Oil and Gas News Briefs
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Gazprom reduces spending on gas pipeline to China

(Russia Beyond the Headlines; Feb. 9) - For the second year in a row, the Russian gas monopoly is reducing its budget for construction of the Power of Siberia pipeline, through which it intends to supply gas to China, and is postponing construction of a liquefaction plant that would have supplied LNG to Japan and South Korea. In 2016, Gazprom will spend 92 billion rubles ($1.17 billion) on building the pipeline to supply gas from Yakutia to China. Last year, Gazprom said it planned to spend twice that amount.

And earlier this month, Gazprom revealed another change in its Asian plans. The company postponed a project it launched in 2011 — the construction of a Pacific Coast LNG plant with a capacity of 10 million metric tons per year. One of the reasons for postponing the project may have been Gazprombank's refusal to finance it. According to the Kommersant newspaper, the decision could have been related to the western sanctions imposed on the bank.

Gazprom has not said there are problems with building the pipeline, which is to link the Chayandinsky deposit in Yakutia to China and the coast at Vladivostok. However, sources said the project is experiencing difficulties and overruns. In December 2015, Gazprom cancelled the largest tender in its history — to build 500 of the 2,500 miles. The other problem is the fall in energy prices. Premier investment company analyst Sergei Ilyin said the line's break-even point is about $10 per 1,000 cubic feet of gas, but since the cost of gas is linked to oil, a return to that price is not expected for a while.

Japanese utilities' joint venture expects to buy less LNG

(Reuters; Feb. 10) - Japan's Jera Co., set to become the world's top buyer of LNG this year, sees its contract buys of the fuel at 30 million to 40 million metric tons per year in the 2030 business year compared with 40 million tons this year, as it adapts to market changes. Jera, a joint venture of Tokyo Electric Power and Chubu Electric Power, will hold 35 million tons a year of long-term liquefied natural gas offtake commitments when the parent companies' existing contracts are integrated into Jera this summer.

Jera sees this falling to 15 million tons in 2030, and it will procure the remainder via short-term and new long-term contracts and spot buys, it said in its business plan. Jera President Yuji Kakimi did not give a breakdown of purchases for 2030 but he has earlier told Reuters that the company plans to significantly cut the amount of gas it purchases on long-term contracts.

"In the 2020s, oil-linked (LNG) purchases will fall significantly, and the weight of purchases linked to gas prices in the West and Asian market prices will rise," he told reporters, resulting in more trading opportunities. "What producers must do most amid dwindling LNG prices is cut costs," Kakimi said. "We would like to support the projects where suppliers are engaged in aggressive cost-cutting."

Cheniere LNG exec says ‘only the strongest projects will survive’

(Platts; Feb. 10) - The startup of LNG exports from the U.S. Gulf Coast, much of which will be headed for Europe, will shift market dynamics, creating a much more competitive European gas market, a senior official from U.S. LNG pioneer Cheniere Energy said Feb. 10. Andrew Walker, Cheniere's vice president for strategy, told a conference in London that the influx of U.S. LNG will also create new pricing points. Cheniere is weeks away from shipping the first export cargo from its plant at Sabine Pass, La.

"The U.S. is going to create increasing competition, create abundance and create lower prices. That can only be good for customers," Walker said. “It's about creating some responsiveness for near-term supply/demand balancing." Walker conceded, however, that current low LNG prices were below long-run marginal costs for new projects, and that this would impact on the industry’s ability to make investment decisions.

"We're going to see a problem making new investments in this lower-price environment," Walker said. "Only the strongest projects will survive." But, he said, "at some point we must come back to the long-run marginal cost of supply or there'll be no new projects." Walker also stressed there could be a bigger demand response to the lower prices than expected. "We're underestimating the demand response."

Federal review says B.C. LNG project not likely to impact salmon

(Vancouver Sun; Feb. 10) - A draft report issued Feb. 10 following a federal government review concludes that the proposed Pacific NorthWest LNG project in northwestern B.C. would increase greenhouse gases and harm harbor porpoises, but not adversely affect salmon. It could be considered a victory for the consortium led by Malaysia’s Petronas, which has faced opposition to the project near Prince Rupert from First Nations and environmentalists over the liquefied natural gas plant’s impact on juvenile salmon.

