Oil and Gas News Briefs
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Spot, short-term LNG sales grow to 28% of market

(Bloomberg; Aug. 15) - The market for liquefied natural gas is about to attract more players and more trading as new supply from the U.S. and Australia strengthens buyers' bargaining power. Historically, LNG has been sold on long-term deals that guaranteed supply for buyers and helped producers finance liquefaction plants. Now, a natural gas glut is causing countries that import LNG to support renegotiating existing deals that can run 20 years or more as suppliers lower their prices in a move to shrink stockpiles.

India already is encouraging importers to rework long-term accords to better align costs with spot market prices. Japan, the world's largest LNG importer, may soon join them. "There will be 40 million to 50 million tons [annual capacity] of homeless LNG by 2020, which can go anywhere or doesn't have any fixed customers," said Hiroki Sato, a senior executive vice president with Jera Co., a Japanese fuel buyer that plans to increase its spot and short-term LNG deals over long-term contracts.

About 28 percent of LNG traded in 2015 was on a spot or short-term basis, up from 18.9 percent in 2010, said the International Group of Liquefied Natural Gas Importers. As the oversupply intensifies next year to the point that Asian buyers can't absorb the surplus, new trading may emerge from Asia to Europe, said Kazuhiko Inomata, a deputy director with Itochu Corp., Japan's third-largest trading house. Jera, a joint venture of Chubu Electric Power and Tokyo Electric Power, plans to resell surplus LNG to Europe. Sumitomo, the fourth-biggest Japanese trader, is considering an LNG office in Europe.

Japanese utilities look to buy coal-trading business

(Nikkei Asian Review; Aug. 18) – Tokyo Electric Power and Chubu Electric Power are looking to acquire Electricite de France's coal-trading business, seeking a new source of income as well as cheaper fuel for Japanese power plants. Jera, a fuel and electricity joint venture established in 2015 by the two utilities, will start negotiations on a possible deal with EDF Trading, a London unit of the state-controlled French energy company.

EDF Trading handles about 100 million tons of the estimated 1.3 billion tons in annual worldwide coal trading. The company's latest annual net profit was 300 million euros ($338 million). EDF Trading also holds mining concessions, including a 7.5 percent stake in the Narrabri coal mine in Australia. Those rights may be part of the acquisition talks. A successful acquisition of EDF Trading's coal business would dramatically boost Jera's yearly coal procurement, which currently totals about 20 million tons.

In addition to increasing its own bargaining power to provide cheaper fuel to TEPCO and Chubu Electric, Jera aims to sell coal to third-parties, creating a new revenue stream. Burning coal for power generation may be on the way out in the U.S. and Europe, but not so in emerging economies with rapidly growing energy needs. Japan is also relying more on coal because many of its nuclear power plants remain idle after the 2011 Fukushima disaster. Several new, high-efficiency coal plants are in the works.

Hawaii governor reaffirms opposition to LNG imports

(Pacific Business News; Honolulu; Aug. 16) - Hawaii Gov. David Ige on Aug. 16 reiterated his opposition to liquefied natural gas at an energy event in Honolulu. “I continue to believe LNG does not have a future for electrical power generation,” Ige said during his State of Clean Energy speech at the 8th Annual Hawaii Clean Energy Day. “It will be a distraction to the core task at hand. We need to focus on renewable energy.”

He has not deviated of late from that stance, although during his 2014 run for the state’s top public office he wasn’t against using LNG as a bridge fuel while the state moves closer to renewable energy. Ige said he switched his stance on LNG due to such factors as declining oil prices and his conversations with federal regulators.

Last month, Hawaiian Electric Co. terminated its deal with FortisBC that called for the Canadian company to supply the Honolulu utility with LNG as a replacement for oil in power generation starting 2021. The deal was contingent on regulatory approval of Florida-based NextEra Energy’s $4.3 billion acquisition of Hawaiian Electric, which was terminated after the Hawaii Public Utilities Commission rejected the plan. Meanwhile, Hawaii Gas, the state’s only regulated gas utility, still plans to import LNG for its needs.

Australia coal-seam gas supply comes up short for LNG plant

(Bloomberg; Aug. 16) - After spending billions of dollars constructing a liquefied natural gas export project in Australia, Santos has found itself short of gas. The country’s third-largest energy producer, which isn’t pumping enough of its own gas to feed its Gladstone LNG plant yet, is having to buy expensive local supplies to fill the gap. Meanwhile, prices for the LNG that Santos is selling have plummeted by more than half the past two years amid a supply glut driven in part by rising Australian production.

