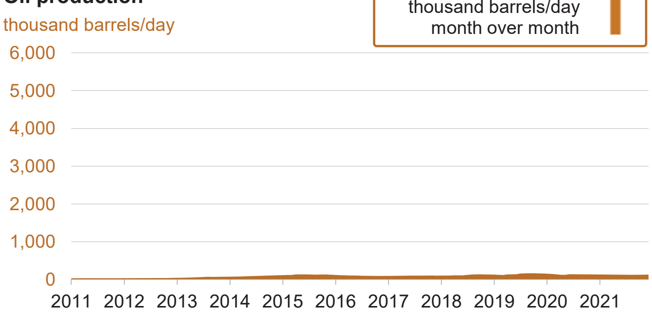


Appalachia Region
Indicated change in natural gas production (Dec vs. Nov)



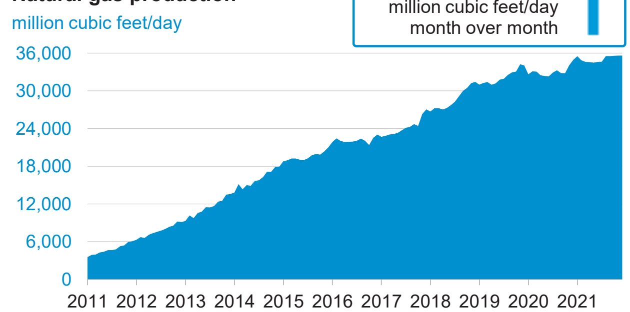
Appalachia Region
Oil production

Oil +2
thousand barrels/day
month over month



Appalachia Region
Natural gas production

Gas +7
million cubic feet/day
month over month



Bakken Region

Drilling Productivity Report

November 2021

drilling data through October
projected production through December

Oil -4
barrels/day
month over month

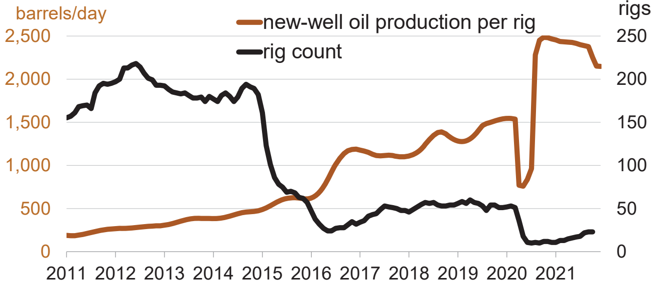
2,148 *December*
2,152 *November*
barrels/day

Monthly additions from one average rig

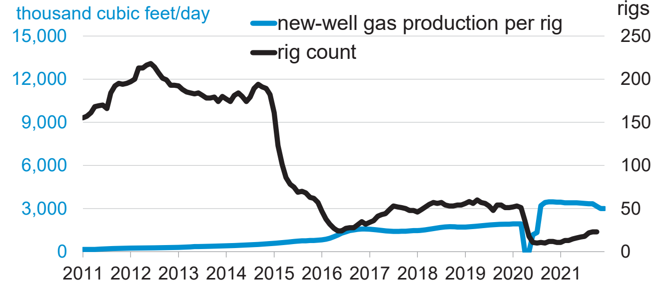
December **3,007**
November **3,013**
thousand cubic feet/day

Gas -6
thousand cubic feet/day
month over month

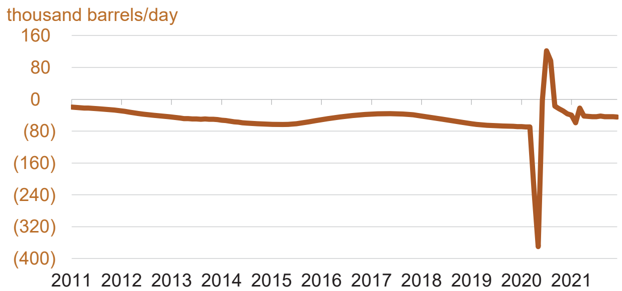
Bakken Region
New-well oil production per rig **Rig count**



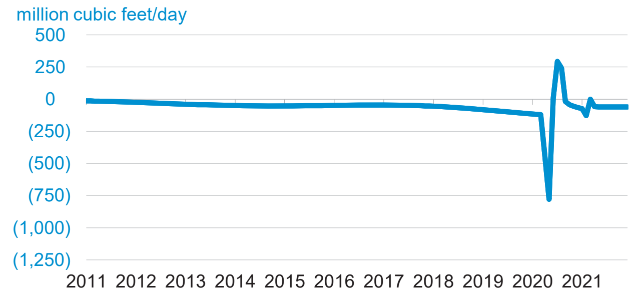
Bakken Region
New-well gas production per rig **Rig count**



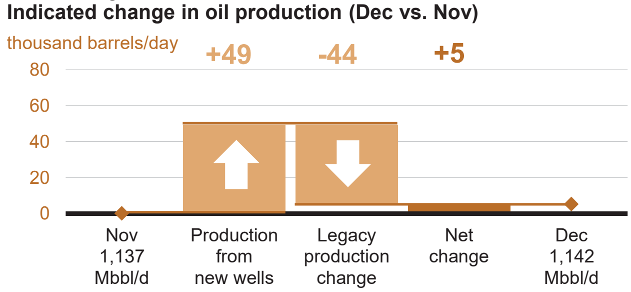
Bakken Region
Legacy oil production change



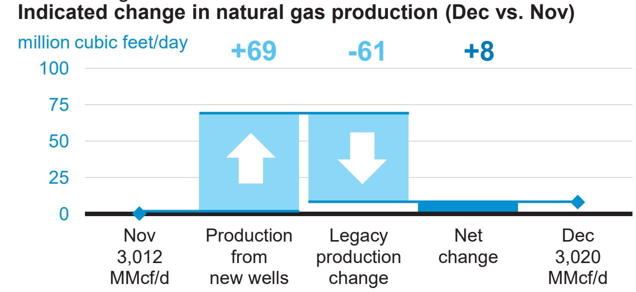
Bakken Region
Legacy gas production change



Bakken Region
Indicated change in oil production (Dec vs. Nov)

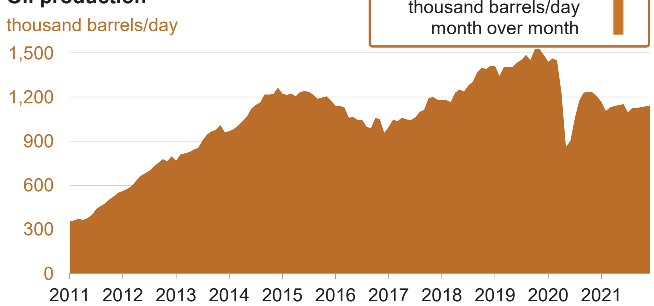


Bakken Region
Indicated change in natural gas production (Dec vs. Nov)



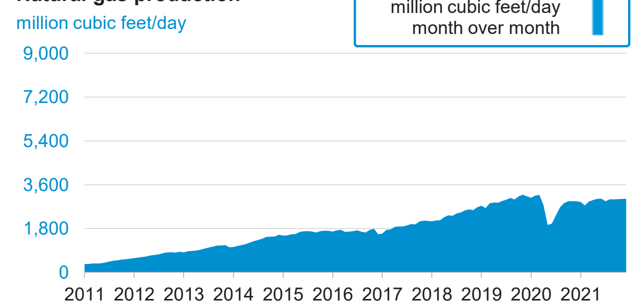
Bakken Region
Oil production

Oil +5
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas +8
million cubic feet/day
month over month



Eagle Ford Region
Drilling Productivity Report

November 2021
drilling data through October
projected production through December

Oil +1 barrels/day month over month

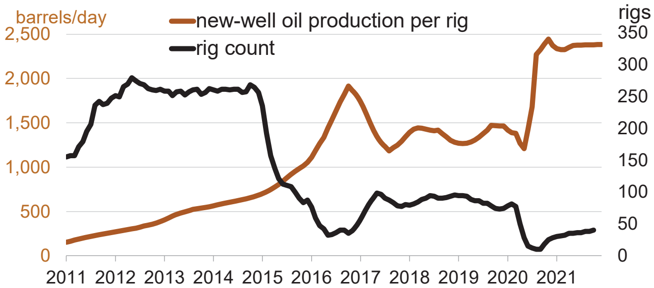
2,383 *December*
2,382 *November*
barrels/day

Monthly additions from one average rig

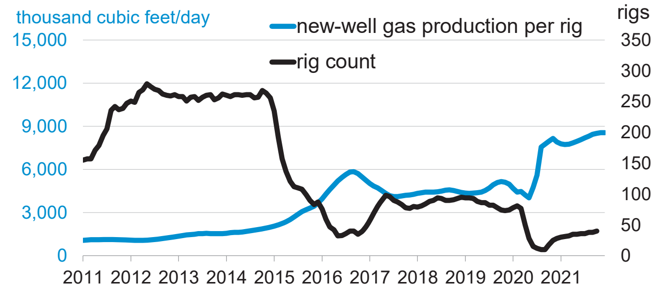
December **8,559**
November **8,557**
thousand cubic feet/day

Gas +2 thousand cubic feet/day month over month

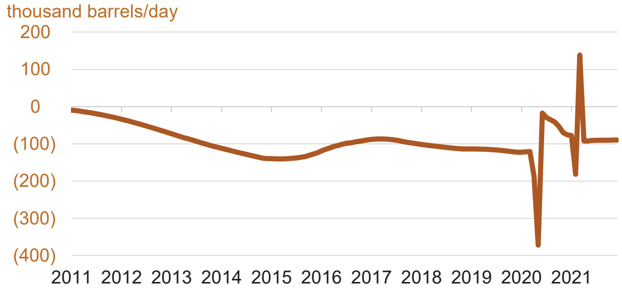
Eagle Ford Region
New-well oil production per rig **Rig count**



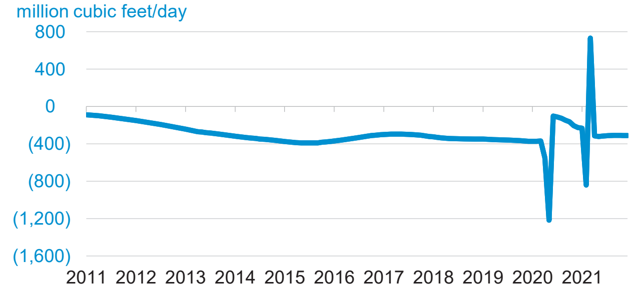
Eagle Ford Region
New-well gas production per rig **Rig count**



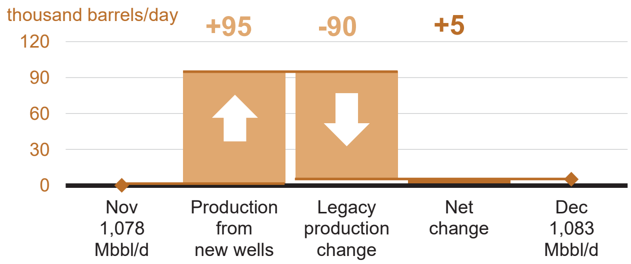
Eagle Ford Region
Legacy oil production change



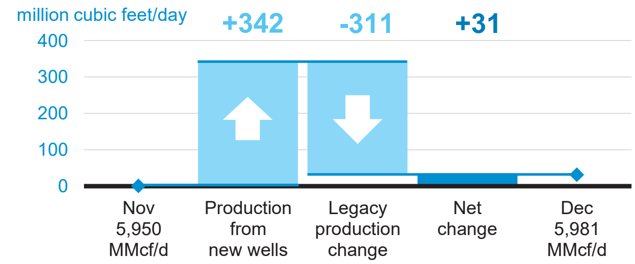
Eagle Ford Region
Legacy gas production change



Eagle Ford Region
Indicated change in oil production (Dec vs. Nov)

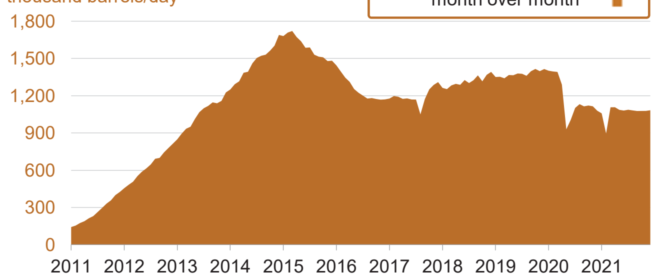


Eagle Ford Region
Indicated change in natural gas production (Dec vs. Nov)



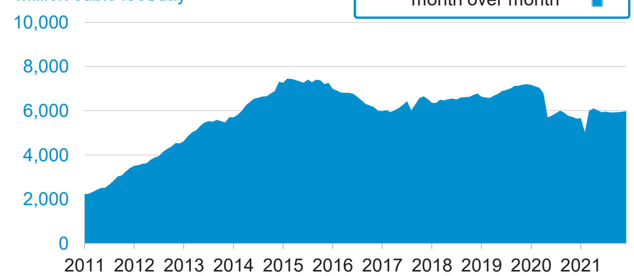
Eagle Ford Region
Oil production
thousand barrels/day

Oil +5 thousand barrels/day month over month



Eagle Ford Region
Natural gas production
million cubic feet/day

Gas +31 million cubic feet/day month over month



Haynesville Region

Drilling Productivity Report

November 2021

drilling data through October
projected production through December

Oil
0
barrels/day
month over month

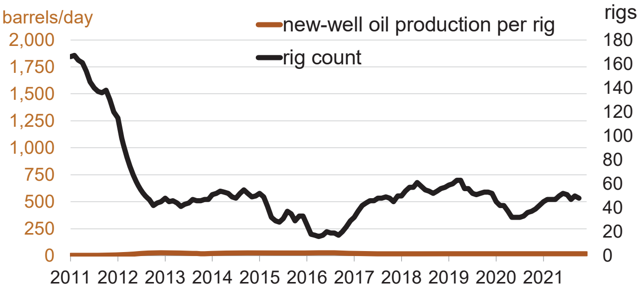
19 *December*
19 *November*
barrels/day

Monthly additions from one average rig

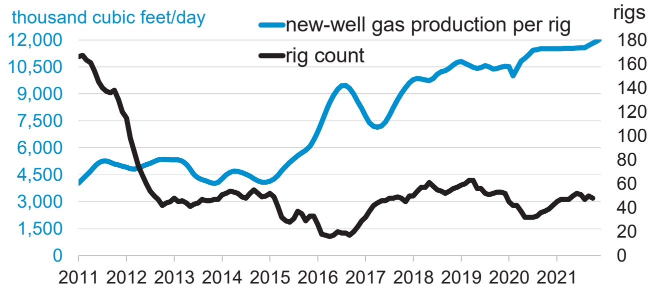
December **12,079**
November **11,924**
thousand cubic feet/day

Gas
+155
thousand cubic feet/day
month over month

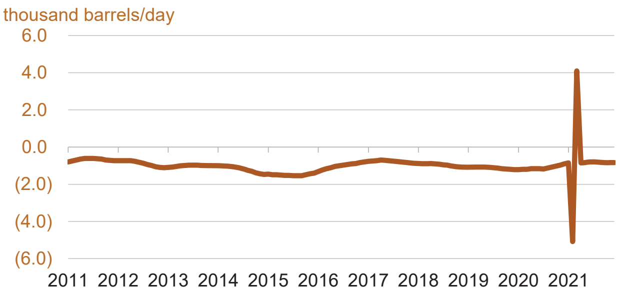
Haynesville Region
New-well oil production per rig



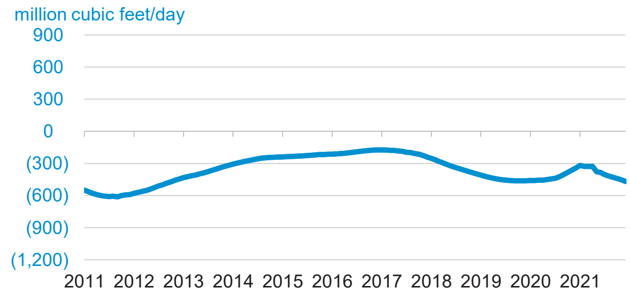
Haynesville Region
New-well gas production per rig



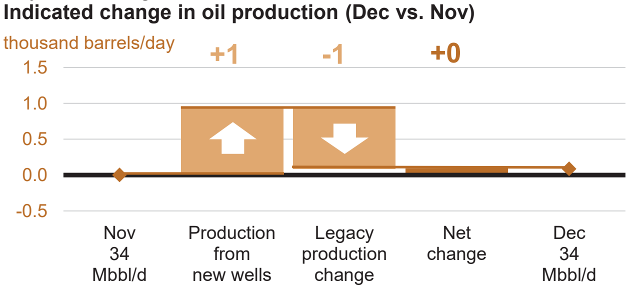
Haynesville Region
Legacy oil production change



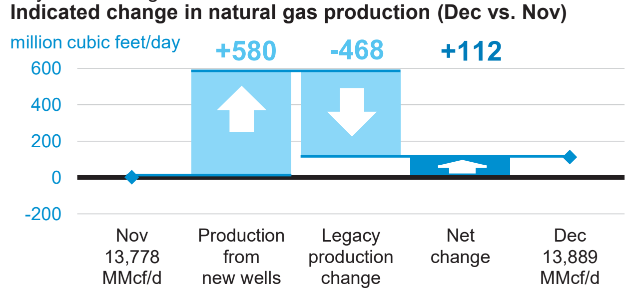
Haynesville Region
Legacy gas production change



Haynesville Region
Indicated change in oil production (Dec vs. Nov)

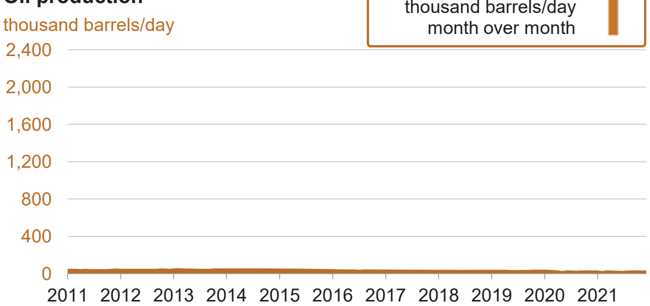


Haynesville Region
Indicated change in natural gas production (Dec vs. Nov)



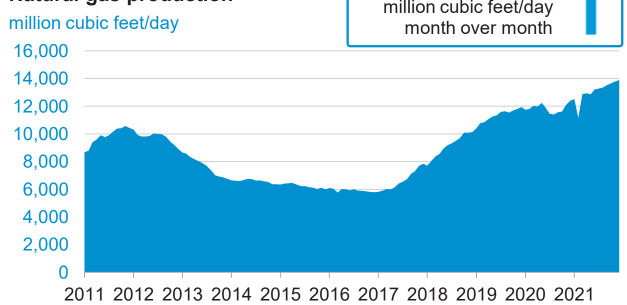
Haynesville Region
Oil production

Oil +0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas +112
million cubic feet/day
month over month



Niobrara Region
Drilling Productivity Report

November 2021
drilling data through October
projected production through December

Oil
-33
barrels/day
month over month

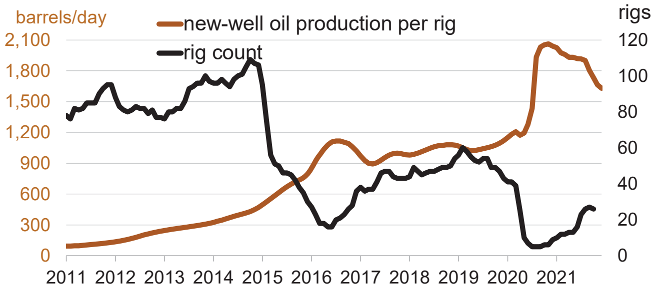
1,629 *December*
1,662 *November*
barrels/day

Monthly additions from one average rig

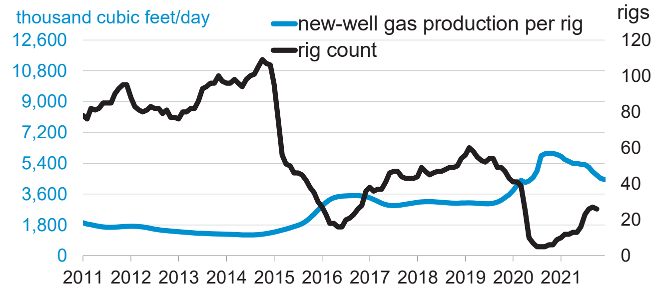
December **4,434**
November **4,524**
thousand cubic feet/day

Gas
-90
thousand cubic feet/day
month over month

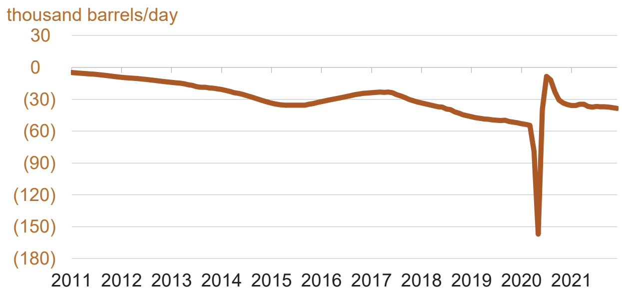
Niobrara Region
New-well oil production per rig **Rig count**



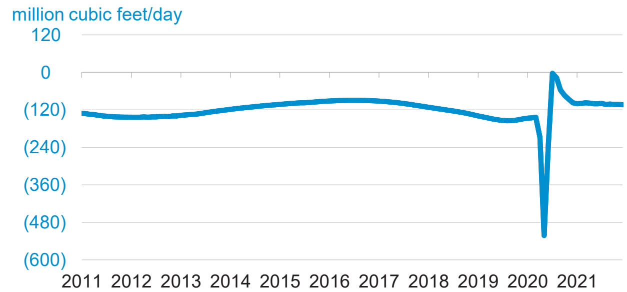
Niobrara Region
New-well gas production per rig **Rig count**



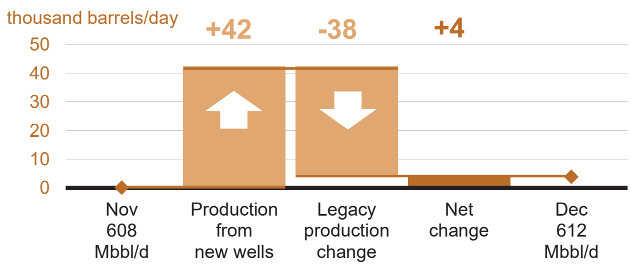
Niobrara Region
Legacy oil production change



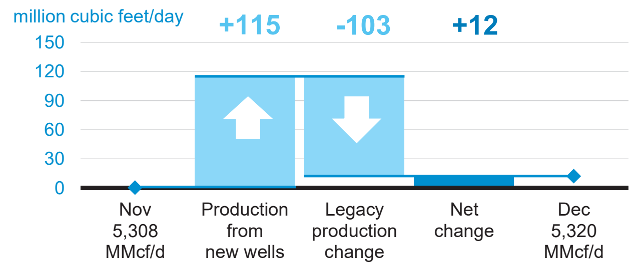
Niobrara Region
Legacy gas production change



Niobrara Region
Indicated change in oil production (Dec vs. Nov)

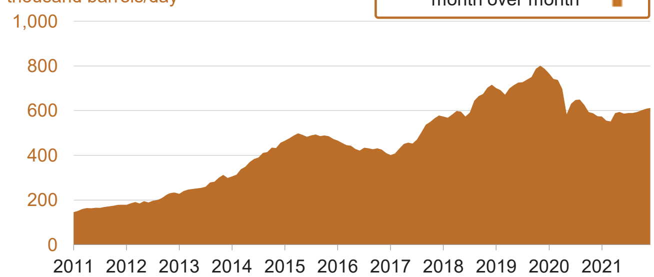


Niobrara Region
Indicated change in natural gas production (Dec vs. Nov)



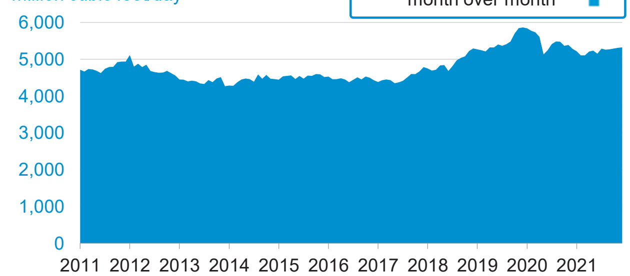
Niobrara Region
Oil production

Oil +4
thousand barrels/day
month over month



Niobrara Region
Natural gas production

Gas +12
million cubic feet/day
month over month



Permian Region

Drilling Productivity Report

November 2021

drilling data through October
projected production through December

Oil -5 barrels/day month over month

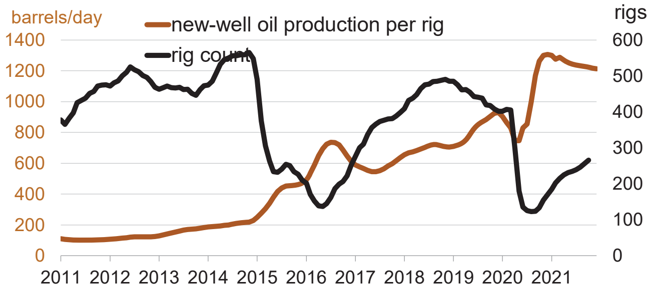
1,213 *December*
1,218 *November*
barrels/day

Monthly additions from one average rig

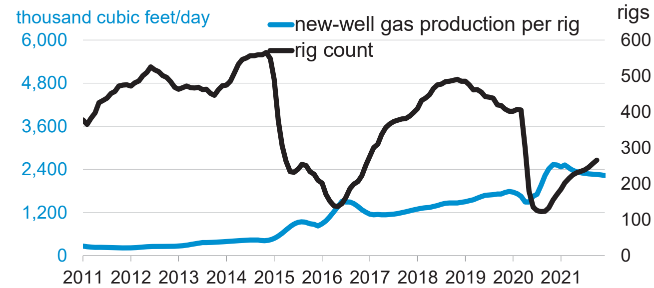
December **2,233**
November **2,245**
thousand cubic feet/day

Gas -12 thousand cubic feet/day month over month

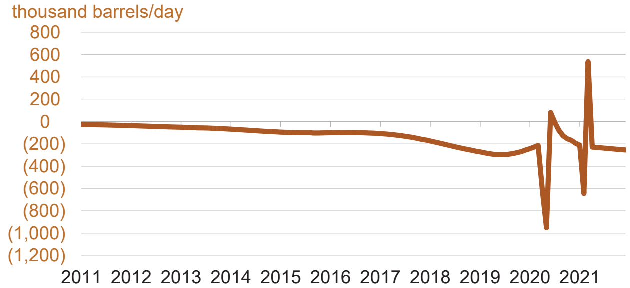
Permian Region
New-well oil production per rig — **Rig count**



