Oil and Gas News Briefs
Compiled by Larry Persily
November 16, 2020

Louisiana LNG project wants 'real commitments,' no more MOUs

(Bloomberg; Nov. 12) – Tellurian said it is in talks with unidentified Asian companies to sell almost half the liquefied natural gas output from its proposed Louisiana export terminal, Chairman Charif Souki said in an interview. Just hours after Indian gas distributor Petronet LNG's chief executive officer signaled a plan to invest in Tellurian's Driftwood LNG project is dead, Souki told Bloomberg News that he has other investors interested in buying 12 million tonnes a year of the terminal's production capacity.

Those deals will be finalized during the first half of 2021, with construction expected to begin during the summer, Souki said Nov. 12. He also said Tellurian no longer will employ memorandums of understanding as preludes to binding agreements. The talks between his company and Petronet were governed by an MOU that is scheduled to expire next month. "We view an MOU as a moral commitment, but we're no longer looking for moral commitments," Souki said. "We're looking for real commitments."

Total remains Tellurian's only customer. The French oil giant has committed to invest $500 million and buy 2.5 million tonnes annually from the project that Tellurian has promoted at up to $28 billion for almost 28 million tonnes annual capacity. Tellurian cut almost 40% of its staff in March to preserve cash, which it was burning through at more than $9 million a month. Tellurian shares plunged 28% on Nov. 12 after Petronet's acting CEO said the company would not invest in the project or sign a long-term deal.

U.S. LNG developers face price challenges in making deals

(Natural Gas Intelligence; Nov. 12) - The global liquefied natural gas supply glut, exposure to European pipeline gas price risk and Asian gas price controls make it difficult for U.S. LNG export project developers to sign long-term deals indexed to U.S. natural gas benchmark Henry Hub prices, according to an industry executive. Potential customers are "looking at a current price scenario of $4 to $5 per million Btu and we're trying to sell something significantly more expensive that has a 20-year term with it; it's a tough sell in this market," said Magnolia LNG commercial director Vince Morrissette.

He spoke Nov. 10 at the LDC Natural Gas Forum in San Antonio. New York City-based Glenfarne Group in June acquired the Magnolia project near Lake Charles, Louisiana, from Australia's Liquefied Natural Gas Ltd. The $2 million purchase price was agreed to after other deals with potential buyers fell through, as Magnolia had not secured any long-term customer deals to finance construction. Glenfarne has said it plans to sign enough deals to fund Magnolia and its smaller Texas LNG project next year.

Like most U.S. LNG projects, Magnolia would sell liquefaction capacity on a take-or-pay basis for at least 20 years. Customers would separately pay for feed gas and pipeline tariffs to the terminal. With liquefaction fees estimated around $2 to $2.50 and Henry Hub futures prices of $2 to $3 through 2032, U.S. LNG would likely cost $5 to $6 before shipping and regasification. Potential European customers increasingly want to buy U.S. LNG at prices linked to Europe's gas benchmark price to avoid the risk of paying more for U.S. gas than they would pay for European pipeline gas, Morrissette said.

Magnolia management expects Southeast Asia to be an important market for the project, but signing deals is often difficult because governments place domestic gas price caps that are lower than the landed cost of long-term U.S. LNG, Morrissette said.

India's top gas importer looks to drop plan to invest in U.S. LNG

(Reuters; Nov. 12) - India's Petronet LNG has no plans to invest in liquefied natural gas developers as the market is awash with cheaper fuel, its finance chief said, indicating it may shelve its plans to invest in Tellurian's proposed Louisiana project. Petronet, India's top gas importer, has until the end of December to consider exercising its option to invest $2.5 billion for 5 million tonnes per year of LNG in Tellurian's Driftwood project.

"Right now, we get LNG at throwaway prices so there is no need … for an investment," VK Mishra said at an analyst conference on Nov. 12. The deal with Tellurian is a non-binding memorandum of understanding and there is no commitment, Mishra said, adding that the company also is in talks for new long-term LNG supply contracts linked to spot-market prices rather than the more traditional oil-price-linked LNG contracts. Spot prices generally are lower in an oversupplied market, but that can change.

India has been scouting for cheap gas for its price-sensitive consumers as Prime Minister Narendra Modi wants to raise the share of gas in the nation's energy mix to 15% by 2030 from the current 6.2% to reduce air pollution. Petronet already has long-term deals to purchase 7.5 million tonnes per year of LNG from Qatar and 1.44 million tonnes per year from ExxonMobil's Gorgon project in Australia.

