Energy Tidbits

LNG Canada Will Inevitably Drive Multi-Year M&A for Cdn Natural Gas

Produced by: Dan Tsubouchi

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https://www.farmersalmanac.com/extended-forecast

Farmers' Almanac Winter 2024 Extended Weather Forecast

Wondering what the extended weather forecast is for the winter ahead? Will there be a snowstorm or three—enough snow to plow and play in? Will cold temperatures bring shivers to your backyard? Here's the *Farmers' Almanac* Winter 2024 Extended Weather Forecast, including a winter weather advisory that you need to see.

The BRRR Is Back!

Winter weather is making a comeback. After a warm winter anomaly last year, traditional cool temperatures and snowy weather conditions will return to the contiguous United States. (Be sure to read our winter weather advisory below.)

When Will The First Snowstorm Come?

Winter officially starts on Thursday, December 21, 2023. But that doesn't mean the cold conditions and snow will wait until then. Did you know that meteorological winter starts on December 1? December 2023 is forecast to start out quite stormy. Our extended weather forecast calls for some blizzard conditions blowing snow into areas over northern New England, the North Central States, and northern and central areas of New Mexico, Oklahoma, and Arkansas.

What about Christmas? What are the chances you'll have a white Christmas?

Reason for the Return of the "Brrr"

There are indications that an El Niño (an unusually high-water temperature off the Pacific Coast of South America), will be brewing in the latter half of 2023, lasting into the winter of 2024. If we consider that alongside our tried-and-true forecast formula, it means that cold temperatures should prevail throughout the country and bring snow, sleet, and ice.

How Cold And Snowy?

Our extended weather forecast, which is based on a mathematical and astronomical formula, calls for below-average temperatures and lots of snowstorms, sleet, ice, rain for much of the Great Lakes and Midwest areas of the country, as well as central and northern New England, especially in January and February. (Brrr…)

When will the first snowfall of the season be?

An unusually snowy and wet winter is also predicted for the Pacific Northwest. Should an El Niño materialize, it could direct the subtropical jet stream into California, translating into copious amounts of rain and snow across the entire Southwest.

Winter in the Great Plains and Rockies will usher in plenty of cold temperatures and occasional bouts of storminess, bringing widespread rains and snows.

Texans will need to bundle up, as unseasonably cold weather is forecast throughout January and February, with a possible major winter storm in mid-January.

The Southeast and Florida will see a wetter-than-normal winter, with average winter temperatures overall, but a few frosts may send many shivers to snowbirds trying to avoid the cold and snow back home.

For those of you living along the I-95 corridor from Washington to Boston, who saw a lack of wintry precipitation last winter, you should experience quite the opposite, with lots of rain/sleet and snowstorms to contend with.

What zone do you live in?

Winter Weather Advisory

The following are a few winter weather advisory times that our extended weather forecast is suggesting you might want to bundle up, buy some extra hot chocolate, make plans to stay home, or plan a skiing trip.

- The second week of January will be stormy, snowy, and wet for both the Pacific Coast and the Eastern States.
- Lots of cold temperatures and some storms will keep folks in the South Central States busy during the middle of January.
- Heavy mountain snows will cover the western US including the mountains on the Pacific Coast during the first week of February.
- An East Coast storm affecting the Northeast and New England states will bring snowfall, cold rain and then frigid temperatures, during the second week of February.
- Unseasonably cold temperatures will blow into the Southeast States mid-February.
- Potential blizzards for this first week of March will remind folks in the North Central States that winter isn’t over yet.
- Another East Coast storm will bring a wintry mess to this area during the first week of March.

- A possible late-season snowfall over the high terrain of New England during the third week of April won't be a fun "April Fools' Day" prank!

Want to see the details of this winter weather advisory? Get the entire year's forecast for your area of the country by signing up for a Farmhouse Membership (or logging in and heading here if you are a member already).

Find out what zone you are in as well as see your month-by-month forecast.

When Will Winter End?

March will remind us that the Brrr is Back and won't let go too easily. March's extended forecast calls for wild swings in the thermometer, especially in the East. And March could go out like a lion, with stormy conditions nationwide.

About Our Extended Weather Forecast

Every year since 1818, we consult our time-tested weather formula to offer you an extended weather forecast not only for the winter ahead, but the entire year. Our goal is to help you plan ahead. Yes, predicting the weather that far in advance has its risks, and at a times, nature likes to remind us that she has the last word. But we do our best with the tools we have to offer you both these summary outlooks and zoned forecasts.

https://totalenergies.com/media/news/press-releases/australia-totalenergies-acquires-26-interest-cash-maple-gas-discoveries

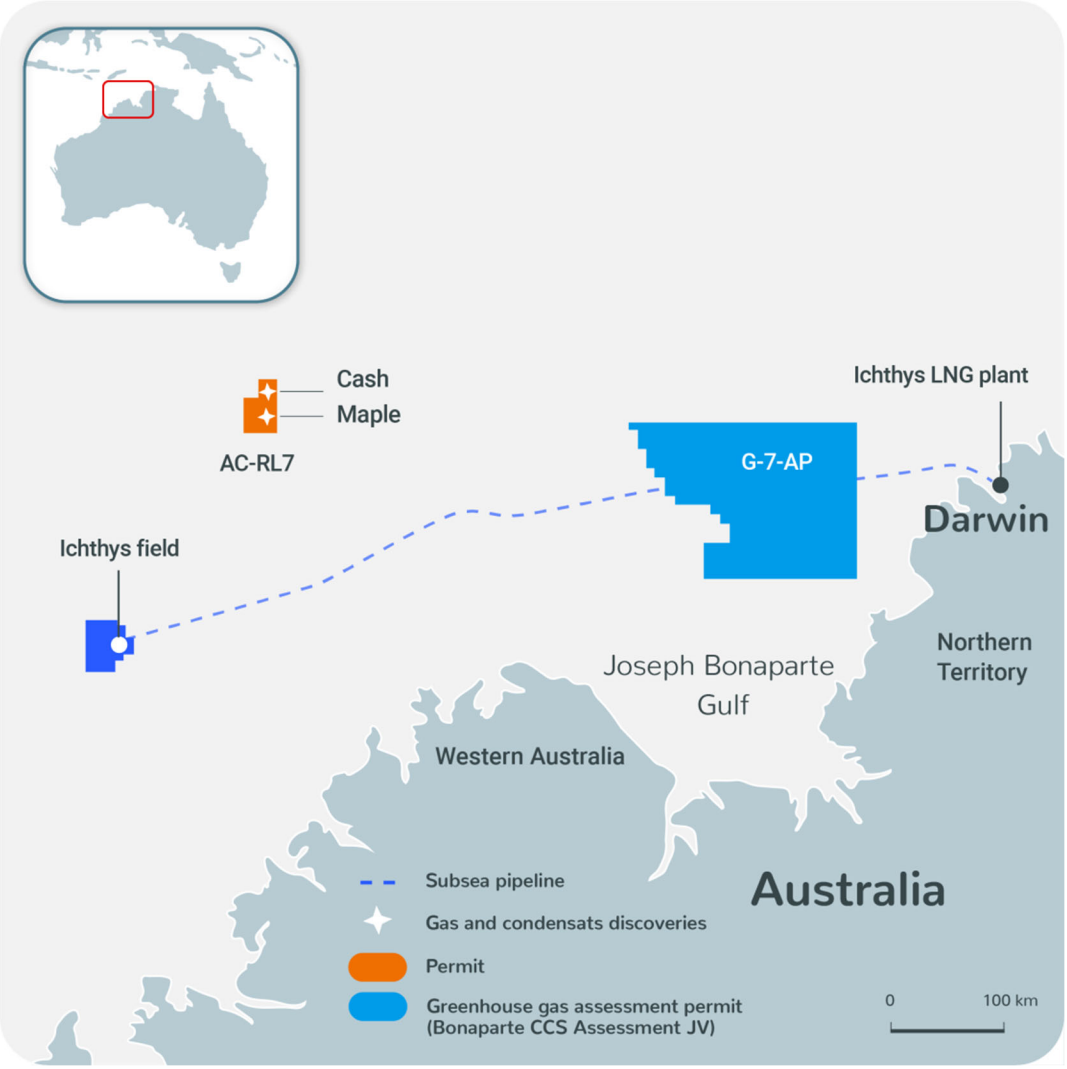
Australia: TotalEnergies acquires a 26% interest in the Cash-Maple gas discoveries for the long-term supply of Ichthys LNG

08/21/2023

Paris, August 21, 2023 – TotalEnergies and INPEX have signed an agreement with PTTEP in order to acquire the 100% interest held by PTTEP in the AC-RL7 permit in Australia. Under the terms of the agreement, which is subject to approval by the relevant authorities, TotalEnergies will acquire a 26% interest in the permit in line with its equity in Ichthys LNG, while INPEX will acquire the remaining 74% and assume operatorship.

The permit covers an area of 418 sq.km in the Timor Sea, approximately 250 kilometers northeast of the Ichthys offshore facilities. This permit includes the Cash and Maple gas and condensate fields, discovered in 2002 and 1989 respectively, and subsequently appraised by several wells. The development of these fields is expected to contribute to the long-term supply of the Ichthys LNG natural gas liquefaction plant, in which TotalEnergies is a 26% partner while INPEX and other Asian minority shareholders hold the remaining 74%.

“Thanks to this joint acquisition together with our partner INPEX, we are pleased to secure additional resources for the future supply of the Ichthys LNG plant. These resources will help us to meet the long-term demand of our customers in the Asia-Pacific region for LNG. This acquisition is also supported by the efforts undertaken with INPEX in the Bonaparte CCS Assessment joint venture to appraise the area’s potential for geological storage of CO_2, in order to abate CO_2 emissions from the Ichthys LNG project”, said **Julien Pouget, Senior Vice President Asia-Pacific, Exploration & Production at TotalEnergies**.



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TotalEnergies, the world's third largest LNG player

TotalEnergies is the world's third largest LNG player with a market share of around 12% and a global portfolio of about 50 Mt/y thanks to its interests in liquefaction plants in all geographies. The Company benefits from an integrated position across the LNG value chain, including production, transportation, access to more than 20 Mt/y of regasification capacity in Europe, trading, and LNG bunkering. TotalEnergies' ambition is to increase the share of natural gas in its sales mix to close to 50% by 2030, to reduce carbon emissions and eliminate methane emissions associated with the gas value chain, and to work with local partners to promote the transition from coal to natural gas.

About TotalEnergies

TotalEnergies is a global multi-energy company that produces and markets energies: oil and biofuels, natural gas and green gases, renewables and electricity. Our more than 100,000 employees are committed to energy that is ever more affordable, cleaner, more reliable and accessible to as many people as possible. Active in nearly 130 countries, TotalEnergies puts sustainable development in all its dimensions at the heart of its projects and operations to contribute to the well-being of people.

August 22, 2023

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

Long-term SPA Expected to Support Sabine Pass Expansion Project

HOUSTON--(BUSINESS WIRE)-- Cheniere Energy, Inc. (“Cheniere” or the “Company”) (NYSE American: LNG) announced today that Cheniere’s subsidiary, Cheniere Marketing, LLC (“Cheniere Marketing”), has entered into a long-term liquefied natural gas (“LNG”) sale and purchase agreement (“SPA”) with BASF (“BASF”).

Under the SPA, BASF has agreed to purchase up to approximately 0.8 million tonnes per annum (“mtpa”) of LNG from Cheniere Marketing on a free-on-board (“FOB”) basis for a purchase price indexed to the Henry Hub price, plus a fixed liquefaction fee. Deliveries will commence in mid-2026 and, subject to a positive Final Investment Decision with respect to the first train (“Train Seven”) of the Sabine Pass Liquefaction Expansion Project (“SPL Expansion Project”) in Louisiana, will increase to approximately 0.8 mtpa upon the start of commercial operations of Train Seven. The term of the SPA extends through 2043.

“We are pleased to enter into this long-term relationship with BASF, a global leader in the chemical industry,” said Anatol Feygin, Cheniere’s Executive Vice President and Chief Commercial Officer. “This SPA demonstrates the critical role US natural gas plays in providing long-term secure, sustainable and affordable energy for Europe. With this agreement, we are supporting the objectives of one of Europe’s key industrial end-use consumers to ensure stability of its supply chain.”

“By establishing our own dedicated LNG supply chain with Cheniere, we are diversifying our energy and raw materials portfolio at a time of critical changes in the European gas market, which is marked by increased demand and volatile prices for LNG,” said Dr. Dirk Elvermann, BASF’s Chief Financial Officer. “While we are reducing our dependence on fossil fuels to reach our goal of net zero CO_2 emissions by 2050, this agreement will ensure reliable supply of natural gas at competitive terms.”

The SPL Expansion Project is being developed for up to approximately 20 mtpa of total LNG capacity. In May 2023, certain subsidiaries of Cheniere Energy Partners, L.P. (NYSE American: CQP) entered the pre-filing review process with respect to the SPL Expansion Project with the Federal Energy Regulatory Commission under the National Environmental Policy Act.

About Cheniere

Cheniere Energy, Inc. is the leading producer and exporter of LNG in the United States, reliably providing a clean, secure, and affordable solution to the growing global need for natural gas. Cheniere is a full-service LNG provider, with capabilities that include gas procurement and transportation, liquefaction, vessel chartering, and LNG delivery. Cheniere

has one of the largest liquefaction platforms in the world, consisting of the Sabine Pass and Corpus Christi liquefaction facilities on the U.S. Gulf Coast, with total production capacity of approximately 45 mtpa of LNG in operation and an additional 10+ mtpa of expected production capacity under construction. Cheniere is also pursuing liquefaction expansion opportunities and other projects along the LNG value chain. Cheniere is headquartered in Houston, Texas, and has additional offices in London, Singapore, Beijing, Tokyo, and Washington, D.C.

For additional information, please refer to the Cheniere website at www.cheniere.com and Quarterly Report on Form 10-Q for the quarter ended June 30, 2023, filed with the Securities and Exchange Commission.

Forward-Looking Statements

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

View source version on businesswire.com:
https://www.businesswire.com/news/home/20230821634304/en/

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Source: Cheniere Energy, Inc.

https://www.adnocgas.ae/en/News-and-Media/Press-Releases/2023/ADNOC-Gas---JAPEX---AR

- August 17, 2023 Abu Dhabi, UAE

ADNOC Gas Signs 5-Year LNG Supply Agreement with Japan Petroleum Exploration Co. Ltd.

ADNOC Gas Signs 5-Year LNG Supply Agreement with Japan Petroleum Exploration Co. Ltd.

LNG Supply Agreement valued at between $450-550 million reinforces ADNOC Gas' position as a global LNG export partner of choice

Agreement builds on the long-standing energy partnership between the UAE and Japan, and underscores the Company's growing global presence, particularly in the Asian LNG market
Natural gas plays a crucial role as a transitional fuel with lower carbon emissions compared to other fossil fuels

Abu Dhabi, UAE – August 17, 2023: ADNOC Gas plc ("ADNOC Gas" or the "Company"), a world-class integrated gas processing company, today announced a five-year liquefied natural gas (LNG) supply agreement with Japan Petroleum Exploration Co., Ltd. (JAPEX), the Japan-based energy company.

The agreement, valued between $450 million (AED1.65 billion) and $550 million (AED 2 billion), builds on the long-standing bilateral relationship between the UAE and Japan and ADNOC's track record of fostering mutually beneficial strategic partnerships with Japanese energy companies.

Commenting on the agreement, Ahmed Alebri, Chief Executive Officer of ADNOC Gas, said: "Japan is one of the UAE's largest and most important energy partners and we are very pleased to strengthen this relationship through this LNG supply agreement with JAPEX. The agreement reinforces ADNOC Gas' position as a global LNG export partner of choice and highlights the Company's growing global presence, particularly in the Asian LNG market."

Natural gas plays a crucial role as a transitional fuel with lower carbon emissions compared to other fossil fuels. It also serves as an important raw material in industrial value chains.
ADNOC Gas continues to leverage opportunities arising from ADNOC's integrated gas masterplan which links every part of the gas value chain in the UAE, ensuring a sustainable and economic supply of natural gas to meet local and international demand.

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About ADNOC Gas

ADNOC Gas, listed on the ADX (ADX symbol: “ADNOCGAS” / ISIN: “AEE01195A234”), is a world-class, large-scale integrated gas processing company operating across the gas value chain, from receipt of raw gas feedstock from ADNOC through large, long-life operations for gas processing and fractionation to the sale of products to domestic and international customers. ADNOC Gas supplies approximately 60% of the UAE’s sales gas needs and supplies end-customers in over 20 countries. To find out more, visit: www.adnocgas.ae.

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https://timesofoman.com/article/134802-oman-lng-signs-a-binding-term-sheet-agreement-with-german-company

Oman LNG signs a binding term-sheet agreement with German company

Oman Monday 14/August/2023 15:43 PM

By: ONA

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The agreement signing ceremony was held under the auspices of Eng. Salim Nasser al Aufi, Minister of Energy and Minerals (ONA)

Muscat: Oman LNG announced the signing of a binding term-sheet agreement with SEFE Secure Energy for Europe (SEFE) to supply 0.4 million metric tonnes per annum (mtpa) of LNG starting from 2026.

The agreement aims to enhance the ever-growing partnership between Oman LNG and international energy firms, where SEFE has become the latest beneficiary of Omani LNG marking the first LNG term deal with a German firm. The move is considered a remarkable milestone for both countries, thus opening doors for new opportunities in the European markets.

The signed term-sheet agreement encapsulates supplying a total volume of 0.4 million metric tonne per annum of LNG from Oman LNG to SEFE. The agreement is based on a 4-year contract, starting in 2026. Signing term-sheet agreements beyond 2024 emphasises Oman LNG's role in sustaining the Sultanate of Oman's reputation as a reliable and trusted LNG supplier, coupled with the effective management of business processes to produce reliable energy, and deliver it to customers around the world safely.

The agreement signing ceremony was held under the auspices of Eng. Salim Nasser al Aufi, Minister of Energy and Minerals. The agreement was signed by Hamed Al Naamany, CEO of Oman LNG, and Frederic Barnaud, Chief Commercial Officer of SEFE.

Mahmoud Abdulsatar Al Balushi, Chief Commercial Officer of Oman LNG, said "The term-sheet signing with SEFE marks another milestone. Going further, the agreement leverages our constant efforts to add value to Oman's economy through growth and collaborations.

On his turn, Egbert Laege, CEO of SEFE said, "We are delighted to announce the historic contract signing between SEFE and Oman LNG, marking a significant milestone for both entities. As pioneers among German companies to embark on this partnership, SEFE is proud to lead the way towards enhanced collaboration."

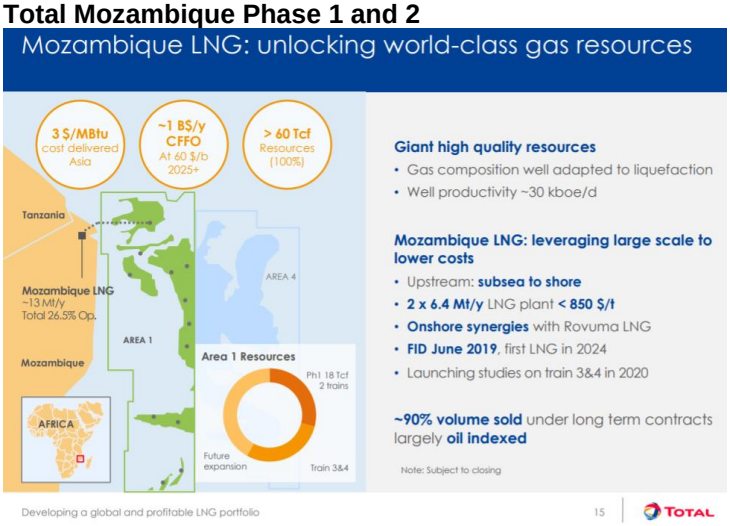
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

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

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

Total Mozambique Phase 1 and 2



Source: Total Investor Day September 24, 2019

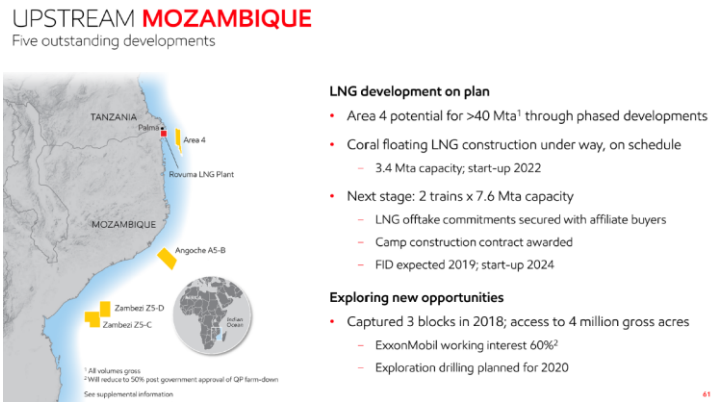
Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner". Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF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

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

Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years. The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and

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

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

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

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

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

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

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

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

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

Source: IEA

On Track More Efforts Needed Not on Track

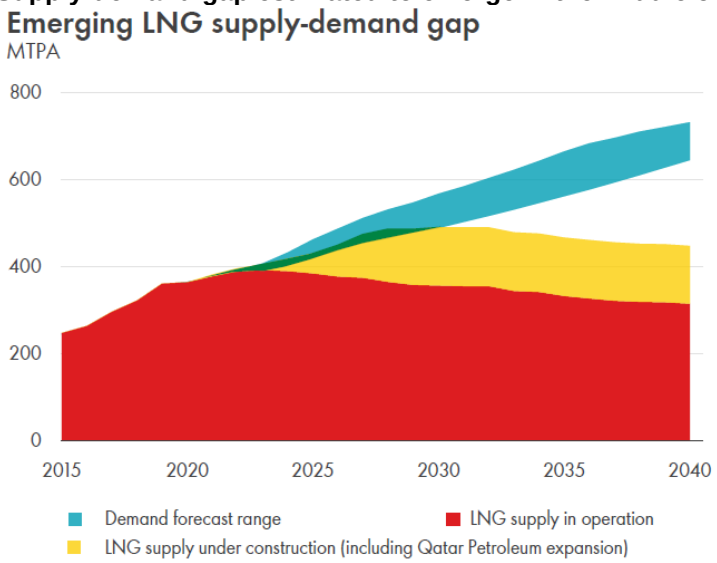
Source: IEA Tracking Clean Energy Progress, June 2020

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

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

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

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

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.

Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs. 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.

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. 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.*

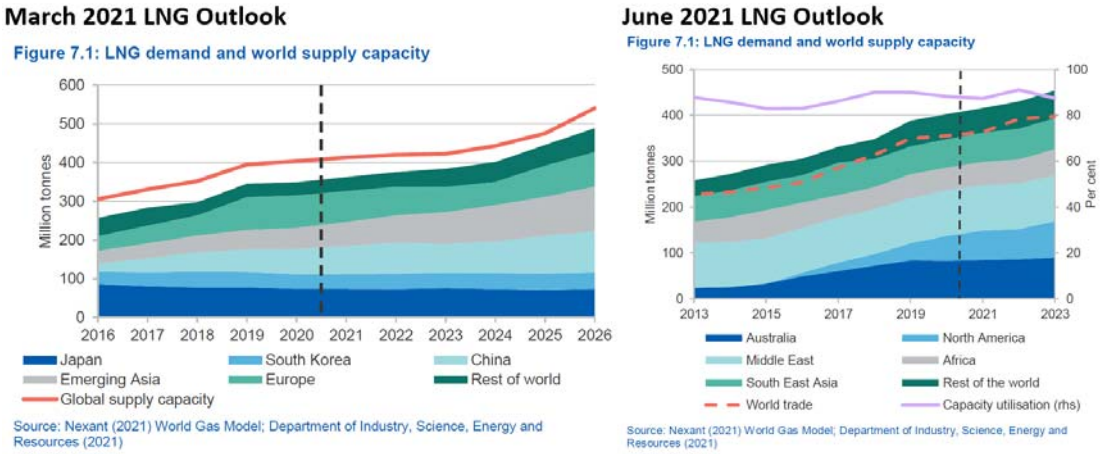
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

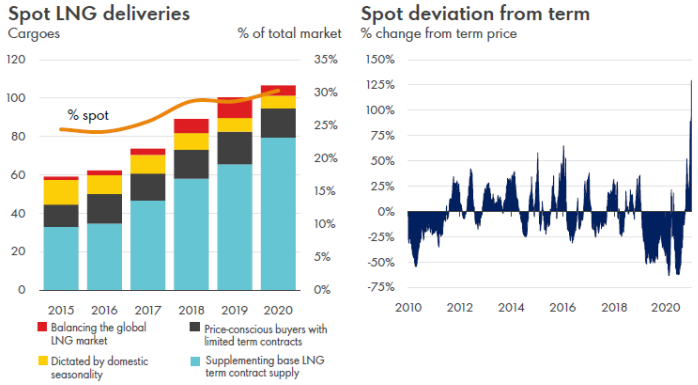


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

> Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d. On July 7, we tweeted [LINK] on the confirmation of a big positive to Cdn natural gas with the Petronas announcement [LINK] of a new 10 year LNG supply deal for 0.3 bcf/d with China's CNOOC. The deal also has special significance to Canada. (i) Petronas said "*This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade*". This is a reminder of the big positive to Cdn natural gas in the next 3 to 4 years – the start up of LNG Canada Phase 1 is ~1.8 bcf/d capacity. This is natural gas that will no longer be moving south to the US or east to eastern Canada, instead it will be going to Asia. This will provide a benefit for all Western Canada natural gas. (ii) First ever AECO linked LNG deal. It's a pretty significant event for a long term Asia LNG deal to now have an AECO link. Petronas wrote "*The deal is for 2.2 million tonnes per annum (MTPA) for a 10-year period, indexed to a combination of the Brent and Alberta Energy Company (AECO) indices. The term deal between PETRONAS and CNOOC is valued at approximately USD 7 billion over ten years.*" 2.2 MTPA is 0.3 bcf/d. (iii) Reminds of LNG Canada's competitive advantage for low greenhouse gas emissions. Petronas said "*Once ready for operations, the LNG Canada project paves the way for PETRONAS to supply low greenhouse gas (GHG) emission LNG to the key demand markets in Asia."*
>
> Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d. Pre Covid, Qatar was getting pressured to renegotiate lower its long term LNG contract prices. Now, it's signing a 15 year deal. On July 9, they entered in a new small long term LNG sales deal [LINK], a 15-yr LNG Sale and Purchase Agreement with CPC Corporation in Taiwan to supply it ~0.60 bcf/d of LNG. LNG deliveries are set to begin in January 2022. H.E. Minister for Energy Affairs & CEO of Qatar Petroleum Al-Kaabi said *"We are pleased to enter into this long term LNG SPA, which is another milestone in our relationship with CPC, which dates back to almost three decades. We look forward to commencing deliveries under this SPA and to continuing our supplies as a trusted and reliable global LNG provider."* The pricing was reported to be vs a basket of crudes.

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

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

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

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

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

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

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

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

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

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

https://www.facebook.com/people/Offshore-Alliance/100063786371409/

Offshore Alliance

13h ·

With a history of over 3 decades of individual employment contracts and no Woodside EBA's on the North West Shelf, the Offshore Alliance campaign to bargain and negotiate a union EBA on behalf of the NRC, GWA and Angel Platform crew was always going to be tough going.

But to the credit of Platform crew, they got organised, unionised and locked in behind the OA campaign to secure Tier 1 union standard rates and conditions.

The Employee Union Reps across all disciplines on each of the 3 Platforms did an outstanding job of ensuring that the rank-and-file EBA claims were clearly articulated during our bargaining negotiations.

And every union member on each of the 3 Woodside Platforms can be proud of their efforts in backing in the Offshore Alliance LOC and being unbending in their commitment to taking Protected Industrial Action if our claims weren't sorted.

99% support for Protected Industrial Action showed the commitment of members to getting our Platform EBA sorted.

The Following Bargaining Claims Are Now Locked Into our Woodside Platform EBA

• Fixed REM of between $265K (Level 4) and $365K (Level 9) with annual indexation of rates;

• Variable REM of between $26K - $59K per annum locked into the EBA;

• Technical Based Level Progression;

• Relativity adjustments for Service Techs, Medics and Stores;

• Individual Performance Appraisals not linked to REM

• All 2-2-2-4 rosters locked in and any roster changes must be mutually agreed;

• Job Security to prevent jobs being contracted out to labour hire;

• Additional 11 permanent Woodside jobs on the Platforms;

• Temporary Transfers locked in (rosters and other TOT conditions are agreed);

• Overcycle at 100% Comp Ratio (x 1.6+);

• Overcycle paid for late demob to Perth + for work on demob day;

• Improved catering standards (Gold Standard + 4 additional chefs to be employed);

• Salary continuance for 2 years;

• Travel from POR + $153 per diem for meals + travel at ATO km rate;

• Cyclone stand down pay at full rate + payment during travel delays;

• Employee Reps + DSP;

Highlights for the month

- Indigenous crude oil and condensate production during July 2023 was 2.50 MMT. OIL registered a production of 0.28 MMT, ONGC registered a production of 1.62 MMT whereas PSC registered production of 0.60 MMT during July 2023. A growth of 2.1% in total Crude Oil & Condensate Production has been achieved in July 2023 as compared to July 2022.
- 'Total Crude oil processed during July 2023 was 21.9 MMT which is 2.2% higher than July 2022. Where PSU/JV Refiners processed 14.7 MMT and PVT Refiners Processed 7.2 MMT of Crude Oil. Total Indigenous Crude Oil processed was 2.4 MMT and total Imported Crude oil processed was 19.5 by all Indian Refineries (PSU+JV+PVT).
- Crude oil imports decreased by 6.3% and 2.4% during July 2023 and April-July 2023 respectively as compared to the corresponding period of the previous year. As compared to net import bill for Oil & Gas for July 2022 of $15.8 billion, the net import bill for Oil & Gas for July 2023 was $9.8 billion. Out of which, crude oil imports constitutes $10.2 billion, LNG imports $2.1 billion and the exports were $4.1 billion during June 2023.
- The price of Brent Crude averaged $80.05/bbl during July 2023 as against $74.70/bbl during June 2023 and $112.70/bbl during July 2022. The Indian basket crude price averaged $80.37/bbl during July 2023 as against $74.93/bbl during June 2023 and $105.49 /bbl during July 2022.
- Production of petroleum products was 22.8 MMT during July 2023 which is 3.6% higher than July 2022. Out of above 22.5 MMT, was from Refinery production & 0.3 MMT was from Fractionator. There was 2.4 % growth in Production of petroleum products in Apr July, 2023 – 24 as compared to same period of 2022 – 23. Out of total POL production, in July 2023, HSD has 41.8 % share, MS has 16.7 %, Naphtha has 6.5 %, ATF has 6.3 %, Pet Coke has 5.8, % LPG has 4.8 % which are the major products and rest is shared by Bitumen, FO/LSHS, LDO, Lubes & others.
- POL products imports decreased by 4.8% and increased by 2.0% during July 2023 and April-July 2023 respectively as compared to the corresponding period of the previous year. Increase in POL products imports during April-July 2023 were mainly due to increase in imports of vacuum gas oil (VGO), bitumen and naphtha.

•	Exports of POL products increased by 14.3% and decreased by 6.0% during July 2023 and April-July 2023 respectively as compared to the corresponding period of the previous year. Decrease in POL products exports during April-July 2023 were mainly due to decrease in exports of high-speed diesel (HSD) and naphtha.
•	The consumption of petroleum products during April-July 2023 with a volume of 76.8 MMT reported a growth of 5.1% compared to the volume of 73.1 MMT during the same period of the previous year. This growth was led by 6.7% growth in MS, 7.1% in HSD & 13.7% in ATF & 10.5% in Naptha consumption besides LPG, FO/LSHS, Lubes, Bitumen and LDO during the period. The consumption of petroleum products during July 2023 recorded a growth of 1.9% with a volume of 18.1 MMT compared to the same period of the previous year.
•	Ethanol blending with Petrol was 11.9% during July 2023 and cumulative ethanol blending during December 2022- July 2023 was 11.8%.
•	Total Natural Gas Consumption (including internal consumption) for the month of July 2023 was 5297 MMSCM which was 4.5% higher than the corresponding month of the previous year. The cumulative consumption of 21398 MMSCM for the current financial year till July 2023 was higher by 3.9% compared with the corresponding period of the previous year.
•	Gross production of natural gas for the month of July 2023 (P) was 3123 MMSCM which was higher by 8.3% compared with the corresponding month of the previous year. The cumulative gross production of natural gas of 11687 MMSCM for the current financial year till July 2023 was higher by 2.2% compared with the corresponding period of the previous year.
•	LNG import for the month of July 2023 (P) was 2234 MMSCM which was 1.1% lower than the corresponding month of the previous year. The cumulative import of 9982 (P) MMSCM for the current financial year till July 2023 was higher by 4.7% compared with the corresponding period of the previous year.

1. Selected indicators of the Indian economy

	Economic indicators	Unit/ Base	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
1	Population (basis RGI projections)	Billion	1.323	1.337	1.351	1.365	1.377	1.388
2	GDP at constant (2011-12 Prices)	Growth %	6.5 2nd RE	4.0 1st RE	-6.6 1st RE	9.1 1st RE	7.2 PE	6.5 BE
3	Agricultural Production (Food grains)	MMT	285.2	297.5	310.7	315.7 4th AE	323.6 2nd AE	-
		Growth %	0.1	4.3	4.5	1.6	2.5	-
4	Gross Fiscal Deficit (as percent of GDP)	%	3.4	4.6	9.5 RE	6.7 RE	6.4 RE	5.9 E

	Economic indicators	Unit/ Base	2021-22	2022-23	July		April-July	
					2022-23	2023-24 (P)	2022-23	2023-24 (P)
5	Index of Industrial Production (Base: 2011-12)	Growth %	11.4	5.5#	12.6*	3.7* QE	12.9#	4.5#
6	Imports^	$ Billion	611.9	714.2	67.8	77.8	306.4	272.4
7	Exports^	$ Billion	422.0	451.0	59.4	62.6	259.7	244.2
8	Trade Balance	$ Billion	-189.9	-263.2	-8.4	-15.2	-46.7	-28.3
9	Foreign Exchange Reserves @	$ Billion	617.6	578.4	573.9	603.9	-	-

Population projection by RGI is taken as on 1st July for the year. IIP is for the month of *June'23 and #April-June'23; @2021, 2021-22 - as on March 26, 2022, Mar 2022 as on Mar 25, 2022, Mar 2023-as on Mar 31, 2023, July 2022 as on July 29, 2022 and July 2023 as on July 28, 2023; ^Imports & Exports are for Merchandise for the month of July 23; E: Estimates; PE: Provisional Estimates; AE-Advanced Estimates; RE-Revised Estimates; QE-Quick Estimates.

