Oil and Gas News Briefs
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Saudis sign up for LNG and take equity stake in Texas project

(Reuters; May 22) - Saudi Aramco signed a 20-year agreement to buy liquefied natural gas from Sempra Energy’s forthcoming export terminal in Texas, the two companies said May 22. The Saudi state oil giant plans to become a major global gas player, and this deal will provide it with access to some of the world's cheapest and most abundant natural gas from the U.S. shale boom. Aramco also will buy a 25 percent equity stake in the first phase of the multibillion-dollar project in Port Arthur, Texas, the companies said.

The sale-and-purchase agreement is for 5 million tonnes per year of LNG, equivalent to about 700 million cubic feet per day of natural gas. This is Saudi Arabia's first known non-binding agreement to buy LNG, and the largest such LNG deal for any project since 2013, according to energy consultancy Wood Mackenzie. While Aramco has been developing its own gas resources for power generation, it also is eyeing gas assets in the United States, Russia, Australia, and Africa as it looks to get into the LNG business.

"It's unclear what the final destination of Saudi Aramco's LNG will be. There continues to be a long-term expectation that, in time, Saudi Arabia will import LNG to be used for power generation," said Giles Farrer, Wood Mackenzie’s research director. The first phase of the Port Arthur project will include two liquefaction trains with production capacity of 11 million tonnes per year. Sempra said it plans to make a final investment decision in the first quarter of 2020. The Federal Energy Regulatory Commission approved the project in April. Sempra’s first LNG export terminal, the $10 billion Cameron LNG project in Louisiana, is starting operations this month.

LNG spot-market price falls to $4.60 in Asia

(Reuters; May 22) - The Asian spot-market price for liquefied natural gas dropped to below $5 per million Btu this week as sellers flooded the market with cargoes, trade sources said. The price is the lowest since the beginning of April. Oil majors Shell and BP each offered a July-loading cargo at $4.60 to $4.65 per million Btu on May 22, well below the $5.35 levels seen last week, S&P Global Platts reported. A year ago, the Asian spot price for July 2018 delivery was about $11.60. A large tender by Egypt to sell up to 13 cargoes, as well as several cargoes offered by Indonesia’s Pertamina and from Angola and Australia producers are also weighing on the market, sources said.

Novatek selects construction contractor for Arctic LNG-2

(Reuters; May 20) - Russia's largest privately held gas producer Novatek said May 20 that it has selected TechnipFMC to construct the Arctic LNG-2 project. The contract terms provide for launch of the liquefied natural gas plant's first production train in 2023, Novatek said. U.K.-based TechnipFMC was formed in 2017 by the merger of U.S.-based FMC Technologies and the French firm Technip. Novatek did not announce terms of the construction contract.

The contract will cover engineering, procurement, supply, construction and commissioning of Arctic LNG-2, planned for three liquefaction trains at 6.6 million tonnes each annual capacity. Novatek is planning to make a final investment decision on the project later this year. Total project cost has been reported at between $20 billion and $25 billion. Arctic LNG-2 would be east of Novatek's first Arctic gas terminal, Yamal LNG, which started loading cargoes in December 2017. That project cost almost $20 billion for 16.5 million tonnes annual capacity.

Much of Yamal LNG being sold on spot market

(Reuters; May 20) - Liquefied natural gas available for spot purchase from Russia's Yamal plant is climbing — and adding to oversupply in the global market — as companies with long-term contracts take their time to ramp up purchases, industry sources said. Long-term contracts with Total, Novatek, PetroChina, Gazprom, and Naturgy were expected to absorb Yamal LNG volumes, but much of the plant's 16.5 million tonnes of annual production is still available for spot trade.

This year up to about 8.7 million tonnes of spot LNG is being traded from the project — spread between equity shareholders Novatek, PetroChina and Total — according to Reuters calculations. Spot volumes sold by Russian gas producer and Yamal LNG operator Novatek, which has a 60 percent share of volumes not locked into long-term contracts from the terminal, are expected to rise above 5 million tonnes this year from less than 4 million tonnes last year.

PetroChina and Total, which each hold 20 percent stakes, both have about 1.74 million tonnes available to sell on the spot market. PetroChina was the last company to start its long-term contract, pegged at 3 million tonnes of LNG for delivery to China. Petro China will ramp up to its full contract by 2021, selling on the spot market until then. Gazprom, Novatek, and Naturgy are expected to take their full contracted volumes next year. Up to 85 percent of Novatek's spot cargoes have already been sold this year.