Strong gas demand growth could require $2 trillion capital by 2040

(Reuters; Nov. 12) - Rapid demand growth for natural gas expected through 2040 as countries implement clean-air policies will require capital of $2 trillion to develop about 200 billion barrels of oil equivalent of new gas resources, consultancy Wood Mackenzie said. Asia's gas demand could grow by an average of nearly 3% a year over the next two decades, with demand expected to double in China and India by 2040 as current low prices boost pro-gas policies, the company said in a report released Nov. 12.

The demand growth will need about $1.36 trillion in capital investment to bring known reserves and yet-to-find resources on-stream, with proposed liquefied natural gas projects requiring an additional $0.6 trillion, Wood Mackenzie said. However, the Paris Agreement goal of limiting the rise in world temperatures could see gas demand peak earlier and "dramatically alter this outlook," requiring a much lower capital investment of $700 billion, the research company said.

As investors globally increasingly focus on low-carbon projects, the gas market's carbon intensity will come under scrutiny, Wood Mackenzie said. Though burning gas emits less planet-warming carbon dioxide than coal per unit of energy, climate scientists have warned that the industry's rapid growth as well as leaks of methane — a potent greenhouse gas — threaten efforts to limit climate change. LNG buyers in Asia are increasingly asking for more transparency on carbon emissions.

Occidental first U.S. major to aim for net-zero emissions

(Bloomberg; Nov. 11) - Occidental Petroleum became the first major U.S. oil producer to aim for net-zero emissions from everything it produces and sells, accelerating an industry trend commonplace in Europe. The Houston-based company announced a target to reach net-zero emissions from its own operations by 2040 and an ambition to do the same from customers' use of its products by 2050, CEO Vicki Hollub said during a conference call with analysts on Nov. 10.

The plan relies heavily on capturing carbon dioxide and burying it, a technology that's so far been prohibitively expensive. The announcement comes weeks after U.S. rival ConocoPhillips unveiled plans to curb climate-damaging pollution from its operations but the company did not address emissions generated by customers. The latter account for about 80% of the total emissions from a barrel of crude.

U.S. oil producers have been hesitant to adopt the sort of aggressive climate goals of European peers, in part because it would require a pivot away from the shale revolution that made U.S. oil relevant again in global markets. Occidental's announcement is significant because the company has one of the biggest footprints in the Permian basin, the sprawling oil field beneath Texas and New Mexico that produces more crude than any other region on the continent. Occidental would be the first major U.S. oil company to target emissions by consumers that burn its products, according to BloombergNEF.

OPEC trims demand forecast for 2021

(The Wall Street Journal; Nov. 11) - Coronavirus lockdown measures in Europe and weakening consumption in the Americas will result in global oil demand taking a larger hit in 2020 than previously expected, the Organization of the Petroleum Exporting Countries said Nov. 11. In its closely scrutinized monthly report, OPEC deepened its forecast for a drop in global oil demand in 2020 by 300,000 barrels a day to 9.8 million barrels a day, a 10% drop from last year's levels. The cartel also softened its forecast rebound in demand for 2021 by 300,000 barrels a day.

Those cuts, combined with the organization's resilient non-OPEC supply forecasts and cut to its 2021 global growth rebound forecast — now 4.4%, down from 4.5% previously — present a dismal outlook for oil markets in the coming months. OPEC hedged its forecasts, saying that "further [economic] support, currently unaccounted for, may come from an effective and widely distributable vaccine as soon as the first half of 2021."

Even with recent gains in crude prices, the short-term outlook for the oil market remains gloomy. Fresh lockdown measures aimed at slowing the spread of the virus in Europe and rising oil supply present two challenges in 2020's final quarter, said Giovanni Staunovo, commodity analyst at UBS Wealth Management. Weak transportation demand and a slower-than-hoped economic recovery in the U.S. added to shutdowns in Europe, prompting OPEC to cut its demand forecast for the wealthy countries of the Organization for Economic Cooperation and Development by 500,000 barrels a day.

IEA revises downward its global oil demand forecast

(The Wall Street Journal; Nov. 12) - Global oil markets may have rallied on the latest positive vaccine trial results, but they are unlikely to feel any significant economic benefits until well into next year, the International Energy Agency said Nov. 12. In its monthly report, the IEA darkened its outlook for crude consumption in the months ahead, citing resurgent COVID-19 infection rates in the U.S. and Europe. It now expects demand for 2020 to fall by 8.8 million barrels a day this year — 400,000 barrels a day more than its last forecast.

