Oil and Gas News Briefs
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OPEC+ deals with markets and geopolitics

(S&P Global Platts; Nov. 30) - OPEC+ is weighing its supply options after the U.S.-led attempt to lower prices by releasing crude stockpiles has been complicated by a steep drop in oil prices amid resurgent COVID pandemic fears. How OPEC+ responds will set the tone for oil markets in 2022. Holding back planned quota increases at its meeting on Dec. 2 will make the producer group look mean and increasingly blamed for causing rampant global inflation that is now endangering the still fragile economic recovery.

Yet, some members are calling for just such an aggressive response to the coordinated 70 million-barrel, multi-nation Strategic Petroleum Reserve release, which is equivalent to about two days of OPEC+ output. Such a strategy, however, could inflame already tense relations with the U.S., where crude trading previously over $80 per barrel had been blamed for inflation surging to a 31-year-high of 6.2% and high gasoline prices.

However, ignoring the U.S. stockpile release also carries risks. Since July, OPEC and its Russia-led allies have been raising crude quotas by 400,000 barrels per day each month, a gradual pace that has allowed them to support oil prices while largely keeping a U.S. shale production rally in check. Many forecasters and strategists now warn that continuing to increase oil output will leave the market oversupplied come January, especially if the new COVID variant restrains the global economy and oil demand.

Geopolitical considerations are influencing the OPEC+ deliberations, according to people familiar with the discussions. "Calculations don't seem to always follow market fundamentals," one OPEC+ source said on condition of anonymity.

JPMorgan says OPEC lacks enough spare capacity to restrain prices

(CNN: Nov. 29) – The surge in oil prices this year has angered drivers, tainted Americans' views on the economy and confounded both the White House and Federal Reserve. Unfortunately, JPMorgan Chase says the oil spike is just getting started. In a new report Nov. 29, JPMorgan warned clients that Brent crude will briefly hit $125 a barrel next year and $150 in 2023, in large part because OPEC doesn't have nearly as much firepower and spare capacity to respond to high prices as many assume.

"They don't have the barrels. It's a mirage," Christyan Malek, JPMorgan's head of oil and gas research and the lead author of the new report, told CNN in a phone interview. $150 oil is more than double today's Brent price of about $73.50. If that forecast proves accurate, it would likely translate to U.S. gasoline prices topping $5 a gallon. The central problem, Malek said, is that while OPEC nations have plenty of oil in the ground, they don't have the capital and logistics to deliver it quickly.

OPEC's real spare capacity, a closely watched metric that measures the amount of barrels that can swiftly be produced, stands at just 2 million barrels per day for next year, JPMorgan estimates. That is far below the average between 1995 and 2020 and well below comfort levels, JPMorgan says. When this buffer gets unusually low, prices can spike. JPMorgan is not calling for oil to sell at $125 a barrel for all of 2022. Instead, the bank is predicting crude will average $88 next year and "overshoot" to $125 at some point. Likewise, JPMorgan sees Brent averaging $82 in 2023 but overshooting to $150.

White House says it is sticking with plan to release 50 million barrels

(Bloomberg; Nov. 29) - The U.S. will proceed with its plan to release 50 million barrels of oil from its strategic reserves despite a new coronavirus variant triggering a sharp drop in crude prices. “We are not reconsidering,” White House Press Secretary Jen Psaki told reporters Nov. 29. The Biden administration announced a release from the nation’s Strategic Petroleum Reserve last week as part of an unprecedented, coordinated attempt by the world’s largest oil consumers to tame high fuel prices.

The Nov. 29 White House comment comes just before OPEC and its allies are scheduled to meet to discuss their own response to the Omicron variant. The group seems increasingly inclined to ditch their plan to raise output after the variant triggered the worst crash oil markets have seen in over a year. Also on Nov. 29, U.S. State Department senior adviser Amos Hochstein told CNBC that the administration stands ready to release even more crude from reserves should the need arise.

