Oil and Gas News Briefs
Compiled by Larry Persily
September 14, 2020

OPEC+ will meet Thursday to discuss stalled market recovery

(Bloomberg; Sept. 12) - It was meant to be the week when OPEC nations gathered in Baghdad to celebrate the cartel's six decades as a dominant force in global oil markets. Instead, the Organization of Petroleum Exporting Countries and its allies will convene online, and reflect on whether the coronavirus has thwarted their best efforts to keep the market afloat. After reviving oil prices from an unprecedented collapse over the spring, OPEC+ now is seeing the recovery stall and fuel demand falter as the pandemic surges once again. Prices slipped below $40 a barrel last week for the first time since June.

On Sept. 17, Saudi Arabia and Russia — the alliance leaders — will chair a meeting to assess if the production cuts, which they started easing in August, are enough to stave off an oil glut. Signs of exporters reneging on the deal are not helping. "There were some major assumptions built in on where demand and the recovery would be now, and it just hasn't happened," said Mohammad Darwazah, an analyst at research firm Medley Global Advisors. "If I'm OPEC and if I'm Saudi Arabia, I would be concerned."

Saudi Arabia and Russia had anticipated that a resumption in global economic activity, combined with the supply curbs, would sharply deplete the hoard of surplus oil built up during lockdowns. But there are growing signs the market isn't tightening so fast. The downturn isn't yet severe enough for OPEC+ to reimpose the full cutbacks made in the second quarter, said Helima Croft, head of commodity strategy at RBC Capital Markets. "For the men who reside in the palaces and the presidential halls, there is a price at which they make a panicked phone call," said Croft. "The question is, what is the price?"

UAE exceeds OPEC quota, analysts say it could affect market

(Bloomberg; Sept. 11) - Just when OPEC seemed to have finally mastered the problem of members breaching their oil-output targets, a new offender is emerging. The United Arab Emirates — traditionally a partner of leader Saudi Arabia — pumped over its agreed limit in July, according to OPEC data. It has admitted doing so again in August. Now many traders are turning attention to data showing the UAE's excess may be far greater than previously believed, contributing to the drop in prices to a two-month low.

The strongest signal that something was amiss came last month from the International Energy Agency, which estimated that the UAE pumped 3 million barrels a day in July. According to Petro-Logistics, which tracks shipping movements, the country supplied even more than that in August. That's significantly higher than the 2.693 million barrels a day of August production announced by UAE Energy Minister Suhail Al Mazrouei, which itself was more than 100,000 barrels a day above the country's OPEC+ target.

The belief that a core member of OPEC is breaching its quota has been influencing prices, according to oil traders who spoke to Bloomberg News. "When one of the core Gulf countries fails to meet its target on compliance, it raises market questions about the sustainability of the whole cuts project," said Bill Farren-Price, a director at consultant RS Energy. "OPEC has done an incredible job of delivering the cuts so far, but they need to keep going," he said. "The market has started losing faith in the recovery," said Tamas Varga, an analyst at PVM Oil Associates in London.

Oil traders stock up on tankers to store surplus

(Bloomberg; Sept. 11) - Some of the world's biggest oil traders are gearing up for a possible resurgence of a coronavirus-induced glut of crude and fuels, snapping up giant tankers for months-long charters so that they can be ready to store excess barrels if necessary. The chartering spree is likely to alarm Saudi Arabia, Russia, and their allies as it indicates that the oil traders believe the crude market is moving into a surplus after OPEC+ managed to create a deficit earlier this summer with its strong cuts to output.

Trafigura, the world's second-largest independent oil trader, in recent days booked about a dozen supertankers that can hold a total of 24 million barrels of oil, according to people familiar with the matter. All in, about 18 similar charters have been arranged with Shell, Vitol, and Lukoil among those also hiring the vessels, according to shipbrokers' lists of bookings seen by Bloomberg. State-controlled China National Chemical Corp., known as ChemChina, has also joined, the lists show.

