Energy Tidbits

Vitol "*seeing jet fuel now back to averaging around 6.9 mmb/d over the last 4-weeks, which is back to 2019 levels*"

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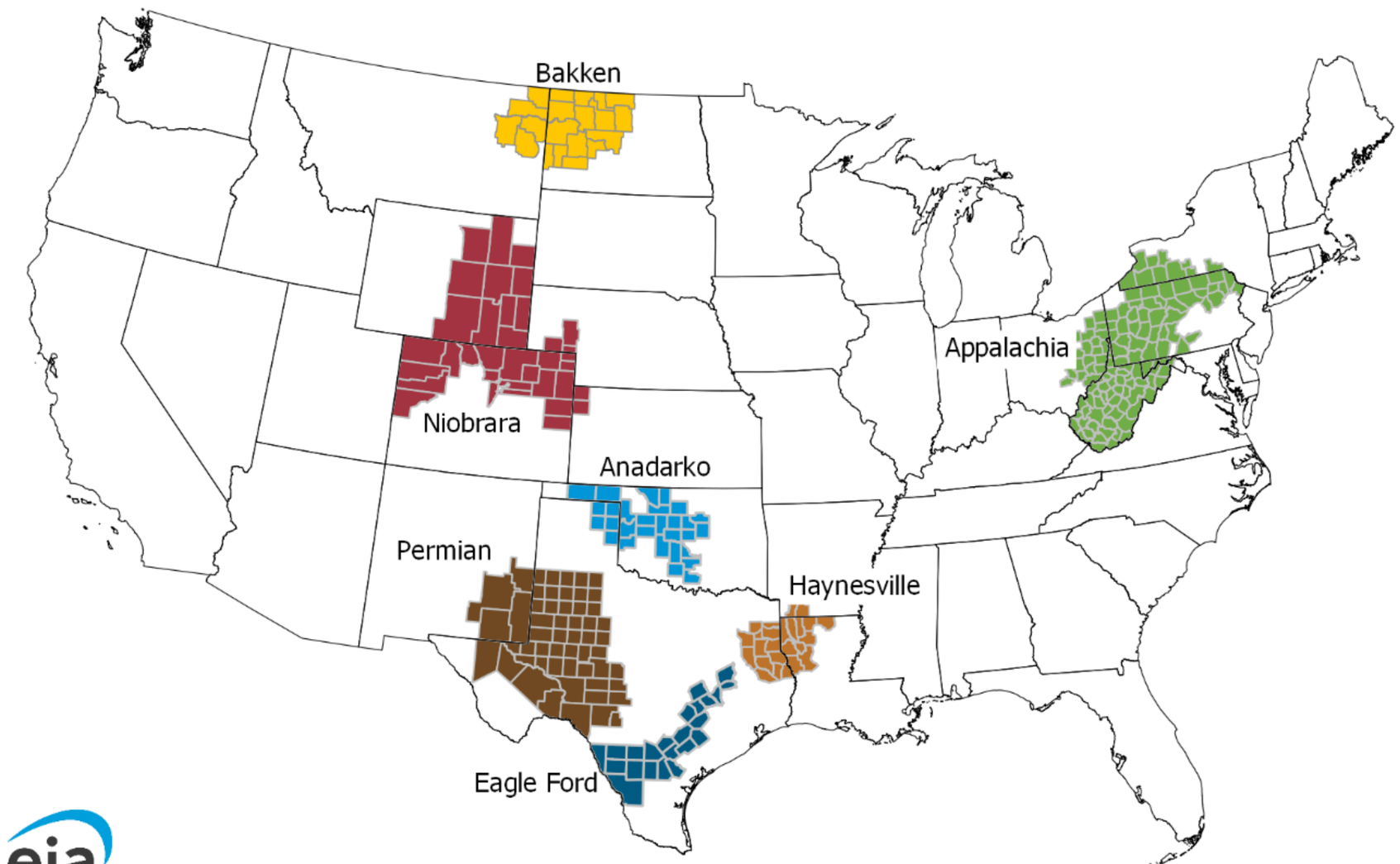
Independent Statistics & Analysis

U.S. Energy Information Administration

March 2024

Drilling Productivity Report

For key tight oil and shale gas regions



Data source: U.S. Energy Information Administration

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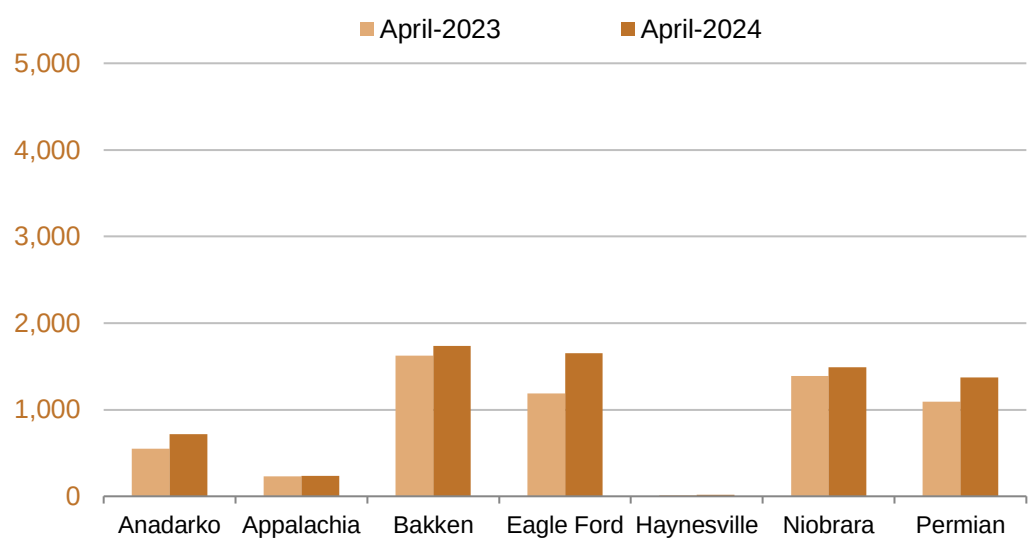
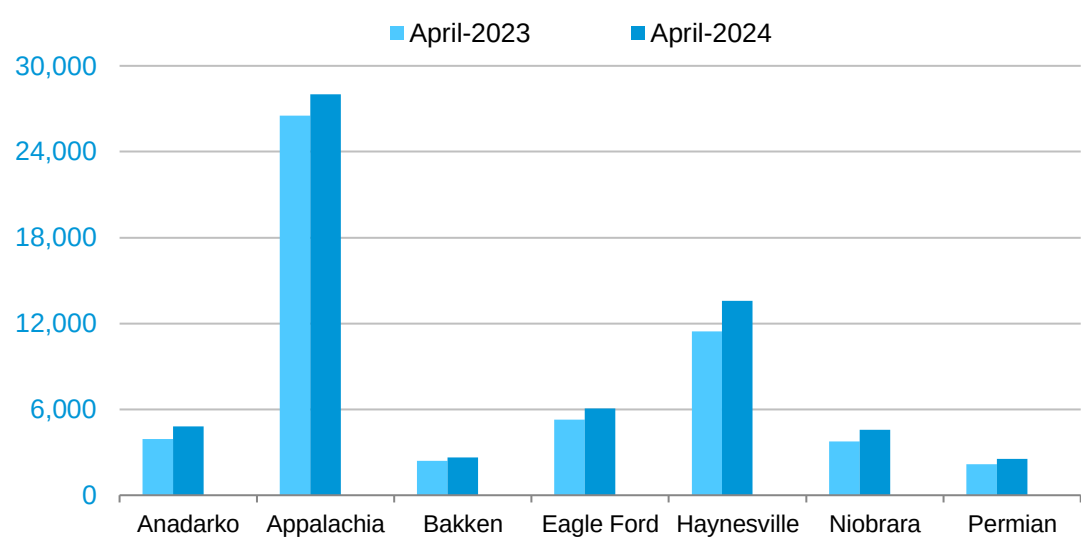
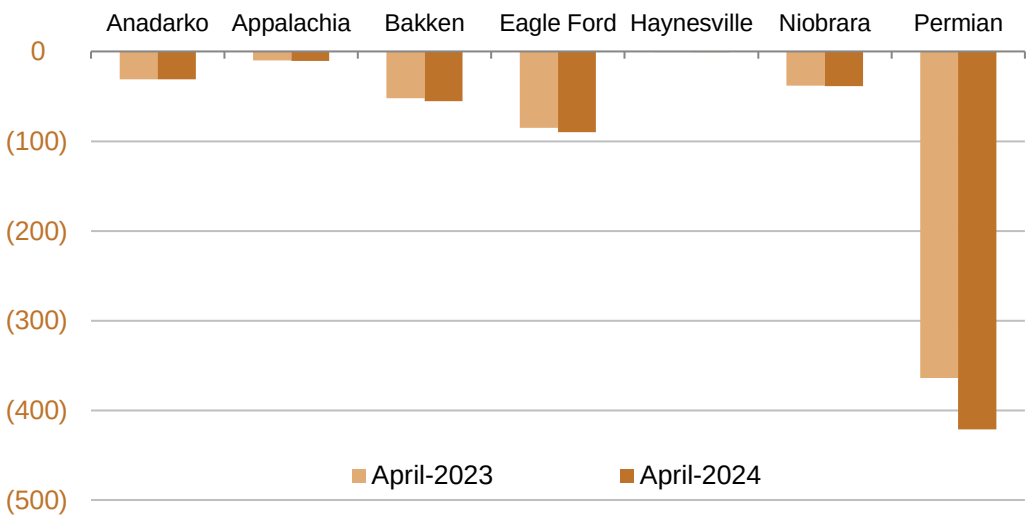
barrels/day



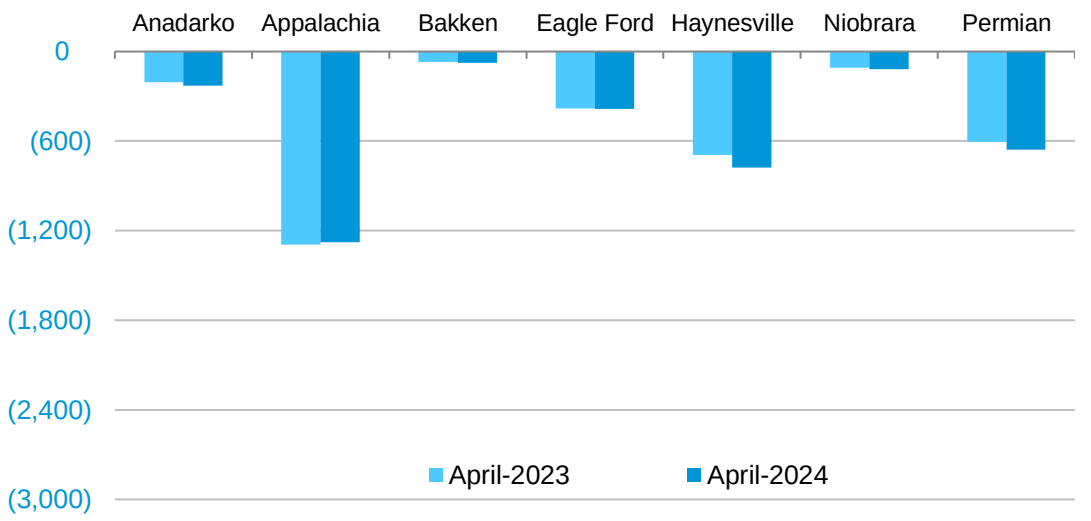
New-well gas production per rig
thousand cubic feet/day



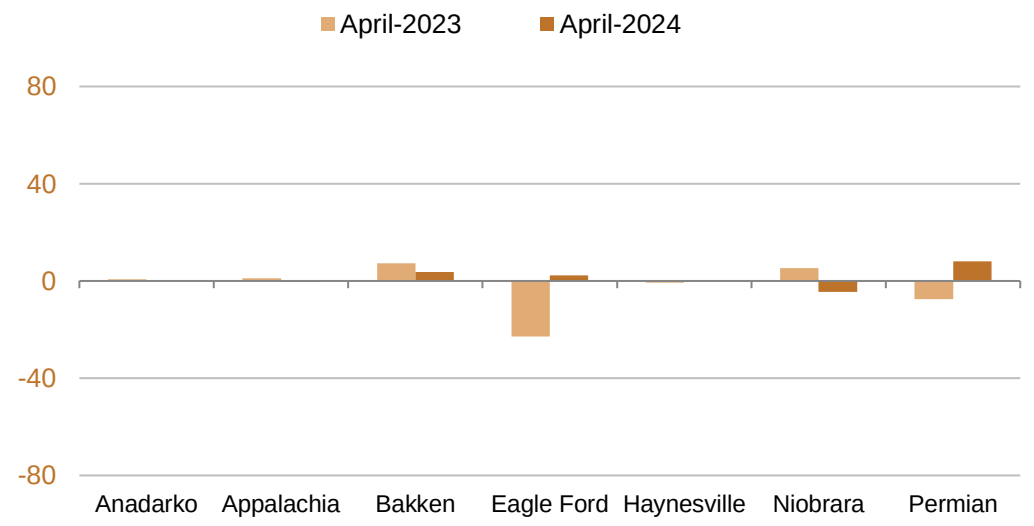
Legacy oil production change
thousand barrels/day



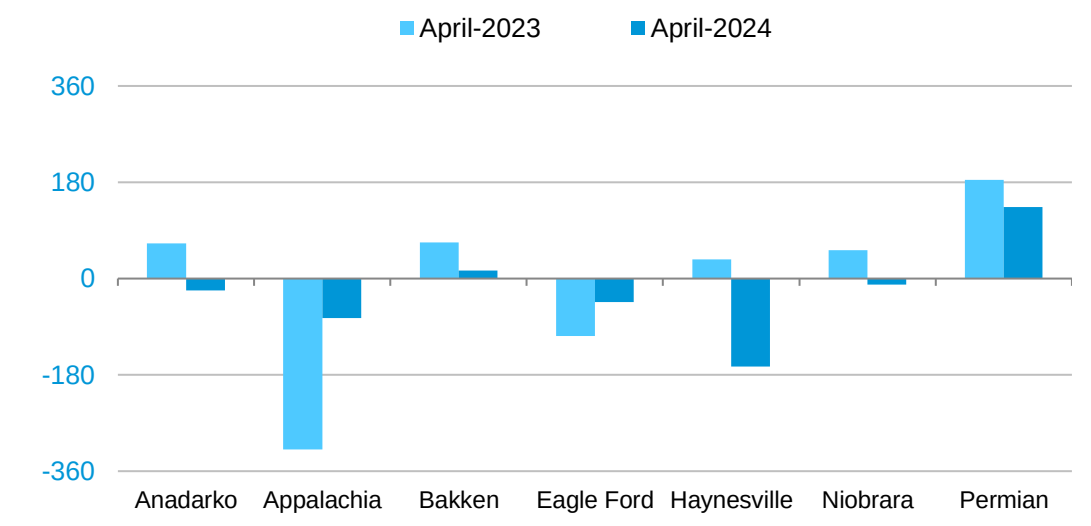
Legacy gas production change
million cubic feet/day



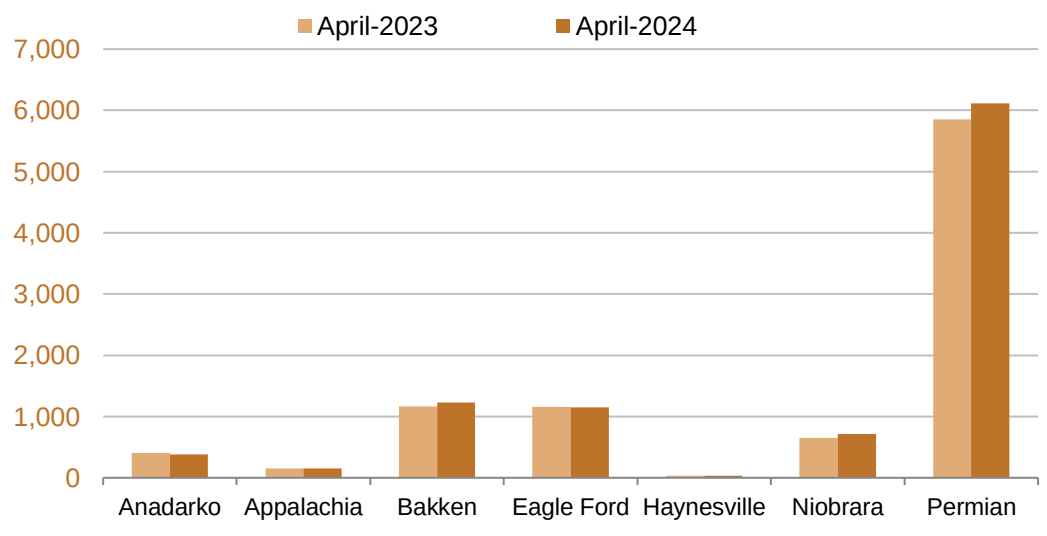
Indicated monthly change in oil production (Apr vs. Mar)
thousand barrels/day



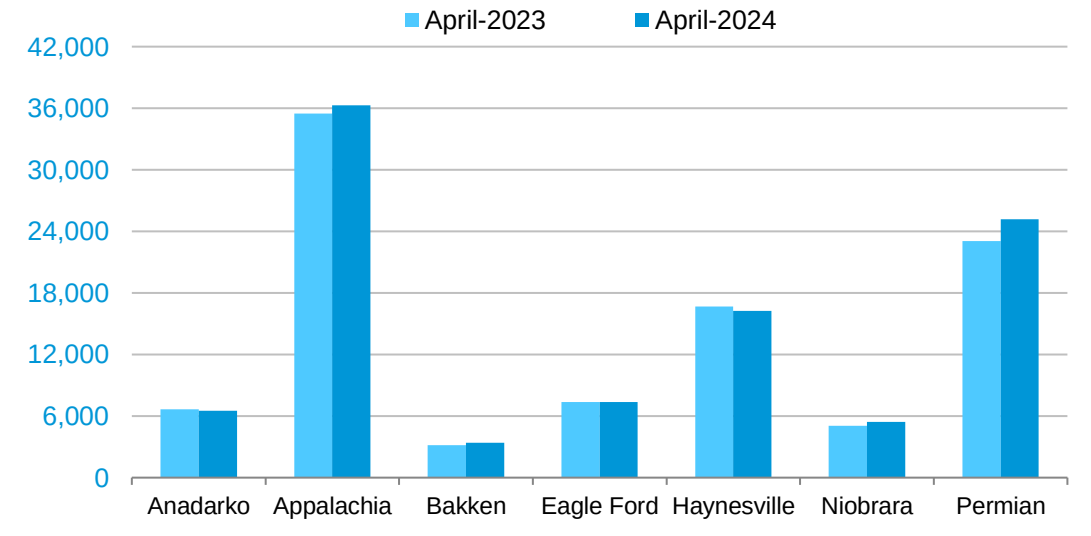
Indicated monthly change in gas production (Apr vs. Mar)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +2 barrels/day month over month

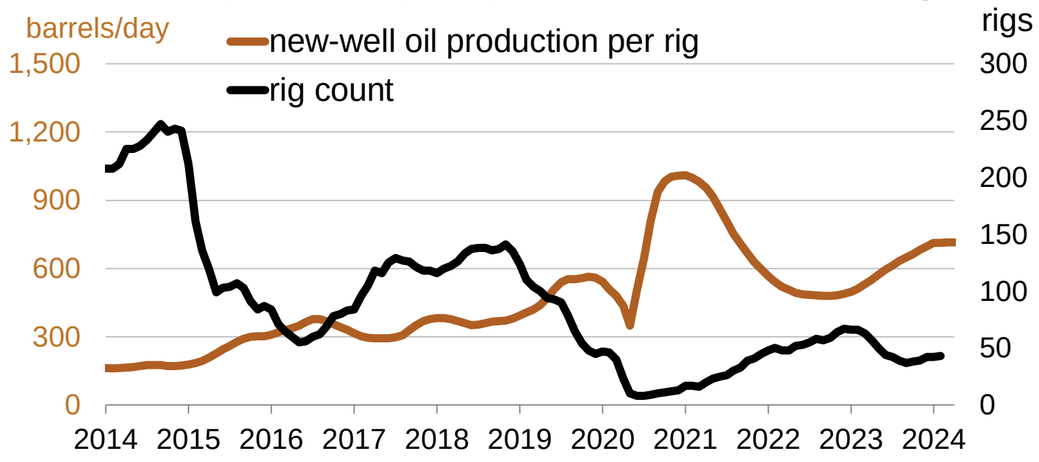
716 *April*
714 *March*
barrels/day

Monthly additions from one average rig

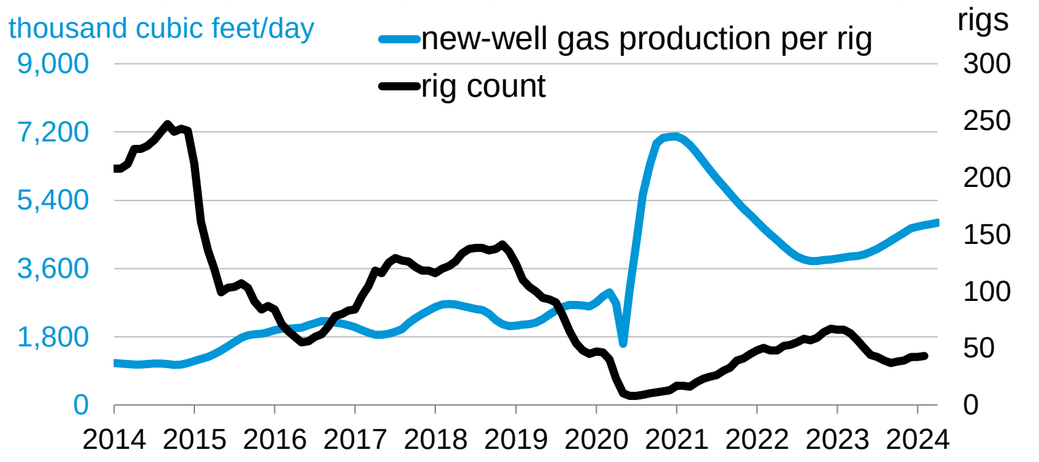
April **4,806**
March **4,772**
thousand cubic feet/day

Gas +34 thousand cubic feet/day month over month

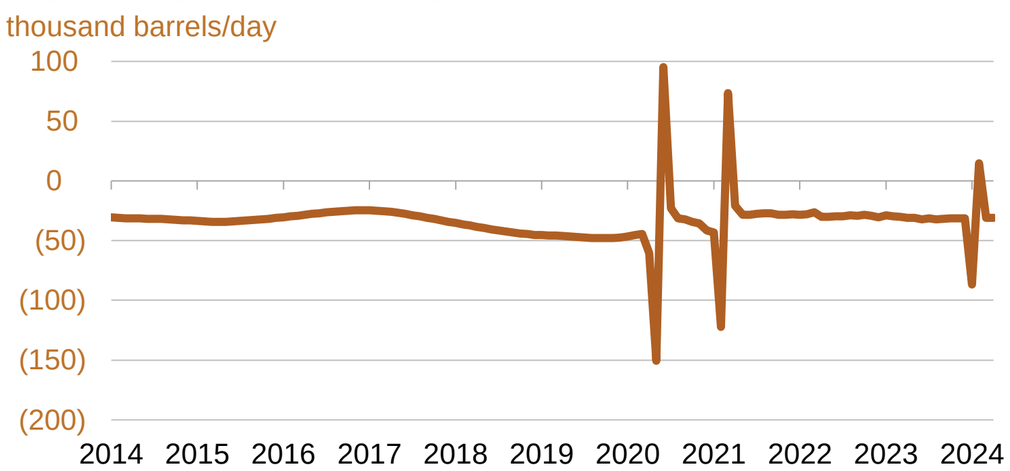
Anadarko Region
New-well oil production per rig



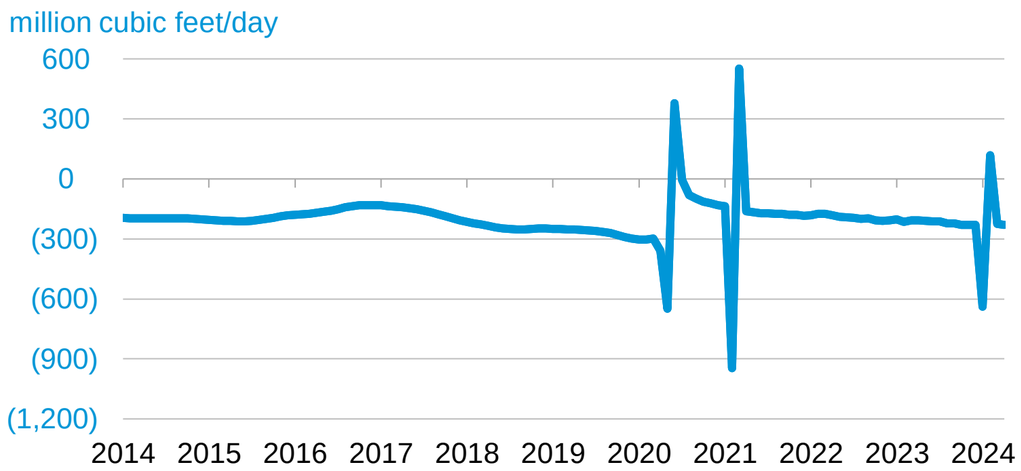
Anadarko Region
New-well gas production per rig



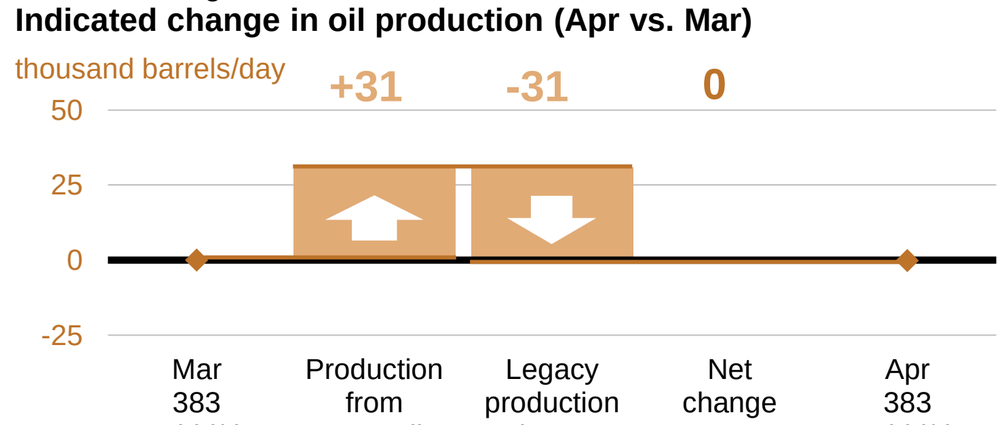
Anadarko Region
Legacy oil production change



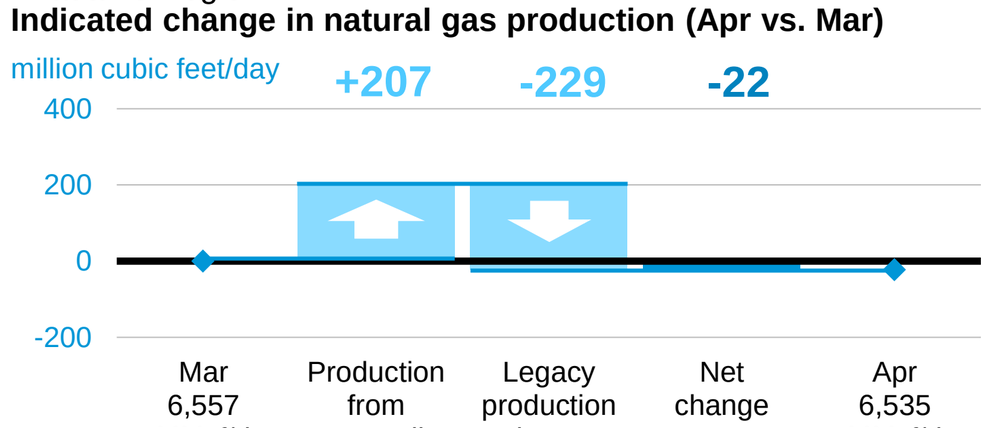
Anadarko Region
Legacy gas production change



Anadarko Region
Indicated change in oil production (Apr vs. Mar)



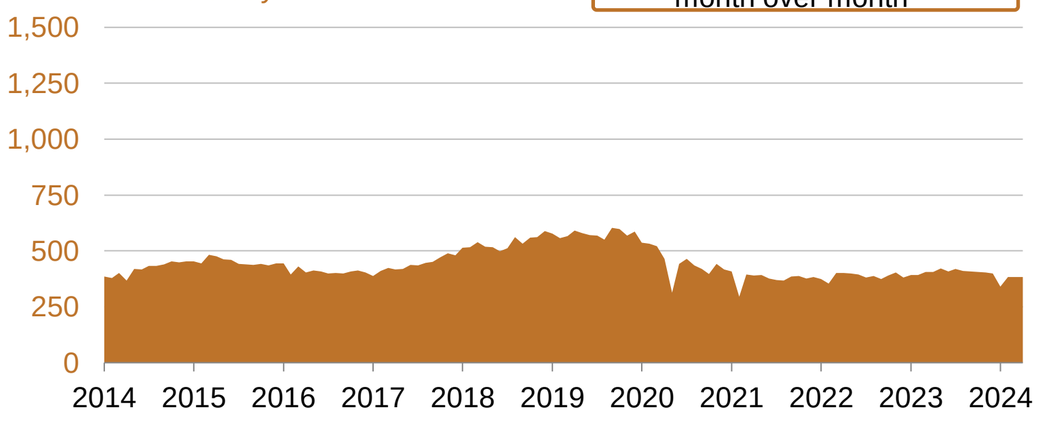
Anadarko Region
Indicated change in natural gas production (Apr vs. Mar)



Mar 383 Mbbl/d	Production from new wells	Legacy production change	Net change	Apr 383 Mbbl/d
Mar 6,557 MMcf/d	Production from new wells	Legacy production change	Net change	Apr 6,535 MMcf/d

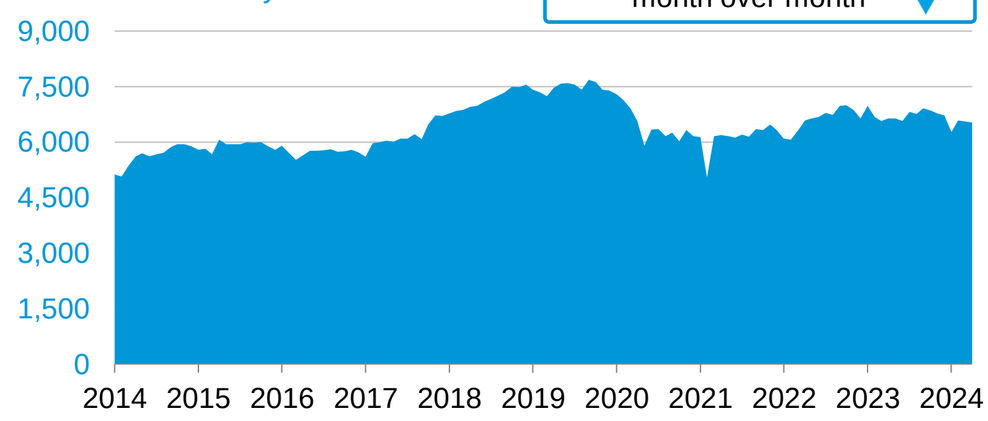
Anadarko Region
Oil production

Oil 0 thousand barrels/day month over month



Anadarko Region
Natural gas production

Gas -22 million cubic feet/day month over month



Appalachia Region
Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +1
barrels/day
month over month

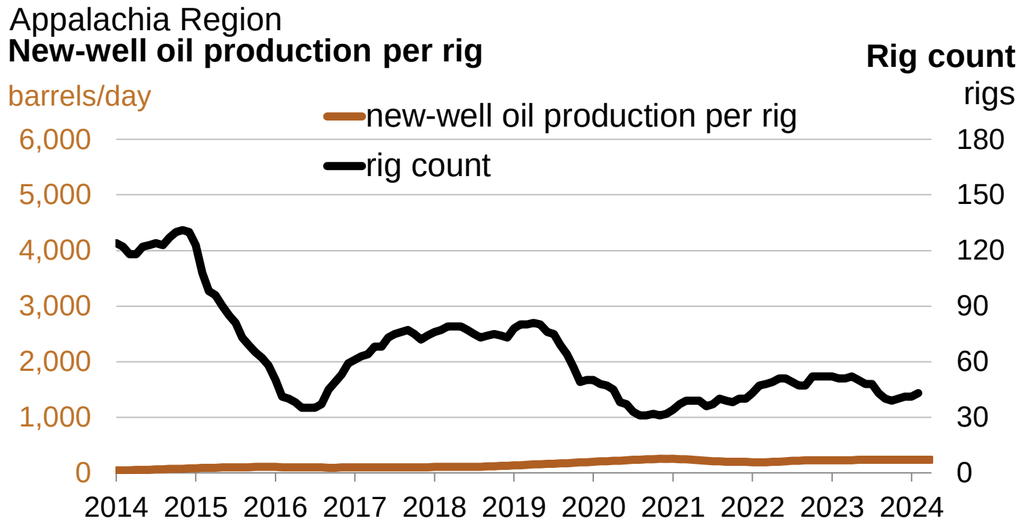
238 *April*
237 *March*
barrels/day

Monthly additions from one average rig

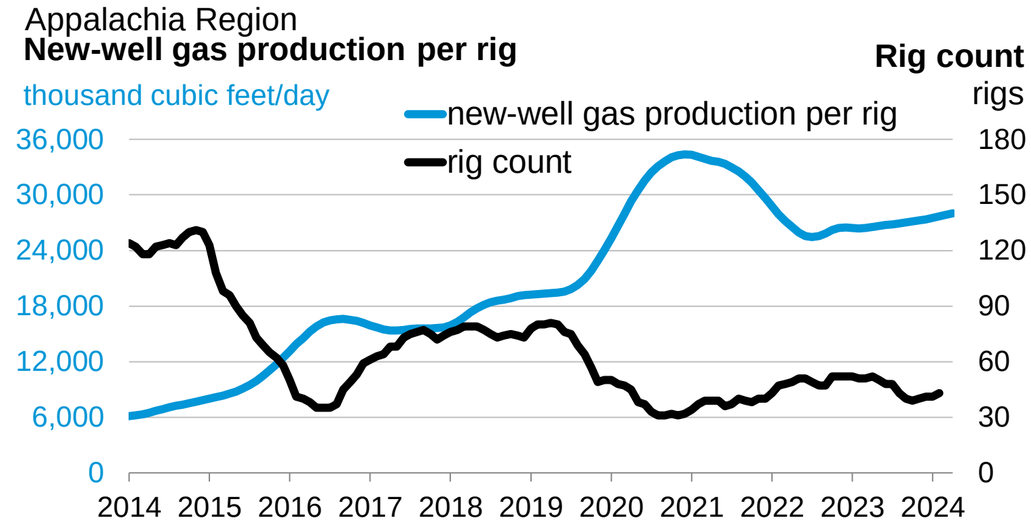
April **28,006**
March **27,832**
thousand cubic feet/day

Gas +174
thousand cubic feet/day
month over month

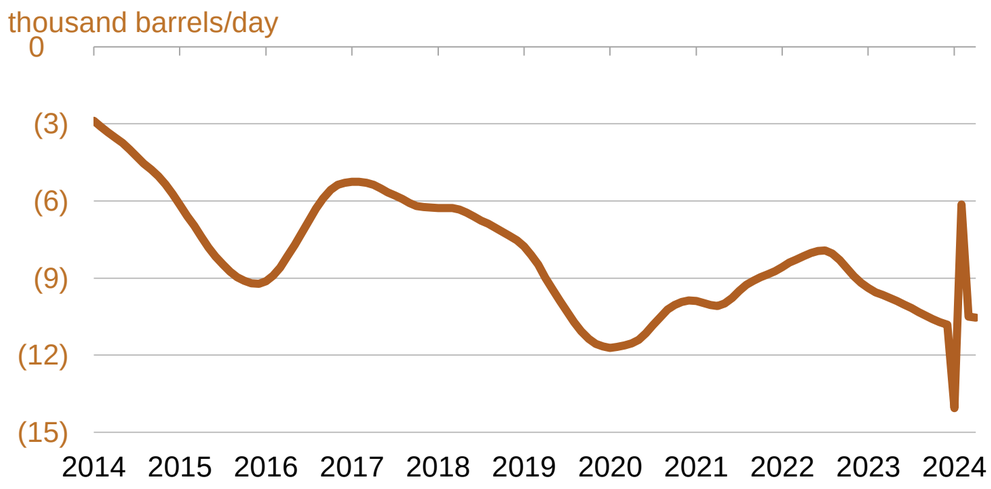
Appalachia Region
New-well oil production per rig



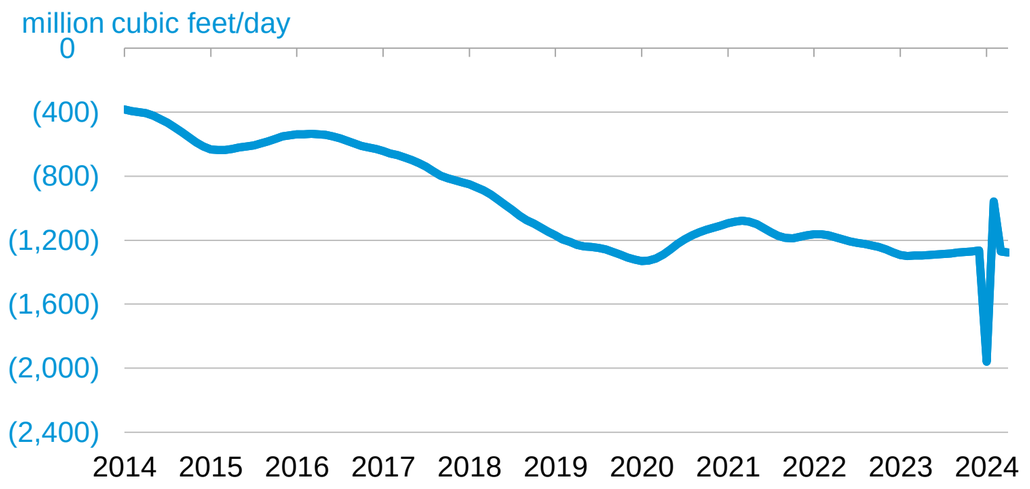
Appalachia Region
New-well gas production per rig



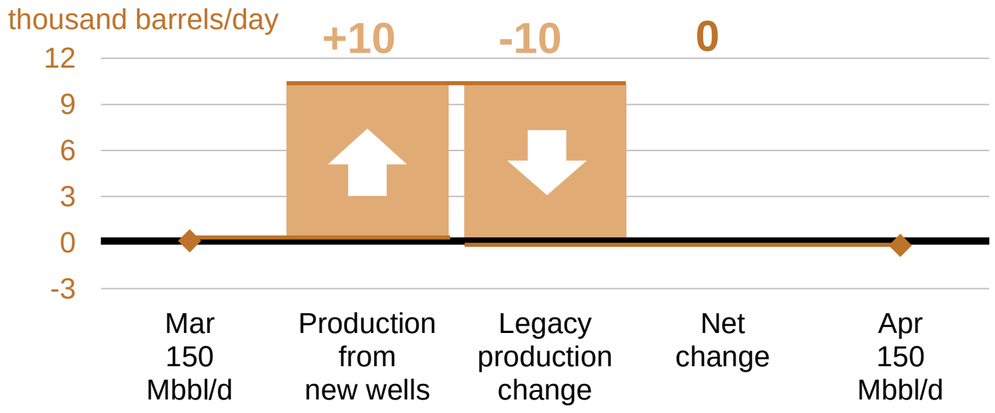
Appalachia Region
Legacy oil production change



Appalachia Region
Legacy gas production change

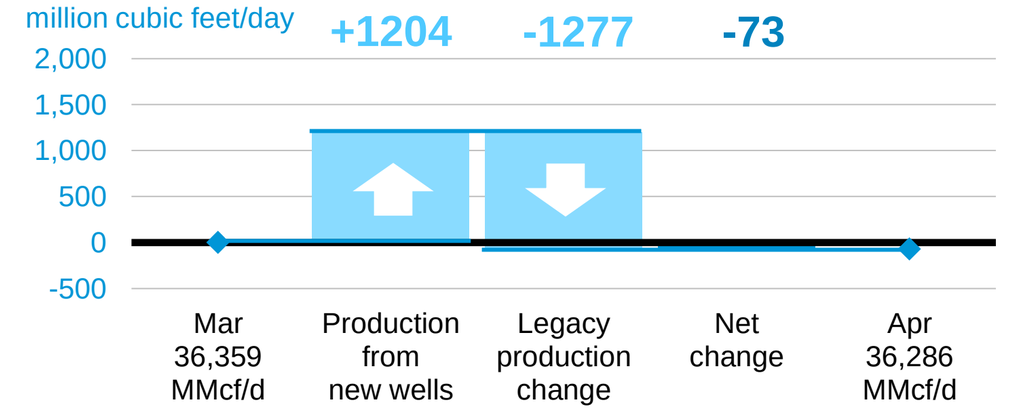


Appalachia Region
Indicated change in oil production (Apr vs. Mar)



Mar 150 Mbbl/d | Production from new wells +10 | Legacy production change -10 | Net change 0 | Apr 150 Mbbl/d

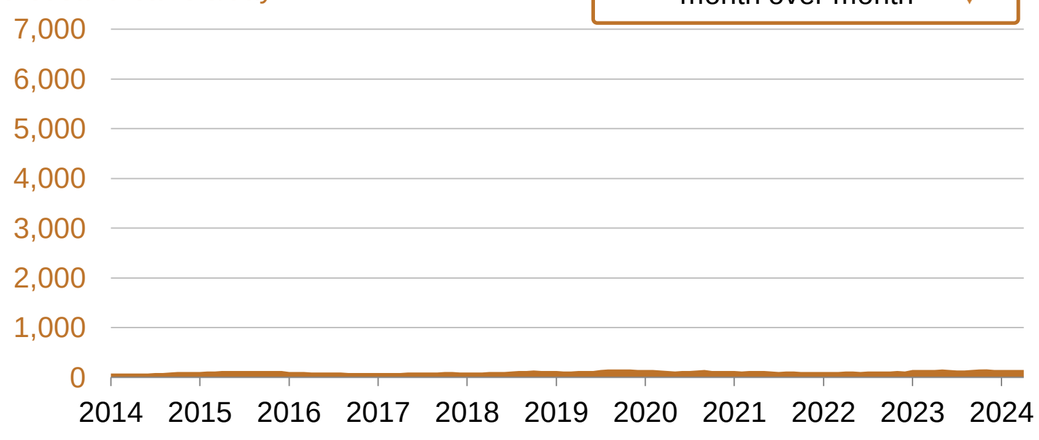
Appalachia Region
Indicated change in natural gas production (Apr vs. Mar)



Mar 36,359 MMcf/d | Production from new wells +1204 | Legacy production change -1277 | Net change -73 | Apr 36,286 MMcf/d