Source: Registrar General India, Ministry of Commerce & Industry, Ministry of Statistics and Programme Implementation, Ministry of Agriculture & Farmer's Welfare, Ministry of Finance, Reserve Bank of India

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

	Details	Unit/ Base	2021-22 (P)	2022-23 (P)	July		April-July	
					2022-23 (P)	2023-24 (P)	2022-23 (P)	2023-24 (P)
1	Crude oil production in India[#]	MMT	29.7	29.2	2.5	2.5	9.9	9.8
2	Consumption of petroleum products*	MMT	201.7	223.0	17.7	18.1	73.1	76.8
3	Production of petroleum products	MMT	254.3	266.5	22.0	22.8	90.1	92.2
4	Gross natural gas production	MMSCM	34,024	34,450	2,883	3,123	11,436	11,687
5	Natural gas consumption	MMSCM	64,159	59,969	5,311	5,297	20,925	21,398
6	Imports & exports:							
	Crude oil imports	MMT	212.4	232.7	20.6	19.3	81.3	79.4
		$ Billion	120.7	157.6	16.3	10.2	64.3	41.6
	Petroleum products (POL) imports*	MMT	39.0	44.5	3.7	3.6	14.3	14.6
		$ Billion	23.7	26.8	2.5	1.5	10.1	6.7
	Gross petroleum imports (Crude + POL)	MMT	251.4	277.3	24.4	22.9	95.7	94.0
		$ Billion	144.3	184.4	18.8	11.8	74.4	48.3
	Petroleum products (POL) export	MMT	62.8	61.0	4.7	5.4	21.3	20.0
		$ Billion	44.4	57.3	4.9	4.1	23.7	14.4
	LNG imports*	MMSCM	31,028	26,304	2,500	2,234	9,773	9,982
		$ Billion	13.5	17.1	1.9	2.1	6.6	6.7
	Net oil & gas imports	$ Billion	113.4	144.2	15.8	9.8	57.3	40.6
7	Petroleum imports as percentage of India's gross imports (in value terms)	%	23.6	25.8	27.7	15.1	24.3	17.7
8	Petroleum exports as percentage of India's gross exports (in value terms)	%	10.5	12.7	8.2	6.5	9.1	5.9
9	Import dependency of crude oil (on POL consumption basis)	%	85.5	87.4	86.3	86.1	86.4	87.8

#Includes condensate; *Private direct imports are prorated for the period June'23 to July'23 for POL. LNG Imports figure from DGCIS are prorated for July 2023.Total may not tally due to rounding off.

3. Indigenous crude oil production (Million Metric Tonnes)

Details	2021-22	2022-23 (P)	July			April-July		
			2022-23 (P)	2023-24 Target*	2023-24 (P)	2022-23 (P)	2023-24 Target*	2023-24 (P)
ONGC	18.5	18.4	1.6	1.6	1.53	6.3	6.5	6.1
Oil India Limited (OIL)	3.0	3.2	0.3	0.3	0.28	1.0	1.1	1.1
Private / Joint Ventures (JVs)	7.0	6.2	0.5	0.6	0.50	2.2	2.3	2.0
Total Crude Oil	**28.4**	**27.8**	**2.3**	**2.5**	**2.3**	**9.5**	**9.9**	**9.2**
ONGC condensate	0.9	1.0	0.08	0.0	0.09	0.3	0.0	0.4
PSC condensate	0.3	0.31	0.03	0.0	0.10	0.09	0.0	0.28
Total condensate	**1.2**	**1.4**	**0.11**	**0.0**	**0.2**	**0.4**	**0.0**	**0.6**
Total (Crude + Condensate) (MMT)	**29.7**	**29.2**	**2.5**	**2.5**	**2.5**	**9.9**	**9.9**	**9.8**
Total (Crude + Condensate) (Million Bbl/Day)	0.60	0.59	0.58	0.60	0.59	0.60	0.60	0.59

*Provisional targets inclusive of condensate.

4. Domestic and overseas oil & gas production (by Indian Companies)

Details	2021-22	2022-23 (P)	July		April-July	
			2022-23 (P)	2023-24 (P)	2022-23 (P)	2023-24 (P)
Total domestic production (MMTOE)	63.7	63.6	5.3	5.6	21.3	21.5
Overseas production (MMTOE)	21.8	19.5	1.6	1.6	6.5	6.6

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

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

	Details	2021-22	2022-23 (P)	July		April-July	
				2022-23 (P)	2023-24 (P)	2022-23 (P)	2023-24 (P)
1	High Sulphur crude	185.0	197.9	17.1	16.9	68.2	68.4
2	Low Sulphur crude	56.7	57.4	4.3	5.0	19.0	19.2
Total crude processed (MMT)		**241.7**	**255.2**	**21.4**	**21.9**	**87.2**	**87.6**
Total crude processed (Million Bbl/Day)		4.85	5.13	5.07	5.17	5.24	5.26
Percentage share of HS crude in total crude oil processing		**76.6%**	**77.5%**	**79.8%**	**77.3%**	**78.2%**	**78.0%**

6. Quantity and value of crude oil imports			
Year	**Quantity (MMT)**	**$ Million**	**Rs. Crore**
2021-22 (P)	212.4	120,675	9,01,262
2022-23 (P)	232.7	157,597	12,60,910
April-July 2023-24(P)	79.4	41,637	3,42,180

7. Self-sufficiency in petroleum products (Million Metric Tonnes)							
Particulars		**2021-22**	**2022-23 (P)**	**July**		**April-July**	
				2022-23 (P)	**2023-24 (P)**	**2022-23 (P)**	**2023-24 (P)**
1	Indigenous crude oil processing	27.0	26.4	2.2	2.4	9.3	8.8
2	Products from indigenous crude (93.3% of crude oil processed)	25.2	24.7	2.1	2.2	8.7	8.2
3	Products from fractionators (Including LPG and Gas)	4.1	3.5	0.3	0.3	1.2	1.2
4	Total production from indigenous crude & condensate **(2 + 3)**	29.3	28.2	2.4	2.5	9.9	9.4
5	Total domestic consumption	201.7	223.0	17.7	18.1	73.1	76.8
% Self-sufficiency (4 / 5)		**14.5%**	**12.6%**	**13.7%**	**13.9%**	**13.6%**	**12.2%**

8. Refineries: Installed capacity and crude oil processing (MMTPA / MMT)										
Sl. no.	Refinery	Installed capacity (01.04.2023) MMTPA	Crude oil processing (MMT)							
			2021-22	2022-23 (P)	July			April-July		
					2022-23 (P)	2023-24 (Target)	2023-24 (P)	2022-23 (P)	2023-24 (Target)	2023-24 (P)
1	Barauni (1964)	6.0	5.6	6.8	0.6	0.6	0.6	2.3	2.2	2.2
2	Koyali (1965)	13.7	13.5	15.6	1.3	1.2	1.3	5.3	4.3	5.1
3	Haldia (1975)	8.0	7.3	8.5	0.7	0.6	0.7	2.8	2.7	2.8
4	Mathura (1982)	8.0	9.1	9.6	0.7	0.3	0.4	3.2	2.8	2.9
5	Panipat (1998)	15.0	14.8	13.8	1.2	1.2	1.2	4.8	4.9	5.0
6	Guwahati (1962)	1.0	0.7	1.1	0.09	0.1	0.1	0.37	0.4	0.4
7	Digboi (1901)	0.65	0.7	0.7	0.06	0.03	0.06	0.2	0.2	0.2
8	Bongaigaon(1979)	2.70	2.6	2.8	0.2	0.3	0.2	0.8	1.0	1.0
9	Paradip (2016)	15.0	13.2	13.6	1.3	1.3	1.4	5.3	5.0	5.2
	IOCL-TOTAL	**70.1**	**67.7**	**72.4**	**6.2**	**5.6**	**6.0**	**25.1**	**23.5**	**24.8**
10	Manali (1969)	10.5	9.0	11.3	1.0	0.9	1.0	3.9	3.7	3.7
11	CBR (1993)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CPCL-TOTAL	**10.5**	**9.0**	**11.3**	**1.0**	**0.9**	**1.0**	**3.9**	**3.7**	**3.7**
12	Mumbai (1955)	12.0	14.4	14.5	0.7	1.3	1.4	4.1	5.0	5.3
13	Kochi (1966)	15.5	15.4	16.0	1.4	1.3	1.4	5.5	5.4	5.7
14	Bina (2011)	7.8	7.4	7.8	0.6	0.5	0.0	2.6	1.8	1.9
	BPCL-TOTAL	**35.3**	**37.2**	**38.4**	**2.7**	**3.0**	**2.8**	**12.3**	**12.1**	**12.9**
15	Numaligarh (1999)	3.0	2.6	3.1	0.3	0.3	0.2	1.0	0.6	0.3

Sl. no.	Refinery	Installed capacity (01.04.2023) MMTPA	Crude oil processing (MMT)							
			2021-22	2022-23	July			April-July		
					2022-23	2023-24 (Target)	2023-24 (P)	2022-23	2023-24 (Target)	2023-24 (P)
16	Tatipaka (2001)	0.066	0.075	0.073	0.005	0.006	0.005	0.025	0.019	0.024
17	MRPL-Mangalore (1996)	15.0	14.9	17.1	1.4	1.5	1.4	5.8	5.7	5.9
	ONGC-TOTAL	**15.1**	**14.9**	**17.2**	**1.4**	**1.5**	**1.4**	**5.8**	**5.7**	**5.9**
18	Mumbai (1954)	9.5	5.6	9.8	0.9	0.8	0.9	3.3	3.1	3.3
19	Visakh (1957)	11.0	8.4	9.3	0.7	0.9	1.1	3.1	3.6	4.1
20	HMEL-Bathinda (2012)	11.3	13.0	12.7	1.1	1.0	1.1	4.3	3.9	4.3
	HPCL- TOTAL	**31.8**	**27.0**	**31.8**	**2.7**	**2.7**	**3.1**	**10.7**	**10.7**	**11.7**
21	RIL-Jamnagar (DTA) (1999)	33.0	34.8	34.4	2.9	2.9	3.0	12.0	12.0	11.5
22	RIL-Jamnagar (SEZ) (2008)	35.2	28.3	27.9	2.5	2.5	2.6	9.6	9.6	10.1
23	NEL-Vadinar (2006)	20.0	20.2	18.7	1.7	1.7	1.7	6.8	6.8	6.7
All India (MMT)		**253.9**	**241.7**	**255.2**	**21.4**	**21.2**	**21.9**	**87.2**	**84.8**	**87.6**
All India (Million Bbl/Day)		**5.02**	**4.85**	**5.13**	**5.07**	**5.00**	**5.17**	**5.24**	**5.10**	**5.26**

Note: Provisional Targets; Some sub-totals/ totals may not add up due to rounding off at individual levels. The Inputs to Refinery includes both Crude Oil and Other Inputs (OI), however Other Inputs (OI) do not form part of the above data.

9. Major crude oil and product pipeline network (as on 01.08.2023)

Details		ONGC	OIL	Cairn	HMEL	IOCL	BPCL	HPCL	Others*	Total
Crude Oil	Length (KM)	1,284	1,193	688	1,017	5,819	937			**10,938**
	Cap (MMTPA)	60.6	9.0	10.7	11.3	53.8	7.8			**153.1**
Products	Length (KM)		654			11,861	2,599	5,121	2,399	**22,634**
	Cap (MMTPA)		1.7			70.6	22.6	35.2	10.2	**140.3**

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

11. Production and consumption of petroleum products (Million Metric Tonnes)												
Products	2021-22		2022-23 (P)		July 2022		July 2023 (P)		Apr-July 2022		Apr-July 2023 (P)	
	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons
LPG	12.2	28.3	12.8	28.5	1.1	2.4	1.1	2.4	4.4	8.9	4.4	9.1
MS	40.2	30.8	42.8	35.0	3.6	2.8	3.8	3.0	14.7	11.6	15.0	12.4
NAPHTHA	20.0	13.2	17.0	12.2	1.4	1.2	1.5	1.1	6.0	3.9	5.9	4.3
ATF	10.3	5.0	15.0	7.4	1.2	0.6	1.4	0.7	4.5	2.3	5.6	2.6
SKO	1.9	1.5	0.9	0.5	0.1	0.0	0.1	0.0	0.4	0.2	0.3	0.2
HSD	107.2	76.7	113.8	85.9	9.3	6.6	9.5	6.9	38.8	28.8	38.8	30.8
LDO	0.8	1.0	0.6	0.7	0.08	0.1	0.05	0.1	0.2	0.2	0.2	0.3
LUBES	1.2	4.5	1.3	3.7	0.1	0.3	0.1	0.3	0.4	1.2	0.5	1.2
FO/LSHS	8.9	6.3	10.4	7.0	0.9	0.6	1.0	0.6	3.3	2.2	3.7	2.3
BITUMEN	5.1	7.8	4.9	8.0	0.2	0.3	0.3	0.5	1.7	2.6	1.8	3.0
PET COKE	15.5	14.3	15.4	18.3	1.3	1.7	1.3	1.6	5.2	6.2	5.1	6.4
OTHERS	30.9	12.3	31.5	15.8	2.6	1.2	2.6	1.0	10.4	5.0	10.7	4.2
ALL INDIA	**254.3**	**201.7**	**266.5**	**223.0**	**22.0**	**17.7**	**22.8**	**18.1**	**90.1**	**73.1**	**92.2**	**76.8**
Growth (%)	**-3.1%**	**-5.4%**	**4.8%**	**10.6%**	**6.2%**	**8.64%**	**3.6%**	**1.9%**	**11.6%**	**16.2%**	**2.4%**	**5.1%**

Note: Prod - Production; Cons - Consumption

15. LPG consumption (Thousand Metric Tonne)

LPG category	2021-22	2022-23	July			April-July		
			2022-23	2023-24 (P)	Growth (%)	2022-23	2023-24 (P)	Growth (%)
1. PSU Sales :								
LPG-Packed Domestic	25,501.6	25,381.5	2,157.1	2,121.8	-1.6%	8,087.5	8,113.4	0.3%
LPG-Packed Non-Domestic	2,238.8	2,606.0	202.0	224.9	11.3%	703.6	858.4	22.0%
LPG-Bulk	390.9	408.9	35.3	34.7	-1.7%	117.0	120.4	2.9%
Auto LPG	122.0	106.7	9.2	7.9	-14.2%	37.2	31.0	-16.7%
Sub-Total (PSU Sales)	28,253.3	28,503.1	**2,403.6**	**2,389.2**	**-0.6%**	**8,945.3**	**9,123.1**	**2.0%**
2. Direct Private Imports*	0.1	0.1	0.00	0.01	-	0.02	0.05	170.8%
Total (1+2)	28,253.4	28,503.2	**2,403.6**	**2,389.2**	**-0.6%**	**8,945.3**	**9,123.2**	**2.0%**

*June -July'23 DGCIS data is prorated

16. LPG marketing at a glance

Particulars (As on 1st of April)	Unit	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	1.08.23 (P)
LPG Active Domestic Customers	(Lakh)				1486	1663	1988	2243	2654	2787	2895	3053	3140	3143
	Growth					11.9%	19.6%	12.8%	18.3%	5.0%	3.9%	5.5%	2.9%	1.1%
LPG Coverage (Estimated)	(Percent)				56.2	61.9	72.8	80.9	94.3	97.5	99.8	-	-	-
	Growth					10.1%	17.6%	11.1%	16.5%	3.4%	2.3%	-	-	-
PMUY Beneficiaries	(Lakh)						200.3	356	719	802	800	899.0	958.6	958.6
	Growth							77.7%	101.9%	11.5%	-0.2%	12.2%	6.6%	1.5%
LPG Distributors	(No.)	11489	12610	13896	15930	17916	18786	20146	23737	24670	25083	25269	25386	25406
	Growth	9.0%	9.8%	10.2%	14.6%	12.5%	4.9%	7.2%	17.8%	3.9%	1.7%	0.7%	0.5%	0.4%
Auto LPG Dispensing Stations	(No.)	652	667	678	681	676	675	672	661	657	651	601	526	496
	Growth	7.9%	2.3%	1.6%	0.4%	-0.7%	-0.1%	-0.4%	-1.6%	-0.6%	-0.9%	-8.5%	-12.5%	-13.1%
Bottling Plants	(No.)	184	185	187	187	188	189	190	192	196	200	202	208	208
	Growth	0.5%	0.5%	1.1%	0.0%	0.5%	0.5%	0.5%	1.1%	2.1%	2.0%	1.0%	4.5%	2.5%

Source: PSU OMCs (IOCL,BPCL and HPCL)

1.Growth rates as on 01.08.2023 are with respect to figs as on 01.08.2022. Growth rates as on 1 April of any year are with respect to figs as on 1 April of previous year.

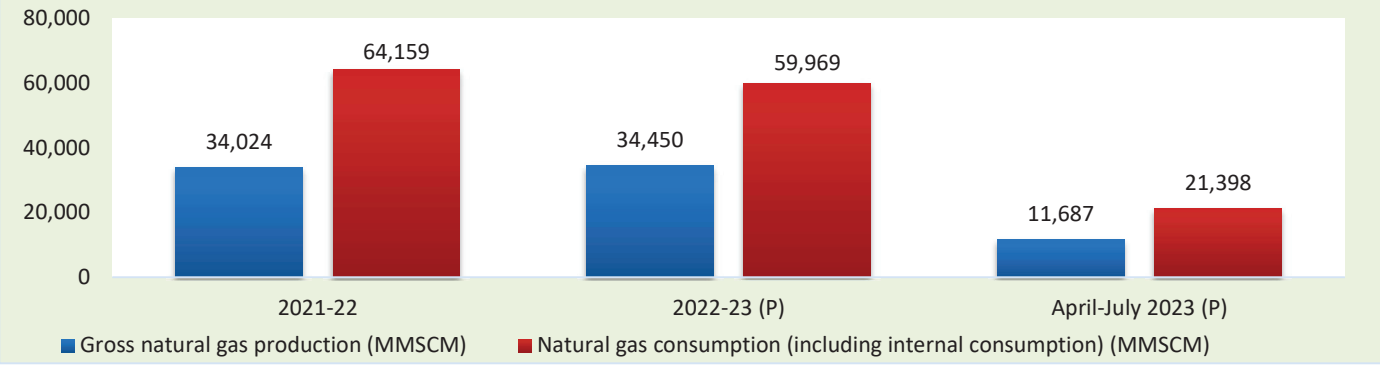
2. The LPG coverage is calculated by PSU OMCs based upon the active LPG domestic connections and the estimated number of households. The number of households has been projected by PSU OMCs based on 2011 census data. Factors like increasing nuclearization of families, migration of individuals/ families due to urbanization and reduction in average size of households etc. impact the growth of number of households. Due to these factors, the estimated no. of households through projection of 2011 census data may slightly differ from the actual no. of households in a State/UT. Further, this methodology does not include PNG (domestic) connections.

18. Natural gas at a glance

(MMSCM)

Details	2021-22 (P)	2022-23 (P)	July			April-July		
			2022-23 (P)	2023-24 (Target)	2023-24 (P)	2022-23 (P)	2023-24 (Target)	2023-24 (P)
(a) Gross production	34,024	34,450	2,883	3,246	3,123	11,436	11,990	11,687
- ONGC	20,629	19,969	1,663	1,740	1,644	6,749	6,881	6,522
- Oil India Limited (OIL)	2,893	3,041	263	274	263	1,005	1,019	996
- Private / Joint Ventures (JVs)	10,502	11,440	957	1,232	1,217	3,681	4,091	4,169
(b) Net production (excluding flare gas and loss)	33,131	33,664	2,811		3,063	11,152		11,417
(c) LNG import#	31,028	26,304	2,500		2,234	9,773		9,982
(d) Total consumption including internal consumption (b+c)	64,159	59,969	5,311		5,297	20,925		21,398
(e) Total consumption **(in BCM)**	64.2	60.0	5.3		5.3	20.9		21.4
(f) Import dependency based on consumption (%), {c/d*100}	48.4	43.9	47.1		42.2	46.7		46.6

July 2023 DGCIS data prorated.



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

Prognosticated CBM resources		91.8	TCF
Established CBM resources		10.4	TCF
CBM Resources (33 Blocks)		62.8	TCF
Total available coal bearing areas (India)		32760	Sq. KM
Total available coal bearing areas with MoPNG/DGH		17652	Sq. KM
Area awarded		20460	Sq. KM
Blocks awarded*		36	Nos.
Exploration initiated (Area considered if any boreholes were drilled in the awarded block)		10670***	Sq. KM
Production of CBM gas	April-July 2023 (P)	216.18	MMSCM
Production of CBM gas	July 2023 (P)	55.06	MMSCM

*ST CBM Block awarded & relinquished twice- in CBM Round II and Round IV -Area considered if any boreholes were drilled in the awarded block. **MoPNG awarded 04 new CBM Blocks (Area 3862 sq. km) under Special CBM Bid Round 2021 in September 2022. ***Area considered if any boreholes were drilled in the awarded block.

19a. Status of Compressed Bio Gas (CBG) projects under SATAT (as on 01.08.2023) (Provisional)

Particulars	Units	IOCL	HPCL	BPCL	GAIL	IGL	Total
No. of CBG plants commissioned and initiated sale of CBG	No. of plants	22	6	2	9	3	**42**
Start of CBG sale from retail outlet(s)	Nos.	50	30	45	1	2	**128**
Sale of CBG in 2022-23	Tons	5,822	77	6	5322#		**11,227**
Sale of CBG in 2023-24 (up to July, 2023)	Tons	1746	8	20	2804#		**4,578**
Sale of CBG in CGD network	GA Nos.				18		**18**

Sale of CBG sourced under CBG-CGD synchronization scheme through its own marketing channels as well as other CGDs/OMCs.

20. Common Carrier Natural Gas pipeline network as on 31.03.2023

Nature of pipeline		GAIL	GSPL	PIL	IOCL	AGCL	RGPL	GGL	DEPCL	ONGC	GIGL	GITL	Others*	Total
Operational	Length	10,930	2,716	1,484	143	107	304	73	42	24				**15,823**
	Capacity	233.2	43.0	85.0	20.0	2.4	3.5	5.1	0.7	6.0				-
Partially commissioned#	Length	4,173			282						1,279	365		**6,099**
	Capacity				-						-	-		-
Total operational length		**15,103**	**2,716**	**1,484**	**425**	**107**	**304**	**73**	**42**	**24**	**1,279**	**365**	**0**	**21,921**
Under construction	Length	5,095	100		1,149						1,077	1,666	2,915	**12,002**
	Capacity	-	3.0		-						-	-	-	-
Total length		**20,197**	**2,816**	**1,484**	**1,574**	**107**	**304**	**73**	**42**	**24**	**2,356**	**2,031**	**2,915**	**33,141**

Source: PNGRB; Length in KMs ; Authorized Capacity in MMSCMD (Arithmetic sum taken for each entity -capacity may vary from pipeline to pipeline); *Others-APGDC, , IGGL, IMC, Consortium of H-Energy.
Total authorized Natural Gas pipelines including Tie-in connectivity, dedicated & STPL is 35379 Kms (P)

21. Existing LNG terminals

Location	Promoters	Capacity as on 01.08.2023	% Capacity utilisation (April-July 2023)
Dahej	Petronet LNG Ltd (PLL)	17.5 MMTPA	95.7
Hazira	Shell Energy India Pvt. Ltd.	5.2 MMTPA	33.3
Dabhol	Konkan LNG Limited	*5 MMTPA	49.4
Kochi	Petronet LNG Ltd (PLL)	5 MMTPA	20.2
Ennore	Indian Oil LNG Pvt Ltd	5 MMTPA	14.7
Mundra	GSPC LNG Limited	5 MMTPA	11.1
Dhamra	Adani Total Private Limited	5 MMTPA	19.0
Total Capacity		**47.7 MMTPA**	

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

22. Status of PNG connections and CNG stations across India (Nos.), as on 30.06.2023(P)				
State/UT (State/UTs are clubbed based on the GAs authorised by PNGRB)	CNG Stations	PNG connections		
		Domestic	Commercial	Industrial
Andhra Pradesh	164	256,372	440	36
Andhra Pradesh, Karnataka & Tamil Nadu	40	382	0	5
Assam	5	50,913	1,354	448
Bihar	101	106,880	85	4
Bihar & Jharkhand	3	7,423	1	0
Bihar & Uttar Pradesh	14	0	0	0
Chandigarh (UT), Haryana, Punjab & Himachal Pradesh	25	25,977	125	25
Chhattisgarh	9	0	0	0
Dadra & Nagar Haveli (UT)	7	11,406	56	59
Daman & Diu (UT)	5	5,158	53	45
Daman and Diu & Gujarat	15	2,468	11	0
Goa	12	11,113	18	33
Gujarat	1,002	3,045,768	22,631	5,736
Haryana	346	326,356	872	1,830
Haryana & Himachal Pradesh	10	0	0	0
Haryana & Punjab	25	294	0	0
Himachal Pradesh	8	6,476	4	0
Jharkhand	79	113,157	5	1
Karnataka	307	391,264	537	318
Kerala	111	49,192	23	16
Kerala & Puducherry	9	419	0	0
Madhya Pradesh	236	212,313	365	458
Madhya Pradesh and Chhattisgrah	7	0	0	0
Madhya Pradesh and Rajasthan	32	454	0	0
Madhya Pradesh and Uttar Pradesh	16	0	0	2
Maharashtra	770	2,919,856	4,658	910
Maharashtra & Gujarat	60	160,219	6	24
Maharashtra and Madhya Pradesh	11	0	0	0
National Capital Territory of Delhi (UT)	480	1,453,894	3,631	1,815

State/UT (State/UTs are clubbed based on the GAs authorised by PNGRB)	CNG Stations	PNG connections		
		Domestic	Commercial	Industrial
Odisha	68	91,688	5	0
Puducherry	2	0	0	0
Puducherry & Tamil Nadu	8	220	1	0
Punjab	206	73,112	414	264
Punjab & Rajasthan	12	0	0	0
Rajasthan	256	231,164	128	1,560
Tamil Nadu	206	3,586	4	10
Telangana	157	193,589	84	105
Telangana and Karnataka	3	0	0	0
Tripura	18	59,854	506	62
Uttar Pradesh	816	1,411,014	2,346	2,782
Uttar Pradesh & Rajasthan	40	18,958	39	344
Uttar Pradesh and Uttarakhand	26	9,974	0	0
Uttarakhand	31	69,831	68	86
West Bengal	72	622	1	1
Total	**5,830**	**11,321,366**	**38,471**	**16,979**

Source: PNGRB

Note: 1. All the GAs where PNG connections/CNG Stations have been established are considered as Operational, 2. Under normal conditions. Operation of any particular GA commences within around one year of authorization. 3. State/UTs wherever clubbed are based on the GAs authorised by PNGRB.

23. Domestic natural gas price and gas price ceiling (GCV basis)

Period	Domestic Natural Gas price in	Gas price ceiling in US$/MMBTU
November 2014 - March 2015	5.05	-
April 2015 - September 2015	4.66	-
October 2015 - March 2016	3.82	-
April 2016 - September 2016	3.06	6.61
October 2016 - March 2017	2.5	5.3
April 2017 - September 2017	2.48	5.56
October 2017 - March 2018	2.89	6.3
April 2018 - September 2018	3.06	6.78
October 2018 - March 2019	3.36	7.67
April 2019 - September 2019	3.69	9.32
October 2019 - March 2020	3.23	8.43
April 2020 - September 2020	2.39	5.61
October 2020 - March 2021	1.79	4.06
April 2021 - September 2021	1.79	3.62
October 2021 - March 2022	2.9	6.13
April 2022 - September 2022	6.1	9.92
October 2022 - March 2023	8.57	12.46
1 April 2023 - 7 April 2023	9.16	12.12

Period	Domestic Gas calculated price in US$/MMBTU	Domestic Gas ceiling price for ONGC/OIL in US$/MMBTU	Period	HP-HT Gas price ceiling in US$/MMBTU
8 April 2023 - 30 April 2023	7.92	6.50	April 2023 - September 2023	12.12
1 May 2023 - 31May 2023	8.27	6.50		
1 June 2023 - 30 June 2023	7.58	6.50		
1 July 2023 - 31 July 2023	7.48	6.50		
1 Aug 2023 - 31 Aug 2023	7.85	6.50		

Natural Gas prices are on GCV basis

24. CNG/PNG prices

City	CNG (Rs/Kg)	PNG (Rs/SCM)	Source
Delhi	73.59	48.59	IGL website (09.08.2023)
Mumbai	79.00	49.00	MGL website (09.08.2023)

Indian Natural Gas Spot Price for Physical Delivery

IGX Price Index Month	Avg. Price		Volume (MMSCM)	Source
	INR/MMBtu	$/MMBtu		
July 2023	866	10.55	45.24	As per IGX website: www.igxindia.com

*Prices are weighted average prices |$1=INR 82.15| 1 MMBtu=25.2 SCM (Data Excluding Ceiling Price Gas)

Trans Mountain Pipeline ULC
Trans Mountain Expansion Project
Certificate of Public Convenience and Necessity OC-065
Application pursuant to section 211 of the *Canadian Energy Regulator Act* – Segment 5.3 (Pipsell area)
File OF-Fac-Oil-T260-2013-03 61

Information Request No. 1 to the applicant

1.1 Mitigation measures

Reference: C25832-1, Trans Mountain Pipeline ULC (**Trans Mountain**), Application, PDF page 5 of 14

Preamble: In the reference, Trans Mountain states that, in light of its suite of proven mitigation measures to avoid or minimize potential environmental, traditional land use, and cultural impacts, including in other important cultural areas for Indigenous communities, it is confident that its proposed combination of horizontal directional drilling and conventional open trench construction will allow it to reasonably avoid or minimize impacts on the lands in question.

Request: Describe Trans Mountain's suite of proven mitigation measures to avoid or minimize potential environmental, traditional land use, and cultural impacts resulting from the proposed deviation.

1.2 Construction methods

Reference: i) C25832-1, Trans Mountain, Application, PDF pages 3 and 4 of 14

ii) C25832-3, Trans Mountain, Application, Appendix B – Differences mapping

Preamble: In Reference i), Trans Mountain indicates the following:

- Trans Mountain is encountering significant technical challenges with micro-tunnelling along an approximately 1.3-kilometre-long portion of the approved route, specifically with the micro-tunnel drive between pads 1 and 2.
- The micro-tunnel drive has been particularly difficult with abnormal upward migration of the Reinforced Concrete Jacking Pipe (**RCJP**) that has substantially limited the ability to apply jacking force to the micro-tunnelling machine (from 1400 tons to 300 tons). As a result, RCJP deflection at the joints has increased over time as micro-tunnelling has progressed, which has increased the risk of losing watertight seal and/or damage to the RCJPs. If either of these risks were to materialize, successful completion of the micro-tunnel could be jeopardized.

- Trans Mountain has made several unsuccessful, costly attempts to address the problem of upward RCJP migration to date. Trans Mountain is currently constructing a new launch shaft along the alignment and abandoning the section of RCJP that has been affected by the vertical deflection. Construction of this new shaft requires a shutdown of tunnelling activities. During this downtime, the annular space between the tunnel wall and RCJP may restrict in diameter or drain of lubrication fluids, which will require high jacking forces to move the tunnel forward. This may create significant delays in restarting tunnelling.
- If the construction of the new shaft is successful and the tunnel commences forward progression, there remains approximately 800 metres of tunnel length to be constructed in medium to hard rock formations (with the potential to encounter other unfavourable construction conditions), which has its own material risk to the project and schedule.
- Trans Mountain has determined that the only feasible option is to change the construction methodology for an approximately 1.3-kilometre-long segment to a combination of horizontal directional drilling (**HDD**) and conventional open trench.

Reference ii) shows the location of the revised route in relation to the route approved by the Commission in Order AO-001-OPL-003-2020.

Request:

a) Provide the length of the section of RCJP affected by the vertical deflection, which Trans Mountain would abandon.

b) Describe the unsuccessful attempts that Trans Mountain has made to address the problem of upward RCJP migration to date.

c) Describe the mitigation measures that Trans Mountain could implement to complete the remaining 800 metres of tunnel if construction of the new shaft is successful.

d) Provide geotechnical reports and HDD feasibility and design reports, along with final design drawings.

e) Provide the contingency method that will be used should HDD be unsuccessful.

f) Provide an updated Reference ii) showing the start and end points for the HDD and conventional open trench portions.

Venezuela and US in Talks Over Possible Easing of Sanctions
2023-08-23 17:56:34.781 GMT
By Andreina Itriago Acosta, Nicolle Yapur and Jennifer Jacobs
(Bloomberg) -- The Biden administration is in talks with Venezuela to explore a temporary lifting of crippling sanctions in exchange for allowing fair elections next year.
The preliminary discussions involve senior officials from both nations, including Venezuela's head of congress Jorge Rodríguez, according to people familiar with the process, who asked not to be identified.
Washington has floated the idea of sanctions relief to persuade the regime of President Nicolás Maduro to hold a competitive presidential vote in 2024, and free political prisoners. Sanctions have aggravated Venezuela's economic and humanitarian crisis by hindering oil sales, though failed in their original objective of ousting Maduro.
If a deal is reached, the US would grant a license to lift some or all of Venezuela's sanctions temporarily.
The talks present the first significant opportunity to ease the restrictions, most of which were put in place by the 2017-2021 administration of US President Donald Trump, who took a hardline approach to the socialist government.
Maduro, in power since 2013, is widely expected to run for a third term next year, but has yet to set a date for the vote or invite foreign observers.
Read more: France, Brazil Urge Venezuela to Hold Fair Elections in 2024
It's unclear how soon a deal might be reached, if at all, and much will depend on the actions of the Maduro regime, according to the people. The government has taken a series of antidemocratic moves, including barring opposition candidates such as María Corina Machado.
"Should Venezuela take concrete actions toward restoring democracy, leading to free and fair elections, we are prepared to provide corresponding sanctions relief," said Adrienne Watson, a spokeswoman for the White House's National Security Council, in a written response to questions.
Any deal would come at a critical time, since Venezuela is soon to announce a new electoral board set to oversee the election.
Press officials for Venezuela's presidency and Jorge Rodríguez did not immediately respond to a request for comment.
Read more: Top Venezuelan Electoral Officials Step Down Ahead of Vote

--With assistance from Eric Martin, Daniel Flatley and Courtney McBride.