The draft report is open for public comment until March 11, after which the Canadian Environmental Assessment Agency will produce a final report. Prime Minister Justin Trudeau’s federal government has the final say. Pacific NorthWest LNG CEO Michael Culbert said the consortium will not make a final investment call until the federal cabinet decision. The consortium — which includes investors from China, India, Japan and Brunei — gave conditional approval eight months ago, pending a federal go-ahead.

B.C. Natural Gas Minister Rich Coleman welcomed the draft report's conclusions on salmon, but admitted the province will need to provide Ottawa with an explanation on how it will deal with the report's conclusion that the project will increase the province's greenhouse gas output by 8.5 percent. The environmental review report was most focused on carbon emissions. The agency also has produced 20 pages of conditions for the project to move ahead, should the federal government give its approval.

FERC delays final EIS for Oregon LNG project

(The Daily Astorian; Astoria, OR; Feb. 10) - Opponents and supporters of Oregon LNG's terminal and gas pipeline project proposed for Warrenton's Skipanon Peninsula near the entrance to the Columbia River will have to wait at least another few months for the Federal Energy Regulatory Commission to release its final environmental review of the $6 billion project. The commission originally planned to release the final environmental impact statement Feb. 8, but has pushed back the date to June 3.

In December, commission staff requested additional information from Oregon LNG in response to comments on the draft statement, but the company didn't fully respond until late January. The commission will consider the final environmental impact statement when deciding whether to authorize the controversial project. Other federal regulatory agencies reviewing the project now have until Sept. 1 to make their own decisions. FERC commissioners will not look at the project until after the final EIS is published.

"In terms of that delay, honestly, we would hope that state and federal agencies would turn this project down before it ever got that far," said Dan Serres of Columbia Riverkeeper, an environmental group opposing the project. The nearly 1,000-page draft EIS, released in August, concludes the project would result in adverse impacts on water quality and fish and wildlife habitat. However, Oregon LNG could minimize the impacts to less-than-significant levels through mitigation measures proposed by the company.

LNG projects in Nova Scotia receive approval to export U.S. gas

(The Financial Post; Canada; Feb. 10) - The first liquefied natural gas project in Canada may be built on the East Coast, not the West Coast. While multiple projects in British Columbia have been delayed, the backers of two proposed export projects in Nova Scotia say they are on pace to sanction their multibillion-dollar facilities this year. "We are still targeting a final investment decision at the end of the third quarter 2016," said Mark Brown, director of project development for Halifax-based Pieridae Energy, which plans to build an LNG plant on the east coast of the province at Goldboro.

The company announced this week it had received U.S. Department of Energy approval to export U.S. natural gas delivered to the Canadian plant for liquefaction and loading aboard tankers. Brown said the authorization was the last major regulatory approval needed from national governments, and the company is applying for a construction permit from the Nova Scotia government before it sanctions the project. Pieridae has a contract with a German company for half of the plant's approved output.

Like Goldboro, LNG Ltd.'s Bear Head LNG project — proposed for Cape Breton — announced last week it had also received U.S. Department of Energy export authorization. Both projects are looking to draw on surplus supplies of U.S. shale gas to feed their plants. "We are really working toward trying to achieve (a final investment decision) this year for Bear Head," LNG Ltd. chief financial officer Michael Mott said, though he added that the fall in global LNG prices "has cut against us."

B.C. premier faces 2017 election without any LNG commitments

(CBC News analysis; Feb. 6) – It's the ultimate political misstep: to over promise and then under deliver. It's also the reality Premier Christy Clark now faces with B.C.'s liquefied natural gas industry. The promises are well chronicled. Clark campaigned in 2013 on B.C. being able to pay off all its debts with LNG money, with those revenues also building a $100 billion prosperity fund and generating 100,000 jobs. What a difference a few years make.

