Oil and Gas News Briefs
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Qatar not about to let competitors take LNG market share

(Bloomberg; May 20) - The world's top exporter of liquefied natural gas is ramping up production dramatically and undercutting competitors in a bid to squeeze them out the market. Qatar is dropping prices and pushing ahead with a $29 billion project to boost its exports of the fuel by more than 50%, stymieing the prospects of new plants elsewhere. It's also established a trading team to compete in the nascent spot market and pushing into Asia more aggressively, according to people familiar with the matter.

The strategy marks a shift for Qatar, which has traditionally prioritized prices over market share. More competition, especially from the U.S. and Australia, has forced Qatar to become more nimble and attract buyers in Asia, a hot spot for demand. The global transition to renewables is adding to the sense of urgency. While LNG was until recently touted as a bridge from coal and oil to the likes of solar and wind power, it's falling out of favor with some governments as they push efforts to slow climate change.

"Qatar's expansion plan is so huge that there are questions on the need for other supply options," said Julien Hoarau, head of EnergyScan, the analytics unit of the French utility Engie. Several factors are playing into Qatar's hands. China, one of the fastest-growing LNG markets, has been reluctant to import more gas from the U.S. or Australia due to trade and geopolitical tensions. But Qatar's main advantage is that it has the world's lowest production costs thanks to an abundance of easy-to-extract gas.

"Nobody can compete with Qatari costs," said Jonathan Stern, a senior fellow at the Oxford Institute of Energy Studies. "They can do whatever they like and everybody will have to respond the way they can." Feedstock costs tell the story. U.S. companies have to buy gas at about $2.50 per million Btu versus Qatar's wellhead price of $0.30 or less.

Gazprom starts work on Baltic Sea LNG and chemicals complex

(S&P Global Platts; May 21) - Russia's Gazprom on May 21 began construction of a major new gas and chemicals complex at Ust-Luga in northwestern Russia that will include the Baltic Sea LNG plant at 13 million tonnes per year capacity. The start of work at the complex — which will have a total gas processing capacity of almost 1.6 trillion cubic feet per year — was marked by a high-level ceremony attended by Russian Deputy Prime Minister Alexander Novak and Gazprom CEO Alexei Miller.

The complex will also include processing ethane-rich gas, with some 3 million tonnes per year of polymer production capacity envisaged. "Today, in the Leningrad region, we have started to build a new high-tech industrial cluster, which is extremely important for the region and the whole country," Miller said in a statement. Gas for the complex will originally be provided from existing fields in Russia's Nadym-Pur-Taz region, but in the future the plant will also take gas from the major Tambey field on the Yamal Peninsula.

Tambey is estimated to hold a huge 184 tcf of gas as well as 2.8 billion barrels of oil and condensate, making it the biggest field in terms of reserves on the Yamal Peninsula. It is expected to start producing gas in 2026, Gazprom said. Gazprom considers the Yamal Peninsula as a strategic region for maintaining or increasing its gas output in Russia. Gazprom is developing the Ust-Luga gas complex together with its project partner RusGazDobycha. The Yamal Peninsula already feeds one operating LNG plant and a second under construction, both led by independent gas producer Novatek.

IEA scenario of declining LNG use favors lower-cost producers

(Reuters; May 21) – The status of natural gas as an acceptable face of hydrocarbons has suffered a grievous blow. Until recently the biggest players — energy majors like Shell or Total and states like Qatar — rested contentedly on forecasts of demand rising for decades to come. Yet the influential International Energy Agency now says that for the planet not to overheat, “peak gas” consumption has to arrive in the next five years.

The shift in attitude to the fuel, usually seen as a bridge between dirtier coal and cleaner wind and solar power, has been dramatic. Only this month energy analysts at Wood Mackenzie called the top of the market for around 2035, based on a scenario that would keep global temperature increases to 2 degrees Celsius above pre-industrial levels. An accelerated decline in demand would be a problem for all the oil majors.

The most conservative forecasts of Total, Shell, BP, and Equinor see global LNG demand staying roughly the same as now. The IEA scenario would mean way less cash to finance the companies’ pivot to wind and solar. It could also mess up the market in liquefied natural gas, the hydrocarbon’s most freely tradeable form. If the IEA is right, that means 15% less LNG trade than today. That’s bad for gas-producing nations, but particularly bad for those with higher costs. Boston Consulting Group analysts reckon it costs players in the U.S. double what it costs LNG from Qatar. In a shrinking market, that means the emirate could grow its share appreciably beyond its current 20%.

