Oil and Gas News Briefs
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February 22, 2024

U.S. shale oil boom could be slowing down

(Wall Street Journal; Feb. 19) - A U.S. shale boom that helped suppress global oil-price surges over the past two years is waning. The country's crude oil output is expected to increase by just 170,000 barrels a day in 2024 from last year, down from a jump of 1 million barrels a day in 2023, according to federal record-keepers. That is the smallest annual increase since 2016, not counting the pandemic. "The ease in growth has gone, unless somebody comes up with a very dramatic new technical innovation," said Paul Horsnell, head of commodities research at Standard Chartered Bank.

New U.S. crude has helped cap soaring oil prices despite OPEC production cuts and global turmoil. The production gains were driven by private companies that put rigs to work after Russia's invasion of Ukraine sent prices soaring over $120 a barrel in early 2022. That growth is expected to slow dramatically. Declining oil prices led producers to lay down rigs last year. Then, many of the operators that had been drilling with abandon were acquired by bigger players looking for ways to expand in the U.S. Those big public companies have given priority to returning cash to shareholders over drilling new wells.

The Permian Basin has accounted for nearly all the country's oil output growth since the pandemic. Last year, the U.S. produced an estimated 12.9 million barrels of oil a day — a record high and more than any other country. But the number of oil rigs operating in the U.S. has dropped nearly 20% since the end of 2022 to about 500, according to oil field services firm Baker Hughes. That decline signals a huge deceleration in growth could be coming, since so many wells have been drilled recently and because a shale well's output declines most rapidly early in its life, said Standard Chartered's Horsnell.

Consolidation brings an era of Big Shale to the U.S.

(Fortune; Feb. 20) - This week's $26 billion combination of two Texas oil companies is the latest in a series of deals that's ushering in the era of Big Shale. Wall Street, which eyed the sector with skepticism for most of the past decade, appears to be all in. Diamondback Energy's takeover of Endeavor Energy Resources announced on Feb. 12 topped off a year of roughly $250 billion in U.S. oil and gas deals that consolidated a fractured collection of private wildcatters into larger corporations.

The consolidation wave is healing the hangover from years of overspending by shale drillers that pursued output growth at the expense of investor returns. While it was small upstarts that pioneered the shale revolution, Wall Street demands for scale, efficiency and cash returns mean the new era is turning into one of survival of the biggest. “It has become a big-company game,” said Mark Viviano, a managing partner at Kimmeridge Energy Management, which has been pushing the shale sector to consolidate for half a decade. “Now you have an arms race for operational scale and investor relevancy.”

“It’s kind of like Pac-Man right now: consolidate or get eaten,” said Kate Richard, CEO at Warwick, which has invested in thousands of shale wells. “We’re probably going back to the ‘70s, where there were seven to 10 major players in the U.S.” Teresa Thomas, U.S. energy leader at Deloitte, described the shift as a positive: “Big buyers are likely to spearhead a fresh wave of efficiency gains driven by technological advancements in both production and cost management.”

Developer wants to store nuclear waste in Permian oil country

(Wall Street Journal; Feb. 18) - From behind the wheel of his Jeep, Tommy Taylor surveyed the windswept patch of land he is intent on keeping oil country. Taylor, the assistant general manager at closely held oil producer Fasken Oil and Ranch, has been fighting plans to shuttle radioactive refuse from nuclear power plants around the U.S. and temporarily park it here in the Permian Basin, the nation’s busiest oil field.

Holtec International, a Florida-based energy tech company, aims to rail thousands of canisters of spent nuclear fuel to Lea County, New Mexico, and store the containers underground. The site has a 40-year license and would be the largest such facility in the world. Holtec says it would further development of U.S. nuclear energy. But Taylor says a nuclear incident in the Permian, which pumps more oil than Iraq and Libya combined, would have devastating consequences for U.S. energy and the local economy.

