Oil and Gas News Briefs
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Russian government commits to second LNG transshipment terminal

(Barents Observer; Norway; May 1) - The Russian government intends to spend 70 billion rubles (US$1.1 billion) on construction of a new Arctic terminal for storage and reloading of liquefied natural gas. As approved by Prime Minister Dmitry Medvedev, the terminal on the Kola Peninsula, near Murmansk on the western edge of Russia, is to be ready for operations in 2023.

The announcement comes only weeks after the government approved a similar terminal for the country's Pacific coast in Bechevinka, on the Kamchatka Peninsula in the Far East. The terminals will serve gas producer Novatek and its Yamal LNG project, which has been operating since 2017, and its proposed Arctic LNG-2 project. Combined, the two plants will have capacity to produce more than 36 million tonnes of LNG per year.

The government did not say where on the Kola Peninsula the new terminal will be built, but Novatek has favored a location near a naval base. The two terminals will enable Novatek to cut its LNG transportation costs. The ice-class LNG carriers it uses to shuttle to and from Yamal are far more expensive to operate than conventional carriers. With transshipment hubs, the ice-class tankers will move LNG to the new terminals and conventional carriers will pick up the gas for delivery to buyers in Europe and Asia.

Yamal sends first LNG cargo to China under long-term contract

(Reuters; May 3) - Russia's Yamal liquefied natural gas project has sent its first cargo to China this year, signaling the start of regular long-term contract flows from the producer to Asia. The cargo is aboard the Clean Planet LNG carrier, on route to the PetroChina-controlled Caofeidian gas terminal in Tangshan, according to Refinitiv Eikon shipping data. It is due to arrive May 20. A low price spread between European and Asian LNG prices this year had confined Yamal's spot cargoes to Europe, Refinitiv data shows.

Yamal has agreed to supply 3 million tonnes of LNG to PetroChina over 20 years. The deal was expected to take effect this month, an industry source familiar with the matter said. In addition to the long-term contract, PetroChina has a 20 percent equity stake in Yamal LNG, allowing it to offtake spot cargoes from the project. PetroChina's London subsidiary has been selling spot cargoes under this equity stake to Europe over the past year. A total of 14 cargoes were shipped from Yamal to China last year on a spot basis.

Occidental would sell Anadarko’s African assets to Total

(CNBC; May 5) - Occidental Petroleum has reached a binding deal to sell Anadarko Petroleum’s oil and gas assets in Africa to French oil major Total for $8.8 billion, including Anadarko’s leading stake in the proposed Mozambique LNG project. The deal is contingent on Occidental beating out Chevron’s bid to buy Anadarko. Occidental’s May 5 announcement offers some clarity on how it would fund its cash-and-stock purchase of Anadarko. The Houston-based company had said it would seek to sell $10 billion to $15 billion worth of assets to underwrite the $38 billion proposed takeover.

Occidental said the sale of Anadarko’s assets in Mozambique, Algeria, Ghana, and South Africa would also reduce the challenges of integrating the two companies. Anadarko and its partners have been planning to reach a final investment decision this year on the $20-plus-billion Mozambique LNG project. The divestment would leave Occidental with Anadarko’s holdings in U.S. shale basins, the Gulf of Mexico and South America. Occidental is primarily interested in Anadarko’s acreage in the Permian Basin, the top U.S. shale field stretching from western Texas to southeastern New Mexico.

Chevron reached a deal to buy Anadarko for $33 billion last month, but Occidental later put in a higher offer. Anadarko’s board of directors is currently considering Occidental’s bid. Anadarko’s global footprint is widely seen by analysts as a better fit with Chevron’s portfolio than Occidental’s holdings, particularly the Mozambique liquefied natural gas project. Chevron is a major player in LNG markets — as is Total.

Mozambique’s debt problems could affect LNG project financing

(S&P Global Platts; May 3) - Mozambique, on the verge of transforming its economy with the development of major liquefied natural gas export projects, needs to improve its government finances and the country's social environment for the projects to generate the expected profit. The country has attracted three potential LNG projects, with total capacity of more than 30 million tonnes per year and $50 billion in capital development, with commissioning expected between 2022 and 2025.