At the same time that so much gas is being siphoned off for export, prices in Australia have soared to more than double last year’s level. “GLNG is in a difficult position,” said Graeme Bethune, CEO of consultancy EnergyQuest, referring to Gladstone LNG. “It’s quite ironic because for years Santos was talking about the need for domestic gas prices to be higher and suddenly they are a gas buyer rather than a gas producer.”

While exports have tightened the market and contributed to higher prices, they aren’t the only driver. Cold weather and the restart of gas-fired power plants also conspired to push up costs, said Andrew Smith, Shell Australia’s chairman. Santos, which owns a 30 percent stake in the $18.5 billion GLNG project with partners Petronas (Malaysia), Total (France) and Korea Gas, has cut spending amid the fall in oil and LNG prices, resulting in a shortage from GLNG’s coal-seam acreage. But it still has to meet obligations to LNG buyers, forcing it to buy gas from rival producers. The plant started up last fall.

Australian gas customers worry about supply and price

(Reuters; Aug. 15) - Australia is on track to become the world's biggest liquefied natural gas exporter by 2019, yet it faces a looming gas shortage at home as states restrict drilling onshore and cash-strapped oil and gas companies cut spending. The paradox has led to urgent calls from everyone from Australia's energy minister to big industrial users like Dow Chemical and fertilizer group Incitec Pivot for action to spur new supply.

The issue is set to come to a head this month, with state and federal energy ministers due to meet Aug. 19 and the government in the state of Victoria set to decide whether to lift a ban on onshore gas developments. In a glimpse of the future, gas prices spiked to about $34 (U.S.) per million Btu in Victoria in July, about six times the spot-market price of Asian LNG, as a cold snap and a power shortage in neighboring South Australia led to a surge in demand, forcing gas to be piped from the country's north at high cost.

"When Australian gas is selling for less in Tokyo than it does on the East Coast of Australia, there's clearly a market failure," Incitec CEO James Fazzino said. Part of the problem is that East Coast gas demand is set to triple by 2018 to feed three new LNG plants in Queensland. The project owners locked in supplies from nearby coal-seam gas fields, as well as gas from central Australia and offshore Victoria. Incitec was so desperate for gas, which comprises half its material costs, that it opted three years ago to build an ammonia plant in the U.S., where prices have fallen with the shale boom.

Construction proceeds at Hackberry, La., LNG plant for 2018 start-up

(American Press; Lake Charles, LA; Aug. 14) - Three cylindrical LNG storage tanks — each larger than the New Orleans Superdome — now dot the Hackberry, La., skyline, signaling that work on Cameron LNG is well underway. The construction of three liquefaction trains started about two years ago and start-up is expected in 2018. The $10 billion project is backed by San Diego-based Sempra LNG and its partners Mitsui, Mitsubishi and NYK Line of Japan, and ENGIE of France (formerly GDF Suez).

Cameron LNG spokeswoman Julie Nelson said more than 75 cranes are working at the job site, and that major pieces of equipment — such as air coolers, pressure vessels and compressor packages — are being received and installed. More than 4,500 workers are on the job. The construction site is next to Cameron LNG's existing import facility, which received its first cargo in 2009 but has mostly been idle as U.S. shale gas production overwhelmed the market.

A second phase of construction at the site — adding two more liquefaction trains and another LNG storage tank — experienced a setback after one partner announced in July that it "currently does not want to invest additional capital in Cameron LNG with respect to the expansion," according to a quarterly report Sempra filed in July with the U.S. Securities and Exchange Commission. The report said the expansion "requires the unanimous consent of all partners," and that failure to obtain this could cause delays.

Canada to review environmental process for resource projects

(Financial Post; Canada; Aug. 16) - A federal panel will review how Canada handles environmental assessments for major resource development projects and provide suggestions. Environment and Climate Change Minister Catherine McKenna said Aug. 15 she had appointed a four-member panel to write a report, due by the end of January, highlighting how to update the country's environmental review processes.

A second, soon-to-be-named panel will have a "complementary mandate" to provide recommendations on "modernizing" the National Energy Board, which oversees major pipeline projects. "Our belief that a clean environment and a strong economy go hand-in-hand is central to the health and well-being of Canadians. This is especially important as we work to get resources to market," McKenna said in a release.

Reuters' columnist advocates for government investment in fracking

(Reuters' columnist; Aug. 12) - British Prime Minister Theresa May probably has the right idea trying to encourage a shale gas fracking industry. But she may have the wrong strategy to implement it. Instead of doling out hand-outs to persuade disgruntled communities that there is a tangible benefit to having a gas well in their back yard, or even generous tax breaks for investors, a better policy could be to cut out the middle man and create a national energy titan to drill the first holes and share the profits.