Yamal will soon take delivery of 12th ice-class LNG carrier

(Reuters; May 20) - A new ice-breaking liquefied natural gas carrier of the Arc7 class, the Nikolay Yevgenov, is due to arrive this week in Sabetta, the Arctic Russian port of Novatek's Yamal plant, Refinitiv shipping data showed May 20. The carrier is off the west coast of Ireland at the moment, having left the Daewoo Shipbuilding and Marine Engineering Okpo shipyard in South Korea at the end of April, Refinitiv Eikon data showed. It is due to arrive at Sabetta on May 26, according to the data.

Another Arc7 carrier, the Vladimir Voronin, also operated by Teekay LNG, is set to begin sea trials imminently in Okpo. It will be the 12th of 15 ice-class carriers ordered to serve Yamal LNG, which began operations in December 2017. The last of the new ships are scheduled for delivery in February 2020.

Yamal needs the ice-class carriers to move LNG out of Arctic waters. The vessels have largely conducted ship-to-ship transfers of LNG to conventional carriers after leaving Yamal, but during summer months they can travel the Northern Sea Route to China.

Australia looks to gain LNG sales in China

(The Sydney Morning Herald; May 20) - Australia's booming liquefied natural gas sector is set to benefit from the increasing trade tensions between the United States and China with potential delays to U.S. LNG export projects forcing Beijing to look at Australia to fill the gaps in its rising demand. In 2018, China imported 23 million tonnes of LNG from Australia, about 42 percent of Australia’s gas exports. China was expected to import about 3 million tonnes from the U.S. this year before the latest tariff fight.

Global research house Rystad Energy said the increasing vitriol in the trade war could delay approvals for U.S. LNG projects waiting on final investment decisions and deals with Chinese buyers. Credit Suisse energy analyst Saul Kavonic said it would benefit Australia as China looks for stable sources of LNG. "Overall, this is a positive for the marketing of Australian LNG," Kavonic said. "U.S. LNG is a competitor to Australia, so the tariffs work to take Australia's main competitor out of the market. If you're a Chinese buyer looking to sign a 20-year deal, you're going to be wary of these [political] risks."

Argentina close to sending out first LNG export cargo

(Reuters; May 20) - Argentina is about to export its first liquefied natural gas cargo from a new floating production facility, marking a milestone for its energy sector boosted by rising gas output from the large Vaca Muerta shale region. State energy firm YPF is reported to be offering a partial cargo from FLNG Tango, the liquefaction vessel off Bahia Blanco, two LNG trading sources said May 20. Argentina will become the 21st country to export the fuel. It has long bought LNG — alongside buying pipeline gas from neighboring countries and producing its own — to boost supplies, especially in winter.

But rising output from Vaca Muerta, one of the world's largest reserves of shale oil and gas, helped it reduce LNG imports by over 20 percent last year to 2.6 million tonnes. The export volume will be small — FLN Tango's capacity is 500,000 tonnes per year — and it does not mean Argentina will cease importing LNG. Energy company Integracion Energetica Argentina has issued buy tenders for LNG cargoes for May to September. The country needs billions of dollars in investment for construction of pipelines, storage terminals and other energy infrastructure to fully benefit from its shale gas resources.

U.S. LNG provides market with variable pricing options

(S&P Global Platts; May 20) - Flexible U.S. liquefied natural gas contracts are helping to create a global, commoditized spot market and transforming project financing models, according to the industry group American Petroleum Institute. The U.S. could become the world's third largest LNG exporter by the end of this year, after Qatar and Australia, and is bringing "unprecedented" options for pricing and contract terms to the market, API policy officer Dustin Meyer told S&P Global Platts in an interview May 20.

"The beauty of U.S. LNG is that no one really knows how it will be priced, and that's a unique amount of flexibility, of optionality, for potential buyers," he said. For decades buyers "really only had one option" for pricing — linking to the global oil benchmark Brent crude. The first wave of U.S. LNG export projects, coming online now, generally used prices linked to the U.S. Henry Hub natural gas benchmark. Developers for the second wave of U.S. LNG export terminals are being more flexible to attract buyers.

There are many pricing options, including hybrid approaches where prices are linked partly to Henry Hub and partly to a European gas price. "Maybe you can mix in a bit of Brent oil, maybe you go all Brent oil," Meyer said. Some developers have even offered a bit of linkage to West Texas gas hubs. Regardless of the pricing, new projects benefit from having long-term contracts to get them to a final investment decision. "If you're a new company and you're only focused on one LNG project in the U.S., then it's going to be more difficult to get financing unless you have those bankable long-term contracts."

