Oil and Gas News Briefs
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Gazprom delays plans to expand Sakhalin LNG plant

(Reuters; March 13) - Russia's Gazprom has delayed plans to expand its liquefied natural gas plant on Sakhalin Island in the Far East and to build a new plant on the Baltic Sea, a Eurobond presentation showed March 13. The state-controlled gas producer is meeting with investors this week to discuss a potential debt offering. The project delays could disrupt Russia's plans to carve out a bigger share of the global LNG market, where it aims to triple its market share of less than 5 percent by 2035.

Gazprom plans to expand the Sakhalin-2 plant off Russia's Pacific coast by 2023-2024, the presentation showed, while previously it had announced plans to launch a third LNG production train at the plant in 2021. The Far East LNG plant opened in 2009. The presentation seen by Reuters also showed a 2022-23 launch for a new Baltic LNG plant in the Leningrad region, later than a 2021 start-up previously discussed by Gazprom.

The third train is expected to boost Sakhalin-2 production by 5.4 million tonnes per year, to 15 million. The facility's partners — Gazprom, Shell, Mitsubishi and Mitsui — have long considered expansion plans, but have been hampered by access to sufficient gas resources. They are considering two options: buying gas from the nearby Sakhalin-1 oil and gas project led by ExxonMobil, developing new resources, or a combination of the two. But Sakhalin-1, where Russian state-controlled oil major Rosneft is a shareholder, has long talked of building its own LNG plant rather than sharing a plant with Gazprom.

More LNG buyers look to swap out U.S. gas to avoid shipping costs

(Bloomberg; March 7) - More Asian LNG buyers are trying to avoid taking the U.S. supplies they signed up for just a few years ago as they try to reduce shipping costs. GAIL India and Indonesia's state-owned PT Pertamina are both seeking to trade liquefied natural gas cargoes they are contracted to buy from U.S. suppliers in exchange for cargoes shipped from projects closer to home.

They're following buyers such as Tokyo Gas in trying to avoid deliveries of U.S. LNG after the global oil price crash reduced the competitiveness of American gas relative to other suppliers. That's made minimizing shipping distances more vital to buyers looking to reduce costs. "The underlying volatility in [U.S.] Henry Hub prices has dented the competitiveness of U.S. LNG, especially in Asia, providing the trigger for the swap deal," said Abhishek Kumar, senior analyst at Interfax Energy's Global Gas Analytics, London.

Most U.S. LNG exports are tied to domestic gas prices, while global LNG sales have traditionally been linked to oil. That made U.S. gas attractive earlier this decade when crude prices hovered above $100 a barrel and U.S. gas slumped amid a production boom. But the oil market crash has removed that price advantage for U.S. LNG. Under its contract with Cheniere Energy for U.S. cargoes, Pertamina, at today's natural gas prices, would have to pay $6.86 per million Btu for U.S. LNG, even before shipping the fuel halfway around the world. Spot-market prices for LNG sent to Asia are about $6.

Korea Gas wants more flexibility in future LNG contracts

(Reuters; March 10) - Korea Gas, the world's second-biggest liquefied natural gas buyer, will seek flexible contracts to have more leeway to trade its LNG cargoes down the road, its chief executive told Reuters on March 10. The changes would follow similar efforts by LNG buyers in Japan, the world's top LNG importer. Companies there have been vocal about the removal of destination clauses in their long-term import contracts that restrict a buyer's ability to resell cargoes it does not need.

But KOGAS will have to wait until 2025, when its long-term contracts expire, before it can start to adjust its import terms. "We are looking for flexible contracts," Lee Seung-hoon, CEO of state-run KOGAS, said in an interview in Seoul. "The market has been a seller's market ... it would be good if buyers can swap when they are short of cargoes or they have more." Korea's long-term contracts include large deals with Qatar and Oman that expire in 2024. Lee said he is unsure if KOGAS would extend the deals, "but terms will change and we won't do it on the same terms."