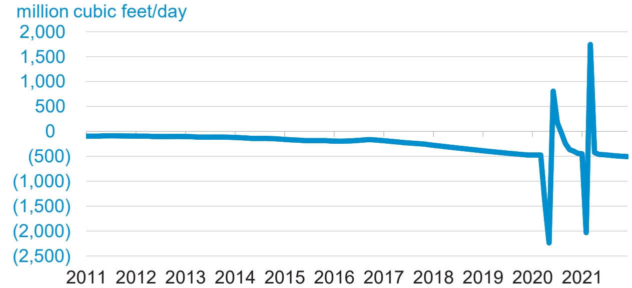
Permian Region
New-well gas production per rig — **Rig count**



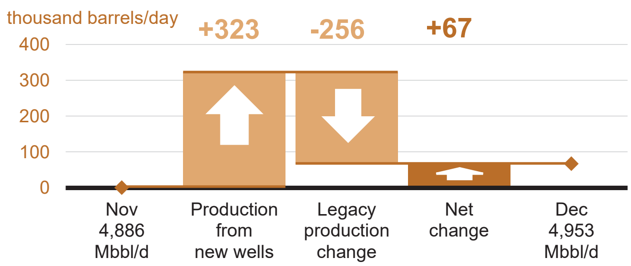
Permian Region
Legacy oil production change



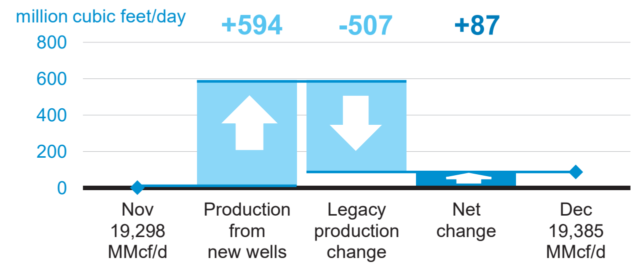
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Dec vs. Nov)

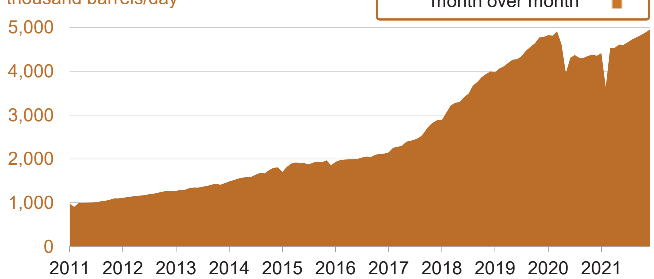


Permian Region
Indicated change in natural gas production (Dec vs. Nov)



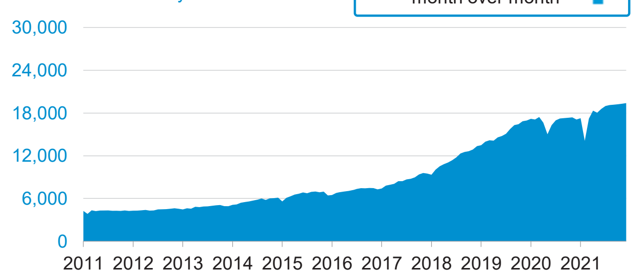
Permian Region
Oil production

Oil +67 thousand barrels/day month over month



Permian Region
Natural gas production

Gas +87 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

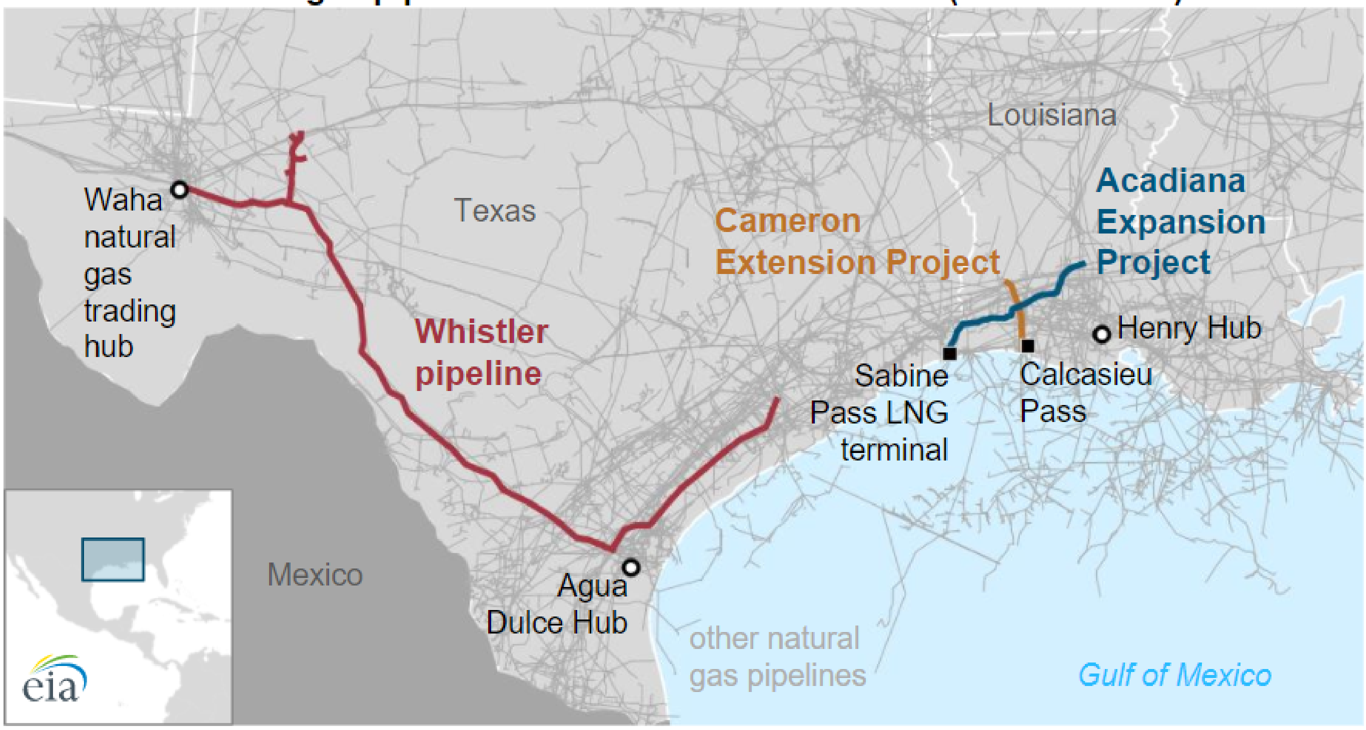
Ohio Department of Natural Resources (http://oilandgas.ohiodnr.gov) Source of well production, permit, and completion data in the counties associated with this report in Ohio

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://www.eia.gov/todayinenergy/detail.php?id=50376

NOVEMBER 17, 2021

New natural gas pipeline capacity expands access to export and Northeast markets

Gulf Coast natural gas pipelines and related infrastructure (October 2021)



Source: U.S. Energy Information Administration, Natural Gas Pipeline Projects Tracker

Reposted at 12:00 p.m. on November 17, 2021 to change the company associated with the Whistler pipeline.

In our recently updated Natural Gas Pipeline Projects Tracker, we estimate over 4 billion cubic feet per day (Bcf/d) of new natural gas pipeline capacity entered service in the third quarter of 2021, primarily supplying Gulf Coast and Northeast demand markets.

In the Gulf Coast, three projects either entered service in the third quarter or were partially completed, totaling 3.6 Bcf/d of additional pipeline capacity. These projects connect U.S. natural gas production to growing U.S. export markets. They include:

- The Whistler pipeline, completed on July 1, 2021. The new 2.0 Bcf/d pipeline, operated by WhiteWater, connects Permian Basin production at the Waha Hub in West Texas to the Agua Dulce Hub in Southeast Texas. The Agua Dulce Hub serves as the supply point for several pipelines that cross the border to supply demand markets in Mexico.
- The Acadiana Expansion Project, partly completed as of August 6, 2021. This 894 million cubic feet per day (MMcf/d) expansion on the Kinder Morgan Louisiana intrastate pipeline increases takeaway capacity out of the Haynesville Basin, connecting it to the Sabine Pass LNG terminal. The project is expected to be completed in early 2022.
- The Cameron Extension Project, partly completed as of August 12, 2021. This 750 MMcf/d expansion on the Texas Eastern Transmission (TETCO) interstate pipeline delivers feedgas to the Calcasieu Pass LNG terminal, which is currently preparing to start commissioning activities. The project is expected to be completed by the end of this year.

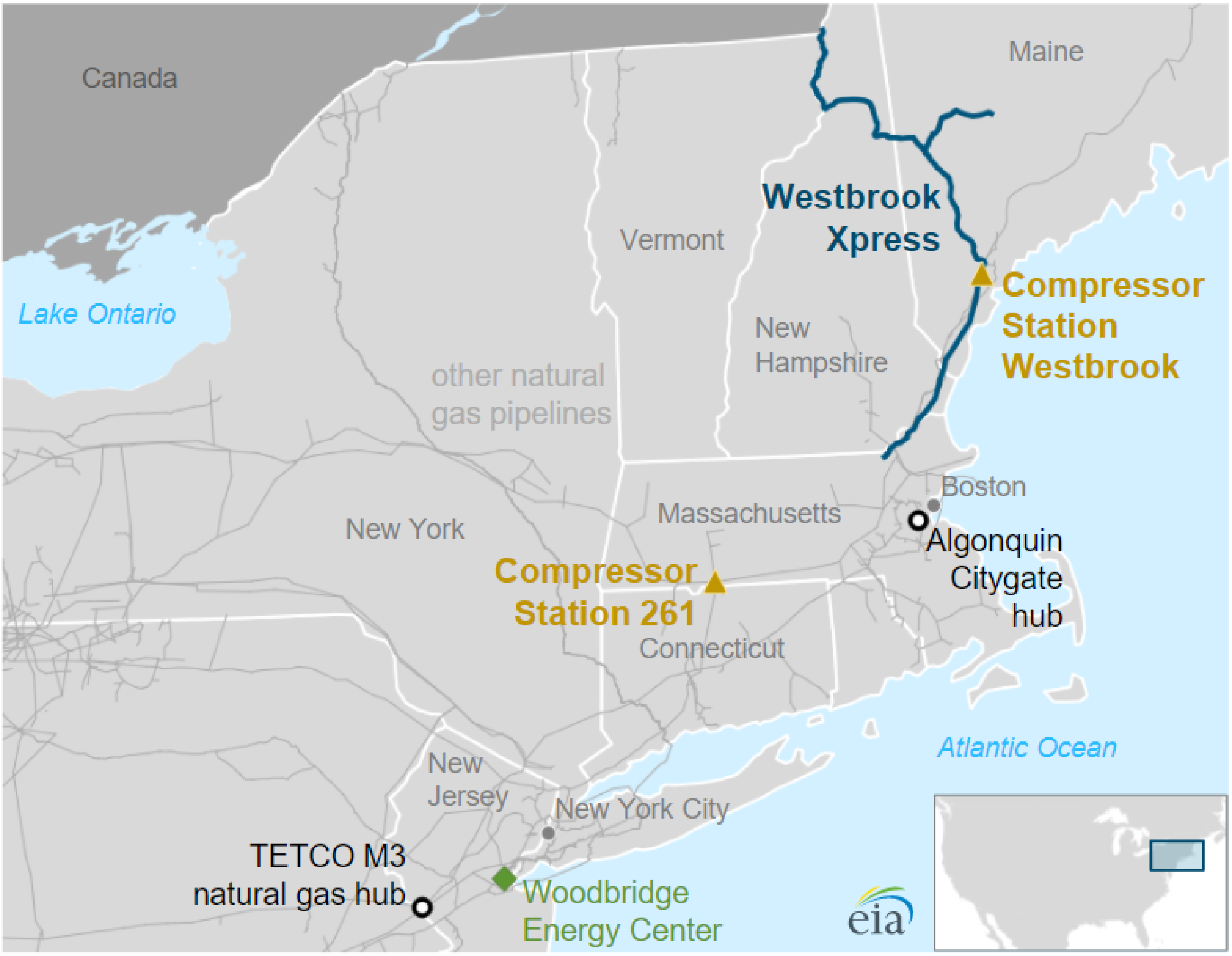
Several other projects have also entered service, increasing supplies to constrained demand markets in the Northeast. In New England, two projects will improve the region's access to winter supplies of natural gas by over 100 MMcf/d:

- The 261 Upgrade Projects completed its second and final phase, entering service on October 6, 2021. With the new, upgraded compressor at Station 261, an estimated 20 MMcf/d of additional natural gas supply can be delivered by the Tennessee Gas Pipeline (TGP) into New England.
- Portland Natural Gas Transmission System's (PNGTS) Westbrook Xpress Project, Phases 2 and 3, entered service on October 21, 2021, increasing natural gas pipeline import capacity from Canada at Pittsburg, New Hampshire, by 81

MMcf/d. The new Westbrook compressor station in Westbrook, Maine, will increase capacity on the co-operated Maritimes Northeast pipeline by 50 MMcf/d.

In addition, the Middlesex Expansion Project entered service in New Jersey on September 28, 2021. This 264 MMcf/d TETCO expansion delivers natural gas—via interconnections with other interstate pipelines—to the 724 megawatt (MW) Woodbridge Energy Center combined-cycle power plant in Woodbridge Township, New Jersey.

Northeast natural gas pipelines and related infrastructure (October 2021)



Source: U.S. Energy Information Administration, Natural Gas Pipeline Projects Tracker

The pipeline project tracker update also includes the cancellation of the 1.3 Bcf/d PennEast Pipeline, which was announced in late September. This 1.3 billion dollar project was designed to bring natural gas supplies from the Appalachia Basin into constrained demand markets in New Jersey and southeastern Pennsylvania.

In total, the Natural Gas Pipeline Projects Tracker includes updates to 25 interstate and intrastate natural gas pipeline projects, including announcements of new projects and estimated dates of completion. We update this resource quarterly; the next update is scheduled for late January 2022.

Principal contributor: Katie Dyl

Tags: natural gas, Gulf Coast, pipelines, exports/imports, Northeast, capacity, map

Morocco to Build New Infrastructure for Nigeria's Gas Delivery
2021-11-16 11:06:20.623 GMT

Morocco to Build New Infrastructure for Nigeria's Gas Delivery Project

By Chika Izuora

Nov. 16, 2021 (All Africa Global Media) --

The government of Morocco is considering setting up a downstream division of state-owned ONHYM to manage domestic natural gas infrastructure, including a project to deliver gas by pipeline from Nigeria to Morocco through 13 countries.

A source at ONHYM who confirmed the development to S&P Global Platts, said,

"It's on the way. It's a new entity created to take care of the downstream business."

ONHYM is in charge of the pipeline known as MNGP to take gas from Nigeria, which holds Africa's largest gas reserves, to Morocco and then to the European market.

Morocco is also building networks to distribute gas to industry hubs where automobile and aeronautics industries are expanding, the source, who asked not to be identified, said.

"The industrial sector in Morocco is growing fast and gas will be an important part of this growth," the source said, and declined to comment on what Morocco plans to do to replace lost gas from Algeria.

Spain's largest gas group Naturgy said November 10 that it remained in talks with parties in Morocco and Algeria to potentially achieve an extension of the gas transit agreement for supplies of Algerian gas in the GME pipeline via Morocco to Spain.

Gas deliveries through the GME pipeline fell to zero November 1 after the long-term transit deal between Algeria and Morocco was not renewed ahead of its expiry October 31.

Morocco has estimated its resources at some 300 Tcf of conventional and unconventional gas in place and is seeking investors to explore and develop these resources. Rabat has received "a lot of interest" for its proposed floating storage regasification unit off the Atlantic coast, the ONHYM source said.

A project to deliver electricity generated from solar and wind to the UK is also under evaluation, the person said.

Morocco needs a big discovery offshore to attract more companies to explore the country, the source said.

COMTEX_397035161/2029/2021-11-16T06:06:18

-0- Nov/16/2021 11:06 GMT

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R2NW6K3V7U9S

[Note there is the 12:49 min Al Arabiya interview at ADIPEC in the report that has all these quotes and more]

https://english.alarabiya.net/business/energy/2021/11/21/India-s-energy-transition-minister-talks-net-zero-goals-green-energy-investments

India's 'energy transition' minister talks net zero goals, green energy investments

Tala Issa & Naser El Tibi, Al Arabiya English

Published: 21 November ,2021: 09:52 AM GSTUpdated: 21 November ,2021: 01:24 PM GST

Earlier this month, India's Prime Minister Narendra Modi announced plans at COP26 to reach net-zero carbon emissions in 2070 and boost the share of renewables in India's energy mix from about 38 percent last year to 50 percent by 2030.

"When India turns around and says it is not just net zero by 2070, but in 2030, 50 percent will come from renewables or that we move up from 450 GW to 500 GW and you know the implications of that. India means what it says. We are the largest democracy in the world, when the prime minister makes a statement, it sets the template. Now clearly, we have a transition to achieve. Now that transition means you have to manage from where you are today first to 2030 then to 2040 then to 2070," India's Minister of Petroleum and Natural Gas Hardeep Singh Puri told Al Arabiya.

"I may be called a minister of petroleum and natural gas but I am actually the minister for energy transition," Puri said in an interview with Al Arabiya Senior Presenter Naser El Tibi.

For now, coal remains a dominant energy source in India, accounting for 70 percent of its electricity output.

After China, India is the world's second-largest coal producer at about 730 million tons annually – yet also imports coal to meet the power needs of its domestic industries, according to the government.

Puri said India is already doing a lot.

"When Mr. Modi became a prime minister, one percent of biofuel blending used to take a place, ethanol from sugar. Today, we are already at 8.5 percent, we had a 20 percent blending target by 2030 but we brought that forward to 2025," the minister said, adding that the country is expecting 60 billion dollars of investment into gas pipelines.

"We started in 2014 when he [Narendra Modi] became prime minister at 14 thousand kilometers. Today, we are 18.5 thousand kilometers, [and in the] next four months we will get another four thousand to [achieve] 22.5 thousand kilometers and we will take that up to 34 thousand kilometers to have the whole country be covered by gas pipelines. I could go on!"

"In renewables, we were one of the founders of the Solar Alliance," he noted.

India has a "massive program" on green hydrogen, according to Puri.

"We are going to be very big [in green hydrogen], we will be pioneers in that. But we need to bring the price down. [We] need to provide power at a particular price then be able to have electrolizers… we are on that journey," the minister told Al Arabiya.

"I think Glasgow is what? 10 days old, we are already on drawing board with people to see how we can accelerate some of these things. There is a massive program going on, our traditional oil marketing companies are into electric vehicles. I think we announced that in the next few years we will have 22 thousand petrol stations [which] will have electric charging as well, which in turn gives a fillip to our electric car manufacturers."

“Equally when you move to 20 percent biofuel mixing, E 20 [20 percent blended petrol ethanol] is going to be available in the pumps from a very short period time. I think in 2022, 2023 we will [offer] 20 percent blended fuel there.”

In reference to Modi’s announcement to achieve net zero emissions by 2070, he noted that while it was an ambitious goal, India has a track record of hitting their green targets.

Strategic reserves
When asked about a deal that India struck with Abu Dhabi’s ADNOC for strategic oil reserves, Puri said that the country has been replenishing its reserves to cater to any kind of emergency such as earthquakes or geopolitical events.

“We have been replenishing out strategic reserves and I think the agreement you are referring to… we are in the process of augmenting our reserves to take it to the global prescribed levels by the international energy agency,” India’s minister said.

“I think we are at 86 days of consumption and the consumption is going up also. We need to go a little farther to make it at 100 days. We are in the process of doing that.”
“I am a student of the energy situation and evolving energy situation I have been oil and natural gas minister- or now I call myself minister of energy transition- for 3 months or so, no country is ever only a consuming country, especially when you are dealing with a big economy,” Puri told Al Arabiya.

“We import crude, our companies refine and export out, we make investments in other countries, in the previous government in the year 2001 we invested in a facility in Sakhalin in Russia’s far east, it has done very well. Investments in Sudan they did well.”

India and the GCC
India and the Gulf Corporation Council (GCC) states have been working together, investing in each other’s countries across a variety of sectors.

“Indian entities are making investments in the gulf as you mentioned, our friends in the gulf cooperation council are making investments in India both upstream and downstream. This is what I call a healthy economic energy cooperation matrix,” said Puri.

“I have many people I talk to including His Excellency the UAE [energy] minister and the [energy] minister from Saudi Arabia, they also want to cooperate with us, not only in traditional energy, but also in green energy. This is an evolving situation and I think it is in one sense a reflection of the maturity of the relationship. That the transactions and investments are going in both directions,” he added.

Last week at Dubai’s megaevent Expo 2020, India invited the GCC member countries to invest in the sustainable energy sectors in the country.

India expects to attract foreign investments of up to $120-160 billion annually, according to a statement released at the India-GCC Business Conference at Expo 2020 last week, which added that Gulf countries are best placed to capitalize on such opportunities given their ties with India.

India's LNG Imports to Jump Near 5 Times by 2030: Petronet
2021-10-22 09:02:33.799 GMT

By Debjit Chakraborty and Rajesh Kumar Singh
(Bloomberg) -- India's import of natural gas is expected to hit 120 million tons/year by 2030 as the nation targets an energy mix goal, Akshay Kumar Singh, CEO of Petronet LNG, said at the India Energy Forum by CERAWeek.
* NOTE: India aims to boost use to natural gas to 15% of primary energy mix from about 6% now
* India's current annual LNG import is about 26 million tons
* The nation's gas production by 2030 is expected to reach 40 million-50 million tons
* Current LNG import capacity is 42 million tons/year, while about 19 million tons/year capacity is under construction
* Another 9 million-10 million tons of capacity addition are at design stage
* Petronet is expanding its biggest terminal at Dahej to 22.5 million tons a year from 17.5 million currently
* India's biggest LNG importer is also looking at building a new terminal on the east coast
* The current volatility in global gas prices is causing demand destruction
* Price volatility pushing consumers to long term LNG contracts
* Consumers are looking at a mix of oil, gas indexation for long LNG deals, which can work good for buyers

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https://www.jera.co.jp/english/information/20211115_790

JERA to Invest in Freeport LNG Development to Secure a Stable LNG Supply

2021/11/15

JERA Co., Inc. (“JERA”) has decided to invest, through its subsidiary JERA Americas Inc., in Freeport LNG Development, L.P. (“FLNG”), which operates the Freeport LNG project in the United States, and has concluded a securities purchase agreement with infrastructure fund Global Infrastructure Partners to acquire the approximately 25.7% interest in FLNG held by its subsidiaries (the “Transaction”). The approximately 2.5 billion USD acquisition is expected to be completed after the necessary approval and authorization procedures. For this Transaction, JERA Americas Inc. appointed Goldman Sachs & Co. LLC as its exclusive financial advisor and Sidley Austin as its legal advisor.

JERA, together with FLNG, has contributed to the stable operation of Train 1 of the Freeport LNG project through its participation in FLIQ 1 Holdings, LLC. As a result of the Transaction, JERA will not only be involved in the entire existing Freeport LNG project (three trains with an annual production capacity of approximately 15.45 mtpa) but will also work with FLNG to advance new LNG projects including production capacity expansion and the development of Train 4.

In Asia, there is demand for both decarbonization and a stable energy supply to support economic growth. Gas-fired power generation—which emits less CO_2 than power generation using other fossil fuels—can be a flexible supplement to intermittent renewable energy, and demand for it as an energy source indispensable to promoting the energy transition is expected to continue to grow. As evidenced by the current gas price hikes around the world, securing a stable supply of competitive LNG is becoming increasingly important.

FLNG’s new LNG projects have extremely low development risk due to the use of the existing Freeport LNG project, which enables the company to flexibly expand production capacity in response to increased global LNG demand. In addition, since there are no resale or destination restrictions on LNG exported from the project, JERA believes it will be possible to supply LNG to Japan when supply is tight and to otherwise respond flexibly to the LNG supply and demand situation in the Asian region.

By leveraging the knowledge and expertise it has accumulated through its global LNG value chain business and power plant operations, JERA will work together with FLNG on its various businesses—such as operation of the existing Freeport LNG project, development of new LNG projects, and flexible LNG transactions—as it strives to improve the competitiveness of the Freeport LNG project.

Under its “JERA Zero CO_2 Emissions 2050” objective, JERA has been working to reduce CO_2 emissions from its domestic and overseas businesses to zero by 2050, promoting the adoption of greener fuels, and pursuing thermal power that does not emit CO_2 during power generation. JERA also plans to establish decarbonization roadmaps optimized for each country and region and to promote zero-emission initiatives that follow these roadmaps.

Leveraging its long experience in the LNG value chain businesses, JERA will follow the decarbonization roadmaps that are to be drawn up for each country and region as it strives to expand the adoption of LNG—an indispensable transitional fuel for achieving decarbonization—and to contribute to global decarbonization and energy solutions.

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

Posted 11am on July 14, 2021

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

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

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

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

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

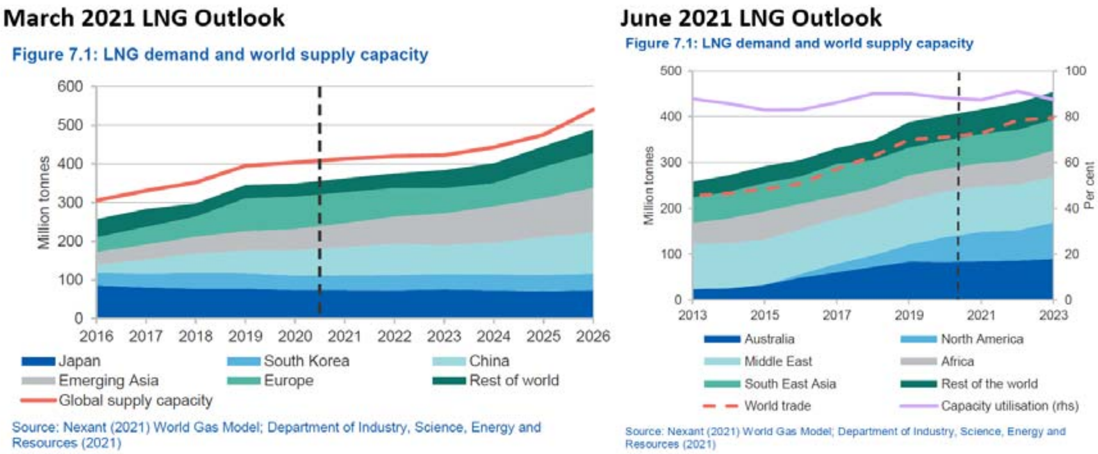
<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total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

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

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

But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner. We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas".* Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

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

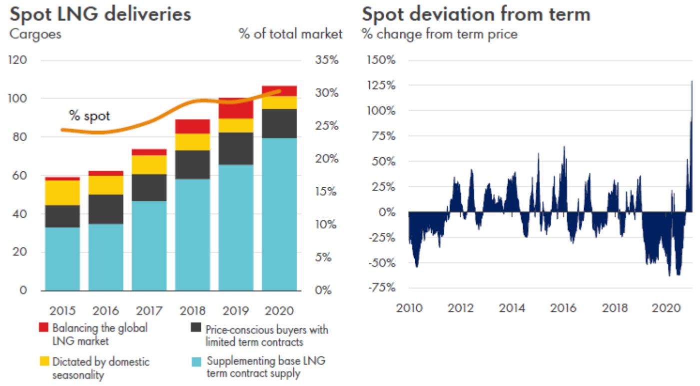


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/DE/2021/20211116_NOS2.html?nn=265778

Nord Stream 2 certification process temporarily suspended

Year of issue2021
Publication date11/16/2021

The Federal Network Agency has temporarily suspended the process for the certification of Nord Stream 2 AG as an independent transport network operator.

