Oil and Gas News Briefs
Compiled by Larry Persily
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Russia, Saudi leaders hold unusual call to discuss oil market

(Bloomberg; Oct. 17) - Russia and Saudi Arabia held a second, and unusual, phone call this week to discuss the OPEC+ production-cutting agreement after officials from the group warned Oct. 16 of the potential for a weaker oil market in 2021. President Vladimir Putin and Saudi Arabia Crown Prince Mohammed Bin Salman spoke Oct. 17 in what the Kremlin said was a continuation of an earlier conversation. The two discussed the OPEC+ cooperation "extensively," the Kremlin said in an emailed statement.

The latest call came two days before several OPEC+ ministers are set to discuss implementation of production cuts during an Oct. 19 meeting of the Joint Ministerial Monitoring Committee. The steering group meets monthly to analyze the market with their recommendation later reviewed by the entire group. The next full OPEC+ ministerial meeting is scheduled for Nov. 30 and Dec 1. Brent has been largely trading between $40 and $45 a barrel since July, capped by the impact of the coronavirus outbreak on global energy demand and supported by the OPEC+ production cut.

Putin and Saudi leaders haven't talked twice in the same week since April. This week's intensive oil diplomacy comes as coronavirus cases surge in Europe and the Americas, weighing on the outlook for demand over the next few months. Oil traders are now questioning whether the market would be able to absorb the OPEC+ planned production increase of nearly 2 million barrels a day in January. In private, some OPEC+ delegates debate whether the additional production should be postponed, at least a few months.

Analysts expect consolidation among U.S. oil and gas companies

(S&P Global Platts; Oct. 16) - Soft oil prices, strained balance sheets, and a lack of support from outside funders have left many U.S. independent oil and gas companies close to bankruptcy. For some, joining forces may be a way to stay solvent. Most independent producers entered 2020 on unstable footing. The oil-price crash and collapse in demand amid the COVID-19 pandemic worsened their predicament. A slow economic recovery has left many facing massive budget and operating cuts into 2021.

"Consolidation makes sense — economies of scale will enable firms to lower supply costs; less fragmentation will ensure more efficient response to price signals and inventory constraints," Morningstar analyst David Meats said. Supermajors could look to snatch up appetizing independents and mergers of equals could continue, he said.

"Industry consolidation is becoming paramount," said Matthew Portillo, managing director in the equity research department covering the exploration and production sector for Tudor Pickering Holt & Co. "Most major plays, with the exception of the Permian and maybe the Marcellus [Shale], need only one or two champions," he said. "There's a very good chance that consolidation will take down 60% to 80% of the companies we cover," Portillo said at a webinar in September.

ConocoPhillips agrees to $9.7 billion deal for Permian producer

(The Wall Street Journal; Oct. 19) – ConocoPhillips has agreed to buy Concho Resources for $9.7 billion in what would be the largest U.S. oil deal since the COVID-19 pandemic began roiling global energy markets. The combined company would easily be the largest U.S. oil independent, with significant output in the prolific Permian Basin of Texas and New Mexico, second only to Occidental Petroleum, according to a JPMorgan Chase & Co. analysis. Concho is entirely focused on the Permian and pumped 319,000 barrels a day in the second quarter, about six times what Conoco produced there.

The deal marks a strategic departure for ConocoPhillips, which has spent years shedding assets even as peers chased aggressive growth. Adding Concho, which drills exclusively in the Permian, would give the company a larger footprint in the nation's top oil basin. The deal is subject to shareholder approval and is expected to close early next year. It's the latest in a series of deals in the oil patch, where companies are bulking up to ride out weak demand and low prices, which have hovered around $40 a barrel since June, below the level many companies need to make money on new shale wells.

Devon Energy agreed last month to a $2.6 billion merger with WPX Energy, while Chevron agreed in July to buy Noble Energy for about $5 billion. It has been a brutal year for U.S. oil companies, which are suffering from prolonged weak demand for fuels during the pandemic. The companies had already been facing investor flight after failing to earn consistent profits, even as they helped lift U.S. oil output to world-leading totals.