So far Clark has not delivered on a single one of those commitments. The premier is poised to enter the 2017 campaign with no LNG revenues and the potential of no shovels in the ground on any major LNG facility. There are 20 proposals for LNG export projects on the B.C. coast — all are waiting for environmental approvals or investment decisions, or both. It has been the issue Clark cannot shrug off. "It's a tough global picture," Clark told CBC Power and Politics host Rosemary Barton.

B.C. Finance Minister Mike de Jong said for the first time this week the province now doesn't expect any LNG revenues until at least 2018, which amounts to quite a blow to the provincial economy. "Success isn't for quitters," Clark said. "In order to succeed in this tough economy, we need to stick with it." Clark remains confident her promises from the last election can still come true. But with no shovels in the ground and no money in the bank, the B.C. government is running out of time before the 2017 election.

Pakistan signs 15-year LNG contract with Qatar; prices linked to oil

(Reuters; Feb. 10) - Pakistan said Feb. 10 it had signed a 15-year agreement to import up to 3.75 million metric tons of liquefied natural gas a year from Qatar (about 180 billion cubic feet of natural gas), a major step in filling Pakistan's energy shortfall. The deal, Pakistan's biggest LNG supply contract, will help the country add about 2,000 megawatts of gas-fired power-generating capacity and improve production from fertilizer plants now hobbled by a lack of gas, a government official said.

Supplies will start in March, Qatar's state news agency said, and will eventually come to around five LNG cargoes per month, a Pakistani official said. Pakistan, a nation of 190 million people, can only supply about two-thirds of its gas needs. The ruling party, which campaigned on promises of resolving the energy crisis, wants to ease shortages by importing more LNG before a 2018 general election. The price for the Qatari LNG will be 13.37 percent of the preceding three-month average price of a barrel of Brent crude.

A price review is permitted 10 years after the start of supply. A cancellation option could shorten the deal to 11 years if the parties fail to agree on a new price. Pakistan, along with Egypt and Jordan, was a newcomer to the LNG import market in 2015, helping drive up demand and absorb growing world supplies from a wave of new projects. Pakistan's first floating import terminal got its initial spot-market imports last April. The country has tendered for a second terminal, which should be operational by mid-2017.

Tanzania moves closer to LNG project, but hurdles remain

(Interfax Global Energy; Feb. 10) - The recent confirmation of a site for Tanzania’s long-delayed LNG plant may finally be the end of the beginning for the project. Tanzania Petroleum Development Corp. unveiled the Machenga Bay location in late January, having finalized land acquisition for the site. It is setting up a compensation and resettlement package for the affected villagers. The decision to allocate the land is a big deal for Tanzania and its partners, led by BG Group.

An investment decision has been delayed by issues including the valuation of the land, which will determine the amount paid to landowners. The national oil and gas company now owns title for some 5,000 acres of land set aside for the two-train LNG plant in the southern Tanzanian town of Lindi, close to large offshore gas finds. The company is working with BG, Statoil, ExxonMobil and Ophir Energy to build the onshore plant. But analysts point out there are still sizeable obstacles to overcome.

First, Tanzania will struggle to keep pace with the nearby LNG project proposed in Mozambique by Anadarko and its partners. A start-up date sometime in the 2020s remains the best-case for Tanzania. "But it is still likely to be limited by the bureaucratic delays that are common in Tanzanian policymaking," said Emma Gordon, a senior Africa analyst at Verisk Maplecroft. There is less support for the project among some of the coastal communities, she said. “Communities … have argued for a greater portion of the gas to be used domestically to spur development,” Gordon said.

Expanded Panama Canal looks to end-of-June opening

(Reuters; Feb. 3) - After more than a year-long delay, a new set of larger locks for the Panama Canal will be complete by the end of June after builders repaired cracks that had formed in the concrete walls, the waterway's administrator said Feb. 3. The consortium building a third, bigger set of locks on one of the world's busiest maritime routes, headed by Italy's Salini Impregilo and Spain's Sacyr, is now in testing, the final step before the opening, said Jorge Quijano, who leads the Panama Canal Authority.

