Oil and Gas News Briefs
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Report says Algeria may be unable to stem decline in gas production

(Interfax Global Energy; May 23) - New projects will not be able to compensate for the drop in Algerian gas reserves, according to a U.K. think tank. The development of "small and costly reservoirs" is not enough to stem the decline of the huge Hassi R'Mel field, warned a report published May 23 by the Oxford Institute for Energy Studies, called "Algerian Gas: Troubling Trends, Troubled Policies." Algeria was the first country in the world to export liquefied natural gas, starting up its initial production line in 1964.

According to report author Ali Aissaoui, subsurface issues and above-ground problems at the 60-year-old field will be difficult to overcome with current recovery techniques, but need to be tackled swiftly to prevent a significant drop in Algerian production. "Not only will the new upstream projects hardly make a difference in compensating for the decline of Hassi R'Mel and other mature fields, but most of them are tight, dry, or, in the case of southwestern formations, have high [carbon dioxide] content [and are] therefore too costly to be able to offset the notable shortfall in government revenues," the report said.

Aissaoui said state-owned Sonatrach is "increasingly being perceived as structurally short on gas supply." Proven reserves were downgraded by the Algerian government in November 2015 to 97 trillion cubic feet compared with previous estimates of 159 tcf. According to the report, Sonatrach could be exporting just 530 billion cubic feet per year by 2030 compared with the current figure of 2.4 tcf. The utilization rate of the country's export capacity has already fallen to 52 percent. The government's current plans to prevent the decline in production could be too little, too late, according to the report.

Analysts doubtful of Iran's gas export ambitions

(Platts; May 23) - Freed from international sanctions against its energy sector, Iran is working quickly to raise it gas production and export capacity — and its medium-term targets are truly ambitious. If realized, Tehran's plans for a major gas export increase could send tremors through global markets. But analysts have raised major doubts on Iran's ability to meet its targets, especially given the difficulties in financing projects, competition across global gas markets and the doggedly low-price environment.

An official at state-owned National Iranian Gas Co. said this month that Iran wants to raise its gas exports to some 12 billion cubic feet per day in the medium term, targeting future buyers in Europe. That volume would surpass neighboring Qatar's current exports and put Iran on track to move closer to world leader Russia. Iran currently produces around 8.8 bcf a day, most of which is consumed domestically. Its exports currently total less than 1 bcf a day to Turkey and small volumes to Azerbaijan.

Analysts remain doubtful that Iran will become a major exporter, especially to Europe. Jonathan Stern, leading gas analyst from the Oxford Institute of Energy Studies in the U.K., said he did not expect any Iranian gas to Europe in the next 10 years. "First, they would need spare gas, which they don't have. Second they would need to accept the price situation in Europe, which they are not likely to. And third, capacity would need to be created and buyers found," Stern said. He sees Iran's first LNG exports after 2026, at the earliest — adding that Iran might find it difficult to compete on price in the market.

Japan's average LNG purchase price lowest in 11 years

(Bloomberg; May 22) - Japan, the world's biggest buyer of LNG, paid the lowest price in about 11 years for the fuel last month amid a global oversupply. The average price of LNG cargoes into the country was about $6.32 per million Btu in April, the lowest since August 2005, according to Bloomberg calculations based on preliminary data from the Ministry of Finance. The average includes contract deliveries and spot-market cargoes.

Prices are expected to rebound in the coming months as crude values have surged, said Junzo Tamamizu, managing partner at Clavis Energy Partners. LNG under long-term contracts imported into Asian countries is typically linked to oil prices with a time lag of several months. "With crude prices bottoming between January and February, LNG prices are set to rebound," Tamamizu said May 23. Asia's spot LNG prices started the week at $4.35.

Future of Big Gas will not be as profitable as Big Oil

(Bloomberg column; May 24) - Natural gas has become an ever more important part of the oil majors' business over the years. Discoveries of gas have outstripped those of oil in each of the past four years. Big Oil — taken here to mean ExxonMobil, Chevron, Shell, BP and Total — has been getting less oily for a while. In 2001, their aggregate oil output was almost 10.1 million barrels a day, according to data compiled by Bloomberg. By 2015, it had dropped by more than 1.5 million barrels a day, or almost 16 percent.