Bitcoin miners see profit potential in old power plants

(The Wall Street Journal; May 21) - Across America, older fossil-fuel power plants are shutting down in favor of renewable energy. But some are getting a new lease on life — to mine bitcoin. In upstate New York, an idled coal plant has been restarted, fueled by natural gas, to mine cryptocurrency, though community opposition is growing over air emissions. A once-struggling Montana coal plant is now scaling up to do the same.

The drive for power has its roots in bitcoin's intractable mathematics: To operate securely, the cryptocurrency's network relies on computers solving puzzles; in return the solvers get fresh bitcoin. The higher the bitcoin price, the more of these miners compete to solve the puzzles — a process that chews up electricity. The more competition, the harder the puzzles get and the more electricity is used. The cheaper the electricity, the more profit potential for the bitcoins.

The coal-fired Hardin Generating Station in Montana had been struggling for years. Late last year a miner called Marathon Digital partnered with Hardin's owner to transform the plant into a hub for mining bitcoin. "It was an idle asset," Fred Thiel, Marathon Digital's chief executive, said in an interview. "We were able to get access to a large amount of power at a very attractive price." The project is in the process of scaling up with more than 100 megawatts of capacity planned. The company is aiming to produce at least 55 bitcoins daily by the first quarter of next year, up from an average of two a day in 2020.

Bitcoin miners drive to drill sites to burn natural gas for electricity

(Reuters; May 21) – In the oil patch along the Rockies and Great Plains, trailers hitched to trucks back up toward well pads to capture natural gas and convert it on the spot into electricity. The trailers — hauling pipes, generators and computers — are called "mining rigs." But their owners aren't drilling for oil. They are using unwanted natural gas from oil companies to power their search for another treasure: cryptocurrencies like Bitcoin.

Cryptocurrencies are virtual coins exchanged without middlemen, such as central banks, to purchase goods and services. Extracting the currency from cyberspace, however, requires vast amounts of often-expensive electricity. Supercomputers must run constantly in a race against other "miners" to solve complex math problems in order to unlock digital vaults holding the currency.

Put in trailers, these supercomputers run as hot as 160 degrees Fahrenheit, and in the cold of North Dakota people stay warm just sitting near them, cryptocurrency miners say. The miners are increasingly sending the rigs out to oil fields because it's one of the cheapest ways to get the energy they need. Oil and gas comes up from the same wells, but drillers want the oil and often have no pipes to get the gas to market. That typically forces them to burn it or vent it into the atmosphere. Both are bad for the environment.

Oil companies face pressure from investors and government officials to reduce emissions that lead to global warming. Sometimes they give the gas away for free to cryptocurrency miners; other times they sell it. Some major oil companies have signed on. In North Dakota, Norway's Equinor and Canada's Enerplus are among those that have used such mining to reduce flaring, company spokespeople confirmed to Reuters.

Wood Mac calls LNG demand growth in Asia 'the prize for suppliers'

(CNBC; May 19) - The buyers' market in liquefied natural gas may continue over the coming years due to oversupply, but sellers could stand to gain as demand in Asia grows, according to analysts at Wood Mackenzie. Global demand is not expected to outpace supply until the mid-2020s, but even then the respite for suppliers may be short-lived once new supply from projects in Qatar and the U.S. come online, said Valery Chow, head of Asia-Pacific gas and LNG research at Wood Mackenzie.

"Despite these developments, the prize for suppliers remains significant given the potential growth of future demand in Asia," Chow said. LNG demand in Asia is growing "significantly faster" than in the rest of the world because of the region's economic and population growth. "Where we see the greatest upside potential is from emerging markets in South and Southeast Asia, where declining (local) production and increased use of gas in the power sector at the expense of coal will facilitate strong LNG demand."

National gas companies — including Qatargas — have a "natural competitive advantage" because they have access to the resource at a low price, Chow said. But all the players are in "constant competition" to develop or secure new low-cost supply and sell the gas to the highest-paying customers, he said. "Companies will benefit to the extent that they can market and contract for new sales, achieve favorable pricing terms, and have access to lower-cost resources," he said.

Australia not ready to stop fossil fuel power projects

(Reuters column; May 19) - It is probably just ironic coincidence, but the same day the International Energy Agency called on the world to end fossil fuel investments, the Australian government announced plans for a new $460 million gas-fired power plant. The stark contrast between the two announcements is, however, emblematic of the challenges the world faces in transitioning from fossil fuels to cleaner renewables as efforts to combat climate change become more urgent and widespread worldwide.