“I’m not antinuclear,” he says. “We just don’t feel like siting all the nuclear waste in the middle of our biggest oil and gas resource is a good idea.” The fight has entangled oil companies, the U.S. nuclear regulator, the states of Texas and New Mexico, as well as local communities that want to host the nuclear waste. Fasken has filed legal challenges to the project’s federal approval and has lobbied Big Oil CEOs and Republicans. The company even hired a high school student to help manage a social media campaign.

Supporters say the storage project could help break a decades-old logjam that has led to radioactive refuse piling up at reactors. Some experts say the interim facilities could be a stopgap until the federal government builds a permanent, deep geologic repository. The federal government is paying utilities billions of dollars to keep used fuel rods in steel-lined concrete pools and dry casks at dozens of sites.

Low prices make it hard on U.S. natural gas producers

(Reuters; Feb. 21) - For nearly a year, U.S. gas producers have slammed the brakes on production as prices fell. But relentless output gains including by oil companies that pump gas as an oil byproduct have unleashed record supplies — and gas producers are losing out. Some are shutting in wells, canceling projects or selling themselves to rivals to avoid losses. Natural gas prices this month fell to an inflation-adjusted 30-year low of $1.59 per thousand cubic feet, benefiting consumers but hurting producers that are selling at prices as low as they were in the depths of the COVID-19 downturn.

Nowhere is the pain of cheap gas as evident as Denver-based BKV Corp. In the past five years, it spent $2.7 billion to acquire 4,000 gas wells and two gas-fired power plants. It also pledged $250 million to build a dozen underground carbon capture and storage sites to make its gas more climate friendly. The nosedive in U.S. gas prices has stalled BKV's plans for an initial public offering and scuttled the carbon joint venture with Verde CO2 to couple its gas and power plants with carbon sequestration. BKV last year narrowly avoided loan defaults with a $150 million bailout by its parent.

Majority-owned by Thailand power giant Banpu Public Co., the little-known BKV in 2016 began buying scores of U.S. gas wells, taking castoffs from ExxonMobil and others. The company launched a plan to build a U.S. version of its Thai parent, tying together gas and power. But BKV fell back to Earth under prices suffering from a relentless expansion of U.S. gas output. The U.S. will pump a record 105 billion cubic feet a day of gas this year, up 2.5 bcf a day in the past year. In most industries, volume increases are good. More production equals more profit. But rising output has led to a price drop that knocked U.S. gas recently to less than a third of 2022's average $6.50 per million Btu.

Chesapeake Energy plans to slash gas production amid low prices

(Reuters; Feb. 21) - U.S. natural gas futures soared by about 13% on Feb. 21 after Chesapeake Energy — soon to be the biggest U.S. gas producer after its merger with Southwestern Energy — cut the amount of gas it plans to produce in 2024 by roughly 30% due to the recent plunge in prices to a 3½-year low. Chesapeake, which said the market is "clearly oversupplied," was just the latest U.S. producer to slash spending and reduce rigs after prices dropped about 30% so far in 2024 after falling 44% in 2023.

Last week, U.S. energy firms Antero Resources and Comstock Resources said they planned to reduce drilling this year too, while EQT, currently the nation's biggest gas producer, reduced its 2024 production guidance range. Front-month gas futures rose 19.7 cents, or 12.5%, to settle at $1.773 per million Btu on Feb. 21 — the biggest one-day percentage gain since July 2022. On an inflation-adjusted basis, U.S. gas prices have collapsed to their lowest in over 30 years.

Chesapeake expects to cut gas production to around 2.7 billion cubic feet per day in 2024, down from around 3.5 bcf per day in 2023. Analysts said projected demand growth for liquefied natural gas exports was the primary reason many producers have — until now — kept gas output near record levels despite low prices. U.S. LNG export capacity is expected to almost double over the next four years from about 13.8 bcf per day now, representing about 15% of U.S. domestic gas demand, to about 24.4 bcf per day in 2028 as new export capacity comes online.

