Oil and Gas News Briefs
Compiled by Larry Persily
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Russia gears up to quickly replace curtailed oil output

(Reuters; June 24) - Russia is taking a leaf out of the U.S. shale playbook so it can ramp up oil production quickly and hang on to its share of the global market when demand recovers after the coronavirus pandemic. At least two state-owned banks, Sberbank and VEB, plan to lend oil firms some 400 billion roubles (US$6 billion) at effectively almost zero interest rates to drill about 3,000 unfinished wells, officials involved in the plan told Reuters.

Once oil prices recover, the wells can be finished off faster than starting from scratch — so that Russia can boost its output back to levels before it agreed along with other leading producers to cut supply because of the fallout from COVID-19. U.S. shale producers tend to drill but not complete wells when prices are low, rather than freezing all activity, so they can finish off the wells and quickly boost output as demand picks up.

A geologist advising Russian oil firms said the new wells would add at least 200,000 barrels per day to production based on average flow rates, but if their assumptions about large reserves pan out the wells could boost output by 2 million barrels. Though Energy Minister Alexander Novak said last week how much would be invested in the drilling program, he did not disclose details or how much oil output could increase.

Russia pumped an average of 11.3 million barrels per day last year, according to the energy ministry. Since the OPEC+ deal to curb global supplies, its output has fallen by 2 million barrels per day, Novak said last week. Russia has mainly shut down old or less-productive wells that won’t necessarily be revived when the supply deal expires in 2022, so the government is helping companies to ensure lost output can be replaced quickly.

China falling far short of U.S. energy imports under trade deal

(Reuters commentary; June 25) - A record amount of crude oil is heading from the U.S. to China next month, but rather than signaling that the trade deal between the two countries is working, it serves to underscore just how far Beijing is from meeting its commitments. A total of 31 million barrels of crude on 26 vessels is due to arrive in China from the U.S. in July, according to vessel-tracking and port data compiled by Refinitiv. That is more than double the previous best month in June 2018, but far from what is needed to meet January’s Phase 1 trade deal the two countries.

In terms of the deal, China was to massively increase its imports of U.S. crude, coal and liquefied natural gas by $52.4 billion over 2020 and 2021 from a base of $9.1 billion in 2017. July's oil cargoes were most likely arranged at the time of the price war between Saudi Arabia and Russia, which saw crude prices plummet, meaning that the price Chinese refiners will have paid for the cargoes is likely to be on the low side. And even if July's numbers continue all year, China will not come close to the trade deal numbers.

And the likelihood of China continuing to import oil at the pace forecast for July already seems remote with August arrivals so far slated at just 7 million barrels, according to Refinitiv. Meanwhile, China hasn't imported any U.S. coal since May, and none is booked for arrival in coming months. There was a little flurry of U.S. LNG cargoes arriving in China in April and May, when 10 vessels unloaded their cargoes. But this has dwindled to two ships in June and one booked for July, and nothing on the horizon beyond that. This is likely because U.S. LNG cannot currently compete in Asia against cheaper spot cargoes from major regional suppliers such as Qatar and Australia.

Norway opens new exploration blocks in the Arctic

(Reuters; June 24) - Norway is planning a major expansion of oil exploration in the Arctic, despite commitments to tackling global warming and opposition from environmental groups. Minister of Petroleum and Energy Tina Bru said June 24 the expansion is needed to protect jobs and generate wealth. The government will auction up to 136 new oil exploration blocks in a major licensing round with 125 of those in the Arctic Barents Sea, a relatively unspoiled corner of the planet.

"We need new discoveries to uphold employment and value creation," Bru said in a statement. Norway is western Europe's biggest oil producer and has built the world's biggest sovereign wealth fund worth over $1 trillion, on the back of its oil wealth. It has signed up to the Paris agreement to tackle global warming and, although not a member of the European Union, has pledged to reduce carbon dioxide emissions. However, this doesn't cover emissions from fossil fuels produced in Norway and used by others.

"This clearly shows the Norwegian government's actions are not based on what is scientifically required to address the climate crisis," Greenpeace's head in Norway, Frode Pleym, told Reuters. The licensing round, Norway's 25th, had been delayed by a long-running debate over how far north the oil industry should be allowed to drill, culminating in a compromise that left significant room for more Arctic licenses. The new round could open eight regions of the Barents Sea previously unavailable for exploration, each with a range of blocks, and one region of the Norwegian Sea.

Financing for North American LNG projects doubtful for 5 or 6 years

(S&P Global Platts; June 23) - Demand, supply chain and capital budget shocks from the coronavirus pandemic make it unlikely any more North American LNG export projects will secure financing for construction in the next five or six years, according to an S&P Global Platts Analytics outlook issued June 23. In recent months, final investment decisions on multiple U.S. and Canadian LNG projects have been delayed to 2021 or beyond. Some developers have stopped issuing timing guidance.

Platts Analytics' outlook reflects the concern that, amid a sustained period of low global prices, developers will not be able to support their delivered costs, especially those with more spot-market exposure and higher upfront expenses. "We think it is more likely this forecast will come to pass," said Ross Wyeno, lead analyst for Americas LNG at Platts.

