Oil and Gas News Briefs
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Shell-led LNG project on B.C. coast wins 40-year export license

(Globe and Mail; Canada; Jan. 8) - The board that regulates natural gas exploration and production in Canada has approved its first 40-year export license to a joint-venture company led by Shell. The National Energy Board permit will allow LNG Canada to export liquefied natural gas from a terminal proposed for the coastal British Columbia community of Kitimat. Until the National Energy Board Act was amended in June 2015, the maximum term length of an LNG export permit was 25 years.

The license must still be approved by Canada’s prime minister and his cabinet. The announcement comes days after the B.C. Oil and Gas Commission approved LNG Canada’s facility permit, outlining design, construction and operation requirements. The joint venture’s partners are Shell, PetroChina, Korea Gas and Mitsubishi. LNG Canada has not made a final investment decision on the project, which is estimated at close to $30 billion and could handle as much as 3.6 billion cubic feet of gas per day.

“The board is satisfied that the gas resource base in Canada, as well as North America overall, is large and can accommodate reasonably foreseeable Canadian demand, including the exports proposed in this application, and a plausible potential increase in demand,” the NEB said. The license will expire Dec. 31, 2022, unless exports have begun. LNG Canada expects to make a construction decision later this year. It is one of 20 LNG proposals for the B.C. coast; none have reached final investment decision.

Malaysia-backed B.C. LNG project sees better market in 2020s

(Globe and Mail; Canada; Jan. 8) - Michael Culbert is heartened when he ponders the prospects for exporting liquefied natural gas from Canada, despite a global glut of LNG that could last years. Culbert, president of Pacific NorthWest LNG, acknowledges the challenges in the short term of making plans for an LNG terminal on Lelu Island, near Prince Rupert on British Columbia’s north coast. He is hoping for approval from the Canadian Environmental Assessment Agency that would allow the start of construction.

If construction begins in mid-2016, it will likely take four to five years to complete the facility, so exports might flow in 2020 or 2021. Pacific NorthWest LNG, led by Malaysia’s state-owned Petronas, is well aware of analysts’ warnings of a worldwide glut of LNG from 2016 to 2019 and possibly beyond. The current price spread between natural gas in Canada and LNG contracts in Asia is narrow, making most B.C. proposals uneconomic in today’s circumstances.

But Culbert believes the consortium will find a sweet spot as early as 2020, since the venture's co-owners are financial backers and also "off-take partners" — long-term buyers of LNG in Asia. The partner companies are from Japan, India, Brunei and China, in addition to Malaysia. Some aboriginal organizations support Pacific NorthWest LNG, but the venture's backers must deal with strong opposition from the Lax Kw'alaams First Nation, which fears the project will harm important salmon habitat at the terminal site.

First LNG carrier scheduled to dock at Sabine Pass terminal Jan. 12

(Financial Tines; London; Jan. 10) - The Energy Atlantic, a 950-foot tanker steaming through the Gulf of Mexico, will make history when it lands Jan. 12 at Cheniere Energy's Sabine Pass liquefied natural gas plant on the Louisiana coast to be loaded with the first LNG export cargo from the Lower 48 states. U.S. exports are likely to have a significant market impact, holding down energy costs for consumers in Europe, Latin America and Asia, and providing tough competition for anyone hoping to build rival LNG plants.

"There is an awful lot of LNG sloshing around the world at the moment, with even more to come," said Frank Harris of Wood Mackenzie, a consultancy. "And that is putting downward pressure on prices." In addition to Sabine Pass, four more LNG export projects are under construction in the U.S. Those projects were able to make progress because they were fast enough at signing up customers on long-term contracts that guarantee their revenues. Since the end of 2014 those customers, mostly utilities in Europe and Asia, have been reluctant to make any further commitments.

That's because the price of LNG delivered in northeast Asia, including Japan and South Korea, the world's two largest markets, has fallen along with oil. It has dropped to about $6.65 per million Btu, just a third of its price of almost $19 two years ago. At that price — with benchmark U.S. gas at about $2.40, plus liquefaction costs of $3 to $3.50, plus transport — LNG from Louisiana or Texas does not look commercially attractive. The plants that have started construction, though, are highly unlikely to be stopped. Their customers have to pay the charges under contract, even if they do not use the capacity.

LNG developer says FERC denial would delay, not kill Oregon project

(The World; Coos Bay, OR; Jan. 7) – The lead spokesperson for the Jordan Cove LNG facility did his best to instill optimism about the multibillion-dollar project on the Oregon coast, forecasting shovels in the ground by the end of 2016. Public affairs director Michael Hinrichs spoke to a packed Coos Bay Area Chamber of Commerce on Jan. 6.

Jordan Cove still needs a decision from the Federal Energy Regulatory Commission. Without it, Hinrichs said, the project doesn't so much die as Calgary-based Veresen goes back to the drawing board. The company already has spent more than $190 million on the permitting process. Jordan Cove has been at the proposal stage since 2004, first as an LNG import facility before switching to exports in 2012. The site at Coos Bay, Ore., is about 100 miles north of the California border.