It'd be even worse without gas, where the companies have managed to grow. While gas has a lot going for it in terms of its lower carbon content compared to oil and coal, that doesn't necessarily mean great profits. The shale boom has cratered the gas price through excess supply. This has been echoed globally as a glut of liquefied natural gas production, commissioned when prices were high, hit the market even as LNG prices have fallen along with oil. Gas markets should re-balance, eventually.

But gas is a fundamentally different market compared to oil. Even if it recovers, being Big Gas won't necessarily be as profitable as it was to be Big Oil. The culture of gas is very different from that of oil. In an oil company, the strategy is driven by discovering crude, with the market a given. By contrast, gas is concerned with securing markets and customers. Produce a barrel of oil and there is a global market to take it off your hands. Gas, because it's so hard to store and move, has always relied on long-term contracts. Shale and LNG are breaking down those barriers, but gas remains a different beast.

Mozambique headed to loan default; bad news for LNG hopes

(OilPrice.com; May 24) - Mozambique is heading toward default on loans for offshore natural gas infrastructure, symbolizing the deflating hopes for a major source of new gas production from East Africa. State-owned Mozambique Asset Management is set to default on $535 million in loans that it took out to build shipyards to serve drilling off its coast. Because of the grace period included in the loan terms, Mozambique is not technically in default, but it could be soon if it fails to convince creditors to make a deal.

Mozambique had tried to renegotiate with creditors, led by Russia's VTB Bank, but has been unable to gain leniency. Meanwhile, its debt has snowballed. The government in April made a surprise announcement that it had $1.35 billion in debt it could not pay. Fitch Ratings quickly downgraded the country's sovereign credit rating to CCC, a rating that denotes a very real risk of default. Its debt owed to foreign creditors, according to Reuters, stands at $9.86 billion, or 80 percent of the nation's gross domestic product.

By all accounts, financial mismanagement has put the country up against a wall. Meanwhile, the ballooning debt presents a problem for developing Mozambique's large offshore gas reserves. Though the government and its oil and gas company partners have wanted to invest in multibillion-dollar liquefied natural gas export projects — which would help build the nation's economy — the oversupplied global LNG market and Mozambique's financial problems are making it harder to attract investments.

BP cuts budget for proposed expansion at Indonesia LNG plant

(Reuters; May 25) - BP has cut its estimated budget for a third liquefaction train at Indonesia's Tangguh LNG plant, trimming the spending plan from its original $12 billion down to between $8 billion and $10 billion, a company official said May 25. "The market is adjusting to oil prices and we have to make a lot of effort to maximize the scope so we can keep costs down," said BP Indonesia country head Dharmawan Samsu.

The two-train plant opened in 2009. BP, at 37.16 percent, holds the largest stake in the project, with partners from Japan, China and Indonesia. BP operates the plant with Indonesia's oil and gas company Pertamina. BP is currently holding a tender for engineering, procurement and construction services for the third LNG train at the Tangguh project and expects a final investment decision on the project mid-year.

Qatar-led partnership says LNG exports from Texas possible in 2021

(Reuters; May 25) - Top liquefied natural gas exporter Qatar expects exports from its Golden Pass joint-venture in Texas to begin in 2021, an adviser to the government said May 25. State-run Qatar Petroleum owns a 70 percent stake in the 6-year-old Golden Pass LNG import terminal, with partners ExxonMobil and ConocoPhillips. Qatar and ExxonMobil formed a separate venture to add liquefaction and export capabilities to the underutilized import terminal. Qatar Petroleum owns 70 percent of that venture, too.

"If everything goes right by 2020-2021, we will export the first cargo from Golden Pass," Abdullah al-Attiyah, a former Qatari oil minister who advises the government on energy issues, told reporters at a media briefing in Doha. Golden Pass is waiting for U.S. Energy Department approval of exports, and the Federal Energy Regulatory Commission in March issued its draft environmental impact statement for the $10 billion project.

Qatar is the world's leading LNG exporter, but the tiny Gulf state faces rising competition as new projects in the United States and Australia are expected to come online in the next few years. Attiyah said the Texas venture would make Qatar a more flexible exporter by allowing it to supply its customers in Europe with gas from the U.S.