India imports less Russian oil as it looks for the ‘cheapest price’

(Nikkei Asia; Feb. 20) - India's imports of Russian crude oil fell in January to a one-year low, down 35% from last year's peak, as New Delhi diversifies its sources. India's petroleum minister said the decline reflects a need to "supply energy at the cheapest price" to the public, referring to New Delhi's price-focused approach to procurement. "We are a democracy. We are answerable to our voters," Hardeep Singh Puri said in an interview in the state of Goa alongside the India Energy Week exhibition.

India ramped up purchases of Russian oil after Moscow's 2022 invasion of Ukraine, capitalizing on steep pricing discounts as a result of Western sanctions. Its imports grew from zero in January 2022, before the war, to 1.27 million barrels a day in January 2023, data from research firm Vortexa shows. Russia was India's largest supplier, accounting for around 30% of 2023 imports. The monthly tally peaked at 1.99 million barrels in July.

But these purchases have declined recently, falling to about 1.29 million barrels a day last month. India now buys more from other suppliers such as Iraq than it did in July. Asked about Russia's share of India's imports this year, the petroleum minister replied it is "very difficult to say," adding, “maybe the other countries will give us more discount.” Some observers see the drop-off in India's imports from Russia as a sign that efforts by the U.S. and partners to tighten sanctions against Moscow are making a difference.

India enjoys growing role in energy markets, looking to save money

(Wall Street Journal; Feb. 21) - Global energy markets have been on a roller coaster the past few years. While industrial economies have been thrown for a loop, India, facing record import needs on a tight budget, is almost enjoying the ride. A deal this month is the latest indication that the world’s most populous country, a distant third in energy demand but growing quickly, is handling its entry into the big leagues with aplomb.

Government-owned Petronet renewed a contract to buy 7.5 million tonnes of liquefied natural gas annually from Qatar from 2028 for 20 years in one of the largest-ever deals for LNG. India is looking to sign more long-term supply contracts as demand grows. The megadeal is another example of India’s emergence as a large buyer in the global market as it gears up to meet the country's ever-expanding energy needs. It has shown an ability to clinch deals when prices drop amid geopolitical or economic disruption.

India's aggressive purchases of cheap Russian oil have angered many in the West but saved its refiners and consumers money. Before that, India was a major buyer of crude from relatively nearby Iran, which also faced sanctions. Raghav Mathur, an analyst at Wood Mackenzie, said the move by India to renew the LNG contract with Qatar during a time of softer prices is a smart one since it sets a base for future contracts.

Nimble energy dealmaking is key as India embarks upon industrializing its economy, upgrading its infrastructure and staking its claims as an alternative to China's factory floor. And even while India is hungry for energy, it is often a price-sensitive buyer.

U.S. gas producers see limited short-term impacts from LNG pause

(S&P Global; Feb. 20) – U.S. gas producers are confident that impacts from the Biden administration's decision to suspend issuance of LNG export permits for new projects will be limited over the next few years as they get ready to serve demand growth from projects already under construction. Though a number of proposed export terminals seeking off-takers could be affected by the pause in new permits, the decision is not expected to affect existing LNG export projects or those already under construction.

"I mean, there's really no impact — at least (not until) the end of 2026," Jeremy Knop, gas producer EQT's chief financial officer, said Feb. 14 during the company's fourth-quarter 2023 earnings call. "So, as we look at the market today, we don't really see any change in the LNG build-out timeline." Fellow Appalachian producer Antero Resources is expecting "very little impact on LNG demand growth into the end of this decade," regardless of the duration of the stoppage in new export authorizations, Justin Fowler, senior vice president of gas marketing and transportation, said Feb. 15.

U.S. LNG terminal feed gas demand is forecast to rise to nearly 25 billion cubic feet per day by the end of 2026 from about 13 bcf per day in 2023, according to S&P Global Commodity Insights. Those growth projections include several projects that already have export authorization from the Department of Energy and which are expected to start up relatively soon. "It's enough of a demand launchpad for them to be excited about," Benchmark Co. research analyst Subash Chandra said via email Feb. 20, distilling the upstream players' attitude. "Then we'll worry about the next stage."