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https://www.argusmedia.com/en/news/2403155-high-hurdles-to-grow-chevrons-venezuela-oil-output

High hurdles to grow Chevron's Venezuela oil output

Published date: 21 December 2022

An internal Chevron plan to increase Venezuelan oil production to 200,000 b/d by mid-2023 relies on efforts to rehabilitate some 18,000 wells in various states of disrepair in the country's once-prolific Occidente region.

According to a report from Venezuela state-owned PdV obtained by *Argus*, about 7pc of existing wells in Occidente are operating. The 1,400 or so "Category 1" wells are producing oil, but many at declining rates.

About 8,700 wells fall into Category 2, which includes non-operating wells that may just need minor work to become operational. These wells may need around $500,000 each in new investment to be viable, according to sources familiar with the field.

In Category 3 are more than 7,900 wells that need between $5mn-$6mn of investment each to be commercially viable.

Hundreds of wells in the PdV report are reportedly shut down just for a lack of reliable electricity, which plagues many parts of the country. Many more have been stripped bare of any surface equipment by thieves.

Production in Occidente has declined from 150,000 b/d earlier this year to around 90,000 b/d in November.

Much of Chevron's work in Venezuela has been curtailed in recent years by US sanctions. The US eased some sanctions in late November when the government agreed to resume talks with the opposition about new elections, which will allow Chevron to sell crude from its Venezuela joint ventures.

Chevron was expected to send its first cargo of Venezuelan crude to a US Gulf coast refiner since 2018 by the end of December, but it is not yet clear if that will happen. Government officials are anxious to send a symbolic message with a cargo before the new year, while Chevron appears less concerned with rushing any shipments.

Chevron plans to increase its global spending in 2023 to $17bn, up from around $15bn in 2022, but has not disclosed any specific plans for Venezuela.

By Carlos Camacho

https://www.wsj.com/articles/chevron-waiting-it-out-in-venezuela-tells-u-s-now-is-the-time-to-pump-oil-11647959248?mod=newsviewer_click&adobe_mc=MCMID%3D43904269652561322512265019543051439235%7CMCORGID%3DCB68E4BA55144CAA0A4C98A5%2540AdobeOrg%7CTS%3D1647963540

Chevron, Waiting It Out in Venezuela, Tells U.S. Now Is the Time to Pump Oil

An oil refinery in Venezuela, where the U.S. has banned American oil companies from operating since 2019. YURI CORTEZ/AFP/GETTY IMAGES

By Christopher M. Matthews and José de Córdoba
March 22, 2022 10:27 am ET

HOUSTON—For months, Biden administration officials snubbed top executives and lobbyists for Chevron Corp. who had pressed officials in Washington to ease sanctions so the company could boost production in Venezuela, where the U.S. has banned such activities since 2019.

Then Vladimir Putin invaded Ukraine.

Now the Biden administration is listening closely to Chevron, say people familiar with the conversations, which says it can help double Venezuela's 800,000 barrels-a-day production within months. That could replace the loss of roughly 700,000 barrels a day the U.S. was importing from Russia before it attacked Ukraine. And it could help lower gasoline prices—a major concern for the Biden administration in a tough election year.

"Chevron came in November, they pitched it around, but got laughed out of town," said Juan Cruz, a former National Security Council official in charge of the Western Hemisphere who has closely followed the Biden administration's policy toward Venezuela. "But what was really funny in November is a plan today."

Since the Russians invaded on Feb. 24 and Mr. Biden canceled Russian oil imports, Chevron Chief Executive Officer Mike Wirth has offered the company's help to Secretary of Energy Jennifer Granholm in shoring up U.S. energy supplies by ramping up production in Venezuela, according to people briefed on the talks. Chevron is the only major U.S. producer to retain assets in Venezuela following nationalizations by the Socialist government and, much later, U.S. sanctions.

Granting the San Ramon, California-based company and other U.S. producers permits to operate could boost Venezuelan production while keeping other sanctions in effect. Broadly easing sanctions on Venezuela faces stiff opposition in the U.S. over concerns it would prop up the country's autocratic regime. U.S. officials are divided over the issue, say people familiar with the situation.

Asked recently by CNN about the outreach to Venezuela and Saudi Arabia for more oil, Ms. Granholm, said, “I think Americans should see the administration calling right now for an increase in supply as something that helps them,” naming the benefit of reducing costs at the pump.

Shortly after Mr. Wirth talked to the energy secretary, three senior U.S. officials—Juan Gonzalez, the senior National Security Council official in charge of Latin America; James Story, the U.S. ambassador to Venezuela; and Roger D. Carstens, a special envoy—flew to Caracas on March 5 and met with President Nicolás Maduro and other top Venezuelan officials.

Another person who spoke with senior Venezuelan officials after the invasion was Ali Moshiri, a charismatic Iranian-American who had headed Chevron’s Latin America division and was considered a “dear friend” by the late Hugo Chávez, the founder of the political movement now led by Mr. Maduro, with whom Mr. Moshiri also has close a close relationship. Mr. Moshiri retired from Chevron in 2017 but now consults for the company in Venezuela, where he has deep ties with senior officials, say people familiar with the matter.

Many oil industry executives say that Mr. Moshiri was essential to Chevron’s controversial decision to stay in the country even as other Western oil companies exited after the Venezuelan government in 2007 nationalized billions of dollars of assets owned by ConocoPhillips, Exxon Mobil Corp. and others. He has also lobbied Biden officials to loosen sanctions on Venezuela, where Chevron has operated for nearly a century.

“You cannot ignore Venezuela,” Mr. Moshiri said in an interview last week. “Venezuela will always be part of our energy security.”

The White House declined to comment about Chevron’s possible role or its own talks in Venezuela. The Energy Department declined to comment.

People briefed on the talks say Mr. Moshiri has argued to U.S. officials that the U.S. can’t cede influence of Venezuelan energy to rivals like China and Russia, which have increased their activities in the country in recent years. He has also spoken with Venezuelan officials for months to try to win the release of Americans imprisoned in Venezuela, these people said.

A Chevron spokesman said Mr. Moshiri isn’t representing the company in negotiations with the U.S. or with Venezuelan officials. Mr. Moshiri declined to provide details about his contract with Chevron. After leaving Chevron, he founded a firm, Amos Global Energy, which seeks investment opportunities in Venezuela, people familiar with the matter said.

A few days after the March 5 meeting in Caracas with U.S. officials, the Maduro government freed two American captives, one of them an executive of Citgo, the U.S. refining subsidiary of state-run oil company Petróleos de Venezuela SA, or PdVSA. The government also agreed to restart negotiations in Mexico with representatives of Venezuela's opposition, who want officials to agree to free and fair presidential elections in 2024.

News of the meeting in Caracas, though, has caused a political backlash in Washington and in Florida, where exiled Venezuelans live and have forged links to the state's powerful and conservative Cuban American community.

"The democratic aspirations of the Venezuelan people, much like the resolve and courage of the people of Ukraine, are worth much more than a few thousand barrels of oil," New Jersey Sen. Robert Menendez, the Democratic chairman of the Senate Foreign Affairs Committee, wrote in a statement. Those sentiments were echoed by both Democratic and Republican lawmakers in Florida.

SHARE YOUR THOUGHTS

Should the U.S. ease sanctions on Venezuela to get more oil? Why or why not? Join the conversation below.

Venezuelan opposition leader Juan Guaidó, whom the U.S. recognizes as Venezuela's legitimate president, was told of the U.S.-Venezuela meeting after it had taken place. Mr. Guaidó wrote a letter to Mr. Biden, according to a person with knowledge of the matter, saying that lifting sanctions on Venezuela would do little to ease the world's crude supply shortages while rewarding Mr. Maduro, a Putin ally whose rule is blamed for leading six million Venezuelans to flee the country.

"Today, more than ever we should be firm and morally consistent," said Mr. Guaidó in a video press conference from Caracas last week. He said any lifting of sanctions on Venezuela or permission for Chevron to pump oil there should only come in exchange for democratic concessions by the regime.

Answering reporters' questions last week White House press secretary Jen Psaki said, "There is no dialogue between us and the regime." She said the administration would consider lifting sanctions on the basis of progress in talks between Mr. Maduro and the opposition.

Chevron officials still say the company could win a license permitting it, along with European oil companies such as Eni Spa and Repsol SA, to operate in Venezuela.

A refinery of state-owned Petróleos de Venezuela in El Palito. Venezuelan oil production has plummeted since the 1990s due to mismanagement.

PHOTO: MANAURE QUINTERO/BLOOMBERG NEWS

Venezuela claims to have the world's largest proven oil reserves. But years of mismanagement, corruption and nationalization of oil ventures led production to fall from 3.2 million barrels a day in

the 1990s to a 10th of that in 2020. Since then, production has more than doubled as Venezuela turned to opaque foreign companies to boost production, say industry executives. Chevron's lobbyists assert that the recent production increases show that the U.S. sanctions aren't working as intended.

But though Chevron has told U.S. officials it could jack up production quickly, some oil analysts who closely track Venezuela doubt the company could deliver. Even in good times, Venezuela had never increased production anywhere near the level of recent optimistic projections, according to Francisco Monaldi, director of the Latin America Energy Program at Rice University's Baker Institute. Chevron's perseverance in Venezuela has come as the company has tried to get Venezuela to pay money owed under production-sharing agreements. The company wrote down all of its assets there in 2020, taking a charge of $2.6 billion. Nonetheless, it stayed, receiving periodic licenses from the U.S. government to retain but not operate assets.

—Timothy Puko in Washington contributed to this article.

Write to Christopher M. Matthews at christopher.matthews@wsj.com and José de Córdoba at jose.decordoba@wsj.com

https://www.npd.no/en/news/Production-figures/2023/production-figures-july-2023/

Production Figures July 2023

22/08/2023

Ekofisk field. © Shutterstock.

Preliminary production figures for July 2023 show an average daily production of 2 036 000 barrels of oil, NGL and condensate.

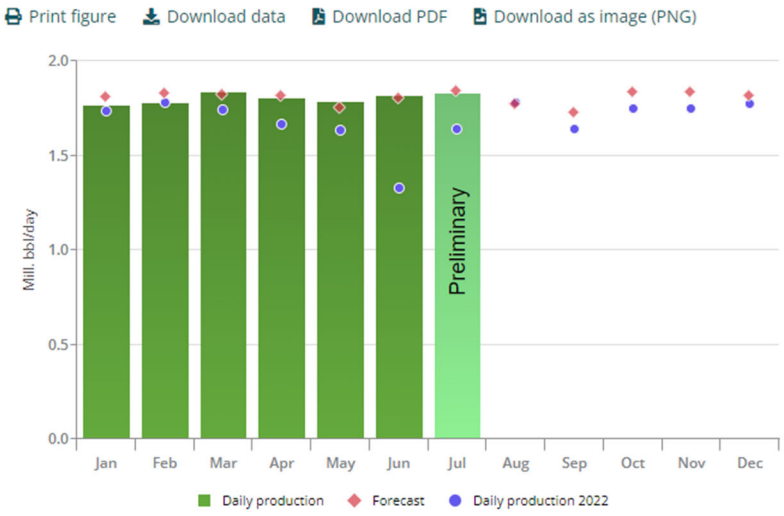
Total gas sales were 10.0 billion Sm3 (GSm3), which is 2.5 (GSm3) more than the previous month. Average daily liquids production in July was: 1 828 000 barrels of oil, 190 000 barrels of NGL and 18 000 barrels of condensate.

Oil production in July is 0.6 percent less than the NPD’s forecast and 0.4 percent lower than the forecast so far this year.

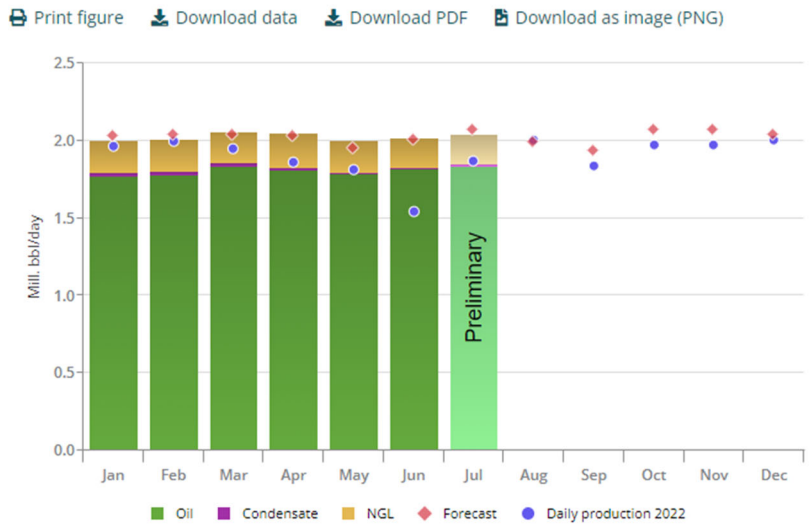
Production figures July 2023

		Oil mill bbl/day	Sum liquid mill bbl/day	Gas MSm³/day	Total MSm³ o.e/day
Production	**July 2023**	**1.828**	**2.037**	**321.4**	**0.645**
Forecast for	July 2023	1.840	2.065	359.3	0.688
Deviation from forecast		-0.012	-0.028	-37.9	-0.043
Deviation from forecaset in %		-0.7 %	-1.4 %	-10.5 %	-6.2 %
Production	June 2023	1.818	2.016	250.7	0.571
Deviation from	June 2023	0.010	0.021	70.7	0.074
Deviation in % from	June 2023	0.6 %	1 %	28.2 %	13 %
Production	July 2022	1.639	1.869	350.6	0.648
Deviation from	July 2022	0.189	0.168	-29.3	-0.003
Deviation in % from	July 2022	11.5 %	9 %	-8.4 %	-0.5 %

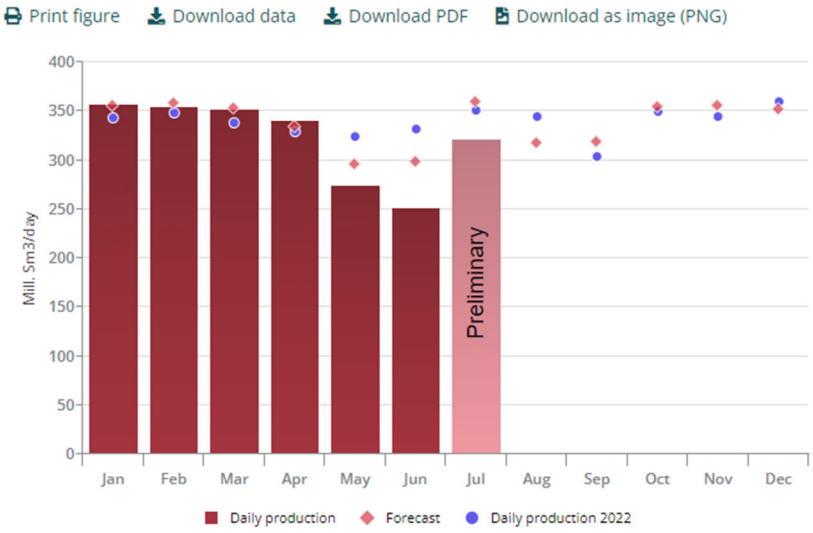
Oil production July 2023



Liquid production July 2023



Gas production July 2023

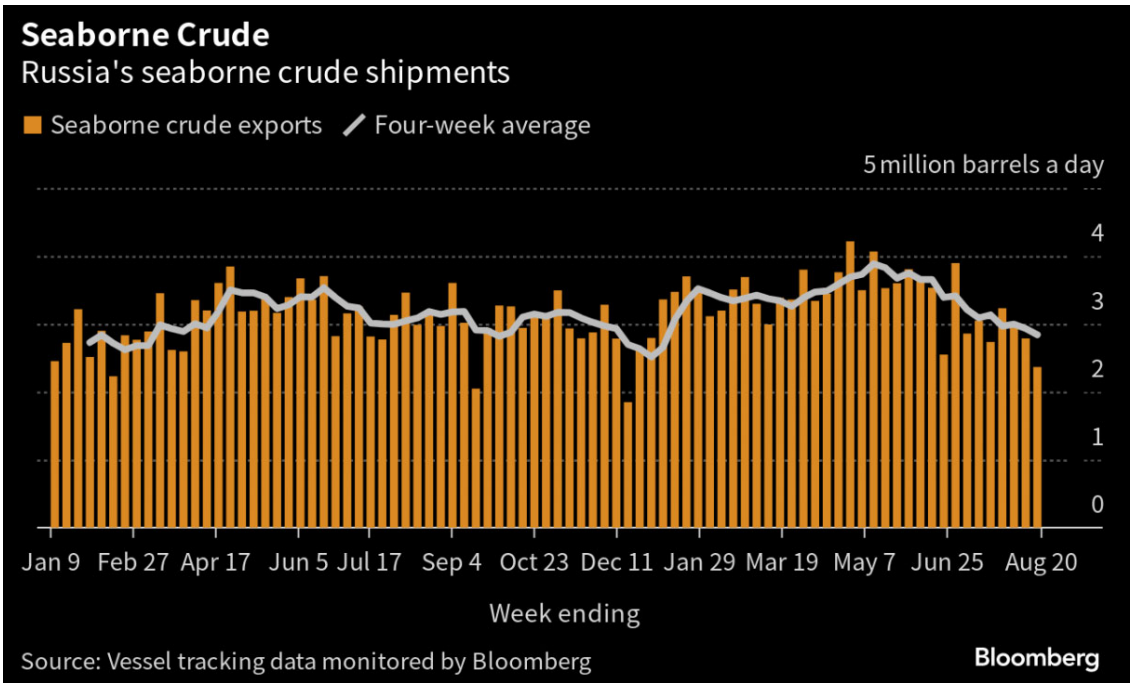


The total petroleum production so far in 2023 is about 136.3 million Sm3 oil equivalents (MSm3 o.e.), broken down as follows: about 60.7 MSm3 o.e. of oil, about 7.5 MSm3 o.e. of NGL and condensate and about 68.1 MSm3 o.e. of gas for sale.

The total volume is 2.0 MSm3 o.e. higher than in 2022.

Russia’s Seaborne Crude Flows Drop to the Lowest Since January
2023-08-22 13:41:46.732 GMT

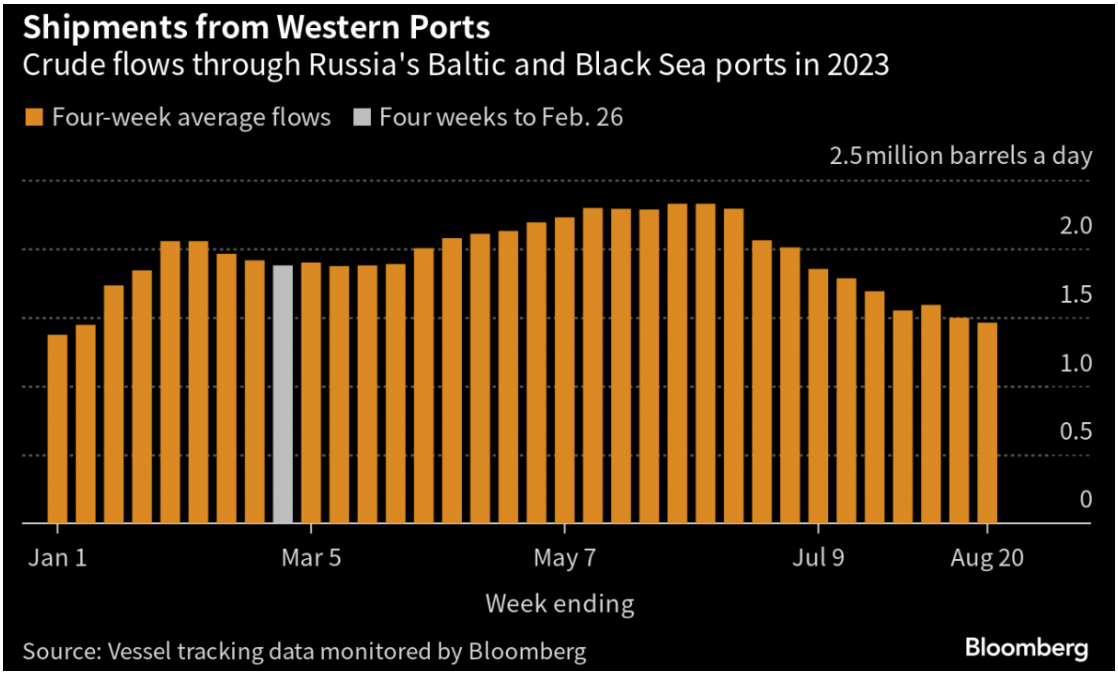
By Julian Lee
(Bloomberg) -- Russia’s seaborne crude flows fell to their lowest since January after an unexplained slowdown at the Black Sea port of Novorossiysk, while the nation pledges to restrict its oil exports.
Average nationwide shipments in the four weeks to Aug. 20 dropped to 2.84 million barrels a day, tanker-tracking data compiled by Bloomberg show. That’s about about 1.05 million barrels a day below the peak in mid-May. More volatile weekly numbers also fell sharply, dropping to their lowest since December.
The amount of Russian crude loaded at Novorossiysk equaled the lowest volume seen since Moscow’s troops invaded Ukraine in February 2022. Shipments fell behind the scheduled program last week, with two gale warnings issued for the area around the port. It does not appear that flows have been affected by Ukraine’s drone attacks on two Russian vessels in the northeastern Black Sea earlier this month, which briefly halted activity at port at the time.



Weekly data are affected by the scheduling of tankers and loading delays caused by bad weather. Port and pipeline maintenance can also disrupt exports for several days at a time.
Weekly shipments dropped by 420,000 barrels a day in the week to Aug. 20 to average 2.37 million barrels a day. The less volatile four-week average was down by about 90,000 barrels a day.
The figures support the notion that Moscow is now honoring a pledge to keep supply off the global market alongside its allies in the OPEC+ producer coalition. Russia initially said it

would cut oil production in retaliation for Western sanctions and price caps on its oil imposed after the invasion of Ukraine, using February 2023 figures as a baseline. But seaborne flows had continued to rise, dropping significantly only in the last few weeks.

Moscow's initial commitment to cut production by 500,000 barrels a day in March had no immediate effect on exports. Flows from western ports actually rose, peaking in late May. The subsequent reduction came after fellow OPEC+ oil producer Saudi Arabia made and then extended its own unilateral output cut, putting pressure on Russia to implement its own reduction.



Moscow eventually followed through on its pledge, with flows from western ports now down by about 420,000 barrels a day from their average February level. Flows from the Baltic and Black Seas have fallen in eight of the past nine weeks.

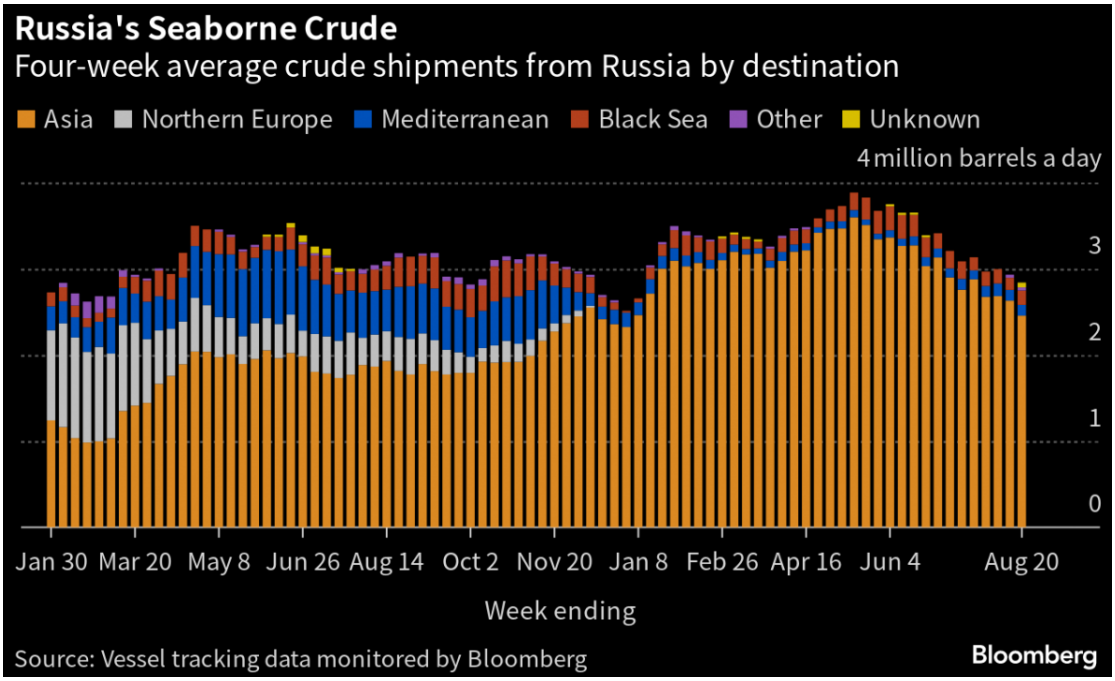
Russia will extend its export cut into September, Deputy Prime Minister Alexander Novak said earlier this month, following a similar announcement from Saudi Arabia. However, the size of the supply reduction will be tapered to 300,000 barrels a day, from 500,000 barrels a day in August. Russia has given no baseline from which the export cut is to be measured.

The latest drop in overseas flows comes as Russia's oil refineries increased crude-processing rates in the first half of August — before a sharp cut to state subsidies that's about to take effect in September. The rise also comes ahead of the next maintenance season, with several refineries due to start work this month.Crude Flows by Destination

Russia's seaborne crude flows are now at a lower level than they've been for most of this year. It was only in the second half of June that shipments began to fall significantly.

With few buyers left in Europe, the impact is being felt in shipments to Asia. On a four-week average basis, overall

seaborne exports to Asian countries — plus the volumes on ships showing no final destination — are now more than 1 million barrels a day below their peak in mid-May. Flows to the region in the most recent period were the lowest since the four weeks to Jan. 8.



All figures exclude cargoes identified as Kazakhstan's KEBCO grade. Those are shipments made by KazTransoil JSC that transit Russia for export through Novorossiysk and the Baltic port of Ust-Luga.

The Kazakh barrels are blended with crude of Russian origin to create a uniform export grade. Since Russia's invasion of Ukraine, Kazakhstan has rebranded its cargoes to distinguish them from those shipped by Russian companies. Transit crude is specifically exempted from European Union sanctions.

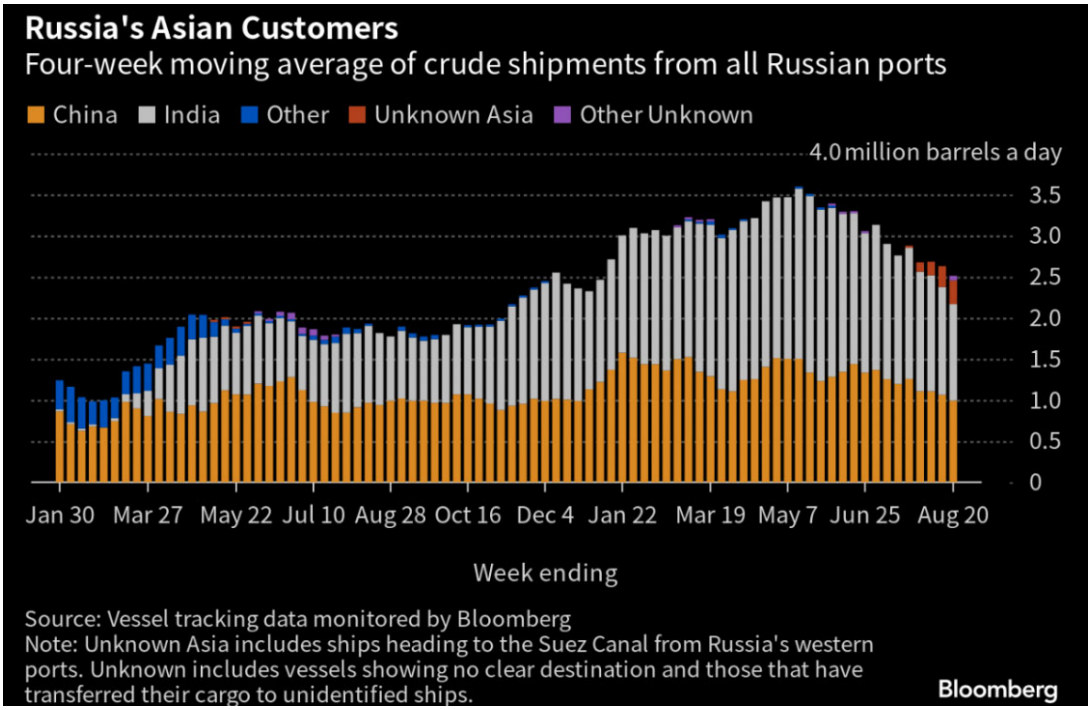
*** Asia**

Observed shipments to Russia's Asian customers, including those showing no final destination, fell to 2.51 million barrels a day in the four weeks to Aug. 20, from 2.63 million barrels a day in the period to Aug. 13.

Most of the cargoes on ships without an initial destination eventually end up in India. Even so, the volumes heading to the country that has become the biggest buyer of Russia's seaborne crude are down from their recent highs. Adding the "Unknown Asia" and "Other Unknown" volumes to the total for India gives a figure of 1.52 million barrels a day in the four weeks to Aug. 20, down from a high of 2.15 million barrels a day in the period to May 21.

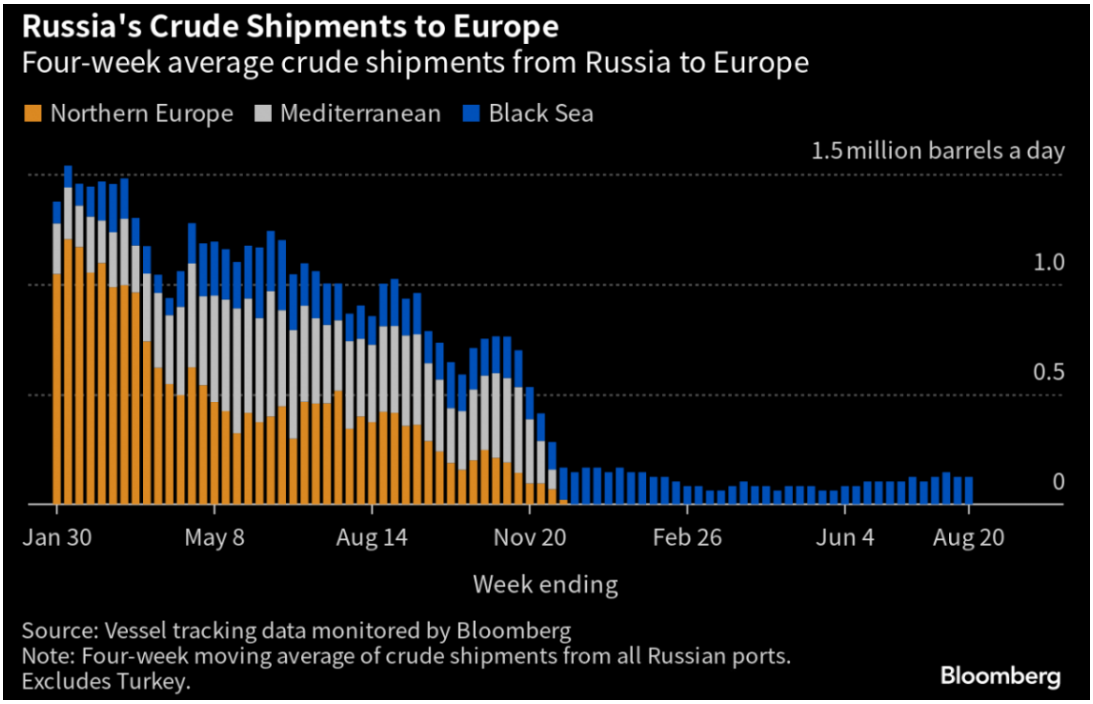
The equivalent of 290,000 barrels a day was on vessels signaling Port Said or Suez in Egypt, or which already have been

or are expected to be transferred from one ship to another off the South Korean port of Yeosu. Those voyages typically end at ports in India or China and show up in the chart below as “Unknown Asia” until a final destination becomes apparent.
The “Other Unknown” volumes, running at 56,000 barrels a day in the four weeks to Aug. 20, are those on tankers showing no clear destination. Most of those cargoes originate from Russia’s western ports and go on to transit the Suez Canal, but some could end up in Turkey. Others could be transferred from one vessel to another, either in the Mediterranean or, more recently, in the Atlantic Ocean.

