Oil and Gas News Briefs
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Indian gas utility renegotiates LNG supply deal with Gazprom

(Reuters; Jan. 16) - Gas utility GAIL (India) has renegotiated the terms of a long-term liquefied natural gas purchase deal with Russia's Gazprom, the Indian company said Jan. 16. This is the third renegotiation by an Indian buyer to make LNG imports more affordable to its price-sensitive customers, as the country has been making the most of its position as one of the world's biggest energy consumers to strike better deals.

In 2015 and 2017, India renegotiated LNG deals with Qatar's RasGas and ExxonMobil, as global prices declined substantially amid a supply glut. Under the latest reworked deal, GAIL and Gazprom have extended the contract's duration by up to three years and GAIL has agreed to buy an additional 6 million tonnes of LNG, a source said. The LNG pricing has been changed from a nine-month average of Japanese Customs-cleared crude to a three-month average of the Brent oil benchmark to diversify GAIL's LNG portfolio by spreading price-reference indexes across multiple geographies.

In the first three years of the deal, GAIL will be buying less gas than expected in the 2012 contract to take 2.5 million tonnes of LNG per year. Deliveries under the 20-year deal are to start in the second quarter of this year. GAIL will now take 500,000 tonnes in the first year, 750,000 tonnes in the second year and 1.5 million tonnes in the third year, with the full 2.5 million tonnes to start in year four or five. GAIL will make up for the smaller volumes in the early years by taking additional gas in later years.

Swiss trader signs 15-year deal with U.S. LNG exporter Cheniere

(Reuters; Jan. 16) - U.S. liquefied natural gas exporter Cheniere Energy has inked a 15-year deal for 1 million tonnes per year with Swiss commodity trader Trafigura, a sign of how the sector's middlemen are expanding market share. LNG deliveries to Trafigura, one of the biggest independent traders of the fuel, will begin in 2019, Cheniere said Jan. 16. It's the first long-term agreement signed between an independent commodities trader and a U.S. LNG producer. Swiss trading houses grabbed a $10 billion share of the rapidly growing global LNG business last year, handling about 8.5 percent of supply.

Traders have benefited from the emergence of new LNG importing countries with rapidly growing energy needs but with high credit risks, acting as a buffer for risk-averse suppliers and producers unwilling to take direct exposure. Traders Trafigura, Vitol, Gunvor, and Glencore are all used to dealing with politically complex markets. As many countries are hungry for gas as a cleaner alternative to oil and coal for generating power, traders are expected to keep growing their market share.

Gunvor was the first independent to gain access to long-term LNG supply in a deal with Russia's new Yamal plant in the Arctic. Last year, Gunvor agreed to buy all the output from Africa's first deepwater floating LNG plant in Equatorial Guinea. Trafigura's deal with Cheniere will help the Houston-based company fund its expansion plans, CEO Jack Fusco said. Cheniere last year started up its Sabine Pass, La., LNG terminal, and is adding to that plant and building a new LNG facility in Corpus Christi, TX. Trafigura's cost for the LNG is indexed to the U.S. benchmark gas price plus a liquefaction fee.

IEA director sees opportunity for U.S. LNG in China and India

(Economic Times; India; Jan. 17) - There is a huge opportunity for the U.S. to export liquefied natural gas to India and China in the next five years as the countries push to replace coal, the head of the International Energy Agency said as he highlighted the growing importance of the two nations in the energy market. Fatih Birol, executive director of the IEA, said India and China use gas at a minimum level. Globally, the share of gas in the energy mix is about 25 percent, yet in both countries it is about 5 percent.

"So, there's a big gap between the world average and them," Birol told U.S. lawmakers during a hearing on domestic and global energy outlook held by Senate Committee on Energy and Natural Resources. "And both of them are facing major challenges in terms of environment, namely local pollution in the cities. And this is an issue for both of these countries and others — a reason for social unrest, in fact," he said.

India, he said, is strongly pushing natural gas to replace coal. "But coal is also growing because, in India, people have no access to electricity." Birol said the Indian government "is pursuing an energy policy which is very good for their people because, in a very short period of time, almost 11 years, they are bringing electricity to about 500 million people. That's a big, big, big achievement … and they are using gas, they are using coal, they are using renewables — all of these technologies."