Canada's Montney production could reach 20 bcf per day in 2030

(Oil & Gas Journal; May 17) - Production in Canada's Montney shale play will likely reach 10 billion cubic feet per day of gas equivalent this year, an increase of 16 percent from 2018, and is forecasted to reach 20 bcf per day by 2030, driven by rising liquids yield across various sub-plays, according to Wood Mackenzie research. Despite falling gas prices, improving economics driven by higher liquids yields have strengthened the Montney and much of the play is economic at C$2 per 1,000 cubic feet. The Montney will be a big supplier to the LNG Canada project under construction in Kitimat, B.C.

"Montney specialists have made major headway on improving completion design and are being rewarded with operational performance. Liquids is driving the story," said Wood Mackenzie senior analyst Nathan Nemeth. Drilling activity during 2010-14 was led by operators with LNG export aspirations. From 2015 activity has been led by operators targeting gas liquids, specifically condensate. Not all areas of the Montney in Alberta and British Columbia are liquids rich. At this stage, two sub-plays supply about half of the liquids production: Heritage in British Columbia and Kakwa in Alberta.

Canada faces hurdles to building LNG projects, gaining market share

(S&P Global Platts; May 21) - The U.S. is embroiled in a protracted trade war with key importer China that gives Canada a chance to seize market share. The rub? How to finance the huge construction costs for liquefied natural gas plants and bring together disparate groups of stakeholders, from municipalities to indigenous groups to regulatory agencies, to advance more projects following Shell-backed LNG Canada's decision last fall to build. That was the focus as Canadian market leaders met May 21 in Vancouver.

Potential LNG projects, like LNG Canada in Kitimat, B.C., would have access to some of the cheapest gas in North America. Cash prices at Westcoast Station 2 in British Columbia averaged just 97 cents (Canadian) per million Btu in 2018 and have traded in negative territory multiple times in 2019, S&P Global Platts data show. With regional production over 15 billion cubic feet per day and limited demand in Western Canada, LNG export terminals are likely to have access to cheap gas for the foreseeable future.

But labor and material make it very expensive to build projects in Canada. The cost of LNG Canada — $1,000 per tonne of output capacity — is about twice as much as the target that some of the second-wave U.S. facilities are aiming to hit. LNG Canada is the only major project to reach a final investment decision in the country, though several are being promoted on both the West and East coasts of Canada. However, none appear ready to move forward in the near-term. Indigenous groups want to be active on the front end in development activities, but there continues to be some local opposition.

Propane exports ready to start from new Prince Rupert terminal

(The Globe and Mail; Canada; May 19) - AltaGas will open its C$500 million propane export terminal next week in British Columbia, forging ahead during a time when energy projects have been cancelled or stalled in Canada. The terminal on Ridley Island in the Port of Prince Rupert will celebrate its opening May 28 after two years of construction.

It will export propane to Japan and other Asian markets. Canada's propane output has long exceeded its consumption with most of the surplus going to the United States.

But in recent years, with American propane output on the rise, the U.S. has been exporting record amounts of the fuel. Canadian exports "will increasingly be diverted from U.S. to overseas markets," the Conference Board of Canada said in December. At least 50 percent of the AltaGas joint venture's Canadian liquefied propane will be shipped to Japan-based Astomos Energy. Calgary-based AltaGas owns 70 percent of the project while Royal Vopak of the Netherlands holds 30 percent.

The terminal has the capacity to ship 1.2 million tonnes a year of liquefied propane, on about 60 rail tank cars a day arriving from gas producers in British Columbia and Alberta. The AltaGas plant will be joined next year by a propane export facility under construction for Calgary-based Pembina Pipeline on Watson Island, near Prince Rupert, while Vancouver-based Pacific Traverse Energy aims to begin propane exports within four years from a new plant in Kitimat, B.C. Tyler Reardon, an analyst at Peters & Co., forecasts exports will lead to higher prices for propane producers in Western Canada.

Washington governor's opposition to LNG surprised developer

(KNKX public radio; Seattle/Tacoma; May 22) - Puget Sound Energy CEO Kimberly Harris wasn't surprised to receive a call from Washington Gov. Jay Inslee the afternoon of May 8. But she was surprised to hear what he had to say. Inslee, who is running for president on a climate-change platform, had just signed his hallmark "100 percent clean energy" legislation — touted as the strongest in the nation. PSE spokesman Andy Wappler said the company was "at the table every step of the way" for that effort, which promises utilities will move away from greenhouse gas emissions entirely by 2045.