While the bookings don't stipulate that they are for storage, it will give traders extra capacity to store if doing so becomes profitable or necessary. Earlier this year, millions of barrels was kept on tankers because demand collapsed and producer nations didn't initially cut their output in response. That led to a profit bonanza for the traders because spot oil prices became so depressed that it rewarded companies to park barrels on ships and sell them later. The charters could begin as soon as this month and will last for at least 90 days, according to the brokers' lists.

BP pays $1.1 billion to buy into two U.S. offshore wind farms

(The Wall Street Journal; Sept. 10) - Last month BP laid out the theory of how it aims to become a clean-energy company. Now it has served up a taste of what that might mean. The supermajor Sept. 10 said it was buying into two undeveloped wind farms offshore New York and Massachusetts, its first foray into the booming offshore wind sector. BP will pay $1.1 billion to its Norwegian peer Equinor for half of its Beacon and Empire wind projects, which are expected to start producing power by the mid-2020s.

The companies will also form a partnership to “pursue other offshore opportunities together in the fast-growing U.S. market.” The move is a signal of intent for BP’s low-carbon plans. It gives a real-life example of how the company plans to fulfill its ambition to sell integrated low-carbon power packages to companies and cities — one of the two green businesses it wants to develop.

It is no surprise that BP is buying into a shared megaproject. Many big oil and gas exploration projects are group undertakings, an approach that spreads the risks. BP also needs the scale: It has a very ambitious target to grow its renewable generating capacity to 50 gigawatts by 2030 from 2.5 gigawatts. The wind farms in the Equinor deal will have 4.4 gigawatts total capacity across the two projects when completed. Many more deals will be required to fulfill BP’s ambition. With green investments, including wind, becoming increasingly popular, this could be costly.

Oil and gas companies increasingly moving toward clean energy

(ICIS; London; Sept. 10) - Oil and gas firms are becoming increasingly active in clean-energy technology investment and are likely to play a huge role in the push to decarbonizing the global economy, according to the executive director of the International Energy Agency. “We are seeing several oil and gas companies, mostly the international oil companies, reshaping their business strategies and putting more emphasis on clean-energy technology,” said Fatih Birol.

“Whether they do it because of pressure from investors or citizens or want to be part of the solution and at the same time prepare their business strategy for a different world is an open question, but many international oil and gas companies are moving in that direction,” he added. The sector has increasingly focused on solar, offshore wind, and carbon capture as the oil and gas industry moves to adapt to projected declines in oil and gas demand in a few decades.

Expanding down the value chain into petrochemicals has also been a priority for energy majors, but instances such as BP selling a large chunk of its operation in that sector earlier this year hint that the industry’s focus may be increasingly on clean-energy solutions. “The world needs big energy companies to be active at the climate change issue because they have deep pockets,” Birol said. “They have expertise in managing huge projects and they are technology leaders in many aspects."

Shell, BP ask Texas regulators to stop routine gas flaring

(Bloomberg; Sept. 10) - Two of Europe's biggest oil companies urged Texas regulators to end the routine flaring of natural gas, joining with large investors who want greater oversight of the harmful environmental practice. BP and Shell are calling for tougher rules than those proposed by the Railroad Commission of Texas, which regulates oil and gas in the state. The commission is considering requiring operators to disclose more data when they apply for flaring permits and issuing them for shorter periods.

"We believe there is a real opportunity for the state to set the bar for others to follow," BP and Shell said in a joint letter to the regulator dated Sept. 4 and published Sept. 9. "We encourage the Railroad Commission of Texas to support an ambition of zero routine flaring in Texas." Last week investors managing more than $2 trillion asked the commission to end routine gas flaring by 2025. AllianceBernstein, the California State Teachers' Retirement System and Legal & General Investment Management said companies have the "financial and technical viability" to end routine flaring.

The boom in shale production over the past decade has led to a massive excess of natural gas, which is often a byproduct of oil in some basins such as the Permian. Prices for gas are often so low that it's cheaper for operators to burn it, releasing carbon dioxide and sometimes methane, rather than pay for pipelines to take it to market. The business-friendly Texas commission has historically taken a hands-off approach to flaring, granting permits and waivers when needed, but that may soon change with increasing opposition from environmentalists, investors, and some oil companies.