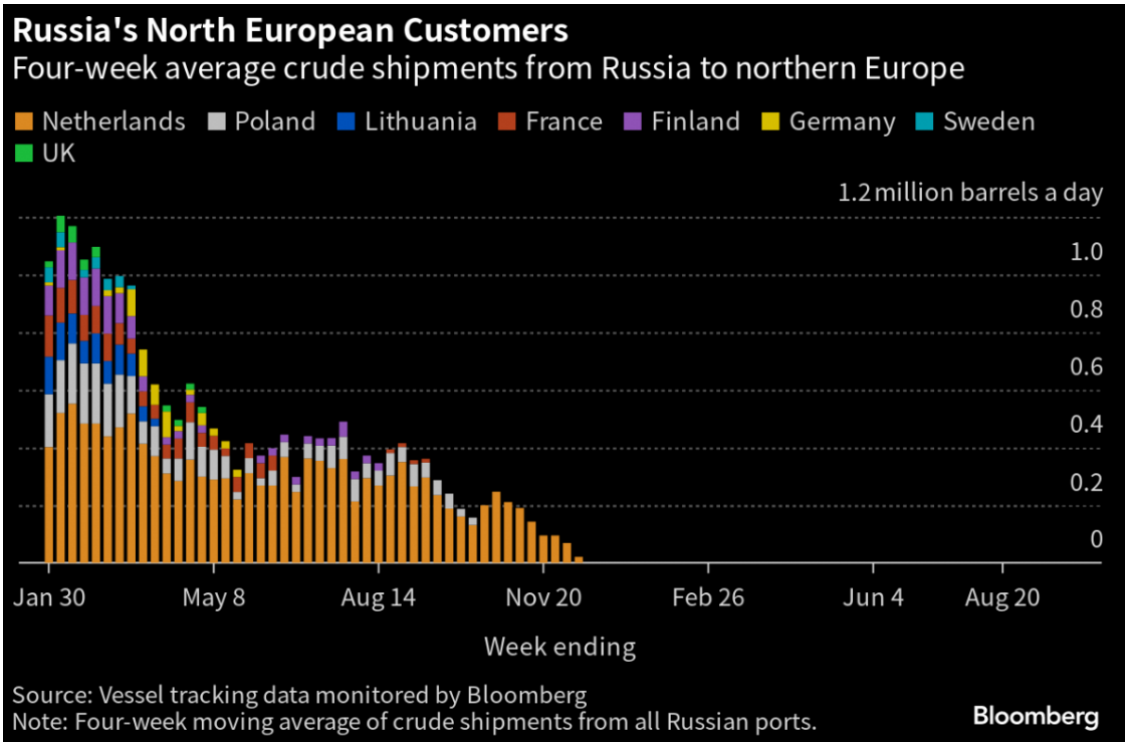


*** Europe**

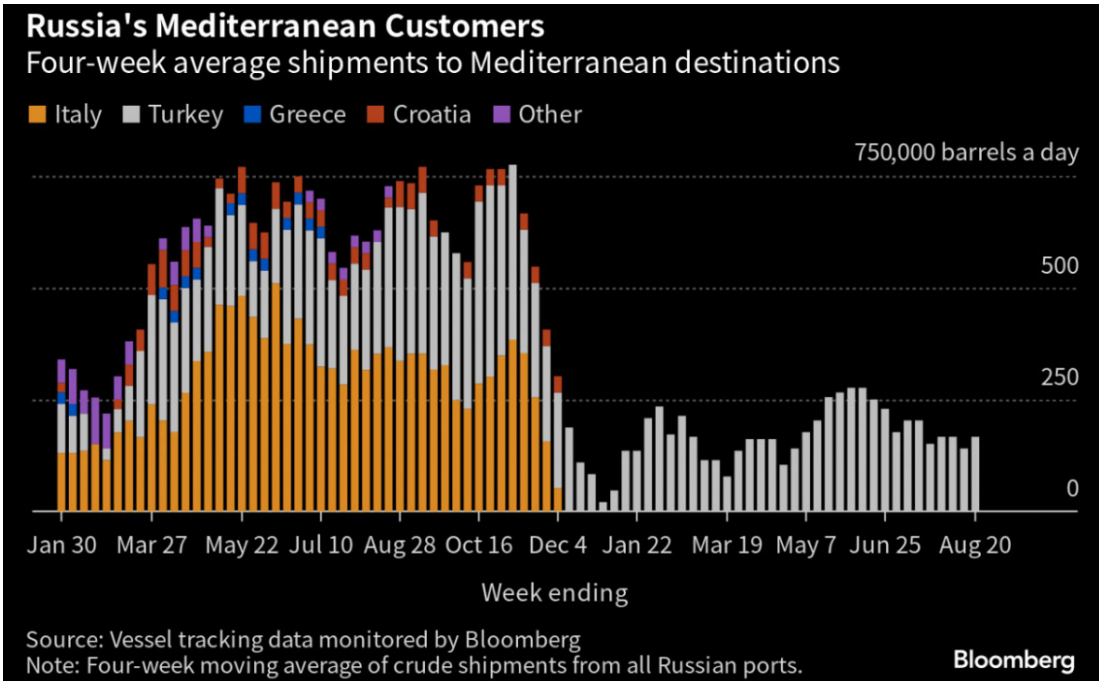
Russia’s seaborne crude exports to European countries were unchanged at 125,000 barrels a day in the 28 days to Aug. 20, with Bulgaria the sole destination. These figures do not include shipments to Turkey.
A market that consumed about 1.5 million barrels a day of short-haul seaborne crude, coming from export terminals in the Baltic, Black Sea and Arctic has been lost almost completely, to be replaced by long-haul destinations in Asia that are much more costly and time-consuming to serve.



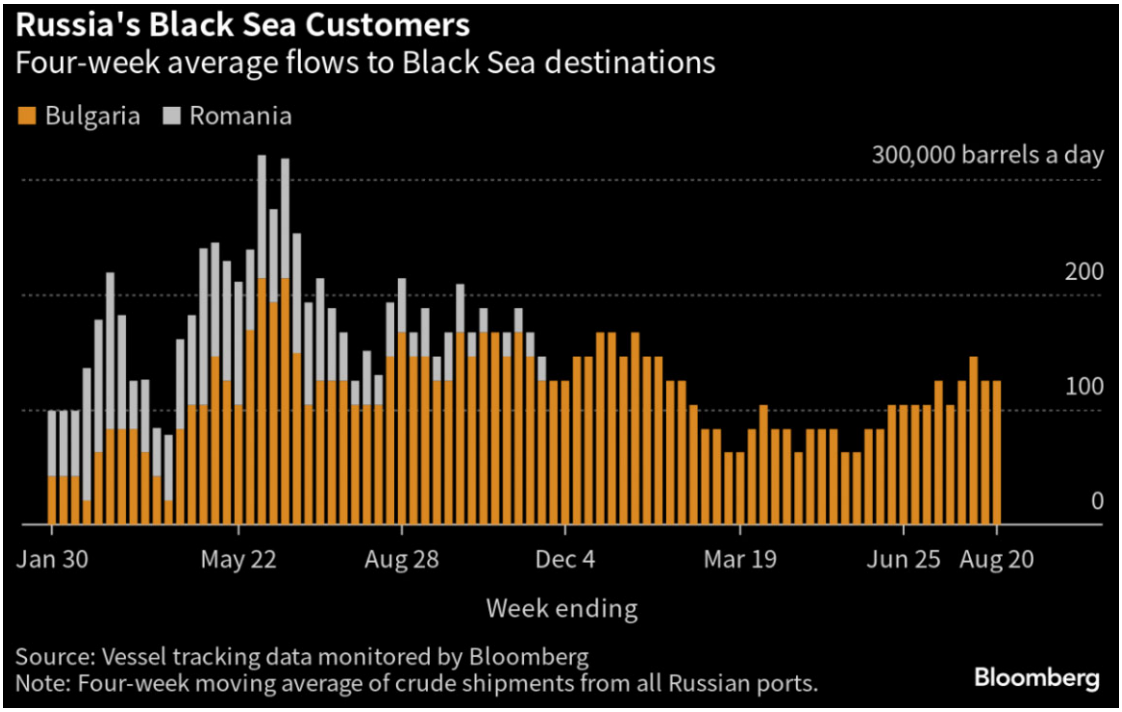
No Russian crude was shipped to northern European countries in the four weeks to Aug. 20.



Exports to Turkey, Russia's only remaining Mediterranean customer, rose to about 167,000 barrels a day in the four weeks to Aug. 20. Flows to the country had topped 425,000 barrels a day in October.



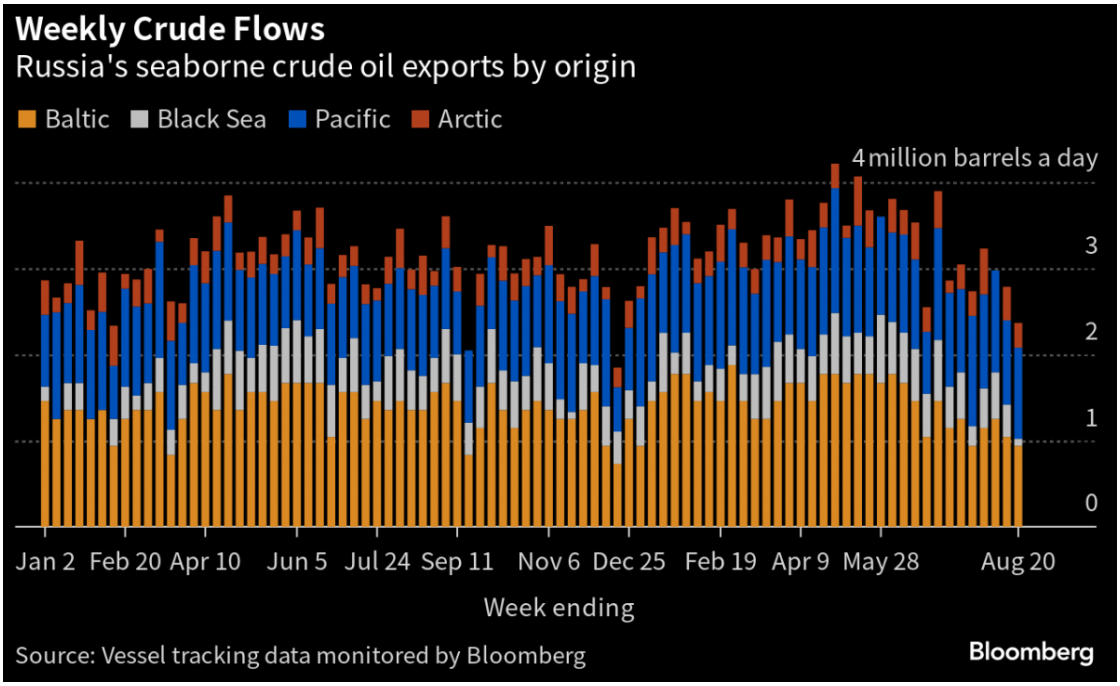
Flows to Bulgaria, now Russia's only Black Sea market for crude, have stabilized at 125,000 barrels a day. That's about twice as much as the country was importing at the lowest points between March and May.



Flows by Export Location

Aggregate flows of Russian crude slumped to 2.37 million barrels a day in the seven days to Aug. 20, down from 2.79 million barrels a day the previous week. The drop came entirely from Russia's western ports, with shipments from the Pacific rebounding above 1 million barrels a day.

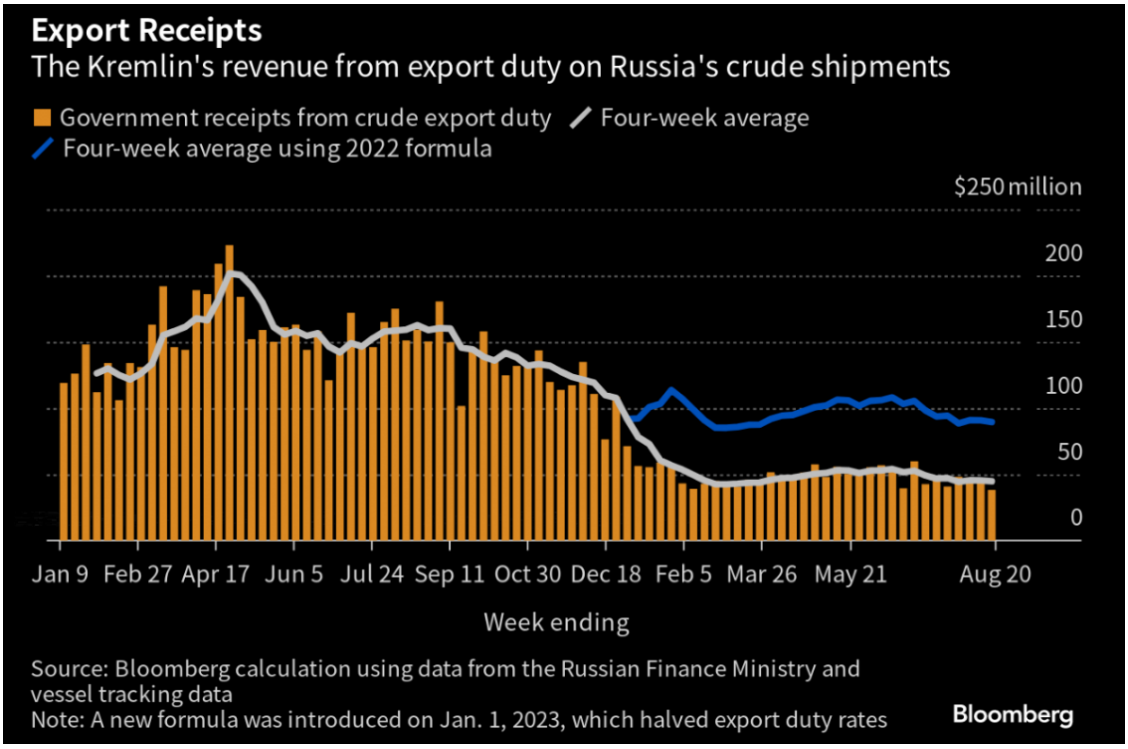
A sharp drop in the volume of crude leaving Novorossiysk in the week to Aug. 20 appears unplanned, with flows falling behind the loading program over the course of the week.
Figures exclude volumes from Ust-Luga and Novorossiysk identified as Kazakhstan's KEBCO grade.



Vessel-tracking data are cross-checked against port agent reports as well as flows and ship movements reported by other information providers including Kpler SAS and Vortexa Ltd.

Export Revenue

Inflows to the Kremlin's war chest from its crude-export duty fell to $38 million in the seven days to Aug. 20, a decrease of $7 million or 15%. Four-week average income slipped to almost $46 million.
Russia's government calculates oil taxes — including export duty — using a discount to global benchmark Brent, which sets the floor price for the nation's crude for budget purposes. If Russian oil trades above that threshold, the Finance Ministry uses the market price for tax calculations, as has been the case in recent months. The discount used to calculate taxes including export duty is set at $25 a barrel for July and August, but will narrow to $20 a barrel from September.



The duty rate for August has been set at $2.31 a barrel, based on an average Urals price of $58.03 during the calculation period between June 15 and July 14. That was $18.02 a barrel below Brent during the same dates.

For September, the duty has been set at $2.92 a barrel, based on an average Urals price of $70.33 during the calculation period between July 15 and Aug. 14. That was $13.90 a barrel below Brent over the same period. September's duty rate is the highest this year.

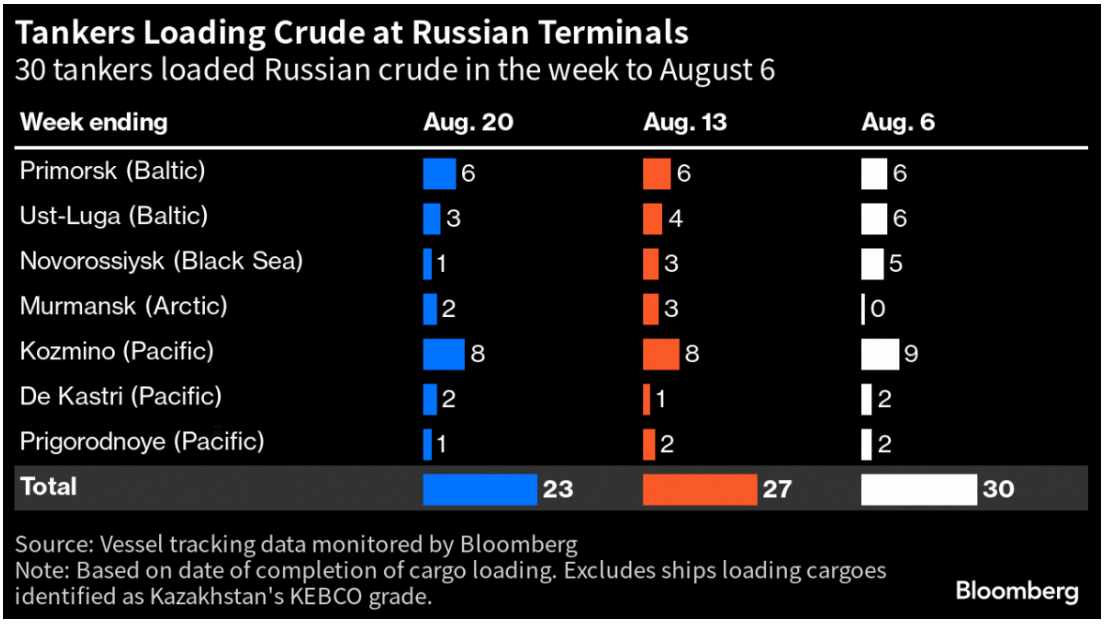
Origin-to-Location Flows

The following charts show the number of ships leaving each export terminal and the destinations of crude cargoes from the four export regions.

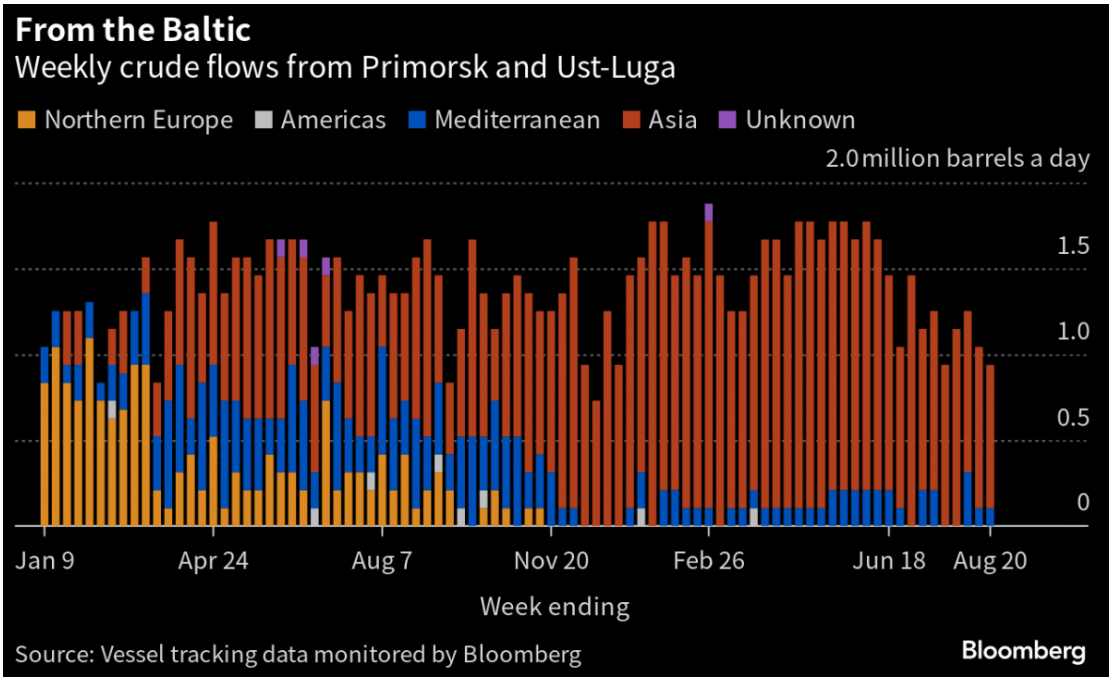
A total of 23 tankers loaded 16.6 million barrels of Russian crude in the week to Aug. 20, vessel-tracking data and port agent reports show. That's down by 2.94 million barrels from the previous week's figure and the smallest figure since December.

Shipments from Novorossiysk slumped, with just one cargo of Russian crude loading at the Black Sea port during the week. Flows from other western regions also fell, with only the Pacific region showing a week on week increase, with exports rebounding above 1 million barrels a day.

Destinations are based on where vessels signal they are heading at the time of writing, and some will almost certainly change as voyages progress. All figures exclude cargoes identified as Kazakhstan's KEBCO grade.

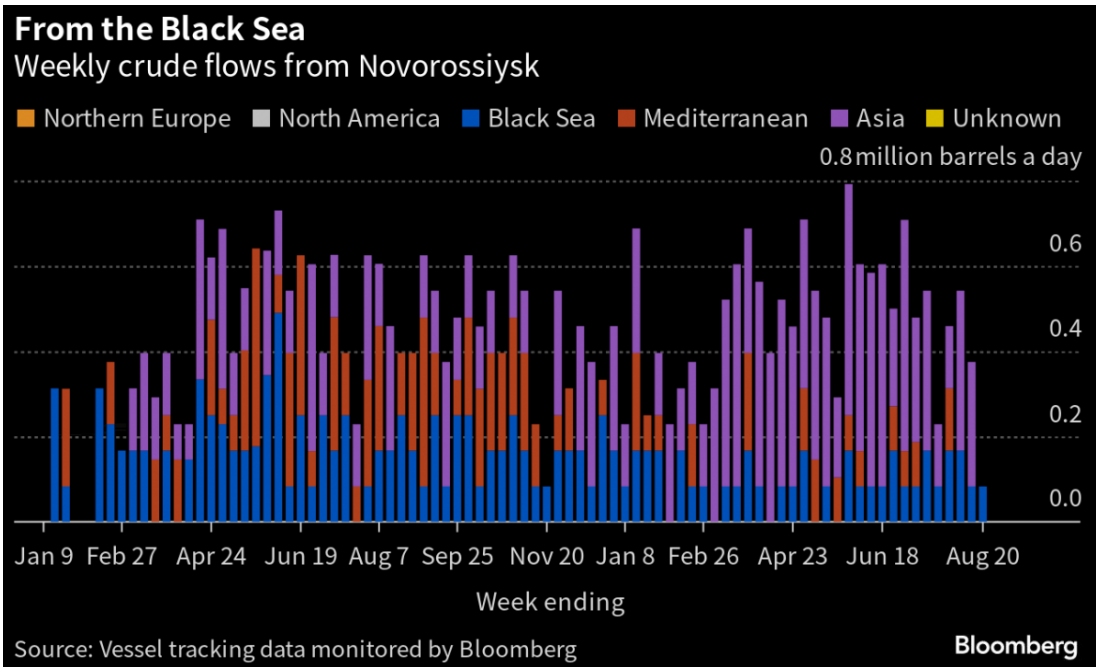


The total volume on ships loading Russian crude from the Baltic terminals continued to fall, dropping below 1 million barrels a day for only the second time this year to equal its lowest level since December. One cargo of Kazakhstani crude was loaded at Ust-Luga during the week. Shipments from the Baltic are down by about 830,000 barrels a day from the highs seen between April and June.



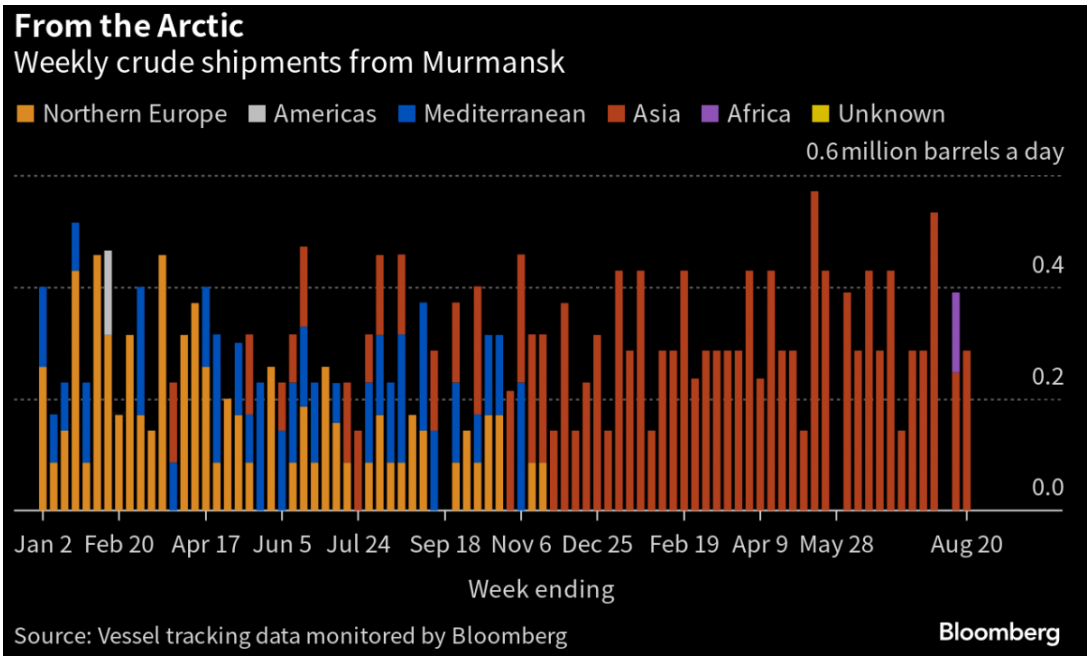
Shipments of Russian crude from Novorossiysk slumped to their lowest since December, with just one tanker loading Russian crude. Shipments were running in line with the loading program for the port at the start of the week, but had fallen several days behind by the end.

One cargo of Kazakhstani crude was also loaded at the port during the week.



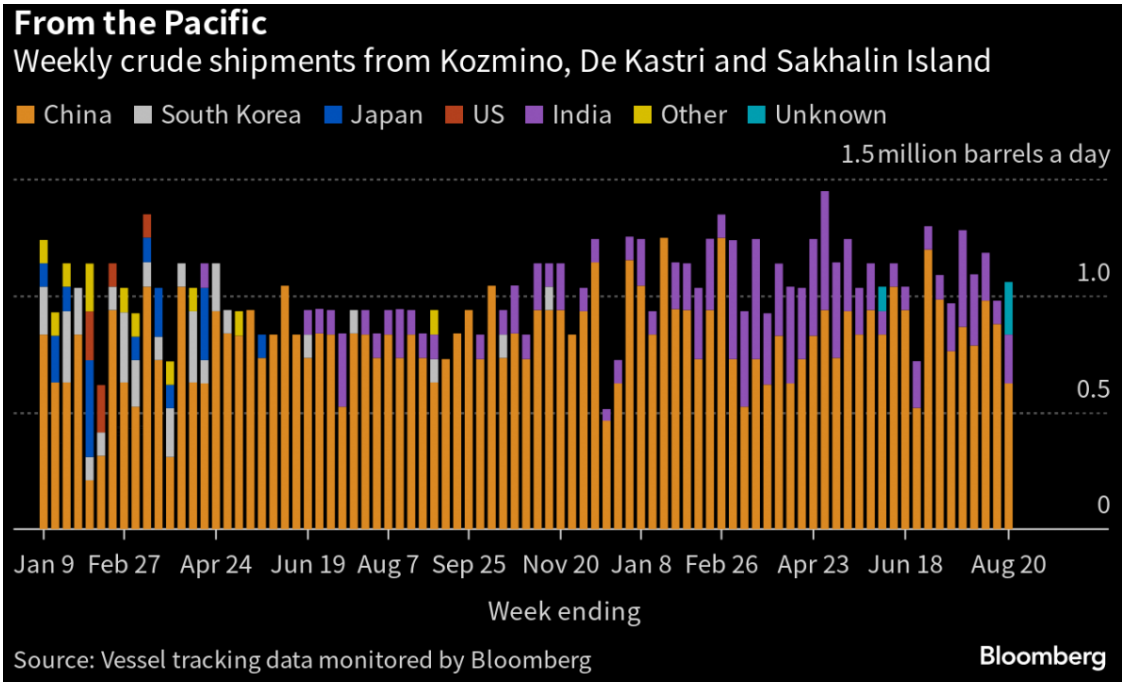
Two Suezmax tankers completed loading cargoes at the Arctic port of Murmansk in the week to Aug. 20, leaving flows down week on week, but broadly in line with their average level so far this year.

One tanker that loaded in the week to Aug. 13 is headed to Ghana, where it's due to arrive later this month. A previous cargo, loaded at Novorossiysk in January, discharged in the West African nation after a six-week wait off the port of Tema.



Eleven tankers loaded at Russia's three Pacific export terminals, unchanged from the previous week. The volume of crude shipped from the region rose to 1.06 million barrels a day, due to larger cargo sizes.

Shipments from the Sakhalin Island terminal continue to be affected by maintenance at one of the Sakhalin 2 project's oil production platforms. The work is set to run until September. One vessel loaded a part cargo of Sakhalin Blend crude from the terminal.



The volumes heading to unknown destinations are mostly Sokol cargoes that recently have been transferred to other vessels at Yeosu, or are currently being shuttled to an area off the South Korean port from the loading terminal at De Kastri. Most of these are ending up in India. The destination of the part-loaded cargo of Sakhalin Blend is also unknown, but previous cargoes have all headed to China.

Some Sokol cargoes are now being transferred a second time in the waters off southern Malaysia. A small number of ESPO shipments are also being moved from one vessel to another in the same area. All bar one of these cargoes have, so far, gone on to India. That one cargo was transferred onto a floating storage vessel off Malaysia. It was then transferred onto another tanker, which was showing a destination in China while anchored off Johor, to the east of Singapore. That ship's draft suggests the cargo has been offloaded into an unidentified tanker.

Shipments of Sokol crude to India have picked up again after slumping to zero in June. Flows in July averaged about 140,000 barrels a day and at least two cargoes are heading there this month.NOTES

Note: This story forms part of a weekly series tracking shipments of crude from Russian export terminals and the export duty revenues earned from them by the Russian government. Weeks run from Monday to Sunday. The next update will be on Tuesday, Aug. 29.

Note: All figures exclude cargoes owned by Kazakhstan's KazTransOil JSC, which transit Russia and are shipped from

Novorossiysk and Ust-Luga as KEBCO grade crude.
If you are reading this story on the Bloomberg terminal,
click here for a link to a PDF file of four-week average flows
from Russia to key destinations.

--With assistance from Sherry Su.

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https://blinks.bloomberg.com/news/stories/RZSOPMT0AFB4

https://www.presstv.ir/Detail/2023/08/09/708652/Iran-oil-output-increase-plan-NIOC-CEO

Iran’s oil output to reach 3.5 mln bpd by late September: NIOC chief

Wednesday, 09 August 2023 6:24 PM **[Last Update: Wednesday, 09 August 2023 6:24 PM]**

CEO of Iran’s state-run NIOC says oil output in the country will reach 3.5 million bpd in late September.

Iran will reach a milestone oil production figure of 3.5 million barrels per day (bpd) in late September, according to the CEO of state oil company NIOC, despite sanctions imposed on the country by the US.

Mohsen Khojasteh Mehr said on Wednesday that Iran’s oil output will increase by 150,000 bpd within the next week and by another 100,000 bpd by the end of the month to September 22 to reach a total of 3.5 million bpd.

The figure would be a major increase from 2.2 million bpd of oil production reported in August 2021 when the current administrative government led by President Raeisi took office, said Khojasteh Mehr.

He said the growth in oil output will entirely serve Iran’s plans to increase its oil exports.

The comments, which came in a meeting with reporters at the headquarters of the National Iranian Oil Company, is the latest sign that Iran is pumping increased amounts of oil to the international markets despite continued pressure of the US sanctions.

Reports earlier this year had indicated that Iran’s nominal oil production capacity had been restored to levels above 3.8 million bpd for a first time since 2018 when Washington imposed its sanctions on the country.

However, reaching an actual output of 3.5 million bpd shows Iran is effectively nearing export levels seen before the sanctions when the country used to sell 2.2 million bpd of oil to international customers.

Central Bank of Iran Governor Mohammad Reza Farzin also said on Wednesday that Iran’s oil exports had risen by 41% year on year in the calendar month to late July to reach a record high in five years.

Turkey Seeks Iraq Revenue-Sharing Deal to Restart Oil Exports
2023-08-25 10:12:01.470 GMT

By Selcan Hacaoglu and Onur Ant

(Bloomberg) -- Turkey is attempting to broker a deal between the central Iraqi government and the semi-autonomous Kurdish administration over how to resume Iraqi crude-oil exports via its territory, according to two Turkish officials.

Turkey halted flows through a twin-pipeline in March after an arbitration court ordered it to pay about $1.5 billion in damages to Iraq for transporting oil without Baghdad's approval. Ankara has no intention of paying the fine and is asking the Kurds to pay it to Baghdad as they were the benefactors, the officials said.

A compromise over competing demands from Iraq and the Kurdish administration over revenue-sharing from oil exports is being sought, the officials who are familiar with the matter said. The two sides have been quarreling for years over rights to Kurdistan oil sales, part of Baghdad's long-running attempt to rein in the semi-autonomous region.

Officials from the Baghdad government didn't comment, while the KRG declined to comment.

Turkey's Foreign Minister Hakan Fidan discussed energy, economic and security relations both with the president and prime minister of the Kurdish government in Erbil on Thursday, after holding talks with his Iraqi counterpart in Baghdad earlier in the week. Turkish Energy Minister Alparslan Bayraktar also traveled to Erbil and has had discussions with Iraqi Oil Minister Hayyan Abdul Ghani.

Repairing Ties

Turkey is reaching out to Baghdad to repair ties after years of estrangement as part of a reset in relations with Arab nations. Ankara is offering the Kurdistan Regional Government, or KRG, as well as the central government in Baghdad help in building power plants and other infrastructure.

Baghdad has asked Turkey to collect the money from oil exports and transfer it to Iraq after deducting 12.6% of the share allocated to the KRG, said the officials, speaking on condition of anonymity. The KRG, however, has told Turkey that it wants to claim the entire revenue from exports via its territory, arguing that it has been unable to collect funds from separate Iraqi oil exports, they said.

The pipeline running from Kirkuk to Turkey's Mediterranean port of Ceyhan remains operational and Iraqi crude exports could start quickly once there is a deal in place, the Turkish officials said, adding that Turkey aims to resolve the conflict as soon as possible.

The closure of the pipeline has cut off nearly half a million barrels of crude from global markets as Ankara refused to pay the $1.5 billion fine. Iraq had been exporting about 400,000 to 500,000 barrels a day from fields in the country's

north, including in the Kurdish region, via the now-halted pipeline.
It's unclear how much of that oil would flow back onto world markets if there was a deal, since Iraq is already pumping at very close to the limit under its OPEC quota.

--With assistance from Khalid Al-Ansary.

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https://ina.iq/eng/28218-bilateral-meeting-between-fm-hussein-and-his-turkish-counterpart.html

Bilateral meeting between FM Hussein and his Turkish counterpart

- Yesterday, 20:09

INA - BAGHDAD

The spokesman for the Iraqi Ministry of Foreign Affairs, Ahmed Al-Sahhaf, confirmed on Tuesday, the start of the bilateral meeting between Foreign Minister Fuad Hussein and his Turkish counterpart, Hakan Fidan, who arrived this evening in Baghdad.

