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Exxon says Mozambique LNG ready for investment decision in 2019

(S&P Global Platts; Dec. 31) - ExxonMobil said its project partners in Mozambique's Area 4 concession have secured offtake commitments for the Rovuma liquefied natural gas project, paving the way for a final investment decision in 2019 and production to begin in 2024. Partners in the Area 4 exploration and production concession in northern Mozambique are Mozambique Rovuma Venture, a joint venture between ExxonMobil, Italy's Eni and China National Petroleum Corp., with a 70 percent interest; and Empresa Nacional de Hidrocarbonetos, Korea Gas, and Portugal's Galp with 10 percent each.

LNG offtake commitments, secured from "affiliated buyer entities of the partners," are "subject to the conclusion of fully termed agreements, which will be finalized and initialed in the next weeks, and the approval of the government of Mozambique," ExxonMobil said. "These commitments are an important step forward for the Rovuma LNG project and provide a solid foundation for securing project financing," Massimo Mantovani, Eni's chief gas and LNG marketing and power officer, said.

Mozambique Rovuma Venture submitted its development plan for the first phase of the Rovuma LNG project, which will comprise two liquefaction trains each with a capacity of 7.6 million tonnes per year, to the government of Mozambique in July 2018. ExxonMobil will head development of the LNG facilities, and Eni will lead the upstream work. The all-in development cost has been reported at $30 billion. A competitor in Mozambique, Anadarko's Area 1 project, also aims to reach a final investment decision in 2019.

U.S. will climb to No. 3 LNG producer in the world in 2019

(Argus Media; Dec. 27) – U.S. nameplate gas liquefaction capacity will likely double by the end of 2019 to 55.7 million tonnes per year, equivalent to 7.6 billion cubic feet of gas per day, as all six facilities comprising the first wave of U.S. LNG export projects are expected to be online. That would make the U.S. the world's third-largest LNG export capacity holder behind Australia at 86.5 million tonnes and Qatar at 77 million.

U.S. gas production is expected to keep up with higher demand for LNG exports and pipeline gas deliveries to Mexico. The U.S. Energy Information Administration recently estimated that domestic dry gas production would rise to an average of 90 bcf a day next year, from 83.3 bcf a day this year.

The six LNG export projects that will be operational in 2019 include three already online — Cheniere Energy's plants in Sabine Pass, Louisiana, and Corpus Christi, Texas, and Dominion Energy's Cove Point, Maryland, terminal — and three nearing the end of construction — Freeport LNG in Texas, Cameron in Louisiana, and Elba Island, Georgia. Next year could also see investment decisions on several of the second wave of U.S. LNG export capacity expected to come online in the early- to mid-2020s.

Wood Mackenzie expects 3 Gulf Coast LNG project decisions in 2019

(LNG Industry; Dec. 27) – Global energy consultancy Wood Mackenzie said North America will lead the next wave of LNG project sanctions in 2019, with three U.S. Gulf Coast developments expected to reach a final investment decision in the first half of the year — the addition of a sixth liquefaction train at Cheniere's Sabine Pass, Louisiana, terminal; the Golden Pass, Texas, LNG export project; and Venture Global's project in Calcasieu Pass, Louisiana. The three could total 30 million tonnes in annual capacity.

"With at least two other Gulf Coast projects — Freeport Train 4 and possibly Driftwood LNG — also not far behind, the first half of 2019 will be an especially busy one for the United States," said Alex Munton, principal analyst, Americas LNG, at Wood Mackenzie. Privately held Freeport LNG in Texas is scheduled to start production from its first trains this year. Tellurian is the developer behind the Driftwood project in Louisiana.

"While the Gulf Coast remains the key growth region for North America LNG, projects in Canada and Mexico are also progressing and attracting interest," Munton said. "Additional western Canadian capacity could help further open Canadian gas supply to global markets, and we are now seeing momentum around Mexico as an alternative export route for U.S. production." Sempra Energy is looking at adding liquefaction and export operations to its existing LNG import terminal in Mexico's Baja California.