Egypt looks forward to resuming LNG exports

(The Financial Times columnist; London; Jan. 14) - With a major new natural gas field on stream, Egypt's energy market is changing. Self-sufficiency should be restored within the next 18 months, putting an end to liquefied natural gas imports. The country can once again become an LNG exporter and build on its existing role as one of the most important trading hubs in the region, ideally placed to link western and eastern markets.

In December, production of gas began from the giant Zohr field 150 miles off the Egyptian coast in the eastern Mediterranean. The field's reserves are estimated at 30 trillion cubic feet, one of the largest discoveries of the past two decades. Production is set to rise to 2.7 billion cubic feet per day by 2019. Its development in little more than two years represents a great success for the operating company, Italy' s Eni. A number of smaller developments, including BP' s West Nile Delta field, are adding to supplies.

Zohr has made Egypt a hotspot for industry investment, with strong potential seen in the new licensing round that will start later this year. Rosneft has bought into the field and ExxonMobil and others are actively looking at other opportunities. In addition, the partly state-owned Egyptian company Sumed is building a new large-scale LNG wharf on the Gulf of Suez. That should be finished by the end of 2018 and will supplement the capacity of the existing LNG facilities at Idku and Damietta on the Mediterranean coast.

Japan paid an average $8.10 for all LNG imports in December

(Platts; Jan. 15) - Japanese LNG buyers paid an average $10.20 per million Btu for spot cargoes contracted in December, up 13.33 percent from November and also the highest level since January 2015, Ministry of Economy, Trade and Industry data showed Jan. 15. The spot market has been well supported by strong demand due to colder winter weather in Northeast Asia, while steady demand from China also provided support on the back of the country's policy to switch from coal to gas for heating.

The ministry said the average price of all LNG cargoes delivered into Japan in December — spot-market buys and long-term contract deliveries — was $8.10 per million Btu, rising 14.08 percent from $7.10 in November.

Exxon and partners find new resource in gas-rich Papua New Guinea

(UPI; Jan. 16) - Working in a partnership with Australian and Japanese partners, ExxonMobil said new hydrocarbons were found while drilling in gas-rich Papua New Guinea. A regional affiliate of Exxon is working in a partnership with Oil Search and JX Nippon at the P'nyang South asset. Oil Search started drilling in October, and Exxon said it could finally declare a discovery of hydrocarbons that extends the boundaries of an existing field. None of the partners publicly reported the size of the discovery.

The new discovery adds to the potential for additional liquefied natural gas exports from the country. The $19 billion, Exxon-led Papua New Guinea LNG project started up in 2014. "We are continuing with our active onshore and offshore exploration program in an effort to provide additional resources to expand existing and planned development projects," said Liam Mallon, president of Exxon Mobil Development.

Montana coal company signs short-term deal to supply Japan

(Reuters; Jan. 16) - Cloud Peak Energy said Jan. 16 it will export coal from a Montana mine for 30 to 40 months to two new power plants in Japan, with shipments starting late next year. Coal from the Spring Creek Mine will move by rail to Vancouver, B.C., and then by ship to two 540-megawatt coal gasification plants in Fukushima Prefecture, Cloud Peak said. JERA Trading, based in Singapore, a joint-venture trading company of Japanese utilities Tokyo Electric and Chubu Electric, will buy the coal.

The coal is destined for a power-plant project led by Tokyo Electric and Mitsubishi companies, the Wall Street Journal reported.

Sales of Powder River Basin coal under the deal are expected to reach 1 million metric tonnes in the final contract year, Cloud Peak said. The company exported 4.5 million tons of coal in 2017. The deal represents a bit of good news for a U.S. industry that has seen production slip to the lowest level since the late 1970s in the face of a glut of competing low-cost natural gas. Backers of coal gasification say the plants burn coal more efficiently than conventional plants, emitting less carbon dioxide.

Analyst drops Canadian natural gas price forecast to $2.21

(CBC News; Canada; Jan. 16) - A prominent commodities analyst struck a gloomy tone as he delivered a blunt assessment of the Canadian natural gas industry's fortunes this year, describing it as a "sad story." In front of a few hundred oil patch members at the Calgary Petroleum Club on Jan. 16, commodities analyst Martin King said: "Prices are likely going to be very volatile, there could be some chaos out there this summer. We're going to have to kind of face the music on this one."