KOGAS is willing to bring more gas from the United States amid increasing U.S. shale gas output, Lee said. The company will start LNG imports this summer from Cheniere Energy's terminal in Sabine Pass, La., under a 20-year supply deal. "We intend to (buy more) but we don't have a fixed plan .... we're thinking to import more by participating in gas liquefaction plant projects as major players," he said.

Shell cancels British Columbia LNG project it inherited in BG takeover

(Globe and Mail; Canada; March 10) - Shell officially, but not surprisingly, shelved its plans to build the Prince Rupert LNG project, which had been proposed for Ridley Island in British Columbia. But the company will continue advancing the $40 billion LNG Canada plant, a separate liquefied natural gas export venture proposed for Kitimat, B.C., on a different costal channel about 70 miles to the southeast of Prince Rupert.

Shell had placed the Prince Rupert LNG proposal on the back-burner since it inherited the project through its 2016 acquisition of BG Group. Earlier this year, Shell said it was reviewing the merged Shell and BG portfolio, including the Prince Rupert project, which

BG unveiled almost four years ago. No work has been done at the site, and Shell is withdrawing from the lease arrangements at the property. “Given the natural advantages and advanced stage of our LNG Canada project in Kitimat, we have decided to focus our attention there,” said Cameron Yost, a Shell Canada spokesman.

Shell’s partners in the Kitimat proposal are PetroChina, Korea Gas and Mitsubishi. Last summer, the consortium announced it was delaying its final investment decision due to market conditions. It’s one of almost 20 LNG export plants proposed for British Columbia, ranging from $2 billion to $40 billion. The closest to an investment decision, Pacific NorthWest LNG, led by Malaysia’s Petronas, could reach a decision later this year on the project proposed for an island near Prince Rupert.

Many disagree with Shell’s view that LNG market is well balanced

(Platts commentary; March 10) - When Shell last month presented its first global LNG Outlook since its 2016 acquisition of BG Group, it surprised some by effectively denying the existence of a global LNG supply glut, pointing instead to a well-balanced market where all produced LNG cargoes were being consumed. However, much of the industry commentary in recent months has said the market is suffering a supply glut and is heading for a period of sustained oversupply until at least the start of the 2020s.

LNG prices across the globe have fallen to multi-year lows, and the expected slew of new project start-ups in 2017 from Australia and the U.S. is forecast by many to lead to a hugely oversupplied market with demand growth unable to keep pace. Some players already talk of an oversupplied market, with things only set to worsen in the coming years. Pablo Galente Escobar, head of LNG at global trader Vitol, said at a London conference last month that his view of the LNG market was "very different" to Shell's.

"We think the market will be significantly oversupplied over the next five years," he said, pointing to expected LNG supply growth to 400 million metric tons a year by 2020 from 240 million in 2015. The growth is unprecedented in the history of commodities, he said, and represented the biggest "supply shock" he had ever known. “The underlying growth in world LNG demand is itself not sufficient to absorb the scheduled growth in supply," Statoil said in its own recent outlook. The main beneficiary of an oversupplied market is the customer, not only because of cheaper prices but also for security of supply.

U.S. could become world’s largest LNG supplier

(Bloomberg; March 9) - By 2035, the U.S. may have surpassed Australia and Qatar to become the world’s biggest supplier of liquefied natural gas, said the chief executive officers of Canadian energy giant Enbridge and U.S. LNG exports-hopeful Tellurian. The U.S. already has about 70 million tons a year of LNG capacity coming in service and under construction — not far behind Australia's 87 million and Qatar's 82 million — Meg Gentle, Tellurian's CEO, said in an interview at CERAWeek in Houston March 8.

"The U.S. will be the cheapest source of new LNG," Gentle said. That could "easily" hand the U.S. the biggest share of the LNG market, she said. This would be a monumental shift for America, which just a decade ago was facing declining gas production and was building terminals in anticipation of importing more of the fuel. The shale boom instead propelled U.S. gas supplies to record levels.