Gas flaring hits record high in Permian as prices go negative

(Wall Street Journal; Dec. 27) – Companies have spent billions of dollars in the past decade exploring for natural gas. But in parts of Texas and New Mexico, there is now so much of it that it is sometimes worthless. Some producers have even had to pay buyers to take it away. Shale drillers in the Permian Basin are producing vast amounts of gas as a byproduct of drilling for oil. But there aren't enough pipelines to take all the gas to market, causing some of it to become landlocked and sending prices into free fall.

Gas prices in parts of the prolific region hovered near zero last month and some trades went negative, to as low as a negative 25 cents per million Btu, according to S&P Global Platts. The price-reporting agency said it was the first time on record that gas traded for less than zero at the Waha hub in West Texas. While prices have since ticked up, averaging $1.68 for the four weeks through Dec. 21, that is still far below the $4.20 that gas has fetched in that time at the main U.S. benchmark, Henry Hub in Louisiana.

Last month's zero pricing could be a sign of things to come in the Permian next year, as more oil pipelines get built and companies ramping up their oil production get stuck with more gas. The U.S. Energy Information Administration estimates December gas output will top 12 billion cubic feet a day in the region, up about 34 percent from a year earlier. "You'll see things get worse and worse and worse as oil production grows and gas production grows alongside it," said J.R. Weston, an analyst for Raymond James.

One option is to burn the gas. Flaring reached record highs in the Permian last quarter, when companies lit up an average 407 million cubic feet a day, said Rystad Energy, an energy consulting firm. But that has serious environmental consequences. The resulting greenhouse-gas emissions are equivalent to the daily exhaust of about 2.7 million cars, according to estimates from the World Bank and Environmental Protection Agency. Texas has thus far allowed companies to flare freely. As of the end of November, state regulators hadn't denied a single permit request in more than five years, records show.

North Dakota flared 527 million cubic feet of gas per day in October

(Bismarck Tribune; ND; Dec. 25) - Natural gas flaring reached record volumes in North Dakota in 2018, averaging 527 million cubic feet per day in October — enough to heat 4.25 million average U.S. homes. Oil operators burned off the gas associated with oil production due to a lack of gas processing plant and pipeline capacity in the state.

Industry is hopeful North Dakota will make significant progress on gas capture in 2019. Several gas processing plants and pipelines were announced or under construction in 2018, totaling more than $3 billion in investment, said Justin Kringstad, director of the North Dakota Pipeline Authority. Four major gas processing plants are expected to be complete next year, adding a total processing capacity of 690 million cubic feet per day. Most projects aren't expected to be ready until mid-2019 or the end of year, however.

But gas volumes are projected to nearly double from current levels, requiring even more long-term investments for 2020 and beyond. "We're probably going to need at least another $10 billion or more in order to build the necessary infrastructure," said Ron Ness, president of the North Dakota Petroleum Council. "Our productivity has just outpaced expectations." North Dakota produced 2.56 billion cubic feet per day of gas in October, and oil reached a record 1.39 million barrels per day. By the end of 2019, he expects North Dakota will produce 2.9 bcf of gas and 1.49 million barrels of oil per day.

U.S. East Coast continues to import LNG

(Bloomberg; Dec. 27) - The U.S. may be exporting natural gas at a record clip but that hasn’t stopped it from accepting LNG imports. A tanker with liquefied natural gas from Nigeria has berthed at the Cove Point import terminal in Maryland, while a ship with Russian gas is idling outside Boston Harbor. Pipeline constraints, depleted stockpiles and a 98-year-old federal law barring foreign ships from moving goods between U.S. ports is opening the way for LNG imports from overseas to meet winter demand.