The IEA report on the path to net-zero carbon emissions by 2050, released May 18, warned that investment in oil, gas, and coal must come to an end if the target has any chance of being reached. The key to the success of the net-zero goal is Asia, and here the pathway faces its biggest challenges and most likely failures. It is easy to pick on

Australia as an example of the challenge Asia is going to face in weaning itself off fossil fuels, and the cheap path to economic growth they have provided so far.

Australia's government has, in some ways, become the poster boy for recalcitrance on climate change with its support of fossil fuels. Energy Minister Angus Taylor said May 18 that the government would use its wholly owned Snowy Hydro company to build a A$600 million (US$464 million), 660-megawatt gas-fired power plant north of Sydney. The justification is that private companies haven't acted to replace retiring coal-fired units and the gas plant is needed to keep electricity supplies stable.

Even if the necessity of backup generation is accepted, which it isn't by all parties, renewable solutions such as wind, solar, and battery storage probably provide better value for money and the same, if not more, reliability and zero-carbon emissions once operating. What appears to be at play in Australia is an energy market being driven by political objectives, rather than one where best policy and practice are implemented.

Costly problem of abandoned wells in Alberta grows worse

(The Canadian Press; May 20) - The costs of Alberta's growing stock of abandoned and inactive oil and gas wells are falling unfairly on landowners and taxpayers, says a report from the University of Calgary. "Landowners have been left behind," said Braeden Larson of the School of Public Policy. "Landowners got the short end of these burdens that have popped up with the number of wells that have grown in this crisis."

Larson and co-author Victoria Goodday used industry and government data as well as previous research to point to troubling trends in Alberta's beleaguered conventional oil patch. More than half of Alberta's wells no longer produce oil and gas but haven't been cleaned up. That includes 97,000 wells that haven't been properly closed and an additional 71,000 that have been closed but not reclaimed. The pace of abandonment is accelerating. Meanwhile, companies owe a growing debt to landowners.

The report says inactive wells increased by more than 50% between 2015 and 2020. The Alberta Energy Regulator expects another 6,014 in 2021. More than half have been inactive for more than a decade and even relatively new wells, once closed, have less than a one-in-five chance of being reactivated. More and more are simply deserted. Over the past six years, the number of orphan wells has quintupled, the report says. Almost always the public picks up the tab. Rural Municipalities Alberta says the amount of outstanding property taxes from the oil patch has tripled since 2019 to $245 million.

[New Mexico could be short billions to clean up wells, pipelines]

(Reuters; May 20) - Drillers in New Mexico have set aside only a tiny fraction of the money they will need to clean up their wells, pipelines, and other infrastructure in the state, leaving taxpayers at risk of footing some of the balance, says a study published May 20. Concerns are growing about who will pay for the environmental impact of more than a century of oil and gas production in the U.S. The issue is front and center in New Mexico, which has rapidly grown into the nation's third-largest oil producer.

State regulations require drillers to pay an upfront bond ranging from more than $25,000 to less than $2,500 per well — depending on how many wells they operate. The funds are set aside to cover cleanups if companies go bankrupt. But those requirements are too low, said the study, conducted by economics research firm The Center for Applied Research with cooperation from New Mexico state agencies that oversee oil and gas.

The study estimated that it would cost $8.38 billion to close all the oil and gas infrastructure on New Mexico's state and private lands, and that the money available to finance that work through security bonds posted by drillers added up to just $201.4 million. That leaves a potential funding gap of nearly $8.2 billion. "The results are staggering," New Mexico Commissioner of Public Lands Stephanie Garcia Richard said in a statement. "Enormous sums of taxpayer money and money meant for public schools, along with the long-term health of our lands, are on the line," she said.

[North Dakota Supreme Court rules against landowners in royalty case]

(Reuters; May 20) - The North Dakota Supreme Court said May 20 that contractual language commonly used in the state to calculate royalties paid to landowners requires oil producers to pay values determined at the well, rather than higher values as the oil gets closer to markets. The opinion was in response to a question by a federal court to clarify a gray area in state law, which should in turn enable rulings against class-action lawsuits by landowners who allege oil companies have underpaid them royalties.