Occidental CEO predicts U.S. will never regain record production

(Bloomberg; Oct. 14) – U.S. oil production will never again reach the record 13 million barrels a day set earlier this year, just before the pandemic devastated global demand, according to Occidental Petroleum. "It's just going to be too difficult to replace the 2 million barrels a day of production that we've lost, and then to further grow beyond that," CEO Vicki Hollub said Oct. 14 at the Energy Intelligence Forum. "Over the next three to four years there's going to be moderate restoration of production, not at high growth."

Occidental is one of the biggest producers in the U.S. shale industry, which added wells at such a rate prior to the spread of COVID-19 that the country became the world's top crude producer, overtaking Saudi Arabia and Russia. But shale's debt-fueled expansion came to a halt due to lower gasoline demand and falling oil prices, and also because of Wall Street's increasing reluctance to fund growth at any cost. Shale operators are now increasingly prioritizing cash flow and returns to investors over production growth.

Occidental, which vies with Chevron to be the biggest producer in the Permian Basin, has been forced to throttle back capital spending, lower growth targets and cut its dividend in a bid to save cash. Its finances were already severely challenged by the debt taken on through its $37 billion purchase of rival Anadarko Petroleum last year.

Libya oil production back up to 500,000 barrels a day

(Bloomberg; Oct. 16) - Libya's daily oil production has risen to around 500,000 barrels, according to people familiar with the situation, as the war-battered nation restarts its energy industry after a truce. Sharara, the country's biggest oil field, is pumping roughly 110,000 barrels a day, according to two people with knowledge of the situation. The southwestern deposit, which has a capacity of 300,000 barrels daily, restarted Oct. 11.

The halt in Libya's civil war led to many fields and ports in the east reopening last month after an almost total shutdown of energy facilities since January. Before then, Libya was producing 1.2 million barrels a day. Libya is home to Africa's largest crude reserves and the return of its barrels to the global market is weighing on oil prices just as tighter virus restrictions in many countries sap demand for energy.

The North African nation is an OPEC+ member, though it's exempt from supply curbs the cartel initiated in May to boost oil prices, which are down around 35% this year. JPMorgan Chase forecasts that Libyan output could hit 1 million barrels a day by March, though that will depend on the truce holding. Libya's oil exports averaged 385,000 barrels daily in the first two weeks of this month, up from 213,000 barrels a day for all of September, according to tanker-tracking data monitored by Bloomberg. Many of those shipments are from storage tanks at ports, rather than freshly pumped crude.

Russian producers look to cut drilling as price recovery weakens

(Bloomberg; Oct. 15) - Russia's crude oil producers are looking to cut 2021 drilling as the pandemic threatens the recovery of prices and global demand, according to one of the country's top-three independent oil-service providers. The nation's producers, which have reduced oil drilling by as much as one-third so far this year, may cut it by a further 20% in 2021, said Vitaly Dokunikhin, chief executive officer at Eriell Russia.

Russia has made unprecedented output cuts this year under a deal with OPEC that's set to last through April 2022. Though that has helped support crude prices, the market is again under pressure as the coronavirus surges, threatening oil drilling everywhere. OPEC and its allies are also debating whether to proceed with their plan to ease the output curbs in January. "Amid expectations of suppressed demand, very specific discussions are ongoing about reductions" of drilling volumes, Dokunikhin said.

The conversations with oil producers come after some respite in the summer when drilling picked up on a short-lived oil price recovery, he said. Oil field spending in Russia and the former Soviet Union is expected to tumble 31% this year to $38.7 billion, according to Evercore ISI. That would make it the world's third-hardest-hit region in the crude crash, behind North America and Africa. The cuts so far have mainly affected more expensive exploration drilling, as well as production drilling at recently launched greenfields, including in the Arctic, according to Dokunikhin.