When asked whether the administration was concerned about the lack of details about China’s plan to release its own oil reserves as part of the multinational effort, Psaki said, “We are always encouraging any country around the world including China to be as transparent as possible on any of their policy maneuvers, but I don’t have any additional concerns to express today.”

Oil producers cut back on hedging for 2022

(The Wall Street Journal; Nov. 30) - A group of producers tracked by Raymond James reduced the share of output they hedged using derivatives by nearly half for 2022 compared with this year. No wonder. With oil and gas prices recently hitting multiyear highs, this wasn’t a great year for energy companies to lock in the price at which they sold those commodities. For example, Pioneer Natural Resources, which estimated that it took a roughly $2 billion loss through Sept. 30 due to hedges, said during an earnings call earlier this month that it will have very minimal hedging in 2022.

There are broadly two reasons for a producer to lock in prices. One is that it is required to do so because banks won't extend loans otherwise. Harder to justify is the kind of hedging strategy that reflects a producer's bet on the direction of commodity prices.

There are two schools of thought on how companies should hedge, according to Philip Verleger, energy economist with PKVerleger. One is to forgo hedging altogether so that the producer, over time, reaps the benefits and losses of fluctuating commodity prices. Major oil companies, with their large balance sheets, tend to eschew hedges, letting the chips fall where they may. The second is to have a continuous hedging strategy that doesn't stop and start based on views of the commodity market. Given the unpredictable nature of the commodity market, companies that hedge based on their views lose money over time without exception, said Paul Cheng, analyst at Scotiabank.

Nigeria changes laws in effort to boost oil investment, production

(Bloomberg; Nov. 30) - Nigeria's vast reserves of oil and gas have generated riches but have also led to decades of conflict and corruption. Resentment has fed bouts of militancy in the petroleum-rich Niger Delta, the low-lying waterways bordering the Atlantic, where minority ethnic groups have struggled for a share of the wealth. Now Nigeria's leaders want to almost triple oil output just as a warming world seeks to move away from fossil fuels. They aim to fill a void left by Shell, which pioneered development of the nation's fields more than 60 years ago but is now pulling back from Nigeria.

After years of stagnant output, the government enacted a law in August cutting taxes on companies to more globally competitive levels. Royalties will range from 5% to 15%, depending on location, down from 7.5% to 20%. The move seeks to end uncertainty that's held back investment and led to disputes. The government also wants to revamp dilapidated state-owned refineries to wean the country off imports of processed fuels. "We are in the last mile of the oil economy," Timipre Sylva, Nigeria's petroleum minister, said when the law was passed. "We are in a race to produce as much oil as we can."

Under the law, oil companies must set aside the equivalent of 3% of their spending to fund education and other projects in towns affected by exploration. While advocates had pressed for 10%, this could still amount to $500 million a year. Oil accounts for about half of government income and more than 90% of foreign exchange earnings in Nigeria, where 80 million people, about 40% of the country, live in abject poverty. Nigeria pumps 1.4 million barrels a day, less than its OPEC quota and down from 2.5 million in 2005.

[Developer gives up on LNG project for Oregon coast]

(The Associated Press; Dec. 1) - A Canadian energy company called it quits Dec. 1 on a controversial natural gas pipeline and LNG export terminal on the southern Oregon coast after failing to obtain all necessary state permits. Opponents of the Jordan Cove project, which would have created the first liquefied natural gas export terminal on the West Coast in the Lower 48 states, rejoiced at the news. The export terminal would have been built at Coos Bay, with a 230-mile feeder line crossing southern Oregon.

Many landowners, Indian tribes and environmentalists had objected, saying the $10 billion project by Calgary-based Pembina Pipeline could spoil the environment and would have contributed to global warming by producing greenhouse gases. In 2019, protesters filled the Oregon State Capitol and occupied the governor’s office until they were hauled away by police. Supporters of the project to ship U.S. and Canadian gas to Asia said it would create jobs and help the economy. The Coos Bay City Council last year approved dredging part of the bay to increase the width and depth of the channel.