North Sea oil in the 1970s came with similar issues to shale. Keen to secure a home-made supply, Britain and Norway created national oil companies, of which only one now remains. Norway's Statoil has since bloomed into one of the world's biggest offshore producers, while the defunct British National Oil Corp. was folded into Britoil and eventually sold to BP in the 1980s. Britain has relied on the private sector since then.

The government now wants to offer hydraulic fracturing tax breaks to investors along with hand-outs from shale production tax revenues to communities and land owners. But neither tax breaks nor hand-outs offer many long-term benefits. And even with the payments and subsidies, shale gas extraction may not be that profitable for companies that do the fracking. Given the challenges, a better strategy to get Britain fracking could be to take the risk and reward through the public purse. That way, if there is a profitable future for shale, the benefit can be more widely spread instead of just the risk.

Agency projects shale gas to reach 30% of global production by 2040

(U.S. Energy Information Administration; Aug. 15) - In the U.S. Energy Information Administration's International Energy Outlook 2016 and Annual Energy Outlook 2016, natural gas production worldwide is projected to increase from 342 billion cubic feet per day in 2015 to 554 bcf per day by 2040. The largest component is gas from shale resources, which grows from 42 bcf a day in 2015 to 168 bcf a day by 2040. Shale gas is expected to account for 30 percent of world gas production by 2040.

Although currently only four countries — the United States, Canada, China and Argentina — have commercial shale gas production, technological improvements over the forecast period are expected to encourage development of shale resources in other countries, primarily in Mexico and Algeria. Together, these six countries are projected to account for 70 percent of global shale production by 2040, the EIA said in its reports.

In the United States, shale gas accounted for more than half of U.S. gas production in 2015 and is projected to more than double from 37 bcf a day in 2015 to 79 bcf by 2040, which would be 70 percent of total U.S. gas production in EIA's reference case. Canada has been producing shale gas since 2008, reaching 4.1 bcf a day in 2015. Shale gas production in Canada is projected to continue increasing and to account for almost 30 percent of Canada's total gas production by 2040.

B.C. adopts no-fracking zone around hydroelectric dams

(Vancouver Sun; Aug. 17) - Internal documents show B.C. Hydro officials have had concerns since at least 2009 that earthquakes triggered by hydraulic fracturing in oil and gas drilling are a potential risk to its Peace River dams. The electricity-generating dams in northeastern B.C. include one of the largest earthen dams in the world, the W.A.C. Bennett Dam, as well as the smaller Peace Canyon Dam, and the $9 billion Site C dam, which is under construction. The Crown agency has not discussed the issue publicly.

But as a result of its concerns, B.C. Hydro worked out an agreement, possibly as early as 2014, with the B.C. Oil and Gas Commission to create 3.1-mile buffer zones around dams where no new fracking and drilling rights are issued, according to a report by the Canadian Centre for Policy Alternatives, a left-wing think-tank. There is no ban on fracking or drilling for companies that hold existing rights.

The buffer zone is the minimum that should be done, said report author Ben Parfitt, a resource analyst for the center. B.C. Hydro deputy CEO Chris O'Riley said as far as the agency knows there has never been any fracking within 3 miles of its northeast B.C. dams. He called the buffer a precautionary measure. The largest fracking-induced earthquake, recorded in August 2015 near Fort St. John, B.C., was 4.6 in magnitude.

Massachusetts court strikes down plan to help pay for new gas lines

(MassLive.com; Aug. 17) - The Massachusetts Supreme Court on Aug. 17 struck down a plan where electrical ratepayers would foot the bill for natural gas pipeline expansion in the state — an arrangement that fossil-fuel foes had dubbed "the pipeline tax." The ruling hands a victory to the Conservation Law Foundation, which has opposed more gas pipelines, and to Engie Gas & LNG, which imports liquefied natural gas into New England and has said it can handle the region's gas demand.

The governor last year asked the Department of Public Utilities to look at a proposal where electrical utilities could help provide stable financing for gas pipeline capacity. The Northeast frequently experiences price spikes during peak demand in the winter, when limited gas pipeline capacity restricts delivery to the region. The state agency in October said it has the authority to approve long-term contracts of electric utilities for gas pipeline capacity. The contract costs would be passed on to electrical ratepayers.

The court ruled, however, that the funding mechanism would undermine the objectives of the state's 1997 utility restructuring act and re-expose ratepayers to financial risks that lawmakers sought to reduce two decades ago. Unlike gas utilities, electric generators have been unwilling or unable to sign long-term pipeline contracts, instead preferring to buy gas on the spot market. However, pipeline operators are unwilling to build more capacity without such long-term contracts in place.