"If FERC denied, we would have to go back and look at why FERC denied and if they said, 'There is a permanent impact that cannot be mitigated, it's significant to the community and therefore on that grounds we cannot approve this section' ... we would have to go back to the drawing board and figure it out until we met that requirement," Hinrichs said. "So there isn't a permanent kill-switch. It would simply delay everything." Jordan Cove LNG proposes to liquefy U.S. and Canadian natural gas for export.

Few details about mini-LNG plants proposed for interior B.C.

(Alaska Highway News; Fort St. John, BC; Jan. 7) - A conglomerate of seven Chinese companies and one Canadian company is looking to build a small liquefied natural gas production facility in Fort Nelson, B.C. Kai Tian Energy Group outlined preliminary plans for the facilities on its website, but would not elaborate on its plans when contacted Jan. 6. "We don't have anything definite to be announced to the public for now," said a woman who answered the telephone at the company’s Vancouver office.

KT Energy says it plans to build several "mini-LNG modular plants" to meet Canadian demand for the fuel. The first plant is proposed for Fort Nelson, on the highway system in northeastern B.C., about 100 miles from the Alberta border. The initial production in the first phase would be 20,000 gallons per day (equivalent to 1.6 million cubic feet of natural gas); that would increase to 60,000 gallons per day in its second phase. The website provided no cost estimate for the plants.

"We have the ability to build mini-LNG modular plants close to customers to meet their specific applications, which will significantly reduce costs and ensure a stable supply of LNG," the company says, calling the fuel an “economic and environmental friendly energy choice to the customers in Northern B.C., Yukon and Northwest Territories.” The website says the first production could come by the end of the year.

Hawaii Gas selects contractor for LNG imports to start in 2019

(Pacific Business Journal; Honolulu; Jan. 8) – Hawaii Gas has chosen the winning bidder for the utility’s $300 million plan to ship in liquefied natural gas in bulk to the islands, an executive from the company said Jan. 8. Hawaii Gas estimates its LNG bulk shipment plan could save consumers more than $2 billion over a 15-year period from the beginning of 2019 through the end of 2033. The utility has been importing small volumes of LNG from California in 40-foot-long tanks since early 2014 as a pilot project.

“We have decided on a company that we made a final award to,” said Joseph Boivin, senior vice president of business development and corporate affairs for Hawaii Gas. “It’s an international company. The contracts will be finalized at the end of the first quarter.” Boivin declined to name the company, although he said it will be responsible for the supply of LNG and ownership and operation of the planned storage and regasificiation vessel that will accept bulk deliveries of the fuel for delivery by pipe to onshore.

“Depending on how things go this year, with support for the [LNG] program, by the end of 2019 is still a reasonable timeframe to get things up and running,” Boivin said, pointing out that its contract with the international firm still needs the approval from the Hawaii Public Utilities Commission. Hawaii Gas is the first company in the state to import LNG to the islands. Other than the small-scale LNG shipments from California, the utility makes synthetic natural gas from naphtha at a plant in Hawaii.

N.D. catches up on gas plants and pipelines during drilling slowdown

(Bismarck Tribune, ND; Jan. 2) - As drilling has slowed in North Dakota, Rob Bertola with XTO Energy said he often gets asked if he’s still busy. But Bertola, operations foreman for a gas processing plant, hasn’t seen a slowdown. In 2014 and 2015, XTO expanded its gas gathering plant near Tioga, added 75 miles of new pipeline and added compressor stations, investing more than $120 million. “The drilling and stuff has slowed down,” he said. “But getting our structures built, pipelines in, we’re very busy.”

Investments in gathering and processing natural gas are expected to continue in 2016, even as companies look to pull more drilling rigs and hold off on completing new wells. North Dakota is scheduled to have four new gas processing plants come online in 2016, plus additional gathering lines and compressor stations. “It’s full steam ahead,” said Lynn Helms, director of the Department of Mineral Resources.

“They feel like now, with the slowdown in drilling and completions, they got some breathing room” to catch up on pipelines and gas plants that will reduce flaring of gas unable to reach market, Helms said. But the uncertainty about low prices is causing companies to delay making commitments for future investments. Some natural gas investments for 2017 and 2018 were suspended, and companies indicate they are delaying making decisions until prices recover, Helms said.

Proposed rail-to-ship oil terminal on Columbia River draws big crowd

(The Columbian; Vancouver, WA; Jan. 5) – Nearly 400 signed up to testify at a public hearing on the proposed oil terminal at Port of Vancouver, Wash., across the Columbia River from Portland. They told the Washington Energy Facility Site Evaluation Council

Jan. 5 the project would be an economic bounty or environmental disaster — opinions varied widely. State and local officials who will play a large role in determining the fate of what would be the largest U.S. oil rail-transfer terminal listened late into the evening.