The Federal Energy Regulatory Commission approved the project in March 2020, during the Trump administration. Oregon’s Democratic Gov. Kate Brown threatened to go to court to stop the project if it didn’t obtain every permit required from state and local agencies. The state had denied a water quality certification for the project, and refused to grant another extension to Pembina for a permit to dredge sediment out of Coos Bay.

Donald Sullivan, manager and associate general counsel of the project, told the Federal Energy Regulatory Commission in a notification Dec. 1 that the company has reviewed the prospects for obtaining the permits and “decided not to move forward.”

[China busy signing long-term LNG deals, many with U.S. suppliers]

(S&P Global Platts; Dec. 1) - China's rush for long-term LNG contracts with the U.S. has been triggered by record high spot prices, but the deals also reflect pent-up demand for uncontracted volumes, attractive pricing offered by suppliers, the benefits of U.S. LNG such as destination flexibility, and optimism about future demand growth. And the deals come amid signs of cooperation between the two nations on trade, climate and energy, and with China becoming the world's single-largest LNG importer, surpassing Japan.

So far this year, at least eight Chinese companies, including state-owned national oil companies, have signed nearly a dozen long-term contracts with overseas suppliers, for a volume of nearly 25 million tonnes per year, more than half of which were signed in the September-November period when spot LNG prices hit record highs. Many are with U.S. suppliers. That almost equals a third of China's annual LNG imports, and does not even include the short-term deals and preliminary agreements signed this year.

Only one long-term contract was signed in 2020, by a Chinese gas buyer with U.K.'s Centrica, when the pandemic had stalled interest across the industry. Several aspects of these latest deals are notable: 15- to 20-year deals are common despite the market veering toward shorter terms; more than 40% of all of China’s deals were for U.S. LNG; and market sources reported surprisingly low liquefaction fees to entice buyers.

The share of U.S. LNG in China's imports had been relatively low because of the recent trade wars and record low spot prices that disincentivized long-term contracting activity. In the first 10 months of 2021, Australia was China's single-largest supplier at 25.9 million tonnes, but its share of total imports dropped to 39.7% from 43% in 2020. Meanwhile, U.S. LNG accounted for just 11% of China's total in 2020, up from 3% in the previous year. The U.S. is set to be the second-largest supplier to China in 2021.

Novatek lines up $10.8 billion bank financing for Arctic LNG-2

(Reuters; Nov. 30) - Russian gas producer Novatek said on Nov. 30 that its Arctic LNG-2 plant has signed loan agreements with foreign and Russian banks worth 9.5 billion euros ($10.8 billion), securing necessary external financing for the project. Earlier this year, Novatek shareholders approved external financing of $11 billion for the $21 billion project, which is expected to start production of liquefied natural gas in 2023.

Novatek has had difficulty in securing funds from Europe, wary of political stand-off with Russia as well as calls against tapping hydrocarbons in the Arctic amid efforts to tackle climate change. Among participating lenders, Novatek said Chinese financial institutions, including the China Development Bank and Export-Import Bank of China, signed credit agreements totaling 2.5 billion euros (US$2.8 billion) for up to 15 years.

Financial institutions from other countries signed credit facility agreements totaling up to 2.5 billion euro. This includes the Japan Bank for International Cooperation and other lenders insured by export credit agencies. Novatek has not disclosed the other international lenders involved in the deal. Sources told Reuters earlier this month that Italy's SACE may insure a loan of around 500 million euros for Arctic LNG-2. The financing to be provided by a syndicate of Russian banks will total 4.5 billion euros under the credit facility agreement. Arctic LNG-2 is expected to be launched in 2023 and reach full LNG production capacity of almost 20 million tonnes a year in 2026.