The Supreme Court said its determination that royalties are calculated at the well, rather than downstream, may result in the dismissal of the class actions. Writing for the panel, Chief Justice Jon Jensen rejected the plaintiffs' contention that the royalty clause of the leases should be interpreted as saying the price must be based on oil value when it enters a pipeline, rather than at the well, where it typically sells for less. Its price goes up as it travels downstream and incurs production and transportation costs.

The plaintiffs argued that because the wording of the contract's royalty clause uses the word "pipeline" as a delivery end point, royalties should be calculated downstream, not at the well. The judge disagreed. He said the same clause also specifies deliveries take place on the leased land, where the lessee "may connect" a pipeline to the wells. "The royalty provision is unambiguous," Jensen said. "It establishes a valuation point at the well." The plaintiffs seek several million dollars for alleged underpayments.

Judge denies request to close Dakota Access oil line

(Reuters; May 21) - A federal court judge May 21 denied a request to shut the Dakota Access oil pipeline after a key environmental permit was scrapped last year, dealing a blow to Native American tribes that sued seeking its closure. The 570,000-barrel-per-day-line out of North Dakota that travels under a Missouri River reservoir is now likely to stay running at least until an environmental review is completed next year.

A closure of the pipeline threatened to roil oil markets and create congestion on rail lines out of the region. The pipeline entered service in 2017 following months of protests by environmentalists, Native American tribes, and their supporters. The pipeline's opponents said its construction destroyed sacred artifacts and posed a threat to Lake Oahe, a critical drinking supply, and the greater Missouri River, and they want it closed pending a court-ordered environmental review.

Washington, D.C.-based U.S. District Judge James Boasberg denied a request for an injunction to shut down the pipeline and ordered the parties to file a joint status report by June 11 on potential next steps. The judge said the tribes did not clear the "daunting hurdle" of proving that the pipeline's continued operation would create irreparable injury. The Army Corps of Engineers is expected to complete its review of the line next March.

China’s tax on lower-grade feedstocks will affect crude market

(Bloomberg; May 20) - Planned tax changes in China are sparking a chain reaction that’s set to boost crude imports and raise refinery run rates across the country, adding to its big role in the global oil market. Starting in mid-June, the world’s top crude importer will introduce a levy on inbound flows of three oil-related items — bitumen mix, light-cycle oil, and mixed aromatics — that are often used to make low-quality fuels or processed in refineries. Faced with the prospect of costlier feedstocks, Chinese buyers are on the hunt for barrels of suitable crudes they can use as replacements.

Already there are signs of a cascading effect. Spot differentials for Middle Eastern and Russian crude have risen to a multi-month high. The knock-on effects of the new levy are playing out as China continues its recovery from last-year’s pandemic-driven hit. With the virus largely under control in China, refiners have been trying to meet the sharp rise in demand for fuels. The government said refiners that buy the lower-grade crudes have an unfair advantage over other processors — thus the tax to level the field.

Outside the industry the affected products are not well-known, but they are just some of the many key building blocks that flow from crude. Bitumen mix can be used to produce material for roads or processed in refineries to yield poor-quality fuels, while light-cycle oil can be blended into diesel or fuel oil. The new tariffs suggest both bitumen mix and light-cycle oil won't be as cheap for processors to import in large volumes anymore. That will push them to buy other types of sludgy crude, or force refiners to pick up more crude that yields more diesel, which they will have to sell domestically or export.

Venezuela rushing to beat China's tax on its low-grade crude

(Argus Media; May 20) - Venezuela's state-owned PdV is scrambling to load crude cargoes before China imposes a new import tax that has blindsided management in Caracas. Most of Venezuela's exports wind up in China's Shandong province, where independent refiners are girding for a new tax on diluted bitumen, the product category under which Venezuela's blend is imported after quietly transshipping the crude through Malaysia and other intermediate destinations to lessen the risk of U.S. sanctions.

Top PdV officials were caught off-guard by the new tax on dirtier, lower-grade crudes, which would effectively squeeze out its heavy sour barrels from the strategic Shandong market. The sanctions sharply limit Venezuela's market alternatives. A shrinking Chinese market also implies that Venezuela's oil-backed debt to Beijing would take much longer to pay off and accumulate more interest.

The tax takes effect on June 12, and PdV is hoping loadings before June 11 will be clear of the new levy. In the meantime, it is hoping Beijing will reconsider the tax. PdV's efforts to rush out cargoes from its main terminal are hamstrung by loading equipment breakdowns and oil-quality issues such as high metals content and sediment.