Small LNG plant in B.C. would need to expand for deliveries to Hawaii

(Delta Optimist; Delta, BC; May 25) - A FortisBC spokesperson said that if the company's deal to supply liquefied natural gas to Hawaii's electric utilities goes through, the LNG producer will need to add additional liquefaction and storage capacity at its 45-year-old Tilbury plant across the Fraser River from Vancouver, B.C. The company already is expanding the plant, at a cost of $400 million, but additional expansion would be required to serve the new customer.

The facility can liquefy almost 5 million cubic feet of gas per day, and can store almost 570 million cubic feet of gas as LNG. The expanded facility will be able to liquefy an additional 32 million cubic feet of gas per day, with new storage for about 1 billion cubic feet of gas as LNG. More storage to hold an additional 1 bcf of gas as LNG would be needed for the Hawaiian Electric contract. The conditional deal with FortisBC calls for delivery of 800,000 metric tons of LNG a year, or about 38 bcf of gas, starting in 2021.

The expansion at the Tilbury plant will be finished later this year. If all conditions are met and government, regulatory and internal approvals are received, FortisBC would start the second expansion in 2018.

Natural gas region in B.C. optimistic at prospects of exports to Hawaii

(CJDC radio; Dawson Creek, BC; May 20) – There are lots of smiling faces in Fort St. John, in the middle of British Columbia's natural gas plays, after FortisBC signed a deal May 19 to export liquefied natural gas to Hawaii. One of those smiling faces is Alan Yu, founder of the group Fort St. John for LNG, which has been fighting for an LNG industry in B.C. for months. "This is very good news because this is a preview of what an LNG industry in Canada would be. This is a very big, good thing for us," Yu said.

The 20-year deal between FortisBC and Hawaiian Electric is subject to regulatory approvals in B.C. and Hawaii. But if it gets the go-ahead, the agreement could see 800,000 metric tons of LNG shipped from the FortisBC plant near Vancouver to Hawaii every year starting in 2021. Despite the deal being relatively small compared to other proposed LNG projects, supporters say the agreement sends a clear message. The Fort St. John region expects to supply much of the gas for the LNG plant.

"What it signals is that there is a large market for LNG and we have a huge amount of gas here, so we are the ideal suppliers," said Chris LaFratta, who is a member of FSJ for LNG. "This is a clear proof that Canada can supply clean natural gas to the world. Hopefully this is just the first step," Yu said. Though several, much larger LNG export projects have been proposed for the B.C. coast, none have received final go-aheads from regulators and investors.

Argentina ups the price as incentive for domestic gas production

(Platts; May 20) - Seeking to rebuild its natural gas production after years of decline, Argentina is allowing producers to charge higher prices on output from new developments, an Energy Ministry source said May 20. "The program is designed to encourage exploration and increase production," the source said. The program took effect May 19 and will run until Dec. 31, 2018, according to a resolution in the Official Bulletin, the newspaper of record.

Gas from new projects can be sold at $7.50 per million Btu, according to the resolution. That's up from a current average of $5.20. "It is necessary to continue with programs to increase gas production in the short term, reduce imports and encourage investment in exploration and production from new deposits that will make it possible to recover reserves," the Energy Ministry said. But recent hikes in wellhead prices to the average of $5.20 from about $3 have pushed up utility rates, sparking public protests.

Argentina has been ramping up gas imports since production started to decline from a record 5.05 billion cubic feet a day in 2004, now down 16 percent at 4.2 bcf a day. This has led to shortages as demand has grown, with peaks of 6.35 bcf a day during the cold months. The country is importing about 1 bcf a day from Bolivia, Chile and the global LNG market to help cover the shortfall, and plans to bring in more LNG next year with a floating regasification terminal. Argentina relies on gas to meet half its energy needs.

Total and Exxon could be competing for Papua New Guinea gas

(Forbes; May 20) - A $2.2 billion natural gas deal in the Pacific island nation of Papua New Guinea would not normally attract the interest of a super-major like ExxonMobil — if it wasn’t for corporate pride and a desire to keep the French out of ExxonMobil’s backyard. Until last week, Exxon was the dominant player in PNG’s gas industry with a 33.2 percent stake in the only existing LNG project, along being the project operator.