The Ministry of Foreign Affairs noted that Deputy Prime Minister and Foreign Minister Fuad Hussein will hold a press conference with his Turkish counterpart after 8:00 pm today.

In his statement to INA, Al-Sahhaf said, "The Iraqi Foreign Minister proposed widen the discussion committee between the two sides to include all sectoral committees between the two countries, and he welcomed the expected visit of the Turkish Minister of Trade."

The two sides stressed that water management is an important file for both sides, and it is necessary to discuss it in depth. The security file was discussed in detail between the two sides in addition to strengthening cooperation mechanisms in this regard.

FM Hussein indicated that a high-level delegation headed by the Iraqi Oil Minister is conducting serious talks in Turkey at this time, and the start of dialogue on cooperation at the regional and international levels at the negotiating table there.

Al-Sahhaf pointed out that "the foreign minister raised the issue of visas to Turkey and pointed out that there are about 700,000 Iraqis residing there. He also pointed out the presence of about 850 Turkish companies operating in Iraq. He stressed the importance of strengthening economic and development cooperation in the service of the two countries."

The Turkish Foreign Minister expressed his happiness at visiting Iraq and stressed the importance of bilateral relations and expressed the priority for the success of his visit, which is the first visit of its kind for him to Turkey's neighboring countries.

He pointed out that "the Turkish minister expressed his hope to conclude a permanent and **comprehensive** agreement that enhances common interests and links the files under discussion between the ministerial authorities in the two countries and in various fields."

The two ministers discussed working jointly on "the issue of some extremists' propagation of so-called Islamophobia to stand against any position that disdains Islamic sanctities bilaterally and within the Organization of Islamic Cooperation. It was proposed to form a joint coordination committee to confront the phenomenon of Islamophobia so that positions do not turn in a direction that reinforces hatred more."

https://ina.iq/eng/28214-oil-minister-meet-with-turkish-minister-of-energy-and-natural-resources.html

Oil Minister meet Turkish Minister of Energy and Natural Resources

- Yesterday, 16:25

Baghdad-INA

Iraqi and Turkish oil ministers stressed on Tuesday, the importance of resuming oil flows after the completion of pipeline rehabilitation operations.

A statement by the Ministry of Oil, received by the Iraqi News Agency (INA), stated, "The Iraqi Deputy Prime Minister for Energy Affairs and Minister of Oil, Hayan Abdul-Ghani, met in Ankara, the Turkish Minister of Energy and Natural Resources, Alparslan Bayraktar."

The statement added, "The two ministers discussed a number of bilateral and regional issues of common concern and stressed the importance of the crude oil pipeline between Iraq and Turkey, and the resumption of crude oil flows, after the completion of the necessary rehabilitation and examination processes that require their implementation after the earthquake incident last February."

The two ministers emphasized "enhancing prospects for joint cooperation in the fields of energy, oil and gas, electrical interconnection and renewable energy."

The statement indicated that "the joint Iraqi-Turkish economic committee, which is chaired by the two ministers, decided to hold the nineteenth meeting of the committee in Baghdad, the date of which will be determined later."

https://english.news.cn/20230824/09c3103ab0a44805ae449e7fe57bedc9/c.html

China not due for major COVID outbreak, but caution advised: experts

Source: Xinhua
Editor: huaxia
2023-08-24 21:52:49

BEIJING, Aug. 24 (Xinhua) -- With the prevalence of coronavirus variant EG.5 rising globally and becoming predominant in China, experts have said the country will not see a large-scale COVID-19 outbreak in the near future, but advised precautions against infections in the coming autumn and winter.

Variant EG.5 is a sub-variant of Omicron XBB.1.9.2. Statistics show that EG.5 currently accounts for 71.6 percent of the prevalent variants in China and has gained predominance in the majority of Chinese provinces.

Despite the rising trend of the EG.5 variant, China's overall COVID-19 prevalence has remained at a low level, without much pressure on the medical system, said the national administration of disease prevention and control.

The World Health Organization has designated EG.5 as a "variant of interest," but meanwhile noted that the variant poses a low risk to public health.

Li Tongzeng, a chief physician with the infection department of the Beijing You'an Hospital, said most of the COVID-19 cases now show mild symptoms, with few serious cases.

The national administration of disease prevention and control predicted that China will not see a large-scale COVID-19 outbreak in the near future.

The public immunity is still effective in guarding against the EG.5 variant, said Hu Yang, a senior physician at the department of respiratory and critical care medicine of a Shanghai-based hospital.

Huang Senzhong, a professor at Nankai University, expressed similar views, saying that there are currently some sporadic COVID-19 infections in China, but they are at a low ebb and have not had a serious impact on society.

Autumn and winter are traditionally high seasons for influenza and respiratory diseases. Experts have warned about the possibility of insufficient medical resources resulting from potential COVID-19 infections.

They suggested speeding up the research and development of vaccines targeting prevalent variants and continuing to promote vaccination among elderly people and those with serious underlying conditions.

They also called on hospitals and fever clinics to take precautions to ensure that necessary medical services are available and expand vaccination among the elderly. ■

https://www.globaltimes.cn/page/202308/1296937.shtml

COVID-19 still No.1 infectious disease in Beijing: health officials

By Global Times Published: Aug 24, 2023 11:40 PM

COVID-19 is still the number one infectious disease in Beijing, said Beijing health officials on Thursday, noting that EG.5, a sublineage of the Omicron variant, is currently the dominant strain across China, accounting for over 70 percent of COVID-19 infections.

According to the 33rd weekly report in 2023 released by the Beijing health commission, the capital reported a total of 11,080 cases of 16 infectious diseases during the 33rd week of the year (August 14-August 20), an obvious increase compared with the 8,287 cases in the 32nd week and 5,434 cases in the 31st week.

The top five reported diseases are, in order, COVID-19, hand, foot and mouth disease, other infectious diarrhea, influenza and tuberculosis, said the latest report.

On Saturday, the National Bureau of Disease Control and Prevention said the proportion of the new variant EG.5 increased from 0.6 percent in April to 71.6 percent in August, becoming the dominant strain in most provinces in China.

The health authority in the city of Foshan in South China's Guangdong Province said on August 17 that the EG.5 variant is gradually becoming dominant among the circulating strains in the city, but the harm caused by it is within a controllable range.

With "a third infection of COVID-19" being discussed on social media by more and more people who worry that EG.5 could become the reason for their third infection, Peng Jie, director of the Difficult Infectious Disease Center at Nanfang Hospital in Guangzhou, said that in the past week, there was no obvious increase in the total number of patients visiting fever clinics, but the proportion of COVID-19 patients had slightly increased. From patients' symptoms, there were no signs of aggravation, Peng said.

On August 18, the Shanghai Center for Disease Control and Prevention said that recent monitoring results indicate that the overall situation of COVID-19 infections in Shanghai is stable, with the infection remaining at a low level.

Global Times

https://www.trucking.org/news-insights/ata-truck-tonnage-index-decreased-08-july

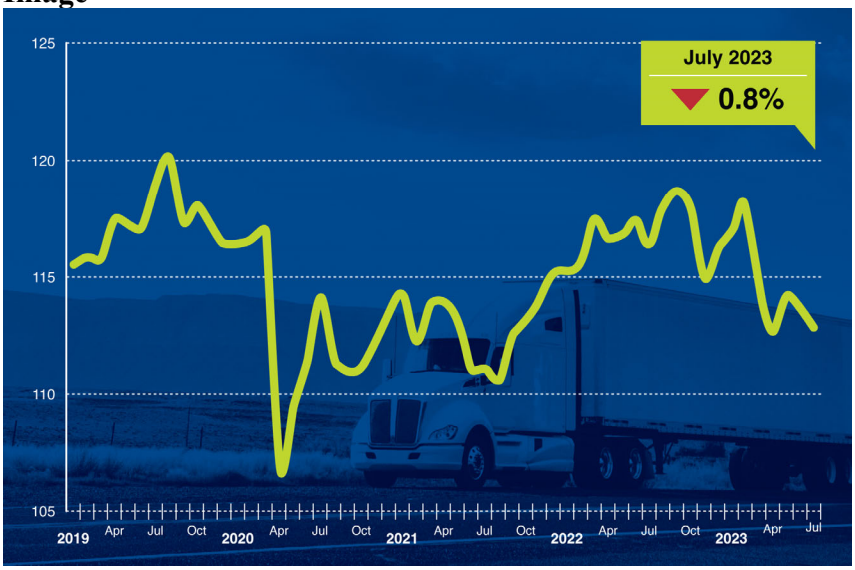
A Truc k Tonnage Index Decreased 0.8% in July

Media Contact: Sean McNally

Aug 22, 2023

American Trucking Associations' advanced seasonally adjusted (SA) For-Hire Truck Tonnage Index decreased 0.8% in July after falling 0.3% in June. In July, the index equaled 112.9 (2015=100) compared with 113.8 in June.

Image



"Headwinds for freight remained in July, pushing the truck tonnage index lower," said **ATA Chief Economist Bob Costello.** "As has been the case for several months, a multitude of factors have caused a recession in freight, including sluggish spending on goods by households as consumers traveled more and went to concerts this summer. Less home construction, falling factory output and shippers consolidating freight into fewer shipments compared with the frenzy during the goods buying spree at the height of the pandemic are also significant drags on tonnage."

June's increase was revised lower from our July 18 press release.

Compared with July 2022, the SA index fell 3%, which was the fifth straight year-over-year decrease. In June, the index was down 3.2% from a year earlier.

The not seasonally adjusted index, which represents the change in tonnage actually hauled by the fleets before any seasonal adjustment, equaled 111.5 in July, 5.5% below the June level (118). In calculating the index, 100 represents 2015. ATA's For-Hire Truck Tonnage Index is dominated by contract freight as opposed to spot market freight.

Trucking serves as a barometer of the U.S. economy, representing 72.6% of tonnage carried by all modes of domestic freight transportation, including manufactured and retail goods. Trucks hauled 11.46 billion tons of freight in 2022. Motor carriers collected $940.8 billion, or 80.7% of total revenue earned by all transport modes.

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

Country Analysis Brief: Ecuador

Last Updated: July 20, 2023

Next Update: July 2025

www.eia.gov
U.S. Department of Energy
Washington, DC 20585

Independent Statistics and Analysis
U.S. Energy Information Administration

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies.

Overview

Table 1. Ecuador's energy overview, 2021

	Crude oil and other petroleum liquids	Natural gas	Coal	Nuclear	Hydro	Other renewables	Total
Primary energy consumption (quads)	0.41	0.01	0.00	--	0.22	0.00	0.65
Primary energy consumption (percentage)	63.4%	1.7%	0.1%	--	34.1%	0.7%	100.0%
Primary energy production (quads)	1.04	0.01	--	--	0.22	0.01	1.28
Primary energy production (percentage)	81.3%	0.9%	--	--	17.5%	0.4%	100.0%
Electricity generation (terawatthours)	5.06	1.19	--	--	25.57	0.51	32.34
Electricity generation (percentage)	15.7%	3.7%	--	--	79.1%	1.6%	100.0%

Data source: U.S. Energy Information Administration, *International Energy Statistics* and staff estimates, and the International Energy Agency, World Energy Statistics 2022
Note: Quads=quadrillion British thermal units

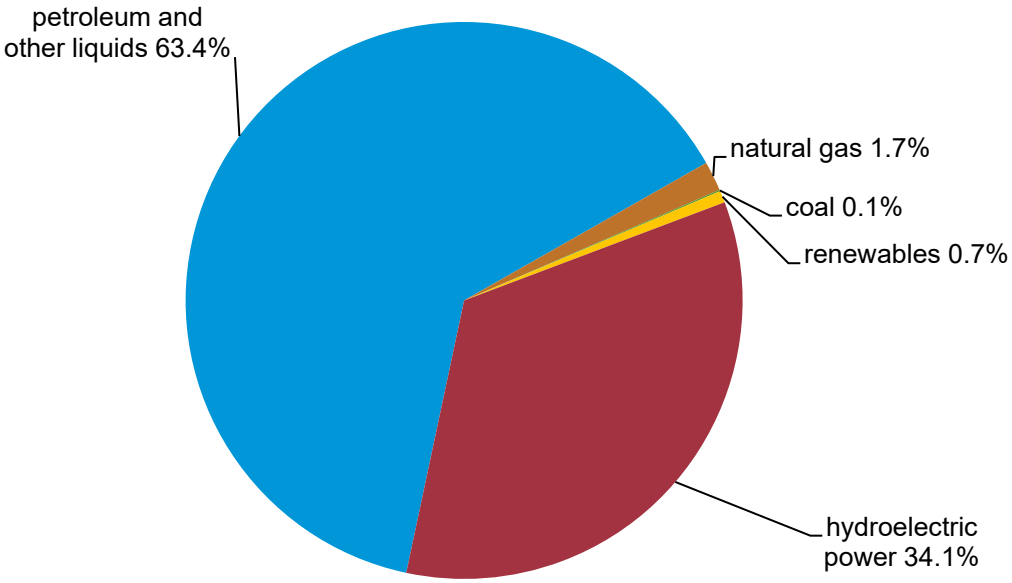
- Petroleum liquids and renewable energy, specifically hydroelectric energy, account for most of Ecuador's energy use (Table 1). Ecuador's energy production increased by a compounded growth rate of 0.5% per year from 2011 to 2021, and renewables accounted for most of the increase. The country's energy consumption also increased by a compounded growth rate of 0.5% per year over the same period, down from 4.9% per year the decade prior.
- Petroleum and other liquids continue to be Ecuador's primary source of energy; crude oil accounted for 63.4% of total energy consumption in 2021. The country has significant oil reserves and is one of South America's top oil producers. Ecuador's global share of petroleum and other liquids produced in 2021 was 0.6%, ranking fifth among oil producers in South America.
- Ecuador's natural gas market is less developed than its oil sector; it has a 0.9% share of total energy production and 1.7% share of energy consumption (Figure 1). Natural gas in Ecuador is mostly used by the industry sector[1].
- Hydropower in Ecuador is a significant source of electricity generation given the country's geographical features, such as the Andes Mountains and the Amazon rainforest. Hydropower accounted for 79.1% of total electricity generation in 2021, up from 55.4% in 2011.[2]

Figure 1. Map of Ecuador

Data source: U.S. Central Intelligence Agency, CIA World Factbook—Ecuador

Figure 2. Total primary energy consumption in Ecuador by fuel type, 2021

percentage of total energy consumption

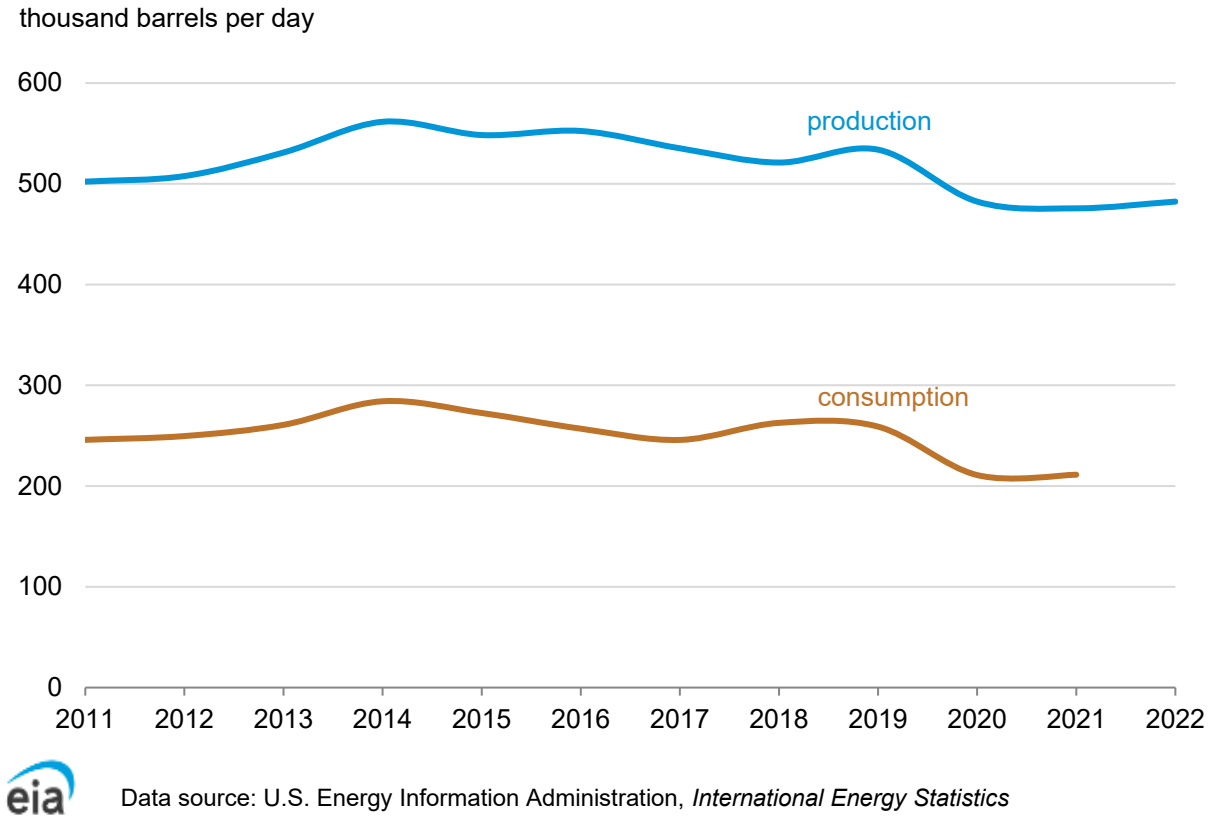


Data source: U.S. Energy Information Administration, *International Energy Statistics*
Note: Non-hydro renewables include geothermal, tide, wave, fuel cell, solar, wind, and biomass and waste.

Petroleum and Other Liquids

- Ecuador held 0.5% of the global share of oil reserves in 2022, making it the fourth highest in Latin America and the Caribbean, with approximately 8.27 billion barrels.[3] In 2022, the country produced approximately 482,000 barrels per day (b/d) of petroleum and other liquids (Figure 3). Most of Ecuador's oil is sourced from the Amazon region, specifically the Oriente Basin. Ecuador's production of petroleum and other liquids peaked in 2014 at about 562,000 b/d. Ecuador's oil industry has struggled to maintain production because of aging fields, pipeline disruptions, and environmental concerns.
- Petroecuador, the largest state-owned enterprise (SOE) in Ecuador, oversees the country's oil exploration, production, refining, and marketing. Petroecuador is the country's top oil producer, accounting for an estimated 80% of Ecuador's output via its subsidiary Petroamazonas. Petroecuador controls the country's crude oil processing capacity through Petroindustrial, its refining subsidiary. The government controls the distributor margins for fuels sold to various domestic and international retailers. Petroecuador invested US $1.9 billion in 2022, a 17% increase over the previous year. This investment included completing 117 wells compared with 64 wells completed in 2021.[4]
- Ecuador's main crude oil pipelines are the Trans Ecuadorian Pipeline (SOTE) and the Heavy Crude Oil Pipeline (OCP). SOTE is operated by the state oil company Petroecuador, and OCP is operated by a private consortium. Both pipelines connect Ecuador's Amazon producing region to refineries and export terminals on the Pacific coast. The 360,000 b/d SOTE pipeline carried an average of 320,000 b/d of medium export grades (24-degree API and 1.59% sulfur content), primarily Oriente, in 2022. It links the Amazon oil fields to the Balao Maritime Oil Terminal and the Esmeraldas refinery. The OCP pipeline, which is more than 300 miles long, transports the heavier Napo export grade (19-degree API and 1.96% sulfur content).[5] The pipeline has a capacity of 450,000 b/d but transported an average of 150,0000 b/d in 2022. The line connects Lago Agrio's Amazonas Terminal to the Esmeraldas OCP Marine Terminal.[6]
- Ecuador's government has maintained its efforts to strengthen the country's hydrocarbon industry. Ecuador's president, Guillermo Lasso, signed an executive decree in July 2021 to privatize the country's oil industry through a series of reforms aimed at selling state-run fields to the private sector. This effort includes selling oil fields to private companies through public tender rounds and continuing to improve Petroecuador's operations. [7]
- In recent years, Ecuador's oil industry has faced numerous challenges. Pipeline disruptions have increased in recent years as a result of accelerated erosion after a nearby waterfall partially collapsed. Both pipelines have also been affected by natural disasters and protests. Landslides ruptured both the SOTE and OCP pipelines in April 2020, resulting in one of Ecuador's worst oil spills. In January 2022, the OCP pipeline was ruptured by falling rocks, resulting in another spill. The spill contaminated over five acres of the Cayambe-Coca National Park. In June 2022, Petroecuador declared *force majeure* as protestors stormed oil fields, demanding reduced fuel prices and economic reforms.[8] A landslide in the Amazonian province of Napo caused the Marker River Bridge to collapse in late February 2023. Both of Ecuador's pipelines were shut down for safety reasons, even though neither had ruptured. As a result, Petroecuador was forced to close wells and declare *force majeure*, and total crude oil production fell by 17.8% (approximately 2,700 thousand barrels) from January to February 2023. The restriction was later lifted in early March 2023.[9]

Figure 3. Ecuador's liquid fuels production and consumption, 2011–2022



Data source: U.S. Energy Information Administration, *International Energy Statistics*

Table 2. Ecuador's oil refineries

Refinery	Operator	Crude oil distillation capacity (thousand barrels per day)	Location
Refinería Estatal de Esmeraldas	Petroecuador	110	Esmeraldas
Refinería La Libertad	Petroecuador	45	Santa Elena
Refinería Shushufindi	Petroecuador	20	Sucumbíos
Total		**175**	

Data source: *Oil & Gas Journal,* 2022 Worldwide Refining Survey

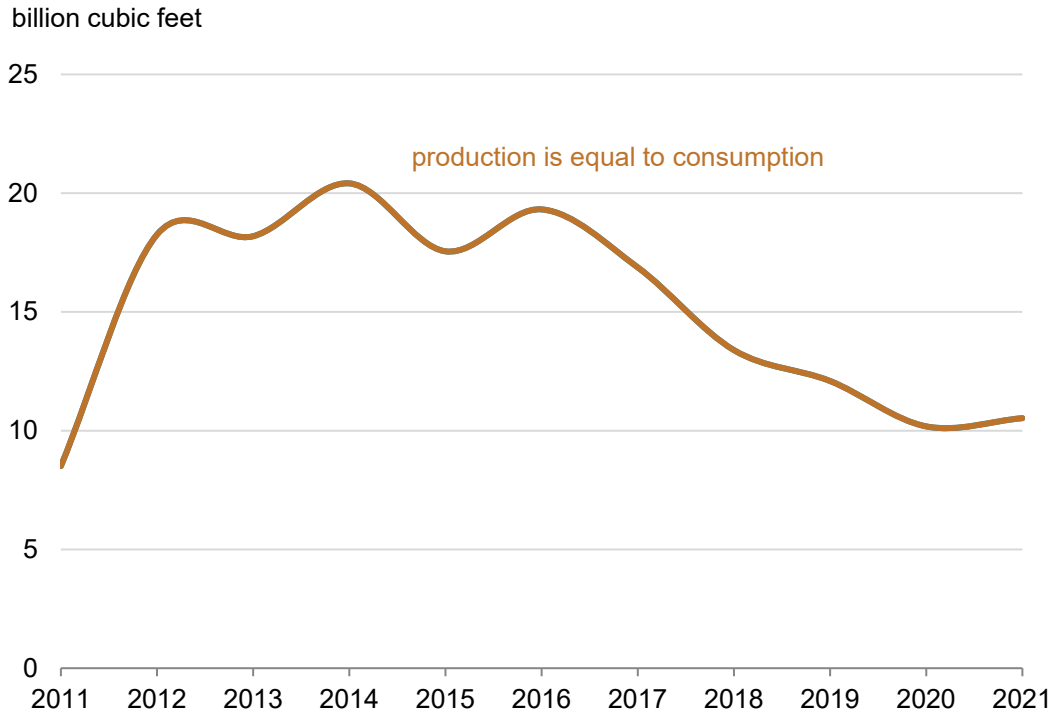
Natural Gas and LNG

- Ecuador's natural gas reserves are associated with its oil fields. Ecuador had 385 billion cubic feet (Bcf) of proven natural gas reserves as of 2022. Ecuador's natural gas reserves account for about 0.14% of South America's total reserves. Ecuador's natural gas production is small compared with oil production, accounting for less than 1% of total energy production in the country in 2021. Natural gas production in Ecuador has historically received very little

investment. As a result, Ecuador lacks the infrastructure for capturing and marketing natural gas, which has limited natural gas production.

- All of the natural gas produced in Ecuador is consumed domestically. The country's dry natural gas consumption per capita is the fourth lowest in South America. Ecuador's natural gas is primarily used by industry for power generation and industrial processes.10
- Petroamazonas, a Petroecuador subsidiary, operates the Amistad conventional natural gas field, located in shallow water in Ecuador. The field is in Block 6, with a water depth of 203 feet. The Amistad conventional natural gas field recovered 70% of its total recoverable reserves after production peaked in 2014 at 20.4 Bcf. [11] Petroecuador last drilled development wells at the field from October 2012 to April 2015 with Diamond Offshore's jackup rig called Ocean Spur, which has since been scrapped. Since then, natural gas production declined by 48% through 2021. Natural gas production is estimated to have averaged 18 Bcf in 2022, compared with 11 Bcf in 2021. Nearly all of the production came from the Amistad offshore field; the rest of the natural gas was associated with oil production.[12]
- The government fixes a set price for natural gas in Ecuador. The country has one of the largest subsidies on liquefied petroleum gas (LPG), making LPG price in Ecuador that are significantly lower than international benchmarks.[13]

Figure 4. Ecuador's dry natural gas production and consumption, 2011–2021



Data source: U.S. Energy Information Administration, *International Energy Statistics*
Note: All natural gas produced in Ecuador is consumed domestically.

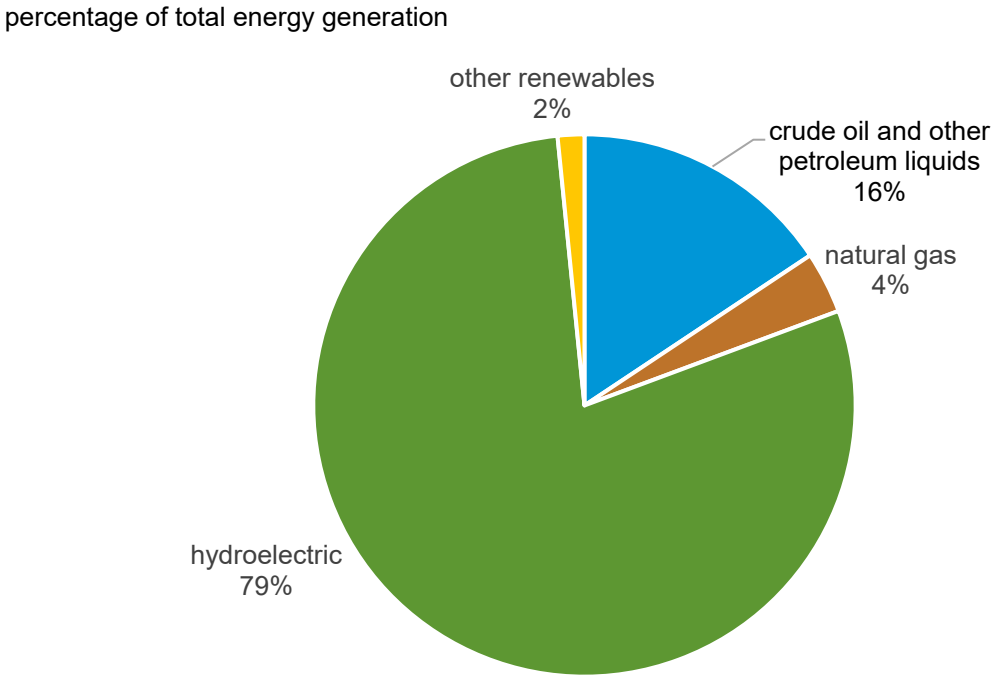
Coal

- Coal does not play a significant role in Ecuador's energy market. The country's 26 million short tons of coal reserves are in the Cañar-Azuay Basin,[14] but Ecuador does not produce coal. In 2021, the country consumed 21 thousand short tons,[15] which it imported primarily from the United States, followed by Peru.

Electricity

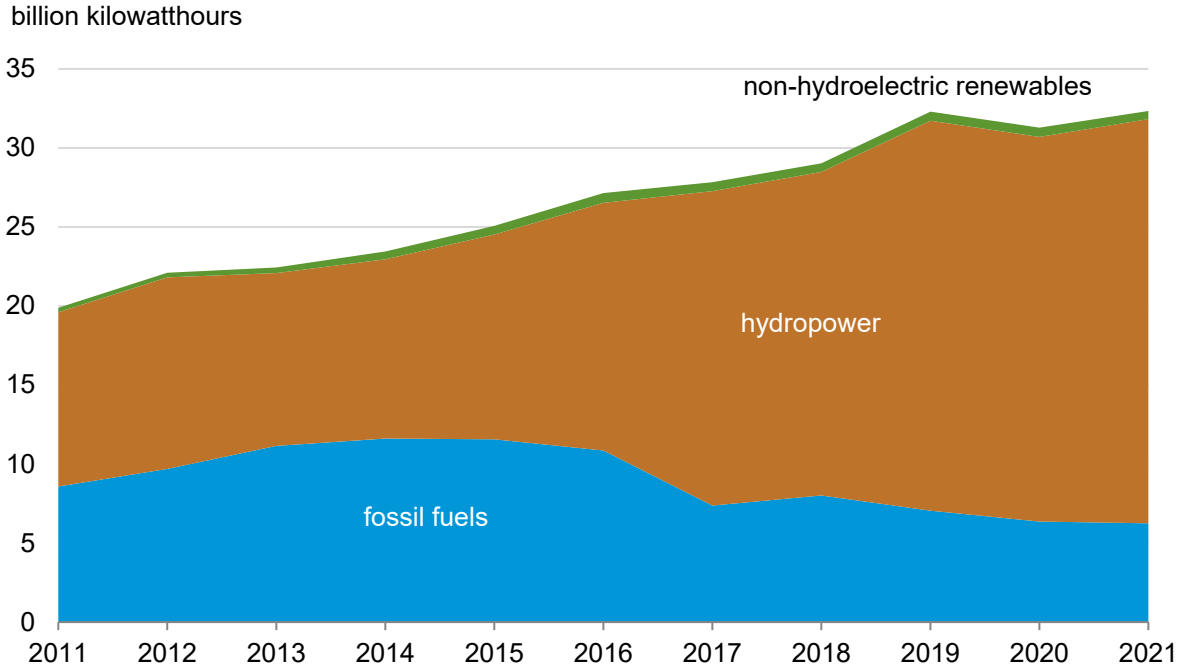
- Ecuador relied heavily on fossil fuel (which include oil, natural gas, and coal) production for power generation a decade ago, with fossil fuel-powered plants accounting for about 43% of total energy production in 2011. The country now generates electricity from a variety of sources, including hydropower, thermal power plants fueled by natural gas and oil, and renewable energy sources, such as wind and solar. In 2021, hydropower was the primary source, accounting for 79% of the country's electricity generation. The remaining electricity was generated from oil-powered conventional thermal power plants (17%), natural gas (4%), and other renewables (2%). As of 2020, industry accounted for almost 40% of total electricity consumption, followed by the residential sector (32%) and the commercial and public services sector (26%).[16]
- Ecuador’s mountainous terrain and numerous rivers allow for hydroelectric power generation. The launch of several large facilities since 1983 has solidified the hydropower sector's leading role in Ecuador's electricity generation mix (Table 3). The Coca Codo Sinclair Hydroelectric Plant, located on the Coca River in Napo Province, is Ecuador's largest hydroelectric facility, with a capacity of 1,500 megawatts (MW). The plant went into full operation in 2016 and is critical to meeting the country's electricity demand. Since its commissioning, the plant has been undergoing repairs, and it has run into operational complications because of the erosion from the Coca River.[17]
- Ecuador's reliance on hydropower for electricity generation makes the country's power sector vulnerable to droughts and low water levels during the dry season, which generally runs from October to March each year. To compensate, Ecuador currently relies on oil-fired plants for non-hydroelectric power generation. The government is committed towards converting old oil-fired plants into natural gas-fired facilities to meet demand and to reduce costs and emissions. Although natural gas-fired generation has the potential to become a stable complement to drought- and erosion-prone hydropower, Ecuador's lack of domestic natural gas supplies prevents its expansion in the short term.
- Ecuador's government opened the country's largest wind farm in 2023 with a US $90 million investment. The Huascachaca Wind Farm is the country's largest plant of its kind. The wind farm is located in the province of Loja and consists of 14 wind turbines of 3,571 MW each, supplying 130 gigawatthours (GWh) of energy per year via the 138-kilovolt (kV) Cuenca-Loja line.[18]

Figure 5. Ecuador's power generation supply, 2021



Data source: U.S. Energy Information Administration, *International Energy Statistics*, and International Energy Agency, *Electricity Information 2022*

Figure 6. Ecuador's electricity generation by source, 2011–2021



Data source: U.S. Energy Information Administration, *International Energy Statistics*

Table 3. Ecuador's operating hydroelectric plants

Name	Owner	Start year	Capacity (megawatts)	Type	Location
Central Hidroeléctrica Agoyán	Corporación Eléctrica del Ecuador (CELEC EP)	1987	160	Conventional storage	Tungurahua
Central Hidroeléctrica Coca Codo Sinclair	Corporación Eléctrica del Ecuador (CELEC EP)	2016	1,500	Run-of-river	Napo
Central Hidroeléctrica Delsitanisagua	Corporación Eléctrica del Ecuador (CELEC EP)	2018	180	Run-of-river	Zamora
Central Hidroeléctrica Marcel Laniado	Corporación Eléctrica del Ecuador (CELEC EP)	1987	213	Conventional storage	Guayas
Central Hidroeléctrica Mazár	Corporación Eléctrica del Ecuador (CELEC EP)	2014	170	Conventional storage	Azuay
Central Hidroeléctrica Minas San Francisco	Corporación Eléctrica del Ecuador (CELEC EP)	2019	276	Run-of-river	Azuay
Central Hidroeléctrica Paute	Corporación Eléctrica del Ecuador (CELEC EP)	1983	1,075	Conventional storage	Azuay
Central Hidroeléctrica San Francisco	Corporación Eléctrica del Ecuador (CELEC EP)	2007	230	Run-of-river	Tungurahua
Central Hidroeléctrica Sopladora	Corporación Eléctrica del Ecuador (CELEC EP)	2016	487	Run-of-river	Azuay
Central Hidroeléctrica Toachi-Alluriquin	Corporación Eléctrica del Ecuador (CELEC EP)	…	204	Conventional storage	Toachi
Total			**4,495**		