More than two years after the port commission unanimously approved the project, the rhetoric remained as heated as ever. “The likelihood of a catastrophe becomes not a probability but an eventuality,” Russell Freeman told the state’s site evaluation council, which is performing an environmental review of the rail-to-marine terminal slated to handle 360,000 barrels of oil per day. “If it can’t be done safely, it won’t be built. This project will provide jobs, good-paying jobs,” Mark Holtz said in support of the project that would be built by Vancouver Energy, a joint venture between Tesoro and Savage Cos.

Opponents from throughout the Northwest outnumbered supporters at the hearing. The $210 million terminal was proposed in 2013. Once the council finishes its environmental review, likely later this year, it will make a recommendation to Washington Gov. Jay Inslee, who gets the final say. In addition to safety and jobs, the terminal has become, to some, a battle of national and international scope over fossil fuels. Oil would come to the terminal from North Dakota’s Bakken Shale and possibly Alberta’s oil sands.

Uncompleted U.S. wells could provide ready supply of oil

(Bloomberg; Jan. 6) - U.S. shale explorers will be able to bring new oil supply to market this year even with most of the rig fleet idled and drilling budgets cut to the bone. Their secret: thousands of mothballed wells. Companies from ExxonMobil to EOG Resources, Anadarko to Chesapeake Energy have almost 4,000 drilled wells with active permits that had not been completed as of Dec. 18, according to William Foiles and Andrew Cosgrove, analysts at Bloomberg Intelligence.

The “fracklog,” as the cache of suspended wells stretching from south Texas to the Rocky Mountains is known, is growing as the worst crude-market downturn in a generation has spurred companies to halt projects early to conserve cash. Finishing the wells means significantly higher spending efficiency for these companies because they won’t have to put new holes in the ground to add to output, Cosgrove said. “Costs for the drilling portion are essentially sunk.”

The unfinished wells are probably the first option for increasing or maintaining output because they will cost less than new wells to bring online, eating up a smaller portion of 2016 budgets, according to Foiles and Cosgrove. Boring a hole into shale represents about 30 percent to 35 percent of the total well cost, with the remaining 65 percent to 70 percent goes to hydraulic fracturing, or fracking. More than one in five of the ready wells reside in the Eagle Ford shale of south Texas.

Oklahoma driller defies state order to stop wastewater injection

(Wall Street Journal; Jan. 7) - A financially strapped Oklahoma oil company is defying a state regulator's request that it shut down six wells used to dispose drilling wastewater, despite fears they may be contributing to earthquakes. Sandridge Energy, which has complied with similar requests in the past, said this time it won't stop using its disposal wells, which are part of the company's oil-and-gas fracking operations. A growing body of research links temblors to the use of drilling wastewater disposal wells.

The Oklahoma Corporation Commission, which regulates energy companies, is working on legal action to modify Sandridge's permits in order to force it to comply, said Matt Skinner, a spokesman for the agency. The regulator has been clamping down on wastewater disposal, asking operators to voluntarily pull back on their use of disposal wells in earthquake-prone areas. Last year, those requests resulted in the shutting down or curtailing of operations of about 300 wells.

The company's earthquake conundrum is one that more drillers could face if oil prices continue to sit at low levels. Some companies, like Sandridge, need disposal wells to keep producing oil. Sandridge may be reluctant to shut down the wells because it needs every bit of revenue it can generate at this point, said Jason Wangler, an analyst at Wunderlich Securities. The company denied its refusal to comply with the order is based on its financial position; it said the order should be based on scientific proof.

Alberta rail terminal operator proposes to double oil-loading capacity

(Edmonton Journal; Jan. 6) - Houston-based USD Group is pushing ahead with plans to double the capacity of its Hardisty rail terminal, about 125 miles southeast of Edmonton, Alberta, adding heavy crude oil, butane and propane to the mix of products it can load onto 120-railcar unit trains and move to markets. The current facility can load two 120-car trains per day. Expanded, it could load four 120-car trains per day. The expansion would provide for more shipments of Alberta oil sands production.

The expansion would supplement existing pipelines and "reduce transportation constraints of oil products in a cost-effective and environmentally responsible manner," USD Group subsidiary USD Terminals Canada said in a project summary filed with the Canadian Environmental Assessment Agency. The summary said the decision to proceed with the project will be contingent on the development of commercial agreements with shippers.

The terminal sits alongside CP Rail's main line. Hardisty is a major hub for moving oil. The existing Hardisty terminal began operating in June 2014. If expanded, the rail terminal could receive shipments by truck. Currently, all crude arriving at the facility comes via pipeline from a nearby Gibson Energy storage terminal. Moving crude by rail has come under increased scrutiny since the 2013 disaster in Lac-Megantic, Que., when an unattended train carrying crude oil derailed and exploded, killing 47 people.