Oil and Gas News Briefs
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Woodfibre to go ahead with small LNG plant north of Vancouver, B.C.

(Vancouver Sun; Nov. 4) - Woodfibre LNG's board of directors has approved a final investment decision for the company's $1.6 billion project near Squamish, about 30 air miles north of Vancouver, B.C., the first LNG project in the province to get the go-ahead. The plant, which will produce 2.1 million metric tons of liquefied natural gas a year, is the smallest of the four leading proposals in British Columbia. Those include a $25 billion venture led by Shell in northwestern B.C. that has been put on hold because of low global LNG prices, growing competitive supply and uncertain future demand.

Work is under way at Woodfibre's coastal site, a former pulp mill, but major construction will not take place until the company receives permit approval from the B.C. Oil and Gas Commission, expected next year, Woodfibre said Nov. 4. The plant could start in 2020. But Chief Ian Campbell of the Squamish First Nation said it is too early to celebrate. "The Squamish Nation set out its 25 conditions to specifically protect sensitive land and marine habitats — in and around the proposed project site," Campbell said in a statement. "Only when all those conditions have been resolved will we sign the deal."

Woodfibre LNG, part of a Singapore-based group of companies, has obtained its export license and environmental approval to build the plant. In May, it signed a tentative 25-year deal to sell about half the plant's output to Guangzhou Gas Co., of China, which would also become a 10 percent owner of the development. The province made a key concession by granting the project a favorable price for power — Woodfibre plans to use electricity to drive its liquefaction process, not gas as other proposed LNG projects. The lower rate is $60 per megawatt hour vs. $84 negotiated with other LNG developers.

Japan's utilities turning away from long-term contracts

(Reuters; Nov. 4) - Forced into action by falling customer counts due to market liberalization and a shrinking population, Japan's utilities are ditching old long-term coal and natural gas supply contracts in favor of more short-term, opportunistic trading. The move represents a sea change for the traditionally risk-averse utilities as they seek to cut costs, but will make life harder for liquefied natural gas producers that have relied on long-term utility sales to underwrite costly new projects and expansions.

Almost entirely without its own energy resources, power companies in Japan have long put security of supply over cost. But a falling population — down 1 million since 2010 to 127 million — a new wave of competition and the rise of renewable energy have forced a re-think. "Things are very uncertain and we have to deal with these uncertainties by changing how we procure LNG, including the flexibility to trade unused LNG in overseas markets," said Yuji Kakimi, president of Jera Co., the world's biggest buyer of LNG.

Barely recovered from higher fuel costs in the wake of the Fukushima nuclear crisis, utilities are grappling with a regulatory shake-up that ended their monopoly powers and threw open the $77 billion a year retail market to more than 350 firms. The biggest changes may come in LNG. The utilities want to rid themselves of fixed-volume LNG supply contracts lasting a generation, and are set to push hard during price reopeners in long-term contracts. Jera plans to cut the amount of LNG it gets from long-term contracts by 42 percent by 2030, while Japan's second-biggest city gas supplier, Osaka Gas, has said it may not sign new long-term LNG contracts for the next several years.

Sempra reports construction delay at Louisiana LNG plant

(The San Diego Union-Tribune; Nov. 2) - Sempra Energy reported increased third-quarter earnings Nov. 2 but much of the attention from analysts taking part in a conference call with executives focused on news of a construction delay at the company's liquefied natural gas project in Hackberry, La. CEO Debra Reed said the contractor at the Cameron LNG export facility, Houston-based CCJV, told Sempra last week about slowdowns at the site.

Sempra and its partners are looking for more specifics, but Reed said CCJV attributed the delays to heavy rain and flooding at the contractor's fabrication facility in Baton Rouge, La. All three of the plant's liquefaction trains had been scheduled to go online by the end of 2018. CCJV is now estimating that Train 1 will be in service in mid-2018, Train 2 in late 2018 and Train 3 mid-2019. Mitsui and Mitsubishi of Japan and France-based ENGIE have partnered with Sempra in the $10 billion Cameron project, signing 20-year contracts to take delivery of LNG and shipping it to clients around the world.