Canada hopes to win back investors, banks for oil sands projects

(Reuters; Oct. 15) - Canada is betting that efforts to incrementally reduce greenhouse gas emissions from its oil sands deposits will win back the growing list of investors, banks and insurers that in recent years have shunned the carbon-heavy resource for environmental reasons. The list grew substantially this year, including:

- Zurich-based UBS in March said it would not finance new oil sands projects.
- Oslo-based Norges Bank in May said in would exclude several Canadian oil sands producers from the country's $1 trillion sovereign wealth fund.
- Mitsubishi UFJ Financial Group in May put oil sands extraction on its "restricted transaction" list.
- Deutsche Bank in July said it would no longer finance new oil sands projects, including exploration, production, transport, or processing.
- Insurer Zurich decided not renew coverage for the Canadian government's Trans Mountain oil pipeline that moves oil sands production to a coastal terminal.
- Dutch asset manager Robeco in September said it would exclude oil sands producers Suncor, Canadian Natural Resources, and others from sustainability funds.

BP may terminate contract to supply Caribbean refinery

(Reuters; Oct. 15) - The problem-plagued Limetree Bay refinery in St. Croix, Virgin Islands, may lose its main supplier of crude, BP, if it isn't successfully up and running by December, according to two people familiar with the matter. The refinery's owner, Limetree Bay Ventures, has spent at least $2.7 billion restoring the facility, initially hoping to tap rising demand for low-sulfur fuels and markets in Latin American and Caribbean. But the plant's restart has been delayed by nearly a year now.

BP invested in the plant with an agreement to supply its crude and market the fuels in anticipation of a late 2019 start-up. BP's investment was to be repaid from product sales. But BP can terminate that contract if the plant cannot reach a certain production target by year-end, the people said. Limetree owners EIG Global Energy Partners and Arclight Capital Partners embarked on the overhaul in expectation of a surge in demand for marine fuels that comply with new maritime rules for low sulfur content.

Limetree has experienced problems trying to restart the crude unit, according to one of the people familiar with the matter. That followed a series of delays due to corrosion uncovered during renovations. With the problems, it's less attractive for BP to remain invested in the refinery, according to sources. The oil major is in the midst of a global overhaul of its operations with plans to boost renewable investments and cut fossil fuel development, which also now makes the refinery investment less attractive. The plant has been closed since 2012. Restarting mothballed refineries is challenging, said John Auers, executive vice president at refining consultancy Turner, Mason and Co.

Petrochemical makers delay plans for U.S. Gulf Coast investments

(The Wall Street Journal; Oct. 15) - Petrochemical makers are pausing multibillion-dollar U.S. expansions as the coronavirus pandemic reduces the rapid growth in demand for plastics. Companies such as Dow and Chevron Phillips Chemical Co. collectively poured tens of billions of dollars into Gulf Coast petrochemical facilities over the past decade, eager to take advantage of the gusher in raw materials unlocked by the shale boom. They bet that ethylene and other plastic-making ingredients would juice earnings.

Surging investments in the heated market overshot demand, as sometimes happens in business. Capacity to produce ethylene rose 41% on the Gulf Coast over the past five years, according to research firm S&P Global Platts, while margins dropped more than three-quarters over that period. Executives remain optimistic that profits will return after the pandemic, but companies are reassessing future projects.

Oil giant Saudi Aramco, chemical maker LyondellBasell Industries and Chevron Phillips, a joint venture between Chevron and Phillips 66, have delayed plans for three Gulf Coast petrochemical investments totaling $17 billion. Taiwan's Formosa Plastics Group and Thailand's PTT Global Chemical also have pushed back plans for large U.S. plants. Chemical companies since 2010 have spent $96 billion to complete more than 200 projects linked to the U.S. shale industry, with a further $99 billion in projects under construction or in planning stages, according to the American Chemistry Council.

Shell's giant floating LNG project will not restart shipments this year

(Reuters; Oct. 14) - Shell said Oct. 14 its Prelude floating liquefied natural gas (FLNG) project off Australia, offline since early February, is working toward restarting operations but would not resume full production this year. The troubled 1,600-foot-long Prelude FLNG platform — essentially, a ship without propulsion — was shut down following an electrical trip and Shell has faced a number of issues over the past few months in trying to restart full production and now does not expect to ship any LNG before next year.

The company hopes to resume shipping LNG from Prelude in the first quarter of 2021, a person familiar with the situation said. The estimated $17 billion Prelude project, centered on the world's biggest floating liquefaction vessel, has been plagued with problems. It shipped its first cargo only last year, more than two years behind schedule, and has yet to achieve steady output at its capacity of 3.6 million tonnes a year of LNG.