After a detailed examination of the documents, the Federal Network Agency came to the conclusion that certification of an operator of the Nord Stream 2 line is only possible if the operator is organized in a legal form under German law.

Nord Stream 2 AG , based in Zug, Switzerland, has decided not to convert the existing company, but to set up a subsidiary under German law only for the German part of the line. This subsidiary is to become the owner and operate the German section of the pipeline. The subsidiary itself must then meet the requirements of the Energy Industry Act for an independent transport network operator (Sections 4a, 4b, 10 to 10e EnWG).

The certification process remains suspended until the transfer of the essential assets and human resources to the subsidiary has been completed and the Federal Network Agency will be able to check the newly submitted documents of the subsidiary as the new applicant for completeness. If these requirements are met, the Federal Network Agency can continue its examination within the remainder of the four-month period provided by law, draw up a draft decision and, as provided by internal market law, submit it to the European Commission for comment.

The Federal Ministry for Economic Affairs and Energy and the European Commission were informed accordingly in advance. The decision was made known to those involved in the proceedings and then published.

Director's Cut
September 2021 Production

Oil Production

August	34,328,132 barrels = 1,107,359 barrels/day (final)	
September	33,402,299 barrels = 1,113,410 barrels/day (all-time high 1,519,037 BOPD Nov 2019)	
	+0.5% RF+1.2% NM 1,120,000	
	1,070,883 barrels/day or 96% from Bakken and Three Forks	
	42,527 barrels/day or 4% from legacy pools	

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

Crude Price[1] ($/barrel)

	North Dakota Light Sweet	**WTI**	**ND Market estimate**
August	60.94	67.71	62.50
September	73.75	80.52	65.92 RF +32%
Today	74.75	80.88	77.82 estimate
All-time high (6/2008)	$125.62	$134.02	$126.75

Revised Revenue Forecast **= $50.00**

Gas Production & Capture

August Production	91,804,467 MCF = 2,961,434 MCF/day
Gas Captured: 92%	84,251,821 MCF = 2,717,801 MCF/day
September Production	90,467,024 MCF = 3,015,567 MCF/day (all-time high 3,145,172 MCFD Nov 2019) +1.8%
Gas Captured: 94%	84,931,701 MCF = 2,831,057 MCF/day (all-time high 2,899,998 MCFD Mar 2020

Rig Count

August	28
September	27
October	29
Today	*34 NM81*
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

	August	September	October	Revised Revenue Forecast
Permitted	79 drilling 0 seismic	69 drilling 2 seismic	37 drilling 0 seismic (All-time high was 370 – Oct. 2012)	-
Completed	47 (Final)	34 (Revised)	41 (Preliminary)	**30→<u>40</u>→50→60**
Inactive[2]	1,672	1,696	-	-
Waiting on Completion[3]	521	503	-	-
Producing	16,956	17,041 (Preliminary) NEW All-time high *14,758 (87%) from unconventional Bakken – Three Forks* *2,283 (13%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	254,896	101,879	153,018
Drilling Rigs	1	0	1
Active Wells	2,607	654	1,953
Waiting on completion	TBD		
Approved Drilling Permits	TBD	TBD	TBD
Potential Future Wells	3,954	1,118	2,836

Drilling and Completions Activity & Crude Oil Markets

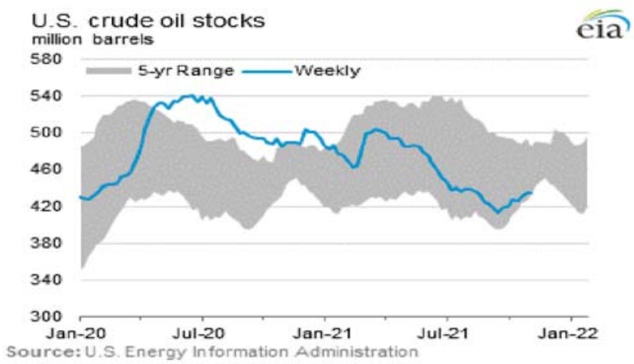
The drilling rig count was stable in the mid 50's second half of 2019 through May 2020. Drilling rig count fell 38% from January 2020 to September 2021 and is slowly increasing.

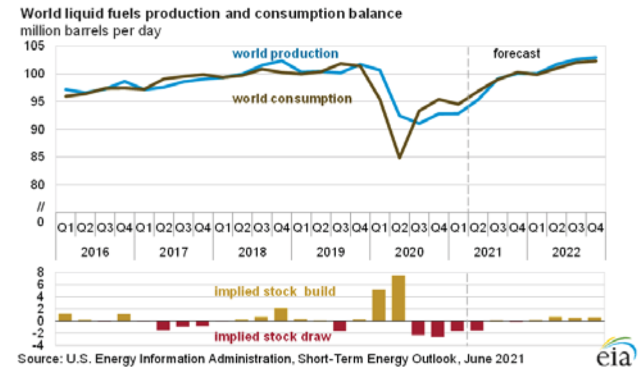
The number of well completions has been low and volatile since April 2020 as the number of active completion crews dropped from 25 to 1 then increased to 6 in August 2021 and to 10 this week.

OPEC+ continues to phase out 5.8 million barrels per day of oil production cuts by September 2022. Coordinated increases in oil supply from the group known as OPEC+ began in August 2021. At their November 2021 meeting OPEC+ decided to stick with their plan to increase production 400,000 barrels per day monthly going forward.

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

[2] Includes all well types on IA and AB statuses: **IA** = Inactive shut in >3 months and <12 months;
AB = Abandoned (Shut in >12 months)
[3] The number of wells waiting on completions is an estimate on the part of the director based on idle well count and a typical five-year average. Neither the State of North Dakota, nor any agency officer, or employee of the State of North Dakota warrants the accuracy or reliability of this product and shall not be held responsible for any losses caused by this product. Portions of the information may be incorrect or out of date. Any person or entity that relies on any information obtained from this product does so at his or her own risk.





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

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

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

Gas Capture

US natural gas storage is now 3% below the five-year average. Crude oil inventories are well below normal in the US, but world storage remains above the five-year average.

The price of natural gas delivered to Northern Border at Watford City increased to $23.42/MCF February 17, 2021 but has returned to a significantly higher than normal level of $4.64/MCF today. This results in a current oil to gas price ratio of 17 to 1. The state wide gas flared volume from August to September decreased 59,124 MCFD to 184,510 MCF per day, and the percent flared decreased to 6.1% while Bakken capture percentage increased to 94%.

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

Gas capture details are as follows:

Statewide	94%
Statewide Bakken	94%
Non-FBIR Bakken	95%
FBIR Bakken	92%
Trust FBIR Bakken	94%
Fee FBIR	78%

Big Bend Field 64.5%

The Commission established the following gas capture goals:

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

Seismic

Seismic activity for oil and gas has stopped.

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

Agency Updates

Sections with updates highlighted in grey.

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

BLM on 1/20/21 DOI issued order 3395 implementing a 60-day suspension of Federal Register publications; issuing, revising, or amending Resource Management Plans; granting rights of way and easements; approving or amending plans of operation; appointing, hiring or promoting personnel; leasing; and permits to drill. On 1/27/21 President Biden issued an executive order that mandates a “pause” on new oil and gas leasing on federal lands, onshore and offshore, “to the extent consistent with applicable law,” while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, which means the president’s moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.

- **What is the percentage of federal lands in ND?**
  - Mineral ownership in ND is 85% private, 9% federal (4% Indian lands and 5% federal public lands), and 6% state. 66% of ND spacing units contain no federal public or Indian minerals, 24% contain federal public minerals, 9% contain Indian minerals,1% contain both.
- **How many potential wells could be delayed or not drilled by a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?**
  - A spatial query found 3,443 undrilled wells in spacing units that would penetrate federal minerals, 2,902 undrilled wells in spacing units would penetrate BIA Trust minerals (700 tribal minerals and 2,202 allotted minerals), and the total number of wells potentially impacted is 6,345. The minimum number of future Bakken wells is 24,000 so the 3,443 wells on federal public lands = 14%, and the 2,902 wells on trust lands = 12%.
- **What is the potential federal royalty loss from a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?**
  - A recent study from University of Wyoming estimated the ND loss as follows: 2021-2025 $76 million, 2026-2030 $113 million, 2031-2035 $160 million, and 2036-2040 $221 million for a total of $570 million over 15 years. Please note that 50% of the royalties on federal public lands go to the state and 50% of the state share goes to the county where the oil was produced.

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

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

- Compel the Federal Defendants to hold quarterly lease sales.
- Prohibit the Federal Defendants from cancelling quarterly lease sales.
- Enjoin the Secretary implementing a moratorium on federal lease sales.
- Declare that Federal Defendants are in violation of MLA, FLPMA, NEPA, and APA.
- Grant other relief sought and as the court deems proper to remedy the violations.

There are 811 tracts nominated for pending lease sales in ND:

- 566 are pending NEPA or surface manager concurrence
- 236 are fully evaluated, and waiting for scheduled auction – value to ND 1,011 wells and $4.8 billion (GPT, OET, NDTL royalties, federal royalties, sales tax and income tax)
- 9 are planned for auction Q1 and Q2 2021 6 for March and 3 for June – value to ND 20 wells and $82.3 million (GPT, OET, NDTL royalties, federal royalties, sales tax and income tax)
- It is too late to notice and hold Q3 sale – 2 more tracts impacted - value to ND 23 wells and $157.6 million (GPT, OET, NDTL royalties, federal royalties, sales tax and income tax)

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 proposed rules suspending, revising, or rescinding those rules". This rule is included in the list as item (iv). North Dakota plans to continue active participation in the litigation of this rule until the BLM takes final action eliminating the rule. **On 5/10/17 the Senate voted 51 to 49 against the CRA, allowing the rule to remain in effect.** On 6/27/17 U.S. D. Ct. Judge Skavdahl granted BLM's motion to extend the merits briefing schedule by 90 days, based on BLM's APA 705 stay and BLM's representations regarding its plans to reconsider the VF Rule. Opening briefs were filed 7/3/17. On 7/5/17 California and New Mexico sued BLM in the U.S. District Court for the Northern District of California, seeking a declaratory judgement that BLM's APA 705 stay was illegal and vacating the stay. The relief they request would vacate the stay of the January 2018 compliance et al deadlines, bringing them all back into force. BLM officials encouraged North Dakota to intervene. On 7/12/17 a group of NGOs including the Fort Berthold Protectors of Water and Earth Rights filed a separate suit against the BLM in federal court in the U.S. District Court for the Northern District of California, seeking a declaratory judgement that BLM's APA 705 stay was illegal and vacating the stay. California and New Mexico, along with various environmental groups, have challenged BLM's stay in the Northern District of California, and filed a motion for summary judgment on 7/26/17. On 8/24/17 North Dakota filed a response supporting BLM's motion, a motion to intervene, and a motion to change venue to Wyoming in an attempt to prevent all of the litigation regarding the timing of the Flaring Rule, including the future rulemakings further extending compliance deadlines that BLM has stated that it intends to publish, could end up in front of the magistrate judge in the Northern District of California instead of Judge Skavdahl in Wyoming. On 10/04/17 the federal magistrate judge in the Northern District of California granted the summary judgement motion by California, New Mexico, and several NGOs throwing out BLM's administrative and temporary postponement of several of the future rules compliance dates/obligations. On 10/05/17 the BLM issued a Federal Register Notice for a proposed rule that if finalized will delay certain requirements of the BLM Rule until 1/17/2019. North Dakota submitted comments to (1) support BLM's decision to delay certain compliance requirements and (2) continue to make the record that BLM exceeded its authority to promulgate the rule in the first place with particular emphasis on the specific/unique North Dakota considerations at issue. NDIC comments are available at http://www.nd.gov/ndic/ic-press/dmr-blm-comments17-11.pdf. BLM, the states of CA & NM, and the NGOs supporting the current final rule were granted an extension to file response briefs to December 11th in the WY court. On 11/29/17 North Dakota filed a response to industry petitioner's motion for a preliminary injunction supporting a preliminary or permanent injunction. On 12/4/17 USDOJ petitioned the 9th US Judicial Circuit Court in San Francisco to review and overturn the Northern District of California court's November decision ordering the US Bureau of Land Management to make oil and gas producers comply with the

MONTHLY UPDATE

NOVEMBER 2021 PRODUCTION & TRANSPORTATION

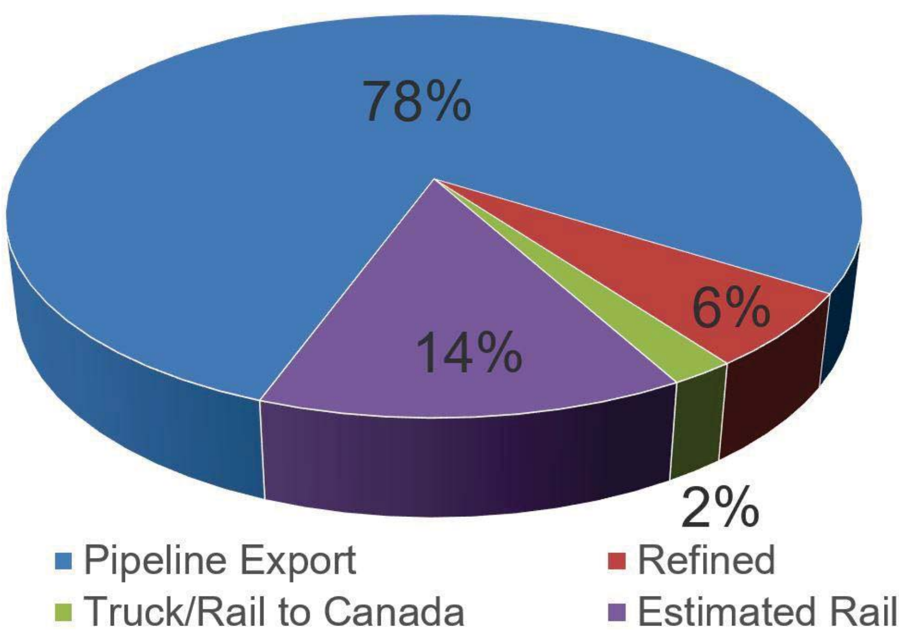
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
Aug. 2021 - Final	34,328,132	1,107,359
Sep. 2021 - Prelim.	33,402,299	1,113,410

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
Aug. 2021 - Final	91,804,467	2,961,434
Sep. 2021 - Prelim.	90,467,024	3,015,567

Estimated Williston Basin Oil Transportation, Sep. 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

34 Rigs

EASTERN MONTANA[2]

1 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (NOV. 16, 2021):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $80.91

Crude (Brent): $82.57

NYMEX Gas: $5.25

SOURCE: BLOOMBERG (NOV 16, 2021)

GAS STATS*

94% CAPTURED & SOLD

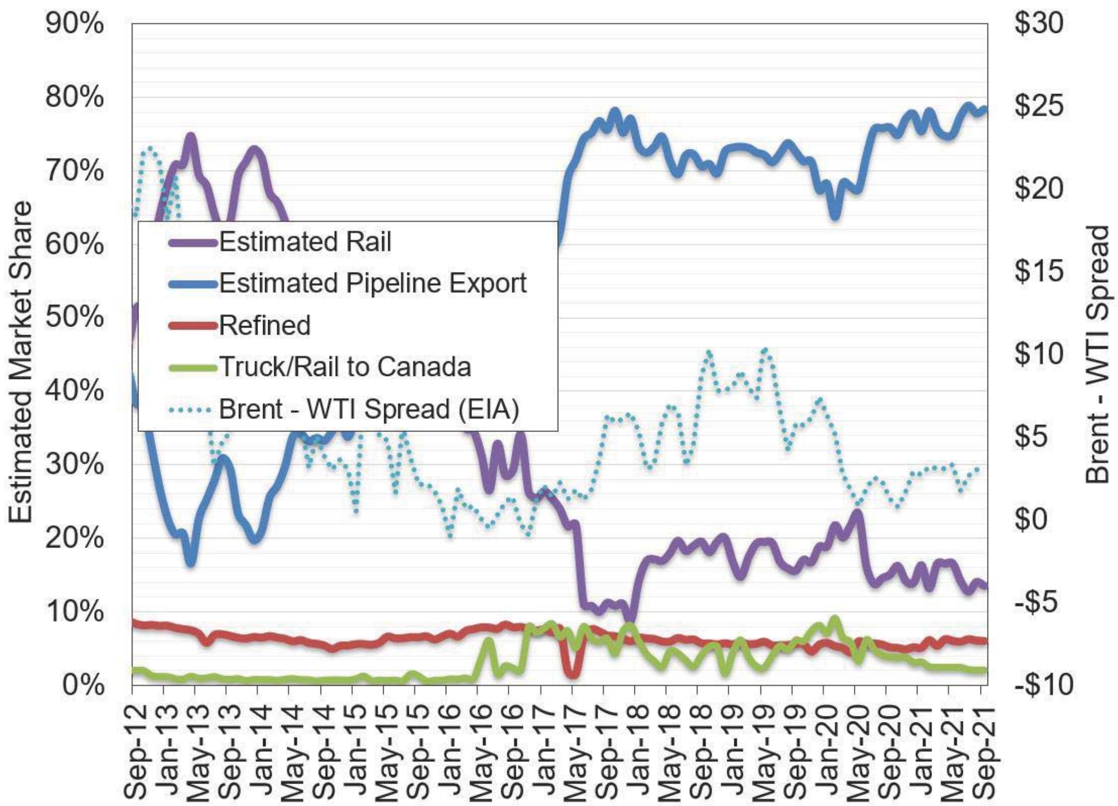
4% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

2% FLARED FROM WELL WITH ZERO SALES

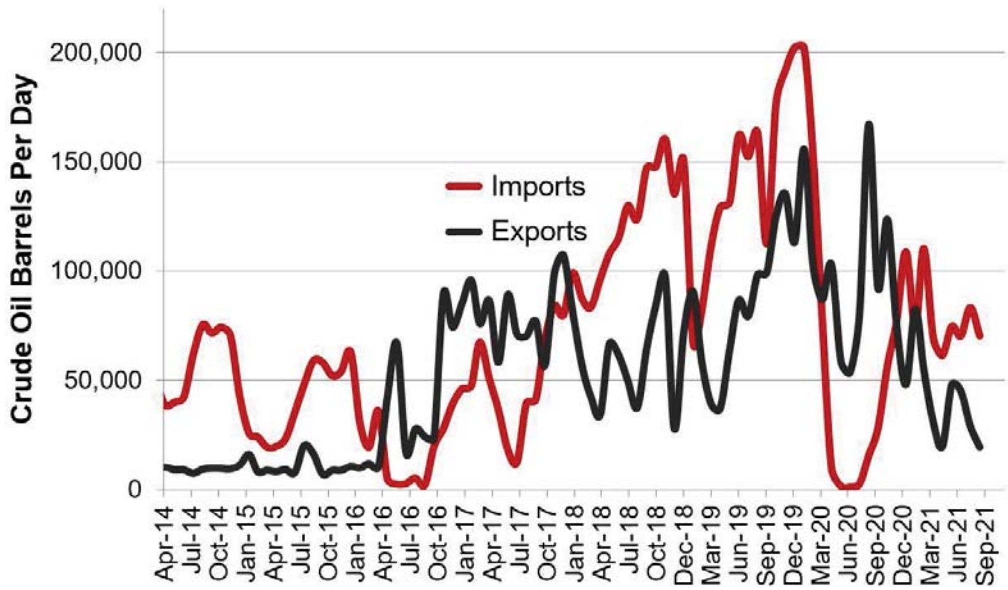
SEP. 2021 NON-CONF DATA

Estimated North Dakota Rail Export Volumes

Estimated Williston Basin Oil Transportation

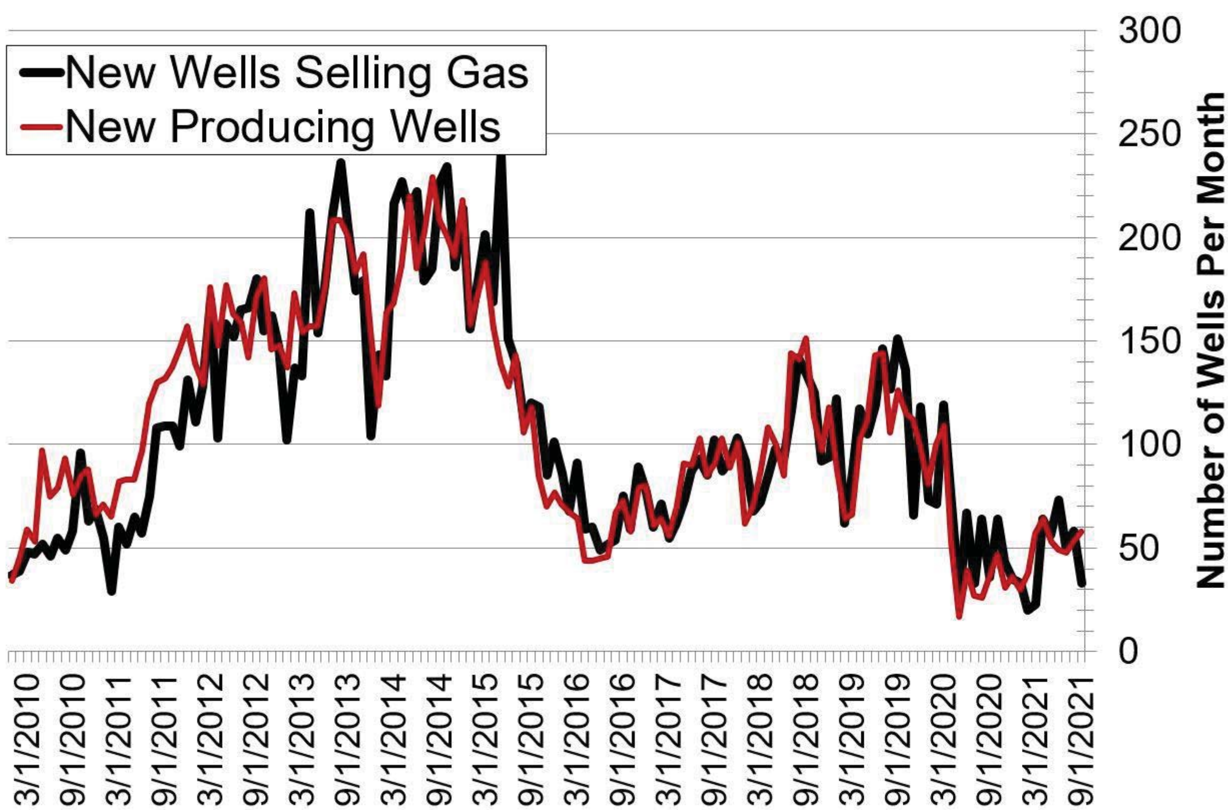


Williston Basin Truck/Rail Imports and Exports with Canada



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

New Gas Sales Wells per Month



US Williston Basin Oil Production, BOPD

2020

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

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,711	50,140	2,874	1,200,724
February	1,083,778	47,971	2,828	1,134,578
March	1,108,979	49,256	2,744	1,160,979
April	1,120,283	48,203	2,644	1,171,130
May	1,128,338	46,662	2,640	1,177,640
June	1,133,494	43,481	3,103	1,180,079
July	1,077,777	43,071	2,884	1,123,732
August	1,107,359	46,518	2,892	1,156,769
September	1,113,410			
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.spglobal.com/platts/en/market-insights/latest-news/oil/111621-colonial-pipeline-allocates-line-2-for-first-time-since-may-2020

- **OIL | SHIPPING**

- 16 Nov 2021 | 15:51 UTC

Colonial Pipeline allocates Line 2 for first time since May 2020

HIGHLIGHTS

Colonial Pipeline freezes, allocates distillates Line 2 for first time since May 2020

Follows similar allocations for gasoline-only Line 1 a month ago

- Author Matthew Kohlman

Colonial Pipeline has restricted shipments on its 1.16 million b/d, distillates-only Line 2 for the first time since May 2020, the company said Nov. 16.

In a notice to shippers, Colonial said for input north of Collins, Mississippi, will be frozen on shipping cycles 63 through 65 and allocated for its 66th shipping cycle for the line, which carries jet fuel, ULSD and heating oil. It follows similar restrictions a month ago for the 1.37 million b/d, gasoline-only Line 1, which was the first allocation since August 2020. The last time Line 2 was allocated was May 18, 2020, for its 31st shipping cycle.

Line 2 carries distillate products from the US Gulf Coast to Greensboro, North Carolina, before merging with Line 1 to become Line 3, which carries refined products to Linden, New Jersey.

Cycles are allocated by Colonial when nominations outweigh available space on the line. A freeze means no more shipments can be taken in, while an allocation means shipments may be pro-rated.

S&P Global Platts assessed Line 2 space at minus 10 points/gal on Nov. 15, which indicated a barely closed arbitrage. Line space value is an indirect measurement of market participant interest in scheduling barrels for a specific shipping cycle. A negative value suggests that shippers, which have take-or-pay contracts, offer their space on the line to fulfill their shipping commitments. On the contrary, a positive value shows interest to get space to ship gasoline.

Diesel flows from the US Gulf Coast to the Atlantic Coast via Colonial Pipeline have remained strong during the coronavirus pandemic, but jet fuel was historically up to a third of the movement and demand has lagged strongly until recently.

https://www.transmountain.com/news/2021/ensuring-safety-during-bc-and-wa-storm-impacts

Trans Mountain Progresses Planning for Pipeline Restart

Nov 19, 2021

November 19, 2021, 3:30 pm PDT

The Trans Mountain Pipeline remains shut down following a voluntary precautionary shut down on Sunday, November 14, in anticipation of the impacts of the heavy rainfall and extreme weather conditions. The pipeline remains safely in a static condition and there is no indication of any loss of containment.

Trans Mountain has more than 200 people dedicated around the clock to getting the pipeline back up and running. Teams are beginning helicopter operations in the Coldwater region to remove fallen trees and debris that are hampering detailed inspection of the pipeline in that area. Another key priority remains getting ground access to the affected areas, and we are actively assisting the BC Ministry of Transportation and Infrastructure with getting roads cleared.