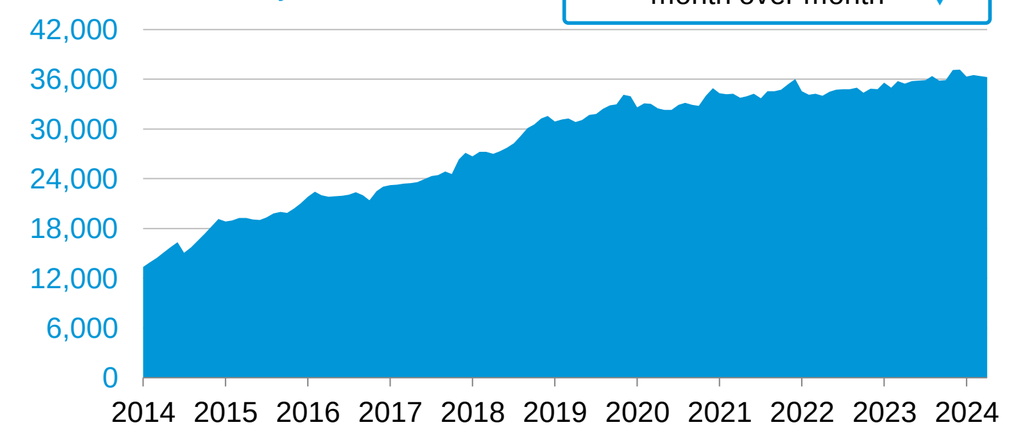
Appalachia Region
Oil production

Oil 0
thousand barrels/day
month over month



Appalachia Region
Natural gas production

Gas -73
million cubic feet/day
month over month



Bakken Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +8 barrels/day month over month

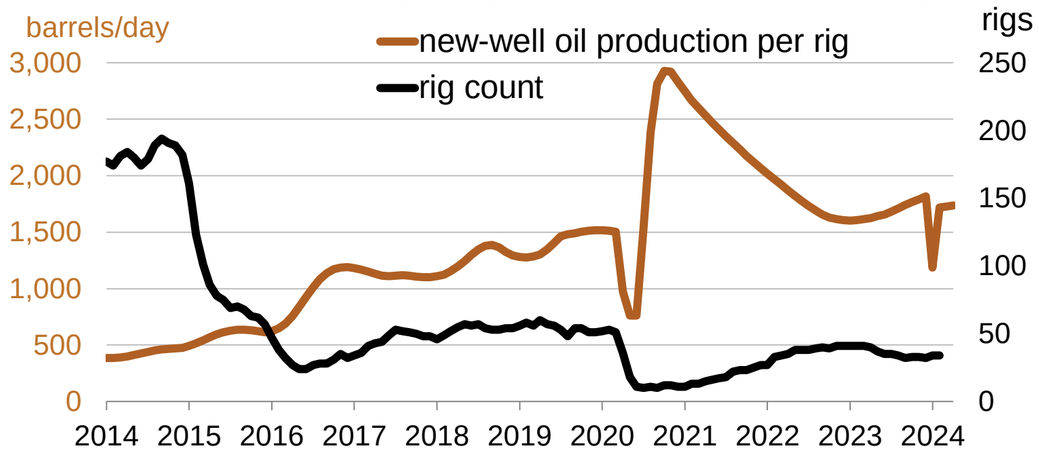
1,734 *April*
1,726 *March*
barrels/day

Monthly additions from one average rig

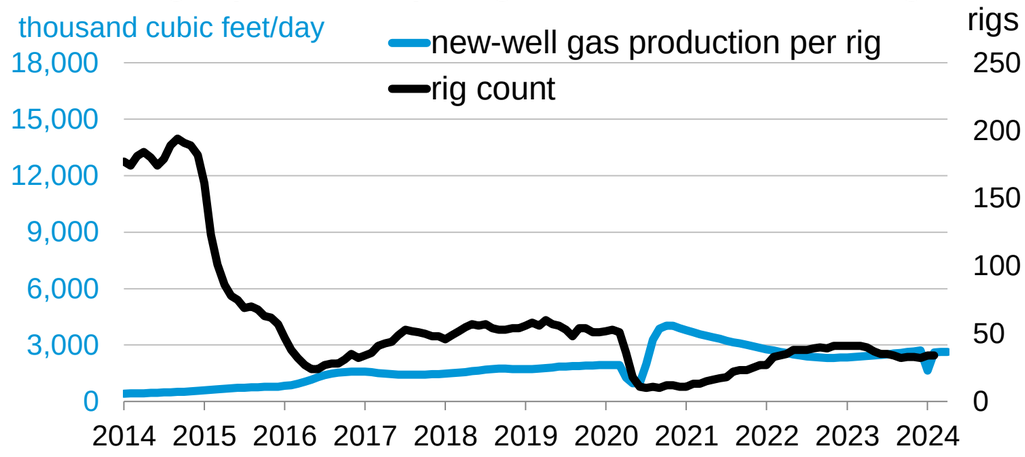
April **2,638**
March **2,624**
thousand cubic feet/day

Gas +14 thousand cubic feet/day month over month

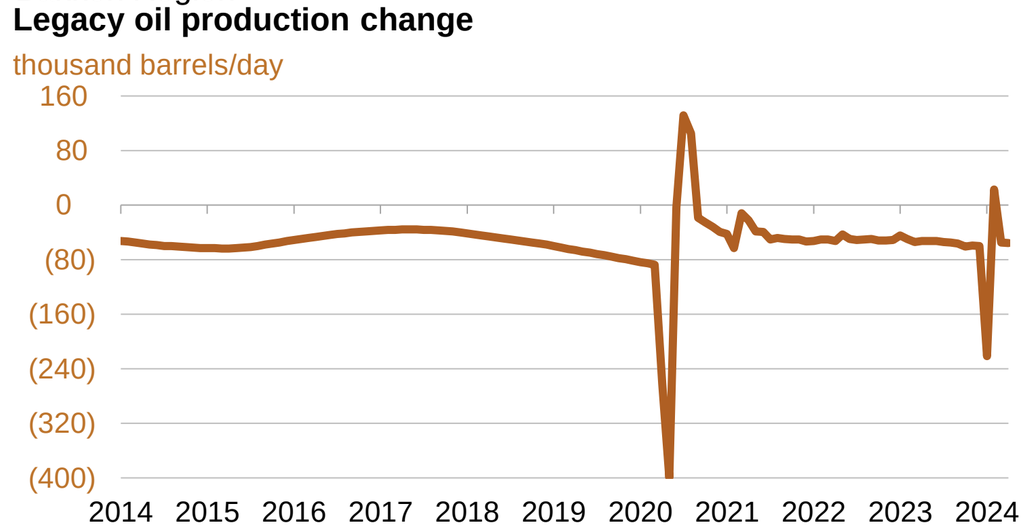
Bakken Region
New-well oil production per rig



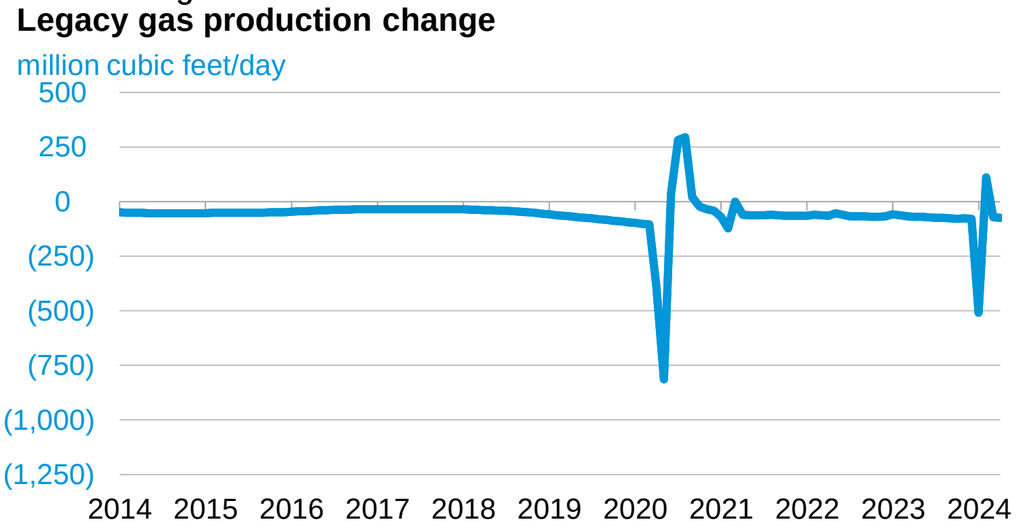
Bakken Region
New-well gas production per rig



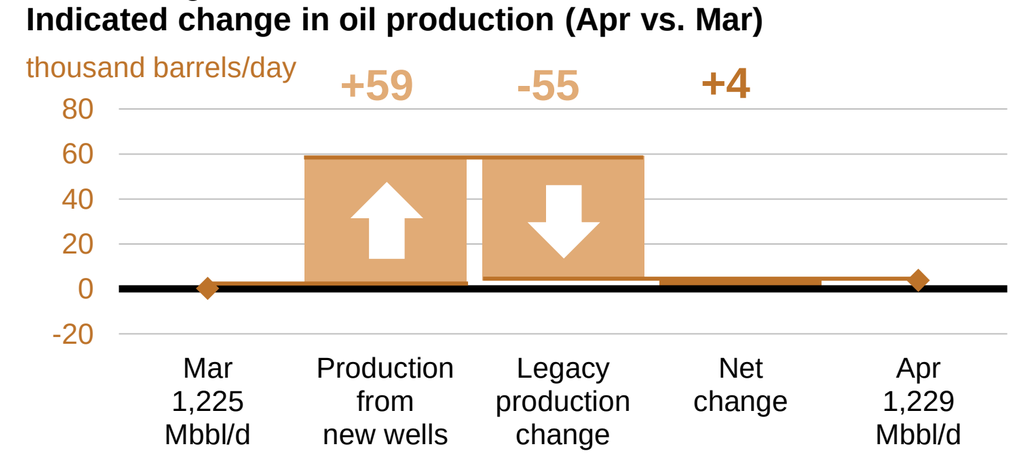
Bakken Region
Legacy oil production change



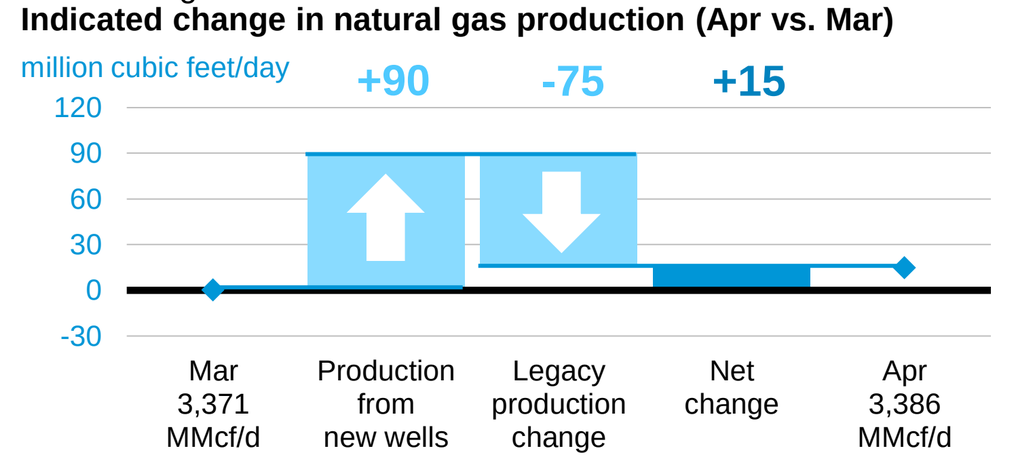
Bakken Region
Legacy gas production change



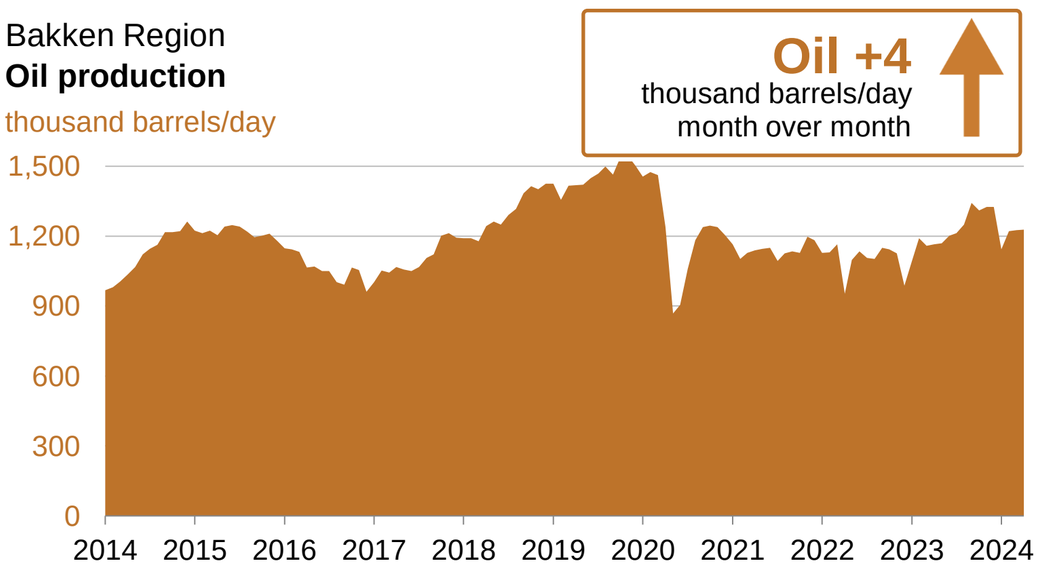
Bakken Region
Indicated change in oil production (Apr vs. Mar)



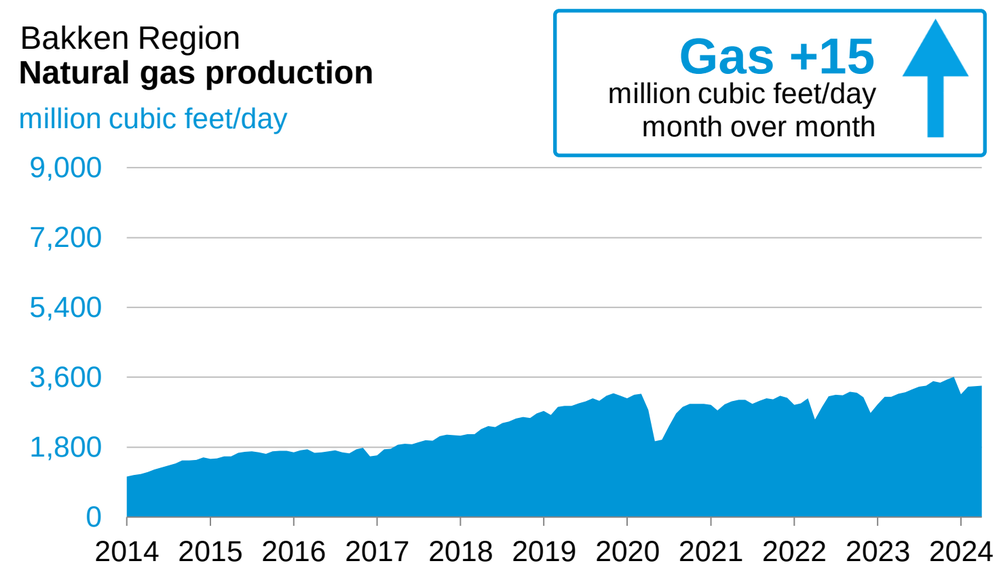
Bakken Region
Indicated change in natural gas production (Apr vs. Mar)



Bakken Region
Oil production



Bakken Region
Natural gas production



Eagle Ford Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +5
barrels/day
month over month

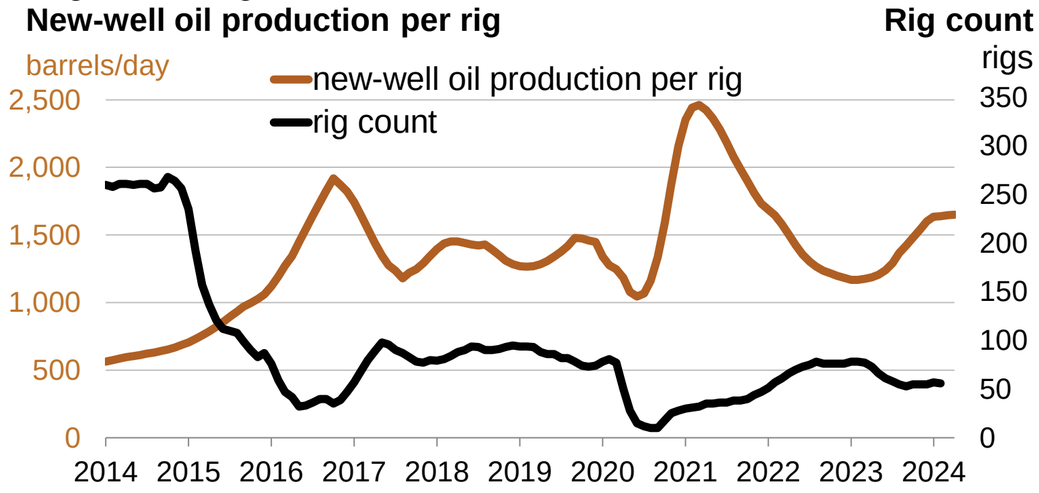
1,650 *April*
1,645 *March*
barrels/day

Monthly additions from one average rig

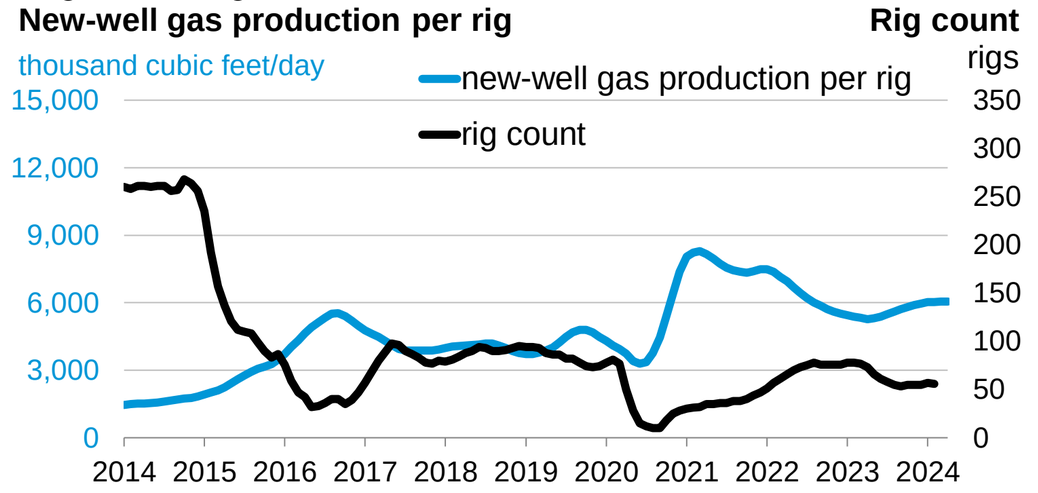
April **6,050**
March **6,043**
thousand cubic feet/day

Gas +7
thousand cubic feet/day
month over month

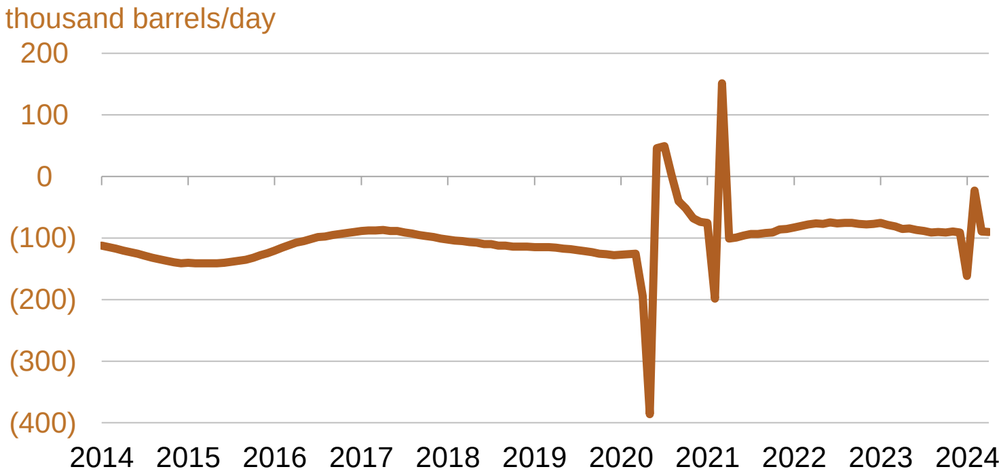
Eagle Ford Region
New-well oil production per rig



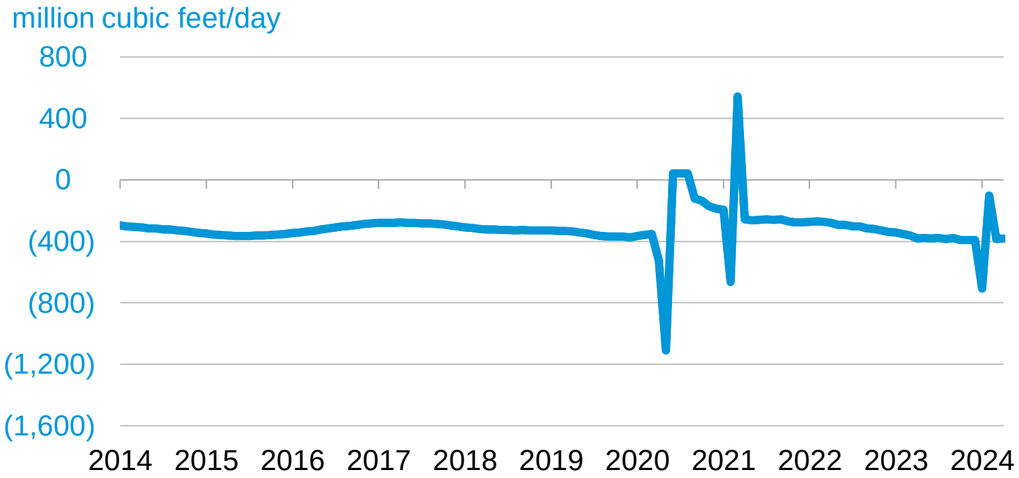
Eagle Ford Region
New-well gas production per rig



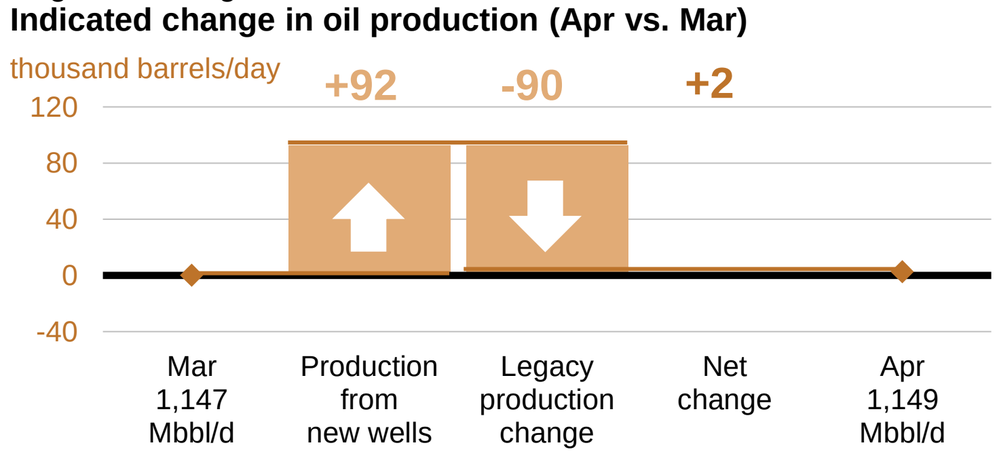
Eagle Ford Region
Legacy oil production change



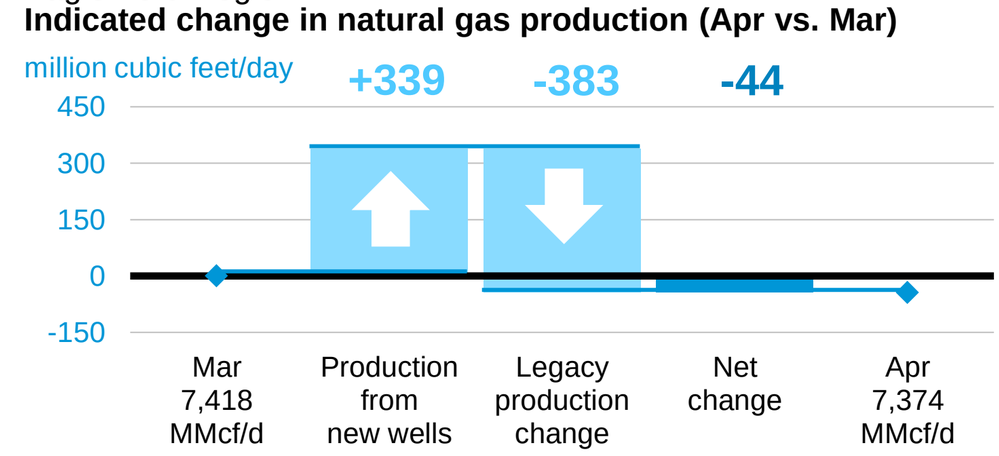
Eagle Ford Region
Legacy gas production change



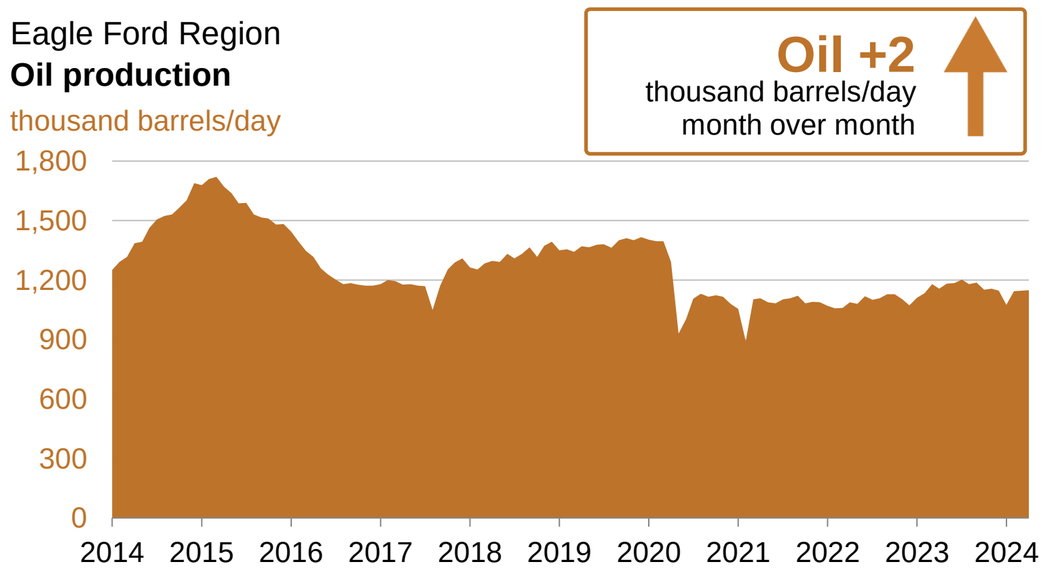
Eagle Ford Region
Indicated change in oil production (Apr vs. Mar)



Eagle Ford Region
Indicated change in natural gas production (Apr vs. Mar)

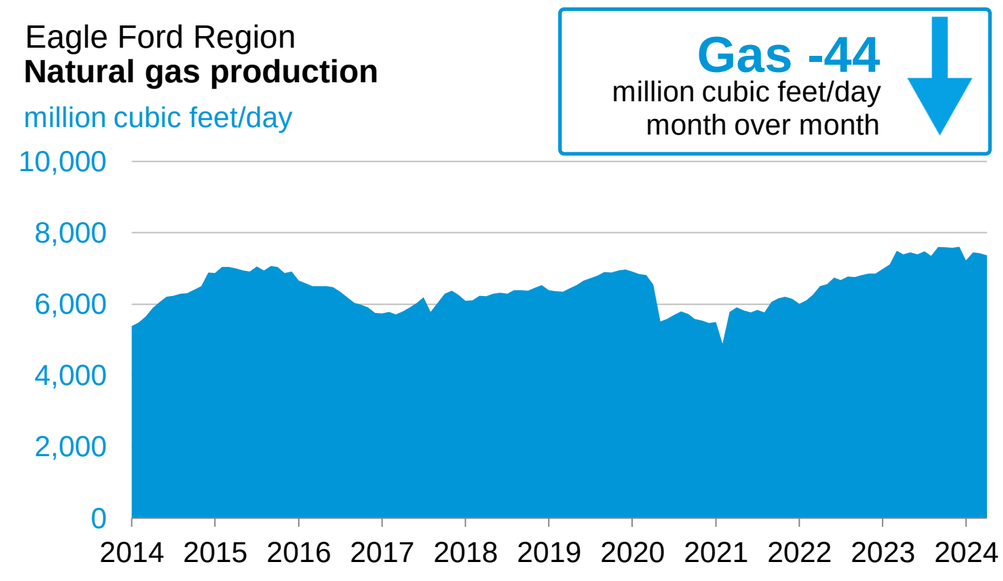


Eagle Ford Region
Oil production



Oil +2
thousand barrels/day
month over month

Eagle Ford Region
Natural gas production



Gas -44
million cubic feet/day
month over month

Haynesville Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil
0
barrels/day
month over month

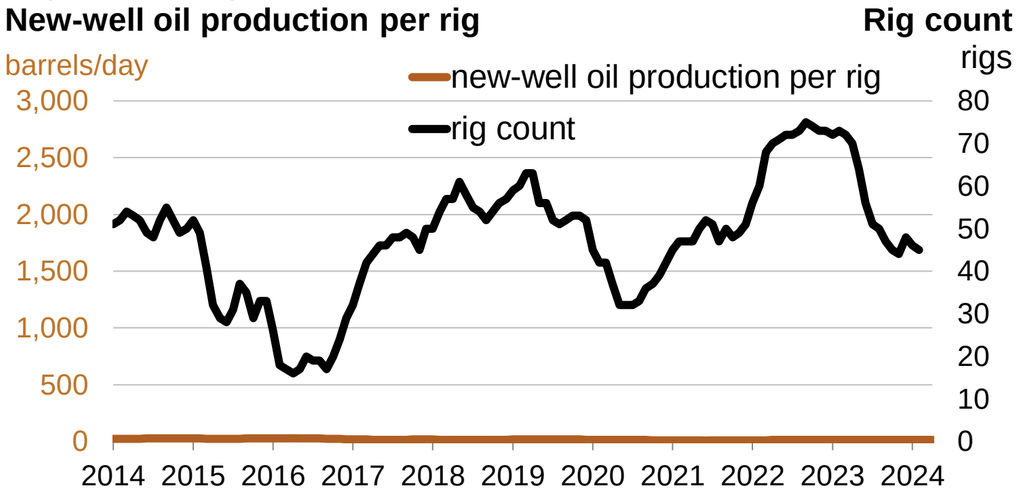
15 *April*
15 *March*
barrels/day

Monthly additions from one average rig

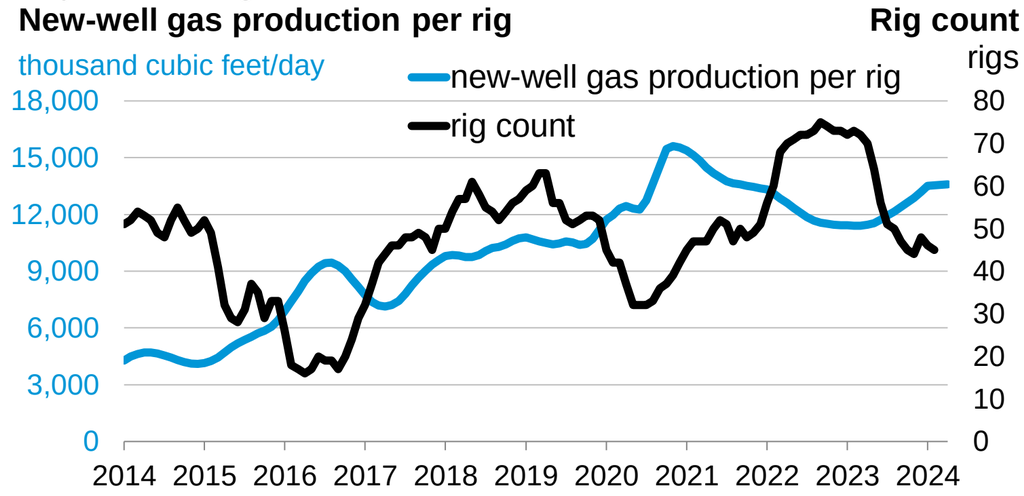
April **13,598**
March **13,571**
thousand cubic feet/day

Gas
+27
thousand cubic feet/day
month over month

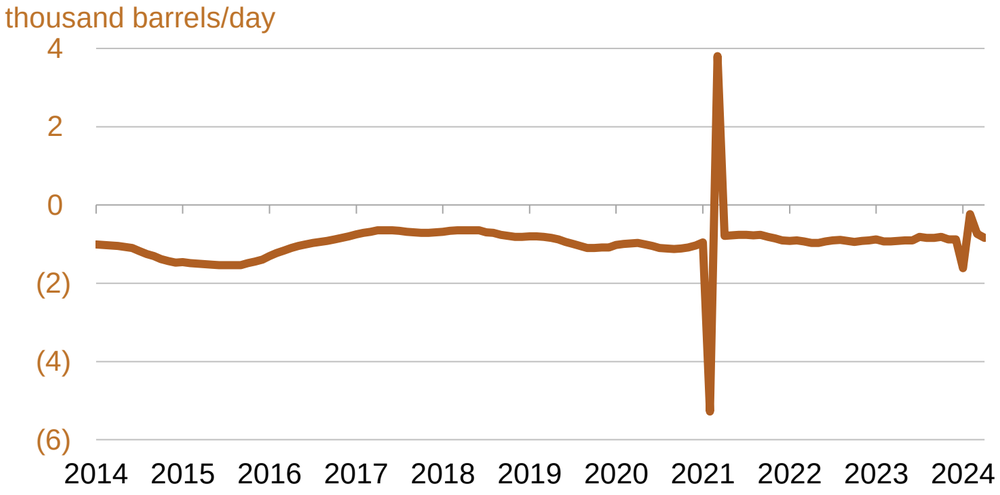
Haynesville Region
New-well oil production per rig



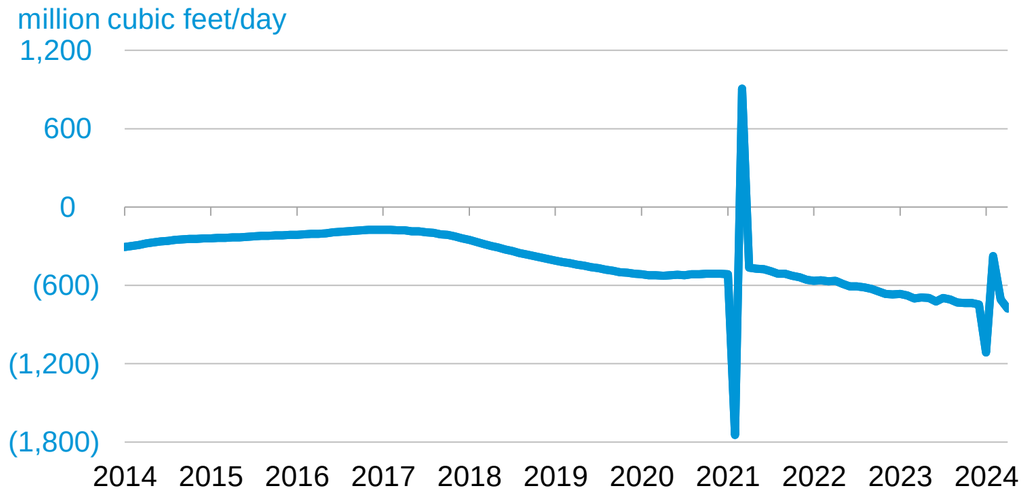
Haynesville Region
New-well gas production per rig



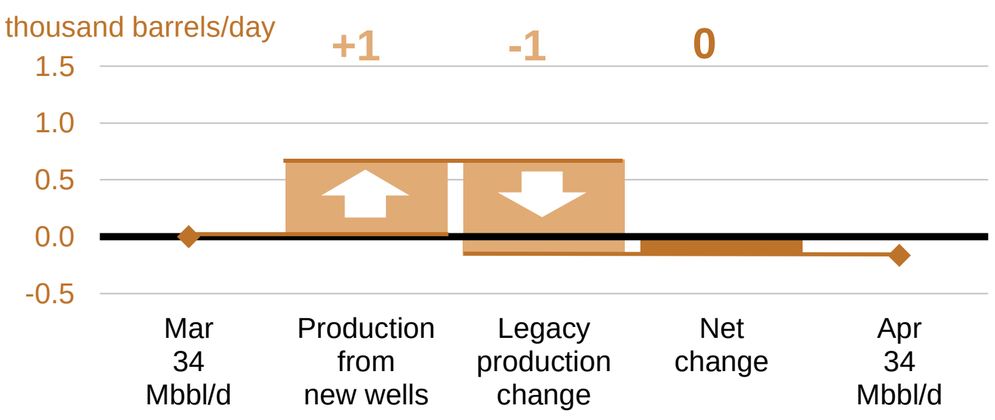
Haynesville Region
Legacy oil production change



Haynesville Region
Legacy gas production change

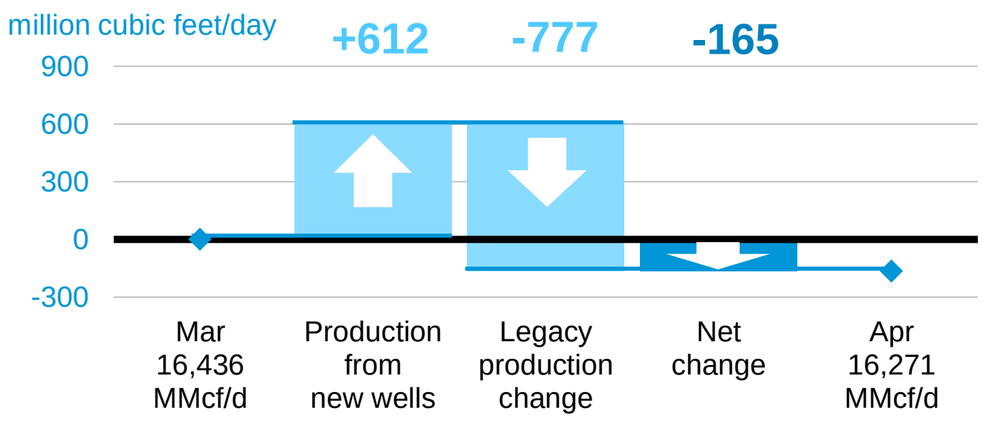


Haynesville Region
Indicated change in oil production (Apr vs. Mar)



Mar 34 Mbbl/d	Production from new wells	Legacy production change	Net change	Apr 34 Mbbl/d
	+1	-1	0	

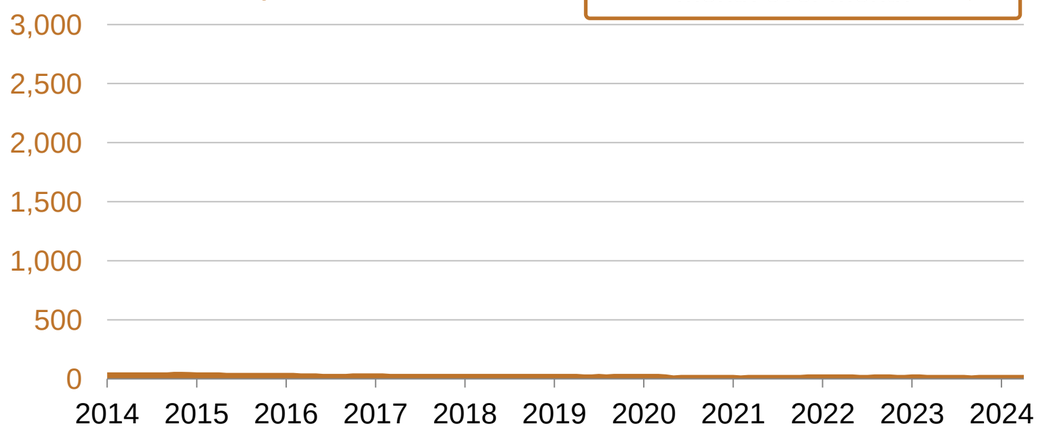
Haynesville Region
Indicated change in natural gas production (Apr vs. Mar)



Mar 16,436 MMcf/d	Production from new wells	Legacy production change	Net change	Apr 16,271 MMcf/d
	+612	-777	-165	

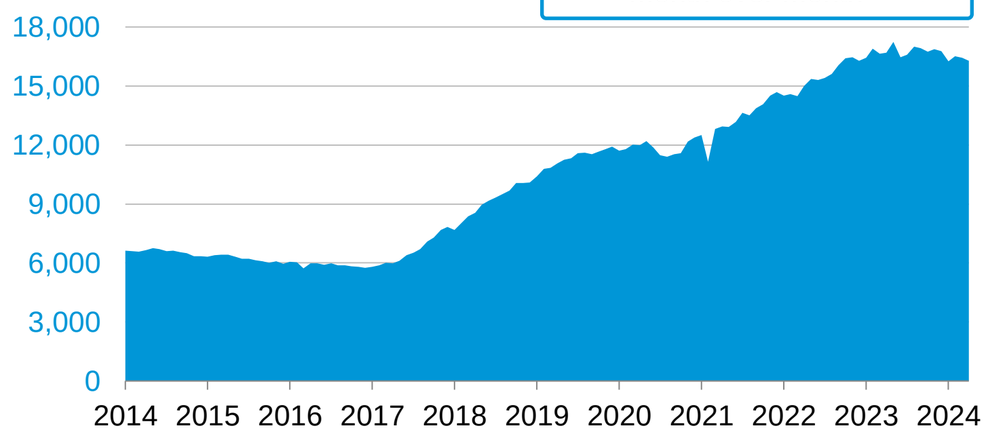
Haynesville Region
Oil production

Oil 0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas -165
million cubic feet/day
month over month



Niobrara Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +3 barrels/day month over month