In fact, America's LNG production may be growing too fast. A worldwide glut of the fuel, brought on by increasing supplies from countries including the U.S. and Australia, sent investments in new LNG export projects to a 17-year low in 2016. Tellurian, which wants to build its own export project in Louisiana, is betting that the market will eventually re-balance, setting the stage for a rebound after 2020.

Big Oil sees future profits in cheaper, quicker, less risky ventures

(Wall Street Journal; March 8) - The world's biggest oil companies are getting thrifty. Oil prices have made a modest comeback from the lows hit a little over a year ago, but companies are not pursuing the extravagant bets they made at $100 a barrel — like commissioning multibillion-dollar projects in Arctic waters and Kazakhstan's Caspian Sea. Companies are putting their money into cheaper, quicker ventures in Texas shale, the Middle East and Brazil, and squeezing more from existing projects worldwide.

ExxonMobil last week unveiled an ambitious plan to make drilling in Texas, New Mexico and North Dakota the heart of its future. By 2025, Exxon said, its daily production from these areas could more than triple to the equivalent of 750,000 barrels. Added to other shale production, that would equal one-third of Exxon's current output. It's a shift away from the business model long-employed by the world's largest oil companies, favoring challenging projects with huge upfront costs that would be paid off over 20 or 30 years.

To drive down costs, big oil companies are abandoning such developments in favor of standardization and bolt-on models that take advantage of existing infrastructure. They are returning to old basins to see what they can extract with new technologies and focusing on the lowest-cost prospects. The appeal of cheaper projects that can bring oil or gas to market within a few years is that it allows companies to avoid being locked in to multibillion investments over as much as a decade, ConocoPhillips CEO Ryan Lance said at the annual CERAWeek conference in Houston on March 7.

Shell sells off nearly all of its Alberta oil sands assets

(Wall Street Journal; March 9) - Shell is selling nearly all its Canadian oil sands developments in deals worth $7.25 billion, deserting a region that has come to symbolize the risks for companies in high-cost, carbon-intensive sources of oil. The deal marks another milestone in an ambitious plan by Shell to sell off $30 billion of assets by next year to help pay down debt and streamline the company following its $50 billion acquisition of BG Group in 2016.

Selling the Canadian assets cements a shift by Shell toward deep-water oil and the fast-growing liquefied natural gas market. “We want to be a player that is world-class in integrated gas, world-class in deep water,” Shell CEO Ben van Beurden said in an interview. “There’s only so many things you can aspire to be at scale at and put money into.” Shell is pulling back from the oil sands only weeks after ExxonMobil signaled that some of its planned output there had become unprofitable at low prices and removed about 3.3 billion barrels of oil from its stated reserves, mostly in the oil sands.

In the deals, Shell is selling to a subsidiary of Canadian Natural Resources, a Calgary-based company with significant oil sands interests. The moves by Shell and Exxon highlight a stark reversal of fortunes for Canada’s oil sands. In the decade leading up to the oil-price collapse of 2014, some of the world’s biggest energy companies raced to build megaprojects in northern Alberta, spending an estimated $200 billion to tap reserves. But the oil sands’ high fixed costs and emissions levels, and the long horizons required to deliver a return on investment, have deterred new spending there.

Rebound spreading among oil field services companies

(Bloomberg; March 7) - Five years ago, the thought of $55-a-barrel oil would have given Piotr Galitzine heartburn. Now it’s keeping one of his steel-pipe shops in Houston open 24/7 and fueling a flurry of orders. It’s stoking business for National Oilwell Varco too, with the oil field equipment giant for the first time in better than a decade selling more land-based gear than offshore gear. And it’s got Perry Taylor on the hunt for truckers to haul fracking sand. Even at $80,000 a year, jobs are hard to fill.