The project is jointly owned by Shell, Japan's Inpex, Korea Gas, and a unit of Taiwan's CPC Corp. Besides LNG, Prelude also has capacity for producing 45,000 barrels per day of condensate and liquefied petroleum gas (mostly propane and butane).

LNG producers move toward reducing carbon emissions

(S&P Global Platts; Oct. 16) - Top liquefied natural gas producers, traders and consumers have outlined plans to decarbonize the LNG supply chain either fully or partially, signaling how carbon pricing is set to become a key component of LNG market competition in the coming years. This presents challenges for legacy LNG projects with limited means to reduce carbon, forcing them to rely on expensive market mechanisms like purchasing carbon offsets while new projects invest heavily in carbon-reduction technologies and "green" marketing of their product.

On the demand side, emerging markets may find low-carbon LNG prohibitively expensive, reaffirming their view of LNG as a rich man's fuel. This is likely to result in parallel markets, much like LNG carriers, where low-efficiency ships with high boil-off rates are restricted to less sophisticated buyers. Meanwhile, LNG producers are already racing to add the decarbonized label to their sales pitches.

Qatar's LNG expansion to 126 million tonnes per year by 2027 will be low-carbon based, helped by the use of renewable energy at production plants, Energy Minister Saad Sherida al-Kaabi said this week at Japan's LNG Producer-Consumer Conference. Shell, Total, BP, and traders like Vitol unveiled strategies to supply carbon-neutral LNG. So far, demand for carbon-neutral or low-carbon LNG has mainly come from Asia, and is expected to be buoyed by recent moves from Japan and China to hit long-term net-zero emissions targets. Major utilities have fallen in line with the government targets.

Korea Electric drops plans to fund two overseas coal-power plants

(Global Construction Review; Oct. 16) - Amid growing international protests, South Korea's majority state-owned utility, Korea Electric (KEPCO), said two of four overseas coal power projects it is funding will be scrapped or converted to liquefied natural gas plants. The two are the 1,000-megawatt Sual 2 project in the Philippines and the 630-megawatt Thabametsi plant in South Africa. But Kepco will still invest more than $230 million in two coal plants in Vietnam and Indonesia, prompting accusations of hypocrisy.

The announcement came 10 days after KEPCO drew condemnation for its decision to buy a $189 million stake in the heavily polluting Vung Ang 2 coal power project in Vietnam. KEPCO drew similar condemnation in June when it decided to invest $51 million in a 2,000-megawatt coal power plant in Banten province, Indonesia. South Korea has been identified as among the top three coal-power financiers in the world.

On Oct. 13, protesters gathered outside the South Korean embassy in Manila to call for scrapping the Sual 2 project, estimated to cost $1.8 billion. KEPCO Chief Executive Officer Kim Jong-gap said, "Out of the four [overseas coal power plants] projects, we decided to go ahead with two and transition the other two to gas or cancel them at this point. KEPCO and its subsidiaries will not be pursuing new overseas coal projects."

Spot LNG prices in Asia highest in 11 months as winter approaches

(Reuters; Oct. 16) - Asian spot prices for liquefied natural gas rose to their highest in more than 11 months this week, underpinned by expectations that an anticipated cold winter will stoke demand for the fuel used in heating. The average LNG price for December delivery into northeast Asia was estimated at $5.80 per million Btu, up 10 cents from the previous week. The price for November delivery was at around $5.70.

Taiwan's CPC Corp. closed a tender earlier this week to buy 12 cargoes for next year, while South Korea's Posco bought a cargo for delivery in the second half of November, traders said. Japan's Kansai Electric and Japex were seeking a cargo each for mid-December delivery while China's Guangzhou Gas was also seeking a cargo for delivery in late December, they said.

Argentina hopes higher prices will spur more gas production

(Natural Gas Intelligence; Oct. 16) - Argentina President Alberto Fernandez unveiled the country's long-awaited plan to boost natural gas production on Oct. 15 from the heart of the Vaca Muerta shale formation in Neuquen province. The president spoke from the oil and gas fields at Loma Campana, considered one of the flagship developments of

Vaca Muerta, estimated to hold more than 300 trillion cubic feet of gas. Well shut-ins there earlier this year were a symbol of a once booming industry slipping into a rut.