"We thought we were getting a thank-you call from the governor," Wappler said. "We weren't. We were getting a flip-flop." The call preceded an unexpected about-face from Inslee, regarding his stance on liquefied natural gas. The governor withdrew his support for PSE's long-debated $310 million LNG project under construction at the Port of Tacoma. The company said the project will provide reliable, clean fuel for vessels while also providing backup for thousands of utility customers across western Washington.

Inslee previously supported LNG as a so-called bridge fuel — cleaner to burn than coal or oil as the country moves toward more renewable energy sources. Officials with PSE and TOTE Maritime — the company that plans to use LNG for its vessels — said the governor's pivot doesn't change what they believe to be sound science in their favor. The Tacoma project, which is still waiting on an air quality permit, would liquefy gas and store the LNG in an 8-million-gallon tank on the waterfront.

Australia natural gas retailers sign up for LNG import terminal

(Reuters; May 22) - EnergyAustralia, the country's third-largest energy retailer, on May 22 agreed to buy gas from a liquefied natural gas import terminal planned by a Japanese-backed joint venture in the first of several deals needed for the project to go ahead. The Port Kembla LNG terminal is one of five proposed import terminals that could help meet a looming gas shortage in southeastern Australia, even as the country is set to become the world's top LNG exporter.

EnergyAustralia is the first to sign up to buy gas from Port Kembla, to be operated by a joint venture called Australian Industrial Energy (AIE), consisting of Japan's JERA and Marubeni and Australian mining magnate Andrew "Twiggy" Forrest's Squadron Energy. AIE is looking to lock in customers before making an investment decision on the A$250 million (US$172 million) project to park a floating storage and regasification unit at Port Kembla, about 62 miles south of Sydney. It would import 2 million tonnes a year of LNG.

AIE has agreed to supply EnergyAustralia for five years starting in 2021 at an oil-linked price. Staff at Australia's Department of Industry, industry executives, and analysts have predicted that only one or two of the five proposed import terminals are likely to go ahead because LNG import prices are likely to be higher than domestic gas by the mid-2020s and there isn't enough demand. Credit Suisse analyst Saul Kavonic said retailers like EnergyAustralia could afford import prices as they value the capacity flexibility and can pass on costs.

Hurricanes could test U.S. oil and gas export infrastructure

(S&P Global Platts; May 21) - As the U.S. becomes a larger oil and gas exporter, the annual threat from the Atlantic hurricane season poses greater risks for global flows on top of the usual risks to electricity demand and domestic fuel supplies. The U.S. now exports more than three times as much crude oil, refined product and liquefied natural gas as it did when Hurricane Harvey hit the Houston area in August 2017. That storm did massive damage across the energy and shipping sectors, roiling markets for weeks.

"Another Hurricane Harvey-type event would cause big problems for exporters if the port infrastructure was closed down," said Sandy Fielden, director of oil and products research for Morningstar Commodity Research. Port closures could ripple across the export infrastructure — canceling vessel loadings, filling storage terminals, and backing up pipelines. However, the U.S. oil sector is banking on major new pipeline routes to help producers and refiners reroute flows around a potential disruption.

For the natural gas sector, hurricanes pose a significant threat of destroying demand by knocking out large swaths of power generation as well as potentially shutting in any of the nation's LNG export terminals. The three terminals on the Gulf Coast and one on the East Coast lie in the potential paths of tropical storms and hurricanes. While the terminals are designed to withstand direct impacts of hurricanes and accompanying storm surges, the knockoff effects could cause the plants to limit or suspend operations.

Booming U.S. oil production creates need for more export capacity

(Forbes' columnist; May 21) - The rapid build-out of new and expanded pipeline capacity is now beginning to transport steadily rising volumes of oil, natural gas, and natural gas liquids from the Permian Basin to the Gulf Coast. The volume of light, sweet crude already exceeds the capacity of refiners to process the oil into gasoline and other products and is testing the capacity of coastal ports to handle more crude exports.