The agency also slashed its demand forecasts for the third and fourth quarters of 2020 as well as the first quarter of 2021, all while estimating a supply increase of more than a million barrels a day in November. Libyan supply is rebounding from its months long export blockade and U.S. production is recovering after hurricane shut-ins in October.

Meanwhile, despite the best efforts of the Organization of the Petroleum Exporting Countries and its allies to balance the market with production cuts, the world has failed to winnow away much of the glut of crude that prompted steep price drops in the spring. Stockpiles held by Organization for Economic Development and Cooperation member nations in September were only 4% below their May highs, according to the IEA.

OPEC+ has little choice but to extend output curbs past January

(Bloomberg commentary; Nov. 14) - The Organization of Petroleum Exporting Countries and its allies meet at the end of the month to decide the future of their record output cuts that helped put a floor under oil prices. Hopes had been high they could ease their restraint as planned in January, but headwinds to the recovery in global oil demand and rising production from countries outside their control mean they'll have to wait.

The pandemic's persistence means the producers can't relax just yet. It's little surprise, then, that the OPEC+ group is getting concerned. It will still be many months before enough people have been inoculated with vaccines to alter the pandemic's path significantly. Until then, the types of restrictions that have slashed oil demand this year remain key tools to slow the virus's spread. That's a problem for producers.

The other headache is rising supply. Libya, not limited by the OPEC+ deal, is restoring production much more quickly than anticipated after a devastating civil war. Output on Nov. 13 reached 1.145 million barrels, up from just 90,000 barrels a day in September. In total, OPEC+ can't afford to relax its output restraint in January. Likewise, they are unlikely to try to agree to deepen the cuts — that would open too many arguments at a time when they need to show unity. Their only realistic option is to delay the January easing of cuts, with the only real question they have to answer: For how long?

U.S. petroleum stockpiles still 7% above 5-year average

(Reuters commentary; Nov. 15) - U.S. petroleum inventories are gradually normalizing as output curbs by OPEC+ and processing restraint by refiners push the oil market back toward balance. But with stocks of crude and distillates still well above the five-year average, OPEC+ and refiners will need to maintain discipline until at least March to avoid renewed downward pressure on prices. U.S. commercial petroleum inventories are 7% above the previous five-year average, down from a surplus of 14% in mid-July.

Commercial inventories have fallen in 15 out of the past 16 weeks, a sign the oil market is undersupplied as a result of production cuts by OPEC+. Undersupply is gradually reversing the overproduction from earlier in the year during the first wave of pandemic-related lockdowns and the market war between Saudi Arabia and Russia. Nonetheless, U.S. commercial crude stocks are 31 million barrels (7%) above the five-year average while distillate inventories are 19 million barrels (14%) above average.

If the current rate of inventory drawdown is sustained, stocks are likely to return to their five-year average toward late February. But that assumes the second-wave of the novel coronavirus and pandemic control measures do not have a further adverse impact on oil consumption over the next few months. It would be risky for OPEC+ to proceed with its scheduled production increase at the start of next year, which would probably push the market back toward overproduction and result in a renewed increase in inventories.

U.S. shale acreage plunges in value an average 70%

(Houston Chronicle; Nov. 12) - Crude prices and energy stocks aren't the only things that plunged during this historic oil downturn. Land prices in shale plays across the U.S. have also plummeted. The average price of U.S. shale acreage has fallen by more than 70% in two years, plunging to $5,000 per acre in 2020 from $17,000 per acre in 2018, according to Rystad, a Norwegian energy research firm. "We do not foresee demand for (oil) assets rising in the coming quarters," said Alisa Lukash, a senior analyst at Rystad.

The value of oil and gas assets have plunged as the coronavirus pandemic crushed crude demand globally. Most energy companies are slashing costs instead of purchasing new land for oil and gas drilling. Oil and gas companies that are forced to sell into this down market have lost money on deals. Occidental Petroleum, which is relying on asset sales to pay down the massive debt incurred from its 2019 acquisition of rival Anadarko Petroleum, said this week that it lost $700 million from its sale of assets in Colombia and Wyoming because of low crude prices.