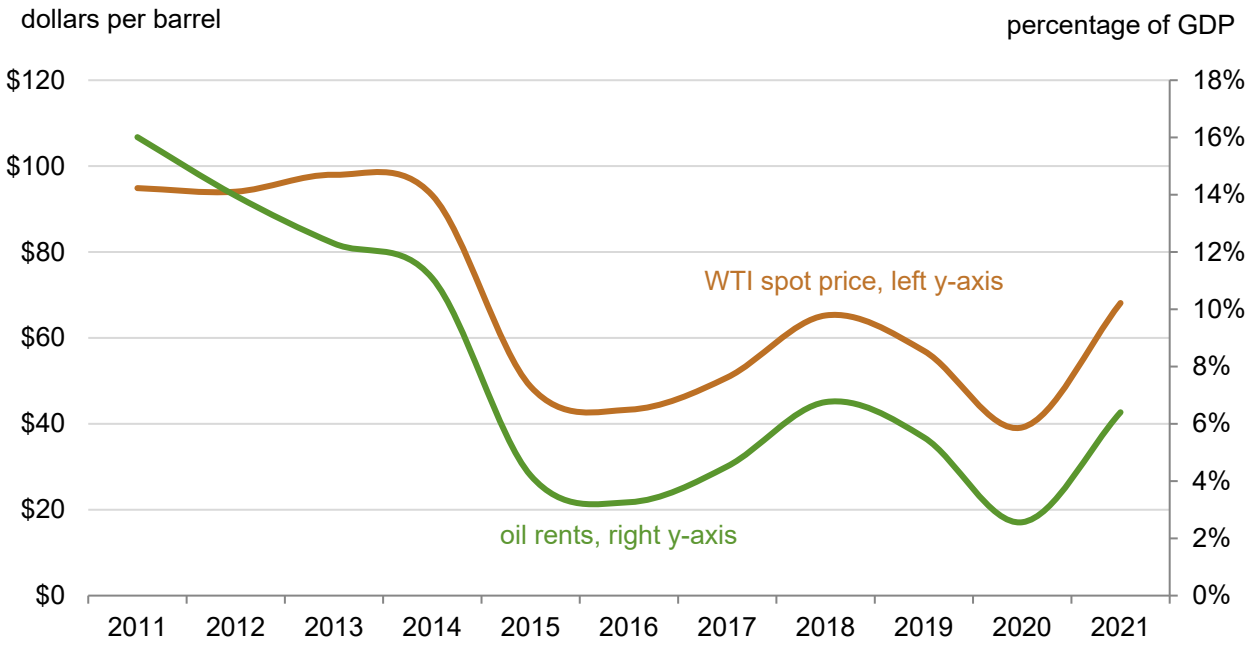
Data source: Global Energy Monitor, Global-Hydropower-Tracker, May 2023

Energy Trade

- Ecuador's oil rents (value of crude oil production minus total costs of production) declined from 16% of GDP in 2011 to 6.4% of GDP in 2021, following a 28% decrease in the crude oil price (Figure 6). During the same period, Ecuador's export diversification increased, as measured by the United Nations (Figure 7).
- Ecuador's crude oil production remains the country's most important export, accounting for 27% of total exports in value. In 2022, about 52% was exported to Latin America and the Caribbean, 40% to North America, 7% to Asia Pacific, and 1% to Europe. Ecuador's main export destinations were the United States (40%), Panama (38%), and Chile (9%). Ecuador was the second-highest non-OPEC source of foreign oil for the U.S. West Coast (PADD 5) in 2022, behind only Canada. As a result, Ecuador is a regionally significant source of oil for the U.S. West Coast, which is isolated from the rest of the continent because of a lack of overland pipelines.
- To meet domestic demand, Ecuador imports refined petroleum products. In 2022, ultra-low sulfur diesel (ULSD) accounted for 25% of total oil and natural gas imports, finished gasoline accounted for 23%, and propane accounted for 19%. Total oil and natural gas imports in 2022 arrived mainly from the United States (68%), followed by Panama (7%) and South Korea (6%).
- The United States is Ecuador's largest supplier of LPG. The Panama Canal expansion that began in 2007 facilitated the flow of LPG from the U.S. Gulf Coast into Ecuador.
- Ecuador does not export natural gas. Ecuador imported 2 million cubic feet of liquefied natural gas (LNG) in January 2022 in two 40-foot ISO containers designed for storage and transportation. The cargo from Panama was Ecuador's first import of LNG in its history.[19]
- Ecuador has electricity transmission grid interconnections with Peru and Colombia. Historically, Ecuador imported electricity mainly from Peru to supplement its domestic supply. Electricity

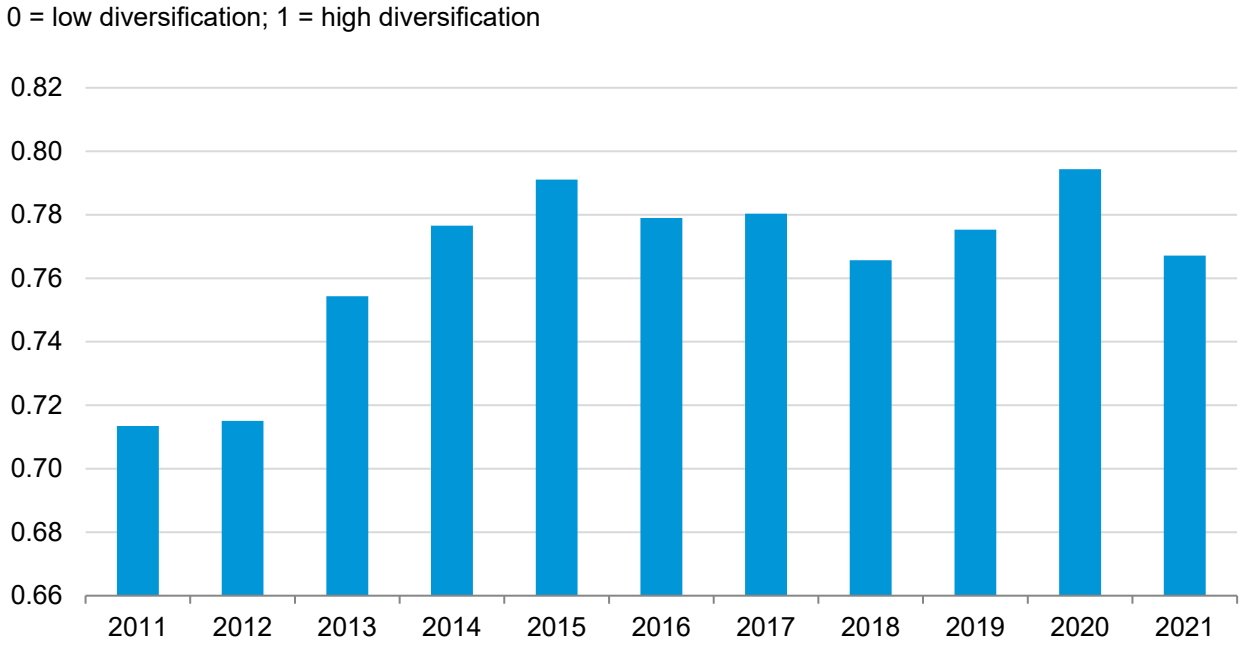
imports have declined since 2017 after the introduction of hydroelectric plants in Ecuador. Since 2020, Ecuador has become a net exporter of electricity, exporting to Peru and Colombia during times of surplus generation.

Figure 7. Ecuador's oil rents compared with the West Texas Intermediate (WTI) spot price, 2011–2021



Data source: U.S. Energy Information Administration and World Bank, *World Development Indicators*
Note: Oil rents represent the value of crude oil production minus total costs of production. WTI determines the price at which oil is sold and is used to calculate oil rents.

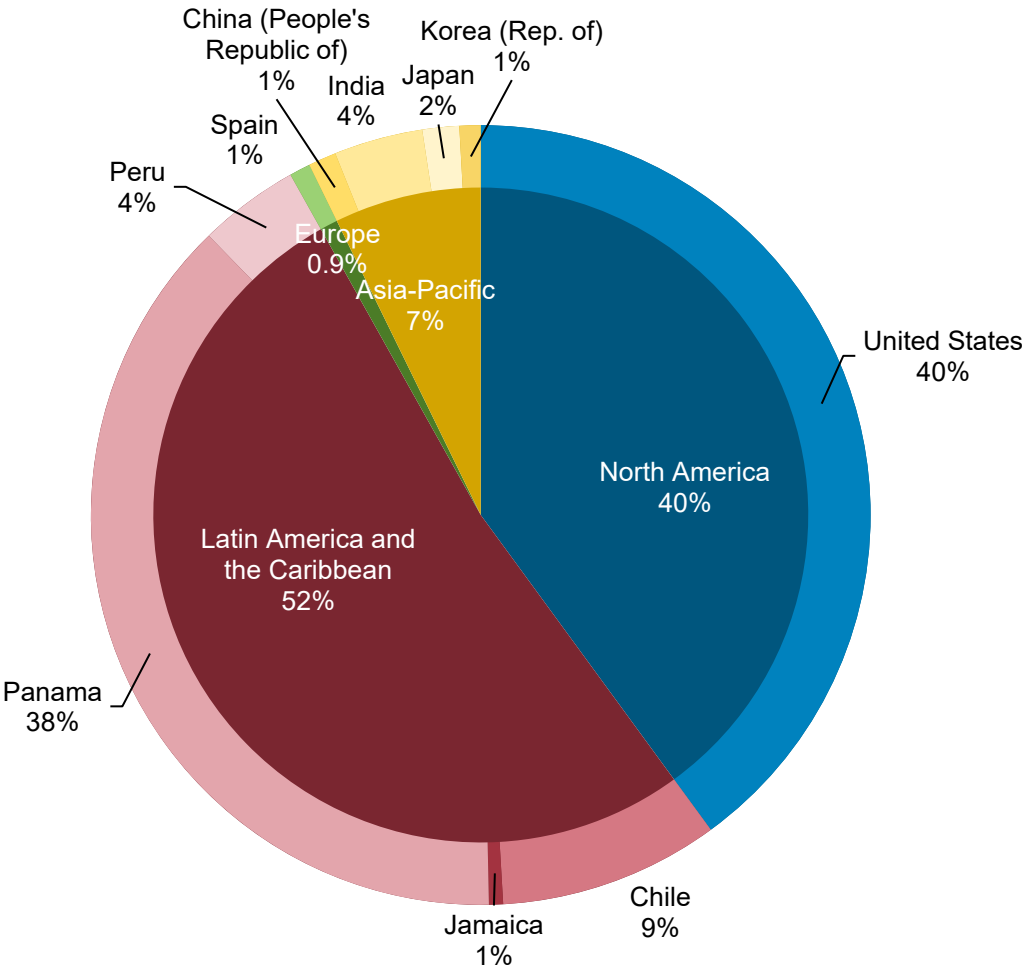
Figure 8. Ecuador's merchandise exports diversification index, 2011–2021



Data source: United Nations Conference on Trade and Development (UNCTAD) secretariat calculations, based on UNCTADStat merchandise trade matrix
Note: The diversification index indicates to what extent the structure of exports by product of a given economy or group of economies differs from the world pattern.

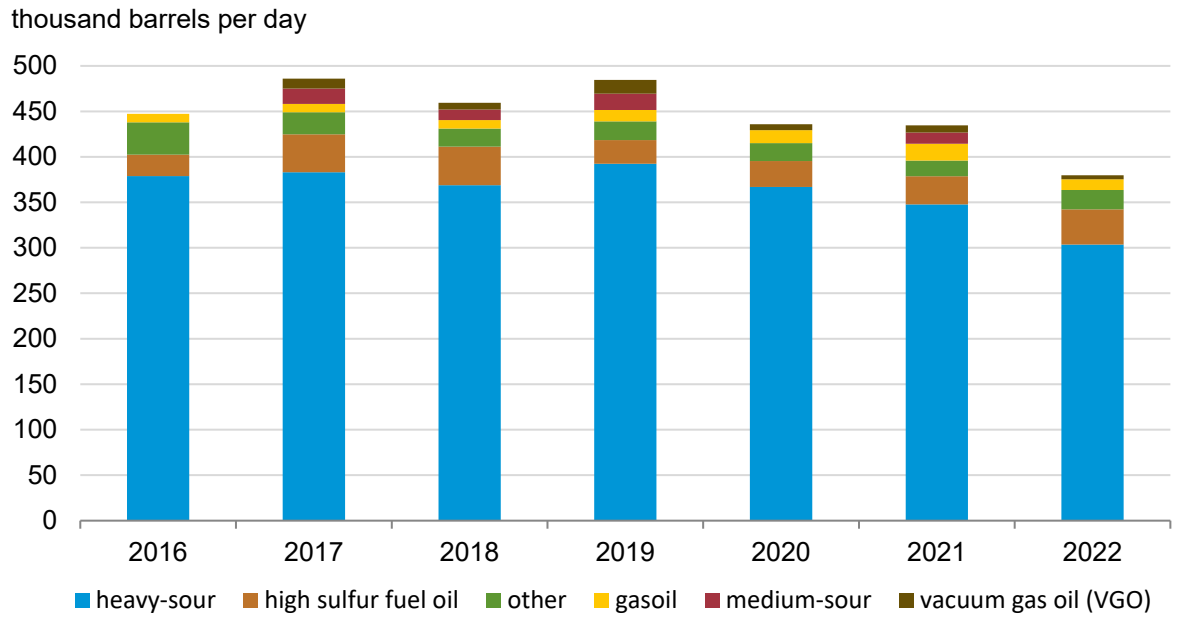
Figure 9. Ecuador's crude oil exports by region and country, 2022

percentage of total crude oil exports



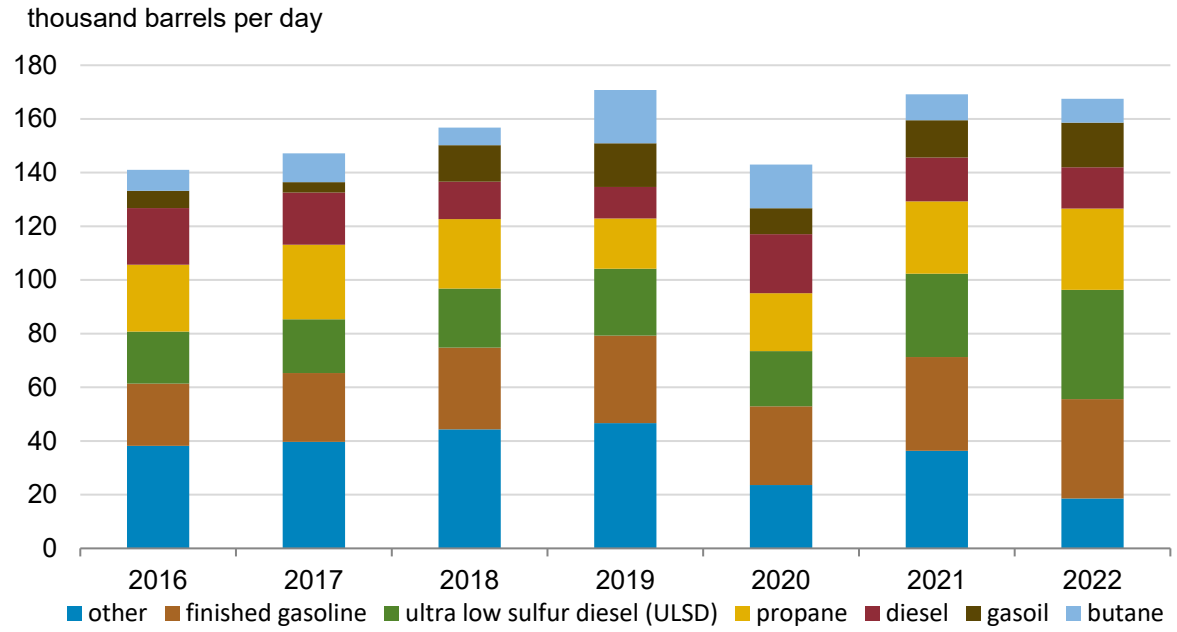
Data source: Global Trade Tracker, provided by Zen Innovations AG © 2023
Note: Regional totals may not equal the sum of the countries due to independent rounding.

Figure 10. Ecuador's oil exports, 2016–2022



Data source: Vortexa Ltd.
Note: *Other* includes biodiesel feedstock, blending components, chemicals, diesel, finished gasoline, heavy naphtha, light naphtha, low-sulfur oil, lube oils, jet fuel, other biodiesel or edible oils, and ultra-low sulfur diesel (ULSD).

Figure 11. Ecuador's oil imports, 2016–2022



Data source: Vortexa Ltd.
Note: *Other* includes high-sulfur fuel oil, biodiesel feedstock, light naphtha, chemicals, lube oils, blending components, dirty condensates, other biodiesel or edible oils, and olefins or other chemicals.

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https://membership.tipro.org/news/13242768

Demand for Texas Oil and Gas Talent Remains Strong

17 Aug 2023 10:30 AM

Austin, Texas - Citing the latest Current Employment Statistics (CES) report from the U.S. Bureau of Labor Statistics (BLS), the Texas Independent Producers and Royalty Owners Association (TIPRO) today highlighted new employment figures showing a decline in Texas upstream employment following four months of consecutive growth. According to TIPRO's analysis, direct Texas upstream employment for July 2023 totaled 206,600, a decrease of 2,100 jobs from adjusted June employment numbers. Texas upstream employment in July 2023 represented the addition of 18,600 positions compared to July 2022, including an increase of 2,800 jobs in oil and natural gas extraction and 15,800 jobs in the services sector.

"Given historical hiring trends and adjustments made in CES data in subsequent months, it is not uncommon to see fluctuations in employment numbers throughout the year," said Ed Longanecker, president of TIPRO. "Absent any major economic factors affecting supply and demand, these variations are often anonymous, especially considering the number of open positions currently available in the Texas oil and natural gas industry. We expect continued growth in Texas upstream employment in the second half of the year," added Longanecker.

TIPRO's new employment data yet again indicated strong job postings for the Texas oil and natural gas industry during the month of July. According to the association, there were 13,557 active unique jobs postings for the Texas oil and natural gas industry in July, including 5,095 new job postings added during the month by companies. In comparison, the state of California had 4,365 unique job postings last month, followed by Louisiana (2,224), Oklahoma (1,905) and Pennsylvania (1,687). TIPRO reported a total of 62,318 unique job postings nationwide last month within the oil and natural gas sector.

Among the 17 specific industry sectors TIPRO uses to define the Texas oil and natural gas industry, Support Activities for Oil and Gas Operations led in the rankings for unique job listings in July with 3,217 postings, followed by Gasoline Stations with Convenience Stores (2,065) and Crude Petroleum Extraction (1,543). The leading three cities by total unique oil and natural gas job postings were Houston (4,737), Midland (1,132) and Odessa (622), said TIPRO.

The leading three companies ranked by unique job postings in July were Cefco (752), John Wood Group (738) and Halliburton (447), according to TIPRO. Of the top ten companies listed by unique job postings last month, four companies were in the services sector, followed by two midstream companies, two in the gasoline stations category with convenience stores, and two in oil and natural gas extraction. Top posted industry occupations for July included maintenance and repair workers (563), first-line supervisors of retail sales workers (534) and heavy tractor-trailer truck drivers (434). The top posted job titles for July included store managers (180), customer service representatives (129) and field service technicians (124).

Top qualifications for unique job postings included valid driver's license (2,324), commercial driver's license (CDL) (347), and CDL class a license (218). TIPRO reports that 40 percent of unique job postings required a bachelor's degree, 31 percent required a high school diploma or GED, and 30 percent had no education requirement listed. There are 1,410 advertised salary observations (10 percent of the 13,557 matching postings) with a median salary of $50,000. The highest percentage of advertised salaries (27 percent) were in the $75,000 to $250,000 range.

Additional TIPRO workforce trends data:

- A sample of 500 industry job postings in Texas for July 2023 can be viewed here.
- The top three posting sources in June included indeed.com (5,326), simplyhired.com (3,144) and dejobs.org (1,941).

- Average annual wages for the Texas oil and natural gas industry can be viewed here.
- Leading industry positions in Texas with median hourly earnings, education, work experience and typical on-the-job training is available here.

TIPRO also highlights recent data released from the Texas comptroller's office showing tax contributions by the Texas oil and natural gas industry for the month of July. Texas energy producers last month paid $437 million in oil production taxes and also contributed $65 million in natural gas production taxes. Tax receipts from the sector are down from earlier this year, due to a slowdown in drilling activity in some of the state's oil and natural gas basins. Still, oil and natural gas severance taxes remain an important source of revenue for state and local governments and continue to be used help to support and pay for road and infrastructure investments, water conservation projects, schools and education, first responders and other essential public services across the Lone Star State.

Furthermore, TIPRO reports that oil and natural gas output from Texas and the United States will remain strong in the coming months, though is forecasted to decline in September. New data from the U.S. Energy Information Administration (EIA) projects U.S. crude oil production will total 9.41 million barrels per day (b/d) next month, a drop of 20,000 b/d from revised August output amounting to 9.435 million b/d. In the Permian Basin, the most nation's most prolific shale oil basin, regional oil output is expected to fall by around 13,000 b/d to 5.8 million b/d in September, estimates EIA experts, after reaching 5.812 million b/d in August. Oil production in the Eagle Ford region in South Texas meanwhile will fall next month by 11,000 b/d to 1.11 million b/d. Domestic natural gas production in the United States also is expected to decrease in September by around 147 million cubic feet per day to 98.262 billion cubic feet per day (bcf/d), according to the latest EIA estimates. Despite the overall decline in natural gas production in the United States, the Permian Basin is still slated to see natural gas output increase to 23.667 bcf/d, with the highest growth in production of natural gas anywhere in the country. Natural gas production in the Eagle Ford and Haynesville formations, however, will go down in September.

"Oil and natural gas are the most consequential products on the planet that fuel modern societies, drive economic growth and fortify our nation's energy security" emphasized Longanecker. "We are incredibly proud to support the hardworking men and women in the Texas oil and natural gas industry that power our homes, transportation and afford us the conveniences, products, and protections that we all value and utilize in our daily lives. With energy demand projected to reach new records in the years ahead, our industry will continue to play a dominant role in supporting our country, allies, trade partners and developing nations around the world, with Texas leading the way," concluded Longanecker.

https://www.ft.com/content/bacb921e-042c-44db-8291-84169a43473d

UN warns banks that fund Saudi Aramco about possible human rights breach

Financiers of world's biggest corporate emitter of greenhouse gases told they could be violating international law

Saudi Arabia's oil company is accused of the largest ever climate-related breach of international human rights law by a business © Dina Khrennikova/Bloomberg
Attracta Mooney in London YESTERDAY

The UN has told banks including Citi, Goldman Sachs and BNP Paribas that their financing of Saudi Aramco may be in violation of global human rights rules because of the state-run oil company's contribution to climate change.

A panel of UN appointed human rights specialists has sent letters to Aramco as well its financiers, following a 2021 legal complaint by environmental campaign group ClientEarth that accused Saudi Arabia's oil company of the largest ever climate-related breach of international human rights law by a business.

Aramco is the world's biggest corporate emitter of greenhouse gases. The burning of fossil fuels is the largest contributor to climate change, accounting for about 75 per cent of global warming.

The concern is that Aramco's continued crude oil production and further exploration of oil and gas, alongside other issues, may be in breach of the Paris agreement to limit global temperature rises and a UN resolution that people have a right to a clean, healthy and sustainable environment.

The UN letter warns the banks that if they are aware of a human rights issue but fail to take "reasonable steps" to prevent or mitigate the impact, "it can be viewed as enabling the situation".

"Businesses should avoid infringing on human rights by taking proactive steps to identify, prevent, mitigate and address adverse impacts with which they are involved, including impacts resulting from climate change," said the letter.

"The alleged involvement of financial institutions in the financing of Saudi Aramco's activities could be in violation of international human rights law and standards."

Banks are already under scrutiny over their role in financing projects that contribute to climate change. While some have set targets to reach net zero carbon emissions, many continue to fund new fossil fuel projects. The International Energy Association said in 2021 that there could be no new fossil fuel projects if the world is to reach net zero emissions by 2050.

The communications, which were signed by five independent human rights experts appointed and mandated by the UN Human Rights Council, are not a legal judgment but may be cited in legal action.

It is the first time the UN has taken action against the oil industry and its financial backers in relation to the human rights implications of climate change.

ClientEarth said it sets "a new legal standard for fossil fuel companies' human rights responsibilities for the climate crisis".

"The UN experts could not be clearer: banks bear their own legal responsibility regarding the escalating and detrimental threat climate change poses to human rights."

Citi declined to comment. Goldman Sachs said: "We consider any correspondence from the UN at the appropriate time."

HSBC said it was "committed to being transparent around the opportunities, challenges and progress we are making in relation to environmental, social and governance issues".

BNP Paribas and Aramco did not respond to requests for comment.

Additional reporting by Stephen Morris, Joshua Franklin, Stephen Gandel and Samer Al-Atrush.

https://www.newswire.ca/news-releases/government-of-canada-announces-federal-support-for-small-modular-reactor-smr-development-in-saskatchewan-838580549.html

Government of Canada Announces Federal Support for Small Modular Reactor (SMR) Development in Saskatchewan

NEWS PROVIDED BY
Natural Resources Canada
19 Aug, 2023, 17:00 ET

SASKATOON, SK, Aug. 19, 2023 /CNW/ - To cement Canada's competitive advantage in the global shift to a net-zero emissions economy and to meet our climate goals, we need to significantly increase the amount of non-emitting energy that we use to power our homes, businesses and industries. New, non-emitting electricity infrastructure projects, including projects powered by next-generation nuclear technologies, such as small modular reactors (SMRs), can play a crucial role in this shift and in delivering economic prosperity to every region of Canada.

The Government of Canada is continuing to support the development and deployment of SMRs, a promising non-emitting form of energy, to help Saskatchewan and other provinces increase their ability to deliver clean, reliable and affordable power to their citizens. To this end, the Honourable Jonathan Wilkinson, Minister of Energy and Natural Resources, was in Saskatoon today to announce that the Government of Canada has approved up to $74 million in federal funding for SMR development in Saskatchewan, led by SaskPower. This funding will support pre-engineering work and technical studies, environmental assessments, regulatory studies and community and Indigenous engagement to help advance this important project. SaskPower has selected the GE-Hitachi BWRX-300 for potential deployment in Saskatchewan in the mid-2030s, subject to a decision to build that is expected in 2029.

SMRs, a non-emitting form of energy, can play an important role in decarbonizing provincial electricity grids and heavy-emitting industries and can help remote communities reduce their reliance on costly and high-polluting diesel power. As an example, a 300-megawatt SMR can supply enough non-emitting power for an estimated 300,000 homes.

With over 75,000 hard-working Canadians employed across its supply chain and decades of experience in this area, Canada's nuclear industry is well positioned to leverage its science and technology innovation to continue to be among the leaders in the development and deployment of SMR technology.

Advancing new non-emitting electricity infrastructure projects is part of the government's comprehensive approach to bringing clean, affordable and reliable power to every region of Canada, as outlined in *Powering Canada Forward* and in the draft Clean Electricity Regulations. The Government of Canada has committed over $40 billion in new federal measures to help provinces and has announced over $500 million to date in support of a variety of projects that are helping to build a clean, affordable and reliable grid in Saskatchewan specifically.

The shift to a non-emitting, affordable and reliable electricity grid across Canada by 2035 is a nation-building project that requires significant investments, thoughtful regulations and our fullest collaboration. Today's announcement brings us one step closer to achieving a clean electricity system for the benefit of all Canadians. With a thoughtful, comprehensive and collaborative approach, we can

ensure that every region of Canada thrives in the global race to fight climate change and seizes the economic opportunities of a low-carbon future.

Quotes

"Delivering clean, reliable and affordable electricity will look different in every region of Canada. That is why the Government of Canada is committing up to $74 million to explore the potential for small modular reactors in Saskatchewan to provide abundant non-emitting power, drive economic growth and create good jobs throughout Saskatchewan. With today's announcement, we are investing in the future of nuclear technology, building on Canada's decades-long legacy as a responsible global leader in nuclear power, and leveraging Saskatchewan's world-leading production of uranium to position the province to thrive in a rapidly decarbonizing global economy."

The Honourable Jonathan Wilkinson
Minister of Energy and Natural Resources

"Saskatchewan has a significant competitive advantage with an abundance of natural resources to be a leader in the development of clean, affordable and reliable electricity grid. Building a clean electricity grid in Saskatchewan is good for the economy, good for communities and good for the planet. The project announced today is yet another example of how our two levels of government can work together to finance the clean energy projects needed to power Saskatchewan's thriving economy."

The Honourable Steven Guilbeault
Minister of Environment and Climate Change

"The approved funding of $74 million serves as a strong indication from the government that Canada is at the forefront of global innovation and implementation of small modular reactors (SMRs). Saskatchewan's SMR program will provide reliable, low-carbon baseload energy to meet increasing electricity needs, supply clean power to its resource extraction industry and fuel the province's economic growth. This is exciting news for the residents of Saskatchewan, including its Indigenous communities, who have supported the province's SMR development."

John Gorman
President and CEO, Canadian Nuclear Association

"GE Hitachi is excited to work with Saskatchewan to be a global leader in the deployment of small modular reactors. Our technology is designed to provide reliable, cost-effective and emissions-free baseload electricity generation for the people of Saskatchewan for decades to come."

Lisa McBride
Country Leader, GEH SMR Canada

Quick Facts

- Up to $50 million for this project has been committed to SaskPower from NRCan's Electricity Predevelopment Program — a $250-million program to support pre-development activities of clean electricity projects of national significance, such as inter-provincial electricity transmission projects and small modular reactors. These kinds of projects will be critical for supporting economic development through investments in new infrastructure and the enhanced security and reliability of our clean energy supply. The funding announced today is conditional on the finalization of a Contribution Agreement between NRCan and SaskPower, which is currently underway.
- Additionally, over $24 million for this project has been committed to the Government of Saskatchewan from Environment and Climate Change Canada's (ECCC) Future Electricity Fund. This program returns pollution pricing proceeds to support clean energy projects, energy-efficient technologies and other initiatives that will help Canada meet its climate goals and achieve a net-zero-emissions economy by 2050. The fund is intended to help spur innovation and encourage the adoption of cleaner technologies and fuels in Canada — including Saskatchewan's small modular reactor project.
- In addition to reducing greenhouse gases, moving to a clean grid will deliver health benefits to Canadians by reducing the air pollutants that result from the burning of natural gas and coal, such as nitrogen and sulfur oxides, particulate matter and mercury. Air pollution is a major contributor to disease and premature death both in Canada and globally. Health Canada estimated that in 2015, air pollution from electricity-generating units contributed to about 150 premature deaths per year in Canada, as well as many non-fatal negative health outcomes, with a total cost of $1.2 billion per year (2015 constant dollars).
- SaskPower anticipates construction of its first SMR could begin as early as 2030, with a targeted in-service date of 2034. Additional facilities could begin construction as early as 2034.
- In 2020, SaskPower and Ontario Power Generation commissioned the Conference Board of Canada to study the potential economic opportunity and job creation related to the development of SMRs in both provinces. The study projects that from 1,200 MW of nuclear power being developed in Saskatchewan, approximately 1,700 new direct and indirect jobs would be created in Saskatchewan during the construction phase and 728 direct and indirect jobs during the operational phase.
- The study also estimates an increase of $8.8 billion in gross domestic product, $5.6 billion in wages and $2.9 billion in tax revenue (over the 60-year lifespan of the facilities).
- Other recent federal investments in Saskatchewan's electricity sector include:
    - In April 2022, $300 million of federal clean energy funding was directed to the Wah-ila-toos partnership for clean energy projects in Indigenous, rural and remote communities in Canada.
    - In July 2022, the Government of Canada invested almost $10 million in clean energy support for Indigenous communities in Saskatchewan.
    - In May 2023, through the Future Electricity Fund, the Government of Canada announced the return of $174 million in pollution pricing proceeds to Saskatchewan for non-emitting electricity projects, including the implementation of new residential smart meters, improvements to rural electricity distribution systems and the refurbishment of the E.B. Campbell Hydroelectric Station.

- In June 2023, The Government of Canada announced a $50-million investment to the Bekevar Wind Power Project in partnership with the Cowessess First Nation.
- The Government of Canada also recently announced over $7 million in investments to Indigenous clean energy projects in Saskatchewan through the Smart Renewables and Electrification Pathways program.
- The Government of Canada invested $18.5 million in the Indigenous-led Awasis Solar Project, a 10-MW solar power generation project to be built on Cowessess First Nations land.
- The Government of Canada has invested over $21.6 million in funding to 14 Indigenous communities to help implement clean energy projects with one of these communities located in Saskatchewan.

- Today's announcement took place at the Sylvia Fedoruk Canadian Centre for Nuclear Innovation at the University of Saskatchewan. The Centre was established in 2011 to help place Saskatchewan among global leaders of nuclear research, development and training and is a participant in Canada's SMR Action Plan.

Quick Links

- *Powering Canada Forward: A vision for a clean, affordable, and reliable electricity system for every region of Canada*
- Saskatchewan: Clean electricity snapshot
- SMR Action Plan
- Output-Based Pricing System Proceeds Fund
- Carbon Pollution Pricing Proceeds Programming and Use of Proceeds
- How Carbon Pricing Works
- How the Price on Pollution Works for Industry

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https://www.forbes.com/sites/ellenrwald/2020/06/25/the-small-canadian-province-that-could-lead-the-future-of-energy/?utm_source=TWITTER&utm_medium=social&utm_content=3449040634&utm_campaign=sprinklrForbesMainTwitter#502268eceba7

EDITORS' PICK|8,789 views|Jun 25, 2020,01:39pm EDT

The Small Canadian Province That Could Lead The Future Of Energy

Ellen R. Wald Senior Contributor
Markets

Saskatchewan, which is a province in Canada, has jumped to the forefront of new energy technology. It is not doing this with loan guarantees for solar power companies or massive land grants for wind power businesses. Rather, it is looking into what may prove to be the biggest change in energy technology in this century: the adoption of small modular nuclear power plants.