There are multiple areas of the pipeline between Hope and Merritt where pipeline cover needs to be restored and there are other sections that we may decide to cut-out and replace entirely, for example long sections that have been fully exposed to river course changes. As a precaution, Trans Mountain is deploying spill-response equipment trailers to areas where we will be working.

If all planning and work continues to progress and no further issues with the pipeline are assessed, Trans Mountain is optimistic that we can restart the pipeline, in some capacity, by the end of next week. Key to successful execution of the restart plan will be access for equipment, fair weather, and no new findings of concern.

The Trans Mountain Pipeline is a critical piece of infrastructure for British Columbia and Washington state and every effort is being made to safely restart the pipeline as promptly as possible. This is the longest period the pipeline has been shut down in its nearly 70-year history. Trans Mountain is in regular contact with its shippers and is working in cooperation with the Province to mitigate the effects of the pipeline shut down on the region.

Work on the Trans Mountain Expansion Project continues in many areas along the pipeline corridor – and crews in the Coquihalla and Merritt regions have been redeployed to assist with efforts to get the Trans Mountain Pipeline restarted.

We are in contact with Emergency Management British Columbia and continue to offer our support and assistance where possible.

https://www.spglobal.com/platts/en/market-insights/latest-news/oil/111721-rosneft-expands-german-refining-footprint-with-move-to-buy-shells-schwedt-stake

- 17 Nov 2021 | 18:59 UTC

Rosneft to become Germany's number two refiner after move on Shell stake

HIGHLIGHTS

Rosneft pre-empts Shell's sale of PCK Schwedt stake

Russian giant already Germany's third-biggest refiner

Shell still owns Germany's biggest refinery

- Author Robert Perkins

Russian state oil giant Rosneft has acquired Shell's minority stake in the 230,000 b/d PCK Schwedt refinery in northeastern Germany, boosting its downstream footprint in Europe's biggest economy where it will become the second-biggest refiner.

Rosneft said Nov. 17 it has exercised its preemption right for a 37.5% share of the Schwedt refinery being sold by Shell, in a move set to increase its shareholding in the plant from 54.17% to 91.67%.

The deal, which is subject to government and regulatory approvals, will see Rosneft's capacity grow by around 86,000 b/d to 344,000 b/d, making the Russian player the second-biggest refiner in the country behind Shell.

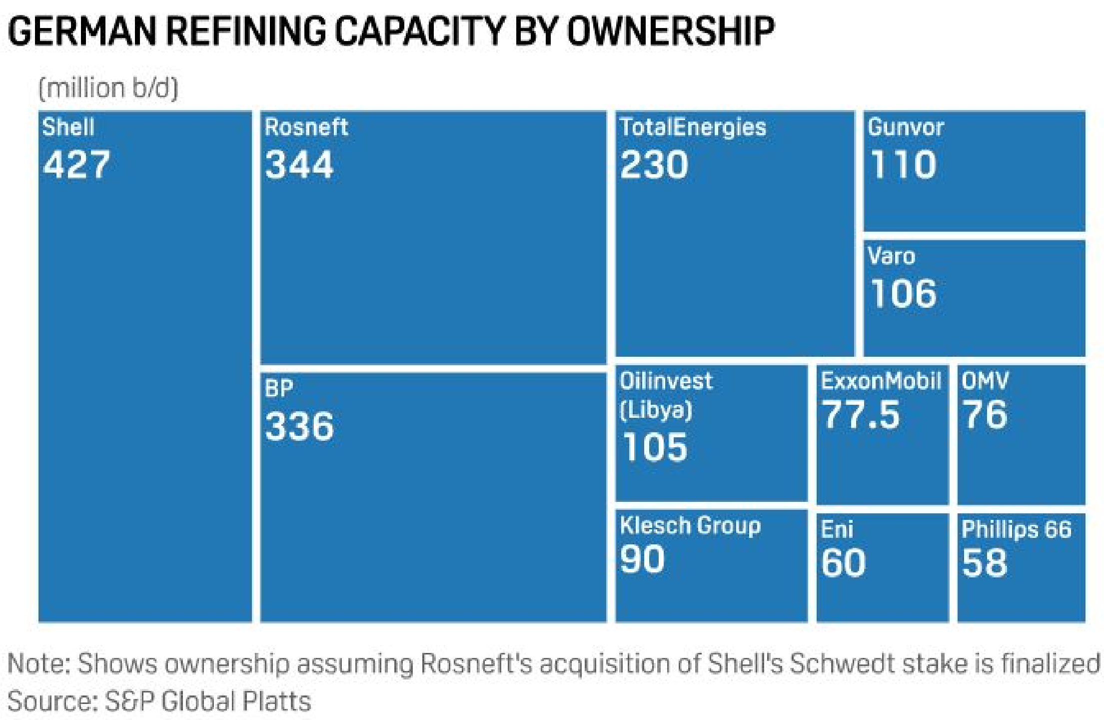
Located 120 km northeast of Berlin, the PCK Schwedt refinery is supplied with Russian Urals crude through the major Druzhba oil pipeline.

Rosneft, already the third-largest player in the German refining sector by capacity, has been growing its downstream footprint in Germany over the last decade. On average, Rosneft is responsible for around a quarter of crude oil imports into Germany.

"Increasing the share of PCK refinery is testament to the strategic importance of the German market for Rosneft," Rosneft CEO Igor Sechin said in a statement, "The company builds long-term relationships with its German partners, provides timely and uninterrupted crude supplies, and modernizes key refinery units."

Rosneft already owns a 24% stake in the 310,000 b/d Miro refinery and a 28.57% interest in the 206,000 b/d Bayernoil plants at Neustadt and Vohburg. The Schwedt deal would see its share of Germany's 2 million b/d refining capacity rise from 12% to 17%.

Europe's biggest fuel market, Germany's diesel and gasoline demand are expected to return to pre-pandemic levels of 1.1 million b/d and 500,000 b/d this year, respectively, according to estimates from S&P Global Platts Analytics.



Clean fuels push

Shell first announced a deal to sell its stake in Schwedt to a subsidiary of Estonia's privately owned Liwathon Group in July as part of a strategy to reduce its global refining footprint to a number of core, integrated sites. At the time, Shell said Liwathon's Austria-based Alcmene unit would provide energy and commodities trading in Germany from its headquarters in Vienna. Shell estimated that the value of its hydrocarbon inventory at the refinery would range between $150 million and $250 million.

No financial details of the deal were given and Italy's Eni, which holds the remaining 8.33% stake in the plant, also has pre-emption rights.

Shell continues to operate Germany's Rheinland refinery, the country's largest, which processes 327,000 of crude oil and consists of two sites; Wesseling and Godorf. But Shell plans to shut crude processing at the Wesseling site within the Rhineland refining complex in 2025, when Rosneft would become Germany's biggest refiner.

PCK is one of the most technologically complex refineries in Germany, with a Nelson index of 9.8.

Rosneft said it plans to "strengthen the technological leadership of the refinery, including through the implementation of low-carbon projects, considering the current environmental agenda of the EU.

The company is already developing projects aimed at the production of cleaner fuels, such as "green" hydrogen and sustainable aviation fuel. Work in this direction will continue."

Germany's refining assets

Operator	Refinery	Capacity b/d	Ownership
Shell	Rhineland	327,000	Shell 100%
Miro	Karlsruhe	310,000	Shell (32.25%), ExxonMobil (25%), Rosneft (24%), Phillips 66 (18.75%)
BP	Gelsenkirchen	240,000	BP 100%
TotalEnergies	Leuna	230,000	TotalEnergies 100%
PCK	Schwedt	230,000	Rosneft (91.67%), Eni 8.33%)
Bayernoil	Neustadt/Vohburg	206,000	Varo Energy (51.43%), Eni (20%), Rosneft (28.57%),
Gunvor	Ingolstadt	110,000	Gunvor 100%
Oilinvest	Holborn	105,000	Libya Investment Authority (100%)
BP	Lingen	96,000	BP 100%
Klesch Group	Heide	90,000	Klesch Group (100%)
OMV	Burghausen	76,000	OMV 100%
Total		2,020,000	

x

Google Translate of El Universal report https://www.eluniversal.com.mx/cartera/produccion-de-petroleo-crudo-de-pemex-y-socios-cae-durante-octubre-12?utm_source=web&utm_medium=social_buttons&utm_campaign=social_sharing&utm_content=twitter

Crude oil production of Pemex and partners falls 1.2% during October

The production results during the first 10 months of 2021 make it difficult for Pemex to reach the goal set by director Octavio Romero
Crude oil production of Pemex and partners falls 1.2% during October

The national production of crude oil in October reported a drop of 1.2%, equivalent to 20 thousand barrels a day less in
According to the National Hydrocarbons Commission (CNH), the platform reported by Petróleos Mexicanos (Pemex) and private operators reached one million 646 thousand barrels per day in the tenth month of the year.

A month earlier, the production volume reached one million 666 thousand barrels per day.

In the case of the allocations granted to the state oil company, the reduction was 19 thousand barrels in October compared to the previous month; migrations reduced by three thousand barrels; and the oil blocks granted to private parties in the last bidding rounds fell two thousand barrels a day.

In other words, the production of Pemex and its partners in October was one million 603 thousand barrels.

Regarding natural gas, the results were similar.

National production registered a decrease of 0.6%, equivalent to 31 million cubic feet less in the same period.

The results achieved in the first 10 months of the year complicate for the state oil company the production goal promised by the Pemex director for 2021, estimated at 1,765,000 barrels per day, with two months remaining to conclude the year.

https://www.japantimes.co.jp/news/2021/11/20/business/japan-oil-reserves-release/

Kishida says Japan considering releasing oil reserves to stabilize prices

- KYODO, JIJI Nov 20, 2021

Japan is considering releasing oil from its reserves along with the United States and other countries to help curb rising crude oil prices, Prime Minister Fumio Kishida said Saturday.

"We are considering what we can do," Kishida told reporters in Matsuyama, Ehime Prefecture, when asked about the possibility, as surging prices of gasoline and other fuel products are squeezing households and companies that have already been hit hard by the coronavirus pandemic.

There are, however, voices in the government cautioning against releasing oil reserves at times other than when there is a supply shortage, officials said.

Japan has never previously released crude oil stockpiles in response to rising prices. Past decisions to tap reserves were made to address supply concerns following natural disasters and overseas political turmoil.

Kishida's Cabinet approved an economic stimulus package Friday with a record ¥55.7 trillion ($490 billion) in fiscal spending, which includes a subsidy program for oil wholesalers and importers to contain gasoline and kerosene prices once they hit a certain threshold to alleviate the financial burden.
Responding to a question during a press briefing Friday about the possibility of a coordinated emergency stockpiles release with Japan and other countries, White House Press Secretary Jen Psaki said Washington has been in discussions with leaders from various countries to ensure there is adequate supply of crude oil, but didn't elaborate further.

Japan, which relies on oil-producing countries in the Middle East for around 90% of its consumption, started keeping crude oil reserves in the 1970s.

Japan has two different types of oil stocks — state-owned and those held by companies.

As a member of the International Energy Agency, Japan is obliged to maintain oil reserves equal to 90 days of net imports of the previous year, while the quantity of private emergency stocks should be more than 70 days of its oil consumption in the previous year.

As of the end of September, Japan had reserves for 242 days of domestic consumption, including joint stockpiles with oil-producing countries.

Under current regulations, state oil reserves are not intended for use to address price surges. As there are more than enough reserves, however, a plan under consideration calls for releasing a surplus after lowering the reserve target, sources said.

It would be Japan's first release of state oil reserves since the country complied with a request from the International Energy Agency in June 2011 due to the deteriorated situation in Libya.

Google Translate of https://www.yomiuri.co.jp/politics/20211121-OYT1T50010/

There is also a plan to sell a part of the surplus and release it to the city for the first release of oil stockpile.

2021/11/21 10:10

The government has decided to release the national stockpile of oil as a measure against high oil prices. It is expected that the sale of stockpiles will temporarily increase the supply and suppress the price increase of petroleum products such as gasoline. Although the amount and period of release is limited, the government has decided that it is necessary to take measures because the high gasoline price has a widespread impact on people's lives.

Prime Minister Kishida said on the 20th about the release of oil reserves, "We are currently considering what can be legally done while assuming cooperation with Japan, the United States and related countries." I answered the questions of the reporters in Matsuyama City, where I visited.

According to government officials, Japan and the United States will be in step with each other within the week to announce the release of oil reserves.

The US Biden administration is under the hood and is consulting with Japan and South Korea to release stockpiles.

Japan's oil stockpiling includes national petroleum stockpiling owned by the government and private petroleum stockpiling required by law for oil companies. As of the end of September, the national stockpile is for 145 days of domestic daily consumption, and the private stockpile is for 90 days.

The Oil Stockpiling Law stipulates that national stockpiling is for 90 days or more of imports and private stockpiling is for 70 days or more of consumption. Currently, the minimum target amount has been exceeded, and there is a plan to sell a part of the surplus stockpile and release it to the market.

The law does not anticipate price increases as a condition for release, but the government believes that surpluses can be dealt with without being bound by the law.

Private stockpiles have been released in the wake of the 1991 Gulf War and the worsening situation in Libya in 2011, but this is the first time that national stockpiles have been released.

China oil markets monthly snapshot

	Indicator	Value	Change		Last update	Comment
Demand	**Traffic**		**M-o-M**	**Y-o-Y**		• Jet fuel has taken another blow from fresh coronavirus outbreaks in November. The flight departures index fell to 39% on November 16, erasing the 25 percentage point gain in the short-lived recovery last month. • Diesel demand remains strong as road freight receives a boost from the seasonal shopping season, which starts in November. However, diesel usage in the power sector will likely decline as power supply from other sources like coal and gas returns on lower prices. • Gasoline demand faces headwinds in the upcoming months as new Covid-19 cases discourage mobility, and the cold weather dampens travel enthusiasm. For more details, see the ***demand*** section from page 3.
	Road freight volume	620 bln tons-km	+4%	+1%	Sep 2021	
	Air passenger traffic	54 bln ppl-km	+59%	-23%	Sep 2021	
	Port cargo throughput	1.3 bln tons	-5%	-2%	Sep 2021	
	High frequency index		**W-o-W**	**M-o-M**		
	Road congestion index	90%	+0 ppt	-14 ppt	Nov 10, 2021	
	Airport departures index	39%	-1 ppt	-25 ppt	Nov 16, 2021	
	Subway traffic index	96%	+2 ppt	-1 ppt	Nov 10, 2021	
Refining	**Refinery utilization**		**M-o-M**	**Y-o-Y**		• State refineries have ramped up operations since October, encouraged by the energy crunch which pushed diesel prices to multi-year highs. Sinopec and PetroChina, China's two biggest refiners, both pledged to boost diesel production through increased run rates and a shift of product yields. • BloombergNEF expects high run rates to continue in the following months despite a softer demand outlook. Independent refiners can benefit from the fourth batch of crude import quotas, and current gasoline and diesel inventory levels are below their five-year averages in Shandong, driving restocking demand. For more details, see the ***refining*** section from page 7.
	Country-wide throughput	13.80 m b/d	+1%	-2%	Oct 2021	
	State-owned refineries	77%	+3 ppt	+4 ppt	Nov 12, 2021	
	Independent refineries	71%	-1 ppt	-4 ppt	Nov 12, 2021	
	Stocks					
	Crude - Shandong ports	36.5m barrels	-15%	-17%	Nov 12, 2021	
	Gasoline – Shandong independents	4.8m barrels	-26%	-32%	Oct 2021	
Trade	**Crude imports**		**M-o-M**	**Y-o-Y**		• The crude import quota for 2022 (maximal allowed volume) is set at 243 million metric tons, or 1.78 billion barrels. This is the same level as in 2021, but this year saw just 73% of the quota granted to independent refiners and the remaining 27% scrapped. • The energy crunch is tightening the domestic diesel market, with refiners planning to halt diesel exports until the end of the year. BNEF expects fuel exports to extend declines seen in earlier months. For more details, see the ***trade*** section from page 11.
	National total	8.94m b/d	-11%	-11%	Oct 2021	
	Selected routes (BBG)	5.04m b/d	-1%	-7%	Oct 2021	
	Independent refinery	3.43m b/d	+5%	-15%	Oct 2021	
	Quota usage	64%			Jan-Oct 2021	
	Fuel exports	0.93m b/d	-8%	-32%	Oct 2021	

BloombergNEF

High frequency transport data

Fresh Covid cases drag down all travel indices

Our weekly **road traffic report** is available on the BNEF Web or the Bloomberg Terminal
Our weekly **global aviation report** is available on the BNEF Web or the Bloomberg Terminal

- BloombergNEF tracks road congestion data to gauge the impact of the Covid-19 outbreak on road fuel demand.
  - The ‘peak congestion index” is the five-day moving average of the arithmetic daily average of hourly weekday peak congestion data, compared to the 2019 average values for nine key cities in China.
- We track the recovery of jet fuel demand by assessing the changes in flight departures from the 20 biggest airports in China.
- We track the daily subway rides of three major cities to measure overall usage of public transportation.

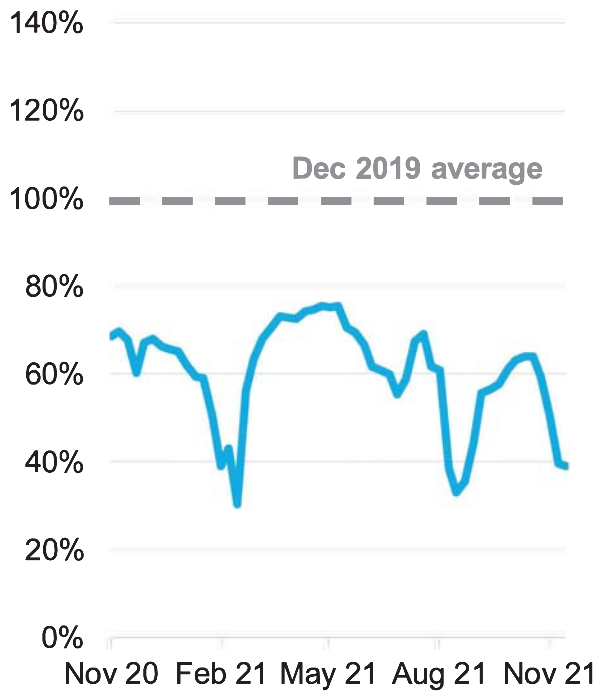
Road congestion

Peak congestion index

Source: TomTom, Baidu, BloombergNEF. Note: Last update November 10. Data unavailable between Apr 22 and June 09.

Airport departures

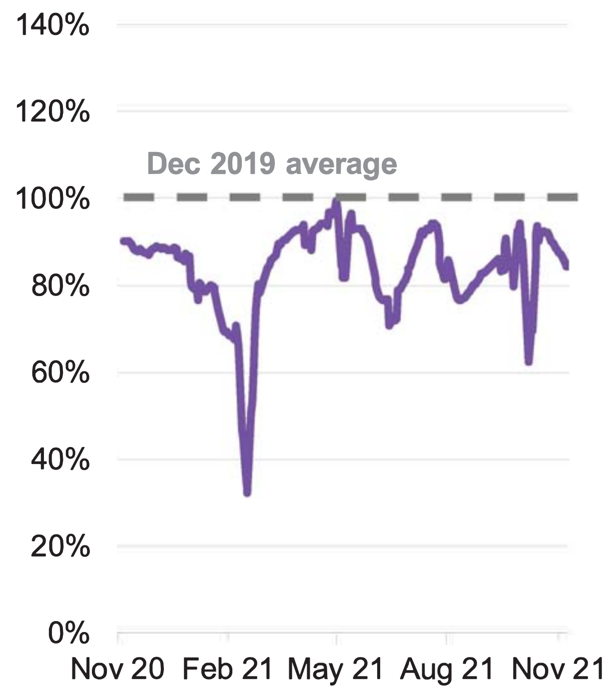
Rebased Dec 2019 = 100%



Source: BloombergNEF. Note: Last update November 16.

Subway rides

Rebased Dec 2019 = 100%



Source: BloombergNEF, Beijing Subway, Shanghai Metro, Guangzhou Metro. Note: Last update November 10.

Refinery runs and outages

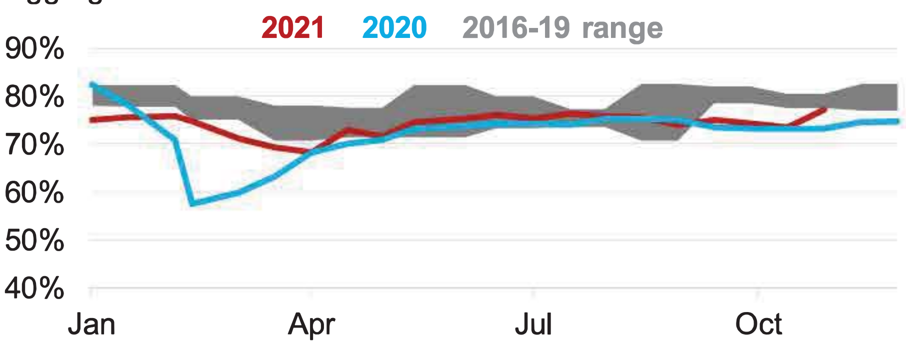
Run rates rebound at state refineries to ease a fuels shortage

Refinery operating data is available on the Bloomberg Terminal via **SCIG <GO>**

Refinery outage data is available on the Bloomberg Terminal via **REFO <GO>**

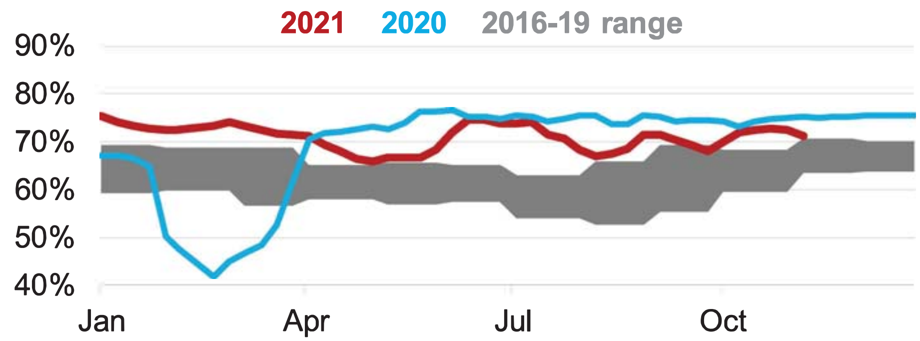
State-owned refinery operating rates

Aggregated utilization rate



Shandong independent refinery operating rates

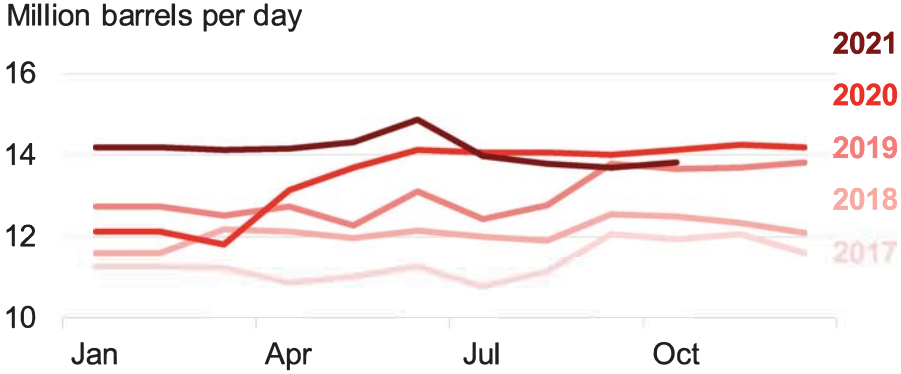
Aggregated utilization rate



Source: BloombergNEF, SCI99. Note: stated-owned refiners aggregated utilization rate is a weighted average calculated from the regional level utilization rates of state-owned refiners. For the tickers used in the calculation, please refer to the Covid-19 Indicators: China Livesheet (web | Terminal)

Total crude oil throughput

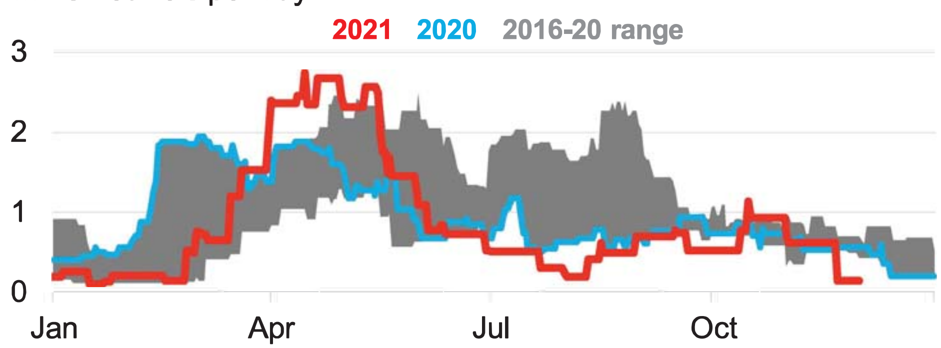
Million barrels per day



Source: National Bureau of Statistics, BloombergNEF. Note: China's statistical bureau reports a combined value for January and February. The charts represent this as an even split between the two months for illustrative purposes.

Total CDU outage in China

Million barrels per day



Source: Bloomberg Energy. Note: Ticker used is CDUTCHNA Index. CDU is crude distillation unit. Source data is collected by Bloomberg reporters. Future outage data is subject to change. Last update is November 10.