Japanese power company puts hold on U.S. investment decision

(Reuters; Feb. 20) - Japan's Kyushu Electric Power will wait until after the United States resumes issuing export licenses for new liquefied natural gas projects before deciding on whether to invest in the Lake Charles, Louisiana, project, an executive said. President Joe Biden froze approvals for LNG exports from new projects late last month to big markets in Europe and Asia in order to take a "hard look" at environmental and economic impacts of the booming business. The United States became the largest LNG exporter last year, and its exports are expected to double by the end of the decade.

The Lake Charles project of Energy Transfer was among those projects affected by the freeze. Before Biden's decision, Kyushu Electric had said it was considering investing in the project, among others, to secure LNG supplies. Asked about whether Kyushu would hold off on the decision until the U.S. pause is lifted, CEO Takashi Mitsuyoshi told Reuters it would likely do so. "We were a bit surprised by the decision," he said.

Kyushu remained in talks with Energy Transfer, he added, including on signing a long-term purchase agreement. Japan is the world's second-biggest LNG importer after China. Given the difficulty to start new LNG projects amid the global push toward decarbonization, Mitsuyoshi said the company is now seeking to secure LNG supplies by buying stakes in development projects, rather than just relying on long-term supply contracts. After peaking at nearly 6 million tonnes after the 2011 Fukushima nuclear disaster, Kyushu Electric's annual LNG demand has fallen to under 2 million tonnes.

Climate activists question why U.S. insurers underwrite LNG projects

(Bloomberg; Feb. 21) - The underwriting of U.S. liquefied natural gas production capacity by major global insurers is at odds with their climate ambition, according to a report from activist groups including Public Citizen and Rainforest Action Network. Chubb, American International Group and The Hartford Financial Services Group are among underwriters listed on certificates of insurance for seven U.S. LNG export facilities in operation and under construction, according to the researchers, who obtained the information through Freedom of Information Act requests.

The report highlights an irony in the insurance industry: While some underwriters are pulling back from traditional coverage areas as climate change exacerbates wildfires, storms and flooding, they are also continuing to support new fossil fuel projects expected to operate for decades. Although LNG generates about half the carbon dioxide as coal when combusted, the climate benefits of coal-to-gas switching often hinges on the amount of methane that leaks across natural gas and LNG supply chains.

The short-term climate impact from the world’s existing LNG supply chains, including final combustion of the fuel, is about 1.5 billion tonnes a year of carbon dioxide equivalent, according to a 2022 IEA model. That exceeds the annual CO^2 emissions of Japan, the world’s fifth-biggest polluter.

Plan would bury power station CO2 in North Sea oil and gas fields

(BBC News; Feb. 18) - Plans have been proposed to lay new undersea pipes to carry carbon emissions from one of Europe's largest gas-fueled power stations. The plan would link the Pembroke power station in coastal Wales with a liquefied natural gas import terminal across the Milford Haven estuary in Pembrokeshire. Supporters said it would launch a new industry shipping CO^2 from the dock in Wales for burial at sea. But it involves major construction work across a protected marine habitat.

The Pembroke station has the capacity to generate enough electricity to power four million homes. Despite being one of Wales' biggest emitters of CO^2 it has an "essential role" in the country's transition to a greener future, according to its operator RWE. "We need to build something that allows it to still operate at times when it's needed without impacting the climate," said Richard Little, who is leading the site's transformation as director of the Pembroke Net Zero Centre.

RWE's answer, alongside new hydrogen production facilities which could eventually replace gas, is carbon capture and storage. But this relies on transporting the CO^2 to old, empty oil and gas fields in the North Sea where it can be buried. That is where the new pipelines come in. Just over half a mile away — across the Milford Haven waterway — is Dragon LNG, one of three terminals in the U.K. where liquefied natural gas arrives from overseas. The plan is for Pembroke power station's carbon emissions to be piped across the estuary to be liquified and put onto ships at the LNG terminal.