But, if a deal involving an undeveloped group of gas fields proceeds as planned, the French oil and gas company Total could emerge as an LNG competitor in the country, potentially hindering ExxonMobil’s plans to expand its own project. What’s happened is that Papua New Guinea’s local oil and gas champion, Oil Search, has agreed to buy InterOil in a deal that will give it increased exposure to the Elk and Antelope gas fields, assets that might form the basis of the country’s second LNG development.

As part of the deal, Total has entered into a secondary transaction that will see it buy a bigger stake in the Elk and Antelope fields with Oil Search. Total is keen to quickly develop Elk and Antelope and use them as its entry into the fast-growing Asian LNG business. ExxonMobil has been eyeing Elk and Antelope as potential sources of additional gas to expand its LNG plant. Questions remain whether Exxon is prepared to stand clear and permit Total into its backyard, and whether the PNG government would prefer two separate LNG projects or one giant development controlled by ExxonMobil.

Company might produce first U.K. shale gas by end of year

(Reuters; May 24) - Britain's first shale gas from hydraulic fracturing could flow this year after local officials in northern England approved Third Energy's plans May 23 to carry out fracking at an existing well. Councillors in North Yorkshire voted in favor of the project after two days of hearings. Third Energy said it could start fracking the well before the end of the year. "If this flows then we will need to assess how it performs for some months before making any conclusions," said Third Energy CEO Rasik Valand.

Third Energy is the first company in years to receive local government approval for fracking. Britain is estimated to have substantial amounts of shale gas, and Prime

Minister David Cameron has pledged to go all out to extract the gas to help offset declining North Sea oil and gas output. Last year, Cuadrilla Resources had two permits rejected by officials in Lancashire. Cuadrilla appealed the decision and the U.K. government later changed the rules to give it the ultimate say in shale gas applications.

Cuadrilla, which is waiting for a government decision, said it could flow first gas from fracking in mid-2017. Only one shale gas well near Blackpool, in Lancashire, has so far been fracked in Britain, but was later abandoned when some of the work undertaken triggered an earth tremor that resulted in an 18-month ban on the technology in 2011. Many environmental campaigners are opposed to fracking, saying the technology can damage the countryside and contribute to climate change through carbon emissions.

Israeli prime minister approves deal for offshore gas development

(Wall Street Journal; May 24) - Israel's Prime Minister Benjamin Netanyahu on May 22 approved an amended deal to develop the country's offshore natural gas fields after months of legal wrangling stunted the growth of the domestic hydrocarbon industry. Israel's highest court in March ruled against an initial framework to develop the fields. It called the deal unconstitutional, citing a clause in the agreement that gave companies pricing and regulatory stability for 10 years regardless of any shifts in the government.

The main stakeholders in the fields, U.S.-based Noble Energy and Israeli partner Delek Group, had argued that the 10-year stability clause was required for them to make the multibillion-dollar investment necessary to develop the fields. Netanyahu said the stability clause had been removed from the amended framework. An Israeli official said the government added another clause that said the gas producers would be potentially compensated for any future changes in government regulation.

The new deal gives Noble and Delek the green light to develop Israel's largest field and export gas to new markets such as Jordan, Turkey and Egypt. The companies have already been through several rounds of regulatory and legislative hurdles that have significantly delayed development. In total, Israel's offshore fields contain more than 32 trillion cubic feet of gas. Israeli officials said they hope the new framework won't face legal or regulatory hurdles — the original deal was highly unpopular domestically.

Calgary company signs up propane buyer in Japan

(Dawson Creek Mirror, BC; May 24) - Weeks after bowing out of the LNG race on the British Columbia coast, AltaGas said it has reached a milestone in its bid to export a different kind of gas. On May 24, the Calgary-based company announced it had signed a deal with Astomos Energy, Japan's largest buyer of liquefied propane gas. AltaGas said the agreement is important for its proposed $500 million facility near Prince Rupert, B.C., to export 1.2 million tons of propane a year to Japan and other Asian markets.

AltaGas has yet to settle on propane suppliers, but said the plant is a key "building block" in its plan to develop more gas processing capacity in the Montney gas field in B.C. and Alberta. The gas would be transported to the Ridley Island export facility by rail. The project still needs approvals from the federal government, the Port of Prince Rupert and local governments. The company hopes to make a final investment decision by the end of 2016.