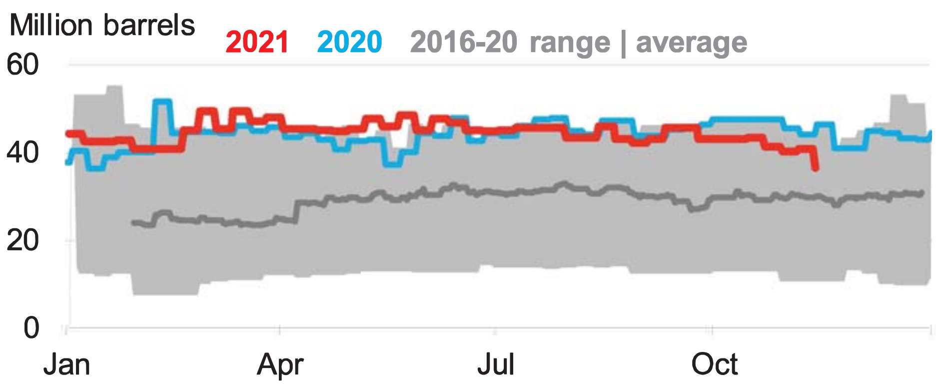
BloombergNEF

Refinery stocks

Gasoline and diesel inventories are below their five-year averages

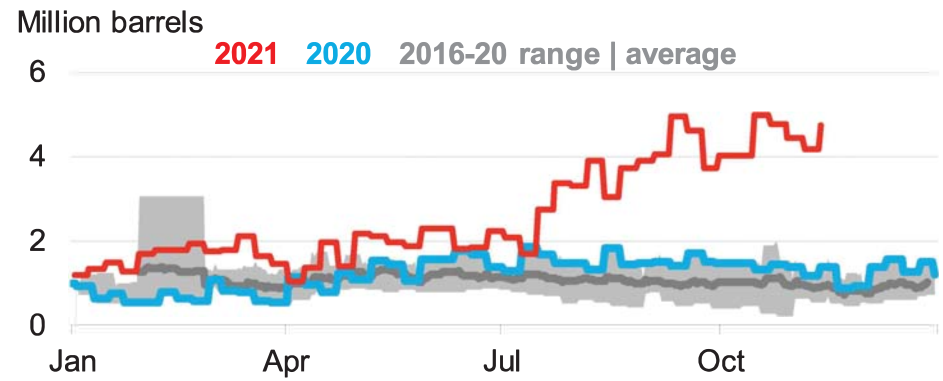
Refinery stock data is available on the Bloomberg Terminal via SCIG <GO>

Crude stocks – Shandong ports



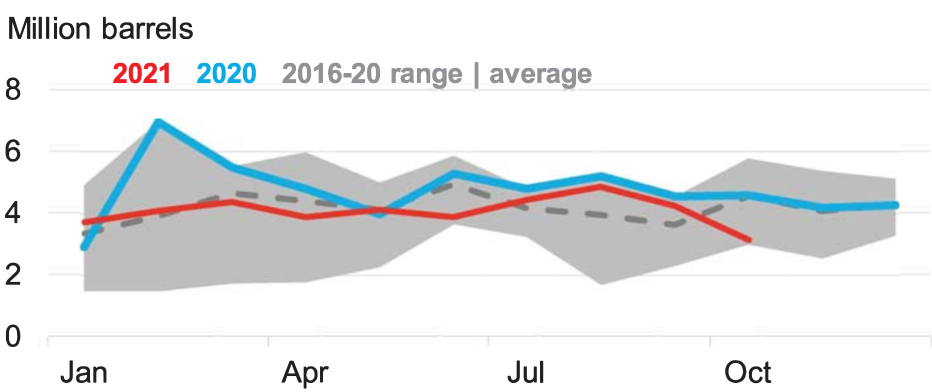
Source: SCIG, BloombergNEF

Fuel oil stocks – Shandong ports

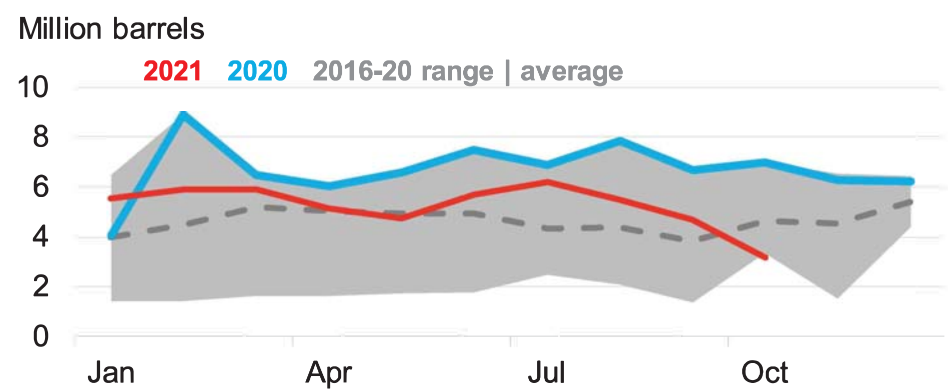


Source: SCIG, BloombergNEF

Gasoline stock – Shandong independents



Diesel stock – Shandong independents



Source: SCIG, BloombergNEF. Note: Gasoline and diesel stock level data include independent refineries in Shandong.

Nov 16, 2021 11:50:10

OIL DEMAND MONITOR: Latam Air Travel Rises as Europe, China Wane

- U.S. gasoline use near 2019's; air passengers top 2 million
- European flight activity wanes in early November: Eurocontrol

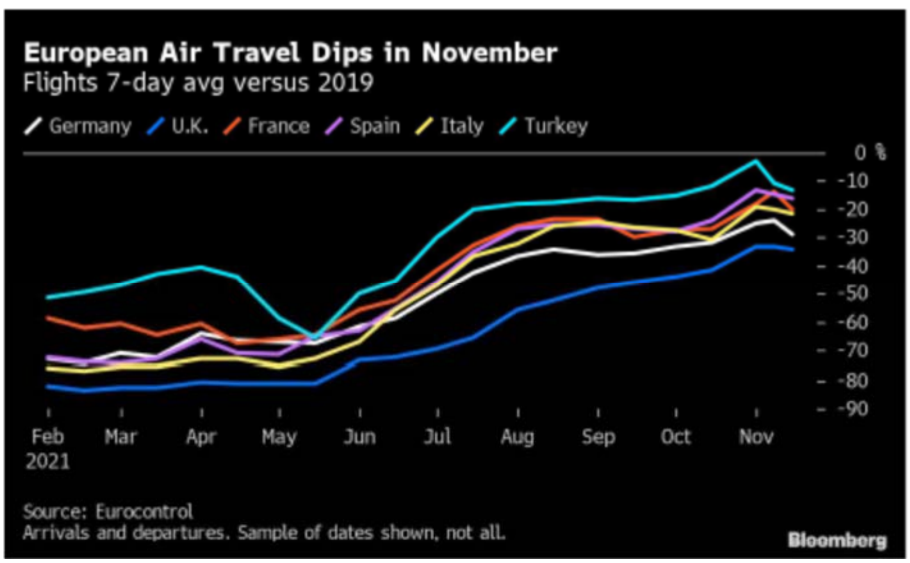
By Stephen Voss

(Bloomberg) -- Demand for aviation fuels -- the weakest link in the oil market during the pandemic -- is strengthening in Latin America and the U.S., even as flight numbers dip in Europe and China struggles with ongoing movement restrictions, high frequency data monitored by Bloomberg shows.

Jet fuel demand worldwide will recover in 2022 to about 19% below pre-Covid levels, the International Energy Agency said Tuesday in a monthly report. Other fuels are already close to normal levels. The latest retail sales figures and government estimates show gasoline demand is 0.7% below 2019 levels in the U.S., 8.5% below in the U.K. and 1.2% higher in India.

Airline traffic declined in Europe in early November, and while that's typical for this time of year, its deficit to 2019 levels has also widened slightly to 23% from 19% at the end of October, which was the narrowest so far this year, according to data from Eurocontrol.

The biggest six markets in Europe have all seen such declines in the past couple of weeks, after making steady gains since the lows at the end of spring when many countries were in extended lockdowns. The number of flights to and from Turkey, as measured by a seven-day average on Nov. 15, was down 13.2% versus 2019, compared with a deficit of just 3.1% on Nov. 1.

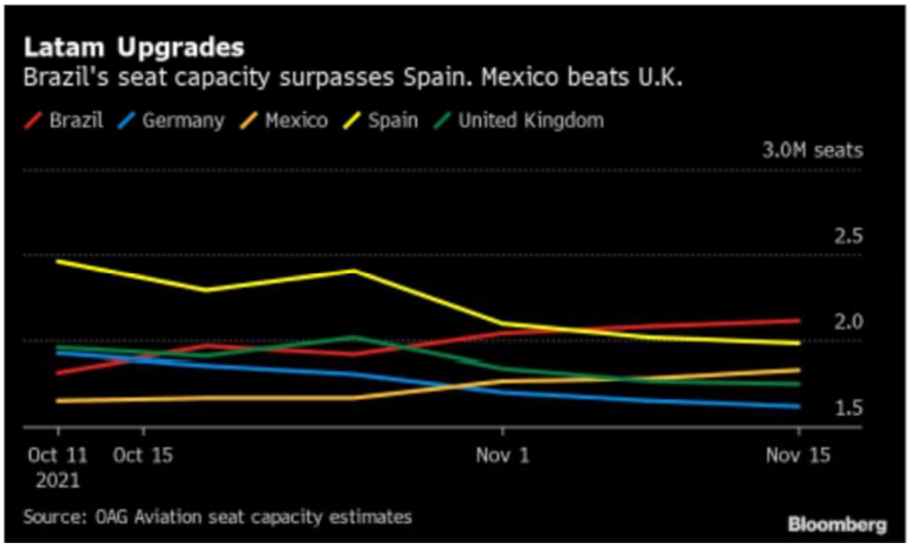


Seat capacity data from OAG Aviation shows a similar trend. France, Spain, Germany and the U.K. were the only places out of 15 major markets to show a decline in the number of scheduled seats versus a week earlier. Australia showed the largest improvement in percentage terms, while the others all showed minor gains.

More Seats for Brazil

Airline activity in the U.S. and Latin America continues to gradually improve though. In the global pecking order of seat capacity, Brazil has advanced above Spain in recent weeks to claim fifth place, OAG data shows. And Mexico has surpassed both Germany and the U.K.

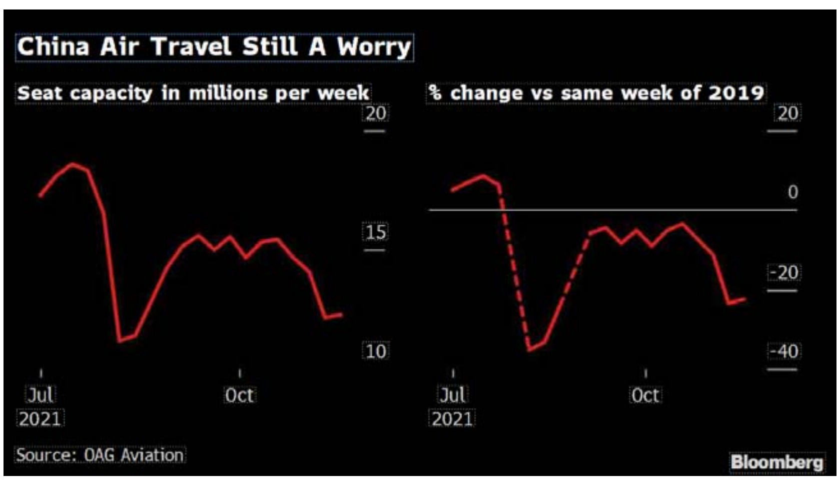
The U.S. has the world's largest airline market, and the number of passengers passing through turnstiles at its airports is getting ever closer to merging with 2019 levels, according to data from the Transportation Security Administration. When compared against the same weekday, Monday's level of 2.01 million passengers was just 2.9% less than two years ago.



Chinese Outbreaks

Meantime, capacity advanced a little in China, the world's second-largest airline market, after a marked three-week decline. New restrictions to combat coronavirus outbreaks led to a quick drop-off in activity at Chinese airports last month. While the nation may have turned a corner, its seat capacity of 12.3 million is still some 3 million less than it was in mid-October.

Unlike the situation for most of this year, China is no longer the closest to matching 2019 levels in terms of seat capacity. Mexico lags 2019 levels by only 3.4%, followed by the U.S. at 12%. India, Brazil and Spain are next, while China's capacity is currently 22% below the equivalent week of the pre-pandemic year.



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

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

Demand Measure	Location	% y/y	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	U.S.	+5.7	-0.7	+0.8	w	Nov. 5	9.26m b/d	EIA
Distillates	U.S.	+5.6	-5.6	+8.9	w	Nov. 5	4.28m b/d	EIA
Jet fuel	U.S.	+20	-9.1	+19	w	Nov. 5	1.59m b/d	EIA
Total oil products	U.S.	-4.4	-10	-2.9	w	Nov. 5	19.3m b/d	EIA
All vehicles miles traveled	U.S.		+0.2		w	Nov. 7	16.2b miles	DoT
Passenger car VMT	U.S.		-2		w	Nov. 7	n/a	DoT
Truck VMT	U.S.		+11		w	Nov. 7	n/a	DoT
All motor vehicle use index	U.K.	+26	-4	-2	d	Nov. 8	96	DfT
Car use	U.K.	+31	-8	-2.1	d	Nov. 8	92	DfT
Heavy goods vehicle use	U.K.	+3.8	+10	unch	d	Nov. 8	110	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+13	-8.5	+0.7	m	Nov. 1-7	6,667 liters/d	BEIS

Diesel avg sales per station	U.K.	+4.4	-9.2	+2	m	Nov. 1-7	9,489 liters/d	BEIS
Total road fuels sales per station	U.K.	+7.7	-8.9	+1.5	m	Nov. 1-7	16,156 liters/d	BEIS
Gasoline	India	+0.5	+1.2		2/m	Nov. 1-15	1.04m tons	Bberg
Diesel	India	-15	-19		2/m	Nov. 1-15	2.43m tons	Bberg
LPG	India	+4.2	+1.9		2/m	Nov. 1-15	1.12m tons	Bberg
Jet fuel	India	+22	-36		2/m	Nov. 1-15	212k tons	Bberg
Total Products	India	+0.8	+3.1	+12	m	October	17.9m tons	PPAC
Toll roads volume	Italy	+38	-2.4		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Spain	+87	+6.1		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	France	+111	+15		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Brazil	-7.6	+1.3		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Chile	+23	+41		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Mexico	+11	+5		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Brazil	-7.6	+1.3		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Chile	+23	+41		w	Nov. 1-7	n/a	Atlantia
Toll roads volume	Mexico	+11	+5		w	Nov. 1-7	n/a	Atlantia
All vehicles traffic	Italy	+9		-5.9	m	October	n/a	Anas
Heavy vehicle traffic	Italy	-2.5		-8.1	m	October	n/a	Anas
Gasoline	Portugal	+5.8	+9.4	-12	m	September	91k tons	ENSE
Diesel	Portugal	+1.8	+4	-2.5	m	September	411k tons	ENSE
Jet fuel	Portugal	+67	-41	-5	m	September	95k tons	ENSE
Gasoline	Spain	+25	+5.5		m	October	493k m3	Exolum
Diesel	Spain	+11	-1.7		m	October	2300k m3	Exolum
Jet fuel	Spain	+165	-34		m	October	440k m3	Exolum

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

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

City congestion:

Measure	Location	% chg vs 2019	% chg m/m	Nov. 15	Nov. 8	Nov. 1	Oct. 25	Oct. 18	Oct. 11	Oct. 4	Sep. 27	Sep. 20
			(Nov. 8)	Congestion minutes added to 1 hr trip at 8am local time								
Congestion	Tokyo	+2	+9	38	34	33	34	35	12	34	35	0
Congestion	Mumbai	-84	unch	6	3	5	7	6	1	7	11	12
Congestion	New York	+6	unch	33	34	31	38	33	8	35	31	35
Congestion	Los Angeles	-8	+10	32	30	25	25	29	23	27	30	28
Congestion	London	+22	+35	46	43	39	19	34	44	43	53	44
Congestion	Rome	+15	+41	56	44	0	41	40	64	44	53	55
Congestion	Madrid	-22	-25	28	10	0	32	37	3	41	35	35
Congestion	Paris	+15	+9	51	50	3	42	47	49	52	52	53
Congestion	Berlin	-7	+68	31	34	34	35	19	20	38	31	29
Congestion	Mexico City	-99	-98	1	34	14	29	28	28	29	26	29
Congestion	Sao Paulo	-93	-91	3	32	13	27	35	10	29	26	26

Source: TomTom. Click here for a PDF with more information on sources, methods.
NOTE: m/m comparisons are Nov. 15 vs Oct. 18. It was a public holiday on Nov. 15 in both Mexico City and Sao Paulo. 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.	+128	-2.9	+0.5	d	Nov. 15	2.01m people	TSA
Commercial flights	Worldwide	+33	-22	-6.9	d	Nov. 15	88,317	FlightRadar24
Air traffic (flights)	Europe		-23	-8.1	d	Nov. 15	21,841	Eurocontrol
Seat capacity	Worldwide	+40	-28		w	Nov. 15	76.4m	OAG
Seat cap.	U.S.	+54	-12		w	Nov. 15	19.4m	OAG
Seat cap.	China	-20	-22		w	Nov. 15	12.3m	OAG
Seat cap.	India	+54	-15		w	Nov. 15	3.68m	OAG
Seat cap.	Japan	+4.5	-42		w	Nov. 15	2.38m	OAG
Seat cap.	Brazil	+45	-17		w	Nov. 15	2.11m	OAG
Seat cap.	Spain	+227	-20		w	Nov. 15	1.98m	OAG
Seat cap.	Mexico	+42	-3.4		w	Nov. 15	1.83m	OAG
Seat cap.	U.K.	+367	-38		w	Nov. 15	1.75m	OAG
Seat cap.	Germany	+244	-40		w	Nov. 15	1.63m	OAG
Seat cap.	France	+280	-25		w	Nov. 15	1.42m	OAG
Seat cap.	Australia	+40	-64		w	Nov. 15	743k	OAG
Seat cap.	S. Africa	+33	-41		w	Nov. 15	355k	OAG
Seat cap.	Singapore	+131	-79		w	Nov. 15	174k	OAG

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

Refineries:

Measure	Location/area	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
		Changes in ppt unless noted					
Crude intake	U.S.	+14%	-3.5%	+2%	Nov. 5	15.4m b/d	EIA
Utilization	U.S.	+12	-1.1	unch	Nov. 5	86.7 %	EIA
Utilization	U.S. Gulf	+15	-1.3	+0.9	Nov. 5	88.4 %	EIA
Utilization	U.S. East	+11	+15	+3.7	Nov. 5	80.1 %	EIA
Utilization	U.S. Midwest	+9.7	+1.1	+3	Nov. 5	90.3 %	EIA
Apparent Oil Demand	China	+1.9%		+1.2%	October 2021	13.39m b/d	NBS
Indep. refs run rate	Shandong, China	-4	+1.7	-0.8	Nov. 12	71.1 %	SCI99
State refs run rate	East China	+1.1	+2.4	+0.4	Nov. 12	80.1 %	SCI99
State refs run rate	South China	-0.1	+7.2	+1.6	Nov. 12	84.4 %	SCI99

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

https://financialpost.com/commodities/energy/renewables/jonathan-wilkinson-says-natural-resources-must-evolve-to-include-renewables-biofuels

Jonathan Wilkinson says natural resources must evolve to include renewables, biofuels

Wilkinson said he still sees a role in Canada for some fossil fuels as long as they are not contributing to greenhouse gas emissions

Author of the article: **The Canadian Press** Mia Rabson
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OTTAWA — In a country intent on helping to slow global warming without destroying its economy, Canada's latest natural resources minister says his department can no longer be thought of mainly as the ministry for fossil fuels.

But Jonathan Wilkinson also says the Liberals are not singling out the oil and gas sector to do an unfair amount of heavy lifting in the fight against climate change because all industries that contribute to the problem have to be part of the solution.

Wilkinson is three weeks removed from the cabinet shuffle that made him the fourth natural resources minister in the last six years. Now after helming the environment department tasked with combating climate change, he's in charge of the department that regulates and promotes many of the products that cause it.

But when the 56-year-old former clean tech CEO took over Natural Resources Canada, some saw it as a signal the department is going to evolve to prioritize clean technology in a way it hasn't yet done.

"I would agree with that," Wilkinson said, in an interview with The Canadian Press, about his priorities for the new job.

"I do think that the way in which we define natural resources going forward actually has to include renewable energy, it has to include hydrogen, it has to include biofuels. I absolutely think that the old sort of way of conceptualizing the department, which is just about oil and gas and mining, is not the way that we think about it going forward."

The push-pull between the fossil fuel sectors that the world, and Canada, have relied on for decades, and the science that blames the burning of fossil fuels for the increasingly warmer planet and associated climate destruction, was on full display in the last two weeks at the United Nations COP26 climate talks in Scotland.

Environment advocates argued hard that the only way to keep global warming from becoming catastrophic is a full-scale phase out of the use of fossil fuels. The creation of a Beyond Oil and Gas Alliance, an initiative to phase out fossil fuels entirely, was among the most talked-about initiatives to come out of COP26.

The Quebec government signed on as an associate member but Canada did not.

Wilkinson, who spent several days at COP26 pushing Canada's position on phasing out fossil fuel subsidies, but promoting the development of hydrogen, said the all-or-nothing polarized positions on oil and gas production are difficult. He said he still sees a role in Canada for some fossil fuels as long as they are not contributing to greenhouse gas emissions.

That includes, he said, using bitumen for non combustible uses like asphalt or carbon graphite, and extracting hydrogen molecules from natural gas, as long as that is done with technology that first reduces and then eventually eliminates the greenhouse gas emissions that come from that process.

“Those are things we should be looking at because at the end of the day, we’re interested in good economic outcomes and no carbon emissions,” he said. “So I think that’s the way people need to think about it, rather than taking the polar position, which is no fossil fuels or fossil fuels are going to continue forever.”

Wilkinson is less bullish on the future for most oil and sees no pathway in Canada to keep using coal because the technology and geological formations needed to capture and store its emissions will not be both affordable and prepared for the 2030 deadline to phase out all “unabated” coal-fired power plants.

“On the oil side. I mean, look, it is primarily a transportation fuel and we’re all committing to actually go to net zero vehicles,” he said. “And so over time, you are going to see a reduction in the amount of oil being used, being combusted for the purposes of transportation That’s just logic.”

Carbon capture technology overall is also not a massive, long-term solution to allow the continued burning of fossil fuels for energy, said Wilkinson, because the geological formations needed to store the gases don’t exist everywhere.

His priorities for the first months of his new job are to work with oil and gas provinces to develop the cap on oil and gas production emissions the Liberals promised in the recent election.

Former prime minister Stephen Harper recently accused the Liberals of targeting oil producing regions to fulfil their climate change goals, because those regions don’t vote for the Liberals. Wilkinson didn’t reference Harper directly, but rejected the sentiment.

“Some people say that we’ve singled out the oil and gas space and to that I actually say that’s just not true,” he said. “If you read the rest of the climate plan, for example, in the in transportation space, we said hard stop of the sale of internal combustion engine vehicles after 2035 for the same reasons.”

He said one of his priorities is working with those regions affected to ensure the transition away from fossil fuels is a positive one.

Varcoe: Oilpatch and new resources minister promise to 'put elbows down' after meeting face to face

Alberta and Ottawa have been at each other's throats for so long on energy policy, it's become a reflex for each side to put their elbows up at every meeting

Author of the article:
Chris Varcoe • Calgary Herald
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Alberta and Ottawa have been at each other's throats for so long on energy policy, it's become a reflex for each side to put their elbows up at every meeting.

Like hockey players going into the corner to retrieve the puck, each side does so preparing for impact.

The energy fault lines are deep between Alberta and the oilpatch on one side and the federal Liberal government on the other: Bill C-69, pipelines and now a cap on oil and gas sector emissions.

But perhaps we're heading into a new era, a period where each side realizes they must co-operate to achieve their own goals, while keeping a wary eye on the other camp.

New federal Natural Resources Minister Jonathan Wilkinson sat down for the first time with oilpatch and business leaders in Calgary on Wednesday and Thursday. He also met separately with Alberta Energy Minister Sonya Savage.

"What I heard from the CEOs, as well as others in the energy sector today, was that they really want to collaborate, they want a partner, they want us to work together," Wilkinson said in an interview.

"I hope that both sides are prepared to put their elbows down."

Similarly, Savage said they talked about areas of mutual interest.

"I take Minister Wilkinson at his word," she said. "There is a willingness to work together."

The reality is they all have to get along if the country is to meet ambitious emissions targets, if the industry is to attract capital, and if both sides are to invest in decarbonization projects and create jobs.

It all sounds promising.

However, you only need to get cross-checked once from behind to restart the hostilities.

"I'd walk away from it and say (to Ottawa), 'If you do what you say you're going to do, and actually listen to industry …' then you feel very encouraged," said Whitecap Resources CEO Grant Fagerheim, who was in Thursday's meeting with Wilkinson.

"Historically, that's not been the case. It's been empty promises."

The federal minister believes progress can happen because Canadians understand climate change is an existential threat and both sides want to lower emissions, while also promoting the economic interests of the provinces and Canada.

Those reassurances need to be backed up with action.

The declaration by Prime Minister Justin Trudeau at the COP26 climate summit that Canada will impose a cap on emissions from the oil and gas sector — making it the first major oil-producing country to do so — certainly triggered anger within Alberta's government.

"It seems to have been an improvised talking point for the Glasgow audience," Premier Jason Kenney said Thursday.

Kenney is awaiting details on Ottawa's promised federal tax credit for carbon capture, utilization and storage (CCUS) projects, which is still being ironed out.

Alberta and the industry also want to see policy certainty going forward, as the Trudeau government has changed national emissions targets several times since the 2015 Paris accord.

"Is there frustration and mistrust? Yes, of course, there is, no question. But our investors are demanding movement," said one oilpatch executive.

"We need to be on the bus, but that doesn't mean we won't produce energy."

The UCP government is seeking more than $30 billion in federal incentives over a decade to ignite investment in CCUS.

A coalition of six of the largest oilsands producers, which are working together to reach net-zero emissions by 2050, have previously pegged the cost of their long-term plans at about $75 billion.

Other companies have their own ambitions for hydrogen and carbon capture projects.

Shell, which is a partner in the LNG Canada mega-project, recently proposed a large-scale carbon capture and storage development at its Scotford refinery and chemicals plant near Edmonton.

Shell Canada country chair Susannah Pierce, who met with Wilkinson on Wednesday, said they discussed how to produce clean and affordable energy while striving to meet climate objectives and ensure a robust economy.

"We are all Canadians and I think we all view that there's an opportunity and an urgency to come together," Pierce said in an interview.

"I do think people are tired of the friction and the polarization and this is an opportunity to come together and say we share a goal."

About 40 senior leaders from Suncor, TC Energy, Imperial Oil and other companies were at Thursday’s meeting, which was organized by the Business Council of Alberta and Calgary Chamber of Commerce.

“There is a massive potential for Alberta and Canada to be a leader and a global hub in energy transition and emissions reduction,” said Adam Legge, president of the Business Council of Alberta.

“That is definitely something we can all get behind.”

Yet, trust will need to be earned on all sides.

Introducing an emissions cap on the oil and gas sector, starting in 2025, has the Alberta government watching closely.

As Savage pointed out, provinces have the constitutional authority to regulate natural resource development, not Ottawa.

However, she said the meeting with her federal counterpart was productive as they discussed critical minerals, hydrogen and carbon capture technology.

“The first test will be where we land with (CCUS) and whether that investment tax credit that ultimately comes out will be sufficient to give our industry a path forward,” she said.

Details on the oil and gas emissions limit will need to be worked out in short order as the cap kicks into place in 2025. Wilkinson pledged there will be more discussions with the industry.

“We need to actually sit down and talk about what is reasonable,” he added. “So that’s a commitment I made to the sector today, that we want to engage.”

Engagement is the first step towards co-operation. It also begins with putting the elbows down and skating towards a common goal.