At one point Dec. 26, the ship carrying Nigerian LNG to Cove Point passed another tanker in the Chesapeake Bay filled with U.S. gas that was headed abroad. The terminal was built in the 1970s for imports with LNG exports starting up this year. "It is ironic,’" said John Kilduff, a partner at Again Capital in New York. But the "super cheap gas” from the nation’s shale fields “is trapped down west of the Mississippi,” unable to reach the East Coast as LNG, he said. “The gas is where the people aren’t.”

The companies importing the LNG into Maryland — BP and Shell — will likely store it until freezing East Coast weather pushes prices higher as local gas suppliers struggle to meet demand, Trevor Sikorski, head of gas, coal and carbon with U.K.-based consultant Energy Aspects, said in a note to clients Dec. 26. U.S. LNG providers cannot supply the gas because the ships that transport the fuel sail under foreign flags. The 1920 Jones Act bans foreign ships from carrying LNG from Gulf Coast terminals to the East Coast.

The LNG carrier Exemplar has been loitering outside Boston harbor after picking up a cargo from a French terminal two weeks ago, according to ship tracking data. The LNG originated from the Yamal facility in Russia, according to Madeleine Overgaard, a market analyst for Kpler. Original destined for a terminal in Canada, the Exemplar turned and was repositioned outside of Boston. It is unclear where the gas will end up.

Gazprom will be busy in 2019 with new gas pipelines

(S&P Global Platts; Dec. 27) - Russia's Gazprom may fall short in 2019 of matching its record natural gas pipeline exports — set to almost reach 7.77 trillion cubic feet in 2018 — as Europe looks likely to mop up additional liquefied natural gas supplies expected to hit the market next year. That won't be a concern for Gazprom, though. It has a lot on its plate in 2019 as it prepares to flow first gas by end-2019 through three new pipelines.

Gazprom has not spared any expense in developing the three giant projects — the controversial Nord Stream 2 pipeline into Europe, at almost 2 tcf a year; the TurkStream link into Turkey and Southeast Europe at more than 1 tcf a year; and the 2,000-mile Power of Siberia line to China at more than 1.3 tcf a year.

It has been a long road to first gas through the Power of Siberia, but the date is now set for December 2019 for first gas to flow. The line will initially be filled with gas from the giant Chayandinskoye field before the Kovykta field is added to the supply. Gazprom expects to begin gas exports to China at around 500 million cubic feet per day in the first year. Supply is expected to double the second year, reaching full capacity in 2022-2023.

Russia also has plans to send an additional 1 tcf a year via a western route to China in the future with high-level talks to resume soon. Moscow and Beijing are drawing closer on energy issues, particularly as they share an economic foe in the U.S. government.

Bechtel will design expansion for Australia's Pluto LNG plant

(The West Australian; Dec. 26) – U.S. engineering company Bechtel has cemented its position to build the second liquefaction train at Woodside Petroleum's Pluto LNG plant in Australia's Pilbara. Woodside said Dec. 26 it had contracted Bechtel to do the design work for the train that would add 5 million tonnes annual capacity to the 4.3-million-tonne plant that opened in 2012. Woodside's proposed US$11 billion Scarborough gas project offshore Western Australia would develop 7.3 trillion cubic feet of reserves.

The producer said the front-end engineering and design award to Bechtel includes an option to advance to a lump-sum engineering, procurement and construction contract. The privately-owned Bechtel already has constructed eight LNG trains at two different gas plants in Australia. Woodside is targeting a final investment decision in 2020 for the Pluto train and a 2024 start-up.

Woodside managing director Peter Coleman said entering the FEED stage for the Pluto expansion is a significant step toward the developing a regional LNG production center. "Our vision is taking shape as we work with Bechtel to progress the Pluto Train 2 project, which will create a pathway for the globally cost-competitive development of Western Australian gas resources," Coleman said.