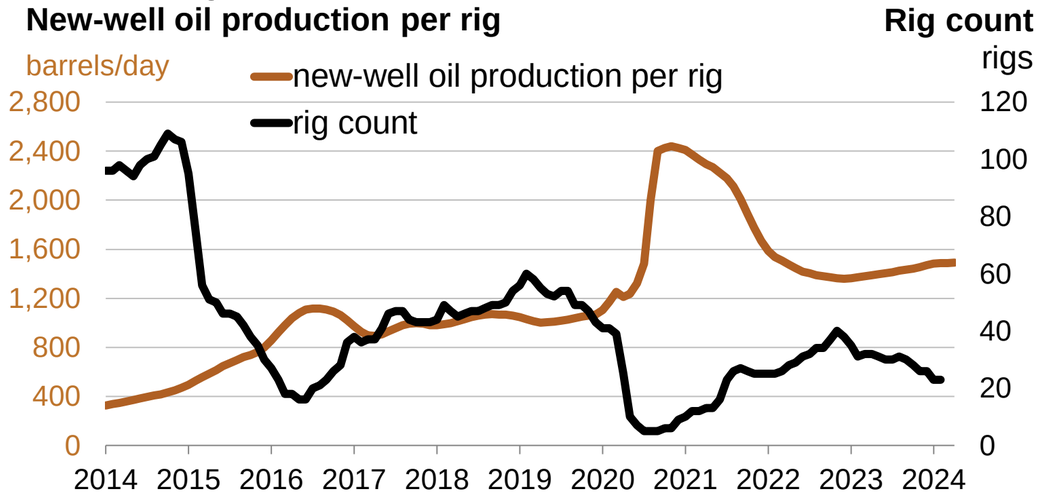
1,491 *April*
1,488 *March*
barrels/day

Monthly additions from one average rig

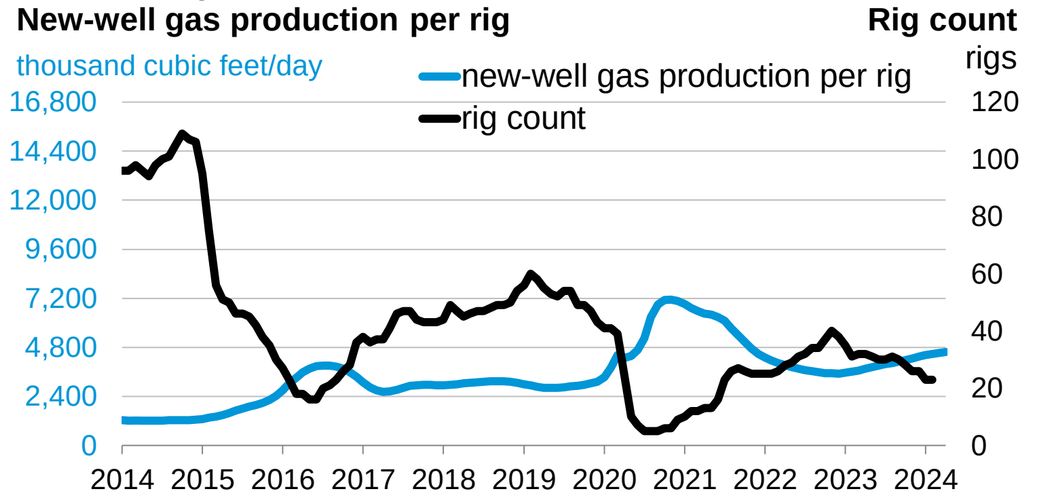
April **4,569**
March **4,523**
thousand cubic feet/day

Gas +46 thousand cubic feet/day month over month

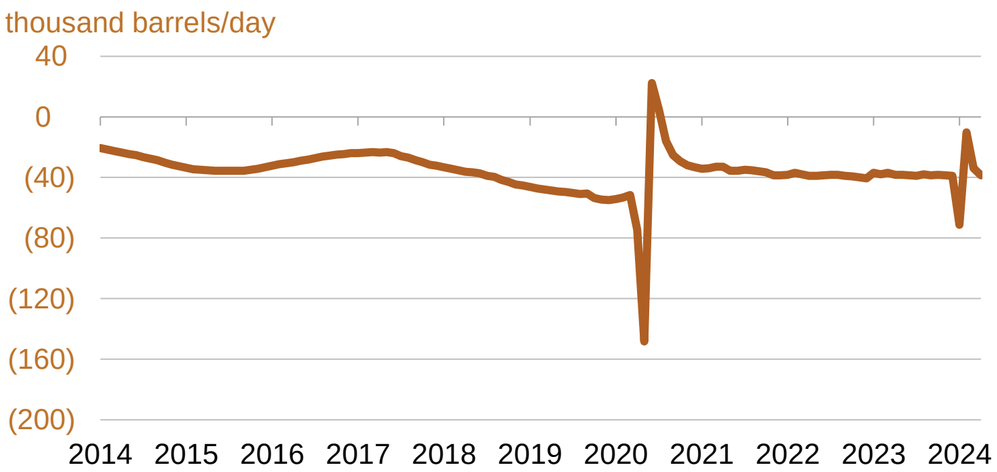
Niobrara Region
New-well oil production per rig



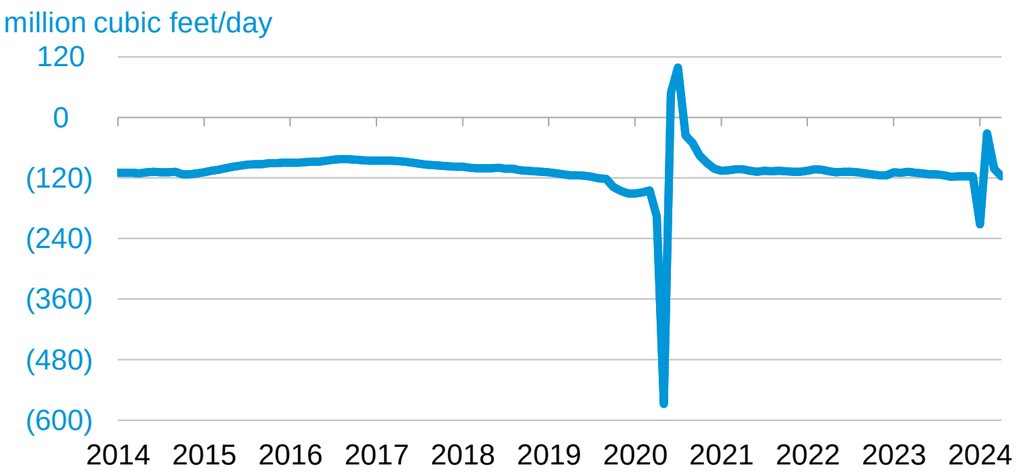
Niobrara Region
New-well gas production per rig



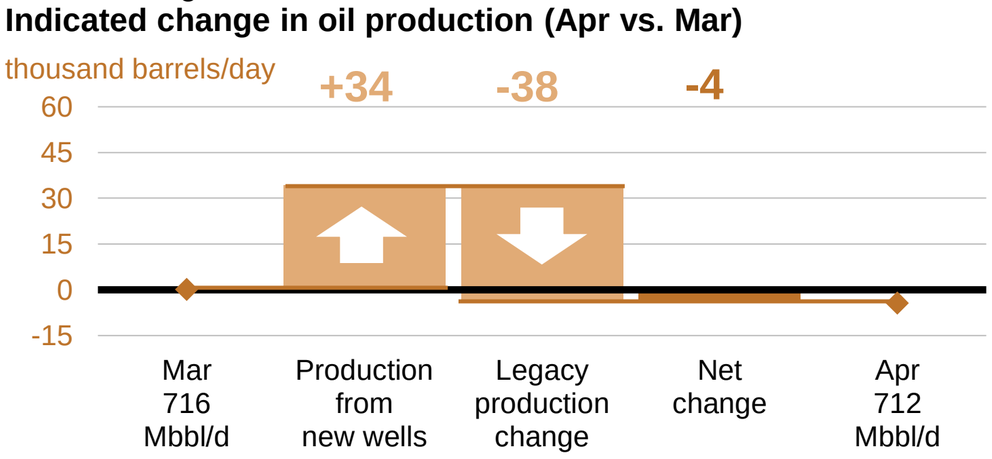
Niobrara Region
Legacy oil production change



Niobrara Region
Legacy gas production change

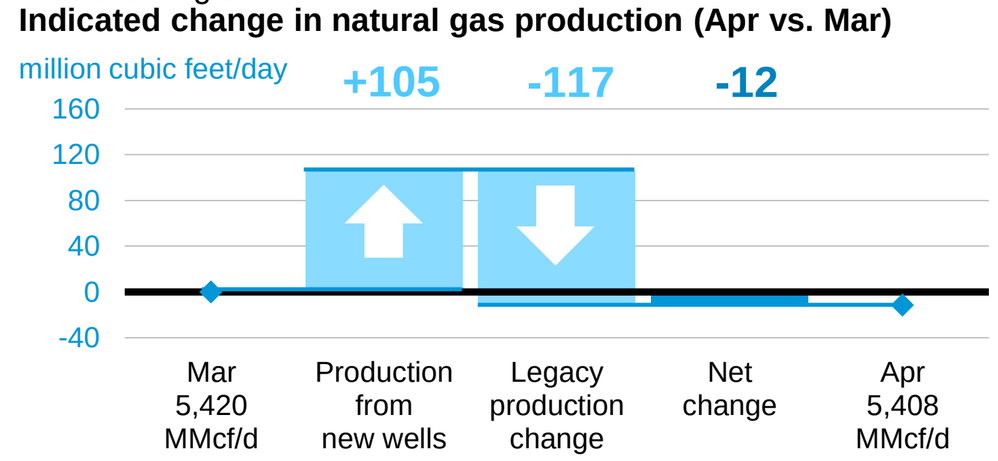


Niobrara Region
Indicated change in oil production (Apr vs. Mar)



Mar 716 Mbbl/d	Production from new wells	Legacy production change	Net change	Apr 712 Mbbl/d

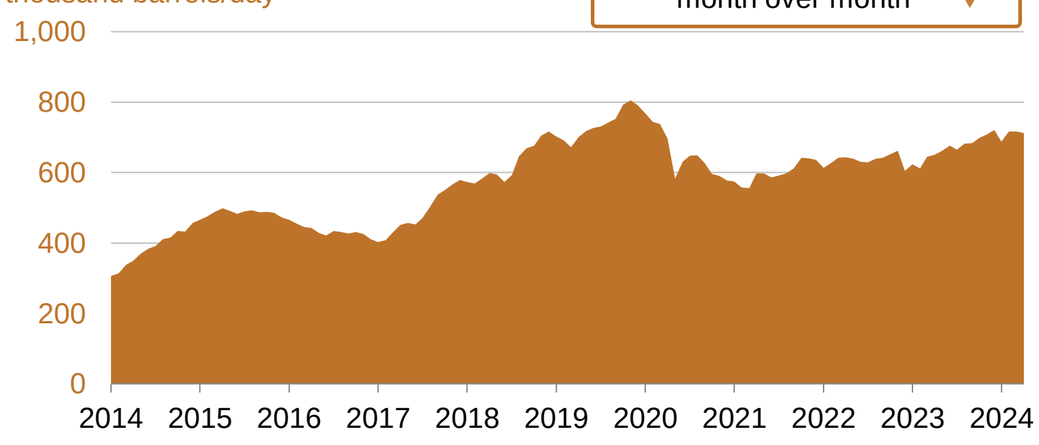
Niobrara Region
Indicated change in natural gas production (Apr vs. Mar)



Mar 5,420 MMcf/d	Production from new wells	Legacy production change	Net change	Apr 5,408 MMcf/d

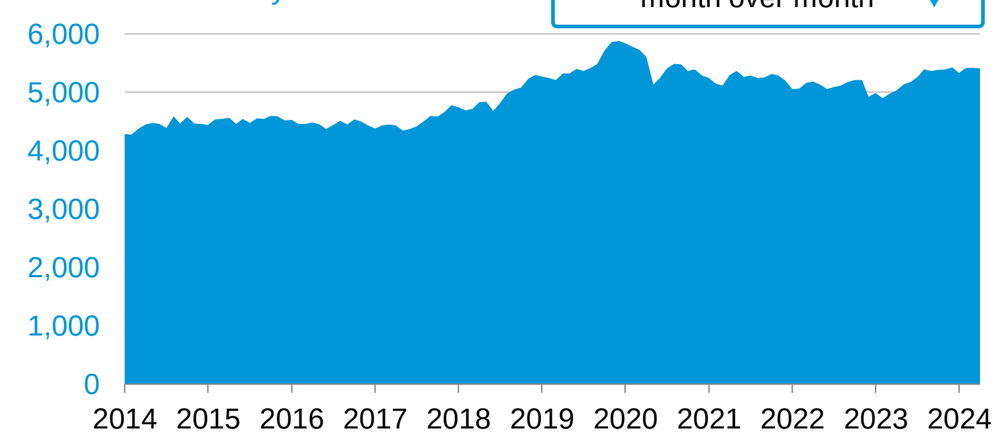
Niobrara Region
Oil production

Oil -4 thousand barrels/day month over month



Niobrara Region
Natural gas production

Gas -12 million cubic feet/day month over month



Permian Region

Drilling Productivity Report

March 2024

drilling data through February
projected production through April

Oil +13
barrels/day
month over month

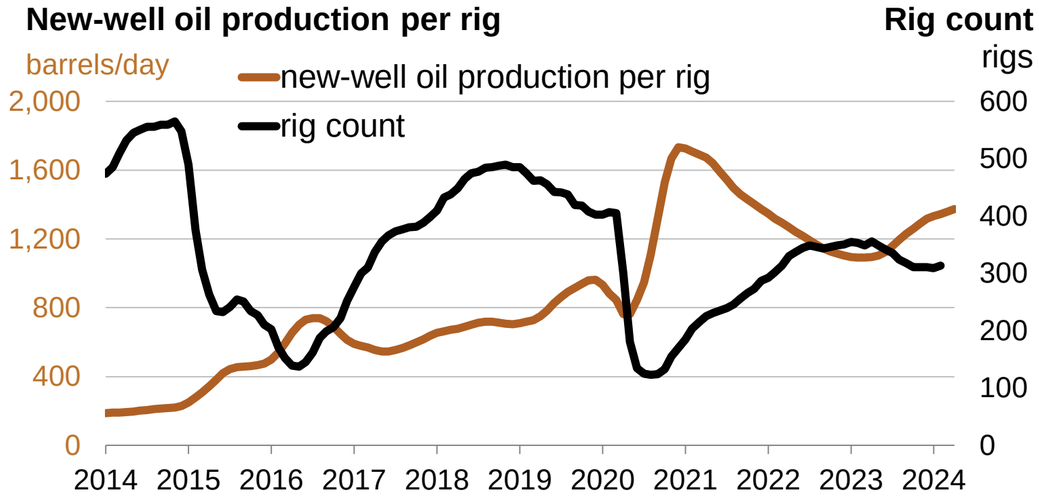
1,372 *April*
1,359 *March*
barrels/day

Monthly additions from one average rig

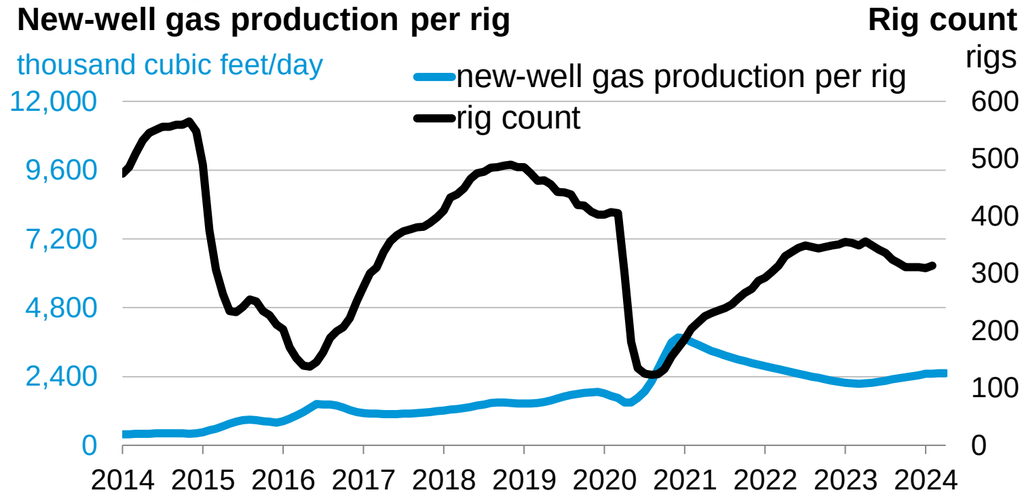
April **2,523**
March **2,512**
thousand cubic feet/day

Gas +11
thousand cubic feet/day
month over month

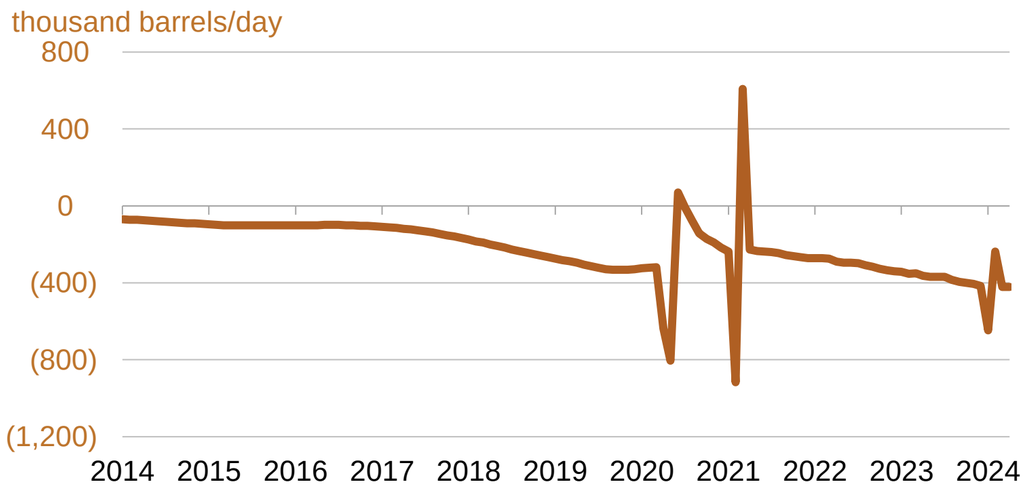
Permian Region
New-well oil production per rig



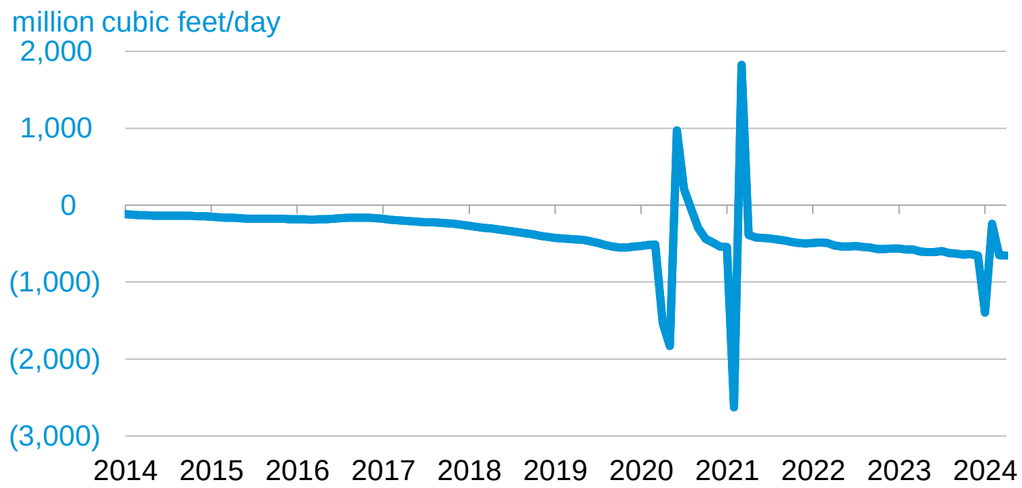
Permian Region
New-well gas production per rig



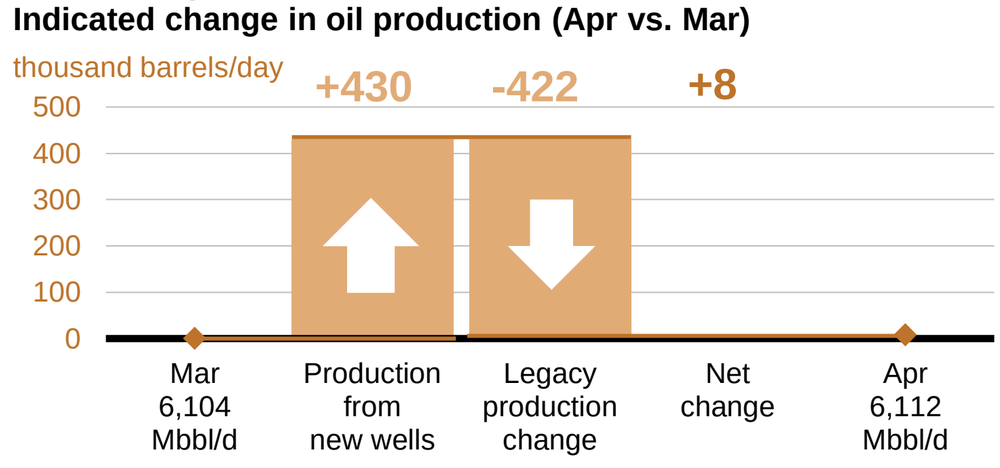
Permian Region
Legacy oil production change



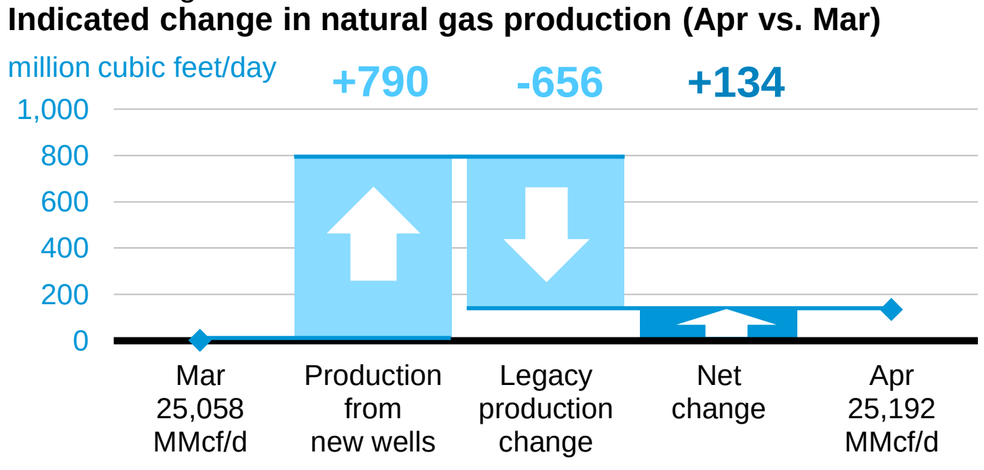
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Apr vs. Mar)

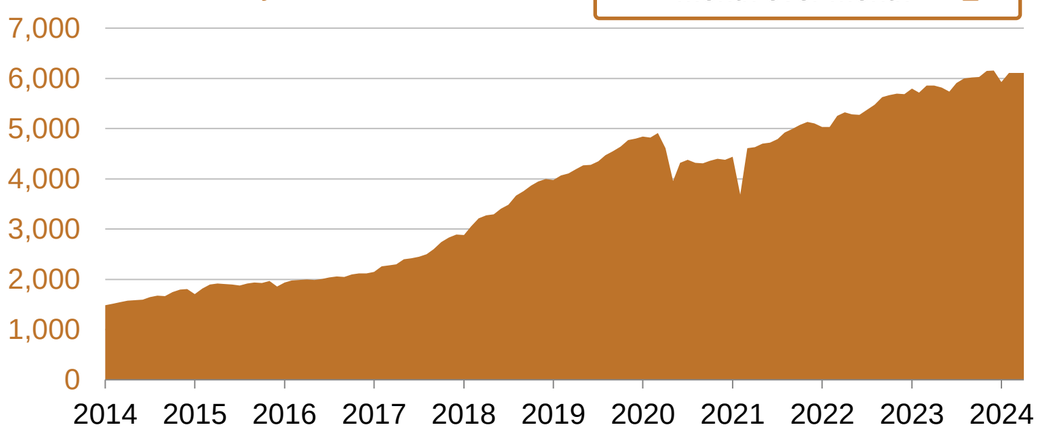


Permian Region
Indicated change in natural gas production (Apr vs. Mar)



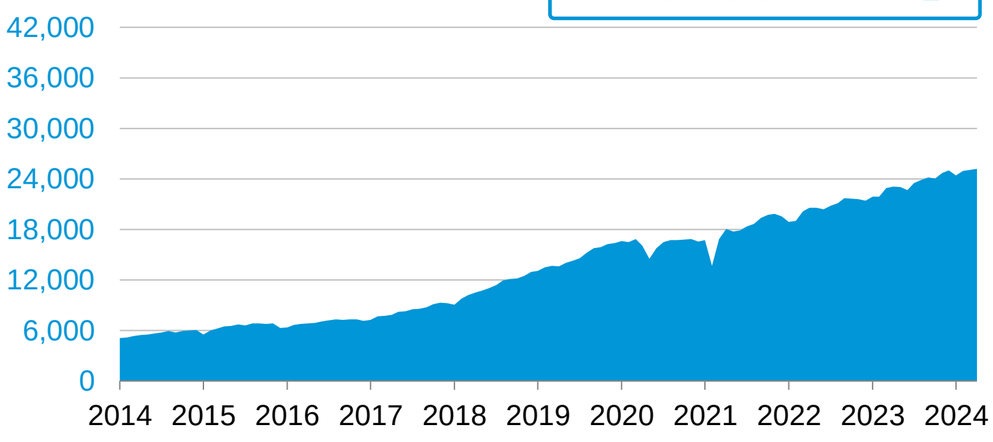
Permian Region
Oil production
thousand barrels/day

Oil +8
thousand barrels/day
month over month



Permian Region
Natural gas production
million cubic feet/day

Gas +134
million cubic feet/day
month over month



Explanatory notes

Drilling Productivity Report

March 2024

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

Monthly additions from one average rig

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

New-well oil/gas production per rig

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

Legacy oil and natural gas production change

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

Projected change in monthly oil/gas production

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

Oil/gas production

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

Footnotes:

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

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

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

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

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

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

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

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

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

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

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

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

Oklahoma Corporation Commission (http://www.occeweb.com/og/oghome.htm) Source of well production, permit, and completion data in the counties associated with this report in Oklahoma

https://www.adnoc.ae/en/news-and-media/press-releases/2023/adnoc-signs-second-long-term-heads-of-agreement-for-ruwais-lng-project

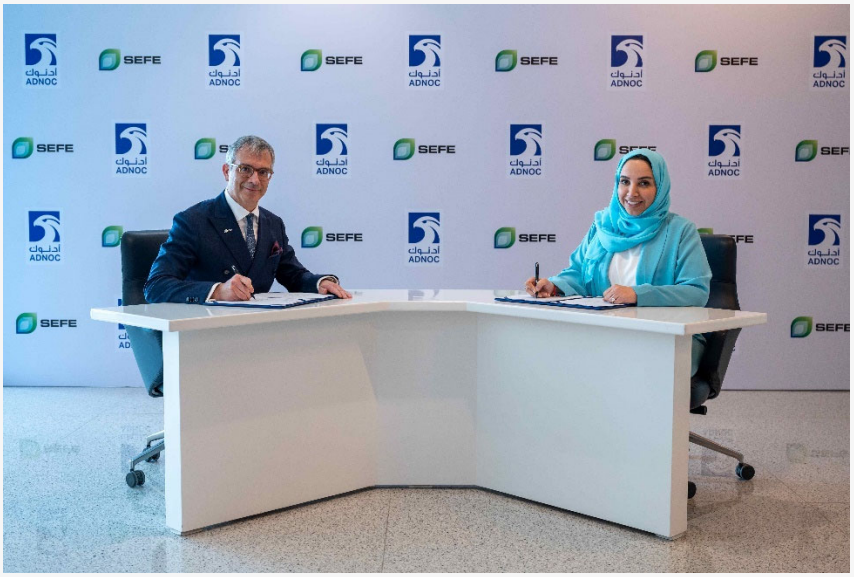
March 18, 2024

ADNOC Signs Second Long-Term Heads of Agreement for Ruwais LNG Project

15-year LNG supply agreement with SEFE for 1 mmtpa reinforces ADNOC's position as a reliable global natural gas provider

LNG agreement demonstrates UAE-German Energy Security and Industry Accelerator in action, advancing cooperation in energy security, decarbonization and lower-carbon fuels

Set to be one of the lowest-carbon intensity LNG facilities in the world, the Ruwais LNG project will leverage the latest technologies and AI tools to lower emissions and drive efficiency



Abu Dhabi, UAE – March 18, 2024: ADNOC announced today the signing of a 15-year Heads of Agreement (LNG agreement) with SEFE Marketing & Trading Singapore Pte Ltd., a subsidiary of Germany's SEFE Securing Energy for Europe GmbH, for the delivery of 1 million metric tonnes per annum (mmtpa) of liquefied natural gas (LNG).

The LNG will primarily be sourced from ADNOC's lower-carbon Ruwais LNG project, currently under development in Al Ruwais Industrial City, Abu Dhabi. The Ruwais LNG plant has been designed to run on clean power and will leverage the latest technologies and Artificial Intelligence (AI) tools to drive efficiency. This is the second long-term LNG supply agreement from the Ruwais LNG project, following the 15-year agreement with China's ENN Natural Gas signed in December 2023. The deliveries are expected to start in 2028, upon commencement of the facility's commercial operations.

Fatema Al Nuaimi, Executive Vice President, Downstream Business Management at ADNOC said: "This LNG agreement, the first with a European company from the Ruwais lower-carbon LNG project, underscores ADNOC's position as a reliable and responsible global energy provider. Gas accounts for almost a quarter of Germany's primary energy use, and we look forward to supporting its efforts to diversify its energy sources and enhance its energy security."

This LNG supply agreement reinforces the Energy Security and Industry Accelerator (ESIA) agreement, signed by the UAE and Germany in 2022, further strengthening bilateral cooperation in energy security,

decarbonization and climate action. It builds upon ADNOC's delivery of the first LNG cargo from the Middle East to Germany in 2023.

Frédéric Barnaud, Chief Executive Officer of SEFE Marketing & Trading and Chief Commercial Officer of SEFE, said: “SEFE and ADNOC have a long and productive partnership, spanning over 15 years. This LNG supply agreement for the Ruwais LNG project, set to be one of the lowest-carbon intensity LNG projects in the world, marks the start of a new chapter. We aim to further build on our existing relationship and explore joint low-carbon energy developments.”

Natural gas plays a crucial role as a transitional fuel, generating lower-carbon emissions compared to other fossil fuels. The Ruwais LNG project is set to be the first LNG export facility in the Middle East and North Africa region to run on clean power. When completed, the project, which consists of two 4.8mmtpa LNG liquefaction trains with a total capacity of 9.6mmtpa, will more than double ADNOC’s LNG production capacity to around 15mmtpa, to help meet increased global demand for natural gas. The project is being designed to leverage AI, digitalization and the latest advanced technology to drive efficiency and safety across the new facility.

The LNG agreement is contingent upon a final investment decision (FID) on the project, including regulatory approvals, and the negotiation of a definitive Sale and Purchase Agreement between the two companies.

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.*

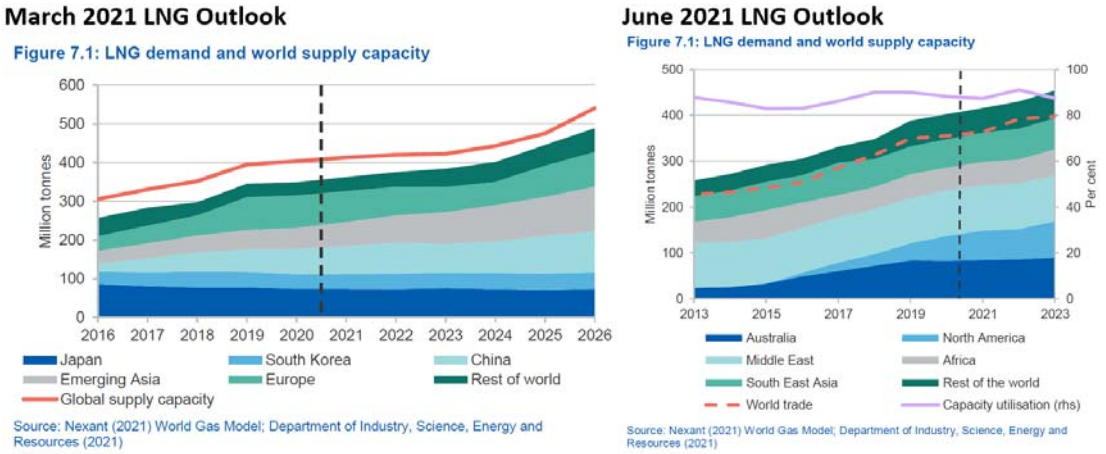
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

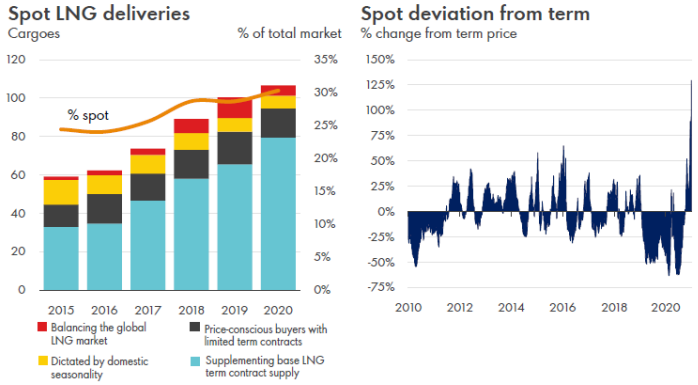


Source: Australia Resources and Energy Quarterly

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.convenience.org/Topics/Fuels/Changing-Seasons-Changing-Gas-Prices

Seasonal Gas Prices Explained

From refinery maintenance to consumer demand, seasonal fuel production affects gasolines prices at the dispenser.

February 28, 2024 3 min read

Traditionally, gasoline prices are at their lowest during the first week of February and then begin to climb, often peaking right before Memorial Day. Seasonal increases in demand plus a transition to unique fuel blends put pressure on gas prices each spring.

Since 2000, gasoline prices have increased about 50 cents from the seasonal low at the beginning of February to the seasonal high in mid-May. Here's a timeline of events that can affect gas prices during the first half of the year.

February: Refinery Maintenance

U.S. demand for gasoline is generally at its lowest during the first two months of the year, so refinery maintenance, known as a "turnaround," is often scheduled during the first quarter. A turnaround is a planned, periodic shut down (total or partial) of a refinery process unit or plant to perform maintenance, overhaul and repair operations and to inspect, test and replace materials and equipment.

Refineries undergo turnarounds roughly once every four year so about 25% of refineries undergo a turnaround each spring. Another reason for scheduling turnarounds is that they allow refineries to retool for summer-blend fuels.

March-April: Refineries Switch to Summer-Blend Production

The U.S. Environmental Protection Agency (EPA) defines April to June as the "transition season" for fuel production. Refineries lead this transition and switch over to summer-blend production in March and April.

Gasoline blends used in the summer months are different than the blends used in the winter. In the winter, fuels have a higher Reid vapor pressure, meaning they evaporate more easily and allow cars to start in colder weather. In the warm summer months, these evaporative attributes would lead to increased emissions and the formation of smog.

There are also more fuels to produce during the transition season. In the winter months, only a few fuels are used across the United States. However, because of various state or regional requirements, 14 different fuel specifications are required for the summer months. Refineries must produce enough fuel for each area to ensure there are no supply shortages, and that can complicate the production and distribution of fuels.

Summer-blend fuel is also more expensive to make than winter-blend fuel. First, the production process takes longer and, second, the overall yield of gasoline per barrel of oil is lower. These complexities add as much as 15 cents per gallon to the cost to produce these higher-grade fuels.

May-June: Deadlines for Terminals and Retailers

The May 1 compliance deadline for terminals to fully purge their systems of winter-blend fuels is considered one of the biggest factors in seasonal price increases. This regulatory requirement can lead to lower inventories at the terminal, which also puts upward pressure on gas prices. It can also take fuels refined in the Gulf Coast several weeks to reach storage terminals throughout the country, which is why it's important to have summer-blend fuel at terminals and storage facilities by May 1. This date is the most important reason that seasonal gas prices tend to peak in May.

In most areas of the country that require summer-blend fuels, retailers have until June 1 to switch to summer-grade gas.

February-August: Summer Drive Season and Increased Demand

Demand can play a role in elevating seasonal gas prices. Gas demand increases a few percentage points each month beginning in February and peaks in August. Total fuel demand is 10% to 15% greater in August than in February, and any stress to the system—such as a refinery or pipeline outage—can cause a supply/demand imbalance and affect prices.

September: A Welcome Change

As gasoline demand decreases and temperatures cool, retailers are able to switch to selling winter-blend fuel beginning September 15. While these winter-blend fuels are cheaper to produce, the complications of the switchover can result in a temporary bump in price. Weather conditions, such as hurricanes, can also affect gas prices in the late summer to fall months.

Unlike in the spring, the change to winter-blend fuel is not required. However, because winter-blend fuel costs less, retailers often sell the fuel blend to remain price competitive. Not all retailers begin selling this fuel on September 15; many make the switch when their inventories are low.

By the end of September, gas prices generally decrease as the switchover processes and demand continues to fall. And despite conspiracy theories, lower gas prices do not correlate to pre-election politics.

In California, the season for summer-blend fuels is longer than the rest of the country. Both Northern and Southern California's summer-blend requirements run through the end of October. This exacerbated supply issues within the state in early October 2012, when fires at two large refineries limited state-specific production and caused wholesale and retail gas prices to spike to record levels.

Meanwhile, demand for distillate fuel (diesel fuel and home heating oil) begins to increase in September because of both greater diesel fuel demand related to the harvest and greater home heating oil demand because of the colder weather.

Exceptions to the Rule

Summer-blend fuel requirements may be relaxed in times of emergencies or when potential shortages are possible.

In 2005, NACS worked with Congress to give the EPA the authority to waive certain regulations affecting the motor fuels system in times of emergency. The EPA's immediate use of these waivers is critical to bringing the entire fuel supply chain into operation as quickly and safely as possible. For example, this flexibility allowed winter blends of gasoline to enter into the market in 2017 before the traditional transition date of September 15 in response to Hurricanes Harvey, Irma and Maria.

Trudeau's Mega Oil Pipeline Startup Hangs on Final 1.6-Mile Leg

2024-03-20 18:25:14.279 GMT

By Lucia Kassai and Devika Krishna Kumar

(Bloomberg) -- The startup date for Canada's mega oil pipeline should be known within weeks as Trans Mountain drills through hard rock in British Columbia's rugged Fraser Valley for the final stretch of the 715-mile conduit.

"The next few weeks will be very important in terms of being able to enter service in the second quarter," Trans Mountain's Chief Financial and Strategy Officer Mark Maki said in a interview during the CERAWeek by S&P Global conference on Wednesday. "We are feeling better and better every day about the startup."

The last 1.6-mile (2.5-kilometer) segment is being enlarged to make space for pipe with a diameter of about 2 1/2 feet. After construction and testing, the entire line will be flooded with crude oil for the first time, a crucial step in commencing service.

Partial filling has been taking place at each of the segments since last summer and roughly 2.1 million barrels will be pumped into the line once construction is complete.

Maki didn't have a firm date on when in the second quarter the line would commence service, despite news reports citing Alberta Premier Danielle Smith saying it would happen in May.

The expansion of Trans Mountain, first devised 12 ago, is a pet project of Prime Minister Justin Trudeau, whose government bought the project from Kinder Morgan Inc. in 2018. Delays have been so chronic that Trans Mountain has been providing nearly daily updates to crude shippers planning to use the conduit.

Costs have surged six-fold to almost C$34 billion ($25 billion). Maki warned the final pricetag may vary from that estimate depending on how construction of the final stretch goes. He expects the line to be at full capacity in 2025.

Read More: China's Sinochem Buys First Oil Cargo From Canadian Pipeline

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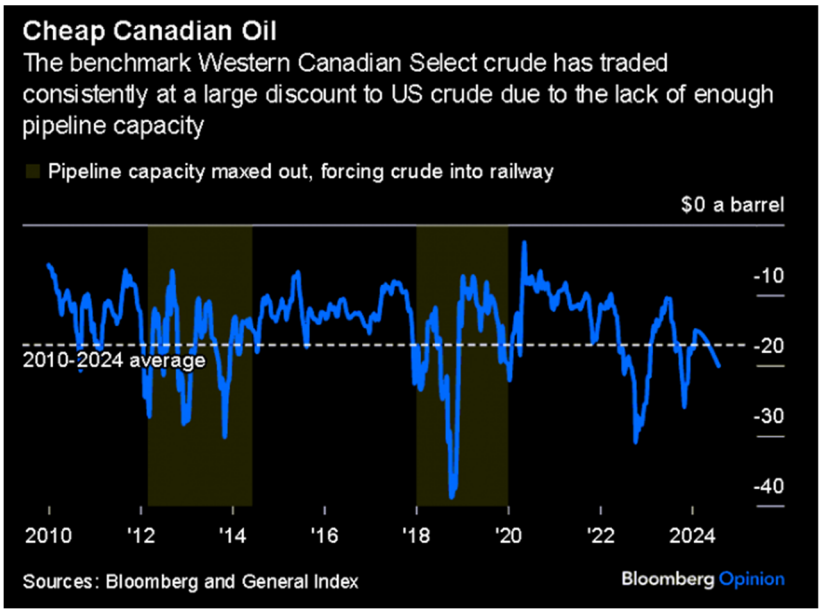
A $10 Billion Mistake That Will Revive Canadian Oil: Javier Blas
2024-02-12 06:54:09.361 GMT

By Javier Blas
(Bloomberg Opinion) -- For the last decade, the Canadian oil industry has experienced firsthand the meaning of "with friends like these, who needs enemies." To its south is an obvious export route and a huge client: the US. But American courts and politicians blocked new oil pipelines, strangling the industry to the north.
The bottleneck has cost Canadian oil companies billions of dollars in forgone revenue, delaying the industry's growth. With existing pipelines full, any extra barrels have had to move via costly railway, depressing their value. At the worst point in late 2018, Canadian crude sold at a discount of $50 a barrelless than American petroleum.



After years in the wilderness, the Canadian oil sector has now solution. It's an expensive one, however. At a cost of C$35 billion ($26 billion), the government, rather than the private sector, has built a pipeline linking the oilfields in Alberta with a port near Vancouver on the Pacific coast. The pipeline is nearly finished. If all goes as planned, the first barrels could be moving before June. With it, the discount of Canadian oil should narrow.
The novelty of the pipeline is that it will be the first significant outlet for Canada to export its oil beyond its southern neighbor. Reaching the Pacific, Canadian oil would be able to flow via tanker to the growing energy markets of Asia, including China.
When in 2018 Canadian Prime Minister Justin Trudeau nationalized the project, his government labelled it a "sound financial opportunity." The plan was for the state to build the new pipeline, called Trans Mountain Expansion (TMX), and then sell it back to private investors, hopefully making a buck. Seen

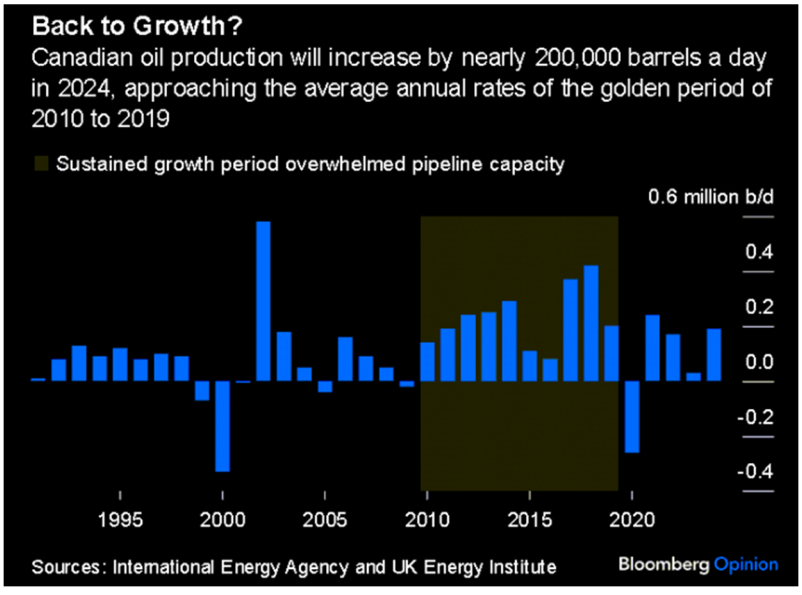
it through that prism, the pipeline has been a colossal taxpayer-funded mistake.