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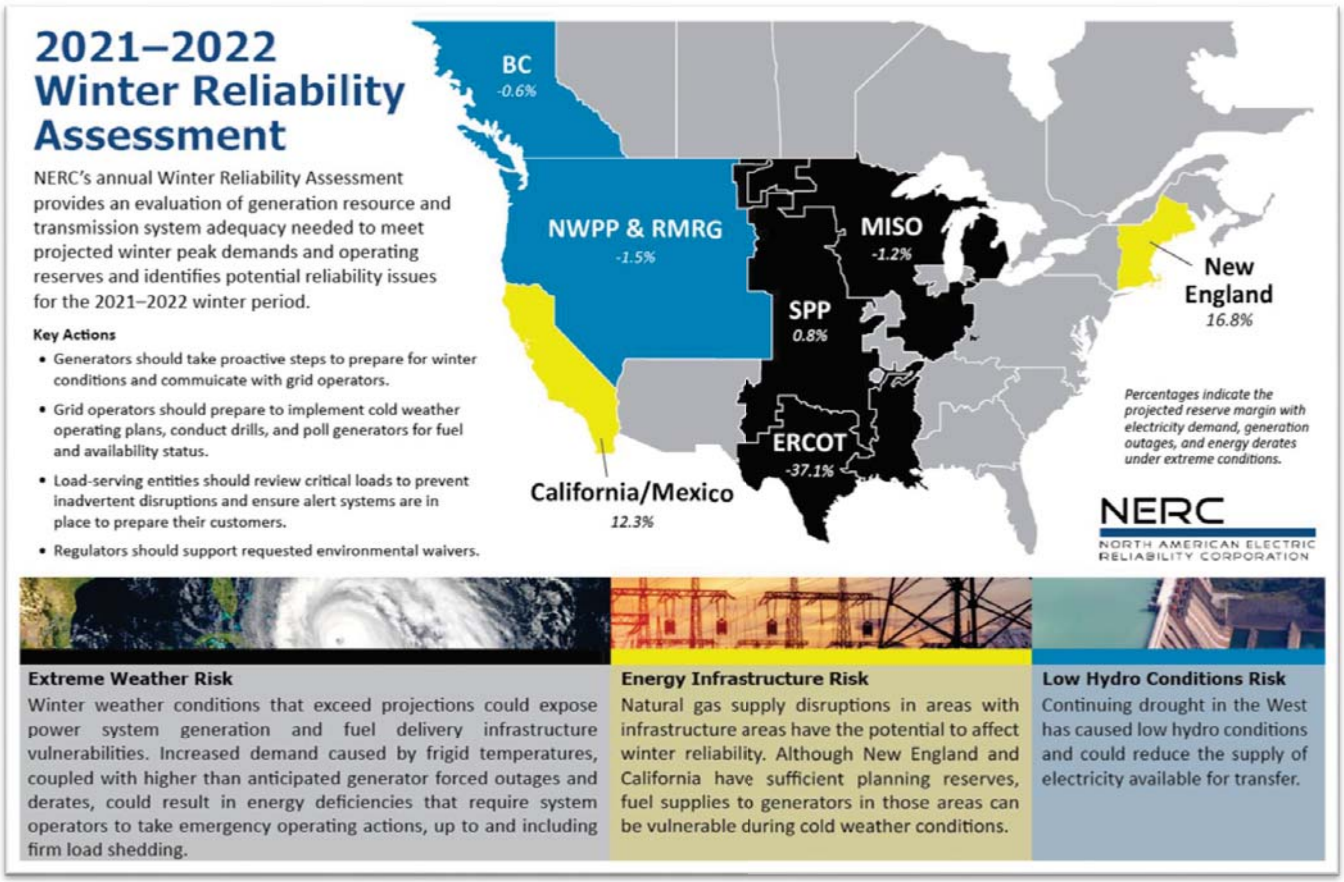
About this Assessment

NERC's *2021-2022 Winter Reliability Assessment* (*WRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the REs, and NERC staff using demand and resource projections obtained from the assessment areas. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period. The below infographic provides a basic overview.



Key Findings

NERC's annual WRA covers the upcoming three-month (December–February) 2021–2022 winter period. This assessment provides an evaluation of generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. The following findings represent NERC's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

- **Extreme weather events, including extended durations of colder than normal weather, pose a risk to the uninterrupted delivery of power to electricity consumers:** Winter weather that exceeds projected conditions can expose power system generation and fuel delivery infrastructure vulnerabilities and challenge electricity system operators' ability to maintain reliability of the BPS. Although Anticipated Reserve Margins meet or surpass the Reference Margin Level in all areas as shown in the **Resource Adequacy** section, harsh conditions characterized by extreme or prolonged cold temperatures over a large area create unique challenges in maintaining grid reliability in many parts of the North American BPS. Such conditions occurred most recently in North America during the February 2021 North American cold weather event.[1] Increased demand caused by frigid temperatures and higher than anticipated generator forced outages and derates in susceptible areas could create conditions that lead system operators to take emergency operating actions, up to and including firm load shedding, as a result of energy emergencies. NERC's operational risk assessment, which is presented in detail in the **Risk Highlights for Winter 2021–2022** section, identifies BPS resource deficiencies in parts of North America (**Figure 1**) that could occur during extreme winter weather. Peak demand or generator outages that exceed forecasts—at levels that have been experienced in previous winter events—can be expected to cause energy emergencies in MISO, SPP, and Texas RE-ERCOT.

Figure 1: Winter Reliability Risk Area Summary

- **Natural gas supply disruptions in infrastructure-limited areas have the potential to affect winter reliability:** Disruptions to pipeline natural gas supplies and natural gas production sites, as observed in Texas RE-ERCOT in February 2021, can have the potential to affect power system reliability in winter. Although New England and the U.S. Southwest have sufficient planning reserves, fuel supplies to generators in those areas can be vulnerable during cold weather conditions. In NPCC-New England, the capacity of natural gas transportation infrastructure can be constrained when cold temperatures cause peak demand for both electricity generation and consumer space heating needs. Potential constraints on the fuel delivery systems and limited inventory of liquid fuels may exacerbate the risks for fuel based generator outages and reductions. Southern California and the U.S. Southwest have limited natural gas storage and lack redundancy in supply infrastructure. As a result, electricity generators face the risk of fuel supply curtailment or disruption from extreme winter weather events.[2, 3] A ruptured interstate natural gas pipeline in August has caused an outage that reduces the amount of natural gas flowing into California. Natural gas storage levels in the

[1] See the FERC and NERC staff Inquiry preliminary findings and recommendations: February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - PPT Version | Federal Energy Regulatory Commission (ferc.gov)
[2] ISO-NE Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/
[3] Western Interconnection Gas–Electric Interface Study: https://www.wecc.org/Reliability/Western%20Interconnection%20Gas%20Electric%20Interface%20Study%20Public%20Report.pdf

area will decline during periods of high demand while the outage persists. Electricity reliability would not be affected in average temperatures and conditions, however prolonged periods of cold temperatures could result in curtailment of natural gas fuel to generators.[4]

- **Continuing drought in the west can cause low hydro conditions for the upcoming winter and reduce the supply of electricity for transfer throughout the area:** Although resources are expected to be sufficient for peak demand, higher demand from more extreme temperatures in the northwest could cause a shortfall. Low hydro conditions can reduce transfers needed to mitigate a wide area cold weather event.
- **Generator Owners are facing challenges in obtaining fuels as many supply chains are stressed:** No specific BPS reliability impacts are currently foreseen; however, owners and operators of fossil-fired generators will need to monitor their coal and fuel oil stores and natural gas contracts as late-stage acquisitions are less assured this winter. Regional natural gas storage levels are below average as a result of natural gas infrastructure maintenance and high natural gas usage throughout the warm summer months. In most assessment areas, natural gas reliance as a generator fuel has increased in recent years. NPCC-New England competes for liquefied natural gas supply on the world market—some of which powers electric generation in the area—and unprecedented high liquefied natural gas demand is anticipated for the upcoming 2021–2022 winter months. These potential constraints could challenge many owners of fossil-fired plants over the winter and underscore the need for operators at the Balancing Authorities (BAs) and Reliability Coordinators (RCs) to include generator fuel surveying in their operating plans.
- **Responses to NERC's Level 2 Alert—*Cold Weather Preparations for Extreme Weather Events*—indicate that operating plans for winter are in place, but generator resource availability could again suffer as a result of equipment failure or lack of fuel under severe winter conditions:** In August, the ERO issued a Level 2 NERC Alert to RCs, BAs, Transmission Operators (TOPs), and Generator Owners (GOs). The alert includes five recommendations as well as a series of questions to help evaluate the Bulk Electric System's winter readiness. Responses indicate that grid operators have put operating plans in place to reduce seasonal risks and maintain system reliability. However, GOs and grid operator's responses to questions about winterization plans and fuel coordination indicate that some plant vulnerabilities can be anticipated for the upcoming winter. The responses indicate the importance for grid operators to be prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.

[4] See California Public Utilities Commission *Winter 2021-22 Southern California Reliability Assessment*: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/winter2021-22-reliabilityassessment.pdf

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Grid operators, GOs, and Generator Operators (GOPs) should review NERC Level 2 alert—*Cold Weather Preparations for Extreme Weather Events*—and take recommended steps prior to winter.
- Grid operators should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, and sustained operations in extreme conditions. BAs should poll their generating units periodically and in advance of approaching severe weather to understand their readiness level for normal and extreme conditions, giving consideration for unit weatherization as well as fuel supply risk.
- BA and RC should conduct drills on alert protocols to ensure that they are prepared to signal need for conservative operations, restrictive maintenance periods, etc. BA and GOPs should verify protocols and operator training for communication and dispatch.
- Distribution providers and load-serving entities should review non-firm customer inventories and rolling black out procedures to ensure that no critical infrastructure loads (e.g., natural gas, telecommunications) would be affected. Rehearse protocols that prepare customers for impacts of severe weather.

February 2021 Cold Weather Event: Winter Storm Uri

From February 13–17, 2021, the Central United States suffered an intense and prolonged cold wave that affected many areas across the Texas RE-ERCOT, MISO, and SPP assessment areas. Increasing demand was unable to be met as generation and transmission experienced widespread outages. FERC, NERC and the REs launched the *February 2021 Cold Weather Grid Operations* joint inquiry regarding the BPS events as a result of winter storm Uri. The inquiry identified the following root causes:

- Generation freezing
- Limited natural gas fuel supply
- Natural gas and electricity interdependency
- ERCOT firm load shed affected natural gas facilities
- Manual and automatic load shed coordination

Generators without winterization experienced mechanical failures from a variety of causes that include frozen instrumentation and loss of ancillary support systems, such as airflow, cooling, and internal fuel delivery. Wind generators' failures were attributable to iced wind turbine blades. Freezing and power outage issues at both gathering and processing facilities for natural gas caused limited natural gas supply for generators. Firm load shed affected power supply to various natural gas production and processing facilities that in turn led to further forced outages for natural gas generators. ERCOT ordered firm load shed for nearly three consecutive days that reached a peak of 20,000 MW ordered off-line at its worst point. During this time, ERCOT experienced a peak of 34,000 MW of generation outages for over two consecutive days. SPP ordered approximately five hours of firm load shed reaching 2,700 MW at its peak, and MISO experienced over two hours of firm load shed with 700 MW ordered off-line at its worst point. The ERO has taken the following actions to address concerns for extreme weather risks for future winters:

- Conducted the joint FERC-NERC Inquiry
- Issued NERC Level 2 alert: *Cold Weather Preparations for Extreme Weather Events*
- Developed cold weather Reliability Standards that have been adopted by the NERC Board of Trustees and filed with applicable regulatory authorities. In the United States, the new cold weather requirements will become effective in 2023.
- Prepared this 2021–2022 *Winter Reliability Assessment*

Recommendations from the inquiry include Reliability Standards, generator winterization, natural gas infrastructure winterization, and establishing a natural gas-electric reliability forum. An in-depth evaluation of the February 2021 cold weather event on BPS operations is included in the joint FERC-NERC inquiry.[5]

[5] FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements

Risk Highlights for Winter 2021–2022

Winter weather conditions that exceed projected conditions and expose power system generation and fuel delivery infrastructure vulnerabilities can challenge electricity system operators' ability to maintain reliability of the BPS. Specific risks for the upcoming winter are analyzed in this section of the *WRA*.

Seasonal Risk Assessments of Area Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, or low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates variables in resources and load and the potential effects that operating actions can have to mitigate shortfalls in operating reserves. **Figure 2** shows an example seasonal risk assessment for the Independent System Operator-New England (ISO-NE) area that was developed with data from NPCC and ISO-NE. The left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. A description of resource and demand variables for **Figure 2** is found in **Table 1**.

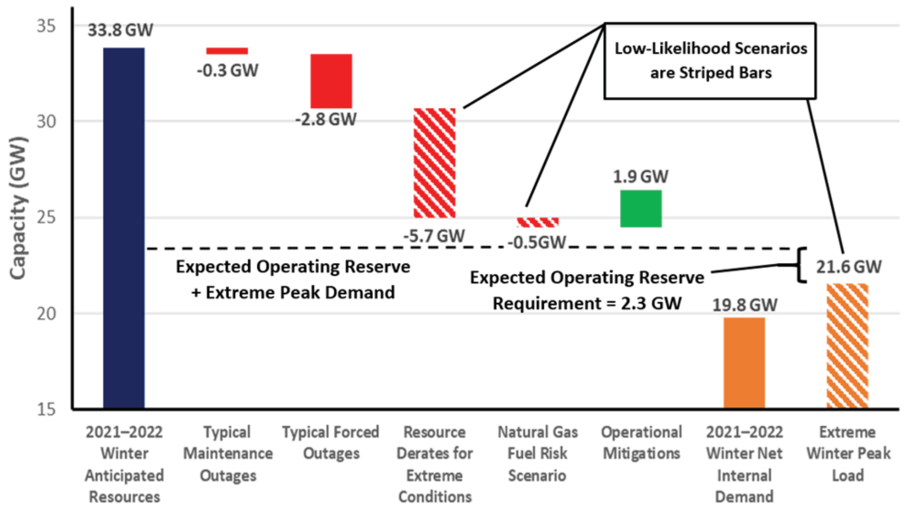


Figure 2: ISO-NE Area Seasonal Risk Assessment at Extreme Peak Demand

The seasonal risk assessment for ISO-NE shows that resources are available to meet extreme conditions. Based on the assumptions in **Table 1**, resources are available to meet expected operating reserve requirements for the normal and extreme demand and outage scenarios analyzed. By examining various maintenance and forced outage scenarios and seasonal derated resource conditions, the seasonal risk assessment analysis provides insights into operational challenges that can occur as a result of prolonged and extreme cold temperatures.

Table 1: Resource and Demand Variables in the ISO-NE Seasonal Risk Assessment		
Resource Scenarios		
Typical Maintenance Planned Outages	Typical maintenance outages refer to all planned outages for the period, including any known long-term outages, generation outages, reductions due to transmission work, and external outages that would affect ISO-NE imports. The value is a snapshot of these considerations that is produced monthly and forecast out two years.	-0.3 GW
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. ISO-NE calculated this capacity value from historical forced outages in previous winters.	-2.8 GW
Resource Derates for Extreme Conditions (Low-likelihood)	A low-likelihood, high forced outage scenario is used to analyze the effect of cold weather-driven generation outages. The assumed forced outage for this scenario is based on the sum of the unplanned outages beyond typical forced outages that are expected to be caused by extreme cold weather physically impacting generator availability (e.g., frozen sensing lines or equipment failure).	-5.7 GW
Extreme Natural Gas Fuel Risk Scenario (Low-likelihood)	ISO-NE depends on a large fleet of natural-gas-fired generation that may be at risk due to high firm demand, resulting in the unavailability of natural gas during colder temperatures. ISO-NE calculates the amount of generator natural gas at risk due to lack of natural gas during cold weather based on dry-bulb average temperature. This assumes no generator natural gas at risk for temperatures at or above 30°F and a reduction curve for temperatures below 30°F. The electric generating capacity depicted as at-risk in **Figure 2** is the maximum.	-0.5 GW
Operational Mitigations	An estimated combination of load relief is achieved through operating procedure actions (e.g., requesting voluntary load curtailment of market participants, the purchase of available emergency capacity and energy from market participants or neighboring RC or BA areas, request for generators and demand response resources not subject to market obligations to voluntarily provide energy for reliability, requesting voluntary load curtailment by large industrial and commercial customers, and radio and television appeals for voluntary load curtailment).	+1.9 GW
Demand Scenarios		
2021–2022 Winter Net Internal Demand	This is the forecast 50/50 net winter peak load that integrates state historical demand, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs. Energy efficiency is included in this demand forecast and assumes that behind-the-meter solar generation will be off-line or unable to generate for the peak winter hours.	
Extreme Winter Peak Load	Demand Scenarios beyond (90/10) are tested to determine the level of risk and actions required to maintain the integrity of the interconnected BPS, which includes emergency actions up to and including load shedding.	

The seasonal risk assessment does not account for all of the unique energy assurance risks associated with the area. Long-duration cold spells and disruptions to primary and back-up fuel supply chains are not explicitly considered in the New England seasonal risk scenario and can cause unique risks to the area's operations. Conditions such as these occurred in the 2017–2018 winter and led to a rapid decline in fuel oil inventories used by electricity generators. Gripped by a cold weather stretch for an extended duration between December 25 and January 8, all major cities in New England had average temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal. Overall, there was significantly higher than normal use of oil, and coal use also increased over its normal use. Natural gas and oil fuel price inversion led to oil being in economic merit and base loaded. As natural gas became uneconomic, the entire season's oil supply rapidly depleted. The amount of electricity generated from natural gas declined significantly at the end of December as temperatures plunged, and most available pipeline capacity was used to serve firm local natural gas distribution company demand for heating customers. Oil-fired generation increased sharply during the same period, surpassing natural-gas-fired generation on December 28. With extended days of burning oil, several resources either had concerns about hitting federal and/or state emissions limitations or were impacted by emissions limitations. This primarily includes resources in Massachusetts, Connecticut, and Rhode Island. As oil inventories depleted, replenishment could not keep up with demand until January 9 when cold temperatures eased. Figure 3 shows the impact the cold weather had on fuel oil inventories during the event.[6]

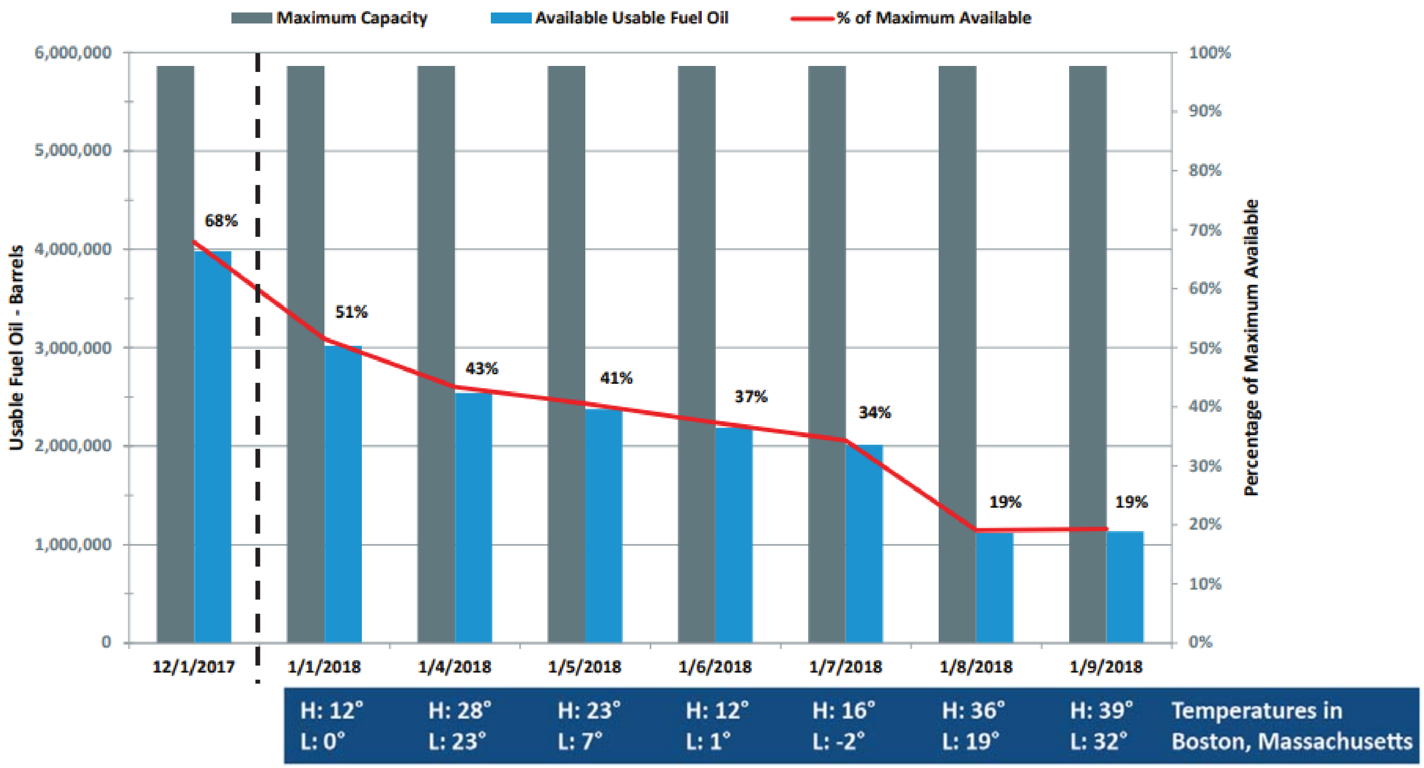


Figure 3: Fuel Oil Inventories in ISO-NE during 2017–2018 Winter[5]

This chart is an approximation of usable oil, discounting unit outages, reductions, or emissions.

[6] https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf

Since the winter of 2017–2018, ISO-NE has implemented the 21-Day Energy Forecast and Report[7] that is published to provide market participants with early indications of potential fuel scarcity conditions and help inform fuel procurement decisions. ISO-NE surveys fossil-fueled generators on a weekly basis in winter to monitor and confirm their current and expected fuel availability. If conditions require more frequent updates, these surveys may be sent daily. ISO-NE also requests that all natural-gas-fired generators confirm adequate natural gas supply and transportation nominations to meet their day-ahead obligations during these energy assessments.

Actual Generation Outages and Derates

Seasonal risk assessments are informed by historical data on generation outages and derates. NERC's Generating Availability Data System (GADS) is one source of information that is used to obtain historical information of the impact to conventional thermal and hydro generation during winter periods.[8] **Table 2** and **Table 3** show the peak generation outage and derated capacity and proportion to overall fuel-type nameplate capacity reported to GADS for affected assessment areas during periods of extreme winter weather that occurred in January 2018 and February 2021. Wind and solar generation also experience outages and derates; however, this data is not collected in the GADS conventional database used for the tables. Wind and solar generation is derated in the *WRA* to account for ambient light and expected weather conditions around the time of peak demand (i.e., peak daily demand in winter occurs in early morning hours or other times of darkness for most areas).

Table 2: February 2021 Peak Generation Outage and Derate [9]

	Coal fired		Nuclear		Natural Gas Fired	
Area	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
MISO	7,202	13%	265	1%	9,323	16%
SERC-Central	564	3%	-		1,185	9%
SERC-Southeast	914	5%			3,383	9%
SPP	6,219	17%	1,973	34%	13,589	42%
Texas RE-ERCOT	3,680	27%	1,181	23%	22,566	38%
WECC-NWPP-US & RMRG	1,968	10%			1,285	6%

Table 3: January 2018 Peak Generation Outage and Derate[10]

	Coal fired		Nuclear		Natural Gas Fired	
Area	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
MISO	7,327	14%	605	3%	7,547	13%
NPCC-New York	177	11%	-	-	6,130	37%
PJM	12,186	23%	-	-	2,500	5%
SERC-East	507	3%	932	8%	292	2%
SERC-Florida Peninsula	695	8%	-	-	356	1%
SERC-South East	4,137	21%	1,422	13%	4,610	12%
SPP	1,434	4%	146	3%	10,664	33%
Texas RE-ERCOT	1,092	8%	-	-	10,696	18%

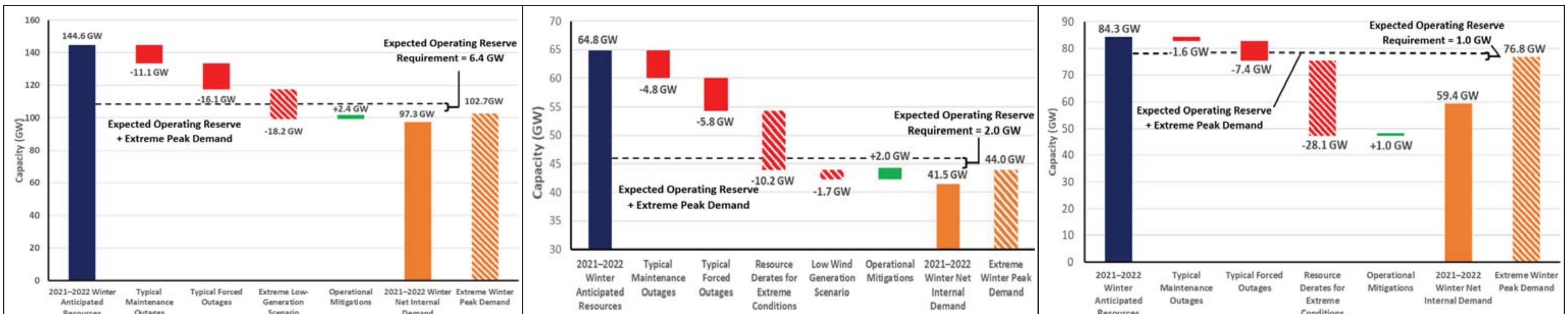
[7] ISO-NE's 21-Day Energy Forecast and Report: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results
[8] See NERC Generating Availability Data System: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx
[9] These are the maximum derates and outages reported in GADS in the affected areas during the Texas and Southcentral United States cold weather event that took place February 8–20, 2021.
[10] These are the maximum derates and outages reported in GADS in the affected areas during the January 2018 Southcentral Cold Event from January 15–19, 2018. Details can be found in the event report: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

Seasonal Risk Assessments for Other Areas

Extreme generation outages and peak loads similar to those experienced in February 2021 are reliability risks in MISO, SPP, and Texas RE-ERCOT areas for the upcoming winter. Seasonal risk scenarios detailing these areas are shown in **Figure 4**. Under studied conditions for these areas, grid operators would need to employ operating mitigations or energy emergency alerts (EEAs) to obtain resources necessary to meet extreme peak demands. **Table 4** describes the various EEA levels and the circumstances for each.

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.



MISO | SPP | Texas RE-ERCOT

Figure 4: MISO, SPP, Texas RE-ERCOT Seasonal Risk Scenarios

Note: The left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources.