Study will look at health effects of gas flaring at Canadian LNG sites

(BBC News; Feb. 20) - The health impacts of air pollutants from a future liquefied natural gas project near Squamish, British Columbia, are the focus of a new joint study between Vancouver Coastal Health (VCH) and a group of scientists from four universities. The federally funded air quality study is set to start next month and will include VCH, the University of Victoria, Simon Fraser University, the University of Toronto and Texas A&M University.

"We're catching up by doing this study," said Dr. Tim Takaro, professor emeritus of health sciences at Simon Fraser University. "It's the first one in Canada on flaring at all, and we've been flaring for decades without really looking at the health effects. We know very little about the human health effects because there's been very little study, and the industry has just skyrocketed in the last decade."

Flaring is the burning of excess methane that can happen as gas is processed into LNG. Flaring can happen for a variety of reasons, including to relieve pressure and to clear gas from systems during tests, maintenance and emergencies. The study begins as Canada’s first LNG export terminal nears completion in Kitimat, B.C., with work just underway at an LNG project near Squamish, and with at least two others in the planning stages. VCH medical health officer Dr. Michael Schwandt said the potential health impacts from flaring are of "great interest from a public health standpoint."

Chevron surrenders last oil and gas permits on Canada’s West Coast

(Reuters; Feb. 21) - Canada has secured the surrender of the last remaining permits for oil and gas development off its Pacific Coast, the federal natural resources minister said on Feb. 21, after Chevron voluntarily relinquished 23 permits this month. Energy and Natural Resources Minister Jonathan Wilkinson said the relinquishment of the permits marked an important milestone in permanently protecting the ecologically rich waters of Canada's West Coast.

While there has been a federal moratorium on oil and gas exploration off the Pacific coast since 1972, permits issued before that date were still valid. ExxonMobil relinquished a number of permits last year. "With these final permits, Natural Resources Canada has officially secured the surrender of all 227 permits in the Pacific offshore," Wilkinson said in a statement. Chevron said it had no plans to pursue development of the offshore area under the permits, covering an estimated 2,300 square miles.

Even with expanded oil pipeline, Canada could run short of capacity

(Reuters; Feb. 21) - Canadian oil producers expect the discount on their crude to shrink significantly when the Trans Mountain pipeline expansion starts this year, but the relief may be short-lived as surging supply looks set to exceed the country's pipeline capacity in just a few years. TMX will ship an extra 590,000 barrels per day, trebling existing capacity to Canada's Pacific Coast once the C$30.9 billion ($22.8 billion) expansion is finally complete. The Canadian government-owned project has hit technical issues on its final leg of construction but is still targeting a second quarter in-service date.

For much of the past decade, oil companies in the world's No. 4 producing country have been forced to sell their barrels at a deep discount to global prices due to lack of pipeline capacity to export markets. Once TMX is operating, Canadian heavy crude differentials should narrow to around $10 to $12 a barrel under U.S. benchmark crude from more than $19 a barrel currently, BMO analyst Ben Pham said in a note last week.

Still, oil sands production is rising so rapidly that some players think Canada could again run out of pipeline capacity in less than two years, said RBN Energy analyst Martin King. "Originally it was thought TMX would give us a four- or five-year window," King said. "It now looks like that window of spare capacity might actually be a lot smaller." Producers could add up to 500,000 barrels per day of supply by 2025, Colin Gruending, executive vice president of liquids pipelines at midstream firm Enbridge, estimated on an earnings call this month.

Guyana delays $1.9 billion gas-to-power project

(Reuters; Feb. 20) - Guyana will delay until 2025 its biggest effort to capitalize on its energy bounty, a $1.9 billion gas-to-power project that was to start this year, using untapped gas to slash electricity costs, a Ministry of Natural Resources consultant said on Feb. 20. The rising oil-producing nation relies on imported fuels for its shaky electric grid and has promised to use its oil wealth to construct a 140-mile pipeline, gas processing facility and up to 300-megawatt power plant.