"The yearly value of the projects could reach $12 billion by 2025, close to Mozambique's current GDP," said Anish Kapadia, founder and managing director of AKap Energy, assuming an LNG price of $7.78 per million Btu. However, there are challenges for the projects to develop successfully. One is the ability of the partners to raise project financing and the second is the funding of state oil company Empresa Nacional de Hidrocarbonetos's obligations as a partner, Kapadia said.

Mozambique has defaulted on its debt, mainly due a secret $1.1 billion loan scandal that emerged two years ago. "The default questions the ability of the state company ENH, which has 10 to 15 percent in the two projects, to finance them," Kapadia said. Total financing commitment from ENH is $7.5 billion to fund its share of equity and debt in the projects. Already more than $1 billion has been spent by partners on behalf of ENH. If Mozambique's financial troubles drive up by 1 percent the cost of borrowing, the life-of-field revenues to the government could be reduced by $2 billion, Kapadia said.

LNG traffic through Panama Canal up 77% last year

(S&P Global Platts; May 2) - The number of liquefied natural gas carriers through the expanded Panama Canal in 2018 increased 77 percent year on year, according to the Panama Canal Authority, with even more traffic in 2019. Already through March, halfway through the agency's fiscal year, 194 LNG tankers had transited the canal, two-thirds of last year's total of 290. The total in 2017 was 163, while it was only 17 in 2016 as the first U.S. Gulf Coast LNG export terminal was just starting operations.

The canal authority reported that since its expansion in June 2016, 11 percent of its traffic has been LNG carriers. According to the agency, more than 90 percent of the world's fleet of LNG carriers can now transit the Panama Canal, making it easier for Atlantic Basin producers, mainly those on the U.S. Gulf Coast, to send cargoes to Asia, where 70 percent of the global demand is found.

The authority last year doubled its guaranteed daily slots for LNG tankers to two and also lifted some daylight restrictions for the ships. However, due to a severe drought caused by an El Nino, the agency has reduced the maximum authorized draft for vessels transiting the locks for the fifth time this year. The drought has reduced water levels in two of the canal's largest tributary lakes. The draft restrictions are likely to reduce traffic significantly. The latest maximum authorized draft is 44 feet as of April 30.

World's second-largest LNG carrier will go through Panama Canal

(Reuters; May 2) - A Q-Flex LNG tanker, the world's second-largest class of liquefied natural gas carriers, is set to pass through the Panama Canal for the first time, the canal's CEO said, expanding the Americas-to-Asia trade route for the fast-growing commodity. The Al Safliyah, which can carry about 4.5 billion cubic feet of gas as LNG, is on its way to Panama from the North Pacific after discharging a cargo from Qatar into Korea's Tongyeong terminal April 21, shipping data in Refinitiv Eikon showed.

The 1,033-foot-long ship is on a long-term charter to Qatargas, the world's biggest LNG producer, according to LNG trading and broker sources. The vessel's owner, Qatar Gas Transport (Nakilat), said in March that it had assessed the ability of Q-Flex LNG carriers to safely pass the Panama Canal's new locks. At 120,000 deadweight tonnes, the Q-Flex will not be the biggest ship to have passed through the Panama Canal, which has accommodated container ships of around 140,000 tonnes.

Q-Flex tankers are able to carry up to 50 percent more LNG than conventional carriers and are typically used by Qatargas to export its LNG to Europe or Asia. The biggest LNG carriers, known as Q-Max, are able to carry 20 percent more LNG than the Q-Flex, but are too large to use the canal. “Qatar has been pushing to use Q-Flex to utilize their vessels more efficiently,” a source with a North Asian buyer said.

FERC issues final EIS for another LNG project in Louisiana

(Reuters; May 3) - Venture Global's Plaquemines liquefied natural gas export terminal in Louisiana took a step toward receiving federal approval for construction on May 3 after the Federal Energy Regulatory Commission concluded that construction and operation would result in some adverse environmental impacts, but those would be reduced to less-than-significant levels with mitigation. FERC said the project would permanently remove 368 acres of wetlands and could harm the habitat of nesting colonies of migratory birds, though the company could take steps to compensate for the impacts.

With the issuance of the 767-page final environmental impact statement, Venture Global said it expects to receive a FERC decision on the project application in August. That would allow the company to make a final investment decision and start construction in late 2019 with first LNG expected in late 2022. The Virginia-based company is planning for Plaquemines to produce as much as 20 million tonnes per year of LNG at full build-out. The initial phase of construction is estimated at $8.5 billion.