Oil-field services sector down 103,400 jobs during pandemic

(Houston Chronicle; Sept. 11) - The oil-field service sector has lost more than 103,400 jobs nationally during the coronavirus pandemic, dragging service employment to the lowest level since the last oil bust of 2014-16. Oil-field service companies shed just 2,600 jobs in August, a sign that job losses in the sector are slowing since the worst of the crude demand destruction in spring, when more than 58,300 jobs were lost in April, the largest one-month drop since at least 2013, according to an industry group.

"While the worst of the cutbacks appear to be behind the industry, considerable uncertainty about the future remains because a surge in COVID-19 cases could derail the economic recovery and suppress demand," said the report from the Petroleum Equipment & Services Association. Since February, Texas has lost the most jobs in the oil and gas sector (59,000), followed by Louisiana (10,200) and Oklahoma (9,200).

Husky asks Canadian governments to invest in Atlantic project

(Calgary Herald; Sept. 9) - Husky Energy is asking for government investment in its C$2.2 billion offshore West White Rose project that's under construction off the coast of Newfoundland and Labrador as it launches a review of its operations in Atlantic Canada. Calgary-based Husky said Sept. 9 it is reviewing and might cancel the 75,000-barrel-per-day project following the COVID-19 pandemic and resulting collapse in global oil prices as the company looks to reduce its costs and improve its debt situation.

In March the company suspended construction work at the site due to the pandemic and to conserve capital amid the global economic downturn. "Unfortunately, the delay caused by COVID-19 and continued market uncertainty leaves us no choice but to undertake a full review of the project," Husky CEO Rob Peabody said. The company is asking for direct investment in the project from the provincial and federal governments, "similar to the government's investment in Hibernia," which is another offshore Newfoundland and Labrador oil project, Husky spokesperson Dawn Delaney said.

West White Rose, located in the Jeanne d'Arc Basin 220 miles east of Newfoundland and Labrador in approximately 400 feet of water, is 60% complete, the company said. Husky is managing the project on behalf of partners Suncor Energy and Nalcor Energy. The project requires an additional $1.1 billion to complete. The province, however, is not in a position to directly invest in the project after the pandemic "battered" oil prices and its finances, Industry, Energy and Technology Minister Andrew Parsons said Sept. 9.

North Dakota gives producers more time to pay disputed royalties

(Grand Forks Herald; ND; Sept. 9) - The North Dakota Board of University and School Lands voted unanimously Sept. 9 to delay the accumulation of penalties and high interest payments on old gas royalty bills. Oil and gas companies operating in the state will now have until the end of April before penalties and steep interest rates begin applying to their overdue royalty bills. The board originally voted earlier this year to defer the accrual of significant penalties and interest until the end of September.

Land Commissioner Jodi Smith said in July that 34 firms owe tens of millions of dollars to the state for public school funding after taking improper deductions on gas royalty bills. He said Sept. 9 that 12 companies have told the state they will try to pay by the end of the month. The issue of repaying old royalties is tied up in two drawn-out lawsuits, and many in the oil industry believe they should not have to pay back what the department is demanding — and certainly not before the courts rule on the matter.

Smith views the "out-of-compliance" companies as reneging on their contracts for extracting state-owned minerals. The department says the companies must pay back the improperly deducted amounts retroactively from when their oil wells first began producing in the state. Gov. Doug Burgum, who sits on the board with four other statewide elected officials, said that pushing back the date when penalties and interest on the payments increase gives some breathing room to companies in dire straits.

Spike in coronavirus cases adds to North Dakota's troubles

(Washington Post; Sept. 11) - A surge in coronavirus cases is rekindling economic anxieties in North Dakota, where wildly fluctuating oil prices and recent drops in crude production threaten to leave the state's finances in fresh disarray. Six months after it registered its first confirmed infection, roughly 80% of the state's drilling rigs are offline and thousands of workers are still out of a job. And now North Dakota has emerged as one of the country's most concerning coronavirus hot spots with a nation-leading 34 confirmed cases per 100,000 residents, according to a Washington Post analysis.