A sunset over the city of Saskatoon located in Central Canada.

GETTY

The Saskatchewan government is creating an office within its Ministry of Environment to plan the adoption of nuclear power. The policy fits for the province in part because Saskatchewan is a source of uranium. This program would allow the province to keep its energy production local. Also, Saskatchewan is large geographically but small in population, so it could benefit greatly from the flexibility of these plants.

The Sue C open pit uranium mine at Areva Resources 16 July 2007 in McClean Lake, Saskatchewan, ... [+]

The small modular reactors (SMRs) Saskatchewan is looking at can produce between 50 and 300 megawatts of power. They are aiming for small plants that could even be transportable. We have written about small modular nuclear reactors before, including its benefits for businesses and small municipalities. For a full province of 251,700 square miles and almost 1.2 million people, these SMRs would provide flexibility and cost efficiency, with the added benefit of providing electricity without pollution.

It is often cost prohibitive to build large, traditional nuclear power plants. Utilities and governments just don't want to build them anymore. According to the Energy Information Administration, the average age of a nuclear plant in the United States is 39 years old. SMRs can be commissioned for much less. They are also ideal for smaller population centers, and the largest city in the province, Saskatoon, has fewer than 300,000 people. SMRs could also be great power sources for factories and server farms.

Saskatchewan is still committed to solar and wind projects to operate in conjunction with traditional power generation like natural gas-powered plants. However, if Saskatchewan does proceed with its nuclear ambitions, it could be a great example and guide for governments across the world.

https://www.alberta.ca/release.cfm?xID=72998DCF71AB1-B09A-B25B-F0EB62BA02A0EFC8

Exploring safe, small-scale nuclear technology

Alberta will enter into an agreement with three other provinces to explore emerging, small-scale nuclear technology that could lower emissions and help diversify the energy sector.

Premier Jason Kenney has signalled the intent for Alberta to enter into a memorandum of understanding with Ontario, Saskatchewan and New Brunswick to support the development of versatile and scalable small modular reactors (SMRs).

SMRs are smaller than traditional nuclear reactors and scalable to suit local needs, with lower upfront capital costs and enhanced safety features. This new and versatile technology could supply non-emitting, low-cost energy for on-grid and off-grid communities in Alberta, including remote and rural areas of the province, as well as industries with a significant need for steam, such as Alberta's oil sands.

"Our government is exploring all opportunities that could help diversify our economy and create jobs for Albertans. We are building on our track record of responsible and innovative energy production by exploring the potential for small modular reactors, which have the potential to generate reliable and affordable energy, while also strengthening our traditional resource sectors and reducing emissions. We are excited to collaborate with our provincial partners to stay ahead of the game in the development of this promising technology."

Jason Kenney, Premier

"Alberta's rich uranium deposits, respected innovation and research sector, and technically skilled and educated workforce could make us an attractive destination to develop and deploy SMRs. By signing on to this agreement, our government is taking another step to attract investment and job creators to our province by ensuring we have the appropriate regulatory framework in place should private industry decide to pursue this emerging technology."

Sonya Savage, Minister of Energy

Alberta's Recovery Plan is a bold, ambitious long-term strategy to build, diversify, and create tens of thousands of jobs now. By building schools, roads and other core infrastructure we are benefiting our communities. By diversifying our economy and attracting investment with Canada's most competitive tax environment, we are putting Alberta on a path for a generation of growth.

Alberta came together to save lives by flattening the curve and now we must do the same to save livelihoods, grow and thrive.

Quick facts

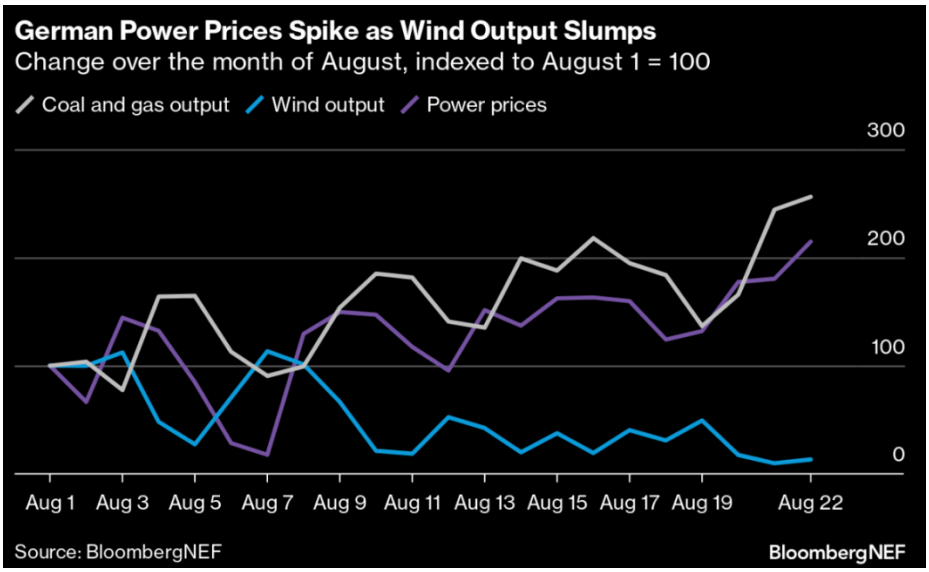
- SMRs are nuclear reactors that are smaller and more flexible than conventional nuclear reactors. SMRs would be small enough to be built in a factory and shipped by truck, rail or ship.
- A typical SMR would generate between two and 300 megawatts of electricity, which could provide power for a village or small city. In comparison, a conventional nuclear reactor can generate 600 to 1,000 megawatts, which can provide power for a large city.
- SMRs could operate independently or be linked to multiple units, depending on the required amount of power.
- In November 2018, the federal government released the Canadian Small Modular Reactor Roadmap that outlines recommendations for collaboration among federal, provincial and territorial governments, Indigenous communities and other stakeholders to support SMR development in Canada.
    - In February 2020, the federal government announced plans for a fall 2020 launch of Canada's SMR Action Plan, which will outline progress and ongoing efforts across Canada.
- In December 2019, New Brunswick, Ontario and Saskatchewan signed a memorandum of understanding to work together to support the development and deployment of SMRs.
- Canada is the second largest uranium producer in the world, with about 15 per cent of total world production.
- The Athabasca Basin, which straddles the northern Alberta-Saskatchewan border, contains some of the greatest uranium resources in the world.

Multimedia

- Video message: Premier Kenney and Minister Savage

German Power Prices Double in August as Wind Output Slumps: BNEF
2023-08-23 13:46:25.383 GMT

By Kesavarthiniy Savarimuthu
(BloombergNEF) -- Germany's power prices have doubled since the beginning of the month, to €147 per megawatt-hour. Falling wind generation, and the consequent rise in thermal output, are the main drivers behind the power price increase.



On August 22, the share of wind in total generation fell to 15%, from 50% in the beginning of the month. The gap left by wind has been filled by coal and gas, as their share in generation rose to 52% from 20% over the same period.
Increased wind capacity is a double-edged sword for power prices in Germany. On the one hand, the influx of cheap wind generation depresses spot power prices. On the other, fluctuations in wind output drive power price volatility, as thermal plants, which are expensive to run, fluctuate their output to meet demand during lulls in wind output.
Over the next decade, Germany's pivot away from coal, combined with closures of nuclear plants and a growing wind fleet, will continue driving up power price volatility, as a shrinking thermal fleet flexes to counter the unpredictability of renewable generation.
For more, see BloombergNEF's European Power Markets Monitor.

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August 25, 2023

Inflation: Progress and the Path Ahead

Chair Jerome H. Powell

At "Structural Shifts in the Global Economy," an economic policy symposium sponsored by the Federal Reserve Bank of Kansas City, Jackson Hole, Wyoming

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Good morning. At last year's Jackson Hole symposium, I delivered a brief, direct message. My remarks this year will be a bit longer, but the message is the same: It is the Fed's job to bring inflation down to our 2 percent goal, and we will do so. We have tightened policy significantly over the past year. Although inflation has moved down from its peak—a welcome development—it remains too high. We are prepared to raise rates further if appropriate, and intend to hold policy at a restrictive level until we are confident that inflation is moving sustainably down toward our objective.

Today I will review our progress so far and discuss the outlook and the uncertainties we face as we pursue our dual mandate goals. I will conclude with a summary of what this means for policy. Given how far we have come, at upcoming meetings we are in a position to proceed carefully as we assess the incoming data and the evolving outlook and risks.

The Decline in Inflation So Far

The ongoing episode of high inflation initially emerged from a collision between very strong demand and pandemic-constrained supply. By the time the Federal Open Market Committee raised the policy rate in March 2022, it was clear that bringing down inflation would depend on both the unwinding of the unprecedented pandemic-related demand and supply distortions and on our tightening of monetary policy, which would slow the growth of aggregate demand, allowing supply time to catch up. While these two forces are now working together to bring down inflation, the process still has a long way to go, even with the more favorable recent readings.

On a 12-month basis, U.S. total, or "headline," PCE (personal consumption expenditures) inflation peaked at 7 percent in June 2022 and declined to 3.3 percent as of July, following a trajectory roughly in line with global trends (figure 1, panel A).[1] The effects of Russia's war against Ukraine have been a primary driver of the changes in headline inflation around the world since early 2022. Headline inflation is what households and businesses experience most directly, so this decline is very good news. But food and energy prices are influenced by global factors that remain volatile, and can provide a misleading signal of where inflation is headed. In my remaining comments, I will focus on core PCE inflation, which omits the food and energy components.

On a 12-month basis, core PCE inflation peaked at 5.4 percent in February 2022 and declined gradually to 4.3 percent in July (figure 1, panel B). The lower monthly readings for core inflation in June and July were welcome, but two months of good data are only the beginning of what it will take to build confidence that inflation is moving down sustainably toward our goal. We can't yet know the extent to which these lower readings will continue or where underlying inflation will settle over coming quarters. Twelve-month core inflation is still elevated, and there is substantial further ground to cover to get back to price stability.

To understand the factors that will likely drive further progress, it is useful to separately examine the three broad components of core PCE inflation—inflation for goods, for housing services, and for all other services, sometimes referred to as nonhousing services (figure 2).

Core goods inflation has fallen sharply, particularly for durable goods, as both tighter monetary policy and the slow unwinding of supply and demand dislocations are bringing it down. The motor vehicle sector provides a good illustration. Earlier in the pandemic, demand for vehicles rose sharply, supported by low interest rates, fiscal transfers, curtailed spending on in-person services, and shifts in preference away from using public transportation and from living in cities. But because of a shortage of semiconductors, vehicle supply actually fell. Vehicle prices spiked, and a large pool of pent-up demand emerged. As the pandemic and its effects have waned, production and inventories have grown, and supply has improved. At the same time, higher interest rates have weighed on demand. Interest rates on auto loans have nearly doubled since early last year, and customers report feeling the effect of higher rates on affordability.[2] On net, motor vehicle inflation has declined sharply because of the combined effects of these supply and demand factors.

Similar dynamics are playing out for core goods inflation overall. As they do, the effects of monetary restraint should show through more fully over time. Core goods prices fell the past two months, but on a 12-month basis, core goods inflation remains well above its pre-pandemic level. Sustained progress is needed, and restrictive monetary policy is called for to achieve that progress.

In the highly interest-sensitive housing sector, the effects of monetary policy became apparent soon after liftoff. Mortgage rates doubled over the course of 2022, causing housing starts and sales to fall and house price growth to plummet. Growth in market rents soon peaked and then steadily declined (figure 3).[3]

Measured housing services inflation lagged these changes, as is typical, but has recently begun to fall. This inflation metric reflects rents paid by all tenants, as well as estimates of the equivalent rents that could be earned from homes that are owner occupied.[4] Because leases turn over slowly, it takes time for a decline in market rent growth to work its way into the overall inflation measure. The market rent slowdown has only recently begun to show through to that measure. The slowing growth in rents for new leases over roughly the past year can be thought of as "in the pipeline" and will affect measured housing services inflation over the coming year. Going forward, if market rent growth settles near pre-pandemic levels, housing services inflation should decline toward its pre-pandemic level as well. We will continue to watch the market rent data closely for a signal of the upside and downside risks to housing services inflation.

The final category, nonhousing services, accounts for over half of the core PCE index and includes a broad range of services, such as health care, food services, transportation, and accommodations. Twelve-month inflation in this sector has moved sideways since liftoff. Inflation measured over the past three and six months has declined, however, which is encouraging. Part of the reason for the modest decline of nonhousing services inflation so far is that many of these services were less affected by global supply chain bottlenecks and are generally thought to be less interest sensitive than other sectors such as housing or durable goods. Production of these services is also relatively labor intensive, and the labor market remains tight. Given the size of this sector, some further progress here will be essential to restoring price stability. Over time, restrictive monetary policy will help bring aggregate supply and demand back into better balance, reducing inflationary pressures in this key sector.

The Outlook

Turning to the outlook, although further unwinding of pandemic-related distortions should continue to put some downward pressure on inflation, restrictive monetary policy will likely play an increasingly important role. Getting inflation sustainably back down to 2 percent is expected to require a period of below-trend economic growth as well as some softening in labor market conditions.

Economic growth

Restrictive monetary policy has tightened financial conditions, supporting the expectation of below-trend growth.[5] Since last year's symposium, the two-year real yield is up about 250 basis points, and

longer-term real yields are higher as well—by nearly 150 basis points.[6] Beyond changes in interest rates, bank lending standards have tightened, and loan growth has slowed sharply.[7] Such a tightening of broad financial conditions typically contributes to a slowing in the growth of economic activity, and there is evidence of that in this cycle as well. For example, growth in industrial production has slowed, and the amount spent on residential investment has declined in each of the past five quarters (figure 4).

But we are attentive to signs that the economy may not be cooling as expected. So far this year, GDP (gross domestic product) growth has come in above expectations and above its longer-run trend, and recent readings on consumer spending have been especially robust. In addition, after decelerating sharply over the past 18 months, the housing sector is showing signs of picking back up. Additional evidence of persistently above-trend growth could put further progress on inflation at risk and could warrant further tightening of monetary policy.

The labor market

The rebalancing of the labor market has continued over the past year but remains incomplete. Labor supply has improved, driven by stronger participation among workers aged 25 to 54 and by an increase in immigration back toward pre-pandemic levels. Indeed, the labor force participation rate of women in their prime working years reached an all-time high in June. Demand for labor has moderated as well. Job openings remain high but are trending lower. Payroll job growth has slowed significantly. Total hours worked has been flat over the past six months, and the average workweek has declined to the lower end of its pre-pandemic range, reflecting a gradual normalization in labor market conditions (figure 5).

This rebalancing has eased wage pressures. Wage growth across a range of measures continues to slow, albeit gradually (figure 6). While nominal wage growth must ultimately slow to a rate that is consistent with 2 percent inflation, what matters for households is real wage growth. Even as nominal wage growth has slowed, real wage growth has been increasing as inflation has fallen.

We expect this labor market rebalancing to continue. Evidence that the tightness in the labor market is no longer easing could also call for a monetary policy response.

Uncertainty and Risk Management along the Path Forward

Two percent is and will remain our inflation target. We are committed to achieving and sustaining a stance of monetary policy that is sufficiently restrictive to bring inflation down to that level over time. It is challenging, of course, to know in real time when such a stance has been achieved. There are some challenges that are common to all tightening cycles. For example, real interest rates are now positive and well above mainstream estimates of the neutral policy rate. We see the current stance of policy as restrictive, putting downward pressure on economic activity, hiring, and inflation. But we cannot identify with certainty the neutral rate of interest, and thus there is always uncertainty about the precise level of monetary policy restraint.

That assessment is further complicated by uncertainty about the duration of the lags with which monetary tightening affects economic activity and especially inflation. Since the symposium a year ago, the Committee has raised the policy rate by 300 basis points, including 100 basis points over the past seven months. And we have substantially reduced the size of our securities holdings. The wide range of estimates of these lags suggests that there may be significant further drag in the pipeline.

Beyond these traditional sources of policy uncertainty, the supply and demand dislocations unique to this cycle raise further complications through their effects on inflation and labor market dynamics. For example, so far, job openings have declined substantially without increasing unemployment—a highly welcome but historically unusual result that appears to reflect large excess demand for labor. In addition, there is evidence that inflation has become more responsive to labor market tightness than was the case in recent decades.[8] These changing dynamics may or may not persist, and this uncertainty underscores the need for agile policymaking.

These uncertainties, both old and new, complicate our task of balancing the risk of tightening monetary policy too much against the risk of tightening too little. Doing too little could allow above-target inflation to become entrenched and ultimately require monetary policy to wring more persistent inflation from the economy at a high cost to employment. Doing too much could also do unnecessary harm to the economy.

Conclusion

As is often the case, we are navigating by the stars under cloudy skies. In such circumstances, risk-management considerations are critical. At upcoming meetings, we will assess our progress based on the totality of the data and the evolving outlook and risks. Based on this assessment, we will proceed carefully as we decide whether to tighten further or, instead, to hold the policy rate constant and await further data. Restoring price stability is essential to achieving both sides of our dual mandate. We will need price stability to achieve a sustained period of strong labor market conditions that benefit all.

We will keep at it until the job is done.

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1. Descriptions of PCE inflation include Board staff estimates of the July 2023 values based on available information, including the July 2023 consumer price index and producer price index data. The July 2023 PCE inflation data will be published by the Bureau of Economic Analysis on August 31, 2023. Return to text

2. For example, 25 percent of respondents to the most recent University of Michigan Surveys of Consumers reported that it is currently a bad time to buy a new vehicle because of higher interest rates and tighter credit conditions, up from only 4 percent of respondents in 2021. For more information, see the preliminary results of the August 2023 survey, available on the University of Michigan's website at http://www.sca.isr.umich.edu. Return to text

3. This slowing in rent growth has likely occurred for a combination of reasons. Some of it likely reflects higher interest rates and the softening in real household income growth over the past couple of years. But the normalization of dislocations due to the pandemic is likely playing a role here as well. For example, the shifts in housing preferences related to working from home likely contributed to the increase in housing demand reflected in the sizable earlier increases in rents. As the price effects of that demand shift played out, the growth rate of rents would naturally decline toward its earlier trend. Finally, multifamily construction is quite high by historical standards, and that supply coming on line has likely also taken some pressure off market rents. Return to text

4. PCE prices for housing services include both the rents paid by tenants and an imputed rental value for owner-occupied dwellings (measured as the income the homeowner could have received if the house had been rented to a tenant). For additional details, see Bureau of Economic Analysis (2022), "Rental Income of Persons (PDF)," in *NIPA Handbook: Concepts and Methods of the U.S. National Income and Product Accounts* (Washington: BEA, December), pp. 12-1–12-15. Return to text

5. For an example of how tighter financial conditions affect economic activity, see the Federal Reserve Board staff's new index measuring U.S. financial conditions through their effect on the outlook for growth; the index is discussed in Andrea Ajello, Michele Cavallo, Giovanni Favara, William B. Peterman, John W. Schindler IV, and Nitish R. Sinha (2023), "A New Index to Measure U.S. Financial Conditions," FEDS Notes (Washington: Board of Governors of the Federal Reserve System, June 30). Return to text

6. Changes in real yields cited in this sentence refer to changes in yields on 2- and 10-year Treasury Inflation-Protected Securities. Return to text

7. In addition, as the policy rate increased, nonbanking lending conditions changed as well. For example, beginning in 2022 and continuing into the first half of this year, net issuance of riskier debt—such as leveraged loans and speculative-grade and unrated corporate bonds—in public credit markets declined. Return to text

8. The relationship between labor market slack and inflation, often called the Phillips curve relationship, is likely nonlinear, steepening in a tight labor market. If the Phillips curve has steepened in this way, a small change in labor market tightness could result in a more substantial change in inflation. It is difficult to know with precision how steep that relationship is in real time or how it might evolve as labor market tightness changes. For more information on nonlinearities in this relationship, see Christoph E. Boehm and Nitya Pandalai-Nayar (2022), "Convex Supply Curves," *American Economic Review*, vol. 112 (December), pp. 3941–69; Pierpaolo Benigno and Gauti B. Eggertsson (2023), "It's Baaack: The Surge in Inflation in the 2020s and the Return of the Non-Linear Phillips Curve (PDF)," NBER Working Paper Series 31197 (Cambridge, Mass.: National Bureau of Economic Research, April); and Nicolas Petrosky-Nadeau, Lu Zhang, and Lars-Alexander Kuehn (2018), "Endogenous Disasters," *American Economic Review,* vol. 108 (August), pp. 2212–45. Return to text

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Last Update: August 25, 2023

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

IFIC Monthly Investment Fund Statistics – July 2023

Mutual fund and exchange-traded fund (ETF) assets and sales

August 22, 2023 (Toronto) – The Investment Funds Institute of Canada (IFIC) today announced investment fund net sales and net assets for July 2023.

Mutual fund assets totalled $1.914 trillion at the end of July 2023. Assets increased by $19.5 billion or 1.0 per cent compared to June 2023. Mutual funds recorded net redemptions of $4.8 billion in July 2023.

ETF assets totalled $356.8 billion at the end of July 2023. Assets increased by $8.3 billion or 2.4 per cent from June 2023. ETFs recorded net sales of $2.8 billion in July 2023.

Mutual fund net sales/net redemptions ($ millions)*

Asset class	July 2023	June 2023	July 2022	YTD 2023	YTD 2022
Long-term funds					
Balanced	(4,571)	(4,439)	(3,275)	(26,270)	(6,897)
Equity	(1,850)	(2,354)	(1,378)	(11,384)	2,823
Bond	396	910	(387)	9,122	(6,554)
Specialty	292	127	(80)	2,168	1,123
Total long-term funds	(5,733)	(5,755)	(5,119)	(26,364)	(9,505)
Total money market funds	895	1,537	500	8,793	2,870
Total	(4,837)	(4,219)	(4,620)	(17,570)	(6,635)

Mutual fund net assets ($ billions)*

Asset class	July 2023	June 2023	July 2022	Dec 2022
Long-term funds				
Balanced	902.5	898.1	917.0	880.6
Equity	707.0	693.6	661.9	649.6
Bond	235.2	235.1	234.4	222.7
Specialty	24.9	24.5	22.1	22.2
Total long-term funds	1,869.7	1,851.3	1,835.5	1,775.1
Total money market funds	44.1	43.1	29.7	34.5
Total	1,913.8	1,894.3	1,865.1	1,809.6

* See below for important information about this data.

ETF net sales/net redemptions ($ millions)*

Asset class	July 2023	June 2023	July 2022	YTD 2023	YTD 2022
Long-term funds					
Balanced	133	151	202	962	1,368
Equity	887	1,066	(730)	6,627	8,814
Bond	986	1,177	719	6,446	3,495
Specialty	37	443	375	1,328	1,139
Total long-term funds	2,042	2,837	566	15,363	14,815
Total money market funds	754	646	938	5,813	2,730
Total	2,796	3,483	1,505	21,176	17,545

ETF net assets ($ billions)*

Asset class	July 2023	June 2023	July 2022	Dec 2022
Long-term funds				
Balanced	13.9	13.6	12.1	12.0
Equity	222.4	215.6	194.1	194.9
Bond	86.2	85.9	77.7	80.4
Specialty	12.2	12.2	10.7	10.2
Total long-term funds	334.8	327.2	294.7	297.5
Total money market funds	22.0	21.2	9.1	16.3
Total	356.8	348.4	303.7	313.7

* See below for important information about this data.

IFIC direct survey data (which accounts for approximately 85 per cent of total mutual fund industry assets and approximately 83 per cent of total ETF industry assets) is complemented by estimated data to provide comprehensive industry totals.

IFIC makes every effort to verify the accuracy, currency, and completeness of the information, however, IFIC does not guarantee, warrant, represent or undertake that the information provided is correct, accurate or current.

*** Important information about investment fund data**

1. Mutual fund data is adjusted to remove double counting arising from mutual funds that invest in other mutual funds.
2. Starting with January 2022 data, ETF data is adjusted to remove double counting arising from Canadian-listed ETFs that invest in units of other Canadian-listed ETFs. Any references to IFIC ETF assets and sales figures prior to 2022 data should indicate that the data has not been adjusted for ETF of ETF double counting.
3. The balanced funds category includes funds that invest directly in a mix of stocks and bonds or obtain exposure through investing in other funds.
4. Mutual fund data reflects the investment activity of Canadian retail investors.
5. ETF data reflects the investment activity of Canadian retail and institutional investors.

About IFIC

The Investment Funds Institute of Canada is the voice of Canada's investment funds industry. IFIC brings together 150 organizations, including fund managers, distributors and industry service organizations to foster a strong, stable investment sector where investors can realize their financial goals. By connecting Canada's savers to Canada's economy, our industry contributes significantly to Canadian economic growth and job creation. To learn more about IFIC, please visit www.ific.ca.

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https://www.npr.org/2010/01/18/122701268/i-have-a-dream-speech-in-its-entirety

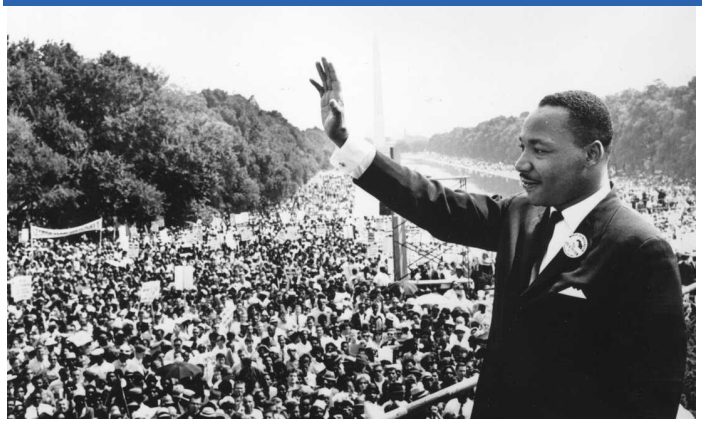
RACE

Read Martin Luther King Jr.'s 'I Have a Dream' speech in its entirety

Updated January 16, 202310:32 AM ET

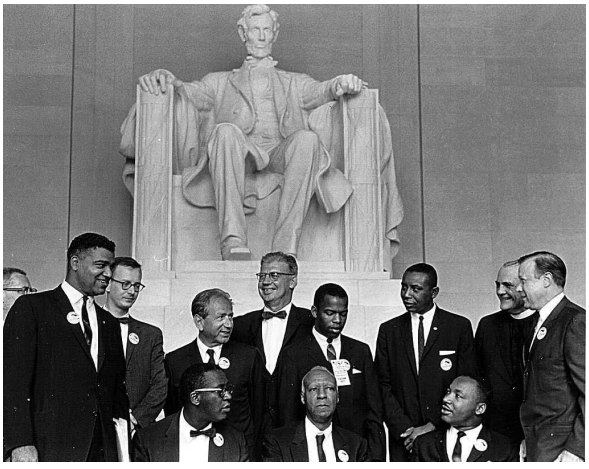
Heard on Talk of the Nation

LISTEN· 17:5017-Minute Listen**PLAYLIST**



Civil rights leader Martin Luther King Jr. addresses the crowd at the Lincoln Memorial in Washington, D.C., where he gave his "I Have a Dream" speech on Aug. 28, 1963, as part of the March on Washington.
AFP via Getty Images

Monday marks Martin Luther King, Jr. Day. Below is a transcript of his celebrated "I Have a Dream" speech, delivered on Aug. 28, 1963, on the steps of the Lincoln Memorial. NPR's *Talk of the Nation* aired the speech in 2010 — listen to that broadcast at the audio link above.



Martin Luther King Jr. and other civil rights leaders gather before a rally at the Lincoln Memorial on Aug. 28, 1963, in Washington.
National Archives/Hulton Archive via Getty Images

Rev. Martin Luther King Jr.: Five score years ago, a great American, in whose symbolic shadow we stand today, signed the Emancipation Proclamation. This momentous decree came as a great beacon light of hope to millions of

Negro slaves who had been seared in the flames of withering injustice. It came as a joyous daybreak to end the long night of their captivity.

But 100 years later, the Negro still is not free. One hundred years later, the life of the Negro is still sadly crippled by the manacles of segregation and the chains of discrimination. One hundred years later, the Negro lives on a lonely island of poverty in the midst of a vast ocean of material prosperity. One hundred years later the Negro is still languished in the corners of American society and finds himself in exile in his own land. And so we've come here today to dramatize a shameful condition. In a sense we've come to our nation's capital to cash a check.

CODE SWITCH

The Power Of Martin Luther King Jr.'s Anger

When the architects of our republic wrote the magnificent words of the Constitution and the Declaration of Independence, they were signing a promissory note to which every American was to fall heir. This note was a promise that all men — yes, Black men as well as white men — would be guaranteed the unalienable rights of life, liberty and the pursuit of happiness.

It is obvious today that America has defaulted on this promissory note insofar as her citizens of color are concerned. Instead of honoring this sacred obligation, America has given the Negro people a bad check, a check which has come back marked insufficient funds.

But we refuse to believe that the bank of justice is bankrupt.

We refuse to believe that there are insufficient funds in the great vaults of opportunity of this nation. And so we've come to cash this check, a check that will give us upon demand the riches of freedom and the security of justice.

We have also come to his hallowed spot to remind America of the fierce urgency of now. This is no time to engage in the luxury of cooling off or to take the tranquilizing drug of gradualism.

Civil rights protesters march from the Washington Monument to the Lincoln Memorial for the March on Washington on Aug. 28, 1963.
Kurt Severin/Three Lions/Hulton Archive/Getty Images

Now is the time to make real the promises of democracy. Now is the time to rise from the dark and desolate valley of segregation to the sunlit path of racial justice. Now is the time to lift our nation from the quick sands of racial injustice to the solid rock of brotherhood. Now is the time to make justice a reality for all of God's children.

It would be fatal for the nation to overlook the urgency of the moment. This sweltering summer of the Negro's legitimate discontent will not pass until there is an invigorating autumn of freedom and equality. 1963 is not an end, but a beginning. Those who hope that the Negro needed to blow off steam and will now be content will have a rude awakening if the nation returns to business as usual.

There will be neither rest nor tranquility in America until the Negro is granted his citizenship rights. The whirlwinds of revolt will continue to shake the foundations of our nation until the bright day of justice emerges.

But there is something that I must say to my people who stand on the warm threshold which leads into the palace of justice. In the process of gaining our rightful place, we must not be guilty of wrongful deeds. Let us not seek to satisfy our thirst for freedom by drinking from the cup of bitterness and hatred.

We must forever conduct our struggle on the high plane of dignity and discipline. We must not allow our creative protest to degenerate into physical violence. Again and again, we must rise to the majestic heights of meeting physical force with soul force. The marvelous new militancy which has engulfed the Negro community must not lead us to a distrust of all white people, for many of our white brothers, as evidenced by their presence here today, have come to realize that their destiny is tied up with our destiny.

And they have come to realize that their freedom is inextricably bound to our freedom. We cannot walk alone. And as we walk, we must make the pledge that we shall always march ahead. We cannot turn back.

There are those who are asking the devotees of civil rights, when will you be satisfied? We can never be satisfied as long as the Negro is the victim of the unspeakable horrors of police brutality. We can never be satisfied as long as our bodies, heavy with the fatigue of travel, cannot gain lodging in the motels of the highways and the hotels of the cities.

We cannot be satisfied as long as the Negro's basic mobility is from a smaller ghetto to a larger one. We can never be satisfied as long as our children are stripped of their selfhood and robbed of their dignity by signs stating: for whites only.

We cannot be satisfied as long as a Negro in Mississippi cannot vote and a Negro in New York believes he has nothing for which to vote.

No, no, we are not satisfied, and we will not be satisfied until justice rolls down like waters, and righteousness like a mighty stream.

I am not unmindful that some of you have come here out of great trials and tribulations. Some of you have come fresh from narrow jail cells. Some of you have come from areas where your quest for freedom left you battered by the storms of persecution and staggered by the winds of police brutality. You have been the veterans of creative suffering. Continue to work with the faith that unearned suffering is redemptive. Go back to Mississippi, go back to Alabama, go back to South Carolina, go back to Georgia, go back to Louisiana, go back to the slums and ghettos of our Northern cities, knowing that somehow this situation can and will be changed.

Let us not wallow in the valley of despair, I say to you today, my friends.

So even though we face the difficulties of today and tomorrow, I still have a dream. It is a dream deeply rooted in the American dream. I have a dream that one day this nation will rise up and live out the true meaning of its creed: We hold these truths to be self-evident, that all men are created equal.

People clap and sing along to a freedom song between speeches at the March on Washington for Jobs and Freedom in 1963.
Express Newspapers via Getty Images

I have a dream that one day on the red hills of Georgia, the sons of former slaves and the sons of former slave owners will be able to sit down together at the table of brotherhood.

I have a dream that one day even the state of Mississippi, a state sweltering with the heat of injustice, sweltering with the heat of oppression will be transformed into an oasis of freedom and justice.

I have a dream that my four little children will one day live in a nation where they will not be judged by the color of their skin but by the content of their character. I have a dream today.

I have a dream that one day down in Alabama with its vicious racists, with its governor having his lips dripping with the words of interposition and nullification, one day right down in Alabama little Black boys and Black girls will be able to join hands with little white boys and white girls as sisters and brothers. I have a dream today.

I have a dream that one day every valley shall be exalted, every hill and mountain shall be made low, the rough places will be made plain, and the crooked places will be made straight, and the glory of the Lord shall be revealed, and all flesh shall see it together.

This is our hope. This is the faith that I go back to the South with. With this faith, we will be able to hew out of the mountain of despair a stone of hope. With this faith we will be able to transform the jangling discords of our nation into a beautiful symphony of brotherhood. With this faith we will be able to work together, to pray together, to struggle together, to go to jail together, to stand up for freedom together, knowing that we will be free one day.