The U.S. Energy Information Administration reported that crude exports for the week ending May 10 surged to over 3.3 million barrels per day. As new pipelines and pipeline expansions are completed in the next 12 to 24 months, demand for export capacity will rise further. A report from DrillingInfo illustrates the industry's new normal: "Every incremental barrel of production since the middle of 2016 has been exported. As U.S. crude production grows, all incremental barrels are (and will continue to be) exported."

As a result of this new energy reality, the International Energy Agency projected in March that the United States will export as much as 9 million barrels per day in 2024, challenging Russia and Saudi Arabia as the world's top oil exporter. U.S. Gulf Coast ports are not equipped to accommodate such demand, so the next few years will see a myriad of new projects designed to meet and profit from it. Before December 2015, it was illegal to export domestic crude without a very restrictive federal permit.

J.P. Morgan says higher oil prices likely to be short-lived

(CNBC; May 20) - Oil prices jumped May 20 after Saudi Arabia indicated a possible continuation of OPEC output curbs amid political supply risks, but that support for higher prices is likely to be short-lived due to fundamental changes in the energy industry, an analyst said May 20. "It's alright to talk about supply-side risks, but that's sort of near-term. ... I don't think expectations for oil prices have actually gone up," said Scott Darling, J.P. Morgan's head of Asia-Pacific oil and gas research.

That's because of the rise of U.S. shale oil production and slowing demand due to global economic uncertainties, Darling said. J.P. Morgan expects OPEC to extend its oil output cuts to 2020. Oil prices jumped after Saudi Energy Minister Khalid al-Falih indicated there was a consensus among OPEC and its allied oil producers to continue limiting supply. Still, Darling said, "things can change by June" at OPEC's next meeting.

J.P. Morgan's forecast for Brent crude is $75 per barrel by the end of June. For the full year, however, the forecast pegs Brent to average $71 a barrel, weakening to $60 a barrel in 2021, Darling said. His comments come as the market expects Iranian oil exports to drop further in May and Venezuelan shipments to fall again in the coming weeks due to U.S. sanctions. Moreover, tensions between Saudi Arabia and Iran are running high after last week's attacks on two Saudi oil tankers and Saudi oil facilities.

Investors push shale producers to cut office overhead too

(Bloomberg; May 17) - U.S. shale producers that have reined in growth plans to mollify investors are now facing increasing pressure to slash their own pay and gut bloated offices. Almost all major U.S. explorers cut their capital budgets after oil prices fell at the end of 2018. The goal: Show they were willing to pay back shareholders at a time when their stocks were underperforming the broader market. But it didn't stop there. Investors are now increasingly focused on general and administrative budgets for everyday costs.

Pioneer Natural Resources recently said it is shrinking spending, offloading assets and asking one-third of its senior managers to retire. Other companies are also finding ways to cut back. Marathon Oil, for instance, has altered the way its exploration team is structured and paid to mirror private equity, using smaller groups with their compensation based on certain milestones. That allows the company to get into relatively unexplored areas for cheap, CEO Lee Tillman said in an interview in March.

"We're really at the point where companies are having to think about this more meaningfully," said Matt Portillo, an analyst at Tudor Pickering Holt & Co. "Investors really just want to know how that general and administrative composition breaks down as it relates to headcount." Part of why overhead costs got out of hand is that the focus was primarily on production growth. "They weren't really caring about profitability," said Evan Lederman, a partner at the New York-based hedge fund Fir Tree Partners.

Columnist warns Trump's orders could land energy projects in court

(Bloomberg Environment columnist; May 21) - The White House issued two executive orders April 10 intended to remove obstacles to developing energy projects and expediting pipeline permitting. While the goal is to accelerate construction, streamlining the process and diminishing reviews could dilute a thorough environmental analysis and could ultimately hurt companies as they navigate project costs. Moreover, projects could be delayed by potential litigation over agency actions resulting from the orders.

The two orders, Promoting Energy Infrastructure and Economic Growth and Issuance of Permits with Respect to Facilities and Land Transportation Crossings at the

International Boundaries of the United States, also focus on reducing regulations and improving opportunities for delivering coal, oil, and natural gas both domestically and internationally. The President Trump administration hopes these orders will make it harder for states and tribes to block pipeline and energy infrastructure development.

Updated rules supporting the energy infrastructure order are due in 13 months. This new guidance could conflict with Clean Water Act requirements and interfere with state and tribe involvement in the permitting process by shortening the review time and scope. It likely will be met with litigation. The order also directs the Department of Transportation to review the safety standards for transporting liquefied natural gas and to propose a rule within 100 days that would allow the fuel to be moved in rail tank cars.