Marred by cost overruns, TMX is worth a fraction of what the government has spent building it. Speak to anyone in the sector, and the estimates of its value vary between C$10 billion and C$25 billion. Take the middle point, put in American dollars, and that's roughly a $10 billion bonfire — equivalent to about $250 per Canadian. From the seemingly tree-hugging prime minister, that's a quite a government handout to the petroleum industry.

Despite its colossal cost, TMX had two advantages that may compensate for the financial folly. One is that it's likely to narrow the differential between Canadian and US crude, leading to higher revenue for everyone involved in the petroleum industry — and that includes provincial governments which take royalties. How much the discount would narrow is hotly debated. On average, it has averaged minus $17 a barrel between 2010 and 2024. The consensus is, that's going to trend now toward minus $10 a barrel. Crucially, TMX probably means that the differential will no longer suffer from its perennial blowouts, when it has widened to as much as minus $40 and even minus $50 a barrel. Second, it should facilitate investment in new production, leading to higher tax revenue.

This matters: Although often overlooked, Canada is the world's fourth-largest oil producer, pumping more than any member of the OPEC+ cartel barring Saudi Arabia and Russia. Despite all the obstacles, Canadian companies have nearly doubled their production over the last two decades. More oil is now under way.

After last year's stagnation, Canadian oil production is set to increase in 2024 by nearly 200,000 barrels a day, matching the average annual growth of its heyday between 2010 and 2015. If the increase is achieved, Canadian petroleum output will reach this year an annual average of six million barrels a day — a record high.



The 2024 growth rate is, in part, a mirage. Heavy maintenance and wildfires depressed output last year, so the increase is a mix of both actual growth and a one-off recovery. Still, it indicates that when new pipeline capacity emerges, Canadian oil producers have quick options to boost output. Rather than invest in new mega-projects, companies are expanding their current operations into nearby areas, a faster and cheaper way of growing.

Put all the extra US and Canadian oil together, and the two North American allies will pump one-in-four barrels worldwide in 2024. Let me emphasize this: A quarter of the world's oil will come from Canada and the US this year. Think about the magnitude of that market share, and now think about the climate-change policies — and politics — of both Trudeau and US President Joe Biden. The gap between what both have campaigned on — green investment and energy transition — and the reality on the ground is large.

The extra 200,000 barrels a day of Canadian oil in 2024 is equal to about 15% of the incremental demand for oil expected this year. As such, it's an important cog of the global supply-and-demand balance. The more Canada grows, the less room there is for Saudi Arabia and its OPEC+ allies.

The growth in Canadian oil production may not last long — rather than decades, think about years. The TMX is adding about 600,000 barrels a day of transportation capacity. Part of it will be filled up with oil that today flows into the US via railway. Growth in 2024 and and in the following two years will fill another bit. By 2025 or 2026, many in the industry believe there will be little pipeline capacity left. The problem? As Rory Johnston, a Toronto-based commodity analyst puts it, "the pipeline of pipelines is empty."

TMX will likely be the last of the big Canadian oil pipelines. Once full, any extra Canadian crude would have to find its way to the market via railway. Over the next two to three years, the oil market will witness the last big increase in Canadian petroleum production. Still, after years of pain, 2024 should be celebrated in the Albertan oilfields as a bumper growth year. A last hurrah, perhaps.

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The Trans Mountain pipeline consist of two conduits. The smaller one, in operation since 1953, has a capacity of 300,000 barrels a day. The new, and largely parallel, pipeline expansion would add an extra 590,000 barrels a day. The 1,150-kilometer pipeline links Strathcona County, near Edmonton, in the province of Alberta, with Burnaby, near Vancouver, in the province of British Columbia.

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NORWEGIAN OFFSHORE DIRECTORATE

https://www.sodir.no/en/whats-new/news/general-news/2024/high-price-to-pay-for-halting-exploration-for-oil-and-gas/

High price to pay for halting exploration for oil and gas

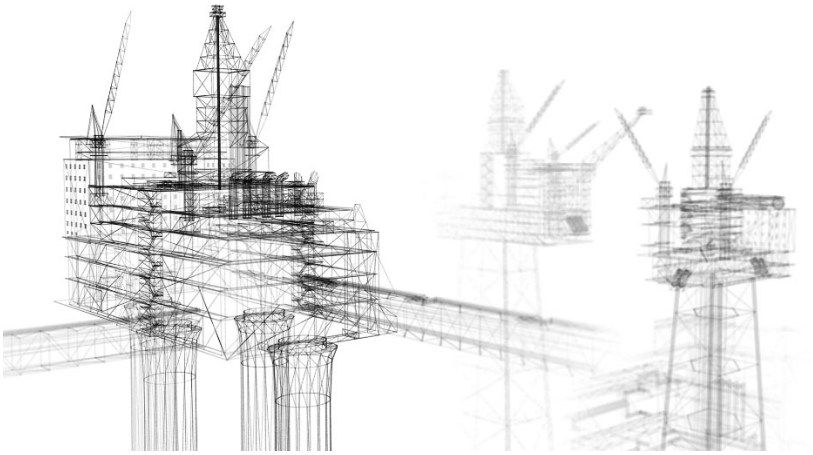


Illustration of a production facility on the Norwegian Continental Shelf.

11/03/2024 Stopping exploration activity on the Norwegian shelf will accelerate the scale-down of the oil and gas industry.

The Climate Change Committee's report was broadly covered when it was published last autumn. The deadline for comments regarding the report has now expired, and the Norwegian Offshore Directorate has submitted a comprehensive consultation response in which we point out significant deficiencies in this report. In light of this, Torgeir Stordal, Director General of the Norwegian Offshore Directorate, wrote this article, which was first published on altinget.no on 11 March.

This will be very harmful for the Norwegian economy and will complicate Europe's situation. Is that truly what we want?

Among other things, the Committee has proposed the development of a strategy for the tail-end phase of Norwegian petroleum activities. Until this strategy is in place, the Committee recommends not awarding new licences for exploration, production or installation and operation.

The Norwegian Offshore Directorate just submitted its input on the report. We believe that the Committee's proposals will have a substantial socio-economic impact if they are adopted. The purpose of a tail-end phase strategy is to discontinue profitable activity faster than what would otherwise have been the case.

The Committee has not addressed the major consequences this will have for value creation, employment around the country and state revenues. It could also weaken the EU's security of supply.

A temporary hiatus will immediately result in reduced exploration activity on the Norwegian shelf, and will weaken the basis for new discoveries that can be developed. Time-critical and profitable oil and gas resources could be lost and existing infrastructure will be shut down earlier than planned.

The 2050 Climate Change Committee has bolstered its mandate and is advocating for an amendment to the Climate Act when it proposes to cut emissions from Norwegian territory by 90-95 per cent by 2050 compared with 1990. This means disregarding the possibility of purchasing emission credits - which are among the most

effective ways to attempt to reach climate targets. The cost of domestic cuts can be much higher than equivalent cuts in the EU.

163,000 jobs in play

Exploration activity on the Norwegian shelf has provided substantial values to society over the last 20 years. Overall net revenues are estimated at more than NOK 3000 billion.

163,000 people were directly or indirectly employed by the petroleum industry in 2020, which means about 6 per cent of total employment in Norway. The industry creates jobs throughout the country and helps maintain less centralised population patterns.

Production is declining on its own

The Committee presumes that activity in the oil and gas industry on the Norwegian shelf is too high leading up to 2050, which means that measures must be implemented to cut production.

On the other hand, the Norwegian Offshore Directorate expects activity in the industry to naturally decline following a production peak in 2025. The production decline towards 2050 is within what the Intergovernmental Panel on Climate Change and the IEA have projected is in line with successfully following up the Paris Agreement.

Despite the decline in activity, the Norwegian Offshore Directorate expects the industry to continue creating significant values leading up to 2050. The net cash flow in 2030-2050 is expected to amount to 4.5 thousand billion 2024-NOK. While the estimate is uncertain, the State's revenues in the form of taxes and ownership will account for close to 90 per cent of this.

Significant values could be lost

The Committee does not want to build new infrastructure that commits us to emissions toward 2050 and beyond. This means that no new export capacity will be built in the Barents Sea. If so, society will be losing out on substantial values.

The Norwegian Offshore Directorate projects that there are significant resources left to discover in the Barents Sea, but the LNG plant on Melkøya has no available export capacity beyond the gas from Snøhvit. This lack of capacity affects the companies' interest in exploration. Gas discoveries are of little value if the gas cannot be transported to the market. Without increased capacity, all other gas resources in the Barents Sea will remain stranded for a long time, which means that society can lose out on substantial values. At the same time, the energy situation in Europe indicates that there will be a need for gas for a long time to come.

Security for Europe

The energy crisis following Russia's invasion of Ukraine demonstrates the importance of stable gas deliveries from Norway to Europe. In 2022, Norway increased its gas exports by about 100 TWh of energy, the equivalent of about 65 per cent of all Norwegian power generation that year. Without Norwegian gas, it would have been more difficult to cover Europe’s demand for gas, and the price of energy would have been higher for all Europeans. Norway can be a safe and stable supplier to Europe for many years to come, but security of supply and geopolitics are crucial considerations that the 2050 Climate Change Committee does not appear to emphasise in its assessments.

The Norwegian Offshore Directorate would like to see calculations of the cost of these proposed measures for the petroleum industry for the broader society. As no such calculations have been made, the Committee's recommendations are deficient and misleading, given that socio-economically profitable measures are being replaced by more costly measures.

Updated: 11/03/2024

opened their arbitrage, that's been closed for quite a while. So that's, of course, a positive indicator for the crude differential.

And then your question on Valhall and the impairment case. Valhall is not impaired in this quarter. And I don't think there are any changes to the 2C reserves or resources on Valhall in this quarter either.

A - David Tonne {BIO 20925193 <GO>}

I can qualify that. So there's impairment of technical goodwill on Valhall this quarter, together with Edvard Grieg and Ivar Aasen, which is, of course, is a bit specific. But it's not impairment of resources. So this is, of course, driven, as you know, and most of you on the line know, by previous acquisitions and the way that we have to account for the differences in accounting and tax. So, that's to be expected over time, specifically in quarters, when the forward curve for oil and gas prices drops. And as you are producing out, call it volumes in the asset.

Q - Yoann Charenton {BIO 17372477 <GO>}

Thank you. Have a nice day, then.

A - Karl Johnny Hersvik {BIO 18337255 <GO>}

Thank you. Let's move on, Kjetil.

A - Kjetil Bakken {BIO 20629786 <GO>}

Yes, absolutely. It's from John Olaisen from ABG. Please, John, go ahead.

Q - John Olaisen {BIO 4949660 <GO>}

Yeah, thank you for taking my question. And good morning, everybody. I can see from fax [ph] pages from the Norwegian offshore directorate that the water production is increasing significantly at the Johan Sverdrup field. So I just wonder if the watering production is higher than expected? And also I had hoped for plateau to be taken -- coming off the plateau would be taking place a little bit later than 2024. But if you could elaborate a little bit about that, do you have sufficient water handling capacity on the top sides, et cetera? And is there anything you could do to handle the water -- increase the water handling capacity and thereby extend plateau? And also maybe if you could elaborate a little bit of what kind of depletion rates we should expect from Johan Sverdrup once it goes off the plateau. And what can be done to fight that apart from, of course, a Phase 3? Thank you.

A - Karl Johnny Hersvik {BIO 18337255 <GO>}

Good. Excellent question. Yes, you are right. We are seeing water in some wells in Johan Sverdrup. The behavior is really related to well by well coning and not -- it's not an overall well. It's not an overall field water-cut development. It's a well issue. We are, in the course of 2024, putting another eight wells on stream on Johan Sverdrup, which will limit the issue as it's directly correlated and linked to well rates.

And of course, the total field rails are capped to the water handling and oil handling capacity. Oil handling, of course, standing at 755,000 barrels of oil equivalents.

So I think the main issue here is to get more wells on stream and therefore more or less production per well. And then, of course, the water handling capacity is at the moment significant and quite in line with what we expected and sufficient for treating the water. And then, of course, the last issue will be mass balance in the reservoir, and we're just doing a turnaround to change out the water injection pump, which are now basically done I think, to make sure that there is sufficient capacity. So those are the three main initiatives that is ongoing in 2024 to extend the plateau. And then, of course, the next line of things will be new wells. And this is as with all oil and gas fields, as you reach the end of the plateau, the way to extend the plateau is to increase capacity, particularly water treatment capacity and gas treatment capacity, and add IOR wells. I mean, this is bread and butter for the oil and gas industry. This is what we do in all fields.

Q - John Olaisen {BIO 4949660 <GO>}

And then on depletion rates once it goes off plateau, please?

A - Karl Johnny Hersvik {BIO 18337255 <GO>}

Yeah. That's -- I don't think I'll guide on that John, at this point in time. And the reason is that, yeah, of course, from a technical perspective, you will see the largest depletion rates, relatively speaking, in the first few months after you go off battle. But they will depend on water volume, on the increase in water volume, well stock, et cetera, et cetera. So that's a pretty difficult assessment to make at this point in time.

Q - John Olaisen {BIO 4949660 <GO>}

But the potential plateau in the second half of 2024, is that what you had expected and what you already have in your charts showing the expected production profile for (inaudible) in the years to come, or is it a little bit earlier?

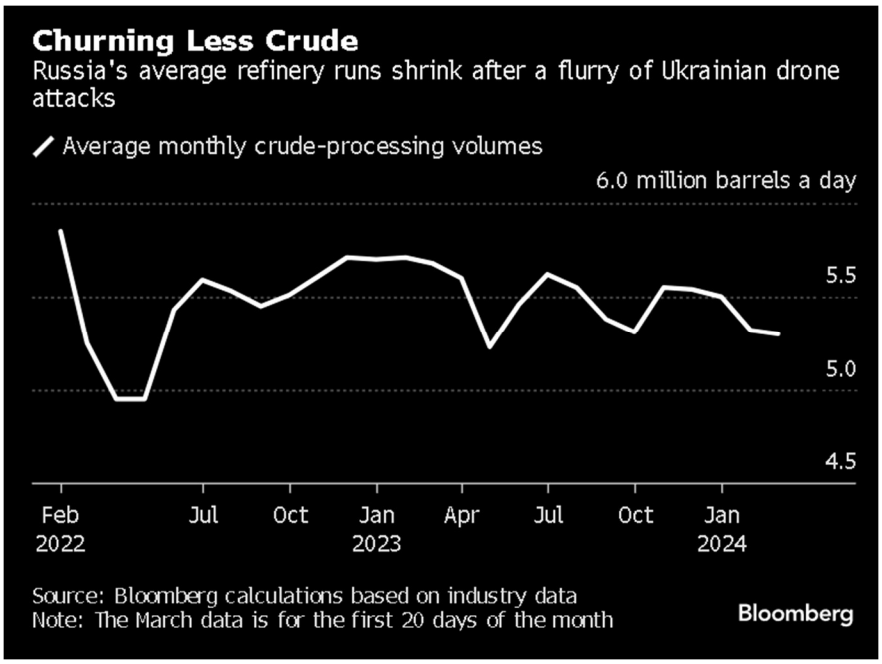
A - Karl Johnny Hersvik {BIO 18337255 <GO>}

So I would say that this -- as you know, we increased the plateau level quite significantly above nameplate capacity in 2023. And it's been producing extremely well at this level, with nearly 100% uptime, low cost, highly energy efficient. One year ago, I would say we expected it to continue that well into 2025. And the operator has now basically said that they assume that this level can be sustained. It's probably a good word until late 2024 or early 2025.

And it's the uncertainty and that timing that is basically incorporated into the guidance of 2024. And of course, that means that maybe starting another -- but that means that when we assessed this earlier, we had an assumption that it'll carry well into 2025. That, of course, means that the guidance for 2024 is a bit lower than we assumed a year ago, but it also means that in the next couple of years, we'll be impacted by this, call it, a little bit more conservative phasing of production. But it's important to note that there are no reserve changes. This is essentially a phasing of production related to the production strategy at the field.

Russia Crude Refining Drops to 10-Month Low on Drone Strikes (1)
2024-03-22 14:24:33.17 GMT

By Bloomberg News
(Bloomberg) -- Russia's average daily oil refining rate fell to the lowest weekly level in ten months after a flurry of Ukrainian drone attacks hit several major facilities.
Refiners processed 5.03 million barrels a day of crude from March 14 to 20, according to a person with knowledge of industry data. That's down more than 400,000 barrels a day from the average for the first 13 days of the month, according to Bloomberg calculations based on historical data.
With Russia's invasion of Ukraine in its third year, Kyiv is using drones to target its enemy's key industry. The government has defended the strategy, saying it's seeking to curb fuel supplies to the front line and cut the flow of petrodollars into Kremlin coffers, but US officials are reported to have warned their ally that the attacks risk driving up the global oil price.



Drones this year have targeted 13 major refineries and two smaller plants, taking offline between 480,000 and 900,000 barrels a day of processing capacity, according to a Bloomberg survey. The actual reduction in total crude-processing is smaller because undamaged plants have increased their throughput to ensure sufficient production of motor fuels.
The nation's crude-processing from March 1-20, including a period before the latest attacks, averaged nearly 5.3 million barrels per day, close to levels seen at the start of February, the calculations show.
Read More: Russia's Spare Refining Capacity Seen Mitigating Drone Attacks
Rosneft PJSC accounted for over the half of Russia's total drop in refinery runs in the past week after its two major

facilities were attacked earlier in March, according to the person familiar with the data.

Primary crude processing at the Ryazan refinery, which was hit on March 13, collapsed by over 160,000 barrels a day on March 14-20, or some 63% lower than the average in the first 13 days of month, according to the person. Rosneft's Syzran plant, which was attacked over the past weekend, reduced refinery runs by some 62,000 barrels a day in the same period, or some 67%, the person said.

Lukoil PJSC's Norsi refinery — damaged by a drone on March 12 — cut daily crude processing rates by over 91,000 barrels, or 36%.

Almost a quarter, or some 97,000 barrels a day, of the drop in Russia's refinery runs came from Gazprom Neft PJSC's refinery in Moscow, which was not attacked but started planned maintenance earlier this week, the person said.

Rosneft, Lukoil and Gazprom Neft did not immediately respond to Bloomberg requests for comment.

Russia's reduced refining rates may mean that more crude is diverted for export, First Deputy Energy Minister Pavel Sorokin told Russian media earlier this month.

Read More: Ukraine's Drone Strikes on Russian Oil Mark New Phase in War

The most recent attack by Ukrainian drones, on the small Slavyansk refinery in Russia's south, happened last weekend. In the absence of a new wave of strikes, Russia's refinery runs over the next few weeks may fluctuate between 5 million and 5.2 million barrels a day, driven not only by damage caused by the drones but also the start of the planned seasonal maintenance, according to the Bloomberg survey of analysts.

As Russia's authorities focus on supplies to the domestic fuel market, any declines in the nation's oil-processing will result in lower fuel exports.

Preliminary estimates suggest the drone attacks may reduce Russian diesel production by 6% to 8%, with only export flows affected, said Sergei Vakulenko, a scholar at the Carnegie Endowment for International Peace in Berlin, who spent 10 years as an executive at a Russian oil producer. Overseas shipments of diesel and fuel oil could each fall by 120,000 to 150,000 barrels a day, he estimated.

Russia's diesel exports may fall by 70,000 to 100,000 barrels per day, said Sergey Kondratiev, head of the economic department at Moscow-based Institute for Energy and Finance Foundation.

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03/20/2024 05:47:31 [BN] Bloomberg News

Russia's Crude Flows Fall Back as Major Ports Hit by Disruptions

Shipments drop from the largest Baltic and Pacific export terminals

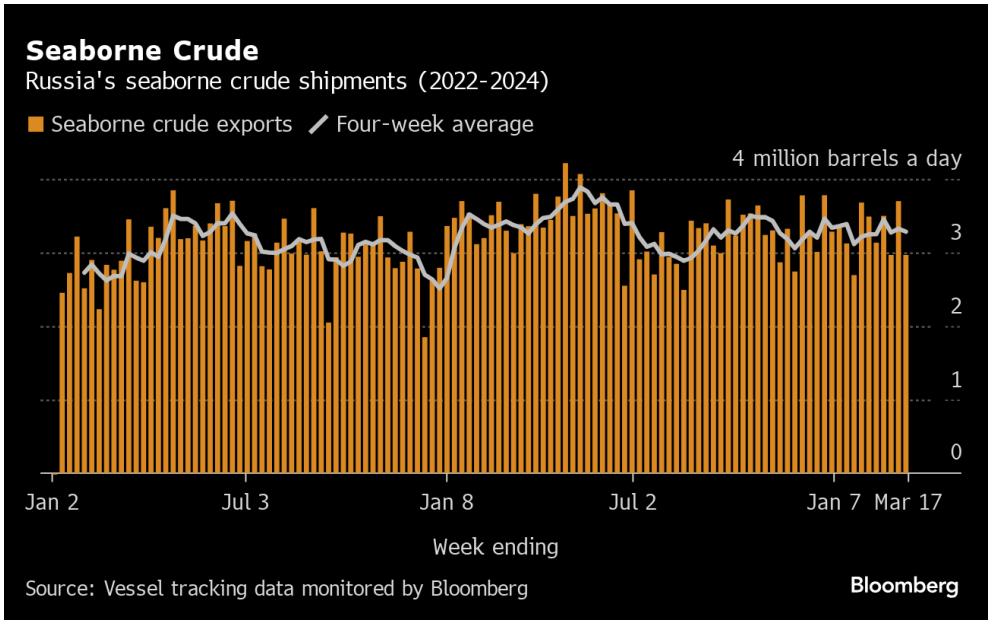
By Julian Lee

(Bloomberg) -- Russia's seaborne crude exports gave up all of the previous week's gains as maintenance work at the Baltic port of Primorsk and strong winds around Kozmino on the Pacific Coast hit shipments from the two most important oil ports.

A three-day gap in the loading program for Primorsk indicates that the work there was planned, but it still cut flows to the lowest since September. To the east, high winds limited loadings from Kozmino again last week, after similar disruption earlier this month. Gusts reached more than 40 miles an hour in the second half of the week.

The maintenance and adverse weather combined to leave weekly crude exports comfortably below the level that Moscow pledged to OPEC+ partners as part of a wider drive to curb output and support prices. Shipments were in line with that target on the more stable four-week measure.

Ukraine's drone attacks on Russian refineries have reduced processing capacity by somewhere around 600,000 barrels a day, according to estimates from Gunvor Group Ltd. That should boost the volume of crude for export, unless oil companies reduce production rates until the plants are repaired.



Separately, sanctions on some tankers hauling Russian crude and several of the companies involved in the trade are having an impact, though so far overall flows have not been reduced on any significant scale.

Russia's state oil tanker company PJSC Sovcomflot said that tougher US measures are putting pressure on its operations, the latest sign that the measures are complicating the delivery of the nation's petroleum.

Two tankers carrying Russian flagship Urals crude have been idling off the west coast of India for more than three weeks without any indication of when they will unload. Both loaded about 700,000 barrels of Urals from Primorsk in January. Indian oil refiners are on track to take the most American crude in almost a year, after tighter enforcement of US sanctions crimped trade with Russia and forced processors to look elsewhere for supply.

Tankers transporting Russian barrels have been doing strange things following a ramp-up in US sanctions. Ships waiting to discharge Sokol crude at Indian refineries turned back in mid-December, with many subsequently diverting to Chinese ports.

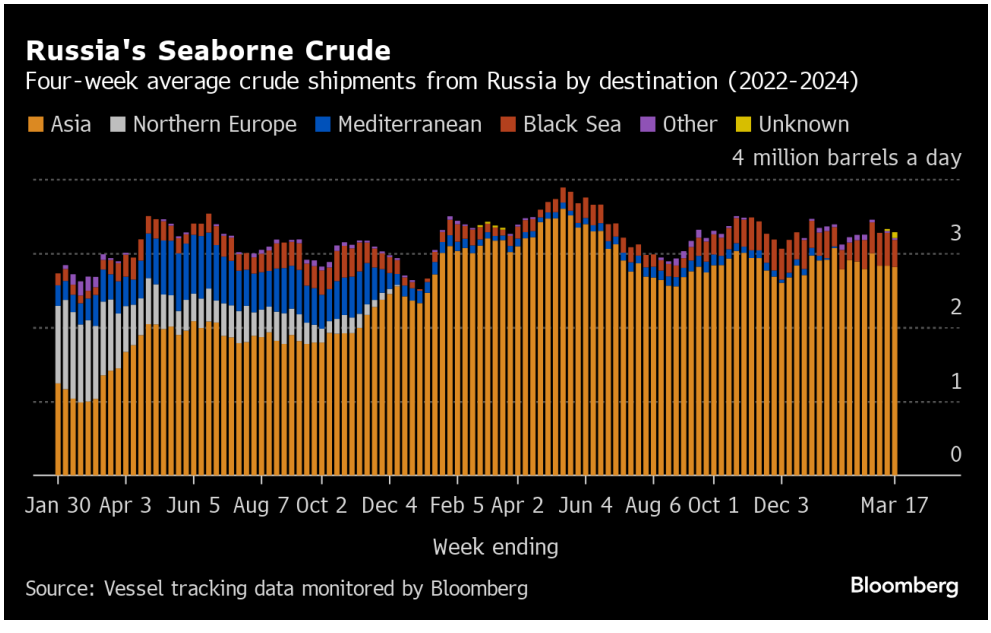
Flows to India of Russia's key Pacific crude grades, ESPO and Sokol, have all but dried up. The last cargo of either grade delivered to the country was loaded in January. At its peak about a year ago, the flow was in excess of 500,000 barrels a day.

The gross value of Russia's crude exports fell back from the previous week's multi-month high, dropping to $1.48 billion in the seven days to March 17 from $1.86 billion the period to March 10.

Flows by Destination

Russia's seaborne crude flows in the week to March 17 fell back by 730,000 barrels a day to 2.97 million. The less volatile four-week average also dropped, slipping by about 40,000 barrels a day to 3.28 million barrels a day.

Weekly shipments were about 620,000 barrels a day below the average seen in May and June, or about 320,000 barrels a day lower than Russia's first quarter target. The four-week average was in line with the target.



All figures exclude cargoes identified as Kazakhstan's KEBCO grade. Those are shipments made by KazTransoil JSC

that transit Russia for export through the Black Sea port of Novorossiysk and the Baltic's Ust–Luga and are not subject to European Union sanctions or a price cap.

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.

- **Asia**

Observed shipments to Russia's Asian customers, including those showing no final destination, edged higher to 2.89 million barrels a day in the four weeks to March 17, up from a revised 2.86 million in the previous four–week period.

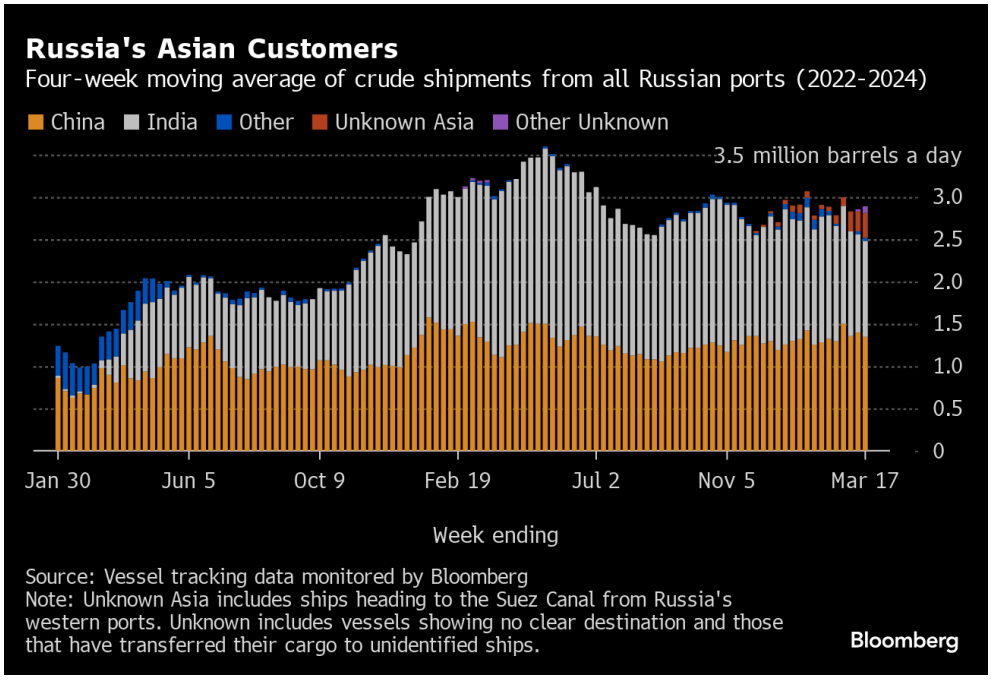
About 1.35 million barrels a day of crude was loaded onto tankers heading to China. The Asian nation's seaborne imports are boosted by about 800,000 barrels a day of crude delivered from Russia by pipeline, either directly, or via Kazakhstan.

Flows on ships signaling destinations in India averaged about 1.13 million barrels a day.

Both the Chinese and Indian figures will rise as the discharge ports become clear for vessels that are not currently showing final destinations.

The equivalent of about 295,000 barrels a day was on vessels signaling Port Said or Suez in Egypt, 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. This figure includes stranded Sokol crude cargoes that are still waiting to discharge after failing to find homes in India since mid–December.

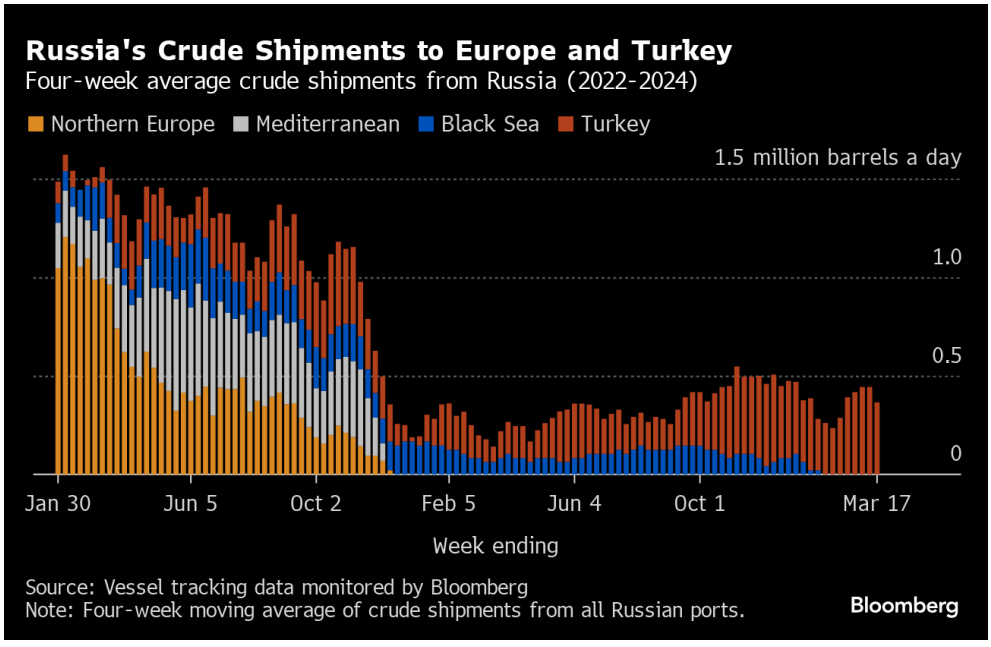
The "Other Unknown" volumes, running at about 80,000 barrels a day in the four weeks to March 17, are those on tankers showing no clear destination. Most of those cargoes originate from Russia's western ports and go on to transit the Suez Canal, but some could end up in Turkey. Others could be moved from one vessel to another, with most such transfers now taking place in the Mediterranean, off the coast of Greece.



Europe and Turkey

Russia's seaborne crude exports to European countries have ceased.

With flows to Bulgaria halted at the end of last year, Turkey is now the only short-haul market for shipments from Russia's western ports.



Exports to Turkey slipped to about 365,000 barrels a day in the four weeks to March 17. That's the lowest in five weeks and down from a revised 443,000 barrels a day in the period to March 10.

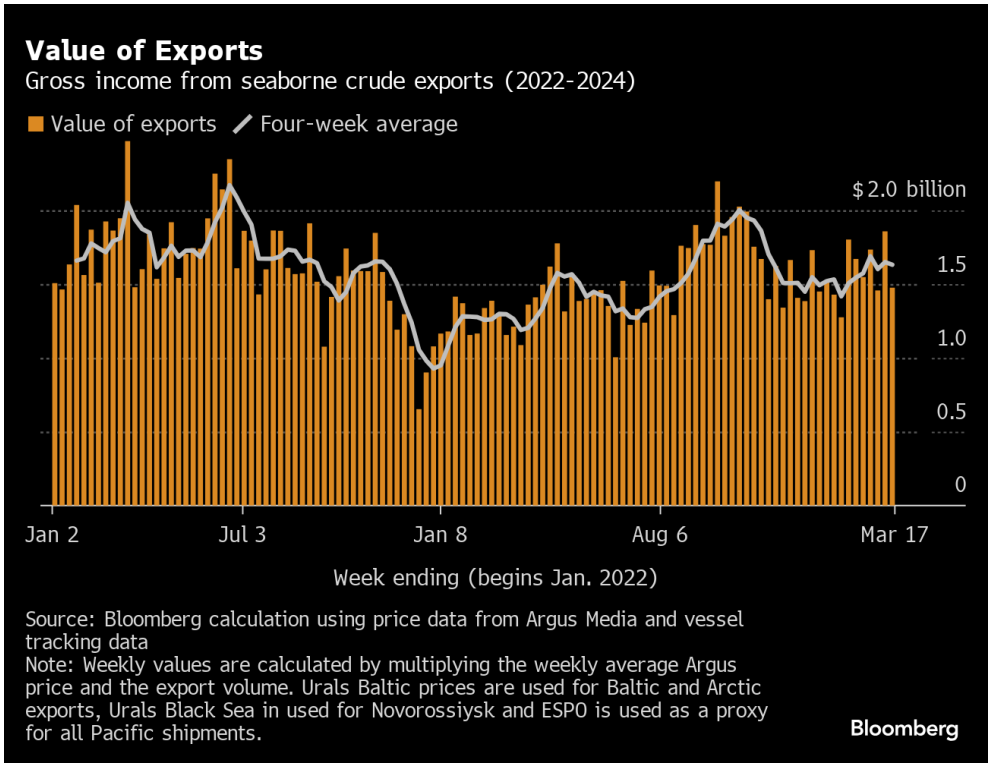
Vessel-tracking data are cross-checked against port agent reports as well as flows and ship movements reported by other information providers including Kpler and Vortexa Ltd.

Export Value

Following the abolition of export duty on Russian crude, we have begun to track the gross value of seaborne crude exports, using Argus Media price data and our own tanker tracking.

The gross value of Russia's crude exports fell back from the previous week's multi-month high, dropping to $1.48 billion in the seven days to March 17 from $1.86 billion in the period to March 10. Four-week average income was also down, falling by about $18 million to $1.63 billion a week. The four-week average is still well off its peak of $2.17 billion a week, reached in the period to June 19, 2022. The highest it reached last year was $2 billion a week in the period to Oct. 22.

During the first four weeks after the Group of Seven nations' price cap on Russian crude exports came into effect in early December 2022, the value of seaborne flows fell to a low of $930 million a week, but soon recovered.



The chart above shows a gross value of Russia's seaborne oil exports on a weekly and four-week average basis. The value is calculated by multiplying the average weekly crude price from Argus Media Group by the weekly export flow from each port. For shipments from the Baltic and Arctic ports we use the Urals FOB Primorsk dated, London close, midpoint price. For shipments from the Black Sea we use the Urals Med Aframax FOB Novorossiysk dated, London

close, midpoint price. For Pacific shipments we use the ESPO blend FOB Kozmino prompt, Singapore close, midpoint price.

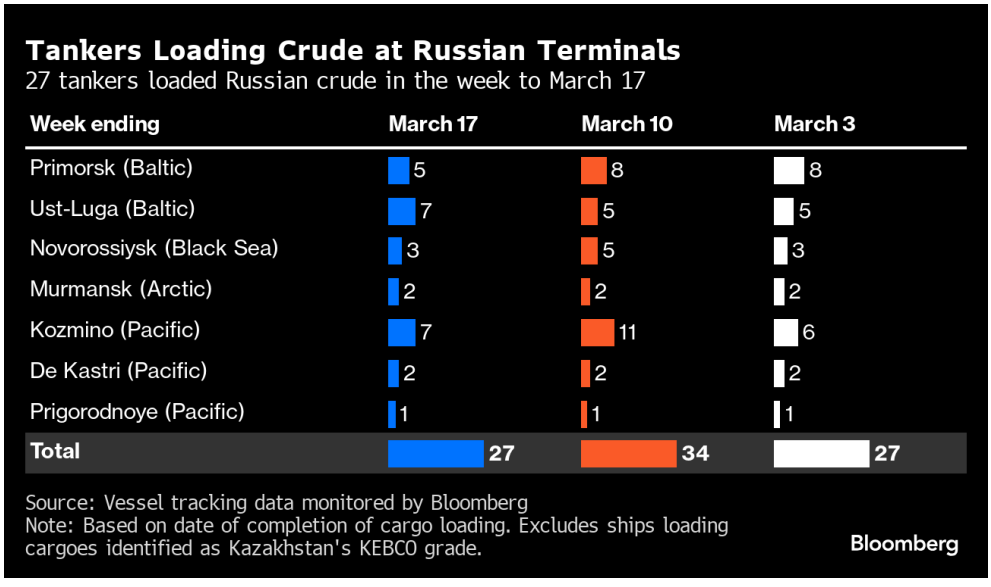
Export duty was abolished at the end of 2023 as part of Russia's long-running tax reform plans.

Ships Leaving Russian Ports

The following table shows the number of ships leaving each export terminal.

A total of 27 tankers loaded 20.8 million barrels of Russian crude in the week to March 17, vessel-tracking data and port agent reports show. That was down by about 5.1 million barrels from the previous week.

Shipments from Russia's Pacific terminal at Kozmino were hampered by high winds, according to data from visualcrossing.com, while a three-day gap in the loading schedule for Primorsk indicates that the port was likely closed for maintenance work.



All figures exclude cargoes identified as Kazakhstan's KEBCO grade. One cargo of KEBCO was loaded at Novorossiysk a during the week.

NOTES

Note: This story forms part of a weekly series tracking shipments of crude from Russian export terminals and the gross value of those flows. Weeks run from Monday to Sunday. The next update will be on Tuesday, March 26.

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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Approx radius map assuming Houthis cruise missile was launched somewhere north of Sana'a

Source: Calcmaps

https://www.timesofisrael.com/in-first-idf-confirms-houthi-cruise-missile-hit-open-area-near-eilat-on-monday/

In first, IDF confirms Houthi cruise missile hit open area near Eilat on Monday

Iran-backed group also claims to target a Marshall-Islands flagged fuel tanker headed for Saudi Arabia as it passed through the Red Sea shipping route

By **EMANUEL FABIAN**, FOLLOW

19 March 2024, 10:46 pm

The Eilat port seen on January 3, 2024. (Yehuda Ben Itach/Flash90)

The Israel Defense Forces confirmed on Tuesday evening that a "suspicious aerial target" that struck an open area near Eilat early Monday morning was a cruise missile.

Yemen's Houthis claimed responsibility for the missile, which crossed into Israeli airspace from the direction of the Red Sea.

No damage or injuries were caused, and according to the IDF, the missile was tracked by the Air Force throughout the incident.

It marks the first time a Houthi projectile hit Israeli territory. In previous attacks, missiles and drones launched from Yemen struck neighboring countries or were intercepted by air defenses.

The IDF said it is further investigating the incident.

Yemen's Houthis also targeted a fuel tanker in the Red Sea with naval missiles, the group's military spokesman Yahya Saree said in a prerecorded statement on Tuesday.

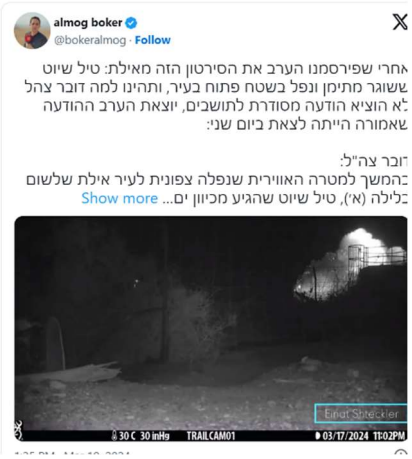
MADO is a Marshall Islands-flagged liquefied petroleum gas tanker heading to Singapore from Saudi Arabia, maritime shipping trackers showed.

The vessel was twice targeted by Houthi fire on March 15 and March 17. Both attacks missed the vessel, causing neither damage nor injuries.

Although the Houthi rebels described the tanker as American, Equasis's shipping database indicates that it is owned by Naftomar Shipping & Trading Co Ltd of Greece. Naftomar did not immediately respond to a request for comment.

Yemen's Houthi rebels began attacking ships in the Gulf of Aden and the Red Sea last November, a campaign they say is intended to signal solidarity with Palestinians in Gaza amid the war between Israel and Hamas, which began with the terror group's devastating October 7 assault on southern Israel.

The Houthi attacks have disrupted global shipping, forcing firms to reroute to longer and more expensive journeys around southern Africa. The cost of insuring a seven-day voyage through the Red Sea has risen by hundreds of thousands of dollars. Beyond economic damage, the attacks have also served to stoke fears that the Israel-Hamas war could spread to destabilize the wider Middle East.



While the group has claimed it only targets vessels owned by or connected to Israel, it has frequently targeted vessels with tenuous or no clear links to the country, imperiling shipping in a key route for trade among Asia, the Middle East and Europe. Those vessels have included at least one with cargo for Iran, the Houthis' main benefactor.

The US and UK began striking Houthi targets in Yemen in January, but despite this, the rebel group remains undeterred and capable of launching significant attacks.

On Monday night, the US military said it destroyed seven missiles and three drones Monday in areas of Yemen controlled by Houthi rebels that presented threats to merchant ships and US Navy vessels.

United States Central Command forces operated "in self defense" when they engaged and destroyed the anti-ship missiles and unmanned aerial vehicles, as well as three weapons storage containers in Houthi-controlled areas, CENTCOM said in a statement posted on X, formerly Twitter.

"It was determined these weapons presented an imminent threat to merchant vessels and US Navy ships in the region. These actions are taken to protect freedom of navigation and make international waters safer and more secure for US Navy and merchant vessels," CENTCOM said.

https://www.saba.ye/en/news3313160.htm

Revolution leader announces preventing ships linked to Zionist enemy from crossing through Indian Ocean

Revolution leader announces preventing ships linked to Zionist enemy from crossing through Indian Ocean

[15/March/2024]

SANA'A 15. March 2024(Saba) - The leader of the revolution, al-Sayeed Abdul-Malik Badr al-Din al-Houthi, announced ships linked to the Israeli enemy would be prevented from crossing through the Indian Ocean in the direction adjacent to South Africa, towards the usurping enemy entity.