Construction of the wider and deeper transitway will allow most of the world's liquefied natural gas carriers to move through the canal, expanding trade opportunities for Atlantic Basin LNG suppliers to deliver to Pacific markets. The first U.S. Gulf Coast LNG export plant will start up this year, with three more under construction. All were marketed to offer U.S. gas to Asian buyers, but falling prices and the supply glut in Asia are expected to push much of the U.S. LNG to European and South American markets.

Panama should start to fully benefit from the canal expansion in 2017, when the government foresees getting an extra $1.4 billion in revenue, a jump of 30 percent compared with this fiscal year. The project was initially set to be finished at the end of 2014, but the date was pushed back to April of this year due to a dispute between the administrator and the building consortium over costs. The project was originally set at $5.25 billion, but the builders successfully argued for an additional $3.2 billion.

Low prices cut into Australia's LNG royalties

(Australia Financial Review; Feb. 7) - The cash-strapped Queensland state government in Australia could lose hundreds of millions of dollars in gas royalties due to the plunge in the international oil price and a major liquefied natural gas venture challenging a ruling of how much it should pay into state coffers. The multibillion-dollar LNG industry was expected to be a cash cow for the state government, but Treasury officials have had to continue scaling back estimates of a royalty bonanza over the past few years.

In a budget update in December, LNG royalties were downgraded from $129 million to $33 million for this financial year. Total royalties expected in fiscal year 2019 have been downgraded by $300 million from $1.5 billion to $1.2 billion. LNG prices are linked to oil prices and, to make matters worse, one of three new plants, the Australia Pacific LNG project of Origin Energy, ConocoPhillips and Sinopec, is challenging the Queensland government's royalty determination and has asked a court for a judicial review.

APLNG is seeking a court decision setting aside the royalty decision from December last year, saying the "netback method" used by the Office of State Revenue was flawed. Royalties are payable at 10 percent of the wellhead value, less deductible costs such as operational and capital expenses. Details of the legal challenge remain confidential because of commercial negotiations, but it is likely to be over the deductions.

Russian LNG production cutback leads to boost in spot price

(Reuters; Feb. 5) - Asian spot LNG prices surged this week after a technical fault at Russia's Sakhalin-2 plant was expected to reduce exports over the coming weeks. Sakhalin-2, Russia's sole LNG production plant, expects maintenance work related to a Jan. 26 fault at its gas compressor to last until March. Traders said the fault impacted one train and would reduce exports by between five to seven cargoes per month.

LNG prices for March delivery in Asia rose sharply to $5.75 per million Btu, from $4.90 the previous week, in the wake of the news. "Sakhalin has given some support to the market and oil prices have recovered a bit," said a trader, adding that at least 10 cargoes had been cancelled from the project. But traders said there is plenty of surplus supply to fill any gaps left by Sakhalin. "I think the price moves are more psychologically led," a second trader said.

Residents organize against Marcellus gas pipelines through Virginia

(Washington Post; Feb. 6) - Virginia Davis fears the day construction on a gas pipeline might begin near her farmers' market in Virginia. Bulldozers rumble over the hillside. Hundreds of jelly jars jangle on the shelves. She and her husband are bracing for a pipeline construction boom, where utility companies stand poised to capitalize on cheap energy from the fuel-rich Marcellus Shale formation. The demand for energy from the deposit spanning Pennsylvania, West Virginia and Ohio in the Mid-Atlantic and Southeast has triggered a vast re-plumbing of the nation's fuel-delivery system.

To move all that energy, it has to go through Virginia. Two pipelines are moving through the federal regulatory process, with two more under consideration. The projects have tapped into anger in swaths of rural Virginia where residents worry their way of life will change. The result of that anger and worry has been the formation of a coalition of activists, residents and environmental groups, which has taken on the projects that it says threatens the land.