The economic and epidemiological shocks now facing the state have created new uncertainty for its residents, workers, businesses and government leaders, some of whom once seemed optimistic that they had weathered the worst of the pandemic. At the start of the year, North Dakota was producing about 1.5 million barrels of oil a day. By June, it was under 900,000 barrels. Local oil and gas and related businesses had shed roughly 35% of their workers by July compared to the same period a year earlier.

The decline in production also threatens to cleave deeply into the state's budget. Taxes generated from oil are expected to come in $145 million short of what North Dakota leaders had anticipated, said Lynn Helms, director of the state's Department of Mineral Resources. The budget trouble could force state leaders to slash spending, cancel potential improvements to local water pipes, and reduce funding for cities and schools, said Helms, pointing out that many of these projects are historically funded by oil revenue now expected to be in decline. "It's hard to overstate the impact," he said.

Low prices drive consolidation in Canada's Montney Shale play

(Reuters analysis; Sept. 11) - A wave of consolidation is underway in Canada's Montney Shale oil and gas region as small companies struggling to weather the impact of coronavirus on the energy industry sell their holdings in what just a few years ago was a booming patch. Lockdowns and sharp contractions in economic activity have hammered global oil demand in 2020, pushing prices so low that producers worldwide have made record output and spending cuts.

Canada, the world's fourth-largest oil and gas producer, was already struggling as investors and foreign companies left to invest in production elsewhere that is cheaper and less carbon-intensive. The Montney, which straddles Alberta and British Columbia, has seen at least nine significant deals worth some C$2.3 billion ($1.75 billion) in the past year. It produces 1.5 million barrels of oil equivalent per day, including 45% of Western Canada's gas supply, according to consultancy Wood Mackenzie.

Smaller producers may have been willing to persevere through losses, but "banks and financial backers are now calling the shots," said Mark Oberstoetter, director of upstream Canadian research at Wood Mackenzie. As smaller companies leave, assets in the Montney are being concentrated in the hands of large oil firms. "It's been six years since the downturn (started) and some guys are saying 'enough is enough,'" said Jeremy McCrea, analyst at Raymond James, referring to smaller names looking to sell.

Developer abandons plan to expand Permian Basin oil line capacity

(Bloomberg; Sept. 10) - Enterprise Products Partners became the first to abandon a major crude pipeline in the heart of America's shale patch on Sept. 9 in what may be yet another sign that the pandemic-fueled rout in oil markets isn't over. With lockdowns across the nation eviscerating fuel demand, Enterprise shelved plans to add 450,000 barrels a day of capacity to a system that carries Permian Basin oil to the Gulf Coast.

Oil production in the Permian, America's most prolific crude play, has fallen as much as 16%, and the number of rigs drilling for crude in the U.S. fell to the lowest level since 2005. It's a stunning about-face for shale drillers, whose previously unbridled drilling turned the U.S. into the world's largest crude supplier. "This cancellation would be the first for a large crude pipe as a direct response to demand destruction from the pandemic," said Elisabeth Murphy, ESAI Energy upstream analyst for North America.

The loss of demand is not the only culprit. Even before COVID-19, the growth in tight-oil production had been declining as investors demanded higher dividends and spending discipline. Supply has fallen enough to create a "vision that oil infrastructure is in surplus," said Raoul LeBlanc, an analyst at IHS Markit. Infrastructure was set up to meet the needs for output and demand of about 100 million barrels a day globally, but that has declined to about 90 million, so more pipeline capacity is not needed, he said.

Rosneft to undertake unconventional oil and gas play on its own

(Reuters; Sept. 10) - Russia's largest oil producer, Rosneft, said Sept. 10 it had started to drill an exploration well at a hard-to-recover oil project, its first without any partners. Russia plans to develop hard-to-recover oil and shale but is hampered by Western sanctions over Moscow's annexation of Crimea from Ukraine in 2014. Rosneft has started to drill a first exploration well at the hard-to-recover Domanik formation in the region of Orenburg in far southern Russia near the border with Kazakhstan.

The company expects its geological reserves to rise by more than 500 million barrels of oil and 800 billion cubic feet of natural gas once the exploration work is completed at the project next year. BP had originally agreed to take part in the project; however, it decided not to proceed following the sanctions.