Al- Sayeed Abdulmalik Badr al-Din al-Houthi said in a speech this evening about the latest developments, and as long as the aggression, siege and starvation of the Palestinian people in Gaza continues, we firm in our position.

He revealed the serious intention to continue expanding the scope of military operations to areas and locations that the enemy never expected.

Al-Sayeed added, "We are moving, with Allah grace to prevent the crossing of ships linked to the Israeli enemy, even across the Indian Ocean and from South Africa towards the Good Hope Road."

He stated that there is no choice at all for the Americans or the British, except to stop the aggression against Gaza and stop the starvation of the people in Gaza.

Al-Sayeed Abdul-Malik Badr Al-Din Al-Houthi called on the masses of the Yemeni people to demonstrate in millions of people tomorrow, Friday in Al-Sabeen Square in the capital, Sana'a and the rest of the governorates to solidarity with the Palestinian people.

He urged the need for the popular momentum to remain parallel to the level and military position targeting the Israeli enemy, and for there to be continuity in the weekly outing of millions.

The Leader of the Revolution pointed out that the Zionist crimes in the Gaza Strip continue for the 160th day and are genocide in every sense of the word, indicating that the martyrs of Gaza are not just numbers that people hear, but rather are human lives.

He stated that the huge numbers of martyrs and wounded, most of whom children and women, are a disgrace to a world that claims to be civilized and sings of rights.

Al-Sayeed pointed out the severe suffering of the residents of the Gaza Strip as a result of the siege and starvation, and it is interesting to hear statements about the possibility of martyrs falling due to thirst.

Sayeed Abdul-Malik Badr al-Din al-Houthi denounced the failure and negligence of Muslims, especially most Arab countries, which contributes to the crime of the century against the Palestinian people.

He explained that the American increasing its contribution to the continuation of the Israeli crime against the Palestinian people by preventing the cessation of the aggression and insisting on the continuation of the siege.

He stated that the American landing operations do not cover a small percentage of the need, and it aimed at deceiving public opinion.

The leader of the revolution said, "In exchange for the limited aid that the Americans drop from the air in a seditious and dishonorable way, they provide tons of bombs to kill the people of Gaza."

He added, "If Muslims had taken a serious approach to supporting the Palestinian resistance, even with less than what America and the West offering to the enemy, the picture would have been different from battle in Gaza."

Al-Sayeed Abdul-Malik Badr al-Din al-Houthi stated that the Palestinian resistance in the first trench is fighting the battle of the entire nation, wondering, "Why the Islamic countries not moving to support it?"

He pointed out that it become shameful to talk about providing support to the Palestinian resistance, as if it should not be helped to continue the battle against the Zionist enemy, even though America and Western countries not

embarrassed to provide the deadliest weapons to the Israeli enemy.

The leader of the revolution criticized some Arab regimes that not only failed the Palestinian resistance, but also abused it, distorted it, and included it on terrorist lists.

He expressed his regret that some Arab countries criminalize the jihad of resistance fighters in Gaza and prevent donations to them.

Al-Sayeed Abdulmalik Badr al-Din al-Houthi reiterated that the Israeli enemy is a dangerous and bad enemy that poses a danger to humanity and life.

The leader of the revolution stated that the Israeli enemy did not achieve, through its heinous crimes, nor the extent of American support, to break the will of the Palestinian people in Gaza.

He reported that hundreds of thousands of enemies suffering from great psychological trauma, widespread psychological illness, and clear evasion of conscription.

Al-Sayeed Abdul-Malik Badr al-Din al-Houthi surprised by the lack of the official side in the Arab and Islamic world to take a serious practical stance to support the Palestinian people.

He touched on how the enemy soldiers boasted about killing a defenseless and sick elderly man on his bed and proud of it.

Al-Sayeed stressed the need for Muslims to bear the responsibility of confronting enemies as they pose a threat to human society in general and to Muslims before others.

He also asked, "When will the nation stand up and take action? What do you want the situation in the Gaza Strip to reach? Do you want more than these tragic scenes?"

He urged everyone to review themselves and evaluate their positions, indicating that some had not reached the point of boycotting American and Israeli goods and products.

Al-Sayeed Abdul-Malik Badr al-Din al-Houthi considered the shameful position and continued disregard of most Arab and Islamic regimes for the tragedy of the Palestinian people to have consequences and penalties.

He pointed out that Yemeni military operations are continuing with missile bombardment to target ships linked to involved with Israeli enemy.

The leader of the revolution stated that the support operations this week were 12 operations targeting ships and were carried out with 58 ballistic missiles in the Red and Arab seas and the Gulf of Aden.

He explained that the military operations this time reached unprecedented extents, and three operations reached the Indian Ocean, with God’s grace, and the total number of targeted ships reached 73 ships and barges.

He pointed out that last Friday, the million people turned out in 146 squares in various governorates and very huge numbers.

Al-Sayeed pointed out that the American-British aggression on Yemen will not affect the course of military operations in the Red and Arabian Seas.

He stated that American intransigence and escalation of aggression produces one result, which the expansion of the conflict and the cycle of war and events at the regional level in general.

M.M

https://www.maersk.com/news/articles/2023/12/15/maersk-operations-through-red-sea-gulf-of-aden
Advisories

Maersk Operations through Red Sea / Gulf of Aden

Updated 22 March 2024

22 March 2024 – Update 08

Over the recent weeks, European Union security operation Aspides has taken shape and we welcome this as a very positive development to increase the safety in the region and reduce in the future the risk of threat to the vessels passing through the Red Sea and the Bab el Mandeb Strait specifically. We are in continuous dialogue with the representatives of this joint operation and we monitor its development. We hope that it will – together with other initiatives already ongoing (such as Operation Prosperity Guardian), as well as future ones – enable the safe return of regular operations via the Red Sea.

Regretfully, both our internal analysis, as well as insight we received from external sources, still indicates that the risk level in the region remains elevated. We have seen attacks on commercial vessels increase in numbers, including the tragic attack on the vessel True Confidence, which resulted in the death of three crew members, and the sinking of the vessel Rubymar, which is posing a serious environmental risk. These incidents unfortunately highlight the lethal effectiveness of missiles currently used by Houthi attackers and are one of the reasons for the elevated security risk we have in place at the moment.

At Maersk, we are aware that some other shipping lines have continued sailing through the Red Sea despite security risks or have announced their plans to resume sailing. We respect the right of each carrier to make such decisions individually. At the same time, we continue with our own assessment that current situation does not allow us to make a similar decision and with thus still believe that sailing via the Cape of Good Hope and around Africa is the most reasonable solution at the moment and the one that currently allows the best supply chain stability. Network changes are complex and take time to implement and we believe we should only implement such changes when they can be sustained over a longer period of time. We continue to believe it is the only way to avoid further disruption under the current circumstances.

As we have mentioned many times, our utmost priority remains the safety and wellbeing of our crews, the safety of vessels they are sailing on and the safety and integrity of our customers' cargo we are transporting. We would like to thank all our customers who have shown appreciation and the understanding of the decisions we have been taking.

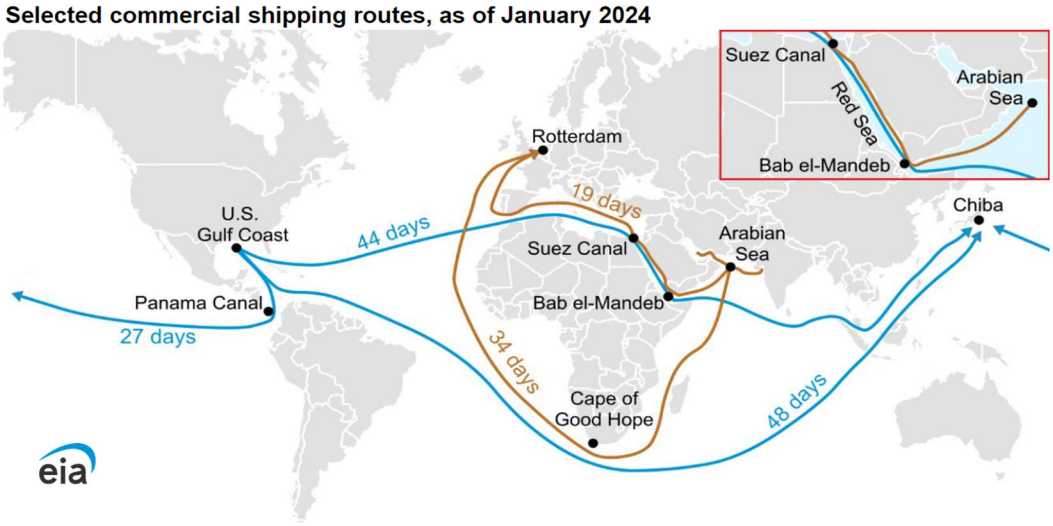
As we navigate through the current uncertainties, we are also gearing up for the future and have announced our new 2025 network, based on modular solutions, allowing greater flexibility and responsiveness to future potential disruptions and improved level of schedule reliability.

We remain hopeful that resuming sailing through the Red Sea will become possible in the near future and we are committed to providing our customers with regular updates on the developments.

https://www.eia.gov/todayinenergy/detail.php?id=61363

FEBRUARY 1, 2024

Red Sea attacks increase shipping times and freight rates



Data source: U.S. Energy Information Administration using calculations from Vortexa
Note: Voyage time is calculated for laden Suezmax tankers traveling at 14 knots without extended chokepoint delays.

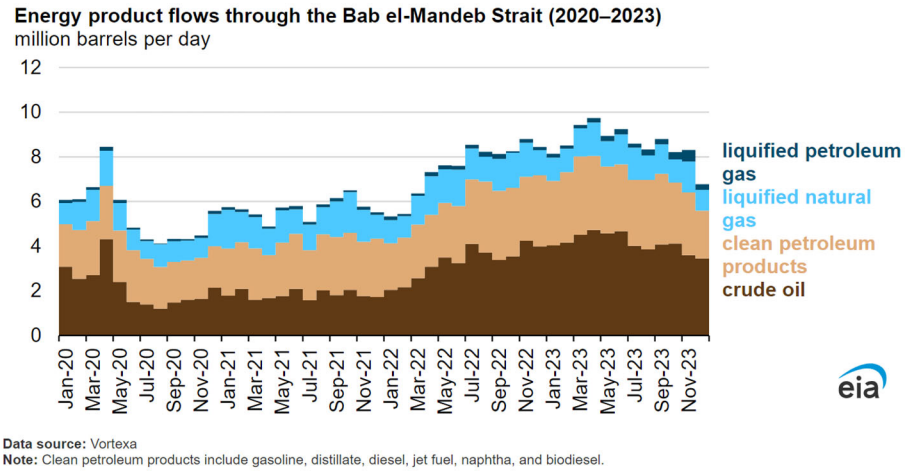
After Yemen-based Houthi militia attacks on commercial ships transiting the Red Sea started in November 2023, some vessels began opting to avoid the Bab el-Mandeb chokepoint—a narrow strait that borders the Yemeni coast and is the southern entrance to the Red Sea. Instead, they're choosing to take longer, more costly routes around the tip of Africa.

Ships transiting between Europe and Asia via the Suez Canal must pass through the Bab el-Mandeb Strait, which connects the Red Sea to the Gulf of Aden. The Bab el-Mandeb Strait is an important oil and natural gas chokepoint, accounting for 12% of seaborne oil trade and 8% of liquefied natural gas (LNG) trade in the first half of 2023. Major oil and natural gas companies that are avoiding the Red Sea include Equinor, which operates mostly natural gas carriers, and bp, which operates both oil and natural gas carriers. As of January 23, 2024, other major energy companies pausing Red Sea transits include Euronav, QatarEnergy, Torm, Shell, and Reliance.

Vessels that do not pass through the Suez Canal via the Bab el-Mandeb Strait and Red Sea can go around southern Africa via the Cape of Good Hope, but that route can add significant time to the voyage, depending on the ship's origin and its destination. A typical voyage from the Persian Gulf to the Amsterdam-Rotterdam-Antwerp petroleum trading hub (ARA) via the Suez Canal takes 19 days. If the ship takes the Cape of Good Hope route, it takes nearly 35 days to reach the ARA. For products leaving the U.S. Gulf Coast and heading toward Asia, vessels typically pass through the Panama Canal, which is nearly a month-long trip. Due to the ongoing drought and restrictions at the Panama Canal, more Very Large Gas Carriers (VLGCs), which primarily carry propane and butane, started going through the Suez Canal. Now some of these VLGCs are going around the Cape of Good Hope. A journey from the U.S. Gulf Coast to Chiba in Japan through the Suez Canal adds about 17 days and one through the Cape of Good Hope adds about 21 days, compared with going through the Panama Canal.

Longer routes put upward pressure on freight rates because of fuel costs and fewer available ships. A VLGC, for example, consumes about $30,000 to $35,000 worth of fuel per day if using high-sulfur bunker fuel at average 2023 prices. In addition to adding to fuel costs, a longer voyage requires more

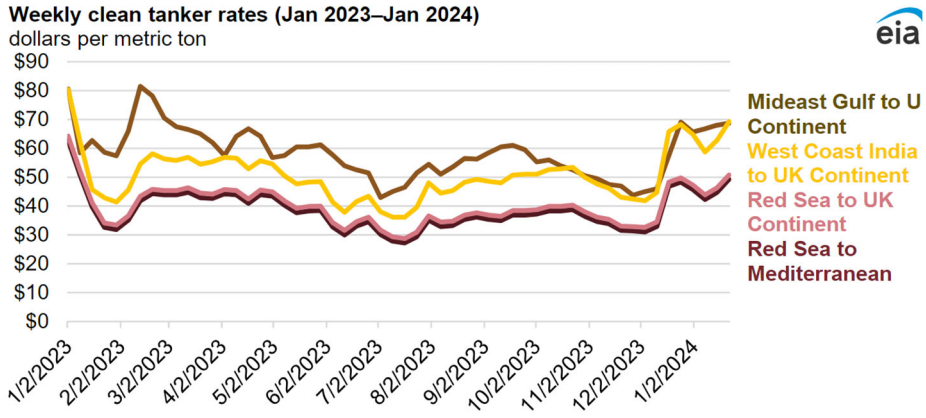
ships to maintain the same delivery schedule, and fewer available ships contribute to higher tanker rates and costs.



Data source: Vortexa
Note: Clean petroleum products include gasoline, distillate, diesel, jet fuel, naphtha, and biodiesel.

After the attacks began in November, flows of oil, refined products, and natural gas passing through the Bab el-Mandeb Strait slowed. About 18% less crude oil flowed through the Bab el-Mandeb in December than on average from January to November 2023. Most crude oil trade that goes through the Bab el-Mandeb Strait leaves Russia and Iraq en route to Asia and the Mediterranean, respectively. Clean petroleum product flows through the Bab el-Mandeb Strait were 30% lower in December than the rest of 2023. The majority of petroleum product trade leaves Saudi Arabia and India bound for Europe and leaves Russia bound for Asia.

In December, 24% less LNG and 1% more liquefied petroleum gas (LPG) were traded globally compared with the rest of 2023. Vessel restrictions at the Panama Canal due to a drought are causing more VLGCs leaving from the United States to head east toward either the Suez Canal or the Cape of Good Hope. LPG flows through the Bab el-Mandeb increased by 59% in 2023 compared with 2022 because water conservation efforts at the Panama Canal began in January 2023, causing delays and higher costs for VLGCs. The Combined Maritime Forces, a partnership representing 39 nations, warned ships to avoid the Bab el-Mandeb Strait on January 12, which will likely reduce passages through January 2024.



Data source: Argus Freight
Note: Rates are for long-range 1 tankers, except the Mideast Gulf to UK Continent rates, which are for medium-range tankers.

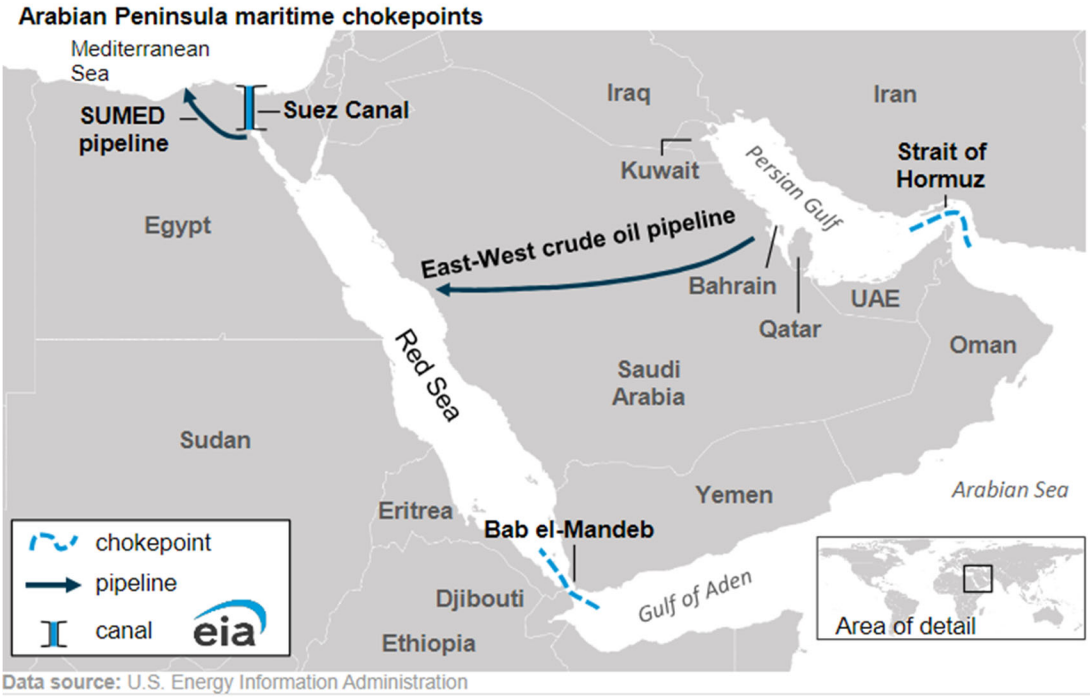
Clean petroleum product tanker rates for routes that cross the Bab el-Mandeb Strait and Suez Canal increased in December 2023 because of the ongoing conflict in the Red Sea. Because routes going through the Red Sea have elevated risk insurance premiums, these costs are passed on to tanker rates. For the four tanker rates that pass through the Red Sea, the average increase was 20% in December compared with November, according to Argus Freight. Long-range 1 tankers traveling from the western coast of India to the UK Continent increased the most (23%), and tankers traveling from the Mideast Gulf to the UK Continent increased the least (16%). Rates for dirty tankers, which mostly transport crude oil, have been relatively unchanged from the elevated prices in November.
Brent crude oil spot prices for the week ending November 17, 2023, the week before attacks on ships in the Red Sea began, were $82 per barrel (b). Since then, prices have traded in range, and they closed at $79/b as of January 18, 2024.

Principal contributor: Josh Eiermann

https://www.eia.gov/todayinenergy/detail.php?id=61025

DECEMBER 4, 2023

Red Sea chokepoints are critical for international oil and natural gas flows



Data source: U.S. Energy Information Administration

The Suez Canal, the SUMED pipeline, and the Bab el-Mandeb Strait are strategic routes for Persian Gulf oil and natural gas shipments to Europe and North America. Total oil shipments via these routes accounted for about 12% of total seaborne-traded oil in the first half of 2023, and liquefied natural gas (LNG) shipments accounted for about 8% of worldwide LNG trade.

The Suez Canal and SUMED pipeline are located in Egypt and connect the Red Sea with the Mediterranean Sea. The SUMED pipeline transports crude oil north through Egypt and has a capacity of 2.5 million barrels per day. The Bab el-Mandeb Strait is between the Horn of Africa and the Middle East, connecting the Red Sea to the Gulf of Aden and Arabian Sea. Most exports of petroleum and natural gas from the Persian Gulf to Europe and North America pass through multiple chokepoints, including the Suez Canal or the SUMED pipeline and both the Bab el-Mandeb and the Strait of Hormuz.

Volume of crude oil, condensate, and petroleum products transported through the Suez Canal, SUMED pipeline, and Bab el-Mandeb Strait (2018–1H23)
million barrels per day

	2018	2019	2020	2021	2022	1H23
Total oil flows through Suez Canal and SUMED pipeline	**6.4**	**6.2**	**5.3**	**5.1**	**7.2**	**9.2**
crude oil and condensate	3.4	3.1	2.6	2.2	3.6	4.9
petroleum products	3.0	3.1	2.6	2.9	3.6	4.3
LNG flows through Suez Canal (billion cubic feet per day)	**3.3**	**4.1**	**3.7**	**4.5**	**4.5**	**4.1**
Total oil flows through Bab el-Mandeb Strait	**6.1**	**5.9**	**5.0**	**4.9**	**7.1**	**8.8**
crude oil and condensate	**3.0**	**2.7**	**2.2**	**1.9**	**3.3**	**4.5**
petroleum products	**3.1**	**3.2**	**2.8**	**3.1**	**3.8**	**4.4**
LNG flows through Bab el-Mandeb Strait (billion cubic feet per day)	**3.1**	**3.9**	**3.7**	**4.5**	**4.5**	**4.1**

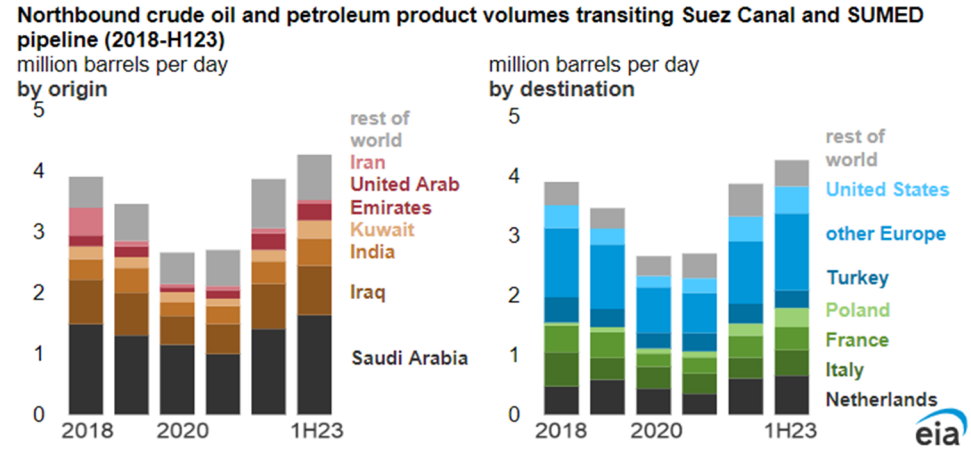
Data source: U.S. Energy Information Administration analysis based on Vortexa tanker tracking
Note: LNG=liquefied natural gas, 1H23=first half of 2023

Oil shipments

Northbound oil flows toward Europe via the Suez Canal and SUMED pipeline fell between 2018 and 2020. Renewed U.S. sanctions on

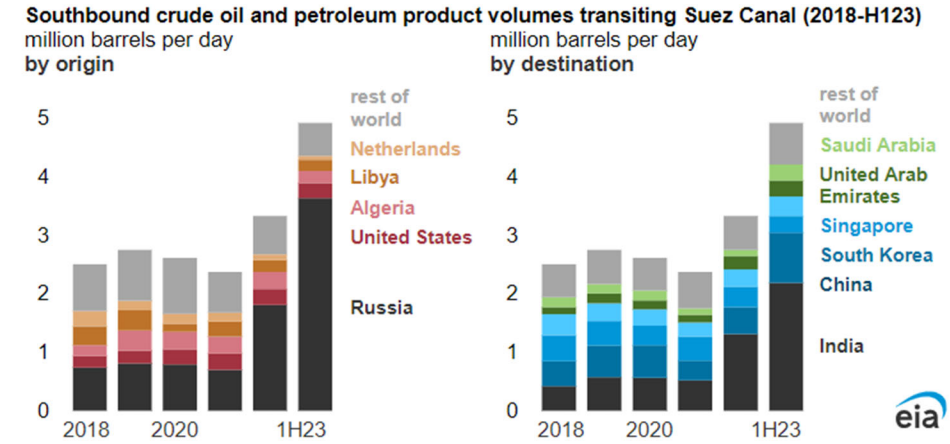
Iran reduced all exports from Iran, including those through the Suez Canal. In addition, less crude oil and oil products from Middle East producers moved through the Suez Canal because Europe imported less oil from the Middle East and more from the United States. The COVID-19 pandemic further reduced flows through the Suez Canal because of slowing global oil demand.

In the first half of 2023, northbound crude oil flowing through the Suez Canal and SUMED pipeline had increased by more than 60% from 2020, as demand in Europe and the United States rose from pandemic-induced lows. Also, Western sanctions on Russia's oil beginning in early 2022 shifted global trade patterns, leading Europe to import more oil from the Middle East via the Suez Canal and SUMED pipeline and less from Russia.



Data source: U.S. Energy Information Administration analysis based on Vortexa tanker tracking
Note: 1H23=first half of 2023.

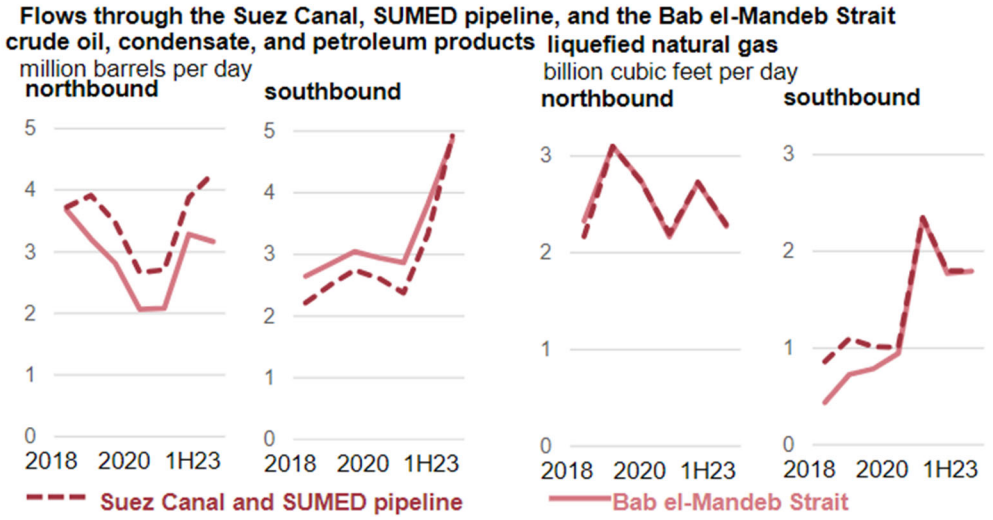
Southbound shipments through the Suez Canal rose significantly between 2021 and 2023, largely because of Western sanctions on Russia's oil exports. Oil exports from Russia accounted for 74% of Suez southbound oil traffic in the first half of 2023, up from 30% in 2021. Most of those export volumes were destined for India and China, which imported mostly crude oil from Russia. The Middle East, primarily Saudi Arabia and the United Arab Emirates, increased imports of refined oil products from Russia in 2022 and the first half of 2023 in order to generate electric power or to store or re-export.



Data source: U.S. Energy Information Administration analysis based on Vortexa tanker tracking

LNG shipments

LNG flows through the Suez Canal in both directions rose to a combined peak in 2021 and 2022 of 4.5 billion cubic feet per day (Bcf/d) before total flows declined in the first half of 2023 to 4.1 Bcf/d. Southbound LNG flows more than doubled from 2020 to 2021, mainly driven by growing exports from the United States and Egypt heading to Asia. In 2022 and the first half of 2023, southbound LNG volumes via the Suez Canal declined as U.S. and Egyptian LNG exports both favored European destinations over Asian markets, supplanting some of the natural gas exports that Russia historically sent to Europe. Most of the variation in northbound volumes reflects changes in Qatar's exports to Europe (via the Suez Canal) compared with Asia. Qatar also sent more LNG to Europe in 2022 to replace some volumes from Russia, increasing northbound flows.



Data source: U.S. Energy Information

Although oil flow trends through the Bab al-Mandeb Strait are similar to those of the Suez Canal, more oil exits the Red Sea (northbound via the Suez Canal and southbound via the Bab el-Mandeb Strait) than enters the Red Sea through these chokepoints. Saudi Arabia transports some crude oil from the Persian Gulf via pipeline to the Red Sea for export mostly to Europe. LNG flows through the Bab el-Mandeb Strait have matched those in the Suez Canal over the last few years because the few LNG import terminals in the Red Sea have been used less.

Principal contributors: Candace Dunn, Justine Barden

China Reports First Crude Imports from Venezuela Since 2019 (1)
2024-03-20 03:38:30.396 GMT

By Bloomberg News
(Bloomberg) -- China imported 352k tons of crude from Venezuela in February, the first shipments since September 2019, according to customs figures released on Wednesday.
* The two importers of the Venezuelan crude are registered in Beijing and Shandong, customs data show
** The total volume is equivalent to more than 2m bbls
* NOTE: China published data for Jan. and Feb.
* Country breakdown for Feb. vs Jan.:
** Russia ~9.1m tons vs 8.62m tons
** Saudi Arabia 6.99m tons vs 6.5m tons
** Iraq 4.98m tons vs 5.16m tons
** Malaysia 4.71m tons vs 4.22m tons
** UAE 3.42m tons vs 2.99m tons
** Brazil 2.58m tons vs 3.36m tons
** Oman 2.68m tons vs 3.82m tons
** Angola 2.49m tons vs ~2.2m tons
** Kuwait 1.92m tons vs 657k tons
** US 757k tons vs 1.02m tons
* No official Iranian imports were reported last two months
* READ: Venezuelan Oil Sanctions Lift May Deal Blow to China Buyers
* READ: Russian Oil Flows to China at Highest Since Ukraine Invasion

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https://www.apikur.uk/publications/facts-and-stats-apikur-marks-1-year-anniversary-of-the-halt-of-oil-exports-through-the-iraq-tuerkiye-pipeline/

23 MAR 2024

Facts and Stats: APIKUR marks 1-year anniversary of the halt of oil exports through the Iraq-Türkiye pipeline

March 23, 2024

Key Points:

- The Iraq-Türkiye pipeline (ITP) has now been closed for one year
- The ITP closure impacts International Oil Companies (IOCs) in the Kurdistan Region of Iraq (KRI), blocking 450,000 barrels per day of crude oil exports
- Continued closure costs the Government of Iraq (GoI), Kurdistan Regional Government (KRG), IOCs, and the people of Iraq billions of dollars

As the 1-year mark for the halt of oil exports through ITP approaches, the Association of the Petroleum Industry of Kurdistan (APIKUR) provides an update on the reported status of the discussions around reopening the ITP, its efforts to restore full production and exports from Kurdistan, and the financial impacts on the Iraqi people and International Oil Companies (IOCs).

On March 25, 2023, oil exports through ITP were halted.

To date, neither APIKUR nor its members have seen any proposal from the GoI or KRG that would lead to a resumption of exports.

All eight APIKUR member companies remain committed to their contracts with the KRG and have been repeatedly assured by the KRG that the KRG, for its part, is fully committed to these contracts as well.

APIKUR continues to seek to engage with all relevant stakeholders to reach an agreement to resume exports via ITP.

“APIKUR remains focused on working with all stakeholders to restore full oil production and exports through the Iraq-Türkiye Pipeline,” said Myles B. Caggins III, spokesman for APIKUR. “Each day the pipeline is closed, losses continue to mount and the people, economy, and investment reputation of Iraq suffers.”

APIKUR’s Assessment:

The GoI has not taken the required actions to reopen the ITP and enable oil exports from the Kurdistan Region of Iraq, despite Türkiye’s announcement in October 2023 that the pipeline is operational and ready to export oil.

APIKUR notes that meetings were held in Baghdad on January 7-9, 2024, between representatives of the GoI, KRG, and IOCs — including representatives of several APIKUR member companies. Despite those meetings and the subsequent press on positive discussions between GoI and KRG, there has been no real progress to reopen the ITP.

APIKUR's efforts to resolve the impasse:

- Holding multiple meetings with the KRG and GoI officials in Baghdad, Erbil, and Dubai
- Consistently and openly communicating APIKUR members' conditions for restoring export production:
    - Any addendums must be agreed between the GoI, KRG, and APIKUR member companies
    - There must be payment surety for past and future oil exports
    - Prospective oil sale payments to APIKUR member companies must be remitted directly to those companies
    - The APIKUR member companies' current commercial terms and economic model must be maintained
- Launching a public awareness campaign across Arabic, Kurdish, and Western media outlets
- Independent of APIKUR, several individual IOCs have proposed solutions to the GoI and KRG

In addition, APIKUR has engaged home governments of member companies—with a particular focus on the United States government (USG)—due to its unique bilateral relationships with the GoI and KRG, including the $300 million direct investment by USG in the Kurdistan Region's energy sector.

APIKUR has conveyed to senior members of President Biden's administration and members of the U.S. Congress that the White House should not proceed with the planned visit of Iraqi Prime Minister Mohammad Shia Al-Sudani, on April 15, 2024, to Washington, DC unless:

- ITP is reopened and allows oil produced in the KRI to be exported to international markets
- IOCs (including APIKUR members) get surety of payment for past and future oil exports
- The GoI fully implements the Iraqi federal budget for the KRG

APIKUR summary of the ongoing impact of the ITP closure:

Financial Impact:

- Estimated revenue loss to Iraq of more than $11 billion, approximately $1 billion each month
- APIKUR understands that while ITP remains unused, Iraq accrues more than $800,000 in daily penalties for failure to meet contractual throughput quotas in the ITP agreement
- Debts of over $1 billion from the KRG to APIKUR member companies for oil produced between September 2022 and March 2023 remain unpaid
- More than $400 million in annual investments paused by APIKUR members
- IOC annual revenues reduced by nearly 60% as local sales have replaced exports to international markets
- Economic strangling of the KRI by GoI through blocking oil exports and non-implementation of budget transfers

Impact on Global Oil and Energy Markets:

- The halt of ITP exports puts pressure on a precariously balanced global energy market currently affected by Russian sanctions and shipping disruptions through the Red Sea

- Iraq continues to receive sanctions waivers to import electricity from Iran, instead of funding its own energy infrastructure through additional oil exports
- Since ITP closed, the U.S. has imported upwards of 250,000 bpd of oil and products from Southern Iraq, while the GoI prevents oil produced by U.S. companies in Kurdistan Region from being exported

Impact on Employment in Iraq's Kurdistan Region:

- APIKUR member companies have laid off hundreds of directly-hired personnel, including both expats and locally-hired staff
- The collapse in IOC investment has caused even greater staff reductions in oilfield-related service and products industries, including lodging and catering, maintenance, security, transportation, and construction companies
- The lack of oil revenue and budget transfers from the GoI to KRG has led to severe delays in payment of civil servant salaries, including teachers and health service workers

Reputational Impact:

- Placing the respect for contract sanctity in question risks a significant downturn in the desire for the global business community to invest in Iraq
- Budget law and oil export impasse has exposed intra-Iraq political rifts

- Ends -

About APIKUR:

APIKUR's objective and purpose is to promote the KRI as an attractive destination for international oil and gas companies, service providers and investors. In addition, APIKUR aims to advocate for and represent the common interests of its members, function as a joint and effective voice towards all relevant stakeholders whether in the KRI, or elsewhere, and provide a forum for its members to share appropriate public industry information and best practices.

For more information, visit www.apikur.uk

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https://libyaobserver.ly/news/pm-urges-transparency-vigilance-over-oil-production-increase-plan

PM urges transparency, vigilance over oil production increase plan

BY SAFAALHARATHY TUE, 19/03/2024 - 13:16

Prime Minister Abdul Hamid Dbeibah has emphasized the importance of monitoring the plan to increase oil production to achieve the target of two million barrels within the established timelines.

Dbeibah's remarks came during a meeting he chaired on Monday, grouping several officials, including the heads of the National Oil Corporation, the Audi Bureau, and the Administrative Control Authority.

To ensure transparency and efficiency, the PM stressed the importance of disclosing all expenses and projects being implemented, and monitoring the companies affiliated with the institution.

For his part, the Chairman of the National Oil Corporation, Farhat Bengdara, confirmed that the production will exceed 1.5 million barrels by the end of 2025 and reach two million within three years. However, he highlighted that ongoing projects require continuous financial flows to achieve the necessary productivity.

Meanwhile, the President of the Audit Bureau, Khalid Shakshak, called for adopting a three-year or five-year budget, considering that sector projects are executed over the years. He also noted that adopting an annual budget would not be practical in terms of monitoring or achievement.

During the session, the head of the Administrative Control Authority, Abdullah Qaderboh, highlighted the need for collaboration between executive and oversight bodies and the Central Bank of Libya to support the NOC in increasing oil and gas production.

According to the "Hakomitna" platform, the meeting also discussed the development of oil discoveries by the Waha Company with foreign partners and reviewed the technical report of the committee tasked with studying the agreement to develop oil and gas discoveries in the Ghadames Basin.

TAGS:

Chorus Call

Cucinelli – March 14th, 2024

Operator:

Good evening and welcome to the presentation of the Brunello Cucinelli fashion house's 2023 results. The speakers will be Brunello Cucinelli, Executive Chairman and Creative Director; Riccardo Stefanelli, CEO; Luca Lisandroni, CEO; Dario Pipitone, CFO; Moreno Ciarapica, senior co-CFO; and Pietro Arnaboldi, Investor relations and corporate planning director.

I would now like to turn the floor over to Brunello Cucinelli. Please.

Cucinelli:

Good evening. I'm really glad because it's been three months since we've heard from you, it's always a great pleasure to speak with you, analysts, investors, some members of the press, so we're pleased.

It's true that we haven't spoken for three months, but many of you came to Pitti in Florence, to Milan, during the men's/women's fashion weeks, so we would like to thank you for coming to these fine events. We are all here in Solomeo.

We would like this call to unfold as follows: we will read out the highlights of the financial statements; then a general report on the major topics for 2023; subsequently, very important, a focus on the trend of the men's/women's autumn/winter 2024 collections; another very relevant subject: the trend of sales in the first quarter, because there are still 15 days to go; then, a broad overview of the markets and how things are going, which is perhaps what interests you most, and it is understandable; then we would like to dwell on what we have defined as "Gentle Luxury" and the great value of exclusivity.

We would then like to give you a pretty visible 2024 turnover forecast, followed by some visibility on 2025 turnover forecast, a brief update on the big projects – eyewear and fragrances; and then, last but not least, our investment in high-quality artisanal production capacity, which should cater for our production planning until 2030 and perhaps even a little beyond.

with a very interesting demand trend in all the main markets.

Let's look at them individually. Asia is performing very well across its geographies, from China to Korea to Japan, very consistently over time. America was excellent, we were very impressed by the huge success of the international events held at the beginning of the year, I'm thinking of the Grammy Awards, the Superbowl, the Academy Awards night, which conveyed some very positive vibes, at least to us. We had our Alessio who experienced first-hand this atmosphere I was trying to describe.

Not least of all Europe: once again great soundness in the European business.

In terms of dynamics, the demand for luxury persists even outside the big capital cities, a phenomenon we had already commented on a few months ago. This feeling is confirmed not only by the revenues in our stores, but probably even more strongly in the sales, orders and confidence of our multi-brand accounts, who are really going through a phase of great trust and dynamic planning. As you might know, the quality of the proposition is always key for them.

Geographically, I would like to close by reiterating the growing importance of top-level resorts, a phenomenon that has been going on for some time now.

Let's look at the channels. At the beginning of this year, the digital channel is back in line with brick-and-mortar, in a fine synergy that we already commented on last time. Sixty per cent of our customers often arrive at the boutique showing us pictures of certain looks seen on our online boutique.

As far as customer behaviour is concerned, local customers are still fundamental in all markets in this quarter as well. However, we report a progressive and constant growth in tourism, as a positive note. We must say that at the beginning of this year this rise in tourism also shows an even wider variety of nationalities than in the recent past.

We are also glad to report that our beautiful Italy, which has always been a benchmark for image, further strengthens its international attractiveness.

Overall, the search for special garments is always strong, in an increasingly conscious purchase by customers all over the world.

If we take a closer look at our sales for this quarter, which will come to an end in a few days, we can only describe them as very good.

One figure that we always look at with great interest is the growth in visits to

our website and the increase in footfall in our physical stores, further evidence of the health of our brand. The above prompts us to envisage for the whole of 2024 a good growth across all areas and all channels; we expect a very similar mix to last year, perhaps with a slight increase in the Asian weight, at least for us.

As Brunello said, I have just returned from Shanghai and there we gathered our team to exchange views, share ideas and experiences, plan. We discussed extensively the values of hospitality, kindness, amiability....

Strongly restating the great value of sales associates staffing the stores, because everything starts from there.

You know that China now accounts for 12% of our turnover, and we feel that in China, on the one hand the brand positioning is clear, absolutely consistent with the international positioning of our brand, and on the other hand there is the recognition of the appeal of our style, as proven by the great recognition awarded to Brunello last December, with the GQ China Award.

In the eyes of Chinese customers, Cucinelli is a lifestyle brand, with its heart set on in ready-to-wear, exclusive, recognisable, obviously associated to the highest quality of made in Italy, and absolutely pure and protected, both in communication and distribution.

We really feel that over time we have succeeded in establishing solid foundations, and this is why this year 2024 marks the first year of a new chapter in our Chinese plan, bearing in mind the 12% base I mentioned earlier.

We are very confident that we will be able to grow organically, within the existing spaces, as well as to be able to seize the opportunities for further development of our direct network and our wholesale network in the coming period, always looking at the top tier cities.

As far as the digital channel in China is concerned, we have managed to come up with a beautiful, authentic, faithful image of our brand on Tmall, and we are very confident of the strategic importance of this channel, first and foremost for communication, even before sales.

You have seen that China has grown steadily for us in recent years, and as this potential is being realised, our confidence about the size of this opportunity is growing. We are growing gradually, step by step, and we believe that this way we will be able to build a business that is long-lasting, long-term and increasingly relevant. I would stop here, so that we leave more room for questions.

https://www.cnbc.com/2024/03/18/saudi-aramco-ceo-says-energy-transition-is-failing-give-up-fantasy-of-phasing-out-oil.html?&qsearchterm=aramco

Saudi Aramco CEO says energy transition is failing, world should abandon 'fantasy' of phasing out oil

PUBLISHED MON, MAR 18 202411:53 AM EDTUPDATED AN HOUR AGO

Spencer Kimball @SPENCEKIMBALL

KEY POINTS

- Saudi Aramco CEO Amin Nasser said the current energy transition strategy is failing.
- The world should give up on the idea of phasing out oil and gas, Nasser said.
- The CEO called for a reset of the strategy that focuses on reducing emissions, not phasing out oil and gas.

Amin Nasser, chief executive officer of Saudi Aramco, speaks at the 2024 CERAWeek by S&P Global conference in Houston, Texas, US, on Monday, March 18, 2024.

F. Carter Smith | Bloomberg | Getty Images

HOUSTON — Saudi Aramco CEO Amin Nasser said Monday that the energy transition is failing and policymakers should abandon the "fantasy" of phasing out oil and gas, as demand for fossil fuels is expected to continue to grow in the coming years.