This will be the day when all of God's children will be able to sing with new meaning: My country, 'tis of thee, sweet land of liberty, of thee I sing. Land where my fathers died, land of the pilgrims' pride, from every mountainside, let freedom ring.

And if America is to be a great nation, this must become true. And so let freedom ring from the prodigious hilltops of New Hampshire. Let freedom ring from the mighty mountains of New York. Let freedom ring from the heightening Alleghenies of Pennsylvania. Let freedom ring from the snowcapped Rockies of Colorado. Let freedom ring from the curvaceous slopes of California. But not only that, let freedom ring from Stone Mountain of Georgia. Let freedom ring from Lookout Mountain of Tennessee. Let freedom ring from every hill and molehill of Mississippi. From every mountainside, let freedom ring.

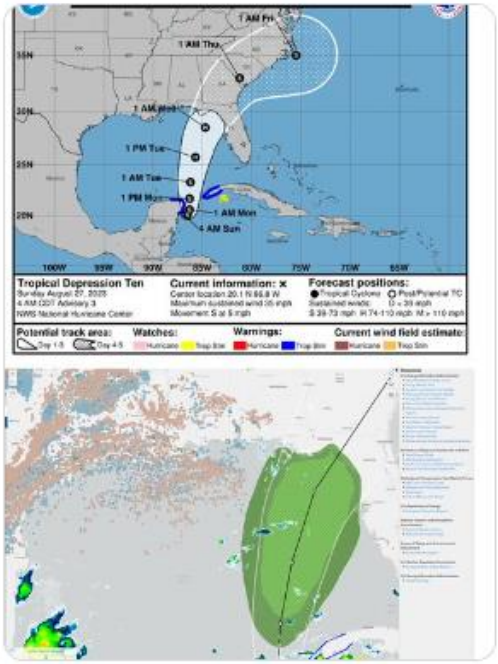
And when this happens, and when we allow freedom ring, when we let it ring from every village and every hamlet, from every state and every city, we will be able to speed up that day when all of God's children, Black men and white men, Jews and Gentiles, Protestants and Catholics, will be able to join hands and sing in the words of the old Negro spiritual: Free at last. Free at last. Thank God almighty, we are free at last.

Dan Tsubouchi @Energy_Tidbits · 4h

Potential hurricane into eastern GoM in next few days @NOAA.

Excellent @EIAgov mapping system shows projected path is east of GoM offshore wells and major LA, MS, TX refineries, export terminals. #Oil #NatGas #LNG

#OOTT



3 10 1,773

Dan Tsubouchi @Energy_Tidbits · 4h

See 12:25 min 👇 bp CEO Looney on reality to have a rapid AND orderly transition.

"if it's not just, there won't be a transition"

"gas prices went up 7-fold"

"countries to fuel their economy turned to the next cheapest alternative, which is what? Coal"

"typically in an OECD... Show more

1 1 6 1,869

Dan Tsubouchi @Energy_Tidbits · 12h

#Fortum CEO Rauramo. wind/solar can be competitive IF you just look at cost of megawatt hour produced.

BUT problem is intermittency and "you just can't have intermittent energy, we need the baseload and the flexibility also".

#NatGas is needed for baseload.
#OOTT @bbcaaron

1 3 12 3,032

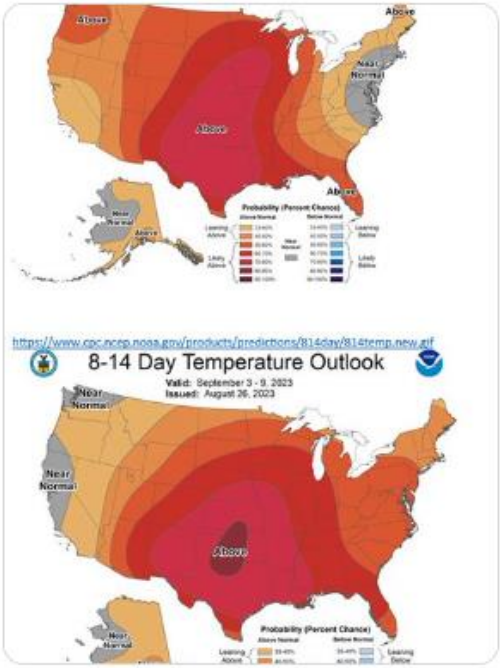
Dan Tsubouchi @Energy_Tidbits · 19h

Today's @NOAA updated 6-10 & 8-14 day temperature outlook covering Sept 1-9.

Going to stay hot across almost all of the Lower 48.

Should provide support for #NatGas this week.

#OOTT



2 4 16 6,229

Dan Tsubouchi @Energy_Tidbits · Aug 26

Less future capital to #Oil #NatGas?

UN warns banks on #SaudiAramco likely not to impact dominant global oil co.

BUT concept trickle down aided by pressure on boards will give excuse for capital providers & govts who prefer to not give capital or "subsidies" to oil & gas
#OOTT

> **Attracta Mooney** @AttractaMooney · Aug 25
> Wonder what this means for banks and fossil fuel lending? The UN has told banks including Citi, Goldman Sachs and BNP Paribas that their financing of Saudi Aramco may be in violation of climate-related global human rights rules on.ft.com/3KVuh0e

3 2 8 3,289

Dan Tsubouchi @Energy_Tidbits · Aug 26

#Vortexa crude #Oil floating storage at 08/25 est 80.31 mmb, down big -24.91 mmb WoW vs revised up by +9.90 mmb 08/18 of 105.22 mmb.

Note: 08/25 80.31 mmb is down a whopping -49.50 mmb vs recent 06/23/23 peak of 129.81 mmb.

Thx @Vortexa @business. #OOTT

4 15 48 7,712

Dan Tsubouchi @Energy_Tidbits · Aug 26

Hmmm!

Did Woodside union deal set the bar for #Chevron to avoid strike on its LNG?

See 👇 Offshore Alliance union lists details of its deal to avoid strike on #Woodside LNG platforms.

It's not just that salaries look good but also job security, cyclone, etc.

#OOTT #NatGas

1 2 6 2,955

Dan Tsubouchi @Energy_Tidbits · Aug 25

Good reminder from Mark that, when a Permian player consolidates within core area, drilling & fracking becomes more of a manufacturing process so there are increased efficiencies and that means less DUCs, rigs & spreads are needed.

See 1:30 min mark.

#OOTT

> **Primary Vision Network** @PrimaryVision · Aug 25
>
> Seasonal Drop Intensified by Extreme Heat - Frac Spread Count
>
> primaryvision.co/youtube-videos...
>
> #BigOil #BigData #PVN #OOTT #FracSpreadCount #FracSpread #RigCount #Permian #OPEC #oil #gas

4 15 6,865

Dan Tsubouchi @Energy_Tidbits · Aug 25

Another bad week for capital flows to China and relative stock performance

See 👇 @business graphs

#OOTT

2 2 1,654

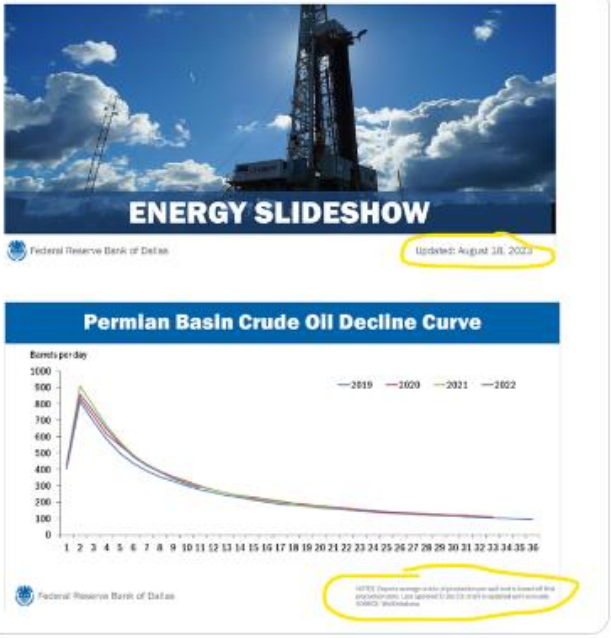
Dan Tsubouchi @Energy_Tidbits · Aug 25

ICYMI

@DallasFed Permian #Oil decline curve updated 07/28

Fits maturing Permian thesis ie. industry generally drilled their best wells in 2020/21 when cash flows were squeezed

2022 wells. Less than 2021 wells. Start little higher vs 2020 but cross over lower ~6 mths.
#OOTT

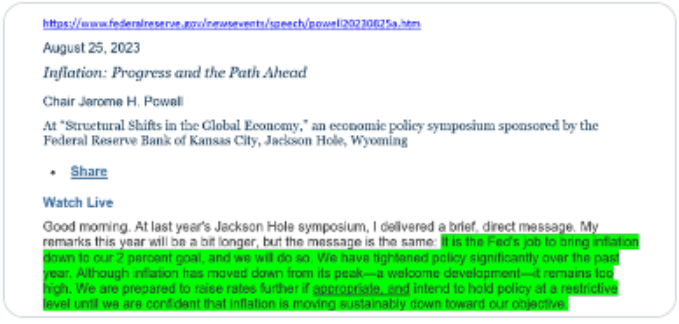


3 9 25 3,770

Dan Tsubouchi @Energy_Tidbits · Aug 25

In case you aren't watching. here is Powell's opening

#OOTT


https://www.federalreserve.gov/newsevents/speech/powell20230825a.htm

August 25, 2023

Inflation: Progress and the Path Ahead

Chair Jerome H. Powell

At "Structural Shifts in the Global Economy," an economic policy symposium sponsored by the Federal Reserve Bank of Kansas City, Jackson Hole, Wyoming

- Share

Watch Live

Good morning. At last year's Jackson Hole symposium, I delivered a brief, direct message. My remarks this year will be a bit longer, but the message is the same: It is the Fed's job to bring inflation down to our 2 percent goal, and we will do so. We have tightened policy significantly over the past year. Although inflation has moved down from its peak—a welcome development—it remains too high. We are prepared to raise rates further if appropriate, and intend to hold policy at a restrictive level until we are confident that inflation is moving sustainably down toward our objective.

3 6 1,621

Dan Tsubouchi @Energy_Tidbits · Aug 25

Best reporting what Turkey wants to resume Kurd #Oil export via Ceyhan.

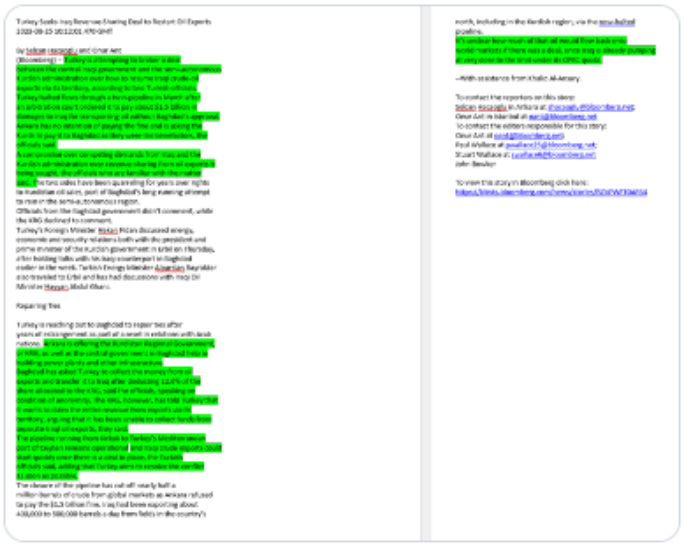
Won't pay $1.5b damages, wants Kurd to pay Baghdad.

Contracts to help build out of power plant & other infra

Iraq/Kurd resolve their % oil splits.

Exports could resume quickly.

Reminder shouldn't be big... Show more



4 9 3,597

Dan Tsubouchi @Energy_Tidbits · Aug 24

the Big Guy is keeping the Small Guy away from his #Canmore elk gang. the 2024 calves are really small. always a good day in the Cdn Rockies when you see the local wildlife.

1 1 1,172

SAF

Dan Tsubouchi @Energy_Tidbits · Aug 24

China summer holidays ending so city-level road congestion "*bounces back after lingering low*" but still *"remain subdued*".

China Baidu city-level road congestion +13.5% WoW to 125.4% of Jan/21 levels.

Still waiting on Sep/Oct expected big ramp up.

Thx @BloombergNEF

#OOTT

3 8 2,149

Dan Tsubouchi @Energy_Tidbits · Aug 24

Europe TTF #NatGas prices down ~10% this morning on last night's news of avoiding strike on Woodside #LNG platforms.

Offshore Alliance post from 7 hrs ago confirms agreement in principle.

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Aug 23
>
> 
>
> Looks like strike avoided on Woodside #LNG platforms.
>
> Woodside & union reps "reached an in-principle agreement on a # of issues, the company & union ...

3 3 3,325

Dan Tsubouchi @Energy_Tidbits · Aug 23

Looks like strike avoided on Woodside #LNG platforms.

Woodside & union reps "*reached an in-principle agreement on a # of issues, the company & union both said. Members will now decide whether to endorse the deal & to withdraw its notice of industrial action.*"
Thx... Show more

Woodside Gas Workers to Vote on Withdrawing Strike Threat
2023-08-23 23:56:38.822 GMT

By Stuart Condie

(Dow Jones) -- SYDNEY--Workers at three Woodside Energy-operated offshore liquefied natural gas platforms will decide Thursday whether to call off the threat of a strike that could have disrupted global gas supplies.

Woodside and union representatives on Wednesday reached an in-principle agreement on a number of issues, the company and union both said. Members will now decide whether to endorse the deal and to withdraw its notice of industrial action, the Offshore Alliance workers' group said.

Workers had threatened to strike over issues including pay if they were not satisfied with the outcome of Wednesday's meeting between company and union officials. Worries over disruptions at one of the world's major LNG exporters had jolted natural-gas prices.

"If members endorse the outcome, it will leave Chevron as the sole operator in the Western Australia gasfields without an enterprise agreement with its workforce," said Offshore Alliance, a partnership between two local unions.

Staff at Chevron's Gorgon LNG facility and downstream facilities are set to return ballots on potential strike action on Thursday, said Offshore Alliance. A similar vote at Chevron's Wheatstone platform is due on Monday, it said.

Write to Stuart Condie at stuart.condie@wsj.com

(END) Dow Jones Newswires

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/RZVBUE073NCW

Dan Tsubouchi @Energy_Tidbits · Aug 20

"Getting ready to rumble"

Woodside platform #OffshoreAlliance vote unanimously in servicing Woodside with 7-day industrial action if no deal by Aug 23....

7 11 9,102

Dan Tsubouchi @Energy_Tidbits · Aug 23

Looks like more Trans Mountain #TMX delays & higher capital costs.

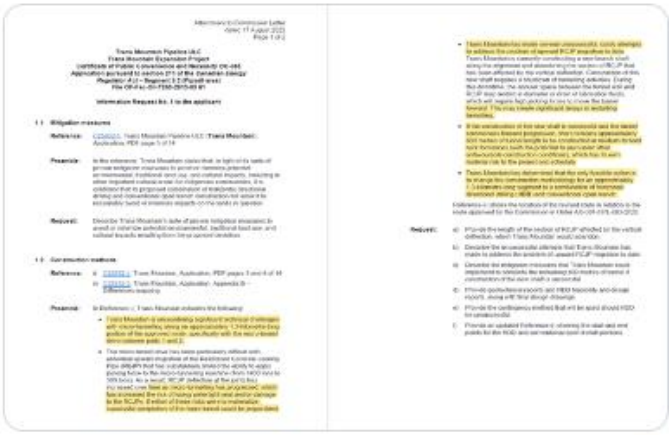
@CER_REC filing.

"encountering significant technical challenges with micro-tunnelling "

".. made several unsuccessful, costly attempts ..."

".. only feasible option is to change the construction .."

#OOTT



2 4 13 3,976

Dan Tsubouchi @Energy_Tidbits · Aug 23

#NatGas #Coal #BatteryStorage generation capacity in DEU greater than #Wind capacity is needed for when wind doesn't blow

And like now when wind is low for weeks, the must have is #NatGas #Coal as battery storage send-out is limited to hours not days!
Thx @BloombergNEF #OOTT

1 3 1,765

Dan Tsubouchi @Energy_Tidbits · Aug 23

For those not near their laptops. At 8:30am MT, @EIAgov released its #Oil #Gasoline #Distillates inventory as of Aug 18. Table below compares EIA data vs @business expectations and vs @APIenergy yesterday. Prior to release, WTI was $78.25. #OOTT

Oil/Products Inventory Aug 18: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	-6.13	-3.00	-0.40
Gasoline	1.47	-0.48	1.90
Distillates	0.95	0.70	-0.15
	-3.71	-2.78	1.35

Note: Oil is commercial so builds in a build of 0.5 mmb in SPR for the Aug 18 week
Note: Included in the oil data, Cushing had a 3.13 mmb draw for Aug 18 week
Source EIA, Bloomberg
Prepared by SAF Group https://safgroup.ca/news-insights/

2 7 1,587

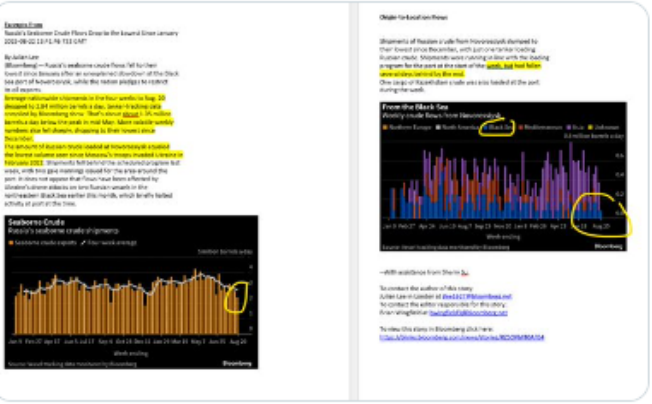
Dan Tsubouchi @Energy_Tidbits · Aug 23

Lower loadings at Novorossiysk led to RUS seaborne crude flows down to lowest level since Jan. @JLeeEnergy weekly recap.

Loadings down at end of week at Novorossiysk lines up with 👇 08/18 tweet on fire at port.

What isn't clear if the fire damage has longer impact?

#OOTT



> **Dan Tsubouchi** @Energy_Tidbits · Aug 18
>
> Reminder Novorossiysk is Russia's major Black Sea #Oil export terminal at ~0.4 mmb/d. See 👇 Aug 5 tweet.
>
> Not clear yet what damage has been done to the port.
>
> ---

3 10 3,394

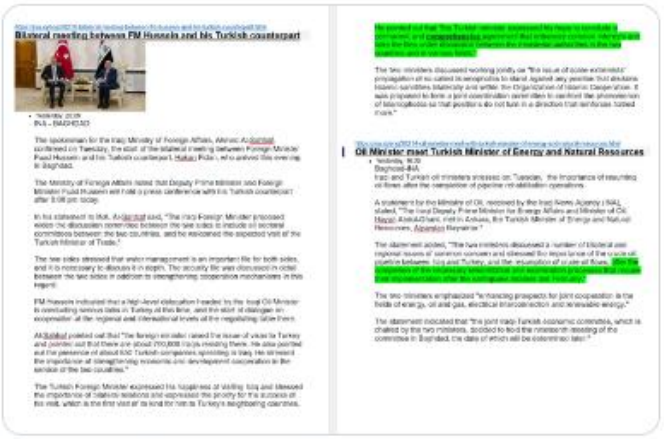
Dan Tsubouchi @Energy_Tidbits · Aug 22

Separate Iraq/Turkey FM & oil minister meetings.

Based on Iraqi New Agency reports, restart Iraq/Kurk #Oil exports via Turkey feels like a matter of months and not a handful of weeks.

Turkey wants "comprehensive" deal ie. oil would be one of the files under discussion.

#OOTT



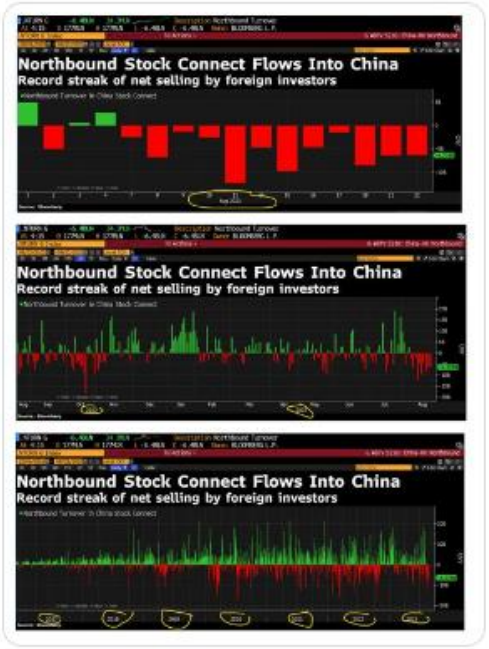
4 9 3,384

Dan Tsubouchi @Energy_Tidbits · Aug 22

Foreign investors continue to be net sellers of China stocks.

No surprise #Oil been dragged down with China economic and capital flows weakness. Brent down $4 since Aug 10.

Thx @business.
#OOTT



3 5 3,006

Dan Tsubouchi @Energy_Tidbits · Aug 22

"*end of the peak summer travel season*" in China.

China scheduled domestic flights -0.1% WoW to 104,716.

How much will air travel dip in Sept/Oct with weaker China economy and consumer?

Thx @BloombergNEF Claudio Lubis
#OOTT #JetFuel

1 1 1 1,625

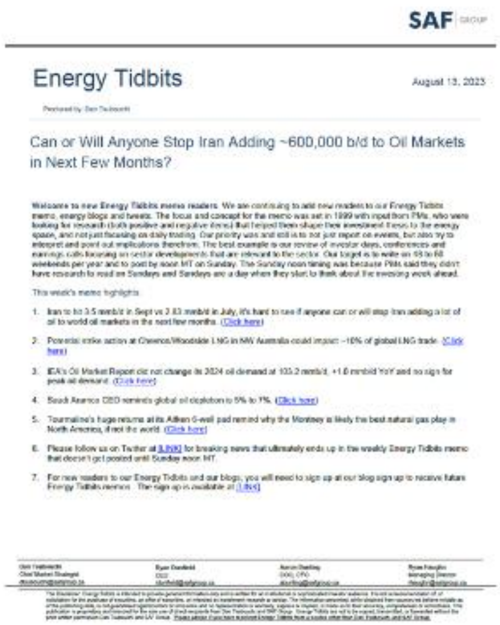
Dan Tsubouchi @Energy_Tidbits · Aug 22

Iran's ramping up its #Oil production and exports is getting more attention.

See 👇 SAF Group Aug 13, 2023 Energy Tidbits memo for more on how they see adding ~600,000 b/d in the next couple months.

Available at news/insights section of SAF website safgroup.ca/news-insights/
#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Aug 13
>
> SAF Group Aug 13, 2023 Energy Tidbits memo is posted on SAF Group website. this 63-pg energy research memo expands upon & covers more items than tweeted this week. Available at news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition



SAF GROUP

Energy Tidbits

August 13, 2023

Produced by: Dan Tsubouchi

Can or Will Anyone Stop Iran Adding ~600,000 b/d to Oil Markets in Next Few Months?

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. Our target is to write on 48 to 50 weekends per year and to post by noon MT on Sunday. The Sunday noon timing was because PMs said they didn't have research to read on Sundays and Sundays are a day when they start to think about the investing week ahead.

This week's memo highlights.

1. Iran to hit 3.5 mmb/d in Sept vs 2.83 mmb/d in July, it's hard to see if anyone can or will stop Iran adding a lot of oil to world oil markets in the next few months. (Click here)
2. Potential strike action at Chevron/Woodside LNG in NW Australia could impact ~10% of global LNG trade. (Click here)
3. IEA's Oil Market Report did not change its 2024 oil demand at 103.2 mmb/d, +1.0 mmb/d YoY and no sign for peak oil demand. (Click here)
4. Saudi Aramco CEO reminds global oil depletion is 6% to 7%. (Click here)
5. Tourmaline's huge returns at its Aitken 6-well pad remind why the Montney is likely the best natural gas play in North America, if not the world. (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]

4 · 12 · 9,200

Dan Tsubouchi @Energy_Tidbits · Aug 22 ·

Just now Macy's CEO to @CourtReagan @SquawkStreet

"record shortage [theft] in 2022, going to be higher in 2023"
"bulk of that is the change in organized theft"
"digital component of this [theft] has really opened up a revenue stream for a lot of these elements"

#OOTT... Show more

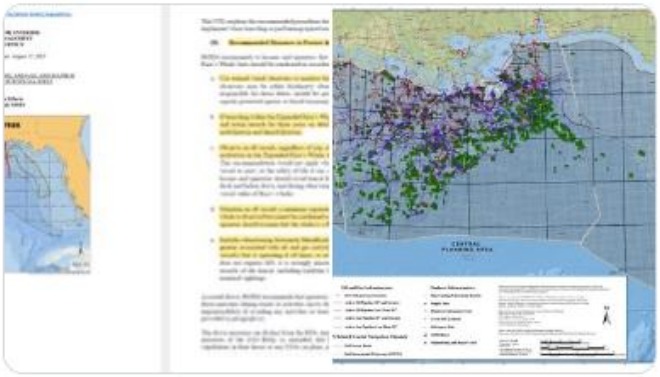
3 4 2,357

Dan Tsubouchi @Energy_Tidbits · Aug 22 ·

New #Biden regulatory rule to impact #Oil #natgas leases in GoM.

BOEM 08/17 new conditions & expanded Rice's whale map that should impact any vessels going to/from all GoM deepwater platforms and drilling rigs to onshore facilities.

#OOTT



> **Dan Tsubouchi** @Energy_Tidbits · Aug 16
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> North Dakota warns on multiple #Biden regulatory rule revisions.
>
> "All of these have significant downside for #Oil and #NatGas production. so a major concern there" says ...

1 2 3 3,013

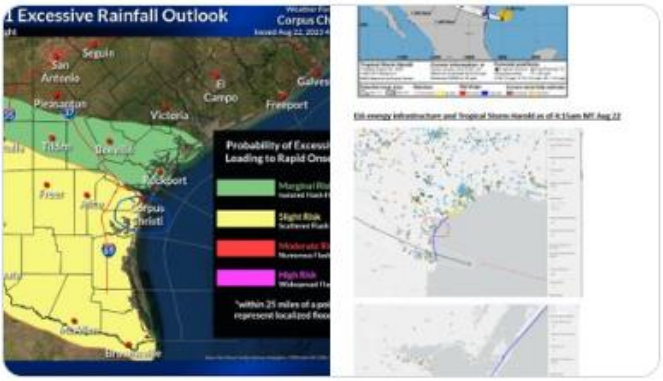
Dan Tsubouchi @Energy_Tidbits · Aug 22

Major #Oil #NatGas #LNG Corpus Christi port is in @NWSCorpus "slight risk" area for Tropical Storm Harold.

Harold fast moving 18 mph so hopefully won't dump too much rain.

Corpus highlighted in 👇@EIAgov's great energy infra mapping system.

#OOTT



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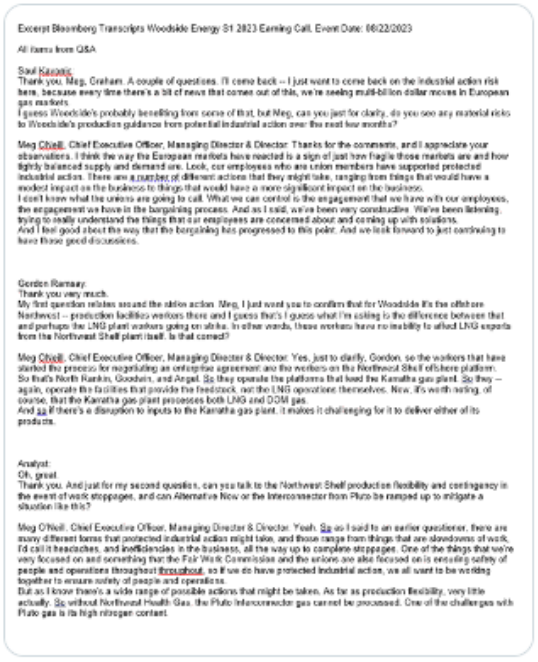
Dan Tsubouchi @Energy_Tidbits · Aug 21

Three questions in Q2 call Q&A but #WoodsideEnergy answers do NOT give any clarity if they expect industrial action/no industrial action at AUS #LNG, or what would impact be if there is an industrial action of some type.

Thx @business transcript.

#OOTT



Excerpt Bloomberg Transcripts Woodside Energy S1 2023 Earning Call, Event Date: 08/22/2023

All Items from Q&A

Saul Kavonic
Thank you, Meg, Graham. A couple of questions. I'll come back -- I just want to come back on the industrial action risk here, because every time there's a bit of news that comes out of this, we're seeing multi-billion dollar moves in European gas markets.
I guess Woodside's probably benefiting from some of that, but Meg, can you just for clarity, do you see any material risks to Woodside's production guidance from potential industrial action over the next few months?

Meg O'Neill, Chief Executive Officer, Managing Director & Director: Thanks for the comments, and I appreciate your observations. I think the way the European markets have reacted is a sign of just how fragile those markets are and how tightly balanced supply and demand are. Look, our employees who are union members have supported protected industrial action. There are a number of different actions that they might take, ranging from things that would have a modest impact on the business to things that would have a more significant impact on the business.
I can't know what the unions are going to call. What we can control is the engagement that we have with our employees, the engagement we have in the bargaining process. And as I said, we've been very constructive. We've been listening, trying to really understand the things that our employees are concerned about and coming up with solutions.
And I feel good about the way that the bargaining has progressed to this point. And we look forward to just continuing to have those good discussions.

Gordon Ramsay:
Thank you very much.
My first question relates around the strike action. Meg, I just want you to confirm that for Woodside it's the offshore Northwest -- production facilities workers there and I guess that's I guess what I'm asking is the difference between that and perhaps the LNG plant workers going on strike. In other words, those workers have no inability to unload LNG exports from the Northwest Shelf plant itself. Is that correct?

Meg O'Neill, Chief Executive Officer, Managing Director & Director: Yes, just to clarify, Gordon, so the workers that have started the process for negotiating an enterprise agreement are the workers on the Northwest Shelf offshore platform. So that's North Rankin, Goodwyn, and Angel. So they operate the platforms that feed the Karratha gas plant. So they -- again, operate the facilities that provide the feedstock, not the LNG operations themselves. Now, it's worth noting, of course, that the Karratha gas plant processes both LNG and DGM gas.
And so if there's a disruption to inputs to the Karratha gas plant, it makes it challenging for it to deliver either of its products.

Analyst:
Ok, great.
Thank you. And just for my second question, can you talk to the Northwest Shelf production flexibility and contingency in the event of work stoppages, and can Alternative Nov or the Interconnector from Pluto be ramped up to mitigate a situation like this?

Meg O'Neill, Chief Executive Officer, Managing Director & Director: Yeah. So as I said to an earlier questioner, there are many different forms that protected industrial action might take, and those range from things that are slowdowns of work, I'd call it headaches, and inefficiencies in the business, all the way up to complete stoppages. One of the things that we're very focused on and something that the Fair Work Commission and the unions are also focused on is ensuring safety of people and operations throughout throughout, so if we do have protected industrial action, we all want to be working together to ensure safety of people and operations.
But as I know there's a wide range of possible actions that might be taken. As far as production flexibility, very little actually. So without Northwest Health Gas, the Pluto Interconnector gas cannot be processed. One of the challenges with Pluto gas is its high nitrogen content.

> **Dan Tsubouchi** @Energy_Tidbits · Aug 20
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> 
>
> "Getting ready to rumble"
>
> Woodside platform #OffshoreAlliance vote unanimously in servicing Woodside with 7-day industrial action if no deal by Aug 23....

3 2,742

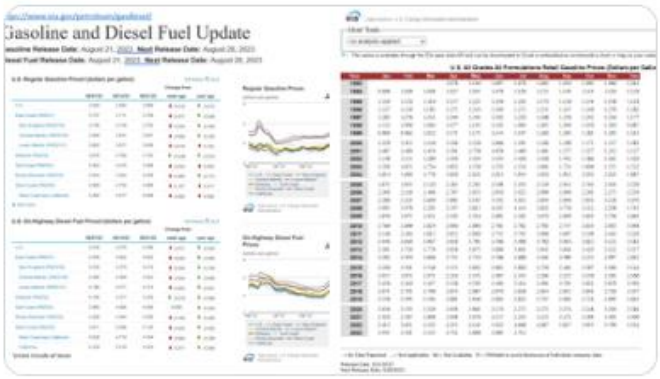
Dan Tsubouchi @Energy_Tidbits · Aug 21

US #Gasoline prices keep inching up.

@EIAgov 08/21/23 national average $3.87, only down $0.01 YoY.

Sept vs Aug last 10 yrs: 5 yrs down MoM, 4 yrs up MoM, 1 yr flat.

#OOTT



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Dan Tsubouchi @Energy_Tidbits · Aug 21

Overlooked Cdn #NatGas upside > 2025

👇#Total reminds #LNG needs ONGOING drilling AND M&A to offset #NatGas supply declines to keep delivering LNG capacity

#LNGCanada has 40 yr license. Phase 1 is 1.8 bcfd. Phase 2 would add 1.8 bcfd

Cdn NatGas M&A inevitable for yrs?
#OOTT

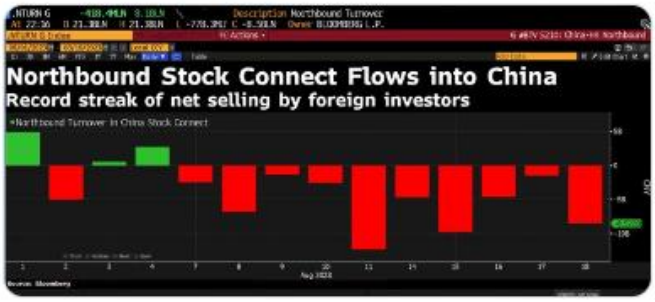
1 6 30 6,336

Dan Tsubouchi @Energy_Tidbits · Aug 21

Bad August keeps getting worse for China markets as foreign investors continue to be net sellers of China stocks.

#Oil bucking the trend this morning, up 50 cents whereas normally just gets dragged down with any China market weakness.

Thx @business.
#OOTT



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