Despite the downturn, some oil and gas acreage is still more valuable than others, Rystad said. The Permian-Delaware Basin, at $30,000 per acre, and the Midland Basin, at $17,000 per acre, are still leading in terms of U.S. acreage prices.

Buyers benefit from falling prices for drilling rights

(Bloomberg; Nov. 12) - The price to drill an acre of land in the biggest U.S. shale basin has tumbled amid the oil rout, creating conditions ripe for more mergers and acquisitions. Drilling rights in the Permian Basin of West Texas and New Mexico averaged about $24,000 an acre in recent deals, down 67% from 2018, according to Rystad Energy, an Oslo-based research firm. Across U.S. shale, the average price has plummeted to about $5,000 an acre, compared with $17,000 two years ago.

The plunge in acreage prices is a sign of the crisis facing U.S. oil and gas explorers that are grappling with a pandemic-driven slide in crude demand after more than a decade of debt-fueled production growth. Large, financially stable producers are gobbling up smaller peers amid a wave of takeovers, the biggest of which was ConocoPhillips' recent deal to buy Concho Resources for $9.7 billion.

Permian-focused Concho's drilling rights were valued at about $10,471 per acre in the proposed ConocoPhillips takeover announced last month, according to Bloomberg

Intelligence. That compares with $75,504 an acre for Concho's purchase of RSP Permian in 2018. Industry-wide costs for drilling and completing wells will probably drop as much as 5% next year because of consolidation, increased standardization and a drop in service costs, Rystad said.

Judge blocks drilling permits in Wyoming, calls BLM analysis 'sloppy'

(The Associated Press; Nov. 13) - A federal court judge once again blocked new oil and gas drilling permits on Wyoming public lands in a ruling Nov. 13 that rebuked the Trump administration for its "sloppy and rushed" analysis of climate change impacts. U.S. District Judge Rudolph Contreras said the administration's Bureau of Land Management failed to look closely enough at climate-change impacts from oil and gas extraction and consumption on almost 500 square miles of land in Wyoming.

Contreras first blocked drilling on the parcels in 2019, saying the bureau needed to consider greenhouse gas emissions from fuels extracted on public lands in the past, present and foreseeable future, including in neighboring states such as Colorado and Utah. In the Nov. 13 ruling, he said the bureau's latest effort to tally up the impact of those emissions had again failed and "does not adequately consider the climate change impacts of the oil and gas leasing decisions."

The judge pointed to numerous flaws in the bureau's climate-change assessment such as failing to consider the cumulative impacts of multiple lease sales over time. He also highlighted math errors that "suggests a sloppy and rushed process" lacking scientific accuracy. The ruling marks the latest in a string of court actions over the past decade that have faulted the U.S. for inadequate consideration of greenhouse gas emissions when approving oil, gas and coal projects on federal land. The case in Wyoming originated with leases that were sold in 2015 and 2016, under President Barack Obama.

Michigan wants to pull 67-year-old pipeline easement

(Calgary Herald; Nov. 13) - North America's largest pipeline company Enbridge warned of "devastating consequences" on Nov. 13 after Michigan Gov. Gretchen Whitmer served the company notice that the state would seek to cancel a 67-year-old pipeline easement across critical waterways in her state. In escalating a longstanding environmental dispute, the state filed a lawsuit seeking to cancel the easement granted in 1953 to cross the Straits of Mackinac, which connects lakes Michigan and Huron.

If the easement were pulled, Enbridge would have to stop flowing oil and natural gas products like propane through its Line 5 pipeline, which connects western Canadian production with refineries in Ontario and across the U.S. Midwest. A shutdown of the line could send gas prices higher in Canada and the Midwest, the company said. The notice is the latest salvo in a prolonged legal tussle over the pipeline. The notice says the easement "is being terminated based on Enbridge's longstanding, persistent, and incurable violations of the easement's conditions and standard of due care."

In its suit filed Nov. 13, Michigan is asking for a permanent injunction requiring Enbridge to cease operating the line within 180 days and permanently decommission the pipeline. A shutdown could affect refineries processing 846,000 barrels of oil per day in Ontario, Michigan, Ohio, and Pennsylvania. Line 5 also supplies about 65% of the propane for winter heating in Michigan's Upper Peninsula, New York-based Eight Capital analyst Phil Skolnick said. Enbridge is seeking state and federal permits to replace the old pipe with a new line protected inside a $500 million underwater tunnel through bedrock.