BP and other majors work to improve shale drilling productivity

(Wall Street Journal; Aug. 16) - The oil-and-gas well BP is drilling in Perryton, Texas, looks ordinary enough from the surface. Yet a mile-and-a-half underground, horizontal pipes shoot off for at least a mile in three directions, like a chicken's foot. The idea, part of an experiment by BP executive David Lawler, is to make three wells from one. It also is designed to help turn the energy giant into a shale oil innovator that can better compete with the entrepreneurial outfits that pioneered hydraulic fracturing.

Majors like BP are in need of a jolt. The multibillion-dollar projects they specialize in — giant offshore oil rigs and gas export projects — are often prohibitively expensive in a world of $40 oil. U.S. shale is a tempting option, but the companies have yet to prove they can master the techniques pioneered by shale drillers, whose innovations fueled a rebirth in U.S. production. If BP, ExxonMobil and others can figure out how to profitably coax enough oil out of fracked wells, it could help them maintain production levels.

If the Perryton well succeeds, BP could try the same thing with leases in Oklahoma, Texas and beyond, potentially yielding oil and gas on a large scale. So far, big companies have compiled a poor record in U.S. fracking. They have taken more than $20 billion in write-downs. In 2014 and 2015, shale wells drilled by BP, Shell, ExxonMobil and Chevron were one-third less productive, on average, than the top 10 operators. But now, in Oklahoma and Texas, BP has reduced well costs by almost two-thirds, and is now drilling wells in 37 days on average, compared with 67 in 2012. The wells are on track to produce 44 percent more gas than those drilled three years ago.

Some analysts skeptical of Arctic shipping route

(Port News; Aug. 12) - Once hailed as the next frontier for global shipping, the Arctic's unpredictable weather and sparse population mean that's unlikely for global container shipping — even if melting sea ice makes its waterways more navigable. Russian, U.S. and Scandinavian experts told Bloomberg News that despite the hopes of some that the Northwest Passage would provide a speedy commercial route through North American waters, Arctic shipping lanes will only be able to sustain small-scale destinational traffic.

Canada's Port of Churchill, in northern Manitoba, was once looked to as the site of future shipping cooperation with Russia. Reports at the end of July, however, said workers there had been given two weeks notice and the port would cease activity only a month into its short season. From July to November the port has dealt with grain shipments. While it was only operational five months out of the year, its closing leaves Canada and the U.S. without a northern deep-water Arctic port.

"The closing of the Manitoba port shows that it's hard to make things work economically in the Arctic," said Malte Humpert, founder and strategic director of the Washington, D.C.-based Arctic Institute. The fact that the port won't operate this season foreshadows future expectations for Arctic activity, he said. "Global shipping operators are not really interested in the Arctic because the infrastructure doesn't exist yet," Humpert said, adding that development of this infrastructure won't happen overnight.

Dispute continues in Papua New Guinea over gas royalties

(Radio New Zealand; Aug. 17) - The Papua New Guinea government says it is committed to resolving a dispute at the country's liquefied natural gas project in Hela province where five wells run by ExxonMobil remain blocked off. ExxonMobil declined to comment about production issues, but said its gas conditioning plant is continuing to operate. The situation remains unclear, with Petroleum and Energy Minister Nixon Duban reporting that a state team has been negotiating with landowners.

However, Duban said the blockade was mounted by what he described as opportunists taking advantage of the situation and not by landowners. Last week, the blockade reportedly was launched by landowners at the Hides gas field because the government allegedly owes them millions of dollars in royalties from production in the area. The government had agreed to share royalties, but has said it needs more time to verify land ownership. The LNG project started up in 2014.

U.S. oil exports averaged 501,000 barrels a day January-May

(U.S. Energy Information Administration; Aug. 16) - The number of countries receiving U.S. crude oil exports has risen since the removal of restrictions in December 2015, according to data from the Energy Information Administration. Based on the latest available data, U.S. exports averaged 501,000 barrels per day in the first five months of 2016 — 43,000 barrels a day more than the full-year 2015 daily average. The 2015 exports were mostly to Canada, which was excluded from the previous restrictions.

In recent years, crude oil exports to destinations other than Canada were often re-exported volumes of foreign crude or cargoes of Alaska oil, which were both exempt from federal export restrictions. The number and variety of destinations for U.S. crude oil exports has increased since the lifting of restrictions. So far in 2016, U.S. crude oil has been exported to 16 different nations, the EIA reported.

U.S. oil exports to countries other than Canada have surpassed exports to Canada in two months in 2016 — most recently in May, when U.S. oil exports to countries other than Canada reached 354,000 barrels. Other than Canada, the largest and most consistent U.S. oil export destination for the first five months of 2016 has been Curacao, a Caribbean Sea island nation with a major refinery. U.S. oil exports to Curacao averaged 54,000 barrels a day January through May.