Environmentalists say LNG competes with greener fuels

(The Associated Press; Dec. 27) - In South Korea's largest shipyard, thousands of workers move between towering cranes lifting hulks of steel as they weld together the latest additions to the rapidly growing fleet of tankers carrying liquefied natural gas across the world's oceans. The boom in fossil-fuel production in the United States has been matched by a rush on the other side of the Pacific to build the ships needed to respond to the seemingly unquenchable thirst for energy among Asia's top economies.

Backers of U.S. LNG exports argue that the boom will produce environmental benefits by helping China and other industrial nations wean themselves from dirtier coal and oil. But environmentalists counter that while massive supplies of U.S. shale gas make coal-fired power plants less competitive, LNG also competes with such zero-carbon sources of electricity as nuclear, solar and wind — potentially delaying the greener sources.

“Typically, infrastructure has multi-decadal lifespans,” said Katharine Hayhoe, a climate scientist and director of the Climate Science Center at Texas Tech University. “So if we build a natural gas plant today, that will impact carbon emissions over decades to come.” Gas has the added appeal of producing about half the carbon dioxide when it’s burned than coal. Its increased use for generating electricity has been pitched as a way for nations to make progress toward meeting their emissions reduction goals.

But the increased use of gas hasn’t really reduced China’s coal consumption, which held largely flat in 2018. Overall carbon emissions for China, the globe’s biggest emitter, saw a nearly 5 percent increase in 2018. But when considering China, researchers can’t just look at whether coal use or carbon emissions are falling, they must try to calculate how much more coal would have been burned had gas not been available, said Daniel Raimi, a researcher at the Washington-based think tank Resources for the Future.

Nova Scotia LNG project will apply for government funds

(Financial Post; Canada; Dec. 27) - Pieridae Energy, the company with ambitions to build a $10 billion liquefied natural gas export project in Nova Scotia, will apply for funds under Ottawa’s recently announced $1.6 billion loan program as it inches closer to a final investment decision. Pieridae CEO Alfred Sorensen said the company is working to raise the funds it needs to build Goldboro LNG and hopes to announce an investment decision in the first quarter if it is successful in raising the necessary funds.

The Calgary-based company, which already has loan guarantees from the German government, has been in discussions with the Alberta and Canadian governments on funding and will apply for a chunk of the $1.6 billion aid package recently announced by Canada’s Natural Resources Minister Amarjeet Sohi. The company has completed all technical requirements necessary to build the project and expects to spend most of January in discussions on raising money through its banker, Morgan Stanley.

“All of the other pieces of the puzzle are now complete,” Sorensen said. However, the recent downturn in equity markets across North America has added a new challenge for the company, which plans to ship Western Canadian gas across the country to be liquefied on the East Coast before exporting it to Europe. Sorensen said the company is currently focused on trying to raise capital from sources in Europe.

Maritime industry has a lot of options to cut emissions

(Bloomberg editorial; Dec. 26) - Shipping is the lifeblood of global commerce — more than 80 percent of world trade goes by water. But the industry is also an environmental menace, producing as much carbon dioxide annually as Germany. The International Maritime Organization has called for ships to emit about 85 percent less sulfur by the end of next year and to halve their total greenhouse-gas emissions by 2050.

The shipping industry is responding with various strategies: emissions scrubbers, slower operating speeds and cleaner-burning fuels, including liquefied natural gas. These are essential steps — yet not adequate. To meet the 2050 target, shippers will need to try alternative sources of energy, including complimentary sail and solar power. Energy storage is needed, too, to take advantage of these intermittent power sources.

Other potential technologies include zero-emission hydrogen fuel cells and biofuels, which can be made of leftover cooking oil to algae. One practical idea is to remove the barnacles that attach themselves to hulls. The drag this creates can increase a vessel's fuel consumption by as much as 20 to 40 percent. And it's still possible that onboard nuclear reactors can overcome the additional costs involved with developing the emissions-free technology and protecting against catastrophic accidents.