Industry investing billions in Canada's Montney shale gas formation

(CBC News; Canada; Nov. 2) - Not many folks outside of Alberta pay much attention to Grande Prairie, an outpost tucked away about 280 miles northwest of Edmonton. Even within the province, the growing city of more than 60,000 keeps a low profile — but that's about to change. Like the oil sands, the industry has long known about the Montney shale gas formation. Canada's National Energy Board estimates the Alberta-British Columbia formation holds 90 billion barrels of oil equivalent, most of it gas.

Output from the Montney has doubled since 2012 and now comprises a third of Western Canada's gas production. By 2040, the NEB projects it will make up more than half of the country's production — you would think the energy industry would be giddy, if only it were guaranteed. Every issue that threatens to derail the ambitions of Canada's oil and gas industry — access to market, First Nations land rights, public acceptance of pipelines and the climate consequences of fossil fuels — is writ large in the Montney.

Even so, it's the one bet a financially strapped industry remains willing to place. In the next four years, natural gas producers are expected to spend more than $34 billion on drilling and completing wells there, according to an estimate from FirstEnergy Capital. Throwing a staggering pile of cash to drill thousands of new wells may go smoothly. More likely, though, the conflicts currently playing out in the oil sands, NEB hearing rooms and along proposed pipeline routes will see action in the Montney, too.

East Coast Canada LNG projects face poor economics

(Natural Gas Intelligence Daily; Nov. 3) - The fiscal case for exporting liquefied natural gas from Nova Scotia to Europe continues to decline, as sponsors eye the global oversupply of the fuel. There are three multibillion-dollar facilities proposed in northeastern Nova Scotia. The leading contender, Pieridae Energy’s proposed $8.3 billion export facility in Goldboro, is waiting on an investment decision by its proponents.

“We’re hoping to make the decision by the end of the calendar year … but these dates can move around a little bit,” said Mark Brown, director of project development. “There are still some milestones to finalize, mainly around supply and some of the financing arrangements.” While Pieridae has a buyer, a German energy company, for half of its LNG production on a 20-year contract, it has not signed up a gas supplier or finalized financing. Natural gas to feed the plant could come from U.S. production, Canadian production, or a combination. But Nova Scotia is a long pipeline away from gas fields.

Meawhile, analysts say the odds of putting any LNG export facility on Canada’s East Coast are low. “The world LNG market is oversupplied and prices have plummeted. … Right now the economics don’t make sense,” said David Hughes, president of Calgary-based consulting firm Global Sustainability and Research. “There’s a whole lot of LNG capacity coming on, so the price will get worse (lower) before it gets better (higher),” said Jackie Forrest, vice president of research at Calgary-based ARC Financial.

Japanese ventures into Canadian shale gas not so profitable

(Nikkei Asian Review; Nov. 3) - Mitsubishi Corp. is the latest Japanese company to postpone or pull out of a shale gas venture in Canada after misjudging the country's competitiveness as an export base. The Japanese trading house said Nov. 3 it had sold off its 50 percent stake in Cordova shale gas assets in British Columbia, which it had acquired in 2010 for slightly more than 36 billion yen ($348 million at current rates). Mitsubishi did not disclose the sale price.

Production began in 2011 and has reached about 30 million cubic feet per day. The Mitsubishi subsidiary holding the stake logged a net loss the past two years. Mitsubishi has had another setback in Canada. In July, the company and partners including Shell announced they were delaying a final investment decision, originally scheduled for the end of this year, on a liquefied natural gas production and export project in British Colombia. That venture was supposed to receive gas from the Cordova development.

One reason Canadian shale gas is struggling is that it's farther from the main market, the U.S., than American plays. The added cost of pipeline transport makes for thin profit margins, especially when U.S. gas already has a lead in low-cost production. Or costly pipelines would be needed over the Canadian Rockies to move gas to the B.C. coast for export. The second reason is local opposition to shale projects over environmental concerns. The third reason is a decline in the export competitiveness of Canadian LNG, as buyers have plenty of cheaper supply options linked to low-priced oil.

India opts for short-term LNG charters after long-term contract fails

(The Financial Express; India; Nov. 3) – GAIL (India) five years ago signed a deal with Cheniere Energy to buy 3.5 million metric tons of LNG per year starting in 2018 from the export terminal Cheniere is building in Sabine Pass, La., with GAIL responsible for the shipping. The Indian energy company has been trying to interest the world's ship owners to contract for as many as nine new LNG carriers to transport the fuel, building three of the ships in India — the first such shipbuilding work in the country. But GAIL had few takers for the long-term shipping contract and now has canceled the bidding.