"In the real world, the current transition strategy is visibly failing on most fronts as it collides with five hard realities," Nasser said during a panel interview at the CERAWeek by S&P Global energy conference in Houston, Texas.

"A transition strategy reset is urgently needed and my proposal is this: We should abandon the fantasy of phasing out oil and gas and instead invest in them adequately reflecting realistic demand assumptions," the CEO said to applause from the audience.

The Paris-based International Energy Agency forecast last year that peak oil, gas and coal demand would come in 2030. Nasser said demand is unlikely to peak anytime soon let alone by that year. Nasser suggested that the IEA is focusing on demand in the U.S. and Europe and needs to focus on the developing world as well.

Nasser said alternative energy sources have been unable to displace hydrocarbons at scale, despite the world investing more than $9.5 trillion over the past two decades. Wind and solar currently supply less than 4% of the world's energy, while total electric vehicle penetration is less than 3%, he said.

Meanwhile, the share hydrocarbons in the global energy mix has barely fallen in 21st century from 83% to 80%, Nasser said. Global demand has increased by 100 million barrels of oil equivalent per day over the same period and will reach an all-time high this year, the CEO said.

Gas has grown by 70% since the start of the century, Nasser said. The transition from coal to gas is responsible for most of the reductions in carbon emissions, he said.

"This is hardly the the future picture some have been painting," Nasser said. "Even they are starting to acknowledge the importance of oil and gas security."

Developing nations in the global south, meanwhile, will drive oil and gas demand as prosperity rises in those nations, which represent more than 85% of the world's population, the CEO said. These nations receive less than 5% of the investment targeting renewable energy, he said.

Nasser said the world should focus more on reducing emissions from oil and gas in addition renewables. The CEO said efficiency improvements alone have reduced global energy demand by almost 90 million barrels per day oil equivalent.

"We should phase in new energy sources and technologies when they are genuinely ready, economically competitive, and with the right infrastructure," Nasser said.

SAF Group created transcript of comments by Saudi Aramco CEO Nasset at CERAWeek 2024 on March 18, 2024. https://twitter.com/aramco/status/1770057187836223534

Items in "italics" are SAF Group created transcript.

Nasser "*Consumers around the world are sending powerful messages that can no longer be ignored. They want energy that helps protect the planet and their pocket books with minimum disruption to supplies and their daily lives. The current transition strategy is visibly failing on most fronts as it collides with five hard realities. The first is that alternatives have been unable to displace hydrocarbons at scale. The second hard reality is that despite the contribution of alternatives to reducing greenhouse gas emissions when the world does focus on reducing emissions from hydrocarbons, it achieves much better results. The third reality is that many alternatives in play are simply unaffordable for the majority of people around the world. The fourth reality is that energy transition narrative will increasingly be written by the Global South. In turn, this is driving the fifth hard reality that a transition strategy reset is urgently needed, and my proposal is this: we should abandon the fantasy of phasing out oil and gas, and instead, invest in them adequately, reflecting realistic demand assumptions. This welcome clarity from consumers is shifting the transition's center of gravity to a multi-source, multi-speed, multi-dimensional road to reality, and to the right side of history where everyone's hopes and ambitions can actually be met.*"

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

https://www.linkedin.com/pulse/amid-all-climate-gloom-lets-ignore-good-news-fatih-birol-mdrge/

Amid all the climate gloom, let's not ignore the good news

Fatih Birol

Executive Director at International Energy Agency (IEA)
50 articles Follow

March 24, 2024

Powerful economic and technological factors are driving the shift to clean energy

This article was originally published by the Financial Times.

It's easy to become overwhelmed by the seemingly relentless onslaught of disturbing news about the world's deepening climate crisis. Last year was by far the hottest on record, bringing with it a catalogue of devastating storms, floods, droughts and heat waves. And the worrying trend of unusual heat has continued into this year. Meanwhile, the amount of greenhouse gas emissions humans are releasing into the atmosphere keeps going up, not down.

What's more, elections in major economies around the world are creating heightened uncertainty about energy and climate policies. vs — the areas where real progress is being made that can still enable us to avoid the most severe effects of climate change. Nowhere is this clearer than in clean energy, where technologies like solar, wind and electric cars are increasingly replacing the need for fossil fuels and reining in emissions.

The impetus here is coming not just from government policies but from other powerful economic, industrial, strategic and technological forces.

The first is simple economics. Clean energy technologies are already competitive in many key areas and are getting more so as production scales up. It's now cheaper to build onshore wind and solar power projects than new fossil fuel plants almost everywhere worldwide.

Meanwhile, the price of electric cars continues to come down and their market share keeps rising. In 2020, around one in 25 cars sold worldwide were electric; just a few years later, in 2023, it was one in five. EVs are now at the heart of most automakers' strategies for the future. Together with the rapidly increasing investments going into battery manufacturing, this makes a U-turn away from them improbable and impractical.

Clean energy is also benefitting from a flurry of technological innovation. After concerns that supply bottlenecks for critical minerals such as lithium could hamper the production of EV batteries, the industry responded by quickly bringing to market new battery chemistries that will reduce their dependence on key minerals. And innovation is moving fast in other emerging low-emissions technologies such as electrolysers for producing hydrogen and new processes for making green steel.

Another key force at work is energy security. The global energy crisis that erupted in 2022 has put a lot of pressure on the cost of living and laid bare the frailties of our existing fossil fuel-dominated energy system. It highlighted the energy security benefits of renewables, nuclear power and energy efficient technologies such as electric cars and heat pumps, that reduce consumers' exposure to volatile fossil fuel prices.

These economic and energy security considerations have made it clear that the future of energy — and therefore of our economies and industries — lies in clean technologies. This has prompted a renaissance of industrial policy among governments around the world as they seek to ensure their economies are at the forefront of the new global energy economy that is emerging.

The country leading the growth of clean energy is China, which installed as much solar capacity in 2023 as the entire world did in 2022. China is also comfortably the biggest player in global supply chains for solar panels, wind turbines, electric cars and other major technologies, and is investing in manufacturing capacity in other regions, as well. Regardless of where they stand on climate policy, if countries want to compete with China in the industries of the future, they need to double down on clean energy plans, not dial back on them.

Clean energy is also where the jobs are. Its industries — including renewables, electric cars and heat pumps — already account for more than half of employment in the global energy sector and are continuing to add more jobs all the time.

Last but not least, the worsening impacts of global warming, mainly caused by emissions from fossil fuels, are increasingly apparent to citizens around the world, who will over time demand more, not less, climate action from their governments.

We already have ample evidence that the journey to net zero emissions is likely to be a bumpy one. But the events of recent years — including the turmoil caused by the global energy crisis, the sharp spikes in fossil fuel prices and the impacts of extreme weather — are all reminders of why we need to press ahead.

And while changes in governments may well affect the pace of energy transitions — accelerating them in some cases, slowing them in others — they won't alter the fundamental direction of travel.

https://www.iea.org/commentaries/a-strong-focus-on-oil-security-will-be-critical-throughout-the-clean-energy-transition?utm_content=bufferabb82&utm_medium=social&utm_source=twitter.com&utm_campaign=buffer

A strong focus on oil security will be critical throughout the clean energy transition

Ronan Graham, Energy Security Analyst
Ilias Atigui, Energy Security ResearcherCommentary — 11 March 2024
CiteShare

Oil security and emergency preparedness remain key priorities for the IEA half a century after its founding amid the oil shock of the early 1970s

Much has changed in the global energy landscape since the IEA was founded 50 years ago, but the security of oil supply remains a pressing concern for governments across the globe.

An enduring focus on oil security is a consequence of the continued need for oil to fuel cars, trucks, ships and aircraft, as well as to produce the petrochemicals necessary to manufacture countless everyday items.

As nearly 200 countries recognised at the COP28 climate change conference in Dubai in December, the world needs to transition away from fossil fuels if it is to avoid the worst impacts of global warming. However, while the world's dependence on oil is lessening, it remains deep-rooted, so supply disruptions can still cause significant economic harm and have a substantial negative impact on people's lives.

Oil supply risks could increase, even as demand falls

While global oil consumption reached a record high in 2023, oil dependence is set to weaken further in many parts of the world in the coming years. The shift to a clean energy economy is gathering pace, with electric vehicle sales soaring, energy efficiency improving, and other clean energy technologies advancing rapidly. Consequently, a peak in global oil demand is in sight before the end of this decade, based on today's policy settings.

However, the threat posed by oil supply disruptions will not disappear anytime soon. Even once demand starts declining, oil will remain an important part of the global energy mix for some time. There is also good reason to believe that oil supply disruptions are even more likely to occur in the coming decades than they are today. This is due to an elevated risk of supply-demand imbalances, increasing supply concentration for both crude oil and oil products, a highly uncertain geopolitical outlook, and a plethora of additional risks including the growing threat of cyberattacks and the increasing frequency of extreme weather events.

Investment uncertainty raises the risk of a supply-demand imbalance

Given the long-term outlook for oil demand and the risks to the climate from its combustion, the eventual need to scale back production activity is undeniable. However, there is a high degree of uncertainty around how quickly demand will fall, leaving oil companies facing difficult and

commercially risky decisions around upstream investment. The consequences of these decisions will have an impact on the security of oil supply, as well as the bottom lines of oil companies.

If oil demand falls quickly and sharply, companies investing in production could struggle to make a return on their investments. But, if production activity is scaled back at a faster pace than demand falls, the outcomes would be increased market tightness, higher prices and an elevated risk of supply disruptions.

Increased crude oil supply concentration could leave importers more vulnerable

As clean energy transitions progress around the world, there will be a tendency for oil production to become more concentrated in the hands of low-cost producers, particularly those in some OPEC countries. For the moment, this tendency has been kept in check, mainly by increased production in the Americas. However, in all three scenarios outlined in the IEA's *World Energy Outlook 2023*, OPEC's share of global oil production is projected to rise well above the 33% the group of producers held in 2023.

Transitions could be destabilising for producer economies that fail to diversify away from their high dependence on hydrocarbon revenues. Therefore, a higher concentration of global oil supply among a smaller group of countries could lead to heightened concerns about security of supply, with disruptions potentially having even greater impacts than if they were to occur today.

Further declines in refining capacity will leave many countries increasingly exposed to potential disruptions in oil product supplies

Developments further along the oil value chain will also result in increased exposure to oil market risk for many countries.

In the refining sector, a significant amount of capacity has been shut down in advanced economies over the past decade, particularly in Europe where some refiners have struggled to remain competitive following the completion of numerous large-scale, highly complex refineries in the Middle East and Asia.

Faced with increased competition and a highly uncertain demand outlook in their main markets, more refineries in advanced economies are likely to close. This will leave many countries increasingly reliant on imports of oil products, such as diesel and jet fuel, even as demand declines. As a consequence of their increased import dependence, these countries will become more vulnerable to disruptions in oil product markets.

Oil supply security is also threatened by an array of additional factors

The risks to oil security are manifold and wide-ranging, extending far beyond risks emanating from structural changes in global oil markets. Governments should take particular note of the threats posed by the increasingly uncertain geopolitical outlook, climate change and extreme weather events, and cyber-attacks. In recent years, supply disruptions have been caused by events that fall into each of these categories.

In the past two years, oil markets have been roiled by Russia's invasion of Ukraine and by conflicts in the Middle East. Meanwhile, water level changes and severe storms have caused

supply difficulties across many regions, and a ransomware attack resulted in an extended closure of the largest oil product pipeline in the United States in 2021.

The IEA has built strong emergency response capabilities, aimed at minimising the risk posed by oil supply disruptions

Energy security has been at the centre of the IEA's mission since its creation in 1974. At the IEA's 2024 Ministerial Meeting last month, ministers responsible for energy in IEA member countries reaffirmed "the IEA's foundational and central mission to ensure global energy security". In the decades since its creation, the Agency's work on energy security has expanded in scope, moving from an initial focus on oil security to promoting the security of natural gas and electricity supply, and more recently, to addressing the emerging security dimensions of clean energy transitions, such as critical mineral supplies.

However, throughout its existence, the IEA has remained focused on oil security and emergency preparedness. All IEA member countries have made a firm commitment to oil security by pledging to maintain readiness to respond to major oil supply disruptions at all times.

One of the IEA's key tools is an oil stockholding system that requires member countries to hold stocks equivalent to at least 90 days of their net oil imports. IEA members are also obliged to maintain demand restraint programs to rapidly reduce oil consumption during disruptions, while some members can implement measures to increase crude oil production when needed. The effectiveness of oil emergency policies and response measures in IEA member countries is periodically assessed in emergency reviews coordinated by the IEA Secretariat.

Over the past five decades, the IEA's oil emergency response mechanisms have proven to be a lynchpin of global oil markets. Since 1991, the IEA has coordinated five collective responses to major oil supply disruptions, bringing critical additional supplies to oil markets amid turbulence triggered by wars, geopolitical strife and extreme weather events. As recently as 2022, the IEA coordinated the largest collective response in its history, involving the release of just over 180 million barrels of oil stocks in response to the market turmoil that followed Russia's invasion of Ukraine.

The IEA will maintain an unwavering focus on oil security throughout the energy transition

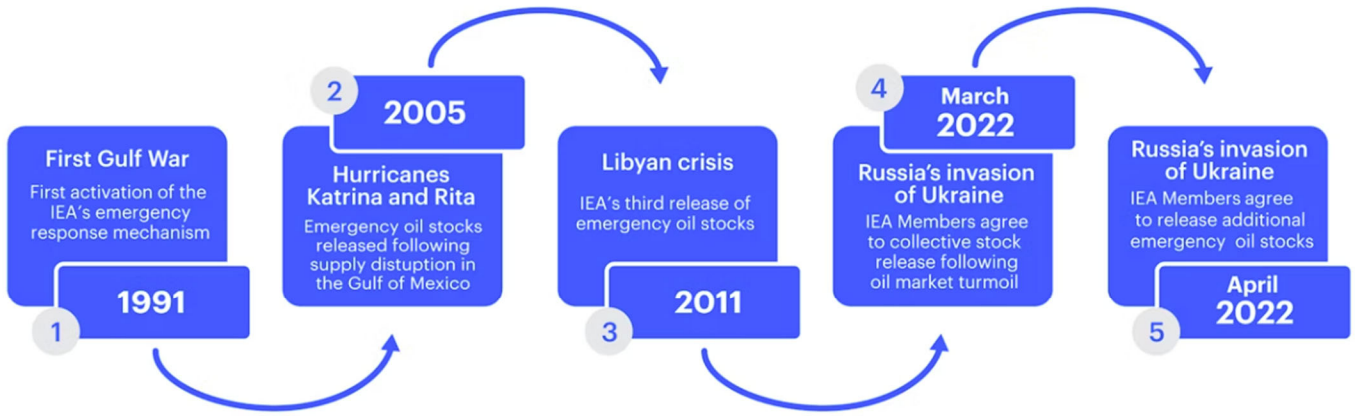
Ultimately, reducing dependence on fossil fuels by promoting the uptake of clean energy solutions is the most effective means for any government to enhance energy security. Shifting to a clean energy economy should be seen as a golden opportunity to build a more sustainable energy system that minimises exposure to oil market volatility and decreases the prospect of supply shocks.

However, the journey to a clean energy economy may not be a smooth one, and oil consumption will not vanish overnight. For many years to come, oil supply disruptions will have the potential to cause significant economic harm and negatively impact people's lives. Maintaining a resolute focus on oil security and emergency preparedness will therefore be critical throughout clean energy transitions worldwide, and the IEA's emergency response capabilities will remain vital.

At the 2024 IEA Ministerial Meeting last month, marking the Agency's 50th Anniversary, ministers reaffirmed the "importance of oil security to the global economy and the key role that the IEA oil stockholding system plays in contributing to global oil security". As always, the IEA stands ready to act in the event of any major disruption to global oil supply.

Timeline of IEA emergency oil stock releases, 1991-2022

Ope



Congress of the United States

Washington, DC 20510

March 20, 2024

Fatih Birol, Ph.D.
Executive Director
International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15
France

Dear Dr. Birol:

We are writing to you because we are concerned that the International Energy Agency (IEA) has strayed from its core mission—promoting energy security.

Indeed, we would argue that in recent years the IEA has been undermining energy security by discouraging sufficient investment in energy supplies—specifically, oil, natural gas, and coal. Moreover, its energy modeling no longer provides policymakers with balanced assessments of energy and climate proposals. Instead, it has become an "energy transition" cheerleader.

Until recently, the IEA has served as a valuable source of reliable information on the security of oil markets, and it has provided a mechanism whereby oil-consuming countries can respond effectively to oil shortages. The IEA also provides global energy forecasts as part of its mission. As you have noted, IEA forecasts have a tremendous influence on shaping how the world sees future energy trends. Consequently, the IEA must conduct its energy security mission in an objective manner. We believe the IEA is failing to fulfill these responsibilities.

By its own admission, the IEA has placed greater emphasis on "build[ing] net-zero emission energy systems to comply with internationally agreed climate goals." Climate change is an extraordinarily complex issue deserving IEA's attention. Excessive focus on an "energy transition," however, has led the IEA to veer away from objectively informing and educating policymakers and toward promoting an agenda with little regard to its implications for economic growth and energy security. Sadly, French President Macron's recent observation that IEA has become the "armed wing for implementing the Paris Agreement" is true.

The IEA's May 2021 *Net Zero Roadmap*, for example, is long on aspiration but short on the things that matter most to policymakers: objective analysis of energy flows, trade patterns, security impacts, and economic effects. These deficiencies severely undermine its usefulness. We are disappointed that a similarly one-sided attitude afflicts the IEA's annual *World Energy Outlook* (*WEO*), which seems more intended on modeling highly aspirational peak demand and similar "backcast" scenarios at the expense of more realistic and objective forecast scenarios.

These shortcomings harm the IEA's reputation for impartiality. Press and policymakers routinely draw conclusions from IEA's products, which recommend that investment in new oil and natural gas projects must stop immediately—a deeply misguided and troubling position for an organization founded to address the security of oil markets. In fact, last year you told the *Financial Times* that, "Looking at the world today or tomorrow, no one can convince me that oil and gas represent safe or secure energy choices for countries and consumers worldwide."

It should disturb you that biased parties are exploiting the IEA's forecasts and other products to advocate for policies that undermine energy security. Last month, your former deputy at IEA, David Turk, now Deputy Secretary at the U.S. Department of Energy, justified President Biden's decision to "pause" the permitting process for U.S. liquefied natural gas (LNG) exports on the basis of IEA forecasts rather than the forecasts of the Department's own Energy Information Administration (EIA). We find Deputy Secretary Turk's decision to rely largely on IEA's outlier forecasts—instead of EIA's forecasts—when discussing world demand for natural gas to be deeply troubling. President Biden's decision to stop approving LNG export permits could have devastating consequences on the future supply of U.S. LNG to developing countries who will experience decades of robust growth in natural gas demand. That is why people across the American political spectrum have condemned the President's decision as reckless.

Like the EIA, respectable energy modeling organizations—including the Institute for Energy Economics in Japan, BP, ExxonMobil, and the Organization of Petroleum Exporting Countries—show in their reference cases that world demand for natural gas will continue to grow through 2050, ranging from about 20 to 47 percent growth from 2020 to 2050. These results compare to just 4 percent growth for IEA's Stated Policies Scenario (STEPS) and an astonishing 40 percent *decline* for IEA's Announced Policies Scenario (APS) over the same period, with demand peaking sometime around 2030.

Considering that U.S. LNG is exported to a global market *outside the United States*, it is worth pointing out that other organizations expect natural gas demand outside the United States to jump between 30 percent and 55 percent from 2020 and 2050. In contrast, IEA's STEPS shows 2050 demand increasing just 15 percent from 2020 levels outside the United States (although as recently as the *WEO* 2021 STEPS it was 38 percent). Moreover, IEA's APS suggests there will be a 31 percent *decline* in natural gas demand outside the United States from 2020 to 2050.

When Deputy Secretary Turk was asked at a hearing before the Senate Committee on Energy and Natural Resources about these other forecasts, which show much more robust natural gas demand growth, he replied that "[a]ll of those scenarios are also reference case scenarios." He went on to say that "[t]hose scenarios are not on track for where we need to be for achieving our climate objectives." Put plainly, he ignored the reality of world energy markets while indulging in the wishful thinking that permeates IEA's APS and Net Zero Emission by 2050 Scenario (NZES).

To defend the indefensible, the Biden administration trots out its ostensible fear that more LNG export capacity may be built than is needed. The basis of that fear is the IEA's unrealistic modeling. Decisions about future LNG export capacity should be left up to market participants

and investors, not politicians or bureaucrats. It is highly concerning that politicians are using the IEA's biased modeling to make highly controversial decisions that undermine world energy security.

These developments also call into question your decision to stop issuing a neutral Current Policies Scenario (CPS), or reference case, which is common practice for modeling groups, including EIA and its *Annual Energy Outlook*. To our knowledge, you have never publicly explained the decision to abandon the CPS. Reference cases are a valuable tool for evaluating energy related policies. The lack of a CPS makes such assessments significantly more difficult.

In light of the importance that the Biden administration has placed on the IEA's forecasts of natural gas demand—and the enormous implications President Biden's "pause" on LNG export approvals could have on the world's energy security—we seek a better understanding of IEA's recent work. We, therefore, ask that you promptly respond to the following questions:

1. The IEA ceased publication of a neutral reference case CPS in 2020.

   (a) Why did the IEA depart from decades of modeling convention and cease to publish a policy-neutral CPS?

   (b) Were stakeholders given the opportunity to weigh in on the pros and cons of this decision? If so, how were they given that opportunity?

   (c) Does the IEA agree that a baseline reference scenario that assumes only policies in place is a valuable tool for policymakers? If not, why?

   (d) Will the IEA reconsider its decision to abandon its CPS? If not, why?

2. There seems to be some confusion whether or not IEA's STEPS is a reference case scenario. Your 2020 *WEO* specifically warned against taking STEPS "as a baseline or reference case." In 2024, however, the IEA apparently backtracked this position: "STEPS for us is the baseline."

   (a) Is the position taken in the 2020 *WEO* STEPS—that the scenario is in fact *not* a reference case—still the IEA's position?

   (b) If the IEA's position has changed, please explain why it has changed.

3. The IEA's description of its APS says that it "assume[s] that all governments will meet, in full and on time, all of the climate-related commitments that they have announced . . . ." It goes on to say that "[s]ince most governments are still very far from having policies announced or in place to deliver in full on their commitments and pledges, this scenario could be regarded as giving them the benefit of the doubt, and very considerable progress would have to be made for it to be achieved."

(a) Are "most governments . . . still very far from having policies announced or in place to deliver in full on their commitments and pledges"?

(b) In your view, how likely is it that all or even most governments will deliver on their announced pledges?

(c) Do you think it is reasonable to assume that governments will meet their pledges fully?

(d) As you analyze national and international climate polices over the past five years, would you say that they are becoming more or less stringent *as implemented*? Please consider in your response not only the text or goals stated in the legislation, but also how governments are implementing and enforcing them.

4. Many countries have made their pledges conditional on government-to-government financial assistance from developed countries, including the United States. The International Monetary Fund has said that "[t]he path to net zero by 2050 requires low-carbon investments to rise from $900 billion in 2020 to $5 trillion annually by 2030. Of this figure, emerging and developing countries (EMDEs) need $2 trillion annually, a fivefold increase from 2020." Others have arrived at similarly large estimates.

   (a) Do you think it is realistic to assume in APS that developing countries, where virtually all of the emissions growth is occurring, will meet their conditional pledges?

   (b) In APS, how much financial support does the IEA assume developed country governments will provide developing counties for the purpose of meeting their conditional pledges by 2050?

5. Forecasts of natural gas demand, especially outside the United States, from EIA, the Institute of Energy Economics of Japan, BP, ExxonMobil, and the Organization of Petroleum Exporting Countries all show large increases for decades to come.

   (a) Do you agree that these organizations are competent to develop and run energy forecast models?

   (b) Do you agree that the consensus is that natural gas demand outside the United States will increase significantly between now and 2050?

   (c) Are the modeling results that these organizations have presented credible?

   (d) What explains why IEA's STEPS demand forecast for natural gas is so much lower than those from these other organizations?

6. The forecast range of natural gas demand outside the United States in 2050 from the highest forecast (EIA's International Energy Outlook 2023 High Economic Growth case) and the

lowest forecast (IEA's APS) is roughly 3,600 billion cubic meters. That amount exceeds the world's current natural gas demand. With such a wide range of forecasts, is it analytically sound to pick an outlier scenario because it fits a policy preference or is it better to accept that there is a broad range of possible future outcomes?

7. The different scenarios in the IEA's *WEO* all assume the same level of GDP throughout the analyses.

   (a) Is it reasonable to expect that world's GDP will be the same under such extremely different circumstances?

   (b) It would appear that world's GDP is a model input. Is that correct? If not, please explain how GDP can be the same across different scenarios.

   (c) Do you think it is useful for policymakers to have estimates of the economic impacts of different scenarios? If not, why not?

8. In the 2023 *WEO* and in earlier *WEO*s, different IEA scenarios show vastly different levels of industrial production. *WEO* 2023, for example, shows production of chemicals, steel, cement, and aluminum in 2050 anywhere from 9 percent to 20 percent lower in the APS and NZES than in the STEPS. GDP, however, remains constant across all of the scenarios. Do you think this is a credible approach to estimating future worldwide GDP under different scenarios?

9. It is important that policymakers and stakeholders do not confuse aspirational climate-outcome centered scenarios that employ optimistic assumptions with a reference case forecast that assumes only current policies in place. Are IEA's STEPS, APS, and NZES modeled as forecast scenarios or backcast scenarios?

10. It has been widely reported that the IEA recommends the immediate halt of all new investment in oil and natural gas production.

    (a) Please clarify whether the IEA recommends an immediate halt in all new greenfield and brownfield investment in oil and gas projects.

    (b) Please clarify whether the IEA *recommends, implicitly or explicitly,* that new greenfield projects should not be permitted.

11. All IEA forecast scenarios show the world's petroleum demand peaking by 2030.

    (a) Does the IEA recommend that governments act on this forecast and begin limiting access to crude oil resources?

    (b) Many modeling outfits have produced reference cases showing petroleum demand increasing out to 2050. Do you agree that if forecasts of rising demand are accurate, limiting access to crude oil resources could result in shortages and price spikes?

(c) Is the IEA worried that its influential peak demand forecasts might contribute to an economically painful energy crisis that the IEA itself was created to prevent?

12. Who is in a better position to assess the future market for U.S. LNG: modelers and bureaucrats or project developers risking billions of dollars?

13. How much United States government funding has the IEA received in each of the last 10 years?

14. For each year over the last 10 years, what share of total IEA funding did the U.S. support comprise?

15. Please provide a line-item breakdown of all IEA expenditures, and the U.S. share of those expenditures, by functional area, such as emergency preparedness, data gathering, forecasting, travel and other overhead, etc. Please show the evolution of each line item over the last 10 years.

16. Please explain why the IEA does not make its data, methodologies, and assumptions publicly and freely available, as the EIA does.

We would appreciate a timely response to our questions. You may contact Mr. Stephen Eule (steve_eule@energy.senate.gov) or Mr. Brandon Mooney (Brandon.Mooney@mail.house.gov) if you need any clarification on our inquiry.

We look forward to continuing a productive relationship with the IEA.

Sincerely,

John Barrasso, M.D.
Ranking Member
U.S. Senate Committee on Energy and Natural Resources

Cathy McMorris Rodgers
Chair
U.S. House Committee on Energy and Commerce

Forecasting a Realistic Electricity Infrastructure Buildout for Medium- & Heavy-Duty Battery Electric Vehicles

EXECUTIVE SUMMARY

March 18, 2024

Roland Berger

Executive Summary: key findings (1/2)

1. To electrify all U.S. medium and heavy-duty vehicles, fleets and charge point operators will need to invest **USD 620 billion into charging infrastructure - which includes chargers, site infrastructure, and utility service costs**

2. **Local MDHD vehicles** would need investment into **on-site charging infrastructure of USD 496 B**, but heavy-duty vehicles will require more significant charging infrastructure and investment compared to medium-duty – **requiring average charging infrastructure investment of 145K per vehicle for heavy duty vs 54K per vehicle for medium-duty**

3. **In addition to on-site** charging infrastructure, **high mileage vehicles** (most of which are Class 7 and 8) **require an investment of USD 69 bn into a reliable local on-route charging network** before they can electrify, but utilization risk poses a major challenge to investment – requiring significant government intervention and business model innovation

4. **To support** full electrification of **long-haul vehicles, USD 57 bn need to be invested** into the development of a sufficiently **dense highway-charging network** – development is constrained by the pace of transmission grid infrastructure buildout

5. Nationally, **just to support local charging demand[2)]** from MDHD vehicles, **utilities would need to invest around USD 370 billion[1)] on distribution grid upgrades and new builds**, which is nearly equivalent what was invested into the entire distribution grid over the past 15 years

6. In terms of **electricity generation and transmission**, while there will be some incremental capacity need (and investment need) created by MDHD charging, **power system operators are already planning for significant generation and capacity growth**, which exceeds projected demand from MDHD charging by a factor of ~10x

1) Based on "overnight" capital cost of grid infrastructure at current price levels - actual utility investment will be higher due to 1) price inflation of labor and equipment, and 2) Utility guaranteed rate of return
2) Distribution grids will serve on-site and on-route charging demand from local fleets - long-haul trucks / highway charging stations will be served by the transmission grid and bulk power system

Executive Summary: implications and key takeaways (2/2)

1. A **phased electrification approach** is clearly needed for MDHD vehicles, with an **initial focus on medium-duty** segment, and with **heavy-duty and long-haul addressed over time** as technology and infrastructure improve

2. **Given the significant** (and in some cases, prohibitive) **investments required for electrification**, there may be greater **value in being open to alternative decarbonization routes**, as opposed to being prescriptive on technology

3. Meeting ambitious electrification and decarbonization targets **may require fleets to explore and innovate alternative operational and fleet management strategies** to optimize upfront investments and long-term value

4. **Without sufficient government and regulatory support**, the transition to fully electric MDHD fleets would **likely result in increased freight rates**, costs that would have to ultimately be passed down to American consumers

5. If faced with completely **"unmanaged" charging demand, distribution grids will require extensive infrastructure investment**, creating a bottleneck for fleet electrification given the need to maintain affordable rates – this **highlights the need for technology solutions and regulatory support** to help fleets and utilities **manage charging**

6. Overall, **these findings clearly highlight the need for greater cross-industry collaboration** to increase alignment and certainty for all stakeholders

To electrify all MDHD vehicles, fleets and charge point operators will need to invest USD 620 billion into chargers, site infrastructure, and utility service costs

Charging infrastructure investment needs

Vehicle cost/TCO not in scope of analysis

Use case segment	Vehicle
1 Medium duty – local (low mileage)	• Vehicles expected to meet performance requirements of all use cases in improved technology scenario • Vehicle prices are assumed to decline to enable positive TCO across use cases
2 Medium duty – local (high mileage)	
3 Heavy duty – local	
4 Heavy duty – long haul	

Charging infrastructure

	Charger	Site	Electric service
Local charging networks			**565 B**
A L2 on-site			163 B
A L3 on-site			333 B
B 500 kW on-route			69 B
Highway charging networks			**57 B**
C L3 on-route			30 B
C 1 MW on-route			27 B

Total on-site charging investment needed
496 B

Total on-route charging investment needed
126 B

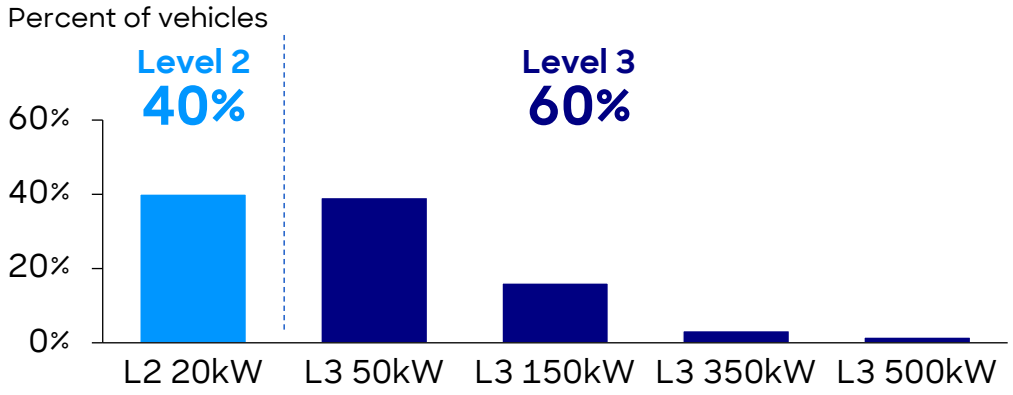
Compared to medium-duty, heavy-duty vehicles will require more significant charging infrastructure and investment due to more intensive charging needs

Investment need for local on-site charging network

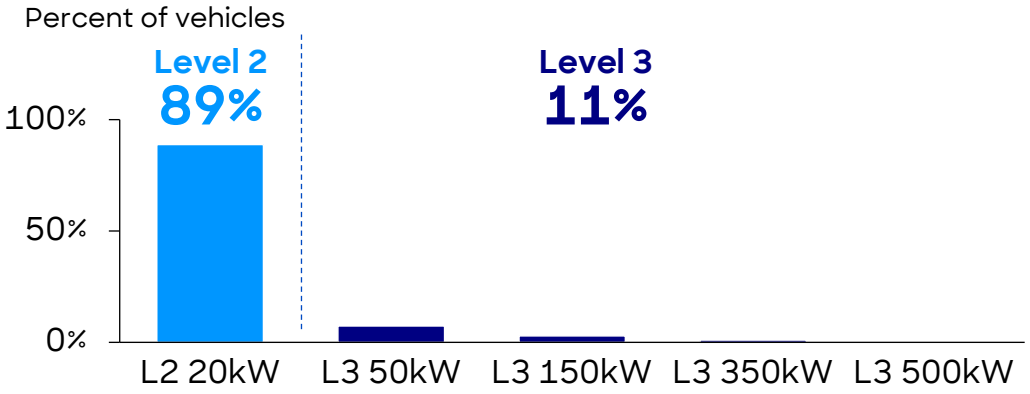
Segment

Required on-site charger technology

Heavy duty - local



Medium duty - local



Total investment need local on-site charging network [USD]

L2 on-site	L3 on-site
163 B	333 B
22 B HD	220 B
141 B MD	113 B

Charging infrastructure investment per vehicle [USD]

Heavy duty - local

145 K

Medium duty - local

54 K

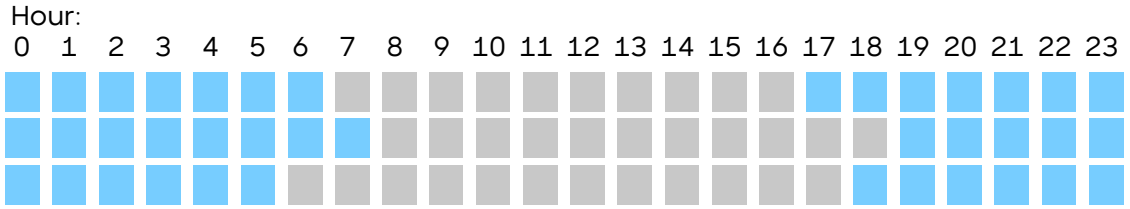
Heavy duty vehicles have more intensive charging requirements, and will require ~3X the infrastructure investment per vehicle compared to medium duty

Source: NREL; US Census Bureau, Roland Berger analysis

Low mileage medium-duty vehicles will not need on-route charging, and can use Level 2 chargers on-site, minimizing charger and make-ready investments…

Illustrative charging and utility service need for MD local fleet (low mileage)

I Illustrative duty cycle for Class 6 delivery fleet



Available charging time at home base typically >12 hours

II Illustrative on-site charging need

x 30	131 kWh	13	20 kW L2 x 30	→	**600 kW**
fleet size	effective full charge	avg. hours overnight	on-site chargers needed		incremental service need

III Indicative cost of utility service upgrades

Minor utility service upgrades can cost in the range of

USD 7,500 per L2 charger

for typical fleet locations

Cost of utility service upgrade (paid by fleet)

USD 225K total

USD ~7,500 per vehicle

at home base on-duty

However, for depot locations with a larger number of vehicles, a more extensive service upgrade may be needed …

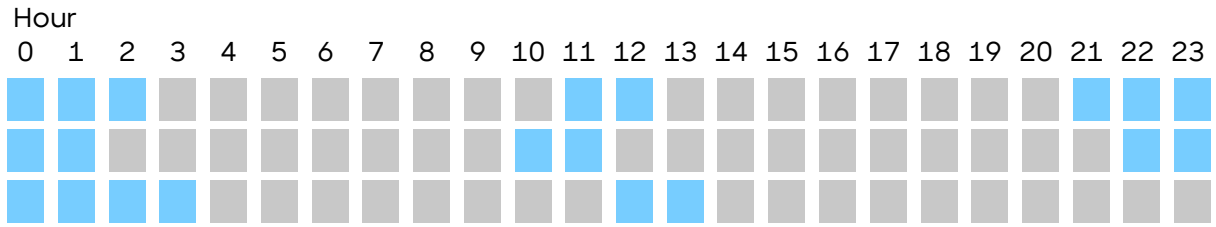
- This same example fleet, if it consisted of 150 vehicles instead of 30, would require a **3 MW service level**
- For individual sites requiring significant power capacity (~ 1 MW and above), **utilities may need to upgrade more upstream infrastructure** (e.g. feeder segments, larger transformers), which can translate into much larger investment need on a per vehicle basis
- These costs are highly variable, depending on existing infrastructure

Source: NREL; Roland Berger analysis

… but for many local HD use cases, fleets would need high capacity L3 or DCFC chargers on-site, but just the cost of utility service upgrades can be prohibitive

Illustrative charging and utility service need for HD local fleet

I Illustrative duty cycle for Class 8 high-mileage local fleet



Available charging time at home base 2-6 hours

II Illustrative on-site charging need

x 30	264 kWh	1.5	350 kW x 20	→	7 MW
fleet size	effective full charge	max vehicles per charger	on-site chargers needed		incremental service need

III Indicative cost of utility service upgrades

Large utility service upgrades can cost anywhere from

USD 500K – 2.5M per MW

of additional electric load

Cost of utility service upgrade (paid by fleet)

USD 4-18M total

USD ~150-600 K per vehicle

at home base on-duty

Source: NREL; fleet interviews, Roland Berger analysis

For HD local fleets, the potential paths to electrification all involve significant cost and risk:

- If high-capacity charging is prohibitive because of utility cost, there are no good alternatives for fleets:
  - Charging vehicles at lower rates will require additional vehicles to ensure continued operation
  - Rely heavily on public charging (at higher electricity rates and additional operational risk)
- In all cases, the incremental cost needs to get passed down to customers, or negatively hits the profitability of fleets

To remove this roadblock, regulators would need to approve use of ratepayer funding for service upgrades and other "make ready" investments, removing the burden from individual fleets

Even with improved technology, a significant share of the HD local fleet requires access to on-route fast-charging locations, driving investment need of USD 69 B

Investment need for local on-route charging network

Results across Class 3-8
[% requiring on-route charging]

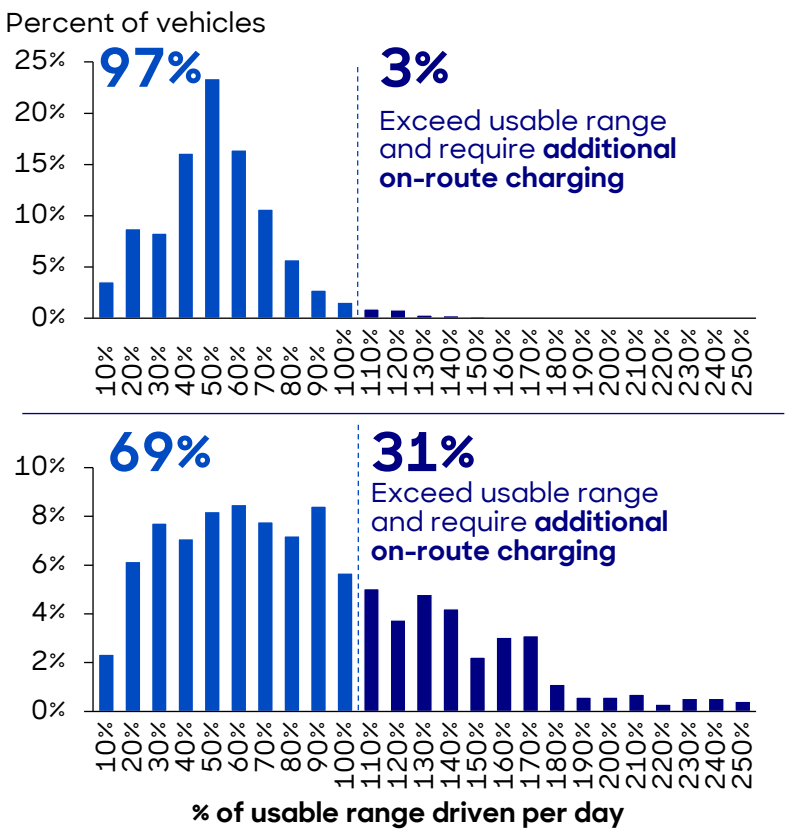
Class 3	100 kWh battery	90 mi usable range	4%	need on-route charging
Class 4	100 kWh battery	90 mi usable range	9%	need on-route charging
Class 5	305 kWh battery	90 mi usable range	3%	need on-route charging
Class 6	305 kWh battery	137 mi usable range	1%	need on-route charging
Class 7	305 kWh battery	137 mi usable range	28%	need on-route charging
Class 8	616 kWh battery	185 mi usable range	38%	need on-route charging

Segment

Medium duty - local

Heavy duty - local

Mileage ratio distribution



Total investment need local on-route charging network [USD]

On-route 500 kW

69 B

Heavy duty vehicles need larger physical footprint at the charging station - likely requiring dedicated charging locations

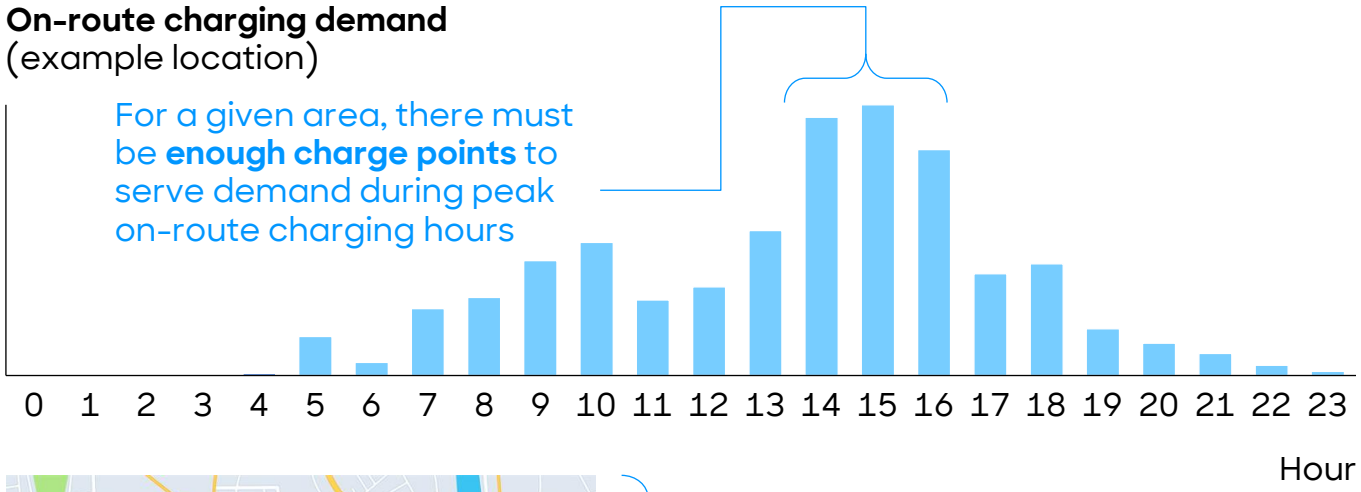
Source: NREL; US Census Bureau, Roland Berger analysis