MISO

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under extreme peak demand and outage scenarios studied. In MISO's seasonal risk scenario, typical maintenance outages and forced outages are derived from the averages over the past five years. The resource derates in extreme conditions are the maximum outages that occurred in the last five years. The two demands shown for MISO in **Figure 4** are the net internal demand (50/50) and the extreme winter peak demand (90/10) that are derived from demand forecasts with 30 years of historical data. More information about the seasonal risk scenario data description can be found in **Table 1**.

SPP

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under extreme peak demand and outage scenarios studied. During winter storm Uri, operators received 3.9 GW of imports to help reduce the amount of firm load shed required to balance supply and demand.

Texas RE-ERCOT

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under the extreme peak demand and outage scenarios studied. In the seasonal risk scenario, typical maintenance outages and forced outages are based on historical averages for December through February from the previous three winter seasons, except for February 15–28, 2021. The resource derates for extreme conditions red bar in **Figure 4** includes actual outage rates from winter storm Uri. The two demands shown for Texas RE-ERCOT in **Figure 4** are the net internal demand (50/50) and the extreme winter peak demand (winter storm Uri projected peak). More information about the seasonal risk scenario data description can be found in **Table 1**.

Other Areas

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 5**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources, less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 5: Seasonal Risk Scenario Anticipated Reserve Margins			
Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Demand, Outages, and Derates for Extreme Conditions
MISO	48.5%	20.5%	-1.2%
MRO-Manitoba	17.2%	14.2%	4.2%
MRO-SaskPower	19.3%	16.1%	11.6%
NPCC-Maritimes	26.5%	19.9%	-2.1%
NPCC-New England	71.1%	55.3%	16.8%
NPCC-New York	78.6%	58.4%	33.5%
NPCC-Ontario	20.0%	20.0%	21.3%
NPCC-Québec	12.4%	9.8%	0.6%
PJM	42.0%	29.1%	11.3%
SERC-Central	32.5%	24.4%	9.3%
SERC-East	25.9%	20.6%	4.3%
SERC-Florida Peninsula	35.4%	29.7%	23.2%
SERC-Southeast	38.7%	31.6%	21.1%
SPP	56.4%	30.9%	0.8%
Texas RE-ERCOT	41.9%	26.8%	-37.1%
WECC-NWPP-AB	34.7%	28.6%	8.3%
WECC-NWPP-BC	17.9%	17.8%	-0.6%
WECC-CA/MX	40.3%	33.3%	12.3%
WECC-NWPP-US & RMRG	27.1%	26.6%	-1.5%
WECC-SRSG	103.3%	93.3%	56.5%

https://www.energylive.cloud/

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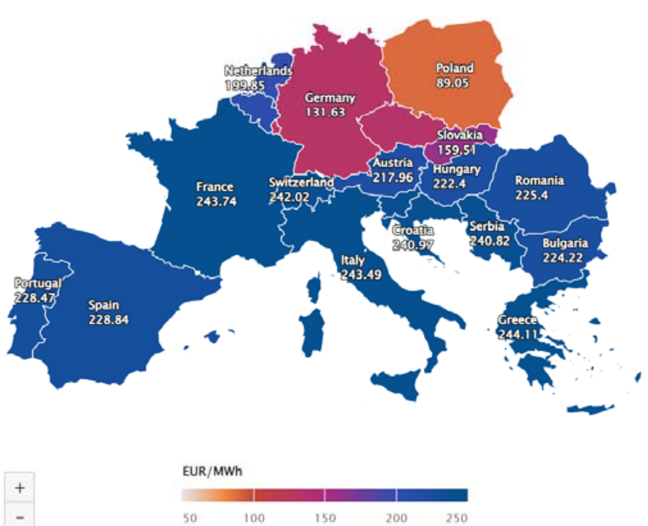
ABOUT LOGIN

Latest European Power Markets data

Day-ahead average prices for 2021-11-19



Index	Value	Month-to-date	Year-to-date
AT_price	217.96 ↑3.3%	188.48	88.67
BE_price	207.00 ↓9.7%	185.65	86.25
BG_price	224.22 ↓11.4%	200.60	94.15
CH_price	242.02 ↓4.0%	206.06	93.83
CZ_price	133.31 ↓5.0%	161.04	84.53
DE-LU_price	131.63 ↓5.9%	160.79	81.33
ES_price	228.84 ↑0.8%	174.51	95.83
FR_price	243.74 ↑2.3%	192.71	88.18
GR_price	244.11 ↓11.7%	222.32	100.81
HR_price	240.97 ↓2.4%	201.13	97.21
HU_price	222.40 ↓11.8%	202.28	96.92
IT_PUN_price	243.49 ↓1.6%	209.11	106.10
NL_price	199.85 ↓4.5%	176.56	86.62
PL_price	89.05 ↓13.3%	107.67	76.53
PT_price	228.47 ↑1.5%	174.47	95.90
RO_price	225.40 ↓10.9%	202.91	96.02
RS_price	240.82 ↓9.7%	202.66	96.93
SI_price	240.97 ↓2.4%	200.89	97.54
SK_price	159.51 ↑13.6%	167.83	86.51

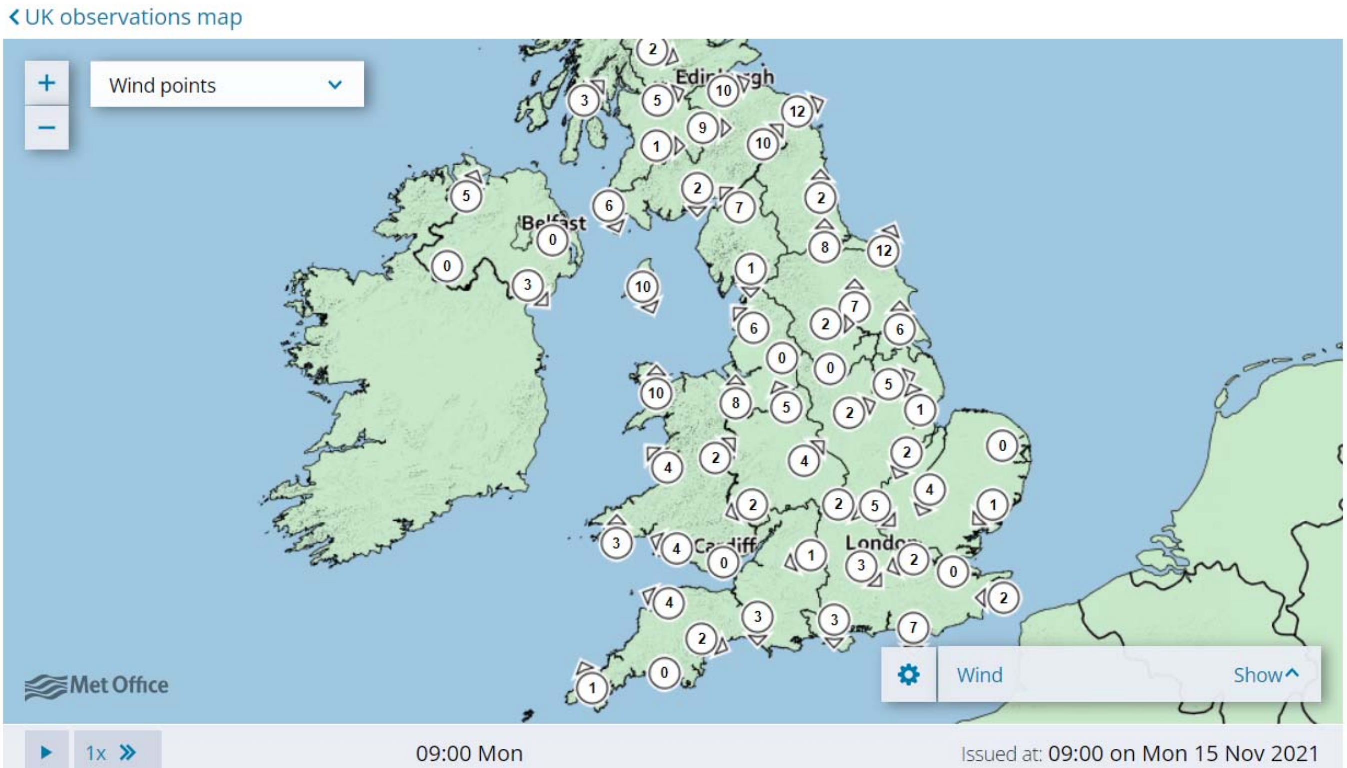
Data time zone : CET – Central European Time
Data updated : Thu Nov 18 2021 05:26:08 GMT-0700 (Mountain Standard Time)
Sources : HENEX (GR_price), GME (IT_PUN_price), IBEX (BG_price), OPCOM (RO_price), HUPX (HU_price), EPEX SPOT (SK_price,CZ_price,FR_price,CH_price,AT_price,DE-LU_price,BE_price,NL_price,PL_price), SEEPEX (RS_price), CROPEX (HR_price), BSP SOUTHPOOL (SI_price), OMIE (ES_price,PT_price)

Primary Energy: Consumption by fuel*

Exajoules	Oil	Natural Gas	Coal	Nuclear energy	Hydro electric	Renew-ables	2019 Total	Oil	Natural Gas	Coal	Nuclear energy	Hydro electric	Renew-ables	2020 Total
Austria	0.55	0.32	0.12	-	0.36	0.15	**1.50**	0.48	0.31	0.09	-	0.36	0.14	**1.38**
Belgium	1.33	0.63	0.13	0.39	^	0.19	**2.67**	0.93	0.61	0.11	0.31	^	0.23	**2.19**
Czech Republic	0.42	0.30	0.60	0.27	0.02	0.09	**1.70**	0.37	0.30	0.49	0.27	0.02	0.09	**1.54**
Finland	0.39	0.07	0.15	0.22	0.11	0.19	**1.13**	0.35	0.07	0.13	0.21	0.14	0.19	**1.10**
France	3.14	1.57	0.27	3.56	0.50	0.63	**9.67**	2.68	1.46	0.19	3.14	0.54	0.68	**8.70**
Germany	4.66	3.19	2.25	0.67	0.18	2.10	**13.05**	4.21	3.12	1.84	0.57	0.17	2.21	**12.11**
Greece	0.64	0.19	0.22	-	0.04	0.12	**1.19**	0.51	0.21	0.11	-	0.03	0.14	**1.00**
Hungary	0.35	0.35	0.08	0.15	^	0.05	**0.98**	0.33	0.37	0.07	0.14	^	0.06	**0.97**
Italy	2.55	2.55	0.28	-	0.41	0.65	**6.45**	2.13	2.44	0.21	-	0.41	0.67	**5.86**
Netherlands	1.64	1.33	0.27	0.03	^	0.23	**3.51**	1.51	1.32	0.18	0.04	^	0.33	**3.37**
Norway	0.39	0.16	0.03	-	1.12	0.07	**1.78**	0.37	0.16	0.03	-	1.25	0.11	**1.93**
Poland	1.36	0.75	1.86	-	0.02	0.25	**4.24**	1.28	0.78	1.67	-	0.02	0.27	**4.01**
Portugal	0.50	0.22	0.05	-	0.08	0.18	**1.03**	0.41	0.22	0.02	-	0.11	0.17	**0.93**
Romania	0.45	0.39	0.21	0.10	0.14	0.10	**1.38**	0.44	0.41	0.15	0.10	0.13	0.10	**1.33**
Spain	2.70	1.30	0.16	0.52	0.20	0.73	**5.60**	2.21	1.17	0.07	0.52	0.24	0.77	**4.97**
Sweden	0.59	0.04	0.08	0.59	0.58	0.36	**2.24**	0.55	0.04	0.07	0.48	0.65	0.41	**2.20**
Switzerland	0.44	0.12	^	0.23	0.34	0.04	**1.18**	0.37	0.12	^	0.20	0.33	0.05	**1.08**
Turkey	2.01	1.56	1.76	-	0.79	0.39	**6.51**	1.82	1.67	1.66	-	0.69	0.45	**6.29**
Ukraine	0.48	1.02	1.08	0.74	0.06	0.05	**3.42**	0.45	1.06	0.98	0.68	0.06	0.09	**3.31**
United Kingdom	3.08	2.78	0.22	0.50	0.05	1.09	**7.73**	2.39	2.61	0.19	0.45	0.06	1.20	**6.89**
Other Europe	2.59	1.08	1.34	0.34	0.60	0.58	**6.53**	2.28	1.07	1.10	0.34	0.59	0.60	**5.97**
Total Europe	**30.27**	**19.93**	**11.13**	**8.29**	**5.60**	**8.24**	**83.46**	**26.07**	**19.48**	**9.40**	**7.44**	**5.82**	**8.94**	**77.15**

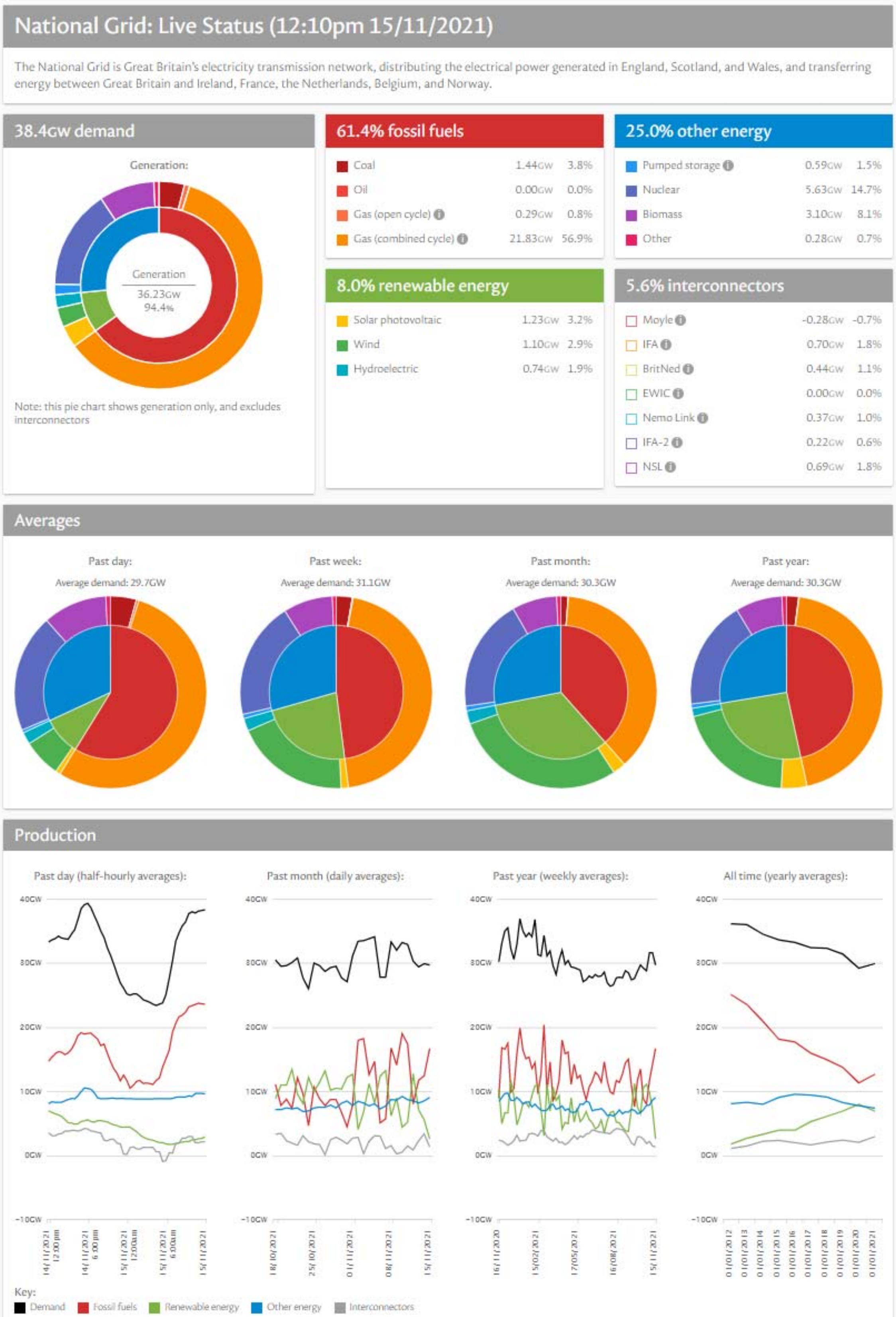
Source: BP Statistical Review of World Energy 2021

Very low wind speeds, these are in MPH. Link to UK wind speeds
https://www.metoffice.gov.uk/public/weather/forecast/map#?map=Wind&zoom=6&lon=-4.00&lat=53.26&fcTime=1607335200



Source: UK Met Office

Wind only 2.9% of UK electricity grid right now vs 27% over past month and 18% over past year , Link to live UK National Grid power supply https://grid.iamkate.com/



Source: National Grid

https://www.argusmedia.com/en/news/2273820-global-oil-industry-needs-600bnyr-investment-adnoc

Global oil industry needs $600bn/yr investment: Adnoc

Published date: 15 November 2021

Share:

The global oil and gas industry has "sleepwalked into a supply crunch" and needs to invest more than $600bn/yr for the rest of this decade to meet expected demand growth, according to the chief executive of Abu Dhabi's state-owned Adnoc.

Sultan al-Jaber told delegates at the Adipec oil and gas exhibition in Abu Dhabi today that the UAE supports a pragmatic approach to the use of fossil fuels to ensure global demand is met during the transition to a lower-carbon energy system.

"If we are to successfully transition to the energy system of tomorrow, we cannot simply unplug from the energy system of today. We cannot just flip a switch," he said. "While the world has agreed to accelerate the energy transition, it is still heavily reliant on oil and gas. As economies bounce back from the Covid-19 pandemic at the fastest rate in 50 years, demand has outpaced supply and after almost a decade of underinvestment in our industry the world has sleepwalked into a supply crunch. It is time to wake up."

Al-Jaber's warning comes after the UN Cop 26 climate change conference in Glasgow ended at the weekend with an agreement calling on countries to adopt policies to speed up "the phase-down of unabated coal power and phase out inefficient fossil fuel subsidies". It marked the first time that a UN Cop summit has explicitly mentioned coal and fossil fuel subsidies in its final cover text, although the language was watered down from previous drafts following an intervention from India and China.

Al-Jaber, who attended Cop 26 as the UAE's special envoy for climate change, said the talks were a success "on balance", despite the toning down of language in the final resolution. The UAE has been selected to host the Cop 28 round of UN climate talks in 2023, and this will present a multi-trillion-dollar opportunity to rewire the global energy system, he said.

The UAE was the first Middle Eastern oil producer to set a target of becoming a net zero carbon economy by 2050, but it is still pursuing a shorter-term expansion of production capacity across the hydrocarbons value chain, including Adnoc's target to boost crude output capacity by 25pc to 5mn b/d by 2030. Alongside investing in growing its oil capacity, Adnoc is trying to position itself as among the lowest cost and least carbon intensive oil producers in the world. From January, the company will switch to using up to 100pc renewable or nuclear power for its oil and gas operations.

"This will significantly reduce Adnoc's operational emissions. It brings us more than one-third of the way towards our 2030 carbon intensity target," Al-Jaber said.

By Adal Mirza

https://www.terrapower.com/natrium-demo-kemmerer-wyoming/

TerraPower selects Kemmerer, Wyoming as the preferred site for advanced reactor demonstration plant

November 16, 2021

PROJECT WILL BRING A FULLY FUNCTIONING NATRIUM™ POWER PLANT TO RETIRING COAL GENERATION SITE

BELLEVUE, Washington – November 16, 2021 – TerraPower today announced Kemmerer, Wyoming as the preferred site for the Natrium™ reactor demonstration project, which is a TerraPower and GE-Hitachi technology, and is one of two competitively-selected advanced reactor demonstration projects (ARDP) supported by the U.S. Department of Energy (DOE). The company selected the Kemmerer location, near the Naughton Power Plant, following an extensive evaluation process and meetings with community members and leaders.

"People across Wyoming welcomed us into their communities over the past several months, and we are excited to work with PacifiCorp to build the first Natrium plant in Kemmerer," said Chris Levesque, president and CEO of TerraPower. "Our innovative technology will help ensure the continued production of reliable electricity while also transitioning our energy system and creating new, good-paying jobs in Wyoming."

"This project is an exciting opportunity to explore what could be the next generation of clean, reliable, affordable energy production while providing a path to transition for Wyoming's energy economy, communities and employees," said Gary Hoogeveen, president and CEO of Rocky Mountain Power, a division of PacifiCorp.

"Just yesterday, President Biden signed the Bipartisan Infrastructure Deal and today DOE is already putting it to work with more than $1.5 billion heading to Wyoming," said Secretary of Energy Jennifer M. Granholm. "The energy communities that have powered us for generations have real opportunities to power our clean energy future through projects just like this one, that provide good-paying jobs and usher in the next wave of nuclear technologies."

The demonstration project team evaluated a variety of factors when selecting the site of the Naughton Power Plant, where the remaining two coal units are scheduled to retire in 2025. Factors included community support, the physical characteristics of the site, the ability of the site to obtain a license from the Nuclear Regulatory Commission (NRC), access to existing infrastructure, and the needs of the grid.

"On behalf of Kemmerer and surrounding communities, we are pleased and excited to host the Natrium demonstration project. This is great for Kemmerer and great for Wyoming," said Bill Thek, the mayor of Kemmerer.

The Natrium reactor demonstration project's preferred siting is subject to the finalization of definitive agreements on the site and applicable permitting, licensing and support. TerraPower anticipates submitting the demonstration plant's construction permit application to the NRC in mid-2023. The plant is expected to be operational in the next seven years, aligning with the ARDP schedule mandated by Congress.

According to project estimates, approximately 2,000 workers will be needed for construction at the project's peak. Once the plant is operational, approximately 250 people will support day-to-day activities, including plant security.

The demonstration plant is intended to validate the design, construction and operational features of the Natrium technology. The project features a 345 MW sodium-cooled fast reactor with a molten salt-based energy storage system. The storage technology can boost the system's output to 500 MW of power when needed, which is equivalent to the energy required to power around 400,000 homes. The energy storage capability allows the plant to integrate seamlessly with renewable resources.

Through the recently signed Infrastructure Investment and Jobs Act, DOE worked with Congress to allocate nearly $2.5 billion in new funding for ARDP. This allocation, along with previous funding, will cover DOE's commitment to TerraPower for the first five years of a seven-year, $2 billion agreement. TerraPower will match this investment dollar for dollar. Federal funding is provided for the demonstration activity under a cost-shared cooperative agreement and the result of the project will be a commercially-owned generating asset.

About TerraPower

TerraPower is a leading nuclear innovation company that strives to improve the world through nuclear energy and science. Since it was founded by Bill Gates and a group of like-minded visionaries, TerraPower has emerged as an incubator and developer of ideas and technologies that offer energy independence, environmental sustainability, medical advancement and other cutting-edge opportunities. It accepts and tackles some of the world's most difficult challenges. Behind each of its innovations and programs, TerraPower actively works to bring together the strengths and experiences of the world's public and private sectors to answer pressing global needs. Learn more at terrapower.com.

Dan Tsubouchi @Energy_Tidbits · 5h

India is in process of building strategic #Oil reserves. "I think we are at 86 days of consumption and the consumption is going up also. We need to go a little farther to make it at 100 days. We are in the process of doing that" @HardeepSPuri. Great interview @NaserElTibi. #OOTT

India's 'energy transition' minister talks net zero goals, green energy investments

3 · 7 · 10

Dan Tsubouchi @Energy_Tidbits · 14h

Here's how Japan releases strategic reserves to support #Biden - its current #Oil reserves are well over the legally required levels. See Google Translate of @Yomiuri_Online story flagged by @SStapczynski #OOTT

Google Translate of https://www.yomiuri.co.jp/politics/20211121-OYT1T50010/

There is also a plan to sell a part of the surplus and release it to the city for the first release of oil stockpile.

2021/11/21 10:10

The government has decided to release the national stockpile of oil as a measure against high oil prices. It is expected that the sale of stockpiles will temporarily increase the supply and suppress the price increase of petroleum products such as gasoline. Although the amount and period of release is limited, the government has decided that it is necessary to take measures because the high gasoline price has a widespread impact on people's lives.

Prime Minister Kishida said on the 20th about the release of oil reserves, "We are currently considering what can be legally done while assuming cooperation with Japan, the United States and related countries." I answered the questions of the reporters in Matsuyama City, where I visited.

According to government officials, Japan and the United States will be in step with each other within the week to announce the release of oil reserves.

The US Biden administration is under the hood and is consulting with Japan and South Korea to release stockpiles.

Japan's oil stockpiling includes national petroleum stockpiling owned by the government and private petroleum stockpiling required by law for oil companies. As of the end of September, the national stockpile is for 145 days of domestic daily consumption, and the private stockpile is for 90 days.

The Oil Stockpiling Law stipulates that national stockpiling is for 90 days or more of imports and private stockpiling is for 70 days or more of consumption. Currently, the minimum target amount has been exceeded, and there is a plan to sell a part of the surplus stockpile and release it to the market.

The law does not anticipate price increases as a condition for release, but the government believes that surpluses can be dealt with without being bound by the law.

Private stockpiles have been released in the wake of the 1991 Gulf War and the worsening situation in Libya in 2011, but this is the first time that national stockpiles have been released.

> **Stephen Stapczynski** @SStapczynski · 15h
>
> UPDATE: Japan and the US could make a joint announcement on the release of strategic oil reserves as soon as this week (!), according to the Yomiuri newspaper, citing an anonymous Japanese government official
>
> ...
>
> Show this thread

1 · 2

Dan Tsubouchi @Energy_Tidbits · 18h

#Vortexa crude #Oil floating storage for 11/19 est 90.00 mmb. Down WoW vs revised up 11/12 of 94.95 mmb (was original 83.48). 11/19 is +13.6 mmb vs recent 06/25 trough of 76.4 mmb. But -130.51 mmb vs 06/26/2020 peak of 222.51 mmb. Thx @Vortexa @TheTerminal #OOTT

Bloomberg, Vortexa

1

4

Dan Tsubouchi @Energy_Tidbits · 21h

Today would have been my dad's, Kiyoshi Thomas Tsubouchi, 100th birthday. A great man, husband, father & friend. He and my mom, Fumiko Frances were the best possible parents. I was lucky. Also he was an amazing athlete, wish he was still here so he could fix my crappy golf game!