The opposition focuses on and around the Shenandoah Valley, where residents are railing against a $5.5 billion, 564-mile pipeline that utility giant Dominion plans to construct from West Virginia through Virginia and into North Carolina. Residents worry about water quality and soil erosion, species habitats, property values, construction noise and sinkholes.

Oil companies have different strategies to survive low prices

(Reuters; Feb. 7) - As oil and gas companies cut ever deeper into the bone to weather their worst downturn in decades, corporate boards have adopted contrasting strategies to lead them out of the crisis. Crude prices have tumbled about 70 percent over the past 18 months to around $35 a barrel, leading to five of the world's top oil companies reporting sharp declines in profits in recent days.

Executives at energy firms face a tough balancing act: They must cut spending to stay financially afloat, while preserving the production infrastructure and capacity that will allow them to compete and grow when the market recovers. Companies have opted for differing approaches to secure future growth, often choosing to narrow their focus to the areas of expertise and geographic location of their main assets.

U.S. firms Chevron, ConocoPhillips and Hess are withdrawing from more costly deep-water projects to focus on shale oil fields on their home turf, for example. Chevron, the second-largest U.S. oil firm after ExxonMobil by market value, last week outlined plans to target spending on "short-cycle" investments — lower-cost projects that can take months, rather than several years, to come online. Britain's BP is betting on offshore gas in Egypt, while Shell has opted for an alternative route as it seeks to safeguard its future: the $50 billion takeover of BG Group, a big player in the LNG industry.

Despite negative cash-flow, companies continue producing oil

(Oil & Gas Journal; Feb. 5) – Despite negative cash flow from low prices for millions of barrels of oil per day, far less production than that has been shut in worldwide, reports Wood Mackenzie. Analysis of the firm’s database of over 10,000 oil fields indicates that 3.4 million billion barrels of oil per day costs more to produce than the revenue it yields with Brent crude at $35. But so far, less than 100,000 barrels per day has been shut in of almost 80 million per day counted in the consulting company’s database.

According to Wood Mackenzie, 2 million barrels per day is cash-negative at a Brent price of $40 and 7.7 million barrels at $25. The study points out that many operators prefer to continue producing oil at a loss rather than stop production, especially for large projects such as oil sands and mature fields in the North Sea. It says production from smaller stripper wells is the category most vulnerable to low prices.

“Given the cost of restarting production, many producers will continue to take the loss in the hope of a rebound in prices,” says Robert Plummer, Wood Mackenzie vice president of investment research, noting that the firm projects an annual average Brent price this year of $41. “The operator’s first response is usually to store production in the hope that the oil can be sold when the price recovers. For others the decision to halt production is more complex."

Low oil prices, new pipelines cut into rail business for Bakken crude

(EnergyWire; Feb. 8) - Crude by rail is no longer king in the Bakken Shale play. For nearly four years, oil shippers favored train tracks over pipelines when shipping light, sweet Bakken Shale crude from North Dakota to coastal refiners or oil-transfer hubs. Railroads pumped billions of dollars into their networks, while refiners snapped up thousands of tank cars and fuel logistics firms signed lucrative crude contracts. But railroads' dominance in the oil business may be coming to a close.

Thousands of miles of new pipelines and continued protests over rail tank car safety have taken their toll on the crude-by-rail industry. Meanwhile, the global crash in crude prices has spread from oil majors' balance sheets to their actual production forecasts, which could cause rail volumes to fall further in 2016. Roughly five years ago, "when crude by rail really expanded in North Dakota, it came on as a way to move out the oil as quickly as possible," said Bridget Hunsucker, of energy research firm Genscape.

Genscape, which tracks crude-by-rail movements throughout the country, has seen volumes moving out of the Bakken drop as low as 330,000 barrels per day in recent weeks, Hunsucker said. In November, railroads moved 41 percent of the oil produced in North Dakota, or about 480,000 barrels per day, based on the most recent data available from state officials. By contrast, pipelines took 52 percent of crude oil transport that month, eclipsing rail volumes in North Dakota for the first time since June 2012.