Exxon says it does not want to pay for another company's failure

(Reuters; May 20) - ExxonMobil on May 20 protested Australia's move to hit the country's oil and gas industry with a levy to cover the cost of removing facilities at an oil field off northwest Australia after a small firm that owned the project collapsed. Exxon said it has proven that it can safely decommission facilities around the world, has the financial backing to do so, and shouldn't have to help cover the costs of other companies unable to meet their obligations.

"Therefore, it was disappointing to see the federal government announce the introduction of an industry levy to pay for the decommissioning of the Laminaria-Corallina oil fields and associated infrastructure," Exxon said in its first public comments on the plan that was announced May 12. The oil and gas industry is working with the government on how the levy will be calculated to cover decommissioning costs at the abandoned offshore fields, which Credit Suisse analyst Saul Kavonic said could top A$1 billion if all of the facilities are required to be removed.

The levy comes on top of huge decommissioning costs that Exxon and its partner BHP Group face on their own this decade in the Bass Strait off southern Australia, where output at their Gippsland Basin is rapidly depleting. Exxon said it has spent more than A$300 million (US$232 million) on plugging and abandoning a number of wells in the Bass Strait that are no longer producing and will spend more than A$150 million in the next two years on further plug-and-abandonment work.

U.S. backs off on efforts to block new Russian gas line to Europe

(Bloomberg; May 19) - The Biden administration said stopping Nord Stream 2 is a long shot now that the gas pipeline from Russia to Germany is more than 90% complete, a shift in tone that came as the U.S. held off on sanctioning the company overseeing its construction. In a report to Congress on May 19, the State Department said that Nord Stream 2 and its CEO Matthias Warnig are engaged in sanctionable activity under U.S. law, but that the administration will waive penalties for national security reasons.

An administration official who briefed reporters said the chances of stopping the pipeline's completion are increasingly remote and suggested that President Joe Biden wants to avoid a confrontation with Germany and other European Union allies that back the project. The official said that waiving the sanctions will give time for further discussions and that the U.S. hopes Germany will address its concerns that the pipeline is a boon to Russia and undermines European energy security.

Construction on the US$11.6 billion pipeline began in 2018 and became a major source of friction between the U.S. and its European allies, particularly Germany. The 764-mile gas pipeline will double the capacity of the existing undersea route from Russian fields to Europe — the original Nord Stream — which opened in 2011. Initially expected to come online by the end of 2019, the link has been delayed by U.S. sanctions that forced Swiss contractor Allseas Group to withdraw its pipe laying vessels.

First Nations coalition disappointed with failure of LNG project

(The Canadian Press; May 20) - A British Columbia First Nations coalition says it is disappointed that the other 50% partner is looking to sell its shares in the proposed Kitimat LNG venture in the northern community. Woodside Petroleum, an Australian company, says it plans sell its stake in the development. The First Nations Limited Partnership, which represents sixteen First Nations in northern B.C., says the decision to sell is both disappointing and poses a threat to its members' commercial interests.

Woodside's announcement comes after Chevron Canada, the operator of the project, said earlier this year that it would stop funding further feasibility work. Chevron put its 50% interest up for sale in December 2019, but has failed to find a buyer. Mark Podlasly, the First Nations partnership's chair, said he believes the energy project has national benefits and the latest news hurts the group's members. "We are incredibly disappointed by this setback. (We) stand ready to support the right buyers who will treat us as a genuine partner and recognize the unique value we can bring to the table."

French major Total prepares name change to TotalEnergies

(France 24; May 21) - French major Total, one of the world's biggest energy companies, is preparing to change its name to TotalEnergies to signal its diversification toward cleaner energy sources. Total, founded in 1924 as the Compagnie Francaise des Petroles, is set to propose the new name at a shareholders' general assembly May 28. Total has begun to invest more in solar and wind power, but it is under pressure to do even more as climate issues rise closer to the top of investors' agendas.

"The group is expressing its intention to transform itself into a multi-energy company to respond to the twin challenges faced by energy transitions: more energy and fewer emissions," CEO Patrick Pouyanne said in a statement. This year Total plans to devote more than 20% of its investment budget to renewable energy as well as electricity. The Total board is expected to present a climate resolution during the shareholders' general assembly, a move it resisted last year.

Total would not be the first energy giant to change its name to reflect the changing times. Denmark's Dong — a name that originated from Danish Oil and Natural Gas — changed its name to Orsted as part of a green rebrand in 2017. And Norway's Statoil renamed itself Equinor in 2018 to reflect its move toward cleaner energy sources.