A reliable local on-route charging network must exist before high mileage vehicles can electrify, but utilization risk poses a major challenge to investment

Challenges and investment hurdles for on-route charging

A sufficiently dense network needs to exist to avoid queueing …

On-route charging demand
(example location)



Further, those charge points must be geographically dispersed such that they **align with fleet traffic volumes and existing routes**

… but the investment case to develop such a network is very challenging …

- **Timing & adoption:** given that significant adoption of high-mileage vehicles will not occur before a sufficient network exists, there is a **"first mover disadvantage"**
- **Utilization & economics:** at full density, individual locations may see **low utilization rates**, which would require **large price premiums** at the plug (which fleets would have to absorb)

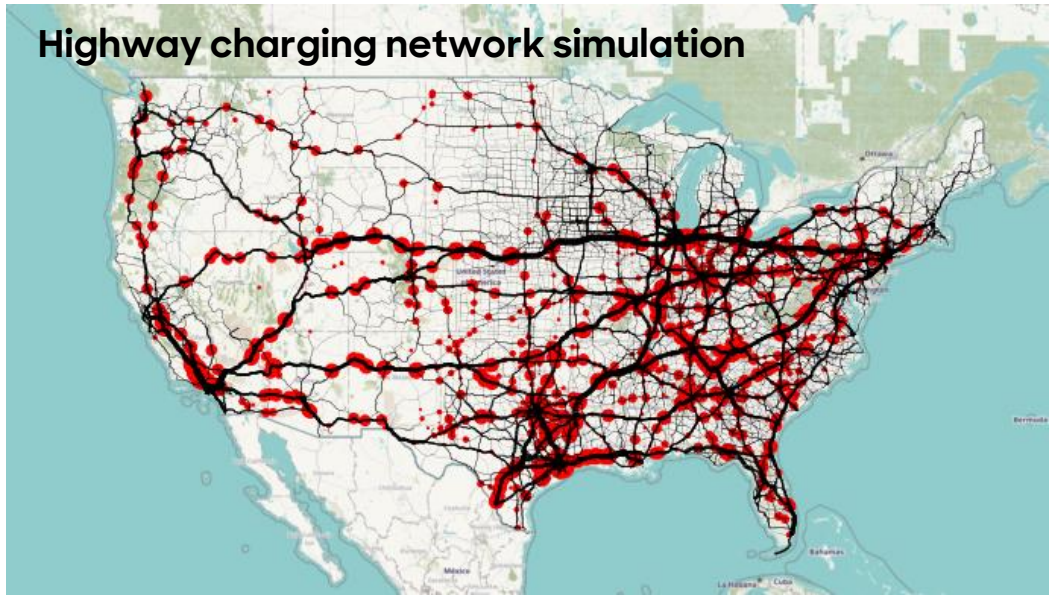
- **Planning and coordination needed to ensure efficient sizing and placement of chargers**
- **Economic support may be required to overcome utilization risk**
- **Concern over utility ownership of public charging infrastructure remains a key regulatory uncertainty**

Source: Expert interviews, Roland Berger analysis

To support full electrification of long-haul vehicles, USD 57 bn need to be invested in converting truck stops into a sufficiently dense charging network

Investment need for highway charging network

Highway charging locations have been simulated across rural and metro areas …



Land cost and space constraints may challenge development, esp. in metro areas

… and each one will need to deploy significant fast charging and overnight charging infrastructure in order to electrify:

Average number of charge points per location:

Rural	Fast chargers	20-25
	Overnight chargers	150-200
Metro	Fast chargers	30-45
	Overnight chargers	200-300

Total investment need highway charging network [USD]

L3 Overnight	On-route 1 MW
30 B	27 B

Total highway charging investment

57 B

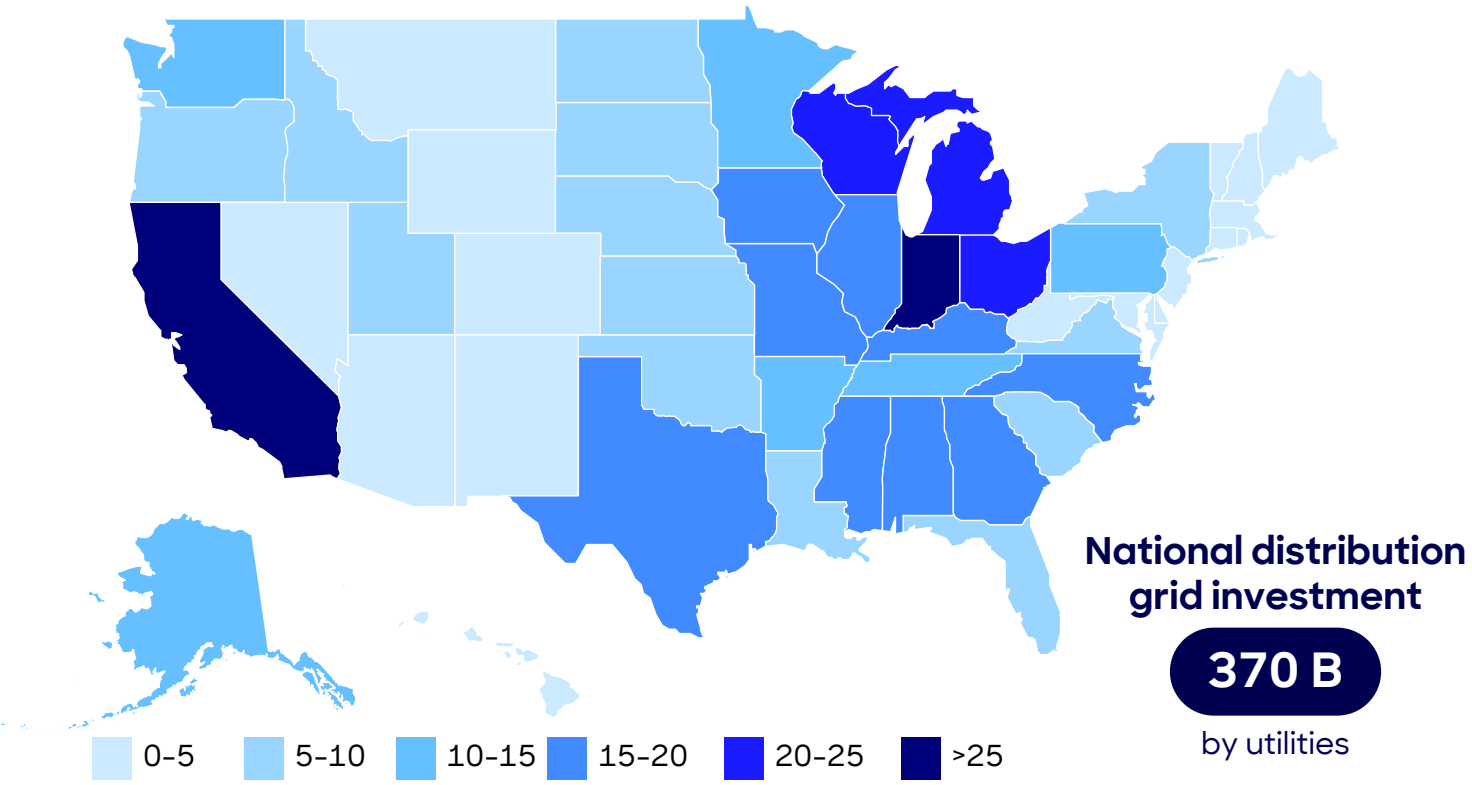
●●● Traffic volume of long-haul combination trucks at simulated charging locations (charging stations will also be utilized by OTRBs)

Source: NATSO; DOT Freight Analysis Framework; Roland Berger Analysis

Nationally, utilities will need to invest around USD 370 billion[1] on distribution grid upgrades and new builds to serve local charging demand[2] from MDHD vehicles

Distribution system investment need - nationwide

Total distribution system investment by state [USD bn]



National distribution grid investment

370 B

by utilities

Challenges and constraints:

- **Utilities will need to build** infrastructure ahead of demand **ahead of MDHD adoption** to avoid bottlenecks and delays
- However, these investments require more **sophisticated grid planning** as well as **regulatory support** – both limited to date
- The overall **pace of utility investment** will still be **constrained** by the need to control rate increases and **maintain affordability**

Potential mitigating factors:

- **This analysis shows** the grid impacts and investment need given **"unmanaged" charging**
- If fleets were able to **shift or manage peak charging** load (e.g. with battery-integrated chargers), **utility investment could be significantly reduced**
- However, **appropriate incentives** and/or price signals would need to exist **to support fleet economics**

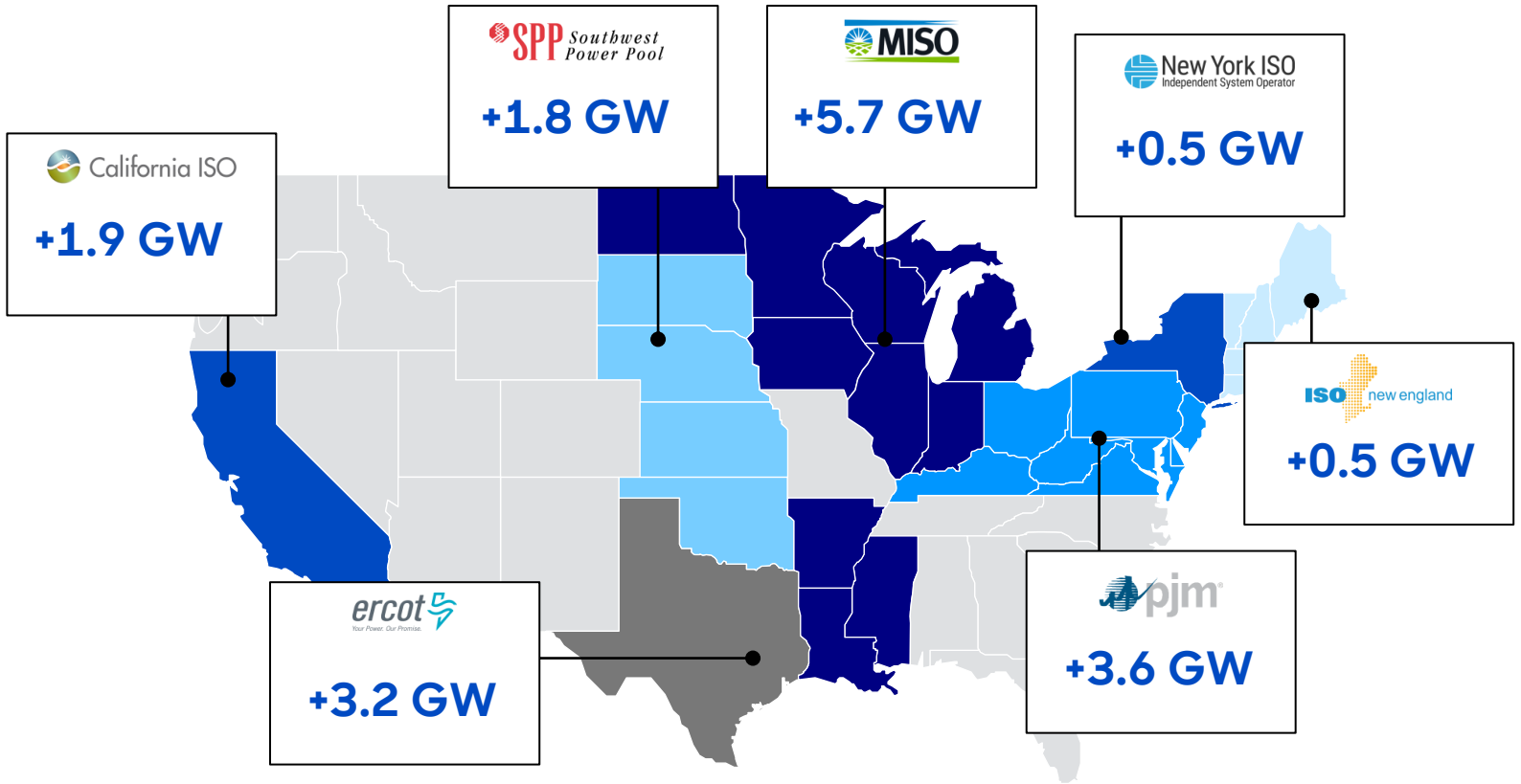
1) Based on "overnight" capital cost of grid infrastructure at current price levels - actual utility investment will be higher due to 1) price inflation of labor and equipment, and 2) Utility guaranteed rate of return
2) Distribution grids will serve on-site and on-route charging demand from local fleets - long-haul trucks / highway charging stations will be served by the transmission grid and bulk power system

Source: NREL, US Census, Roland Berger analysis

While there will be some incremental capacity need (and investment need) created by MDHD charging…

MDHD charging – impact to annual system peak load by ISO

Incremental coincident peak demand [GW]



Incremental investment in generation and transmission capacity:

Generation

22 B

Transmission

12 B

Based on EIA forecasted mix of resource additions and forecasted capital costs (by year of addition) through 2040

Source: EIA AEO 2023, S&P Capital IQ, ISONE 2050 Transmission Study, Roland Berger analysis

…power system operators are already planning for significant generation and capacity growth from transportation electrification, as well as from other trends

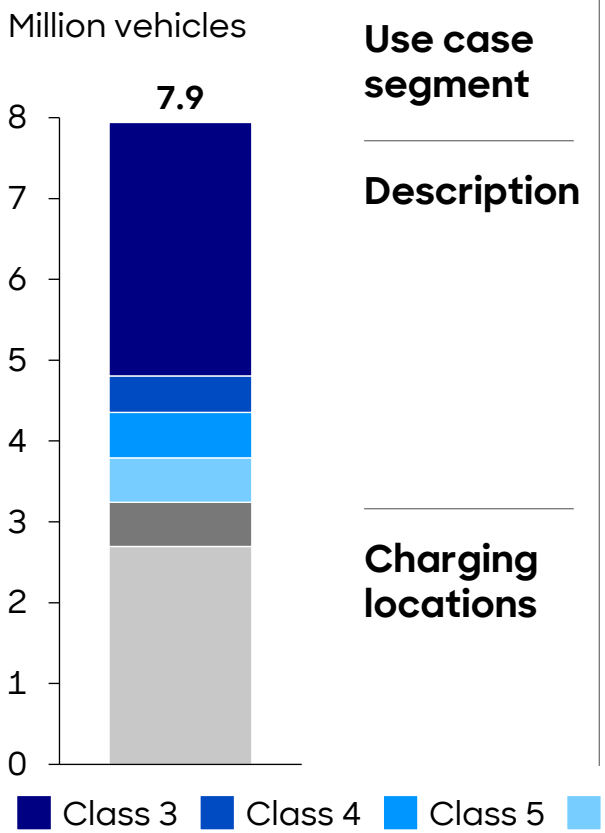
MDHD load impact vs ISO forecasts of overall load growth

ISO region	Generation				Capacity			
	2022 annual generation [GWh]	MDHD charging [GWh]	Increase from MDHD [incremental % of 2022]	2040 ISO load forecast [incremental % of 2022]	2022 peak load [GW]	MDHD peak impact [GW]	Increase from MDHD [incremental % of 2022]	2040 ISO load forecast [incremental % of 2022]
SPP Southwest Power Pool	283,187	19,932	**7%**	**48%**	53	1.8	**3%**	**26%**
MISO	665,254	64,493	**10%**	**17%**	120	5.7	**5%**	**18%**
pjm	795,214	45,998	**6%**	**39%**	148	3.6	**2%**	**20%**
California ISO	223,677	30,980	**14%**	**68%**	52	1.9	**4%**	**42%**
ISO new england	118,887	8,180	**7%**	**46%**	25	0.5	**2%**	**72%**
ercot	429,895	31,556	**7%**	**58%**	80	3.2	**4%**	**29%**
New York ISO Independent System Operator	152,681	8,284	**5%**	**34%**	31	0.5	**2%**	**44%**
	Historical	**RB estimate**	**RB estimate**	**ISO forecast**	**Historical**	**RB estimate**	**RB estimate**	**ISO forecast**

Source: ISO long-term load forecasts, Roland Berger analysis

Within the MDHD population, we categorized four broader use case segments that can be mapped to the different charging location types

Use case segments



Use case segment	Medium Duty (Class 3-6)		Heavy Duty (Class 7-8)	
	1 Local (low mileage)	2 Local (high mileage)	3 Local	4 Long-haul
Description	MD vehicles (e.g., P&D, utility service, school buses, walk in vans) where daily driving distance **does not exceed usable range of BEV**	MD vehicles (e.g., P&D, utility service, school buses, walk in vans) where daily driving distance **exceeds usable range of BEV**	**All other Class 7-8** vehicles (e.g., drayage, distribution)	**Over-the-road** vehicles primarily running longer inter-regional routes, incl. trucks and OTRB
Charging locations	**On-site** at depot locations	**On-site** at depot locations, in addition to **on-route** charging at public locations	**On-site** at depot locations, in addition to **on-route** charging at public locations	Both top-up and overnight charging at **highway truck stop** locations

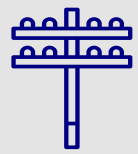
Note: Simulations are based on today's fleet size, except for long-haul trucks. The incremental weight of batteries results in a payload penalty. Trucks that weigh out today would exceed the maximum GVW limit and additional truck capacity is needed to carry the same amount of freight. For each diesel long-haul truck today, ~1.1 battery electric trucks will be needed.

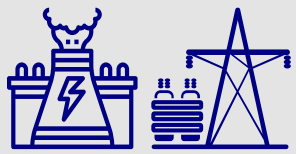
Source: US Census Bureau; Roland Berger Analysis

Our analysis focuses on characterizing the investment needs and challenges across both charging infrastructure and energy infrastructure

Investment landscape analyzed in this study

	Not in scope	Charging infrastructure			Energy infrastructure	
			"Make ready" infrastructure			
	Vehicle	Charger	Site	Electric service	Distribution grid	Generation/ transmission
Investment need	BEV purchase	Charger cost & installation	Civil & electrical	Utility service upgrade	Increased grid capacity	New power system assets
Capital outlay	Fleets	Fleets Developers	Fleets Developers	Fleets Developers Utilities	Utilities	Utilities, IPP's and developers
Subsidies or public funding (including utility rate base)	• Federal EV tax credit • State incentives	• Federal EVSE tax credit • State rebate programs	• N/A	• Utility-side make ready support in some states	• Federal funding available in some cases	• Federal funding available in some cases






Roland
Berger

Progress installing heat pumps

15 Uptake of the Boiler Upgrade Scheme has been lower than DESNZ expected, leading it to increase the grant that is available. The Boiler Upgrade Scheme funded the installation of nearly 18,900 heat pumps in England and Wales from May 2022 to December 2023. The original business case budgeted for up to 50,000 installations by this point. DESNZ underspent by £100 million in the scheme's first year. To increase uptake, in October 2023 DESNZ increased the grant value available through the scheme to £7,500 per household, up from £5,000 for an air source heat pump and £6,000 for a ground or water source heat pump. It covers nearly 60% of the average cost of installing a heat pump, based on the average cost in 2023. The grant uplift has enabled some energy suppliers to offer heat pump installations starting at £500. The number of applications to the scheme in December 2023 increased by nearly 50% compared with December 2022, and applications in January 2024 increased by nearly 40% compared with January 2023. Data over a longer period will be required to determine whether the change is sustained (paragraphs 1.9, 3.4, 3.19, and Figure 3).

16 Average heat pump installation costs have fallen, but more slowly than DESNZ hoped, and it has not made the progress it had planned on reducing running costs.

- **Installation costs:** DESNZ considers installation cost a key factor affecting demand for heat pumps. As at December 2023, the average market rate for replacing a gas boiler with a heat pump was around four times higher than replacing like-for-like. In 2021, DESNZ set an ambition for industry to reduce the costs of installing a heat pump by at least 25–50% by 2025 and to ensure heat pumps are no more expensive to buy and run than gas boilers by 2030. Data from MCS (Microgeneration Certification Scheme), a quality assurance scheme, indicate the average cost of installing a heat pump in 2023 reduced by up to 6% in real terms compared with 2021, to £11,287 (in 2021 prices).[2] Installation costs will need to fall around three times faster over the next two years if they are to reach the minimum 25% reduction ambition. DESNZ told us that costs had not fallen significantly, due to pressures in the global supply chain. This includes, for example, a shortage of semiconductors that are a key heat pump component; manufacturers not being able to keep up with increased global demand for heat pumps; and high energy prices increasing the cost of manufacturing (paragraphs 3.7, 3.8 and Figure 4).
- **Running costs:** Electricity remains more expensive per unit than gas, making heat pumps potentially more expensive to run than a gas boiler. The government has committed to rebalance energy prices over the course of the 2020s, including shifting energy levies and obligations from electricity to gas bills, but its plans around this have been delayed by nearly two years. DESNZ told us that its focus for energy bills in 2022 was tackling the high energy costs since autumn 2021, and that price rebalancing remains essential but politically challenging (paragraph 3.10).

2 We have adjusted the MCS cost data to 2021 prices.

17 DESNZ does not have all the information it needs on heat pump installations to monitor whether progress is on track and to identify key barriers to uptake. DESNZ does not have a single measure of the number of heat pumps installed. DESNZ told us it is considering how it can combine a range of datasets to produce a publishable series. It is planning to monitor uptake of the Boiler Upgrade Scheme grant among different socio-economic groups through an externally commissioned evaluation, for which interim results are due in the second half of 2024. DESNZ's understanding of the key barriers to installation is based on commissioned research, industry insight and qualitative information. However, it tracks progress against some barriers in more detail than others, and does not monitor the reasons why some applications to the Boiler Upgrade Scheme do not progress to heat pump installation. It told us it intends to take a more systematic approach to monitoring these barriers and will gather six-monthly insights through the Boiler Upgrade Scheme evaluation. Regular monitoring of progress in reducing all key barriers would help DESNZ better understand whether it is on track to deliver the anticipated increase in heat pump installations and where further intervention may be required from government or industry (paragraphs 3.3, 3.5, 3.16 and 3.17).

18 DESNZ, along with DLUHC, has developed plans for further measures aimed at increasing heat pump uptake. In 2023, DESNZ stated it would introduce the Clean Heat Market Mechanism in April 2024. This is an obligation on the manufacturers of fossil fuel heating systems to sell a certain level of low-carbon heat pumps proportional to their fossil fuel boiler sales in the UK market. In February 2024 there were media reports that ministers were considering whether to delay or remove the mechanism. DESNZ has told us that as at early March, no decision has yet been made. From 2025, DLUHC's Future Homes Standard is expected to require all new homes in England to be built to a higher standard of energy efficiency and to have low-carbon heating. DESNZ estimates this will account for 200,000 new heat pump installations a year (paragraphs 3.23, 3.24 and Figure 6).

19 DESNZ is relying on optimistic assumptions about consumer demand and manufacturer supply of heat pumps increasing substantially to achieve 600,000 installations per year by 2028. Heat Pump Association data indicates that 55,000 heat pumps were sold in the UK in 2022. Achieving the target of 600,000 annual installations by 2028 requires an elevenfold increase from 2022 to 2028, using sales as a proxy for installations. DESNZ regards the target as viable given the planned policies and regulation for 2024 onwards. This relies on the Clean Heat Market Mechanism and the Boiler Upgrade Scheme delivering 400,000 heat pump installations per year by 2028, supported by other energy efficiency and low-carbon heating retrofit schemes such as the Social Housing Decarbonisation Fund (SHDF) and the Energy Company Obligation (ECO). A third of respondents to the 2023 consultation on the Clean Heat Market Mechanism reported that the government's targets would be unachievable under market conditions at the time, although this pre-dated the increased grant available through the Boiler Upgrade Scheme. Some of the government's net zero policy announcements in September 2023, such as the delay to the phase-out of fossil fuel heating systems for off-gas-grid homes, make this target more challenging (paragraphs 3.3, 3.6, 3.23, 3.26, 3.27 and Figure 6).

Executive summary

The aim of the Annual Local Authority Road Maintenance (ALARM) survey is to highlight the connection between local road maintenance funding and conditions in England (including London) and Wales. The findings are based on information provided directly by those responsible for their upkeep.

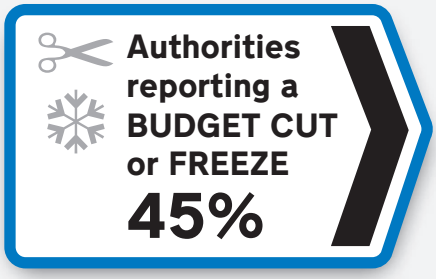
More than 70% of local authorities responded to this year's survey, providing robust data for analysis and underscoring the value that those working in the sector place on its annual findings. It is used by local authorities for benchmarking and by stakeholders across the sector as a valuable tool for tracking local road conditions and funding.

Key facts 2023/24

Funding:

- Local authorities in England and Wales effectively experienced **a real-terms cut** due to the impact of rising costs due to inflation, despite average highway maintenance budgets increasing by 2.3% to £26.4 million per authority.
- **45% of authorities reported a cut or freeze in their highway maintenance budget**, even before inflation is taken into account.
- Against this challenging backdrop, the average percentage of highway maintenance **budget spent on the carriageway increased slightly to 52%. Average carriageway maintenance budgets also increased by 8.5% to £14.1 million** from £13.0 million last year.
- The additional amount local authorities across England and Wales would have needed to maintain their network to their own targets was **£1.22 billion**. This means that the average shortfall in the 2023/24 carriageway budget was **£7.2 million per authority**.
- The **one-time catch-up cost has increased by 16% to a new record high of £16.3 billion** and the work to address it would still take a decade to complete. This is the amount needed, as a one-off (at today's prices), to bring the network up to a condition that would allow it to be managed cost-effectively as part of a proactive asset management approach.

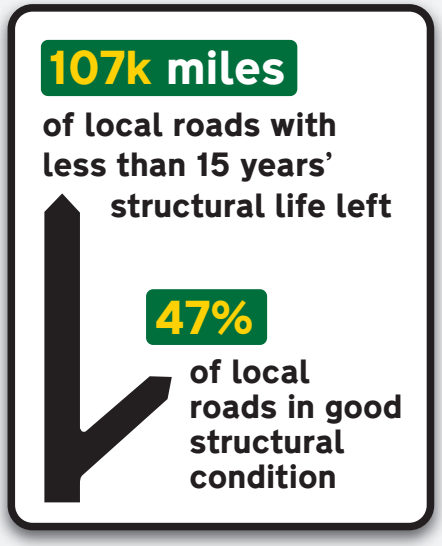
> We have seen a small increase in our highway maintenance budget, but this has been wiped out by the effects of rising inflation. In fact, if anything, we've been able to do less with the money than we did a year ago.



Detailed key findings can be found on page 20.

Conditions:

- Road Condition Index (RCI) data reports the general condition of the surface of the carriageway, not necessarily the structure of the road. It shows there has been another **drop in the length of roads classed as GREEN** (in a good state of repair) and a corresponding increase in those classed as AMBER (showing some deterioration).
- Roads classed as RED (poor overall condition) have again remained stable but still **one in every 10 miles** (11%) of the local road network in England and Wales is likely to require maintenance in the next 12 months. This equates to around 22,300 miles.
- **2 million potholes were filled** over the last year – up more than 40% from 1.4 million last year – equivalent to one every 16 seconds.
- The average frequency of resurfacing for all classes of roads is **once every 80 years**.
- Structural conditions continue to decline and now less than half (only 47%) of local road miles in England and Wales are classed as being in 'good' structural condition, down from 51% last year. The remaining **53% – more than 107,000 miles – now have less than 15 years' structural life remaining**. Structural maintenance is needed when surface maintenance alone won't suffice, and this data helps provide a more complete assessment of the overall carriageway asset.



We have spent the last year firefighting and trying to manage expectations of what can be achieved with the budget we have and a deteriorating network.

Recommendations

Only 6% of ALARM respondents in England and Wales reported that the structural condition of their local road network improved over the last year. The continued decline of our local roads, on which we all rely, is borne out by the fact that the cost of tackling the backlog of carriageway repairs has jumped by more than £2 billion, standing at a new record high of £16.3 billion.

Surface conditions are also reported to be worse – demonstrated by a 40% increase in the number of potholes filled over the last 12 months adding to the existing patchwork of previous repairs. This indicates that local authorities, who have a statutory responsibility to keep local roads safe, don't have the funds to do so in a cost-effective, proactive way, which would allow them to carry out the appropriate maintenance interventions at the right time.

We recognise that there continue to be many pressures on the public purse, but local roads are one of the country's biggest assets, so we call on the Government to:

- **Fulfil its promise** to deliver £8.3 billion in **additional** Network North funding over the next 11 years.
- **Sustain** current levels of funding through the Highway Maintenance Block and Pothole Fund allocations and extend their timeframe to match the additional funding to drive more effective asset management.
- **Increase** the level of all these sources of funding at least in line with inflation to ensure a real-terms increase in highway maintenance budgets.

In addition, the Welsh Government should also honour its commitments to prioritising highway maintenance. Combined these measures would allow local authority highway engineers in England and Wales to proactively plan and deliver improved conditions and create a safe, resilient and sustainable network for the future.

Highway maintenance budgets

There are 202,600 miles of local roads in England and Wales, including London, representing 97.3% of the total road network (source: Department for Transport, 2022). They are considered to be local authorities' most valuable asset, with a combined value in excess of £400 billion, and are maintained by local highway authorities, who have a statutory obligation to keep them in a safe condition.

Highway maintenance is a key service provided by local authorities but is just one of many areas of responsibility and necessary expenditure along with, for example, education, social care and housing.

Feedback received for 2023/24 suggests that the proportion of total local authority budgets allocated to highway maintenance continues on a downward trend. It now represents less than one per cent of local authorities' overall budgets and a small fraction of the total asset value.

These total budgets are funded by central government as well as local authority sources, which includes borrowing, use of capital reserves and monies collected through council taxes and a share of business rates as well as parking fines and other fees.

Highway maintenance funding in England

Local authority budgets for all highway maintenance activity in England (excluding London) were reported to have seen an increase to an average of £34.5 million per authority – the highest monetary value recorded in ALARM but, as an increase of just 3.6%, this was well below the prevailing rate of inflation experienced over the last year.

As to be expected, this average hides a wide disparity between those local authorities seeing increased budgets and those which have experienced a cut from the previous financial year.

In England, 43% of responses report an absolute cut or freeze in monetary terms on last year's highway maintenance budgets, despite the additional Network North funding announced by the Government in October 2023. These are funds reallocated from the cancelled second leg of HS2, which the DfT announced amount to £150 million in 2023/24.

> Unfortunately, the extra funding from DfT isn't extra at all – it's just counterbalancing the effects of inflation. The reality is, there is no additional money.

Of total budgets allocated for highway maintenance, 56% is reported to be funded by central government, while the remaining 44% comes from local authorities' own sources.

The DfT provides 92% of the central government funding to English highway authorities – equating to approximately 52% of authorities' total highway maintenance budgets.

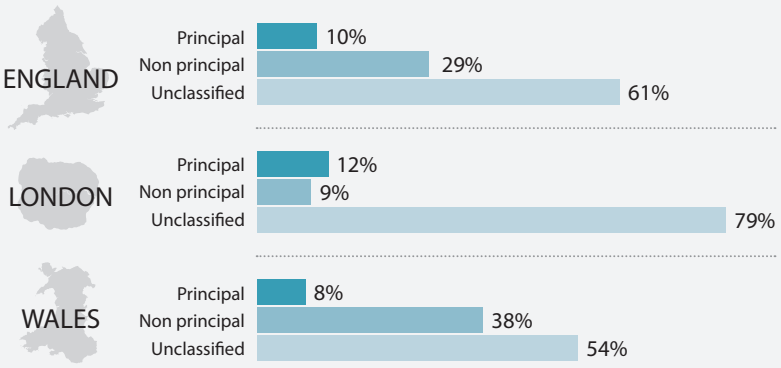
The majority of this DfT funding is not specifically allocated for highway maintenance or improvements and comes from three pots: Highways Maintenance Block needs-based funding, Pothole Fund plus the additional Network North funding.

The remainder of central government funding is from other sources such as the Department for Levelling Up, Housing and Communities, Environment Agency grants and regional and mayoral areas growth funding, although this represents a small proportion of local authorities' total highway maintenance budgets at 4.6%.

In England, 34% of local authorities, particularly those in and surrounding large cities, are members of a Combined Authority, which takes responsibility for allocating all DfT transport-related funding, including highway maintenance, among

Local roads in England and Wales

Proportion of road by type (source: DfT road length data 2022)



Carriageway maintenance budgets

Average per authority, with change from 2022/23

These figures acknowledge that circumstances can create an immediate need for maintenance to keep the roads safe and useable. It is extremely difficult for local authorities to predict and allocate the percentage of budget required for this kind of work but, it is generally agreed that around 16% (the same figure reported for the last four years) is considered a more ideal level, far less than the reported reality.

Unforeseen costs

A sizeable number of respondents have reported having to cope with unforeseen highway maintenance costs over the year.

The reasons identified for this include dealing with the effects of extreme weather events, rising traffic volumes and increased average vehicle weights on a deteriorating network, as well as the impact of inflation which has had a noticeable impact on costs.

In England, 57% of respondents have dealt with unforeseen costs, down from 70% reported last year. The average additional cost incurred has remained in line with that reported last year at £1.9 million per authority.

More London boroughs reported experiencing unforeseen costs – 89% this year compared with 72% last year – but the additional cost incurred dropped to an average of £385,500 per authority from £687,000 reported last year.

The number of respondents in Wales reporting dealing with unforeseen costs remains extremely high at 83% (2022/23: 80%) and the average cost per authority has increased dramatically to £530,300 (2022/23: £98,800), significantly compounding the impact.

Overall, £249.3 million was spent addressing unforeseen costs in England and Wales in 2023/24, up 5.5% from last year, so while the frequency of dealing with such eventualities was less; the cost of addressing them increased.

Adverse weather

Adverse weather conditions, particularly wetter winters with more intense downpours and storms and hotter, drier summers, coupled with increased traffic volumes and the age of the network can result in accelerated deterioration and a cycle of reducing resilience.

The combined impacts are more acute on evolved and often less well-maintained roads, where water can penetrate existing cracks or defects, leading to the formation of potholes which proliferate over time, compromising the serviceability of the road.

Reactive maintenance

Proportion of carriageway maintenance budget spent on reactive maintenance (**16%** considered ideal)

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

IFIC Monthly Investment Fund Statistics – February 2024

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

March 21, 2024 (Toronto) – The Investment Funds Institute of Canada (IFIC) today announced investment fund net sales and net assets for February 2024.

Mutual fund assets totalled $2.012 trillion at the end of February, up by $57.1 billion or 2.9 per cent since January. Mutual fund net sales were $3.2 billion in February.

ETF assets totalled $403.7 billion at the end of February, up by $16.0 billion or 4.1 per cent since January. ETF net sales were $5.5 billion in February.

February insights

- For the first time since March 2022, mutual fund asset levels surpassed $2 trillion.
- ETF assets reached a new high, surpassing the $400 billion mark for the first time ever.
- Mutual fund net sales were positive, after 11 consecutive months of negative net sales.
- Bond mutual funds had the highest inflows with $1.8 billion in net sales, followed closely by equity funds with $1.5 billion in net sales.
- Within ETFs, equity funds had the highest inflows with $4.0 billion in net sales, followed by bond funds with $1.2 billion in net sales.

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

Asset class	Feb 2024	Jan 2024	Feb 2023	YTD 2024	YTD 2023
Long-term funds					
Balanced	(877)	(4,475)	(945)	(5,352)	(5,345)
Equity	1,548	(1,058)	425	490	(244)
Bond	1,815	3,797	2,365	5,612	5,827
Specialty	775	747	87	1,522	713
Total long-term funds	3,261	(988)	1,932	2,272	952
Total money market funds	(40)	487	1,261	447	2,318
Total	3,221	(501)	3,193	2,720	3,269

Mutual fund net assets ($ billions)*

Asset class	Feb 2024	Jan 2024	Feb 2023	Dec 2023
Long-term funds				
Balanced	923.3	904.2	898.5	904.3
Equity	760.7	725.7	677.6	714.6

Bond	247.4	245.8	231.3	242.5
Specialty	29.1	27.9	23.1	27.0
Total long-term funds	1,960.5	1,903.6	1,830.5	1,888.5
Total money market funds	52.0	51.8	37.1	51.0
Total	2,012.5	1,955.4	1,867.6	1,939.5

* Please see below for important information regarding this data.

ETF net sales/net redemptions ($ millions)*

Asset class	Feb 2024	Jan 2024	Feb 2023	YTD 2024	YTD 2023
Long-term funds					
Balanced	450	403	167	853	232
Equity	4,032	2,396	1,021	6,428	639
Bond	1,182	321	1,228	1,502	288
Specialty	22	(346)	313	(325)	805
Total long-term funds	5,685	2,774	2,729	8,459	1,963
Total money market funds	(207)	401	1,371	194	1,646
Total	5,479	3,174	4,100	8,653	3,609

ETF net assets ($ billions)*

Asset class	Feb 2024	Jan 2024	Feb 2023	Dec 2023
Long-term funds				
Balanced	16.5	15.6	12.7	15.1
Equity	250.6	238.1	204.3	233.0
Bond	94.8	94.1	81.3	94.6
Specialty	16.3	14.2	11.6	14.4
Total long-term funds	378.2	362.0	310.0	357.2
Total money market funds	25.6	25.7	17.9	25.3
Total	403.7	387.7	327.9	382.5

* See below for important information regarding this data.

IFIC direct survey data (which accounts for approximately 87 per cent of total mutual fund industry assets and approximately 80 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 Regarding Investment Fund Data:**

1. Mutual fund data is adjusted to remove double counting arising from mutual funds that invest in other mutual funds.
2. 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. Learn more about IFIC

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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.*

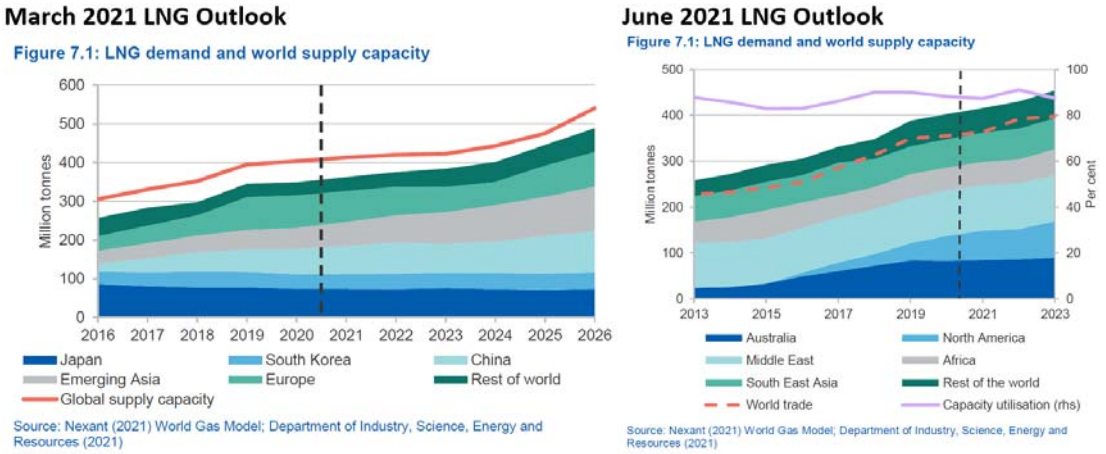
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required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

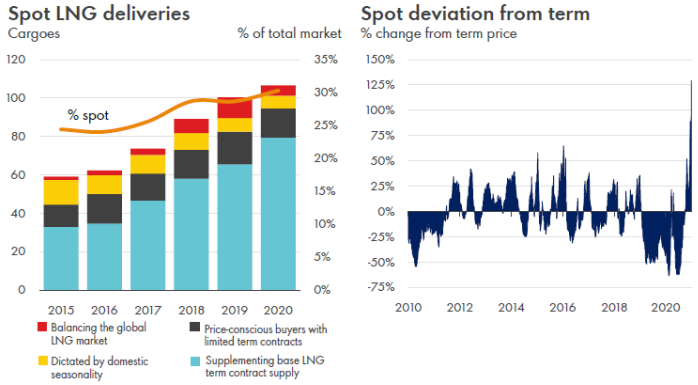


Source: Australia Resources and Energy Quarterly

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.

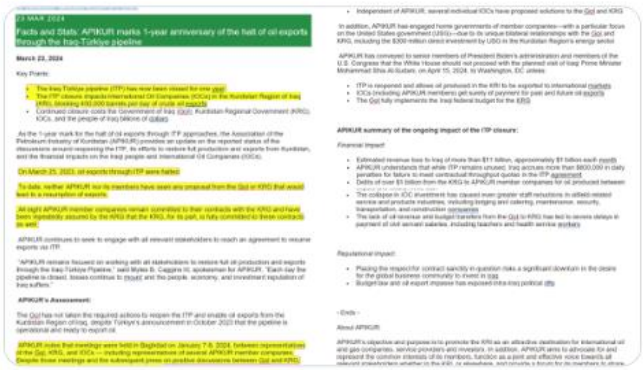
A LNG Canada Phase 2 would be a big plus to Cdn natural gas. LNG Canada Phase 1 is a material natural gas development as its 1.8 bcf/d capacity represents approx. 20 to 25% of Cdn gas export volumes to the US. The EIA data shows US pipeline imports of Cdn natural gas as 6.83 bcf/d in 2020, 7.36 bcf/d 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.

Dan Tsubouchi @Energy_Tidbits · 2h

Still no sign Iraq govt is showing any real desire to resume Kurdistan #Oil that was shut in 03/25/23.

@apikur_oil "To date, neither APIKUR nor its members have seen any proposal from the GoI or KRG that would lead to a resumption of exports."

#OOTT



Facts and Stats: APIKUR marks 1-year anniversary of the halt of oil exports through the Iraq-Türkiye pipeline

March 23, 2024

Key Points:

- The Iraq-Türkiye pipeline (ITP) has now been closed for one year.
- The ITP closure impacts International Oil Companies (IOCs) in the Kurdistan Region of Iraq (KRI), blocking 450,000 barrels per day of crude oil exports.
- Continued closure costs the Government of Iraq (GoI), Kurdistan Regional Government (KRG), IOCs, and the people of Iraq billions of dollars.

As the 1-year mark for the halt of oil exports through ITP approaches, the Association of the Petroleum Industry of Kurdistan (APIKUR) provides an update on the reported status of the discussions around reopening the ITP, its efforts to restore full production and exports from Kurdistan, and the financial impacts on the Iraqi people and International Oil Companies (IOCs).

On March 25, 2023, oil exports through ITP were halted.