None of these strategies can work alone, and some may turn out not to work at all. But the shipping companies, shipbuilders, and nations whose economies depend on them are going to need to get more inventive — 2050 is coming faster than they think.

Bloomberg survey shows Brent averaging $70 in 2019

(Bloomberg; Dec. 27) - The world's biggest banks are reckoning on a rebound in oil prices next year as fears of a recession prove misplaced. The London-traded Brent benchmark will average $70 a barrel in 2019, almost a third higher than its $53.50 price on Dec. 27, according to a Bloomberg survey of 24 oil analysts. They expect markets will tighten as demand stays strong, OPEC supply cuts kick in and production losses in Venezuela and Iran escalate.

"Fundamentally speaking, we believe that prices are nearing a bottom," said Michael Tran, commodities strategist at RBC Capital Markets. "Global supply and demand should reach a fine balance next year." And although doubts remain that OPEC will cut output deep enough to prevent a surplus, the survey shows analysts are confident that the group's strategy will ultimately succeed.

"We could even see something similar to a V-shaped recovery next year on two very important conditions," said Michael Cohen, head of energy and commodities research at Barclays in New York. "That the reduction in OPEC exports leads to a reduction in inventories. And that we don't see a further deterioration in macroeconomic conditions."

But with political and economic uncertainty, the range of estimates in the survey was broad, with a $20 gap between the high and low. Citigroup said the relentless growth of U.S. shale will keep a cap on prices, predicting Brent will average $59.50 in 2019.

Canada will refund $14.7 million in fees to failed pipeline project

(The Canadian Press; Dec. 27) – Calgary-based Enbridge is getting a $14.7 million refund on fees it paid Canada's federal energy regulator for an oil pipeline it won't build. The Northern Gateway pipeline was supposed to connect Alberta's oil patch to a port in Kitimat, British Columbia, but the plan came apart when the federal government banned tankers carrying large amounts of crude from British Columbia's northern coast. Without tankers to serve the port, there was no point in building the pipeline.

Then the Federal Court of Appeal ruled in June 2016 that Indigenous peoples affected by the pipeline had not been adequately consulted. A few months later, in late November, the government decided to revoke the regulatory approvals that had let the project get as far as it had. Enbridge had paid the National Energy Board $14.7 million in regulatory fees to monitor the $7.9 billion pipeline's construction and operation.

In February, the energy company asked for a refund. Just before Christmas, Prime Minister Justin Trudeau's cabinet agreed, saying in a formal decision that "it is just and reasonable to remit the funds." Enbridge said it is still out $373 million in lost costs for the cancelled project. Spokeswoman Tracie Kenyon said Dec. 27 the company has no other outstanding claims for reimbursements or refunds.

Report blames overproduction for low oil prices in Canada

(The Canadian Press; Dec. 27) - A new report from Canada's National Energy Board said the "primary factor" in recent steep discounts on Western Canadian crude is that oil production outstripped pipeline capacity by about 365,000 barrels per day. The report was compiled for federal Natural Resources Minister Amarjeet Sohi who has asked the NEB for advice on how to optimize existing pipeline and rail transport of crude.

The NEB said it has launched an online forum to gather public input and will meet with pipeline companies, producers, shippers, government officials, and other experts in January to gather more answers for the minister. The report notes that about 1 million barrels per day of nameplate Canadian oil pipeline capacity was added between 2013 and 2016 but there has been no new capacity since then.

It estimates that the available pipeline takeaway capacity from Western Canada in September was 3.95 million barrels per day, but output had risen to about 4.3 million barrels per day. The price discounts narrowed in early December after the Alberta government announced it would impose a temporary cutback of 325,000 barrels per day on the industry starting Jan. 1, a measure designed to draw down storage and restore normal market prices. Western Canadian crude has been selling in recent months at between $17 and $40 a barrel less than the U.S. benchmark West Texas Intermediate.