18

Dan Tsubouchi @Energy_Tidbits · Nov 20

#Oil price watch. Is US relaxing Iran position? @SecDef "we will look at all the options necessary to keep the US secure". hard to believe it was slip of the tongue vs normal keep IR from getting nuclear weapon. #JCPOA starts 11/29, Hmm! #OOTT

reuters.com/world/middle-e...

nse Secretary Austin Nov 20, 2021. ""*We remain committed to a diplomatic outcome of the nuclear issue," "But if isn't willing to engage seriously, then we will look at all the options necessary to keep the United States secure."* ce: Reuters on Austin's speech on Nov 20 in Bahrain.

etary of State Blinken Oct 31, 2021 *"If -- if it isn't, if it won't, then we are looking together at all of the options ssary to deal with this problem."* Source: Bloomberg transcripts on Blinken CNN State of the Union

:en, Oct 13, 2021. *"We're united in the proposition that Iran cannot be allowed to acquire a nuclear weapon, and ident Biden is committed to that proposition." "And so as the foreign minister said, we -- we are discussing this ng -- among ourselves and we will look at -- at every option to -- to deal with the challenge posed by Iran."* Source: mberg transcrips on Blinken, Israel Foreign Minister Lapid and UAE Foreign Minister al Nahyan Oct 13 press erence.

ident Biden Sept 21, 2021. ""*The United States remains committed to preventing Ira- — to preventing Iran from ing a nuclear weapon. We are working with the P5+1 to engage Iran diplomatically and seek a return to the JCPOA e prepared to return to full compliance if Iran does the same."* Source: White House transcript of Biden address to General Assembly Sept 21

1 1 4

Dan Tsubouchi @Energy_Tidbits · Nov 20

"We are considering what we can do" says Japan PM Kishida re US request to release strategic #Oil reserves. Is the only legal option to do so by lowering their required level of oil reserves? #OOTT

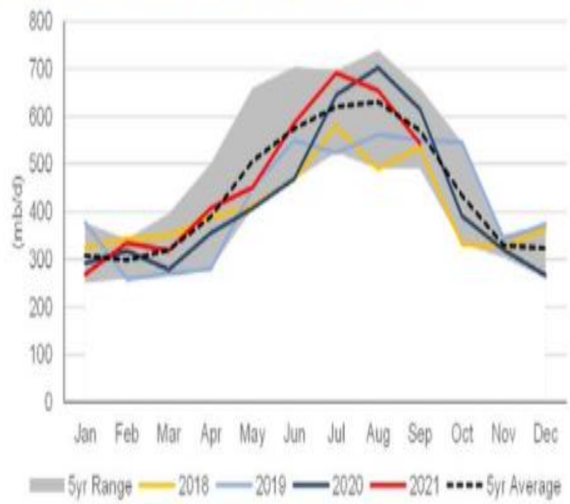
> The Japan Times @japantimes · Nov 19
>
> In response to the spike in crude oil prices, the United States has asked multiple countries — including Japan — to consider tapping oil stockpiles. japantimes.co.jp/news/2021/11/2...

2 3

Dan Tsubouchi @Energy_Tidbits · Nov 19

Saudi has more #Oil for export as it is in the normal seasonal decline for less oil for electricity. Summer peak 691,000 b/d in July, down to 654,000 b/d in Aug & @JODI_Data is down 111,000 b/d MoM to 543,000 b/d in Sept. Should drop another ~300,000 b/d to winter trough #OOTT

Figure xx: Saudi Arabia Direct Use of Crude Oil For Electric Generation



Source: JODI
Prepared by SAF Group https://safgroup.ca/news-insights/

1 5 5

SAF GROUP

Dan Tsubouchi @Energy_Tidbits · Nov 19

#TransMountain "is optimistic that we can restart the pipeline, in some capacity, by the end of next week", also "pipeline remains safely in a static condition". Restart can't happen quick enough for Cdn crude #Oil prices. Not clear what "in some capacity means". #OOTT

https://www.transmountain.com/news/2021/ensuring-safety-during-bc-and-wa-storm-impacts

Trans Mountain Progresses Planning for Pipeline Restart

Home › News

Nov 19, 2021

November 19, 2021, 3:30 pm PDT

The Trans Mountain Pipeline remains shut down following a voluntary precautionary shut down on Sunday, November 14, in anticipation of the impacts of the heavy rainfall and extreme weather conditions. The pipeline remains safely in a static condition and there is no indication of any loss of containment.

Trans Mountain has more than 200 people dedicated around the clock to getting the pipeline back up and running. Teams are beginning helicopter operations in the Coldwater region to remove fallen trees and debris that are hampering detailed inspection of the pipeline in that area. Another key priority remains getting ground access to the affected areas, and we are actively assisting the BC Ministry of Transportation and Infrastructure with getting roads cleared.

There are multiple areas of the pipeline between Hope and Merritt where pipeline cover needs to be restored and there are other sections that we may decide to cut-out and replace entirely, for example long sections that have been fully exposed to river course changes. As a precaution, Trans Mountain is deploying spill-response equipment trailers to areas where we will be working.

If all planning and work continues to progress and no further issues with the pipeline are assessed, Trans Mountain is optimistic that we can restart the pipeline, in some capacity, by the end of next week. Key to successful execution of the restart plan will be access for equipment, fair weather, and no new findings of concern.

The Trans Mountain Pipeline is a critical piece of infrastructure for British Columbia and Washington state and every effort is being made to safely restart the pipeline as promptly as possible. This is the longest period the pipeline has been shut down in its nearly 70-year history. Trans Mountain is in regular contact with its shippers and is working in cooperation with the Province to mitigate the effects of the pipeline shut down on the region.

Work on the Trans Mountain Expansion Project continues in many areas along the pipeline corridor – and crews in the Coquihalla and Merritt regions have been redeployed to assist with efforts to get the Trans Mountain Pipeline restarted.

We are in contact with Emergency Management British Columbia and continue to offer our support and assistance where possible.

3 4

Dan Tsubouchi @Energy_Tidbits · Nov 19

No one disputes @JonathanWNV is a good person, like predecessor @SeamusORegan. But aren't @JustinTrudeau & his advisors calling the shots? #Liberals Canadian Net-Zero Emissions Accountability Act requires them to ensure emissions cutting is on track to meet Net Zero. #OOTT

> Calgary Herald @calgaryherald · Nov 19
>
> Varcoe: Oilpatch and new resources minister promise to 'put elbows down' after meeting face to face bit.ly/3x1HE71

2

Dan Tsubouchi @Energy_Tidbits · Nov 18

Well deserved to see SAF Group CEO, Ryan Dunfield, recognized as one of Canada's Top 40 Under 40 Leaders. Great person, great leader. Pretty exciting to see where he's already taken SAF knowing he is just starting his peak years! safgroup.ca

caldwellpartners.com

Canada's Top 40 Under 40 Announces 2021 Hono...

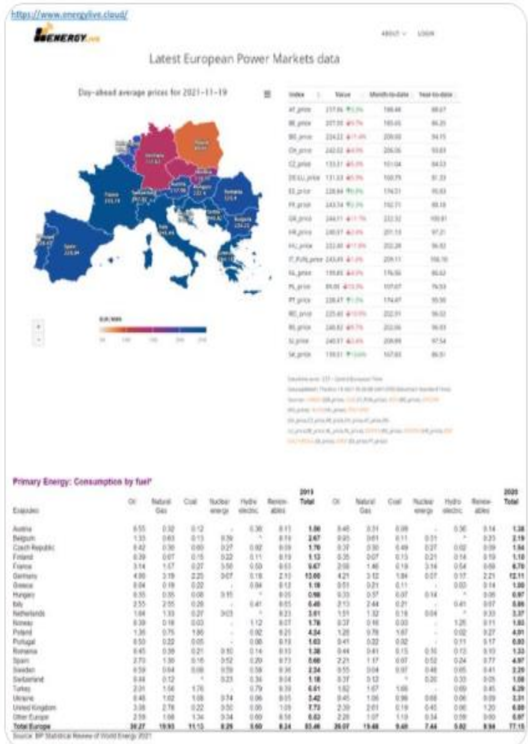
Canada's Top 40 Under 40 announced the 2021 recipients today in the National Post with Foundin...

2 9

Dan Tsubouchi @Energy_Tidbits · Nov 18

Most Europe power prices are >2x vs YTD. Big exception is Poland as #Coal supplies 42% of its energy mix. Thx @JavierBlas for highlighting the EnergyLive energylive.cloud data.
#NatGas #OOTT

energylive.cloud



3 3

Dan Tsubouchi @Energy_Tidbits · Nov 18

Will China actually release strategic #Oil reserves as per mkt reports? On 11/7, @vitolnews Mike Muller to @sean_evers highlighted only did 4 of 7 mmb Oct release, hadn't tendered for Nov release (ie. too late for a release) or Dec release. See SAF Group transcript. #OOTT

SAF Group created transcript of excerpt from Gulf Intelligence PODCAST: Daily Energy Markets Forum – New Silk Road Nov 7th https://soundcloud.com/user-846530307/podcast-daily-energy-markets-3

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

Sean Evers, Managing Partner Gulf Intelligence

Mike Muller, Head, Vitol Asia

At 20:00 min mark, Evers. "*Just sticking with China for a second on that point of view, a shortage. Clearly they still have a huge, still have a significant amount of oil in storage from stockpiling last year, is there an ability to bring that to for crossing over to power generation? Is there enough coal? What sort of winter does China face from a shortage point of view do you think?*

Muller: *There's a few things there, Sean. Number one, China is a major part of the switching from gas to oil where that is possible. So there's a fleet of LNG trucks that don't make sense to run at spot marginal prices and therefore should be seeing themselves replaced by diesel fleets and so forth. There is coal to gas liquids manufacturing processes, which have been halted as well. China is pretty well the only place in the world that does it. China has gone through a cycle in the last few weeks where there have been shortages and embarrassments in terms of brownouts, traffic lights not working in some of the northern cities to edicts from the central government not to run out. to a depletion of the Australian coal that is still not open for trade but there were stockpiles in China and ships sitting off of China, which have all been sucked in to the tune of one million tons. And a clear build up in LNG stocks. And then there is the oil you refer to. China was going to release about 27 million barrels of oil in three phases. In three chunks of 7 million barrels each, in the months of October, November and December. And we saw the first cycle where only four and bit million barrels of the seven million barrels were awarded. only domestic companies can partake in this of course. And there is no sign of the second release, at present. And there always tends to be a bit of an overtone on price on this, but, if China had a conviction of sticking to what they were going to do, we would have seen the second tender by now. And we have not yet seen it. so my personal view is that China is very much in an inventory building mode because they don't want to be caught short in a colder winter. And they have had extremely high domestic prices. I mean for a couple of weeks in October, China had the world's highest LNG, coal, diesel and gasoline prices. And they very successfully talked this down by policy and by edict a couple weeks back such that the steam got taken out of the whole thing. But you cannot move markets by words, in the end its all about inventories and about behaviour at the spot end of the market. But yes. watch this space. China is very much in a state of flux on NDRC rhetoric and directives versus real demand. And as I said a few minutes ago, there is a bit of a standoff in crude markets where the Chinese buyers for the January trading cycle haven't come to the table yet and are now faced with offers that are $1 or $2 a barrel higher at differentials vs Brent and Dubai than they were a month ago. And the view on the street is they will buy it because they need to.*"

Evers: "*They will buy it because they need to. That's not a good position to be in if you are a buyer*".

Prepared by SAF Group https://safgroup.ca/news-insights/

Dan Tsubouchi @Energy_Tidbits · Nov 7

2/2 China is very much in inventory building mode, its buyers haven't come to table yet to Jan Oil trading cycle, offers now $1/2 higher & "view on the street is they will buy because they need to". See SAF transcript of Muller's comment. Thx @sean_evers. Positive for ...

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2 4

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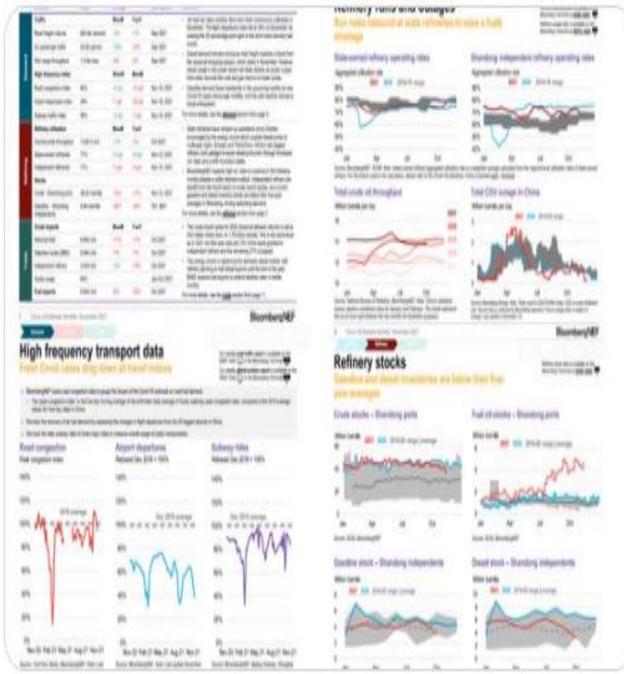
Dan Tsubouchi @Energy_Tidbits · Nov 17

China low refinery #Diesel #Gasoline stocks = increased refinery runs + halt diesel exports. #Oil demand travel indicators down due to Covid. Usual great insights from @BloombergNEF China Oil Markets Monthly. Thx stang237@bloomberg.net #OOTT



8 8

Dan Tsubouchi @Energy_Tidbits · Nov 17

US #Oil demand has recovered. @Colpipe allocates Line 2 for 1st time since May 2020, Line 2 carries #JetFuel, ULSD & heating oil. Line 1 carries #Gasoline & was allocated for 1st time since Aug 2020. Thx @SPGlobalPlatts Matthew Kohlman #OOTT

spglobal.com
Colonial Pipeline allocates Line 2 for first time sinc...
Colonial Pipeline has restricted shipments on its 1.16 million b/d, distillates only Line 2 for the first ...

4 4

Dan Tsubouchi @Energy_Tidbits · Nov 17

Slowing Arctic circulation could be a good sign for near term #NatGas. @NOAA reminds when the #PolarVortex is strong & stable, this keeps cold air contained over the Arctic. Thx @LeopoldHeinrich for all your updates. #OOTT

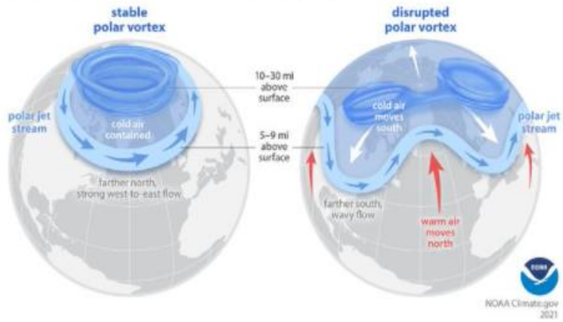
https://www.climate.gov/media/11999

Understanding the polar vortex

The Arctic polar vortex is a strong band of winds in the stratosphere, surrounding the North Pole 10–30 miles above the surface.

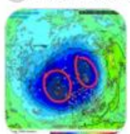
The polar vortex is far above and typically does not interact with the polar jet stream, the flow of winds in the troposphere 5–9 miles above the surface. But when the polar vortex is especially strong and stable, the jet stream stays farther north and has fewer "kinks." This keeps cold air contained over the Arctic and the mid-latitudes warmer than usual.

Every other year or so, the Arctic polar vortex dramatically weakens. The vortex can be pushed off the pole or split into two. Sometimes the polar jet stream mirrors this strato-spheric upheaval, becoming weaker or wavy. At the surface, cold air is pushed southward to the mid-latitudes, and warm air is drawn up into the Arctic.



File name: PolarVortex_Feb2021_large.jpg Original Resolution: 4034 pixels × 3370 pixels File Size: 1798 KB (MIME Type: image/jpeg) Publish Date: March 5, 2021

Heinrich Leopold @LeopoldHeinrich · Nov 17



The supercharged frigid Arctic air bubble has slowed its circulation speed as the reduction of the temperature differential between Arctic and oceans has slowed the centrifugal forces. The bubble disintegrates and cold air will spill over the continents by early December. ...

2 5 16

Dan Tsubouchi @Energy_Tidbits · Nov 16

one of our #Calgary squirrels putting our planters to good use for the winter.

1 1 2

Dan Tsubouchi @Energy_Tidbits · Nov 16

US #Oil production back to pre-Covid levels at end of 2022. @IEA Oil Market Report "US is set to account for 60% of 2022 non-OPEC+ supply gains, now forecast at 1.9 mb/d. Even so, the US will not return to pre-Covid rates until the end of 2022". #OOTT

iea.org

Oil Market Report - November 2021 – Analysis - IEA

Oil Market Report - November 2021 - Analysis and key findings. A report by the International Energy Agency.

1 1

Dan Tsubouchi @Energy_Tidbits · Nov 16

DE regulator "certification process remains suspended until ..if requirements are met..can contine its examination with the remainder of the 4-month period provided by law" Infers Jan 8 deadline extends for # days takes for #NordStream2 to comply. Thx @Wattwurm73! #NatGas #OOTT

https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/DE/2021/20211116_NOS2.html?nn=265778

Nord Stream 2 certification process temporarily suspended

Year of issue2021
Publication date11/16/2021

The Federal Network Agency has temporarily suspended the process for the certification of Nord Stream 2 AG as an independent transport network operator.

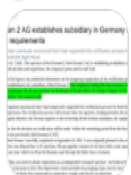
After a detailed examination of the documents, the Federal Network Agency came to the conclusion that certification of an operator of the Nord Stream 2 line is only possible if the operator is organized in a legal form under German law.

Nord Stream 2 AG , based in Zug, Switzerland, has decided not to convert the existing company, but to set up a subsidiary under German law only for the German part of the line. This subsidiary is to become the owner and operate the German section of the pipeline. The subsidiary itself must then meet the requirements of the Energy Industry Act for an independent transport network operator (Sections 4a, 4b, 10 to 10e EnWG).

The certification process remains suspended until the transfer of the essential assets and human resources to the subsidiary has been completed and the Federal Network Agency will be able to check the newly submitted documents of the subsidiary as the new applicant for completeness. If these requirements are met, the Federal Network Agency can continue its examination within the remainder of the four-month period provided by law, draw up a draft decision and, as provided by internal market law, submit it to the European Commission for comment.

The Federal Ministry for Economic Affairs and Energy and the European Commission were informed accordingly in advance. The decision was made known to those involved in the proceedings and then published.

Dan Tsubouchi @Energy_Tidbits · Nov 16



#NordStream2 establishing subsidiary to ensure compliance. "we do not comment on the details of the procedure, its timing or impact on the timing putting the gas pipeline into operation". #NatGas #LNG #OOTT twitter.com/CNBCJulianna/s...

1 1 2

Dan Tsubouchi @Energy_Tidbits · Nov 16

#NordStream2 establishing subsidiary to ensure compliance. "we do not comment on the details of the procedure, its timing or impact on the timing putting the gas pipeline into operation". #NatGas #LNG #OOTT

https://tass.ru/ekonomika/12937031

Nord Stream 2 AG establishes subsidiary in Germany to meet regulatory requirements

The German regulator previously announced that it had suspended the certification process for Nord Stream 2 due to organizational and legal issues.

MOSCOW, November 16. / TASS /. The operator of Nord Stream 2, Nord Stream 2 AG, is establishing a subsidiary in Germany to ensure compliance with all rules and regulations, the company's press service told TASS.

"The German Federal Grid Agency has published information on the temporary suspension of the certification procedure in connection with the establishment of a subsidiary of Nord Stream 2. Our company is taking this step to ensure compliance with applicable rules and regulations. We do not comment on the details of the procedure, its timing or impact on the timing putting the gas pipeline into operation, "the company said.

Earlier, the German regulator announced that it had temporarily suspended the certification process for Nord Stream 2 due to organizational and legal issues. The certification process will resume when the operator, headquartered in the Swiss city of Zug, transfers the share capital related to the German segment to the ownership of the German subsidiary, the regulator noted.

The regulator explains that the decision on certification will be made "within the remaining period from the four months provided by law." The deadline was previously called January 8, 2022.

The construction of Nord Stream 2 was fully completed on September 10, 2021. It was originally planned to be completed by the end of 2019, but construction was delayed due to US sanctions. The gas pipeline consists of two lines with a total capacity of 55 billion cubic meters. meters per year, which run from the Russian coast through the Baltic Sea to Germany.

To launch the gas pipeline, you need to obtain registration as an independent transport operator - the Federal Network Agency must publish a draft decision by January 8, 2022. This department cannot prohibit the pumping of gas, but if it starts before registration is received, the operator will be fined. This registration is required to comply with the EU Gas Directive.

Julianna Tatelbaum @CNBCJulianna · Nov 16

NEW: Germany energy regulator says #NordStream2 certification process SUSPENDED until its operating company arranges German company status compliant with national law

1 2 1

Dan Tsubouchi @Energy_Tidbits · Nov 16

month ahead dutch ttf prices jumped +6% once the #NordStream2 news broke. should also provide support for #Oil with continued #NatGas to fuel switching support. #OOTT

Source: Bloomberg

Julianna Tatelbaum @CNBCJulianna · Nov 16

NEW: Germany energy regulator says #NordStream2 certification process SUSPENDED until its operating company arranges German company status compliant with national law

3

Dan Tsubouchi @Energy_Tidbits · Nov 15

"Inventories have stopped drawing, which shows there is no deficit at the moment," Russia's Deputy Energy Minister Pavel. #OPEC+ keeps throwing the ball back in @POTUS @SecGranholm court if they want to see increased #Oil supply. #OOTT

bloomberg.com

Russia Joins OPEC+ Pushback on U.S. Calls to Boost Oil Output

Russia says there is no shortage of oil in the global market and there may even be a surplus from early next year, adding to the chorus of ...

1 2 4

Dan Tsubouchi @Energy_Tidbits · Nov 15

looks like the fishing on the #Calgary Elbow River is better on the left than right

1 1

Dan Tsubouchi @Energy_Tidbits · Nov 15

UK #PowerPrices soared to 2nd highest level on record today as low wind levels exposed the market to a supply crunch report @JesperStarn @rachelmorison . Wind currently 2.9% of grid vs 27% past mth & 18% past yr. #NatGas stepping in to save the day. #OOTT

1 1

Dan Tsubouchi @Energy_Tidbits · Nov 15

Best support for strong #LNG #NatGas prices thru 2030, Asian LNG buyers are locking up long term supply. And now JERA goes further & pays $2.5b to buy 25.7% intreest in #FreeportLNG to secure stable supply of cmpetitive LNG. See retweeted SAF July 14 blog. #OOTT

https://www.jera.co.jp/english/information/20211115_790

JERA to Invest in Freeport LNG Development to Secure a Stable LNG Supply

2021/11/15

JERA Co., Inc. ("JERA") has decided to invest, through its subsidiary JERA Americas Inc., in Freeport LNG Development, L.P. ("FLNG"), which operates the Freeport LNG project in the United States, and has concluded a securities purchase agreement with infrastructure fund Global Infrastructure Partners to acquire the approximately 25.7% interest in FLNG held by its subsidiaries (the "Transaction"). The approximately 2.5 billion USD acquisition is expected to be completed after the necessary approval and authorization procedures. For this Transaction, JERA Americas Inc. appointed Goldman Sachs & Co. LLC as its exclusive financial advisor and Sidley Austin as its legal advisor.

JERA, together with FLNG, has contributed to the stable operation of Train 1 of the Freeport LNG project through its participation in FLIQ 1 Holdings, LLC. As a result of the Transaction, JERA will not only be involved in the entire existing Freeport LNG project (three trains with an annual production capacity of approximately 15.45 mtpa) but will also work with FLNG to advance new LNG projects including production capacity expansion and the development of Train 4.

In Asia, there is demand for both decarbonization and a stable energy supply to support economic growth. Gas-fired power generation—which emits less CO_2 than power generation using other fossil fuels—can be a flexible supplement to intermittent renewable energy, and demand for it as an energy source indispensable to promoting the energy transition is expected to continue to grow. As evidenced by the current gas price hikes around the world, securing a stable supply of competitive LNG is becoming increasingly important.

FLNG's new LNG projects have extremely low development risk due to the use of the existing Freeport LNG project, which enables the company to flexibly expand production capacity in response to increased global LNG demand. In addition, since there are no resale or destination restrictions on LNG exported from the project, JERA believes it will be possible to supply LNG to Japan when supply is tight and to otherwise respond flexibly to the LNG supply and demand situation in the Asian region.

By leveraging the knowledge and expertise it has accumulated through its global LNG value chain business and power plant operations, JERA will work together with FLNG on its various businesses—such as operation of the existing Freeport LNG project, development of new LNG projects, and flexible LNG transactions—as it strives to improve the competitiveness of the Freeport LNG project.

Under its "JERA Zero CO_2 Emissions 2050" objective, JERA has been working to reduce CO_2 emissions from its domestic and overseas businesses to zero by 2050, promoting the adoption of greener fuels, and pursuing thermal power that does not emit CO_2 during power generation. JERA also plans to establish decarbonization roadmaps optimized for each country and region and to promote zero-emission initiatives that follow these roadmaps.

Leveraging its long experience in the LNG value chain businesses, JERA will follow the decarbonization roadmaps that are to be drawn up for each country and region as it strives to expand the adoption of LNG—an indispensable transitional fuel for achieving decarbonization—and to contribute to global decarbonization and energy solutions.

Dan Tsubouchi @Energy_Tidbits · Jul 14

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

3 7

Dan Tsubouchi @Energy_Tidbits · Nov 15

Saudi/Kuwait toss ball back in @POTUS court - you want more #Oil above #OPEC plans, then use your SPR or get your oil co's to produce more. & Saud's Abdulaziz reminds its not an oil issue, its an issue of #NatGas #LNG #Coal & availability of #Electricity. thx @HermsTheWord #OOTT

> Herman Wang @HermsTheWord · Nov 15
>
> As many #OPEC+ members struggle to hit their oil production targets, Saudi Arabia and Kuwait are preaching harmony and respect, saying they won't chase market share at the expense of their counterparts #OOTT #ADIPEC2021
>
> spglobal.com/platts/en/mark...

1 1 7

Dan Tsubouchi @Energy_Tidbits · Nov 14

Our weekly SAF Nov 14, 2021 Energy Tidbits memo is posted on our SAF Group website. This 43-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/

SAF GROUP

Energy Tidbits

Nov 14, 2021

Produced by: Dan Tsubouchi

OPEC: OECD/non-OECD Global Oil Stocks Down 938 Million Barrels Since June 2020 Peak

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

This week's memo highlights:

1. OPEC highlights global oil stocks down 938 mmb since June 2020 peak: OECD commercial -411 mmb, OECD SPR -46 mmb, non-OECD -320 mmb, and oil at sea -160 mmb. (Click Here)
2. Vitol CEO is latest to see global oil demand back to pre-Covid levels (Click Here)
3. Eni CEO oil demand is rebounding yet "*those who must ensure energy are unable to maintain production at necessary pace*" (Click Here)
4. COP26 President "we have kept 1.5 alive… but I would say that the pulse of 1.5 is weak" (Click Here)
5. Macron says France will work with the EU to "*build a credible strategy for reducing our CO2 emissions*" ie. need a realistic plan (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.
7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

2 · 2 · 4