Minnesota approvals move Enbridge closer to oil line project

(The Associated Press; Nov. 12) - Minnesota regulators granted a stack of important permits and approvals Nov. 12 for Enbridge Energy's Line 3 oil pipeline replacement across northern Minnesota, setting the long-delayed $2.9 billion project on the road toward beginning construction soon. The approvals from the Minnesota Pollution Control Agency and Department of Natural Resources clear the way for the Army Corps of Engineers to issue the remaining federal permits, which is expected fairly quickly.

The pollution control agency could then approve a final construction storm water permit that's meant to protect surface waters from pollutant runoff. Environmental and tribal groups have been fighting the project for years. They contend it threatens pristine waters where Native Americans harvest wild rice and that production of the Canadian oil sands crude the line would carry would aggravate climate change.

Line 3 — which runs from Alberta across North Dakota and Minnesota to a terminal in Wisconsin — was built in the 1960s but is deteriorating and can run at only about half-capacity. Enbridge says replacing it will allow it to move oil more safely. New sections of the 1,097-mile line in Canada, North Dakota, and Wisconsin are operating, but the work in Minnesota has been moving through regulatory agencies and the courts for six years. A court appeal is pending from the Minnesota Department of Commerce, which argues that Enbridge failed to conduct a legally adequate long-range demand forecast.

U.S. gas industry dependent on global economy, BP official says

(S&P Global Platts; Nov. 11) - The track of the coronavirus pandemic and global demand for LNG will be major drivers of demand for U.S. natural gas through the coming year, the head of one of BP's largest North American subsidiaries said. Demand for gas to be liquefied and exported from the U.S. has recovered beyond pre-pandemic levels to nearly the maximum capacity of the six operating U.S. terminals, Orlando Alvarez, president and CEO of BP Energy, told the LDC 2020 Natural Gas Forum.

Europe, however, which is leading demand for the fuel, could see its LNG intake drop amid new lockdowns caused by a second wave of the coronavirus, Alvarez said. The pandemic's impact on fuel demand throughout the world could still have a major effect on gas demand in the coming year. "We're not through it yet, and how that manifests itself through the year 2021 is important," Alvarez said Nov. 10.

The U.S. natural gas industry "is more dependent on the global economy than it's ever been, and that's exacerbated by the COVID-19 and everything else that's going on," he said. "If you think about your projection for what you think is going to happen to gas prices ... more than ever you need to stay glued to what's going on in the rest of world because that's impacting our U.S. prices as much as I've ever seen."

Chinese refiner finds new use for supertankers on first voyage

(Bloomberg; Nov. 12) - China's biggest refiner is eyeing a novel strategy to help rid Asia of a persistent diesel glut — new supertankers usually reserved for crude oil. Unipec, the trading arm of China's biggest oil refiner Sinopec, hired a newly built very large crude carrier to load low-sulfur diesel in Asia to take to Europe. The vessel ordinarily would have sailed empty from its shipyard in Northeast Asia to the Middle East or West Africa, where it would pick up crude for delivery to customers across the globe.

While supertankers are built to transport dirty fuels such as crude oil, they can carry cleaner products like gasoline and diesel on their maiden voyage. Unipec intends to charter brand new vessels on a regular basis to transport more diesel to Europe, thereby clearing out bloated fuel stockpiles in Asia, according to two traders familiar with the matter who asked not to be identified as the information is private.

Asia has traditionally been an exporter of diesel to Europe as well as Africa. The difference now is that the new supertankers allow traders to at least double the size of their cargoes compared to long-range vessels, usually the largest reserved for refined fuels. "This is definitely good news for Asia refiners. Moving these barrels out of Asia will tighten supplies and support regional margins," said Serena Huang, senior analyst at Vortexa. Unipec isn't alone. Up to four fresh supertankers, chartered by trading houses and oil majors, are expected to ship diesel west of the Suez Canal in November.

Saudi oil revenues insufficient to cover government payroll

(Argus Media; Nov. 13) - Saudi Arabia will not earn enough from its oil this year to cover the state payroll, according to Crown Prince Mohammad bin Salman. He said projected oil revenues of 410 billion riyals ($109 billion) this year undershoot the budgeted 504 billion government wage bill. Before the oil price collapsed earlier this year, the government had budgeted for oil revenues of 513 billion riyals.

Non-oil revenues will cover the gap this year, Prince Mohammad said. The government tripled Saudi Arabia’s value-added tax (VAT) from 5% to 15% in July and reduced bonus and benefit payments for government workers.