Speaking to reporters afterward, King struggled to find much reason for optimism. He said there are problems with too much gas supply in Alberta, weak demand, and pipeline constraints for moving the fuel to market. "For Canadian gas, we're facing a lot of challenges," he said. "Absolutely, no doubt about it. We have a lot of problems on our hands." Companies are slashing their spending plans for 2018 and will drill fewer wells. Companies are also considering shutting down some gas wells until prices improve.

The struggles come at a time when companies are unlocking more gas. Estimates for Western Canada's gas potential has tripled in the past decade because of technological advancements, such as horizontal drilling and fracking, according to the National Energy Board. King had previously forecast 2018 Alberta benchmark gas prices to average $3.61 per 1,000 cubic feet, but dropped his estimate dramatically on Jan. 16 to just $2.21. "I've followed Canadian gas for 25 years and never seen anything like it.”

[B.C. wrestles with support for LNG projects and climate action targets]

(Globe and Mail columnist; Canada; Jan. 14) - British Columbia Premier John Horgan is heading off on a trade mission to Asia later this month, hoping to continue the government's quest to secure a liquefied natural gas export industry for the province. However, just weeks ago, his government tried to bury the latest unhappy news about the lack of progress on the province's efforts to curb greenhouse-gas emissions — a task that is incompatible with the development of LNG.

Since the province launched his ambitious climate action agenda 10 years ago, British Columbia has barely put a dent in its greenhouse-gas output. The latest numbers, which cover through 2015, were published in a spreadsheet posted on a government website in December with no news release. They showed that emissions have been rising since 2010. Horgan departs Jan. 20 for a tour that will take him to Japan, South Korea, and China. He intends to meet with Asian partners in the proposed LNG Canada project.

The government wants to be seen embracing the potential economic boon of LNG at the same time that it promises to get the province back on track to meet its climate action targets. The Pembina Institute estimated in 2016 that the carbon pollution from the two phases of the now-canceled Pacific NorthWest LNG plant near Prince Rupert, B.C., and associated upstream gas production, would total up to 9.2 million tonnes a year by 2030 — the equivalent of adding more than two million cars on the road.

[Canada moves closer to nationwide carbon tax]

(Financial Post; Canada; Jan. 15) - Whether they like it or not, every Canadian province will soon see some form of carbon tax trickling through its economy as the federal government pushed ahead with detailed plans for a country-wide carbon price on Jan. 15. Environment and Climate Change Minister Catherine McKenna and Finance Minister Bill Morneau released the government’s carbon tax framework and a draft of the Greenhouse Gas Pollution Pricing Act for public comment.

The legislation includes new charges on fuels such as gasoline, diesel, propane, and natural gas. It would also set an emissions limit for industrial facilities such as oil and gas projects, pulp and paper mills, chemicals facilities, cement plants, mines, fertilizer plants, and steel mills. Any facility that emits more than its limit will need to pay, and those that emit less could be eligible for credits that could be sold to bigger polluters.

The government is also considering ways to apply carbon taxes to the offshore oil and gas sector and to electricity generation. The release said the government may extend the tax to other sectors of the economy. Alberta, British Columbia, Ontario, and Quebec have all implemented carbon-pricing systems that satisfy the federal requirements, but

Ottawa could impose the new rules on other provinces — such as Saskatchewan and the Atlantic provinces — unless they adopt their own carbon tax system by September.

California depends on gas for electricity as renewables gain ground

(San Diego Union Tribune; Jan. 14) - Natural gas has overtaken coal as the nation's No. 1 source of electricity and the gap appears to be getting wider each year. Even in California, gas is at the top. Hydraulic fracturing and horizontal drilling techniques have made gas abundant, which has driven down its price. The costs of renewable energy sources like wind and solar are dropping too and, in an ironic twist, adding renewables to the grid often requires gas to "fill in the gaps" of inconsistent power generation.

"The biggest, most disruptive innovation in the energy sector in the last 30 years is unconventional natural gas," said Frank Wolak, professor of economics and an energy expert at Stanford University. "There is no doubt that if that innovation had not occurred, we would be burning even more coal and coal would probably be an even greater share of the U.S. electricity mix than it was even in, say, 2000, before the shale gas boom." But gas faces headwinds, especially from environmental groups that consider fracking anathema and are uniformly opposed to gas.