Since the start of 2016, AltaGas has walked away from two small liquefied natural gas projects proposed for the B.C. coast. They include Douglas Channel LNG, a barge-mounted LNG plant that was one of the smallest in contention, as well as the Triton LNG joint venture. The Ridley Island proposal would be Canada's first propane export terminal. AltaGas currently operates a propane export facility in Ferndale, WA.

Expanded Panama Canal to open in June; U.S. LNG industry is ready

(Bloomberg; May 25) - A century after transforming global markets, the Panama Canal is about to redraw world trade once again. Nine years of construction, at more than $5 billion, has added a third set of locks and deeper navigation channels, doubling the canal's capacity for moving cargo between the Atlantic and Pacific oceans. When the new locks open to traffic in late June, the reverberations will be felt from Asian LNG terminals to Great Plains farms, and at ports from Miami to Long Beach to Chile.

The debut coincides, fortuitously, with a surge in U.S. natural gas supplies that has shale gas producers seeking export markets. The deeper channels will be able to accommodate the kind of massive tankers that transport liquefied natural gas, shaving 11 days and a third of the cost off the typical round-trip to the Far East. Markets from Chile to China will also become more accessible for oil producers across the Americas while millions of tons of container shipments originating from Asia could start bypassing western U.S. ports and opt to dock instead along the Gulf Coast or Eastern seaboard.

For oil and gas companies suffering low prices, the drop in shipping costs will provide a needed lift. While the current locks are too small for most LNG carriers, almost 90 percent of the world fleet will be able to use the expanded canal. That will cut the round trip from the U.S. Gulf to Asia to about 20 days vs. 31 days through the Suez Canal or 34 days around Africa's Cape of Good Hope. "It certainly gives U.S. LNG producers options," said Jason Feer, of Houston-based ship broker Poten & Partners. The first of four U.S. Gulf Coast LNG export terminals under construction has started operations.

Norwegian oil minister says it's best to plan for $60 oil

(Bloomberg; May 25) - The oil market is rebalancing, but no one should count on prices recovering to $100 a barrel again, said Norway's petroleum and energy minister. Brent crude has surged more than 75 percent from a 12-year low earlier this year as a global glut shows signs of easing, bringing relief to oil companies and producing countries like Norway, which have been pummeled by the worst market downturn in a generation.

While it's "quite obvious" supply and demand will return to equilibrium, it doesn't mean Norway is planning — or even hoping — for prices to go back to what they were, Tord Lien said in a Bloomberg interview May 24. "It's better to plan for $60 and let the people who want to hope for $100, hope for $100," he said. "We saw prices hitting $140 a barrel, and that does not contribute to economic growth. Therefore I'm not hoping for it."

The collapse in prices has put Norway, western Europe's biggest oil and gas producer, at a crossroads, with investments in its offshore industry falling the most since 2000 and the government for the first time dipping into its $850 billion sovereign wealth fund to plug budget holes. State-controlled Statoil said Lien's comment on planning for $60 was a "reasonable business model." The Norwegian petroleum tax system, which includes a top tax of 78 percent but offers generous deductions for exploration and development spending, is "the best" there is and remains attractive because of its stability, Lien said.

Investment cutbacks could reduce future oil supply, Statoil says

(Bloomberg; May 25) - Global crude supplies will start to dwindle in as little as two years, boosting prices, as the industry cuts investment to weather the worst market collapse in a generation, according to Statoil. Oil companies reduced capital expenditure last year and are likely to cut it further this year and next, Statoil's chief financial officer Hans Jakob Hegge said in an interview. Lower spending means there could be a "significant effect" on crude supply after 2020, he said.

"For the first time in history, we've seen cutting of capex two years in a row and potentially we risk a third year as well for 2017," Hegge said. "It might be that we see quite a dramatic reduction in replacing the capacity and of course that will have an impact, eventually, on price." The industry reduced capital spending by 24 percent last year and is expected to cut it by an additional 17 percent to about $330 billion this year, the International Energy Agency said in February.

There are more cuts to come, Hegge said. In boom years, companies allowed costs to increase as they looked to add reserves and production. The downturn is forcing them to take a hard look at expenditures. From 2007 to 2013, companies took investment decisions on 40 mid- to large-sized oil and gas projects a year on average, according to consultancy Wood Mackenzie. That fell below 15 in 2014 and to less than 10 last year. Morgan Stanley estimates nine projects are in contention to get the green light this year.