Winston Brassington, a government consultant involved in the project, said the combined-cycle power plant is delayed and full operation will not be possible until the fourth quarter of 2025. The project suffered work delays, late equipment deliveries and issues on the foundation at the location chosen for the project, he said. The project was an election-year pledge to the country's 800,000 residents to reduce their energy costs by 50% this year. Guyana has been seeking a $646 million loan from the Export-Import Bank of the United States to finance the onshore facilities.

ExxonMobil is building the $1 billion pipeline and will be reimbursed by proceeds from the country's offshore oil production. Guyana will pay Exxon and its partners $55 million over a 20-year period, at a fixed price with no adjustments, totaling $1.1 billion, Brassington said. The pipeline is expected to be ready by the end of this year.

Exxon considers LNG for monetizing Guyana's gas resources

(Bloomberg; Feb. 21) - ExxonMobil is considering the potential to produce liquefied natural gas in Guyana in the world's fastest-growing major oil basin. A gas-focused development is one of three options being weighed by Exxon and its partners, country manager Alistair Routledge said in an interview in Guyana on Feb. 21. The other two options are additional oil developments from existing and new discoveries, he said.

Exxon will drill five wells this year in the southeast portion of the block, near the border with Suriname, to better understand the "substantial resources" of gas, Routledge said. "We do think that LNG needs to be in the mix because there's no large market nearby within an economic range of (a) pipeline," he said. Exxon is "narrowing concept ranges" this year and should have a better idea of timelines by 2025. The earliest the partners could expect to start gas production would be 2029 or 2030, Routledge added.

Exxon plans to double oil production from Guyana to 1.2 million barrels a day by 2027. But the country's government is keen to also monetize its large gas resources. Vice President Bharrat Jagdeo said on Feb. 20 it's imperative that Guyana develop its estimated 16 trillion cubic feet of gas quickly as the world transitions to cleaner energy. He also said the country wants another international partner to sign on. "If we allow Exxon to go on their own, they may just slow the pace and tell us there is not enough for a commercial project," he said. "We want another international developer participating."

Offshore gas field in Denmark will restart after 5-year closure

(Reuters; Feb. 20) - Denmark's offshore Tyra natural gas field remains on track to restart production by the end of March, BlueNord, a partner in the TotalEnergies-operated development, said on Feb. 20. Denmark's largest gas field, which was temporarily shut for redevelopment in 2019, is expected to produce almost 100 billion cubic feet of gas per year, TotalEnergies said, more than the country consumed in 2023.

Denmark currently depends on imports of gas, but restarting Tyra would again make the country self-sufficient and a net exporter of natural gas. The field will undergo a four-month ramp-up phase and is expected to reach its plateau production level in mid-2024, Norway's BlueNord said. TotalEnergies operates Tyra on behalf of the Danish Underground Consortium, where the French group holds a 43.2% stake. BlueNord holds 36.8%, while Denmark's state-owned Nordsofonden owns the remaining 20%.

Tyra's operations were halted after the seabed had sunk several metres under its platforms after more than 30 years of production. As part of its redevelopment project, called Tyra II, its old installations were replaced with new ones, and the legs of its platforms were extended. Prior to the shutdown, Tyra served as a processing and export hub for more than 90% of gas produced from the Danish sector of the North Sea.

Amid sanctions, Russian LNG transshipment hub sits unused

(The Barents Observer; Feb. 20) - The vessel that was built as logistical hub for Novatek's Arctic LNG operations is haunted by international sanctions and project delays. The 1,312-foot-long vessel arrived in Ura Guba on the Barents Sea coast in late June and appears not to have handled a single shipment of liquefied natural gas. Judging from available shipping data, the Saam FSU (floating storage unit) has been lying idle in the remote bay ever since arrival.

The unit was to serve as transshipment base for Novatek's cargoes from the Yamal LNG and Arctic LNG-2 projects, transferring cargoes from expensive ice-class LNG carriers to conventional tankers for delivery to Europe. Meanwhile, Arctic LNG-2 has been delayed and Novatek is unlikely to get its three liquefaction units in operation as planned. The international sanctions are a problem for Novatek, energy expert Mikhail Krutikhin said. "The problem is with the recent U.S. sanctions … it is open to speculations whether Novatek will be able to use this hub."