Saudi Aramco awards $10 billion in contracts to develop shale play

(S&P Global Platts; Nov. 29) - Saudi Aramco expects its Jafurah shale play to yield up to 2 billion cubic feet of gas per day, 418 million cubic feet per day of ethane and 630,000 barrels of oil equivalent of gas liquids and condensates by 2030, as the company ramps up its development of unconventional resources. Awarding engineering and construction contracts worth $10 billion for work at the field on Nov. 29, Saudi Aramco said the projects will expand its gas production, while also providing feedstock to support growth in its chemicals and hydrogen sectors.

Jafurah is located in Saudi Arabia's Eastern Province and is the kingdom's largest discovered non-associated gas reservoir with some 200 trillion cubic feet of resource, Aramco CEO Amin Nasser said at the contracts' signing ceremony. Aramco averaged 9.03 bcf per day of gas production in 2020, according to its most recent annual report. The bulk of the output comes from associated gas pumped along with Saudi Arabia's massive crude oil production.

Aramco announced ambitious plans for the Jafurah Basin in 2020, with many observers questioning the cost-effectiveness of developing the field, compared to its relatively low-cost conventional reserves. Fracking to access the shale gas requires major volumes of water, a resource Saudi Arabia lacks in abundance. Saudi officials, however, said developing Jafurah is central to the kingdom's goal of achieving net-zero emissions by 2060. Nasser said the gas produced from Jafurah would displace more than 300,000 barrels per day of crude that would otherwise be used for domestic power production.

New investments in Papua New Guinea gas could total $18 billion

(Reuters; Nov. 30) - ExxonMobil sees its P'nyang gas project and the separate but coordinated Papua LNG project, led by TotalEnergies, investing more than $18 billion in Papua New Guinea over a decade, Exxon’s managing director in the Pacific nation said on Dec. 1. Exxon is in talks with the government of Papua New Guinea to seal an agreement on development of the P'nyang gas field, which will feed its 7-year-old PNG LNG plant after its existing gas sources run down.

The PNG LNG plant produces about 8 million tonnes per year. Exxon, Total and other partners are looking to more than doubling Papua New Guinea’s gas production and exports by adding liquefaction capacity to the existing plant and developing new fields.

Environmental group will challenge Australia LNG expansion

(Reuters; Nov. 30) - Woodside Petroleum said on Nov. 30 that an environmental group will challenge the government's decision to approve the expansion of the company’s Pluto LNG terminal over concerns of environmental harm caused by greenhouse gas emissions. The Conservation Council of Western Australia will challenge the state's approval for a second liquefaction train at the project in the Burrup Peninsula.

The company and BHP Group recently approved A$12 billion to develop the offshore Scarborough gas field and Pluto expansion, which are essential to Woodside, the country’s biggest independent oil and gas company. Scarborough, slated to produce feed gas for 8 million tonnes of LNG a year for export and gas for the domestic market, is expected to revive Woodside, which has had limited growth the past several years.

The environmental group says the government approval was unlawful as it did not properly consider the project's environmental harm, alleging it would more than double the annual greenhouse gas emissions from the Pluto facility. This is the second challenge to Scarborough from the group, with the first being launched in December last year and set for its first hearing next month.

Natural gas prices, winter supply risks could get worse in Europe

(Bloomberg; Nov. 29) – Natural gas prices in Europe are repeatedly breaking records even before winter really kicks in, and one of the most damaging cost crunches in history is about to get worse as the temperature starts to drop. A super price spike in the U.K. last month forced some industrial companies to cut output and seek state aid, a harbinger for what could play out in Europe as it contends with a COVID resurgence.

The trouble is that any fix is unlikely to come from the supply side any time soon, with exporters Russia piping only what it has to deliver and Qatar saying it’s producing as much liquefied natural gas as it can. The energy industry is instead faced with relying on “demand destruction,” said Fabian Roenningen, an analyst at Rysted Energy. “We have seen it over the last couple of months already, and in many industries it will most likely continue and even increase,” he said from Oslo. “It’s just not profitable to operate for a lot of the players in the current market conditions.”