Crude is nowhere near its $100-plus highs of recent years, but drillers pounced after it steadily crept back up from the $26 bottom it sank to early last year. And as they tap more and more new wells, the rebound is spreading quickly, and powerfully, to the oil field services outfits that were so hard hit during the collapse. “Everyone is so hungry,” said Joseph Triepke, founder of the industry research company Infill Thinking in Dallas. “It’s like we’re hanging a steak in front of a bunch of starving people.”

The activity is due in large part to technological advances that help explorers find more pockets of petroleum and to drill faster and frack smarter. That last bit is key in the shale formations that hold the most promising on-land pockets of oil and gas. The burst of activity has helped drive U.S. oil output, with an average 125,000 barrels a day added since September. Pipe-supplier Galitzine said he has started hiring again. “Every time I push that computer button that says ‘approved’ on the rehire, I feel better.”

Fracking sand producers able to demand higher prices

(Wall Street Journal; March 6) - Most Silicon Valley companies would kill for the sorts of gains made by sellers of plain old silicon. Even after a recent selloff, leading producers of sand used by oil and gas producers — companies like Hi-Crush Partners and U.S. Silica Holdings — are up between 170 percent and 380 percent over the past year. Their gain is turning into oil producers’ pain, though, and could affect the energy market.

Used in fracking shale formations, sand was a hot item during the boom that ended in 2014. Now that activity is on the upswing, sand producers have rebounded from crisis to expansion mode. Some analysts see demand equaling or exceeding the peak, even with drilling activity far lower. Drillers have discovered that more sand produces more oil or gas. Praveen Narra, an analyst at Raymond James, estimates the amount of sand used per foot of well depth last year was 40 percent to 50 percent greater than in 2014.

With per-well usage higher and prices for sand about twice what they were just a year ago, costs are starting to bite the drillers. A typical well in the booming Permian Basin might have cost about $6 million to drill last year including around $350,000 worth of sand, according to George O’Leary, an equity analyst at Tudor, Pickering, Holt & Co. By late 2017, that could reach $800,000 and conceivably top $1 million if sand providers flex their pricing muscles, O’Leary said.

Kinder Morgan raises cost estimate on oil pipeline to B.C. coast

(The Canadian Press; March 9) - Kinder Morgan has increased the estimated cost of the Trans Mountain oil pipeline to $7.4 billion and says it has confirmed shipping interest from producers to move their oil from Alberta to the B.C. coast near Vancouver. The cost is up from the previous estimate of $6.8 billion, with Kinder Morgan citing increased compliance costs including the National Energy Board’s 157 conditions, thicker pipe walls, additional horizontal-drilled water crossings, and the Burnaby Mountain tunnel.

The federal government has approved the project, but opponents have launched legal challenges to delay construction. Houston-based Kinder Morgan, which holds an interest in 84,000 miles of oil and gas pipelines across North America, said construction on the Trans Mountain project is set to begin in the fall.

Expansion of the 710-mile pipeline will boost capacity from 300,00 to 890,000 barrels a day. The Trans Mountain line has been in operation since 1953. In 2012, 13 shippers made 15- and 20-year commitments of 708,000 barrels per day, representing about 80 per cent of the expanded capacity, with the remaining 20 percent left open to spot volumes. Kinder Morgan said it will make open capacity available on the market.

Britain will look at tax change to help North Sea deals

(Reuters; March 8) - Britain will look at ways of making it easier to sell North Sea oil and gas fields by changing tax rules in order to keep the fields producing longer, the finance ministry said. The move, which is due to be announced by Finance Minister Philip Hammond on March 8, follows a call by the industry's lobby group for a change to decommissioning tax rules that have prevented deals in the North Sea.

Owners of oil and gas assets get tax relief on future dismantlement costs, but as assets are sold the relief cannot be passed on to new owners. "The U.K. government will publish a discussion paper and establish a panel of industry experts to consider how tax can assist sales of oil and gas fields, helping to keep them productive for longer," the ministry said in a statement.