To date, neither APIKUR nor its members have seen any proposal from the GoI or KRG that would lead to a resumption of exports.

All eight APIKUR member companies remain committed to their contracts with the KRG and have been repeatedly assured by the KRG that the KRG, for its part, is fully committed to these contracts as well.

APIKUR continues to seek to engage with all relevant stakeholders to reach an agreement to resume exports via ITP.

"APIKUR remains focused on working with all stakeholders to restore full oil production and exports through the Iraq-Türkiye Pipeline," said Myles B. Caggins III, spokesman for APIKUR. "Each day the pipeline is closed, losses continue to mount and the people, economy, and investment reputation of Iraq suffers."

APIKUR's Assessment:

The GoI has not taken the required actions to reopen the ITP and enable oil exports from the Kurdistan Region of Iraq, despite Türkiye's announcement in October 2023 that the pipeline is operational and ready to export oil.

APIKUR notes that meetings were held in Baghdad on January 7 & 2024, between representatives of the GoI, KRG, and IOCs — including representatives of several APIKUR member companies. Despite those meetings and the subsequent press on positive discussions between GoI and KRG:

- Independent of APIKUR, several individual IOCs have proposed solutions to the GoI and KRG.

In addition, APIKUR has engaged home governments of member companies—with a particular focus on the United States government (USG)—due to its unique bilateral relationships with the GoI and KRG, including the $300 million direct investment by USG in the Kurdistan Region's energy sector.

APIKUR has conveyed to senior members of President Biden's administration and members of the U.S. Congress that the White House should not proceed with the planned visit of Iraqi Prime Minister Mohammad Shia Al-Sudani, on April 15, 2024, to Washington, DC unless:

- ITP is reopened and allows oil produced in the KRI to be exported to international markets
- IOCs (including APIKUR members) get surety of payment for past and future oil exports
- The GoI fully implements the Iraqi federal budget for the KRG

APIKUR summary of the ongoing impact of the ITP closure:

Financial Impact

- Estimated revenue loss to Iraq of more than $11 billion, approximately $1 billion each month
- APIKUR understands that while ITP remains unused, Iraq accrues more than $600,000 in daily penalties for failure to meet contractual throughput quotas in the ITP agreement
- Debts of over $1 billion from the KRG to APIKUR member companies for oil produced between
- The collapse in IOC investment has caused even greater staff reductions in oilfield-related service and products industries, including forging and catering, maintenance, security, transportation, and construction companies
- The lack of oil revenue and budget transfers from the GoI to KRG has led to severe delays in payment of civil servant salaries, including teachers and health service workers

Reputational Impact

- Placing the respect for contract sanctity in question risks a significant downturn in the desire for the global business community to invest in Iraq
- Budget law and oil export impasse has exposed intra-Iraq political rifts

- Ends -

About APIKUR

APIKUR's objective and purpose is to promote the KRI as an attractive destination for international oil and gas companies, service providers and investors. In addition, APIKUR aims to advocate for and represent the common interests of its members, function as a joint and effective voice towards all relevant stakeholders whether in the KRI, or elsewhere, and provide a forum for its members to share

> **Dan Tsubouchi** @Energy_Tidbits · Mar 2
>
> 
>
> Breaking!
>
> AKIPUR (Kurdistan oil industry association) says no deal has been made to restart Kurdistan #Oil exports ...

2 12 1.6K

Dan Tsubouchi @Energy_Tidbits · 2h

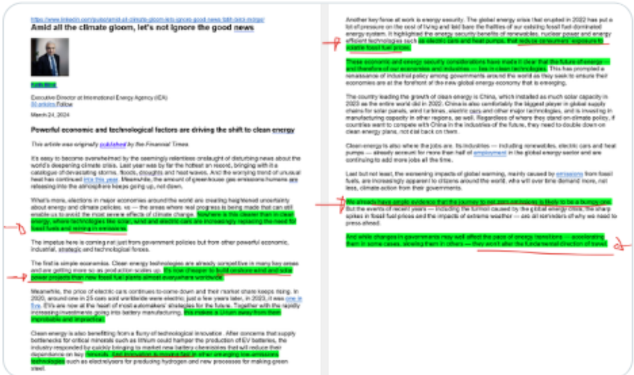
Good read @fbirol op-ed today.

Birol admits "*ample evidence that the journey to net zero emissions is likely to be a bumpy one*".

Crafty drafting to only tell half the story.

"*cheaper to build onshore wind and solar power projects than new fossil fuel plants*". Yes but that...

Show more



Amid all the climate gloom, let's not ignore the good news

Executive Director at International Energy Agency (IEA)

March 24, 2024

Powerful economic and technological factors are driving the shift to clean energy

This article was originally published by the Financial Times

> Dan Tsubouchi @Energy_Tidbits · Mar 17
>
> "***However, while the world's dependence on oil is lessening, it remains deep-rooted.***"
> "***However, there is a high degree of uncertainty around how quickly [Oil] demand will fall,***" IEA
> ...

2 · 11 · 3K

Dan Tsubouchi @Energy_Tidbits · 4h

#Houthis drone hits tanker.

#OOTT

> U.S. Central Command @CENTCOM · 12h
>
> MARCH 23 RED SEA UPDATE
>
> From 2:50 to 4:30 a.m. (Sanaa time)
> March 23, the Iranian-backed Houthis launched four anti-ship ballistic missiles (ASBM) into the Red Sea in the vicinity of M/V Huang Pu, a ...
> Show more
>
> UNITED STATES CENTRAL COMMAND

6 · 1.7K

Dan Tsubouchi @Energy_Tidbits · 23h

#Oil floating storage 66.24 mmb Mar 22

Last 7 wks ave 71 mmb. Floating normalizing at much lower level.

Refiners/tankers have worked in longer tanker trips = lower floating storage as OPEC keeps cuts thru Q2

Thx @vortexa @business #OOTT

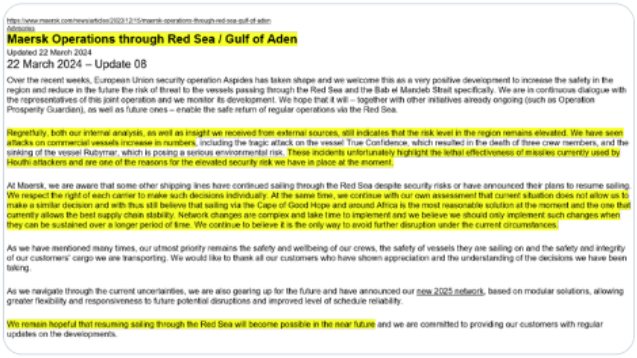
7 33 3.5K

Dan Tsubouchi @Energy_Tidbits · Mar 22

Maersk to continue to avoid Red Sea & sail via the Cape of Good Hope .

👇03/22 update also reminds *"Network changes are complex and take time to implement and we believe we should only implement such changes when they can be sustained over a longer period of* time"

#OOTT



https://www.maersk.com/news/articles/2023/12/15/maersk-operations-through-red-sea-gulf-of-aden

Maersk Operations through Red Sea / Gulf of Aden

Updated 22 March 2024

22 March 2024 – Update 08

Over the recent weeks, European Union security operation Aspides has taken shape and we welcome this as a very positive development to increase the safety in the region and reduce in the future the risk of threat to the vessels passing through the Red Sea and the Bab el Mandeb Strait specifically. We are in continuous dialogue with the representatives of this joint operation and we monitor its development. We hope that it will – together with other initiatives already ongoing (such as Operation Prosperity Guardian), as well as future ones – enable the safe return of regular operations via the Red Sea.

Regretfully, both our internal analysis, as well as insight we received from external sources, still indicates that the risk level in the region remains elevated. We have seen attacks on commercial vessels increase in numbers, including the tragic attack on the vessel True Confidence, which resulted in the death of three crew members, and the sinking of the vessel Rubymar, which is posing a serious environmental risk. These incidents unfortunately highlight the lethal effectiveness of missiles currently used by Houthi attackers and are one of the reasons for the elevated security risk we have in place at the moment.

At Maersk, we are aware that some other shipping lines have continued sailing through the Red Sea despite security risks or have announced their plans to resume sailing. We respect the right of each carrier to make such decisions individually. At the same time, we continue with our own assessment that current situation does not allow us to make a similar decision and with thus still believe that sailing via the Cape of Good Hope and around Africa is the most reasonable solution at the moment and the one that currently allows the best supply chain stability. Network changes are complex and take time to implement and we believe we should only implement such changes when they can be sustained over a longer period of time. We continue to believe it is the only way to avoid further disruption under the current circumstances.

As we have mentioned many times, our utmost priority remains the safety and wellbeing of our crews, the safety of vessels they are sailing on and the safety and integrity of our customers' cargo we are transporting. We would like to thank all our customers who have shown appreciation and the understanding of the decisions we have been taking.

As we navigate through the current uncertainties, we are also gearing up for the future and have announced our new 2025 network, based on modular solutions, allowing greater flexibility and responsiveness to future potential disruptions and improved level of schedule reliability.

We remain hopeful that resuming sailing through the Red Sea will become possible in the near future and we are committed to providing our customers with regular updates on the developments.

> **Dan Tsubouchi** @Energy_Tidbits · Feb 2
>
> 
>
> Great map courtesy of @EIAgov Josh Eiermann
>
> Shows relative tanker travel times from US Gulf Coast to China.
>
> ...

7 · 10 · 16K

Dan Tsubouchi @Energy_Tidbits · Mar 22

Blinken's ceasefire comments led to oil down $0.41 Wow to WTI close at $80.63.

BUT continuing positive for WTI over coming weeks.

321 crack spreads at $32.20 are very big margins for refineries ie, huge incentive to maximize runs & buying crude.

#OOTT Thx @business

1 · 8 · 42 · 4.8K

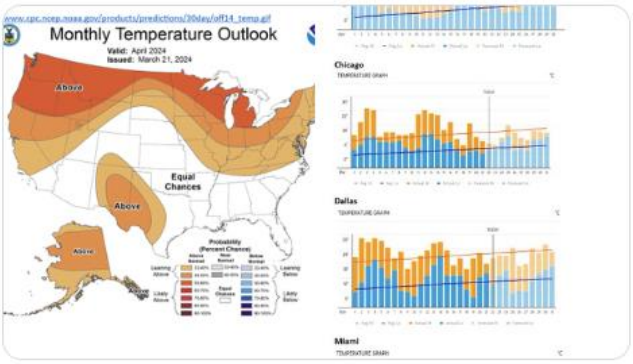
Dan Tsubouchi @Energy_Tidbits · Mar 22

No significant temperature driven demand for #NatGas expected based on @NOAA 30-day temperature outlook for April.

For the most part, it will be leave your windows open weather, no need for A/C or for furnaces.

Thx @NOAA @AccuWeather

#OOTT



1 7 1.6K

Dan Tsubouchi @Energy_Tidbits · Mar 21

ICYMI.

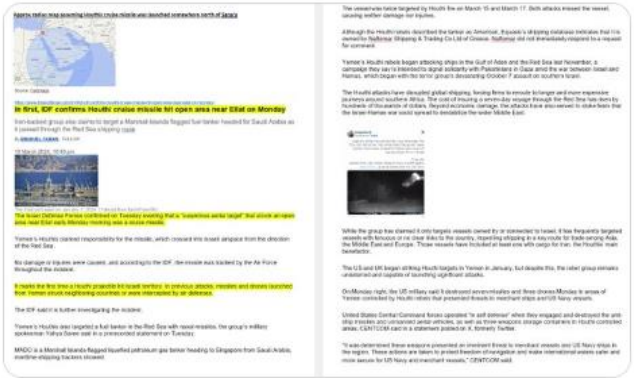
1st time a Houthi missile wasn't shot down by IDF missile defense systems and hit near Eilat in southern Israel.

IDF says no damage/injuries.

Reminds if Houthis can hit Israel, their missiles can reach all of Saudi Arabia and UAE.

...

Show more



1 2 2K

Dan Tsubouchi @Energy_Tidbits · Mar 21

Bullish for near term #Oil.

"we're seeing jet fuel now back to averaging around 6.9 million barrels per day over the last 4-weeks, which is back to 2019 levels"

"we see growth in Q2, which brings it up to record highs"

@vitolnews Kieran Gallagher to @sean_evers
#OOTT

Note the correction in the headline says "now back to.." as opposed to the autocorrect first time that had "not back to"

***"...We're seeing jet fuel now back to averaging around 6.9 million barrels per day over the last 4-weeks, which is back to 2019 levels."* Kieran Gallagher, Managing Director Vitol Bahrain E.C.**

SAF created transcript of comments by Kieran Gallagher (Managing Director Vitol Bahrain E.C.) with Sean Evers (Founder & Managing Partner of Gulf Intelligence) on Gulf Intelligence Daily Energy Markets podcast on March 21, 2024. [LINK]

Items in "italics" are SAF Group created transcript.

At 12:00 min mark, Gallagher "We're seeing jet fuel now back to averaging around 6.9 million barrels per day over the last 4-weeks, which is back to 2019 levels". Evers "which of course is a global number". Gallagher "It's a global number. And at 6.9, you know we see growth in Q2 which brings it up to sort of record highs".

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

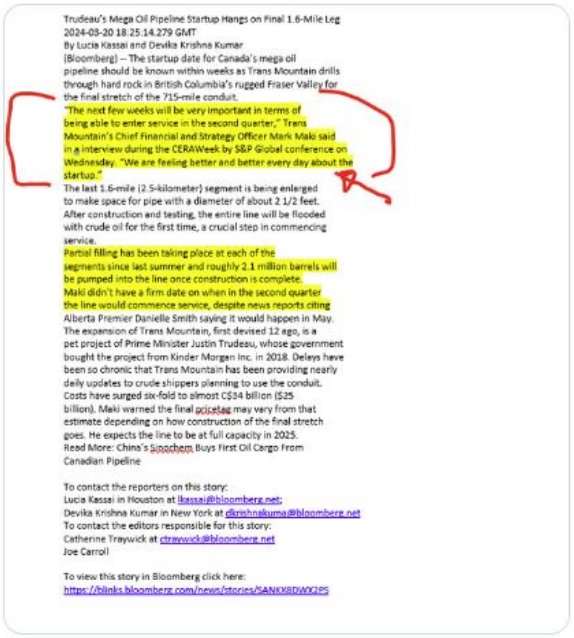
8 32 3.8K

Dan Tsubouchi @Energy_Tidbits · Mar 21

"***We are feeling better and better every day about the startup***" Trans Mountain's Mark Maki about 590,000 b/d TMX entering service in Q2 Report @lkassai @Devikakrishnak.

Big positive for Cdn #Oil with expected narrowing of differentials ie. less of a discount to Cdn oil.

#OOTT



Trudeau's Mega Oil Pipeline Startup Hangs on Final 1.6-Mile Leg
2024-03-20 18:25:14.279 GMT
By Lucia Kassai and Devika Krishna Kumar
(Bloomberg) -- The startup date for Canada's mega oil pipeline should be known within weeks as Trans Mountain drills through hard rock in British Columbia's rugged Fraser Valley for the final stretch of the 715-mile conduit.
"The next few weeks will be very important in terms of being able to enter service in the second quarter," Trans Mountain's Chief Financial and Strategy Officer Mark Maki said in a interview during the CERAWeek by S&P Global conference on Wednesday. "We are feeling better and better every day about the startup."
The last 1.6-mile (2.5-kilometer) segment is being enlarged to make space for pipe with a diameter of about 2 1/2 feet. After construction and testing, the entire line will be flooded with crude oil for the first time, a crucial step in commencing service.
Partial filling has been taking place at each of the segments since last summer and roughly 2.1 million barrels will be pumped into the line once construction is complete.
Maki didn't have a firm date on when in the second quarter the line would commence service, despite news reports citing Alberta Premier Danielle Smith saying it would happen in May.
The expansion of Trans Mountain, first devised 12 ago, is a pet project of Prime Minister Justin Trudeau, whose government bought the project from Kinder Morgan Inc. in 2018. Delays have been so chronic that Trans Mountain has been providing nearly daily updates to crude shippers planning to use the conduit.
Costs have surged six-fold to almost C$34 billion ($25 billion). Maki warned the final pricetag may vary from that estimate depending on how construction of the final stretch goes. He expects the line to be at full capacity in 2025.
Read More: China's Sinochem Buys First Oil Cargo From Canadian Pipeline

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To contact the editors responsible for this story:
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Joe Carroll

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/SANKX8DWX2PS

> **Dan Tsubouchi** @Energy_Tidbits · Mar 20
>
> 
>
> Big positive to Cdn #Oil about to kick-in with 590,000 b/d TMX expected start by end of Q2.
>
> China's Sinochem takes 1st cargo from Suncor in May/June reports @business....

3 3 16 4.9K

Dan Tsubouchi @Energy_Tidbits · Mar 21

"*The IEA has become, so to speak, our armed wing of implementing the Paris agreement" Macron.*

See 👇 02/19/24 tweet.

Looks topical in light of @SenJohnBarrasso @cathymcmorris letter to @IEA @fbirol. spglobal.com/commodityinsig...

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Feb 19
>
> "*The IEA has become, so to speak, our armed wing of implementing the Paris agreement*" Macron.
>
> The IEA has no guns, is Macron saying analysis/fcasts are their weapons to implement Paris as opposed to analyzing energy!...
> *Show more*
>
> ***"The IEA has become, so to speak, our armed wing of implementing the Paris agreement"***
> **France President Macron**
>
> 
>
>
> SAF Group created transcript of France President Macron at the IEA Ministerial meetings on Feb 13/14 in Paris.
>
> Items in "italics" are SAF Group created from IEA's posted video https://twitter.com/IEA/status/1759625691795005474
>
> At 0;52 min mark, Macron "*We are also very proud that since its creation, the Agency has been able to profoundly shift its mandate. From an agency dedicated to managing strategic oil reserves, it has now become a global hub for debate, collective action to meet the challenge of the energy transition. The IEA has become, so to speak, our armed wing of implementing the Paris agreement, given that energy accounts for more than 75% of global greenhouse gas emissions.*"
>
> Prepared by SAF Group https://safgroup.ca/news-insights/

2 · 2 · 1.5K

Dan Tsubouchi @Energy_Tidbits · 59m

China consumer.

Great line on Gucci China sales drop from @FerroTV @lisaabramowicz1

JF "*They're [Gucci] trying to move from Loud Luxury to Quiet Luxury. Good Luck*"
LA "*Are they really going to migrate to what someone else might wear*"
JF "*Brunello. Something like that. People...*
Show more

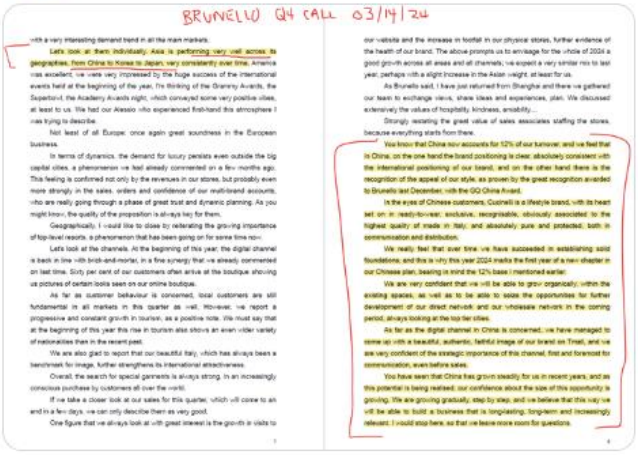
2 · 1 · 873

Dan Tsubouchi @Energy_Tidbits · 59m

Wealthy China consumer not feeling the pinch, still stepping up for very high price Brunello.

Brunello Q4/23 call on 03/14/24.

"*Asia is performing very well across its geographies, from China to Korea to Japan, very consistently over time*".
#OOTT


BRUNELLO Q4 CALL 03/14/24

524

Dan Tsubouchi @Energy_Tidbits · 1h

For those not near their laptops, @EIAgov just released at 8:30am MT its #Oil #Gasoline #Distillates inventory as of Mar 15. Table below compares EIA data vs @businessexpectations and vs @APIenergy yesterday. Prior to release, WTI was $82.00. #OOTT

Oil/Products Inventory Mar 15: EIA, Bloomberg Survey Expectations, API			
(million barrels)	EIA	Expectations	API
Oil	-1.95	-1.00	-1.50
Gasoline	-3.31	-2.60	-1.60
Distillates	0.62	-0.50	0.50
	-4.64	-4.10	-2.60
Note: Oil is commercial. So excludes a +0.7 mmb in SPR for the Mar 15 week			
Note: Included in the oil data, Cushing had a 0.02 mmb draw for Mar 15 week			
Source EIA, Bloomberg			
Prepared by SAF Group https://safgroup.ca/news-insights/			

3 8 1.1K

Dan Tsubouchi @Energy_Tidbits · 4h

China #Oil imports for Feb

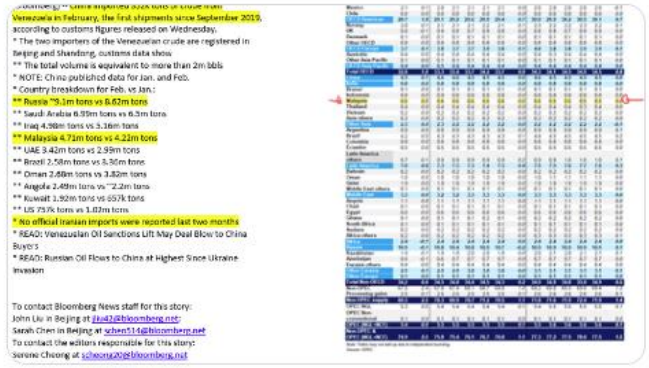
89 kbd from VEN, 1st imports since Sept 2019

2,300 kbd from RUS vs 2,180 kbd in Jan

Zero imports from Iran. BUT likely rebranded as Malaysia as 1,190 kbd in Feb vs Malaysia total prod of 600 kbd.

Thx @business John Liu, @sarahchen...

Show more


Venezuela in February, the first shipments since September 2019, according to customs figures released on Wednesday.
* The two importers of the Venezuelan crude are registered in Beijing and Shandong, customs data show
** The total volume is equivalent to more than 2m bbls
* NOTE: China published data for Jan. and Feb.
* Country breakdown for Feb. vs Jan.:
** Russia 79.1m tons vs 8.62m tons
** Saudi Arabia 6.95m tons vs 6.3m tons
** Iraq 4.96m tons vs 3.16m tons
** Malaysia 4.71m tons vs 4.22m tons
** UAE 3.42m tons vs 2.99m tons
** Brazil 2.58m tons vs 3.36m tons
** Oman 2.58m tons vs 3.82m tons
** Angola 2.49m tons vs ~2.2m tons
** Kuwait 1.92m tons vs 657k tons
** US 757k tons vs 1.02m tons
* No official Iranian imports were reported last two months
* READ: Venezuelan Oil Sanctions Lift May Deal Blow to China Buyers
* READ: Russian Oil Flows to China at Highest Since Ukraine Invasion

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Sarah Chen in Beijing at schen514@bloomberg.net
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Serene Cheong at scheong20@bloomberg.net

2 6 1.4K

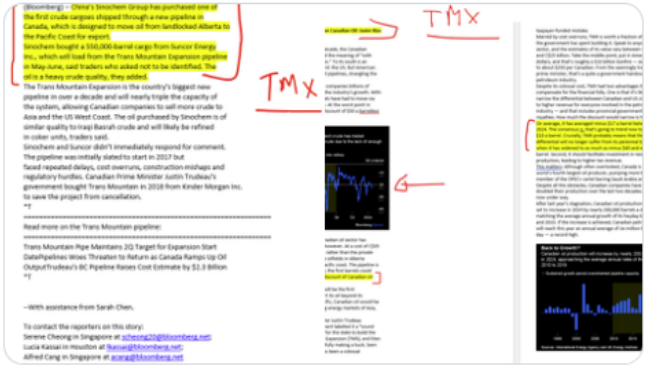
Dan Tsubouchi @Energy_Tidbits · 4h

Big positive to Cdn #Oil about to kick-in with 590,000 b/d TMX expected start by end of Q2.

China's Sinochem takes 1st cargo from Suncor in May/June reports @business.

Recall 👇 @JavierBlas 02/14 column, expected to give $7/b lift to Cdn crude.

#OOTT



> **Javier Blas** @JavierBlas · Feb 12
>
> COLUMN: After years of pain, Canada's expensive new pipeline expansion is set to put its oil industry back on track | #OOTT #Canada | @Opinion bloomberg.com/opinion/articl...

4 13 53 7.6K

Dan Tsubouchi @Energy_Tidbits · 13h

"*we need more*" long-haul travelers to Peninsula hotels in Beijing, Hong Kong & Shanghai says @HSH_HongKong CEO Kwok to @DavidInglesTV

"We are seeing a gradual pickup and, as I said, we are seeing a bit more long-haul business coming back. But we need more. We need more." #OOTT

***"We are seeing a gradual pickup and, as I said, we are seeing a bit more long-haul business coming back. But we need more. We need more."* Clement Kwok on future bookings at The Peninsula Hong Kong.**

SAF Group created transcript of comments by Clement Kwok (The Hongkong & Shanghai Hotels CEO) with Bloomberg's David Ingles on Bloomberg The China Show on March 19, 2024 (North America time) /

Items in "italics" are SAF Group created transcript.

Ingles "*what are future bookings looking like for the Hong Kong property?*" Kwok "*We are seeing a gradual pickup and, as I said, we are seeing a bit more long-haul business coming back. But we need more. We need more.*"

Ingles "*How much growth do you see, Beijing and Shanghai, those two specific properties moving forward, this year?*" Kwok "*Well, I think in terms of long-haul travel, the same comment applies to Hong Kong, Beijing, and Shanghai. Beijing and Shanghai however, as you would expect, we are seeing the development of a more affluent domestic market as well. You will see that, in the US, a lot of the customers come from the US. And in China you are seeing, with the growth of affluence in China, that more customers come from within China as well. So we are seeing growth in all of those places. Difficult to put a percentage on it David because it is difficult to predict business a few months out.*"

Ingles "*When are you able to reach pre-Covid levels if all things go to plan? Let's put it that way. What are your assumptions?*" Kwok "*Well, I think for the group as a whole, I'm really hoping to exceed pre-Covid by the end of the coming year. But, of course we are always ambitious and we work very hard to try to achieve that*".

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

2 2 1.8K

Dan Tsubouchi @Energy_Tidbits · 14h

Yes @aramco CEO Nasser is talking his book **BUT** hard for anyone to argue he is wrong, when he says "*the current energy transition strategy is visibly failing on most fronts as it collides with five hard realities*".

A great short and sweet speech.
See 👇 transcript
#OOTT

"They want energy that helps protect the planet and their pocket books with minimum disruption to supplies and their daily lives. The current transition strategy is visibly failing on most fronts as it collides with five hard realities". **Saudi Aramco CEO Amin Nasser**

SAF Group created transcript of comments by Saudi Aramco CEO Nasset at CERAWeek 2024 on March 18, 2024.
https://twitter.com/aramco/status/1770057187836223534

Items in "italics" are SAF Group created transcript.

Nasser *"Consumers around the world are sending powerful messages that can no longer be ignored. They want energy that helps protect the planet and their pocket books with minimum disruption to supplies and their daily lives. The current transition strategy is visibly failing on most fronts as it collides with five hard realities. The first is that alternatives have been unable to displace hydrocarbons at scale. The second hard reality is that despite the contribution of alternatives to reducing greenhouse gas emissions when the world does focus on reducing emissions from hydrocarbons, it achieves much better results. The third reality is that many alternatives in play are simply unaffordable for the majority of people around the world. The fourth reality is that energy transition narrative will increasingly be written by the Global South. In turn, this is driving the fifth hard reality that a transition strategy reset is urgently needed, and my proposal is this: we should abandon the fantasy of phasing out oil and gas, and instead, invest in them adequately, reflecting realistic demand assumptions. This welcome clarity from consumers is shifting the transition's center of gravity to a multi-source, multi-speed, multi-dimensional road to reality, and to the right side of history where everyone's hopes and ambitions can actually be met."*

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

> **Dan Tsubouchi** @Energy_Tidbits · Mar 18
>
> 
>
> "*We should abandon the fantasy of phasing out* #Oil & #NatGas *and instead invest in them adequat****ely reflecting realistic demand assumpt****ions" @aramco CEO Nasser.
> ...

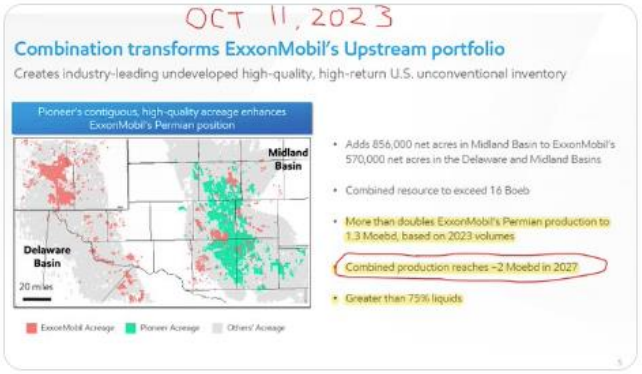
4 8 4K

Dan Tsubouchi @Energy_Tidbits · 16h

Reports Exxon to bring Permian to 2 MBD by 2027 is not new.

10/11/23 "A*t [PXD] close, XOM's Permian production volume would more than double to 1.3 MOEBD, based on 2023 volumes, and is expected to increase to approximately 2 MOEBD in 2027.*"

#OOTT
reuters.com/markets/commod...



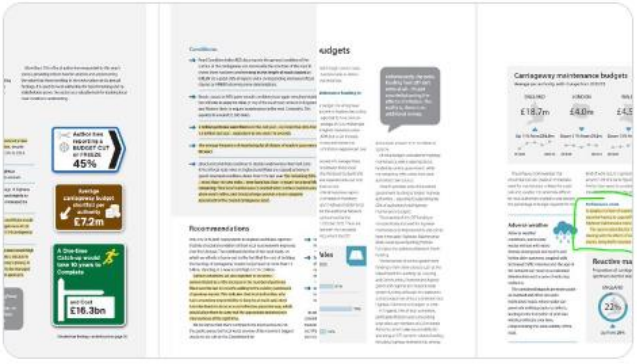
2 · 1 · 1.1K

Dan Tsubouchi @Energy_Tidbits · 1h

Blame EVs & SUVs for UK potholes.

reasons for unforeseen UK highway maintenance costs incl "*.. effects of extreme weather events, rising traffic volumes and* ***increased average vehicle weights*** *on a deteriorating network..*" @AIA_Asphalt

#OOTT



3 · 3 · 1K

Dan Tsubouchi @Energy_Tidbits · 1h

Here's why it will take a very long time for US medium & heavy duty E-trucks.

~$1 trillion just for the required infrastructure including **US utilities will need to invest $370b AHEAD of MDHD adoption** to avoid bottlenecks and delays.

Diesel trucks are here for longer!
#OOTT
Thx...
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5 9 1.7K

Dan Tsubouchi @Energy_Tidbits · 8h

Hmmm!

Toyota 1:6:90 rule "*for all the precious metals & everything are put in a battery in an EV, they can make 6 PHEV or 90 HEV. With those 90 hybrids, they save 37 times the CO2 as you do with 1 EV*" BofA Murphy to @lisaabramowicz1 @FerroTV

Is this why 👇 02/18 Guilbeault said...
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> **Dan Tsubouchi** @Energy_Tidbits · Feb 18
>
> 
>
> Is phasing out of ICE vehicles in 🇨🇦 about to be delayed?
>
> Did Min Guilbeault highlight EVs not a panacea to set stage to relax his 👇 #EVs sales targets >20% by 203...

1 11 38 7.7K

Dan Tsubouchi @Energy_Tidbits · 10h

Digitization/AI wiping out non-producer, non-revenue generator white collar jobs.

"300,000 people, we have 212,000 today"
"It's going to have less labor content. Are those people paid more, a lot more because the way the labor content shifts"
"it will have less labor content...
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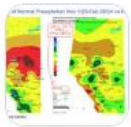
3 13 28 14K

Dan Tsubouchi @Energy_Tidbits · 11h

Needed snowfall this week in Alberta, especially in key agricultural areas. @weathernetwork

See 👇 03/08 tweet, hugely less snow this winter even vs last year lows so every bit of snow helps.

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Mar 8
>
> 
>
> Here's why there is increased risk to wildfire season & crops this summer vs last summer.
>
> % of normal precipitation is significantly lower this winter vs last winter. ...

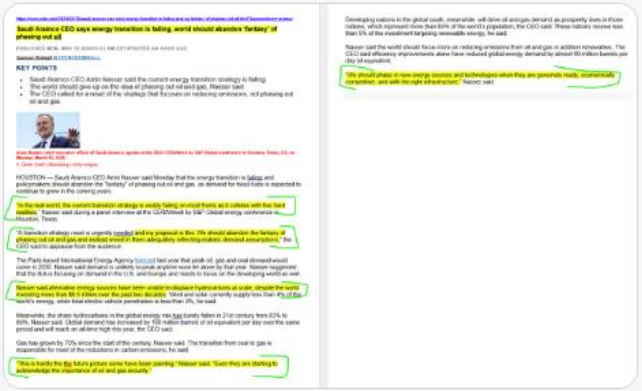
1 4 1.7K

Dan Tsubouchi @Energy_Tidbits · Mar 18

"*We should abandon the fantasy of phasing out* #Oil & #NatGas *and instead invest in them adequat**ely reflecting realistic demand assumpt**ions*" @aramco CEO Nasser.

See 👇 03/11 tweet, IEA finally admitting world dependence on o*il "remains deep roo*ted"

Thx @spencekimball #OOTT



Saudi Aramco CEO says energy transition is failing, world should abandon 'fantasy' of phasing out oil

KEY POINTS

- Saudi Aramco CEO Amin Nasser said the current energy transition strategy is failing.
- The world should give up on the idea of phasing out oil and gas, Nasser said.
- The CEO called for a reset of the strategy that focuses on reducing emissions, not phasing out oil and gas.

HOUSTON — Saudi Aramco CEO Amin Nasser said Monday that the energy transition is failing and policymakers should abandon the "fantasy" of phasing out oil and gas, as demand for fossil fuels is expected to continue to grow in the coming years.

"In the real world, the current transition strategy is visibly failing, on most fronts as it collides with the hard realities," Nasser said during a panel interview at the CERAWeek by S&P Global energy conference in Houston, Texas.

"A transition strategy reset is urgently needed and my proposal is this: We should abandon the fantasy of phasing out oil and gas and instead invest in them adequately reflecting realistic demand assumptions," the CEO said to applause from the audience.

The Paris-based International Energy Agency forecast last year that peak oil, gas and coal demand would come in 2030. Nasser said demand is unlikely to peak anytime soon let alone by that year. Nasser suggested that the IEA is focusing on demand in the U.S. and Europe and needs to focus on the developing world as well.

Nasser said alternative energy sources have been unable to displace hydrocarbons at scale, despite the world investing more than $5.5 trillion over the past two decades. Wind and solar currently supply less than 4% of the world's energy, while total electric vehicle penetration is less than 3%, he said.

Meanwhile, the share hydrocarbons in the global energy mix has barely fallen in 21st century from 83% to 80%, Nasser said. Global demand has increased by 108 million barrels of oil equivalent per day over the same period and will reach an all-time high this year, the CEO said.

Gas has grown by 70% since the start of this century, Nasser said. The transition from coal to gas is responsible for most of the reductions in carbon emissions, he said.

"This is hardly the big future picture some have been painting," Nasser said. "Even they are starting to acknowledge the importance of oil and gas security."

Developing nations in the global south, meanwhile, will drive oil and gas demand as prosperity rises in those nations, which represent more than 85% of the world's population, the CEO said. These nations receive less than 5% of the investment targeting renewable energy, he said.

Nasser said the world should focus more on reducing emissions from oil and gas in addition renewables. The CEO said efficiency improvements alone have reduced global energy demand by almost 90 million barrels per day of equivalent.

"We should phase in new energy sources and technologies when they are genuinely ready, economically competitive, and with the right infrastructure," Nasser said.

> **Dan Tsubouchi** @Energy_Tidbits · Mar 17
>
> 
>
> "*However, while the world's dependence on oil is lessening, it remains deep-rooted.*"
> "*However, there is a high degree of uncertainty around how quickly [Oil] demand will fall,*" IEA
> ...

1 · 7 · 3.5K

Dan Tsubouchi @Energy_Tidbits · Mar 18

Optimistic to Realistic - UK heat pumps

@NAOorguk progress report on replacing #NatGas boilers

18,900 installs vs 50,000 target

Costs to replace still around 4x higher to replace gas boiler.

"*Potentially more expensive to run..*"

...

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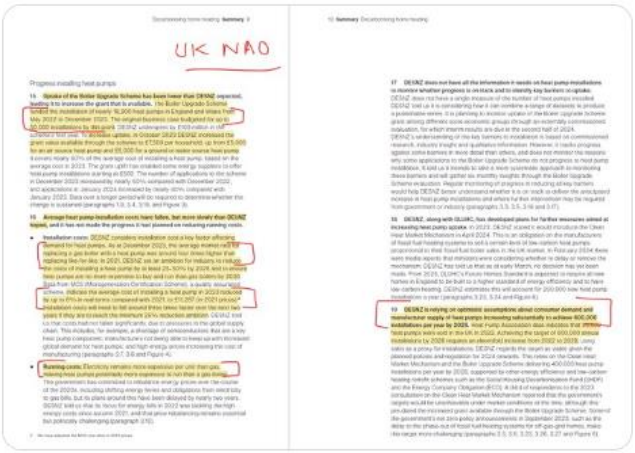

3 4 2.7K

Dan Tsubouchi @Energy_Tidbits · Mar 18

Iraq to reduced #Oil exports to 3.3 mmb/d "during the coming months to compensate for any increase recorded in January and February."

thx @DLKhraiche

#OOTT #OPEC

> **اقتصاد سكاي نيوز عربية** @SNABusiness · Mar 18
>
> #عاجل |
>
> وزارة النفط العراقية: العراق سيخفض صادراته من النفط الخام إلى 3.3 مليون برميل يومياً خلال الأشهر المقبلة لتعويض أي زيادة مسجلة في يناير وفبراير
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3 2K

Dan Tsubouchi @Energy_Tidbits · Mar 18

#Oil story this morning

very big margins for 🇺🇸 refiners to buy oil now

#OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Mar 15
>
> Positive for WTI #Oil over coming weeks.
>
> 321 crack spreads at $33.00 are very big margins for refineries ie, huge incentive to maximize runs/crude input.
>
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6 · 45 · 6.7K

Dan Tsubouchi @Energy_Tidbits · Mar 18

"***Well, hang on, maybe the Lunar New Year being strong is actually indicative of the fact that oil demand growth in China is going to be strong overall.***"

@Jamie_Ingram on IEA being relatively bearish on China despite strong signals from Lunar New Year.

#OOTT @gulf_intel

> ***"Well hang on, maybe the Lunar New Year being strong is actually indicative of the fact that oil demand growth in China is going to be strong overall."*** **Jamie Ingram MEES on IEA being relatively bearish on China despite strong signals from Lunar New Year.**
>
> 
>
>
> SAF Group created transcript of comments by Jamie Ingram, Senior Editor, Middle East Economic Survey with Gulf Intelligence Founder & Managing Partner Sean Evers on Gulf Intelligence Daily Energy Markets podcast on March 18, 2024. [LINK]
>
> Items in "Italics" are SAF Group created transcript.
>
> At 26:55 min mark, Ingram *"look at China. The IEA has been talking, interestingly, about how they still are relatively bearish on the outlook for demand growth in China despite strong signals coming out of the Lunar New Year. Well hang on, maybe the Lunar New Year being strong is actually indicative of the fact that oil demand growth in China is going to be strong overall."*
>
> Prepared by SAF Group https://safgroup.ca/news-insights/

3 · 3 · 19 · 3.2K

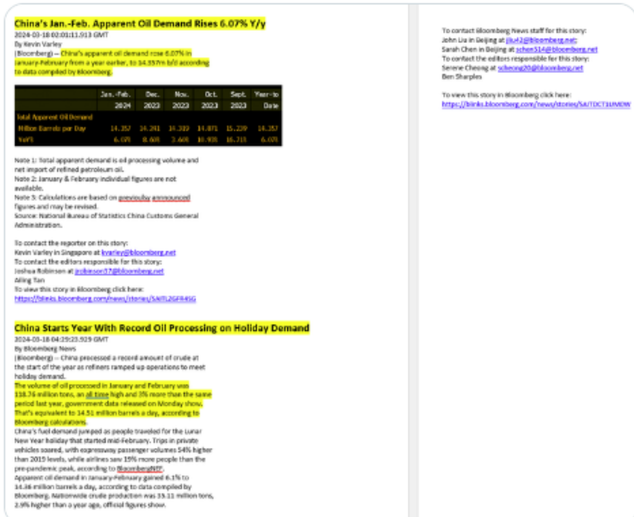
Dan Tsubouchi @Energy_Tidbits · Mar 18

Positive Jan/Feb China #Oil indicators posted today.

"China's Jan-Feb. Apparent Oil Demand Rises 6.07% Y/y"

"China Starts Year With Record Oil Processing on Holiday Demand"

thx @business John Liu, @sarahchen, Kevin Varley
#OOTT



China's Jan.-Feb. Apparent Oil Demand Rises 6.07% Y/y
2024-03-18 02:01:11.913 GMT
By Kevin Varley
(Bloomberg) -- China's apparent oil demand rose 6.07% in January-February from a year earlier, to 14.357m b/d according to data compiled by Bloomberg.

	Jan.-Feb. 2024	Dec. 2023	Nov. 2023	Oct. 2023	Sept. 2023	Year-to Date
Total Apparent Oil Demand						
Million Barrels per Day	14.357	14.291	14.319	14.871	15.229	14.357
YoY%	6.07%	8.60%	3.60%	10.93%	16.71%	6.07%

Note 1: Total apparent demand is oil processing volume and net import of refined petroleum oil.
Note 2: January & February individual figures are not available.
Note 3: Calculations are based on previoulsy announced figures and may be revised.
Source: National Bureau of Statistics China Customs General Administration.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/SAITL2GFR4SG

China Starts Year With Record Oil Processing on Holiday Demand
2024-03-18 04:29:23.919 GMT
By Bloomberg News
(Bloomberg) -- China processed a record amount of crude at the start of the year as refiners ramped up operations to meet holiday demand.
The volume of oil processed in January and February was 118.76 million tons, an all time high and 3% more than the same period last year, government data released on Monday show. That's equivalent to 14.51 million barrels a day, according to Bloomberg calculations.
China's fuel demand jumped as people traveled for the Lunar New Year holiday that started mid-February. Trips in private vehicles soared, with expressway passenger volumes 54% higher than 2019 levels, while airlines saw 19% more people than the pre-pandemic peak, according to BloombergNEF.
Apparent oil demand in January-February gained 6.1% to 14.36 million barrels a day, according to data compiled by Bloomberg. Nationwide crude production was 35.11 million tons, 2.9% higher than a year ago, official figures show.

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1 · 6 · 1.3K

Dan Tsubouchi @Energy_Tidbits · Mar 17

"*However, while the world's dependence on oil is lessening, it remains deep-rooted.*"
"However, there is a high degree of uncertainty around how quickly [Oil] demand will fall," IEA

Is IEA going to push back when it forecasts peak oil demand?

Good blog, just a decade late...
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1 · 6 · 18 · 7.5K