Some companies do not consider the Domanik formation to be shale oil, but a limestone project. Geologists are unanimous, though, that even though shale and limestone formations are different geological structures, they both constitute unconventional oil resources. Both are extracted through hydraulic fracturing. The sanctions were designed to prevent Russia countering sluggish output from its conventional wells by tapping these hard-to-recover reserves which require newer extraction techniques like fracking, an area where it relies on Western technology.

Russian oil companies resist proposal to end tax breaks

(S&P Global Platts; Sept. 11) - Russia's Finance Ministry is hoping to pass a law amending the excess profit tax (EPT) for oil fields as early as this fall, despite opposition from oil companies warning of a potential long-term slump in production. Russian producers have been enjoying the tax breaks on four groups of fields since 2019, when the government adopted the tax to boost greenfield projects by primarily taxing profits from oil sales while reducing the role of the mineral extraction tax and export duty.

Now the ministry is proposing changes to fix what it has called "its biggest mistake," which allegedly resulted in a tax revenue loss of more than Rb200 billion ($2.67 billion) last year, according to its calculations. "We will submit a draft law to revise the EPT parameters in any case. We plan to submit it to the government in the next two weeks," Deputy Finance Minister Alexey Sazanov told reporters Sept. 8, as quoted by TASS.

The proposed tax change will mainly first target two groups of oil fields in East Siberia. "I would expect that a change would again make investment in these greenfields less attractive," Mitch Jennings, Sova Capital's oil and gas analyst, told S&P Global Platts. Not surprisingly, Russian oil majors have not been enthusiastic about the idea of yet another tax change, which they argue will undermine their investments. Rosneft and Gazprom Neft, which stand to lose the most from proposed amendments, have both openly resisted the change whenever it has been proposed previously.

Weak market adds to Oregon LNG's already substantial problems

(E&E News; Sept. 9) - An embattled liquefied natural gas export project in Oregon is facing yet another pitfall — an economic crisis spurred by a pandemic. The Jordan Cove LNG export terminal in Coos Bay has been opposed by state officials, landowners, and environmental groups, and has been mired in permitting delays and court battles over federal approval. Even if developer Pembina Pipeline prevails in those challenges, the $10 billion project is being promoted in the midst of a global LNG market that has seen a sharp decline in demand due to the global coronavirus pandemic.

Market and legal pressures on the project are drawing comparisons from environmental groups to the now-canceled Atlantic Coast and Constitution gas lines on the Eastern Seaboard. Those projects had also faced protracted opposition in court and numerous permitting problems before developers eventually gave up. "It is increasingly difficult to permit and build these types of projects ... whether it's market demand or public outcry," said Susan Jane Brown, an attorney at the Western Environmental Law Center.

One of the obstacles ahead for Jordan Cove is a public health crisis that has, among other economic impacts, slashed demand for LNG. That has left a market flooded with surplus gas, and reluctant buyers are demurring from committing to long-term offloading agreements. "The challenge facing U.S. LNG projects … has everything to do with project finance," said Fred Hutchison, president and CEO of industry advocate LNG Allies. "Companies have to have sufficient off-take agreements to secure bank financing to build their projects," he said. "And that's the holdup everywhere you look."

Japanese buyers will not renew 50-year Indonesia LNG deal

(Bloomberg; Sept. 9) - One of the world's oldest liquefied natural gas deals may be set to end as buyers face a supply glut and demand uncertainty exacerbated by the coronavirus pandemic. The almost 50-year-old agreement to buy fuel from PT Pertamina's Bontang terminal in Indonesia is set to expire at the end of this year. Kyushu Electric, one of six Japanese utilities in a buyers' consortium, won't renew its contract. Toho Gas is also walking away, a person familiar with the matter said.

The end of the accord would underscore how a global supply glut and persistently low spot prices are hurting the long-term agreements that the LNG industry was built on. Such deals fell to 66% of the LNG trade by 2019 from 84% a decade earlier, according to the International Group of Liquefied Natural Gas Importers. The Indonesia pact can be traced back to 1973, when a group of Japanese firms agreed to purchase LNG from then-unbuilt Bontang, helping Indonesia get financing and launch its first gas export plant in 1977. Some of the buyers signed a separate deal with the plant in 1981.