Venture Global already has made a final investment decision to build its 10-million-tonne Calcasieu Pass facility in Louisiana, which it expects to enter service in 2022. The company also is looking at a third LNG export terminal in Louisiana, though that project, called Delta, is at the early stages of regulatory approvals.

Shell and partner seek construction bids for Louisiana LNG project

(Houston Chronicle; May 3) – Dallas-based pipeline operator Energy Transfer and oil giant Shell have opened the bidding process for construction of the proposed Lake Charles LNG export terminal in Louisiana. The companies issued an invitation to tender for an engineering, procurement and construction contract to convert Energy Transfer's existing liquefied natural gas import terminal into a large-scale export terminal.

Energy Transfer developed the facility as an LNG import terminal in 2006 but the pipeline company got permission from Federal Energy Regulatory Commission to build an export terminal at the site in 2015, shortly after the shale revolution created a surplus of gas in the United States. Shell entered into a 50-50 venture with Energy Transfer in 2016 to develop a liquefaction plant to produce up to 16.5 million tonnes of LNG a year.

Under the joint venture, Energy Transfer will own and finance the proposed liquefaction facility while Shell will oversee engineering, design and construction work as well as operate the terminal once. Although Lake Charles LNG received FERC authorization in December 2015, the export project has been waiting for a final investment decision for nearly four years. Energy Transfer officials said a final investment decision will depend on the bids, overall project competitiveness and global LNG market conditions.

U.S. net natural gas exports reach 4.6 bcf a day in February

(U.S. Energy Information Administration; May 2) - U.S. net natural gas exports in February totaled 4.6 billion cubic feet per day, marking 13 consecutive months in which U.S. gas exports exceeded imports. The United States exports gas by pipeline to both Canada and Mexico and ships increasing volumes of liquefied natural gas worldwide.

Although U.S. LNG exports have grown in recent years, most U.S. gas exports are sent by pipeline to Canada and Mexico. Exports to Canada tend to be seasonal, increasing in the winter because of Canada's use of gas as a heating fuel in its populous eastern provinces. U.S. gas exports to Canada were 3.3 bcf per day in February, the highest on record. U.S. exports to Mexico are steadier, averaging 5.2 bcf per day in 2018, reflecting its use of gas for over half of its power generation and for industrial purposes.

LNG exports averaged 3 bcf per day in 2018 and hit a high of 4.1 bcf per day in January 2019. The volume of U.S. LNG is rising steadily as more liquefaction capacity goes into service at Gulf Coast terminals. LNG export volumes are expected to continue to rise in 2019 as an additional 4 bcf of liquefaction capacity is brought online by the end of the year. The U.S. Energy Information Administration forecasts that U.S. net gas exports will average 7.5 bcf per day in 2020, most of it attributable to increases in LNG exports.

European buyers complain U.S. LNG is too expensive

(Reuters; May 3) - As European and U.S. officials praise the growing trade of liquefied natural gas between the regions, some buyers are bristling at the terms for U.S. gas. Trading executives at French, German, and Spanish utilities said accelerating U.S. LNG production undoubtedly added liquidity and transparency to the global market, but they pointed out that prices for Europe were often too high. They said certain commercial terms in long-term contracts that underpin U.S. liquefaction projects need to change.

Spain's Naturgy, the second largest buyer of U.S. LNG, said future contracts must change away from the buyer taking on both volume and pricing risk. "We think it is critical that LNG projects take some of that market risk,” Naturgy LNG supply director Carlos Humphrey told a roundtable of U.S. and European LNG executives and European Union officials in Brussels on May 2. “If they don’t take this market risk, I think it’s very difficult anyone in Europe will contractually buy more U.S. LNG,” he said.

Several executives referred to offtake deals with Cheniere Energy, the dominant U.S. producer, which sells LNG at the U.S. benchmark price for the feed gas, plus 15 percent to cover the gas used in liquefaction, plus a liquefaction fee of $2.50 to $3 per million Btu. Add shipping and regasification costs and the LNG price amounts to $7 compared to the Dutch gas trading hub price of $4.75 on May 3. “It’s a $7 million loss per cargo,” RWE Supply & Trading Chief Commercial Officer, Andree Stracke, told the forum. “Right now, U.S. LNG is not competitive.”