The North Sea has seen an uptick in deals this year, but there could be more if the decommissioning tax regime is updated, said Mike Tholen, economics director of Oil and Gas UK. "For (new buyers) it would be easier for the deals … if decommissioning tax relief between the vendor and the purchaser was part of the tax regime." Many traditional North Sea operators are winding down ownership of assets as smaller, more nimble companies snap them up to apply new technologies to extract more oil or gas.

Statoil plans to boost its investment in renewables

(Wall Street Journal; March 6) - Norway's Statoil aims to increase its investment in renewables to between 15 percent and 20 percent of total spending by 2030, up from 5 percent today. The commitment to increasing the company's alternatives to fossil fuel energy is driven by a view that global demand for oil will eventually peak, and the company wants to get ahead of that shift, Statoil CEO Eldar Saetre said in an interview March 6 at the CERAWeek conference in Houston.

Statoil, which is majority state-owned, has focused its renewable investments so far in offshore wind, an area where it can tap its offshore oil expertise, Saetre said. "One day, there will be a peak in oil demand," he said. "There is a debate about when that will happen. At some point, it will be a shrinking business." Varying scenarios put the date of oil's growth peak somewhere between the mid 2020s and well into the 2030s, he said.

While long-term concern over oil and gas demand is stirring investment in alternatives, such ventures can also provide a hedge against volatility of the oil and gas business, which depends heavily on price, Saetre said. That kind of bulwark against cyclical ups and downs in prices is especially important to a company like Statoil, which has focused heavily on oil and gas production, leaving it with an even more concentrated exposure to price swings than other players with more sizable refining and pipeline businesses.

Australia prime minister calls on states to allow more gas exploration

(Bloomberg; March 9) - Australia, the world's No. 2 liquefied natural gas exporter, needs to remove roadblocks to gas exploration on its East Coast that Prime Minister Malcolm Turnbull blames for a looming domestic supply crisis. "We are facing an energy crisis in Australia because of this restriction of gas," Turnbull told a business group in Sydney on March 9. "Gas reserves or gas resources are not the issue. The biggest problem at the moment is the political opposition from state governments to it being exploited," he said.

Turnbull will meet the country's major upstream producers the middle of next week, according to his office. He will discuss how they can restart gas exploration despite restrictions from state governments. Sydney-based AGL Energy, the nation's largest energy retailer, walked away from gas exploration and production activities in February last year, citing commodity price volatility and long development lead times. The state of Victoria and the Northern Territory have a moratorium over onshore gas exploration.

The eastern states need additional energy to stave off an expected shortfall in gas-powered electricity generation in 2018-19, according to the Australian Energy Market Operator. Origin Energy, Australia's largest electricity company, on March 7 said gas intended for LNG exports to Asia may be diverted to ease an expected supply shortfall this winter. Energy security has come under scrutiny since a statewide blackout in September hit South Australia, the mainland state most reliant on renewable energy.

Norwegian company divests shares in Dakota pipeline partners

(The Guardian; March 1) - Norway's largest private investor is divesting from three companies tied to the Dakota Access oil pipeline, a small victory for the Standing Rock movement one week after the eviction of the main protest encampment. Storebrand, a sustainable investment manager with $68 billion in assets, sold off $35 million worth of shares in Phillips 66, Marathon Petroleum and Enbridge, the investment manager announced March 1. The three companies are partial owners of the pipeline.

"We hope our actions and the actions of other like-minded investors in either divesting or calling for an alternative [pipeline] route will make some sort of an impact," said Matthew Smith, the head of Storebrand's sustainability team. The Standing Rock Sioux Tribe's attempt to halt or reroute the North Dakota pipeline away from their water source became an international rallying cry for indigenous peoples and environmental activists.

Opponents of the pipeline have waged divestment campaigns against the pipeline company, Energy Transfer Partners. Activists have also urged individuals and institutions to move money out of banks that are financing pipeline construction, including Wells Fargo and Bank of America. Victories thus far include decisions by a Norwegian bank, DNB, and Norwegian mutual fund Odin Fund Management to sell their shares in companies connected to the pipeline.