The outlook adds to the sense of foreboding in Europe. The region is back at the epicenter of the pandemic again with COVID-19 cases surging and fears about a new variant identified in South Africa swirling the globe. Meanwhile, France, Europe’s second biggest economy, is particularly at risk. The possibility of a chill in January and February is causing concern for the nation’s grid operator. Availability at nuclear stations, the workhorse of the French power system, is low after the pandemic delayed the maintenance of some reactors, according to a report on Nov. 22.

China struggles with coal’s role in future power generation

(S&P Global Platts; Nov. 30) - Chinese policy makers and top power utilities have adjusted their stance on coal-fired power generation after the recent energy crisis, and have called for a more realistic assessment of the energy transition instead of impulsive plant closures that endanger energy security.

The reassessment includes making room for gas in the energy transition as a bridging fuel with efforts to cut in half the emissions footprint of coal, as well as keeping coal plants as back-up power instead of complete decommissioning until technologies and costs to solve the intermittency of renewables meet a certain threshold.

"Coal-fired power plants are required to be upgraded and retrofitted, however, where does the money come from?" Chen Zongfa, deputy general counsel with China Huadian Corp., one of China's largest state-owned generation utilities, said at a recent industry forum. China Huadian was one of the generation utilities impacted by soaring coal prices and regulated electricity prices in recent months. The double whammy on margins has left utilities with fewer resources to fund decarbonization efforts.

"Since 2007, 294 gigawatts of coal-fired power capacity have been phased out. It is reasonable to phase out the excessive coal-fired power capacity. Is it necessary to phase out so much? Are they being phased out in a proper way?" Chen said.

Putin highlights energy cooperation between Russia and China

(Barents Observer; Norway; Nov. 29) - In his greetings to the third Russian-Chinese Energy Business Forum on Nov. 29, President Vladimir Putin started by praising the good relations between the two countries. Putin highlighted the energy cooperation and said it “has developed significantly in recent years.” He pointed to Russian gas going by pipeline to China, Russian coal, China’s investment in Russian Arctic LNG projects, and Russian-designed reactors for two Chinese nuclear power plants.

“An effective mechanism for direct dialogue between companies in our countries operating in various sectors of the fuel and energy complex is the Russian-Chinese Energy Business Forum,” Putin said.

New Mexico watchful of seismic events linked to disposal wells

(The Associated Press; Nov. 29) - New Mexico oil and gas regulators are watching closely as increased seismic activity is being reported in the Permian Basin along the Texas state line. Under a plan recently rolled out by the New Mexico Oil Conservation Division, pending permits for wastewater injection in certain areas will require extra review. More reporting and monitoring also could be required and if things worsen. New Mexico could limit how much wastewater is injected into underground disposal wells.

State officials say the protocols were developed in partnership with the New Mexico Institute of Mining and Technology and after getting feedback from the oil and gas industry. Division Director Adrienne Sandoval said New Mexico is trying to be proactive with what she described as a pragmatic approach. “While some of the biggest (seismic) events have occurred over the state line in Texas, the time is now to ensure larger events do not occur in our part of the oil field," she said in a statement.

The protocols call for reporting and monitoring when two magnitude 2.5 quakes occur within 30 days and within a 10-mile radius. Within that area, operators will be required to provide weekly reports on daily injection volumes and average daily surface pressure and share that with the state when requested. If one magnitude 3.0 occurs, operators will have to reduce their injection rates — with higher reductions required closer to the epicenter. Between March and September, the state received reports of seven earthquakes with magnitudes from 2.5 to 4.0 in an area of southeastern New Mexico.