Meanwhile, the price of renewable energy sources such as solar and wind is falling, too. The percentage of California's in-state generation from renewables reached 27.9 percent in 2016 — nearly twice as much as 2009. Mark Zoback, director of the Natural Gas Initiative at Stanford, said the long-term future of energy will belong to renewable sources but they're not there yet and abundant supplies of gas will help foster the transition. "I'm 69 years old. I'm not going to be able to test these theories, but my sense is that we're going to see expanded use of gas for the next 20 years," he said.

Dutch may have a problem due to further production cuts at gas field

(Bloomberg; Jan. 16) - The world may never have produced more natural gas, but that's little comfort for the Dutch government as it seeks to replace flows from Europe's biggest field. Lawmakers in the Netherlands will discuss options to supply residents through the country's pipeline network, which was built around the relatively poor-quality gas (lower Btu value) from the Groningen deposit. However, more than a half century of production there has triggered earthquakes, forcing scaling back of production.

At first glance, losing one field shouldn't be a problem for a market flush with supply from Russia and Norway. But Dutch home appliances and heating systems were built around the low-calorie gas Groningen produces. The field was hit Jan. 8 by the biggest tremor in more than five years, leading the government to call for further cuts in production. GasTerra, which markets the gas, said there could be shortages if output is cut further because of bottlenecks in units that can convert richer gas from abroad.

Facilities that convert richer imported gas by adding nitrogen are running near capacity at peak periods, said Anton Buijs, a spokesman for GasTerra, a venture between the state, Shell, and ExxonMobil. A Shell-Exxon venture operates Groningen. Conversion facilities, which can cost almost half a billion euros, take years to build. “Converting more than 7 million households takes time and active government regulation,” Gerald Schotman, CEO of the Shell-ExxonMobil venture, said in a speech Jan. 15.

North Dakota oil producers risk cutbacks if they flare too much gas

(The Associated Press; Jan. 16) - Fearing sanctions by the state, some North Dakota oil drillers have begun cutting output to control the amount of natural gas burned off at well sites and wasted as a byproduct of crude production, industry and state officials said. Rebounding oil prices and technology advances in western North Dakota's oil patch have boosted crude output, spurring unanticipated record levels of gas that comes with it, said Justin Kringstad, director of the North Dakota Pipeline Authority.

The state's gas-gathering and processing capacity is 2.1 billion cubic feet per day. In November, the latest figures available, the industry was right at that ceiling — with a record 2.09 billion cubic feet of gas produced daily. Pipeline capacity is adequate to move the gas to market, but it's the lack of gas-gathering and processing facilities in between that's the problem. That forces some drillers to restrict oil output at some wells to meet anti-flaring rules, said Ron Ness, North Dakota Petroleum Council president.

The 2014 rules allow the state to set oil production limits if the flaring targets are not met. The rules require drillers to capture 85 percent of the gas by 2016, 90 percent by 2020. The rules came after as much as a third of gas was being flared, drawing criticism from environmentalists and residents who said the state was losing revenue from the wasted gas, and that it contributed to carbon dioxide emissions. Less than 1 percent of gas is flared from U.S. oil fields, less than 3 percent worldwide, the Energy Department said. North Dakota drillers in November flared 14 percent of the gas, the state said.

U.S. drilling efficiencies help drive record oil production

(Reuters; Jan. 15) - Surging shale production is poised to push U.S. oil output to more than 10 million barrels a day — toppling a record set in 1970. The new record, expected within days, likely won’t last long. The government forecasts U.S. production will climb to 11 million barrels a day by late 2019, rivaling Russia, the world’s top producer.

The economic and political impacts are breathtaking, cutting U.S. oil imports by a fifth over a decade, providing high-paying jobs in rural communities and lowering prices for domestic gasoline by 37 percent from a 2008 peak. The U.S. now exports up to 1.7 million barrels per day of crude. U.S. oil now competes with Mideast crude for buyers in Asia. The question of whether the sector can continue at this pace remains an open debate. The rapid growth has stirred concerns that the industry is already peaking and that production forecasts are too optimistic.

The costs of labor and contracted services have recently risen sharply in the most active oil fields; drillable land prices have soared; and some financiers are calling on producers to focus on improving short-term returns rather than more drilling. But U.S. producers have outpaced expectations and overcome challenges, including OPEC's effort to sink shale firms by flooding global markets with oil. "We continue to see and drive improvements" in drilling speed and efficiency, said Mathias Schlecht, a technology vice president at Baker Hughes' oil field services business. New wells can be drilled in as little as a week, he said. A few years ago, it could take up to a month.