Sources said that even though two Japanese consortia participated in the bidding process that lasted two years, they would not agree to protect GAIL from any overruns or other construction problems with the made-in-India LNG ships. The sources said GAIL would now look to charter LNG carriers for short terms of three to four years, until it can figure out a new proposal to attract bidders for longer contracts on its terms.

The delay in finalizing the tender could land GAIL in a crisis for not having LNG carriers under contract in time to move LNG from the U.S. GAIL also is under contract to take 2.3 million tons of LNG per year from the export terminal under construction in Cove Point, Md., with deliveries expected to start mid-2017.

Oklahoma shuts down more disposal wells after earthquake

(EnergyWire; Nov. 4) - Oklahoma state oil and gas officials have ordered four more oil field disposal wells to shut down in the wake of another earthquake larger than magnitude 4. The quake struck shortly after midnight Nov. 2 near Pawnee, where the largest quake ever recorded in the state hit in September. In addition to the four closures, the operators of 10 wells were told to cut disposal volumes by 25 percent.

The quake occurred close to Osage County, home of the Osage Nation, where the U.S. Environmental Protection Agency has jurisdiction over drilling disposal wells. The EPA directed the operators of 26 wells to limit their volume to the average injected in the past 30 days; six more must reduce volumes to 75 percent of their 30-day average. The state listed the quake at magnitude 4.3, while the U.S. Geological Survey listed it as magnitude 4.5. Last year, 903 quakes of magnitude 3 or greater shook Oklahoma.

Scientists have known for decades that injecting industrial fluid deep underground can lead to earthquakes. The fluid gets into the fault and changes the pressure, and the rocks slip. Oil and gas wells usually also produce large amounts of toxic fluid that gets injected underground.

No damage found at oil storage operations after 5.0 Oklahoma quake

(Energy Wire; Nov. 7) - Oklahoma officials reported no immediate problems with pipelines after the oil transportation and storage hub of Cushing, Okla., was rocked Nov. 6 by one of the largest earthquakes recorded in the state. The magnitude 5.0 quake caused power outages and structural damage to buildings in the city's downtown area, according to media reports. About 40 people were evacuated from a retirement home. A few minor injuries were reported.

Schools will be closed Nov. 7 to assess damage, and the Red Cross announced it was opening a shelter for people worried about the safety of their homes. News outlets reported Magellan Midstream Partners shut down its Cushing oil storage operations but found no problems. The quake was the third this year registering magnitude 5.0 or higher. State oil and gas regulators said they were working with state scientists to evaluate the quake. Many attribute the increase in earthquakes in Oklahoma to the underground disposal of oil and gas drilling wastewater.

Cushing, a city of about 8,000 people, is called "Pipeline Crossroads of the World" because so many large lines terminate and originate there. It also has an expanse of oil storage called the "tank farm," where dozens of companies store about 50 million barrels of U.S. and Canadian oil. Scientists have known for decades that injecting industrial wastewater underground can cause quakes. The wastewater can seep into faults, changing the pressure and unleashing quakes. Oil and gas drilling produces millions of gallons of such wastewater.

Indigenous leaders ask Norway to pull investment in U.S. oil pipeline

(News in English; Norway; Nov. 1) - Norway’s biggest bank, DNB, and the country’s huge sovereign wealth fund are both involved in construction of a highly controversial oil pipeline project in the U.S. Norway’s Sami Parliament, the representative body for the Arctic indigenous people, is calling on the oil wealth fund to withdraw its investments in companies behind the Dakota Access Pipeline Project, which opponents say threatens the health and human rights of indigenous people living in the area.

Norway’s state-owned oil company Statoil, meanwhile, has major ownership stakes in the shale oil coming out of the Bakken in North Dakota that would flow through the line. Statoil bought Brigham Exploration in 2011, taking what Statoil called a “strong position” in the Bakken (named for a Norwegian immigrant in North Dakota) and Three Forks shale projects. Statoil has distanced itself from the pipeline project, telling a Norwegian newspaper Oct. 31 there is “no connection between Statoil and this oil pipeline.”