Fernandez said the plan would allow higher prices and spur state producer YPF to invest $1.8 billion in production over the next three years. Gas production has been in steady decline this year due to investment uncertainty in a country facing heavy external debt and mired in a three-year recession. The pandemic also slammed the upstream industry, and the country's drilling rig count fell to zero in April.

Production had grown in the past decade, and in 2018 Argentina began to export gas to neighboring countries. In 2019, it contracted a liquefied natural gas production barge to send out small-scale cargoes. But drilling in Vaca Muerta began its dramatic collapse at the end of last year. The new plan is a four-year program that will allow producers to earn a higher market price for just over half of their gas, up to $3.70 per million Btu.

Australian state ban on gas exports threatens project

(Australian Broadcasting Corp.; Oct. 14) – An oil and gas fracking project that gained support of traditional land owners after more than a year of negotiations is unlikely to go ahead under a Western Australian state gas export ban, the proponent said. Karajarri title holders in the West Kimberley signed an indigenous land-use agreement with Theia Energy just two weeks after the state government announced the export ban in August. The policy prevents onshore gas from being sold outside of Western Australia.

Theia Energy's agreement with Karajarri allows for drilling and fracking a well in the Great Sandy Desert as part of a project that proponents hope will become a major oil and gas producer. Karajarri Traditional Lands Association chief executive Martin Bin Rashid said the deal offers economic benefits while ensuring environmental protections. "We've had extensive consultation on environmental, cultural, social, and economic impacts," he said. "We see this as an opportunity to take Karajarri forward."

But Theia Energy's chief operating officer Jop van Hattum said the government policy to ban gas exports to eastern states or overseas threatens the viability of the project. "It would be unlikely to see this project go ahead if there's an absolute ban on export," van Hattum said. "We haven't had much detail on what that policy entails; there was no consultation with industry on that policy." The government declined comment. Theia Energy hopes that its Great Sandy Desert Project will develop a network of oil and gas wells with pipelines to new and existing ports in northwestern Australia.

Louisiana will vote on change in oil and gas well tax assessment

(KTBS TV; Shreveport, LA; Oct. 14) – Louisiana voters will consider a constitutional amendment Nov. 3 that would allow parish tax assessors to consider a well's production when putting a value on it for property tax assessment. Those assessments generate revenue for parish and state governments. Currently, tax assessors determine the value of an oil and gas well without considering the income it might produce. That means they are left to factor in items such as replacement of a well or its market value.

The proposed change — which is supported by assessors and the oil and gas industry — specifies that oil and gas wells' production be included when considering its value for taxation purposes. The intent is not to raise or lower taxes on the wells but rather shift the burden so that low-producing or shut-in wells are assessed less and wells with higher production are assessed more.

Assessors and the oil and gas industry came together to create the amendment after decades of disagreement. This amendment is narrow and does not affect severance taxes. The amendment would mean that newer, more productive wells would tend to be valued higher than older, poorer wells, which is not necessarily the case now.

Abu Dhabi National Oil Co. sells $2 billion stake in gas pipelines

(Bloomberg; Oct. 15) - Abu Dhabi government institutional investors are paying $2.1 billion for a stake in a natural gas pipelines unit run by Abu Dhabi National Oil Co. (Adnoc). The Abu Dhabi Pension Fund and holding company ADQ will take an indirect stake in the pipelines unit that Adnoc set up earlier this year, the oil and gas company said in a statement. Adnoc agreed in June to sell a stake in the gas pipelines business to international investors and valued the business at $20.7 billion.

The deal enables local government funds to earn returns on infrastructure assets alongside global money managers. Adnoc has raised about $16 billion so far this year from its assets and from the sale of shares in its service station unit as part of a financial and organizational restructuring the company started four years ago. Abu Dhabi, capital of the United Arab Emirates, is using its hydrocarbon wealth to attract investors to the country and generate cash from new sources.

Abu Dhabi government funds will buy 20% of a special purpose vehicle Adnoc has set up to hold its stake in the gas pipelines unit. That structure allows Adnoc to keep control of the assets.