More rail transport could help Canadian oil get better prices in 2018

(The Canadian Press; Jan. 16) - Steep price discounts for Canadian oil are moderating and should gradually ease through 2018 to allow producers to reap bigger rewards from strengthening world oil prices, according to Calgary-based GMP FirstEnergy. A spike in the gap between Western Canadian Select crude prices and benchmark U.S. oil prices was made worse by volume constraints on the Keystone pipeline system from Alberta to the U.S. Gulf Coast following a leak in South Dakota in November.

GMP FirstEnergy analyst Martin King said the transportation blockage meant growing volumes from Alberta's oil sands couldn't easily get to market, driving prices lower for the bitumen blend. During a period in December, Canadian oil earned was more than $20 per barrel under U.S. prices. Crude-by-rail terminals in Western Canada had been using a small part of their 1-million-barrels-per-day capacity but are now activating idle capacity to fill the transport gap, King said in a presentation in Calgary on Jan. 16.

Rail transport is more expensive than pipelines, but the shipper has the advantage of sending its crude to the market where it will fetch the best price. King predicted the Canadian crude discount will fall from US$17.30 per barrel in the fourth quarter of 2017 to average US$16 in the current quarter and US$13 in the third quarter of this year. On Jan. 16, Calgary producer Obsidian Energy said it will begin shipping some of its northwestern Alberta heavy oil by rail in the next few weeks to try to get better prices.

Shell approves first major new North Sea investment in six years

(Reuters; Jan. 15) – Shell gave the green light Jan. 15 for expansion of the Penguins oil and gas field in the U.K. North Sea, its first major new project in the aging basin in six years. Shell said the development, which includes construction of a floating production, storage and offloading vessel, reaffirmed the company's commitment to the region after it sold about half of its assets there last year. The field was discovered in 1974 and first developed in 2002. It is a 50-50 joint venture with ExxonMobil.

The new development is expected to produce up to 45,000 barrels of oil equivalent per day. The Shell-operated venture is the first major project Shell has announced since 2012, when it made a final investment decision for the Fram field in the central North Sea. Penguins will generate a profit even with oil prices below $40 a barrel, Shell said, making it competitive against other offshore basins and most North American shale oil.

"We struggled to make it economic until the last couple of years when we closely worked with supply to redefine and redesign the development to reduce costs," Steve Phimister, head of Shell Upstream in the U.K. and Ireland, told Reuters. After Penguins, Shell is expected to decide on a number of new projects in the central North Sea in the next year or two, Phimister said. Shell gave no details on the cost of the project, which analysts at Bernstein last September estimated would be up to $2.5 billion.

Shell is selling its last holdings in Iraqi oil fields

(Wall Street Journal; Jan. 15) - Shell is giving up on its last oil fields in Iraq, leaving the world's second-biggest oil company with a dwindling footprint in the Middle East — a region it helped build into a petroleum powerhouse. Shell said Jan. 15 it is selling for an undisclosed amount a stake in Iraq's West Qurna 1 field to Japan's Itochu, the latest step in a gradual retreat. The company is also expected to give up its holding in Iraq's Majnoon oil field later this year, though it will retain its natural gas interests in Iraq.

Shell's departure from Iraqi oil marks one of the final chapters in a slow pullback from the Middle East's vast fields of petroleum. Shell pumped as much as 450,000 barrels of oil a day in 2003 in the Middle East. Once it officially leaves Iraq later this year, Shell will have oil assets in Oman that produce about 220,000 barrels a day. The move reflects the waning attraction of the Middle East's once-prized oil reserves, as companies find that the free flow of crude in the region often comes at a political or financial cost.

In addition to the escalating security risks following the Arab Spring, oil contracts offered by Mideast governments often don't have profitable terms, analysts say. Iraq has some of the toughest terms in the business. Foreign companies are paid fixed fees per barrel of oil pumped, terms that many in the industry say is low. "The terms are too tight for

Shell," said Robin Mills, a former Shell executive involved in the Middle East who is now CEO of Dubai-based Qamar Energy. For Shell, "it isn't worth the trouble," Mills said.