Oregon LNG developer delays investment decision a year

(The Canadian Press; May 2) - A Calgary company proposing to build an LNG export facility in Oregon said the timeline for the project — worth an estimated US$10 billion — is being delayed by about a year. Pembina Pipeline Corp. said it has decided to minimize project spending at about $50 million this year as it tries to vault remaining regulatory and permitting hurdles for the Jordan Cove liquefied natural gas project at Coos Bay, Ore., and a related 229-mile pipeline through the state.

Pembina, which inherited the project when it purchased Calgary-based Veresen in 2017, said it received a draft environmental impact statement from the U.S. Federal Energy Regulatory Commission in March that provided a framework for approval of the Jordan Cove project with "reasonable" conditions. However, a final FERC decision is not expected until January 2020, and critical Oregon state permits are not expected until near the end of this year. The company has yet to make a final investment decision.

The reduced level of work is expected to result in construction delays such that the earliest the LNG plant could start deliveries is 2025. Pembina said it still intends to bring in partners for the pipeline and liquefaction development to reduce its ownership to between 40 and 60 percent. It said it has non-binding offtake agreements with customers in excess of the planned design capacity of 7.5 million tonnes per year but will pause executing binding LNG deals until early 2020.

U.S. LNG terminals could exceed nameplate production capacity

(S&P Global Platts; April 30) – Some U.S. gas liquefaction facilities under construction will be able to exceed their nameplate production capacities, as confirmed in documents from the Federal Energy Regulatory Commission. Should this additional capacity materialize on a reliable, long-term basis, it could relieve some anticipated tightness in the global LNG market. S&P Global Platts Analytics has also researched production debottlenecking that Cheniere is considering at its Sabine Pass, Louisiana, terminal.

While debottlenecking is one way to achieve additional LNG production gains, there is also potential for additional incremental volumes that are not quantified until after a year or two of operations at a new facility and efficiency gains are realized at individual liquefaction trains. If these additional volumes are ultimately achieved, they could be marketed in new supply contracts.

This relates to performance and capacity guarantees by engineering, procurement, and construction companies. These include turbine manufacturers and other liquefaction technology licensing companies. The guarantees specify a minimum performance and liquefaction capacities to meet the obligations of supply contracts. But terminals can exceed those minimums. An example of this could be at a Texas LNG export facility with its first train slated to come online this year. Freeport LNG said it could have excess production over and above what is currently committed to firm contracts.

Editorial says Trump should approve Jones Act waiver for U.S. LNG

(Bloomberg editorial; May 2) - President Donald Trump has reportedly rejected a waiver of the Jones Act — the law that requires the use of U.S-built and U.S.-crewed vessels to move cargo between U.S. ports — for shipments of liquefied natural gas. That’s bad news. Recently, the White House was said to be leaning in favor of the waiver, which could have sent cheaper and cleaner energy from the U.S. mainland to Puerto Rico, whose decrepit power grid relies on old plants burning oil and coal. It would also have helped Northeast consumers tap into the U.S. gas boom by providing an alternative to overloaded pipelines and their use of imported LNG from suppliers such as Russia.

Best of all, it could have helped to sink the Jones Act altogether. Ships that comply with this law cost more to build and operate than foreign-flagged counterparts, raising the cost of almost all goods transported between U.S. ports. Those higher costs make it more attractive to buy oil, lumber, rock salt, wheat, and other bulk goods from foreign suppliers. They keep more trucks on the road clogging highways and spewing carbon.

The Jones Act was meant to maintain a healthy merchant marine. But since 1960 the number of U.S.-flagged ships has plunged anyway. Hundreds of shipyards have closed. The act is no longer working, if it ever did, but the shipping lobby defends it tenaciously. Building Jones Act-qualified LNG carriers could cost two or three times more than in South Korea. If Trump changes his mind (again), it would help Americans benefit from cleaner energy, and could put a hole below the Jones Act’s waterline.

Prelude will ship first LNG cargo before June 30

(S&P Global Platts; May 2) - Shell expects to ship the first LNG cargo from its Australian floating gas liquefaction facility, the 1,600-foot-long Prelude, in the second quarter which ends June 30, the company's chief financial officer Jessica Uhl said May 2. Uhl said the first LNG would follow the shipment of Prelude's first condensate cargo last month.