That long-term deal is based on one of the most expensive pricing structures that Japan has in its supply portfolio, according to data from BloombergNEF. Meanwhile, Japan's LNG imports fell 6.5% this year with growing renewable power generation, restarts of nuclear reactors and the COVID-19 outbreak cutting domestic demand for the fuel. Japan's LNG buyers could be forced to let more deals expire in the coming years as losses on resale of surplus supplies mount amid discounted spot prices. Kyushu

Electric has no plans to renew because it has excess supplies, an executive officer said Sept. 8.

FERC allows Freeport LNG more time to add 4th train at Texas plant

(Reuters; Sept. 10) - U.S. energy regulators on Sept. 10 granted Freeport LNG's request for three more years — until May 2026 — to complete its proposed fourth liquefaction train at its gas liquefaction plant in Texas. The Federal Energy Regulatory Commission approved construction of the fourth train in May 2019, requiring Freeport to finish the facility by May 2023. Like other LNG exporters around the world, Freeport put off making a final investment decision on the fourth train earlier this year after prices in Europe and Asia collapsed to record lows as energy demand fell due to the coronavirus.

Freeport has said it does not expect to make a FID to build the fourth train this year due to "the current market conditions resulting from COVID-19," but noted, "We can be ready to start construction by mid-2021 if market conditions improve." Before delaying the FID in March, Freeport said it planned to make a decision on Train 4 during the first quarter of 2020, which would have enabled the unit to enter service in 2023.

In mid-2019, about a dozen North American developers, including Freeport, said they planned to make FIDs by the end of the year. But none of those projects are under construction. All of those FIDs were delayed until 2020 or later. Each train at Freeport is designed to produce about 5 million tonnes per year of LNG.

Judge allows full restart for pipeline beneath Great Lakes

(The Associated Press; Sept. 9) - Enbridge said Sept. 9 it will fully resume operation of a Michigan Great Lakes oil pipeline after a partial shutdown this summer because of damage to an underwater support structure. The judge signed an order allowing the Canadian company to restore the flow through one of its Line 5 pipes beneath the Straits of Mackinac, which connects Lake Huron and Lake Michigan.

The line carries oil and liquids used in propane between Superior, Wisconsin, and Sarnia, Ontario, passing through parts of Michigan’s upper and lower peninsulas. A 4-mile-long segment divides into two pipes that cross the straits. Enbridge reported in June that an anchor supporting the underwater section’s eastern leg had been bent and scraped, although the pipe itself was unharmed.

An investigation concluded that a vessel might have dragged a mooring cable across the pipes. The judge approved a request June 25 from Michigan’s attorney general to close the line, but six days later allowed Enbridge to restart the western leg. On Sept. 9, the judge said Enbridge could resume the flow through the eastern leg as well, noting that the U.S. Pipeline and Hazardous Materials Safety Administration had given its approval last week, saying it found no “integrity issues” at the damaged support anchor.

Turkey wants better terms before it renews long-term gas deals

(Reuters; Sept. 9) - Turkey expects natural gas suppliers to offer more competitive pricing and flexibility if they want to renew long-term contracts totaling about 560 billion cubic feet per year, a senior energy ministry official said. More than 25% of Turkey’s long-term gas contracts expire next year, including imports via pipeline from Russia’s Gazprom and Azerbaijan’s SOCAR and a liquefied natural gas deal with Nigeria.

Competition from cheap U.S. LNG and the potential for Turkey to start its own gas production in the Black Sea have changed market dynamics, the Turkish ministry official told reporters. “Old-fashioned” gas contracts, which are often indexed to oil prices and commit buyers to penalties if they do not buy their full quota, no longer match market realities, he said, and prices should be set against those at major gas hubs.

“We started to discuss whether we are going to renew (or) whether we are going to find an alternative supply,” said the official, who spoke at a briefing on condition of anonymity. The decision would depend on whether suppliers “approach with same old habits — no flexibility, not very competitive price offers.” In that case, “I don’t think we will see the existing contracts continue,” he said. Turkey relies on imports for nearly all its oil and gas needs.