DNB bank is heavily involved after lending about $340 million to the project. Norwegian Broadcasting reported that DNB is among 38 banks taking part in the project estimated to cost about $3.8 billion. The Dakota Access Pipeline Project is itself owned by eight energy companies including Sunoco Logistics, Phillips 66 and Energy Transfer, and Norway’s oil fund has billions invested in the companies. Several indigenous Sami people have traveled to the U.S. to participate in the pipeline protests. They also have written to Norway’s Finance Ministry ethics council that monitors oil fund investments.

Record volume of oil goes into storage in U.S.

(Wall Street Journal; Nov. 3) - A record amount of oil went into storage in the U.S. last week. Some of it is probably only an accounting snag, but a lot of it appears to be from a wave of imported oil heading to the United States. All the pressure pushed U.S. crude to new one-month lows Nov. 3, down $4 a barrel from a week ago. More crude went into storage last week than in any other week in 34 years of government records.

Imports hit a four-year high as and international exporters are still pumping full tilt, loading up more and more oil into ships for sale around the world. The rush of oil is a bad sign for bullish traders who had been hoping stockpiles were truly falling and signaling the end of two years of oversupply. Even more foreboding for the oil market is that, with storm season now ending, the cargos could keep coming. “Until we see that crude on the water dropping down, surely we’re not going to see this market rebalance,” said Matt Smith, ClipperData’s director of commodity research.

State budgets struggling in the oil patch; pain may continue

(EnergyWire; Oct. 31) - When lawmakers filed into the North Dakota capitol in August, they were repeating a familiar scene. North Dakota was in the throes of an oil bust after a six-year drilling boom that transformed parts of the state. The price of oil had been in free fall, state revenue was down almost one-fourth, and the state's primary savings account was almost empty. They had assembled for a three-day special session to decide winners and losers. Would they cut the road budget? Schools? Nursing homes?

It could have happened in any state capitol in the oil patch, in any of the downturns that have plagued the oil business since its inception. Maybe a few of the legislators were praying for the next oil boom, the way their fathers and grandfathers did. But this oil bust could be different. A growing body of research says changes in the global oil market, rapid advances in wind- and solar-powered generation and regulations aimed at curbing climate change may hold down the price of oil and gas for years or even a decade.

A lot of people disagree. And even among those who agree, there are different ideas about how a long-term decline in oil demand could happen and, crucially, when it could happen. But if the predictions are accurate, it could mean that even though oil prices are recovering, they may not hit the $100-a-barrel peaks they reached just two summers ago. And it could extend the economic pain that's already rippling across a half-dozen states dependent on taxes on oil production, from Alaska to the Gulf of Mexico. Mark Muro, who studies state and local government at the Brookings Institution, said a lot of states may have missed a chance to diversify their economies when times were good.

LNG a better option for remote Canadian town, but not without a road

(CBC News; Nov. 4) – Canada’s Northwest Territories government is looking into introducing LNG-fueled power generation in the far north community of Tuktoyaktuk, which currently relies on diesel. But it would need completion of the all-season road from Inuvik to Tuktoyaktuk on the Beaufort Sea to truck the gas there. "Until the Tuk highway is done, there will be no opportunity to use the LNG solution," said Andrew Stewart, director of energy solutions with the Department of Public Works and Services.

"An actual decision on this project is years away. This will be part of just establishing a business case. It's part of our normal work to try and explore ways to decrease diesel consumption in our remote diesel communities,” Stewart said. The Northwest Territories Power Corp. began using liquefied natural gas in Inuvik in February 2014. Inuvik, population about 3,400, is 77 air miles south of Tuktoyaktuk, population about 800.

The government is seeking proposals that would introduce LNG to Tuktoyaktuk in a practical and cost-effective way. One of the challenges will be that, unlike Inuvik, Tuktoyaktuk does not currently have any gas-fueled power plants. LNG fuel is both cheaper and cleaner, Stewart said. Since moving to LNG in Inuvik, about $1.8 million has been saved — 20 to 25 percent of the landed cost of diesel in that community. The fuel is trucked to Inuvik from plants near Vancouver, B.C., and Grand Prairie, Alberta.