Prelude is one of the most anticipated LNG projects in recent years due to its status as the world's largest floating facility, though it has experienced delays due to unspecified production issues. At full operation, Prelude has a production capacity of 3.6 million tonnes per year of LNG and 46,000 barrels a day of condensate and liquefied petroleum gas. The production unit is anchored about 125 miles offshore Western Australia. Shell, which is the operator, owns a 67.5 percent stake. Japanese explorer Inpex holds 17.5 percent, Korea Gas has 10 percent, and Taiwan's CPC Corp. owns 5 percent.

Explorer will drill in search of large shale gas deposit in Australia

(Bloomberg; May 1) - In a corner of outback Australia, a drilling crew will soon try tapping shale rocks that could hold more than three times the world's annual consumption of natural gas. Origin Energy plans to drill two wells later this year in the Northern Territory's Beetaloo Basin after the local government ended a three-year ban on fracking. With an estimated 500 trillion cubic feet of gas, Beetaloo has been compared to famed U.S. shale regions such as the Marcellus and Barnett.

But its isolated location, lack of infrastructure and the likelihood of tough environmental opposition make Beetaloo a speculative investment. "There are some big numbers being quoted and people have to realize this is exploration," said Mark Schubert, Origin's head of integrated gas, noting that only some of the total reserves would be extractable. Beetaloo is about 1,500 miles away from Sydney and even further from Melbourne, so the project would require pipelines that would connect to and expand the capacity of Australia's growing gas transmission network.

Origin, and its joint-venture partner Falcon Oil & Gas, have a long way to go before they could bring Beetaloo gas to market, probably around the middle of next decade. That may be just in time to head off a domestic shortage of the fuel in Australia's populous East Coast, which has traditionally relied on the now-declining Bass Strait offshore field. Beetaloo could also feed the nation's growing gas export business. Drilling in Beetaloo, named after a cattle ranch, has broad political support in the national parliament.

[U.S. EIA reports record high 8,504 uncompleted oil and gas wells]

(U.S. Energy Information Administration; May 3) – The number of drilled but uncompleted wells (DUCs) in seven key oil and gas production regions in the United States has increased over the past two years, reaching a high of 8,504 wells in February 2019, according to well counts in the U.S. Energy Information Administration's drilling productivity report. The most recent count, at 8,500 wells in March, was 26 percent higher than March 2018.

Drilled but uncompleted wells are oil and gas wells that have been drilled but have not undergone well completion work to start production. The completion process involves casing, cementing, perforating, hydraulic fracturing, and other procedures required to produce crude oil or gas. The number of uncompleted wells has generally increased since the end of 2016. A high inventory of DUCs may be attributable to economic factors or resource constraints, the federal agency reported.

For example, a low oil-and-gas price environment may postpone well completion activities in areas where the wellhead break-even expense is too high relative to the market price. Another example may be the lack of available well completion crews to perform hydraulic fracturing in areas of high demand. Insufficient pipeline capacity could be another reason, the agency said. Most of the recent increase in DUCs has been in regions dominated by oil production where limited pipeline capacity makes gas a real problem, especially the Permian Basin in western Texas and eastern New Mexico.

[Asian refiners ask Saudis to cover global oil supply disruptions]

(Bloomberg; May 2) - Asian refiners are asking Saudi Arabia for more crude as buyers in the world's top oil-consuming region face supply disruptions from Iran to Venezuela, according to people with knowledge of the matter. Customers are seeking additional cargoes for loading in June and July from OPEC's biggest producer, said the sources. The requests are for supplies on top of what the refiners are due as part of their term contracts with state-run Saudi Aramco, the sources said.

The scramble for shipments follows a U.S. decision to end waivers of sanctions for buyers of Iranian oil after the current exemptions expire on May 2. Unexpected disruptions to supply from Russia and Nigeria as well as turmoil in OPEC member Venezuela are also adding to fears of a global supply crunch. Prices have seesawed in the past week on uncertainty over how Saudi Arabia will respond, with the Trump administration saying the kingdom will pump more oil.

While Saudi Oil Minister Khalid Al-Falih has said the producer will seek to keep the market balanced, he's also signaled that OPEC and its allies including Russia could extend their output curbs until the end of this year. In Asia, the end of the U.S. waivers that allowed purchases from Iran has caused a headache for refiners that are being forced to seek potentially costlier alternatives. Some Asian refiners are asking Saudi Arabia for more crude even before the producer sets the cost for the cargoes.