Texas city faces decision on drilling site near day care center

(The Associated Press; Nov. 30) - At a playground outside a North Texas day care center, preschoolers chase each other into a playhouse. Toddlers scoot by on tricycles. A boy cries as a teacher helps him negotiate over a toy. Uphill, peeking between trees, is a site where TotalEnergies is drilling for natural gas. The French energy giant wants to drill three new wells on the property next to Mother's Heart Learning Center, which serves mainly Black and Latino children. The three wells, along with two existing ones, would lie about 600 feet from where the children planted a garden of sunflowers.

For the families of the children and for others nearby, it's a prospect fraught with fear and anxiety. Living too close to drilling sites has been linked to a range of health risks, especially to children, from asthma to neurological and developmental disorders. And while some states are requiring energy companies to drill farther from day cares, schools and homes, Texas has taken the opposite tack: It has made it exceedingly difficult for localities to fight back.

The city council in Arlington, a city situated between Dallas and Fort Worth, last year denied Total's drilling permit request. Many residents worry this time Total will succeed. Drilling is supposed to occur no closer than 600 feet from day care centers or homes in Arlington, population about 400,000. But companies can apply for a waiver from the city to drill as close as 300 feet. Some Arlington council members said they fear litigation if they don't allow drilling. That's because a Texas law bars localities from banning, limiting or even regulating oil or gas operations except in limited circumstances.

North Dakota looks to infrastructure bill for well cleanup

(Bismarck Tribune; North Dakota; Nov. 27) - North Dakota's top oil regulator wants to extend the state's abandoned well-plugging program by tapping into $4 billion made available in the federal infrastructure bill for the purpose of cleaning up old oil and gas sites across the nation. Tens of millions of dollars could potentially come North Dakota's way each year over the next decade to continue the work that the state Oil and Gas Division started in 2020 to clean up hundreds of wells.

Other oil and gas states also are eligible to apply, and advocates for North Dakota landowners say the rest of the country could learn from the state's experience. The funding is meant "to tackle this problem nationwide and to improve state regulations and federal regulations so that the problem not only doesn't continue to grow but doesn't continue to extend," State Mineral Resources Director Lynn Helms said. North Dakota spent tens of millions of dollars in federal coronavirus aid plugging more than 300 abandoned wells and reclaiming the sites over the past two years.

State officials billed the program as a way to keep oil workers employed when the pandemic prompted a downturn in their industry, as well as addressing the growing number of abandoned wells. Reclamation work in North Dakota over the past two years has cost $148,000 per well on average but it can vary widely, according to data from the Oil and Gas Division. One site cost nearly $1.9 million. That's in addition to the plugging process, which takes place first and costs $134,000 on average per well.

Regulator rejects plan to turn Canadian oil line into contract carrier

(Reuters; Nov. 27) - The Canada Energy Regulator (CER) on Nov. 26 rejected Enbridge's plan to sell nearly all space on its Mainline oil pipeline under long-term contracts, rather than rationing it on a monthly basis. The regulator said the change would have dramatically changed how shippers gain access to the 70-year-old Mainline, benefiting some with shippers while hurting others that lack contracts. "Overall, Western Canadian oil producers could suffer too many negative consequences," the CER said.

A new proposed framework for setting tolls to move oil would also "excessively favor" those with contracts, the regulator said. Enbridge planned to sell 90% of the line's capacity under long-term contracts on the 3 million-barrel-per-day Mainline. Canada's longest oil pipeline system moves oil from Western Canada to refineries in Eastern Canada and the U.S. Midwest. Enbridge applied for the change in 2019 when demand for the Mainline greatly exceeded its capacity. That congestion has since eased.

Any party can appeal the decision to the courts. Fourteen shippers, representing 75% of the Mainline volume and primarily companies with refineries, expressed support for Enbridge, including Canadian producers Cenovus Energy and Imperial Oil. BP and Marathon Oil, which have U.S. refineries, were also Enbridge's supporters. Canada's biggest producer, Canadian Natural Resources, was among the opponents, and said it is pleased with the ruling. The current system will remain in effect on an interim basis.