In September, the U.S. launched a series of additional sanctions against Russian companies. Novatek and its Arctic subsidiaries were among the key targets. Arctic Transshipment, a Novatek subsidiary and owner of the Saam, also owns and operates the Koriak, a sister ship of the Saam, based in Kamchatka to handle shipments to the Far East and Asia. Novatek is now at odds over what to do with its two FSUs.

New firm takes leading role in moving Russian oil and fuel products

(Wall Street Journal; Feb. 19) - In the early days of the Ukraine war, data trickled out showing that a mysterious firm called Nord Axis had become one of the biggest global traders of Russian oil. The company seemed to have sprung from nowhere. It had been incorporated in Hong Kong nine days before Russia's invasion. With Western buyers of Russian oil beating a retreat, Nord Axis and several other obscure firms were keeping the nation's most important industry afloat by finding new places to sell the oil, generating billions of dollars in revenue for President Vladimir Putin's war effort.

TBut who was masterminding the deals? The answer: a little-known trader from Azerbaijan named Etibar Eyyub, who swiftly assembled a clandestine trading and shipping empire that now moves vast quantities of oil to buyers in China, India and other new markets, according to people who have worked with or done deals with him. He cobbled together a fleet of aging tankers and disguised the trading by using a maze of companies registered in Dubai and Hong Kong, those people said.

Nord Axis and four other companies those people say are operated by Eyyub exported at least $33 billion in Russian crude and fuel in 2023, according to data from the Kyiv School of Economics, representing about 20% of Russian exports. Those people said Eyyub also operated other firms involved in the Russian trade. Russia's giant state producer, Rosneft Oil, came to depend on trading and shipping firms with opaque ownership and management to get its crude to market after the invasion.

Russia crude arrives in Venezuela

(Bloomberg; Feb. 20) - A supertanker carrying Russia's flagship Urals crude has arrived off the coast of Venezuela as Moscow looks for new buyers amid tightening sanctions and travel disruptions in the Red Sea. The Ligera is now near Amuay Bay, which is linked to a refinery run by state-owned company PDVSA, vessel-tracking data compiled by Bloomberg show. It collected at least 1.7 million barrels of Urals via ship-to-ship transfers off southern Greece last month before sailing to Venezuela.

The tanker's arrival marks the first observed shipment of Urals crude to the South American country in at least five years. Russia has typically looked to buyers in Asia in the face of Western sanctions over the Kremlin's war in Ukraine. Venezuela in the past has received foreign oil to help dilute its own extra-thick crude, making it easier to export, though it's not clear if that's the reason behind the Ligera's cargo.

Greece nears start-up of its first floating LNG import terminal

(Offshore Energy; Feb. 19) - Greece’s first floating storage and regasification unit (FSRU) to serve as a liquefied natural gas import terminal is gearing up for commissioning with the arrival of the first LNG cargo. The commissioning cargo to the Alexandroupolis was delivered on Feb. 18 by the GasLog Hong Kong LNG carrier. Once the cargo is unloaded, the FSRU terminal will undergo commissioning. Greece is the latest of several European nations to employ floating LNG import terminals to help cope with the steep cutback in Russian pipeline gas deliveries to the continent.

The Alexandroupolis, formerly the 2010-built LNG tanker GasLog Chelsea, was converted to the FSRU at Seatrium shipyard in Singapore in 2023. It will be connected to a 17-mile-long, high-pressure subsea and onshore gas transmission pipeline, which will deliver natural gas to the Greek transmission system and onward to consumers in Greece, Bulgaria, Romania, North Macedonia, Serbia and further to Moldova and Ukraine to the East and Hungary and Slovakia to the West.

Upon completing all testing activities, the terminal is planned to be commercially operational in the first quarter of 2024 and will have a maximum sustainable regasification capacity of almost 200 billion cubic feet per year of gas. It will be the second import facility in Greece — the other is a 25-year-old onshore plant.