Because of Western Canada's relative proximity to the world's biggest LNG buyers in Northeast Asia, there had been a lot of hope that more export projects would be sanctioned there, especially after Shell-backed LNG Canada decided in October 2018 to move forward with construction. But global oversupply pushed prices down, and then the coronavirus hit depressing demand and further pushing prices to record lows. On the U.S. side, new commercial contracting has all but dried up, making it impossible for many LNG export project developers to secure financing for construction.

Industry expects only the lowest-cost LNG projects will proceed

(Reuters; June 24) - The natural gas industry sees no change to the strong long-term outlook for demand following the COVID-19 crisis, but expects a supply shortfall in the next four years as the pandemic lockdowns and oil-price collapse lead to delays on gas projects. Producers, buyers, liquefied natural gas developers and a major contractor said in the long run the fuel will be needed to back up wind and solar power, replace coal-fired power, and produce hydrogen globally.

However, lingering uncertainty following a crash in LNG prices to record lows this year below $2 per million Btu means only the lowest-cost LNG projects will go ahead, major producers said at Credit Suisse's annual Australian Energy Conference. Projects worldwide totaling more than 140 million tonnes of annual capacity have been deferred. In Australia and Papua New Guinea alone, five are on hold. Japan's Chiyoda, a major contractor to LNG projects, said work has largely dried up and there would need to be stability in the market before developers move ahead with projects.

Shell sees short-term concerns weighing on decisions about new projects. "I'm sure all companies … across the globe are going to be focused on that affordability question just because of the uncertainty they see in the macro markets," said Shell Australia Chair Tony Nunan. Research firm Rystad Energy said with gas prices around the world trading near $2 per million Btu, LNG developers with all but the lowest costs will hold off on new projects. “But that will cause a shortfall for the LNG market four or five years down the road,” Rystad’s head of analysis, Per Magnus Nysveen, told the conference.

Texas LNG terminal delays expansion decision to at least 2021

(S&P Global Platts; June 23) - Freeport LNG has delayed its target for making a final investment decision on a fourth liquefaction train at its Texas facility until at least next year, amid market and pandemic-related challenges that have hurt development efforts, the operator said June 23. With the ability to secure new long-term supply contracts with buyers to finance projects all but shut off, multiple other developers of new U.S. LNG terminals and liquefaction units have put off sanctioning decisions until 2021 or beyond.

Some have stopped updating timing guidance. One major, Shell, pulled out of a proposed export project in Louisiana. "As with most LNG projects around the world, COVID-19 and other market challenges have negatively impacted our development efforts," Freeport LNG spokeswoman Heather Browne said. "As such, we do not expect to reach FID on Train 4 this year. Given we are a brownfield expansion, if market conditions improve, we can easily be in a position to start construction by mid-2021."

In an interview with S&P Global Platts in February, CEO Michael Smith said Freeport LNG did not have any firm long-term contracts tied to Train 4. A preliminary agreement signed in 2018 by Japan's Sumitomo for the purchase of 2.2 million tonnes per year of LNG from Train 4 expired without being finalized, he said. At the time, Smith lamented that the substantially lower fees that U.S. LNG developers were being asked to accept for their supplies was making it very difficult for most developers to build new capacity.

U.S. shale will not find it easy to return to record production

(Bloomberg; June 24) - As oil prices tick up to $40 a barrel following a pandemic-induced plunge, there’s a sense the U.S. shale industry is snapping back to life with Continental Resources, EOG Resources and Parsley Energy all saying they’re restarting closed wells. But top industry forecasters are painting a far darker picture. The reopenings, they say, will do little to bring new growth to an industry that is being increasingly starved of cash by Wall Street after a decade of excess.

Even before the pandemic, investors demanded companies spend no more than they earn. That’s now a major barrier to future growth. Looking out 18 months, U.S. oil output will still be around 16% below its peak, according to an average of surveys from the International Energy Agency, Genscape, Enervus, Rystad and IHS Markit. It’ll probably be at least 2023 before the U.S. again hits its record of close to 13 million barrels a day. Even so, OPEC and its allies should not rest easy. The shale revolution that made the U.S. the world's No. 1 producer of oil and gas still retains its disruptive potential.

Forecasters say there's a high chance that shale could rebound quicker than expected if futures continue climbing and settle in the $55 to $65 a barrel range for an extended period of time. America's shale industry has defied the doubters for 15 years in terms of sheer volume of oil produced. In that period, it has more than doubled output, adding about 8 million barrels a day to global markets. But that achievement came at a huge cost. Shale operators burned through about $340 billion over the past 11 years, using borrowed money and equity raised from Wall Street, leaving little left over for investors.

Russia and Saudi Arabia need China more than China needs their oil

(Forbes; June 24) - Russia and Saudi Arabia both rely on oil sales to fund a majority of their budgets. In the past five-plus years, China has become the biggest customer for both countries. In fact, China is the world's largest importer of oil, though it could cut imports if it stopped adding to its reserves. China has stored so much oil over the past five years that it could practically halt all oil imports and get by just fine for a while.

This has global consequences. Reuters estimated last year that China had 788 million barrels in its strategic petroleum inventory. That did not include the large commercial reserves, even though nothing is truly beyond the government's reach in a nominally communist country. If China wanted to cut all imports from Russia or Saudi Arabia and did not replace that oil with other imports, it would immediately drop global demand by almost 2 million barrels per day but could make up for the loss by drawing from storage.

This would send shockwaves through the oil market. Oil prices would fall. The country whose oil was cut — whether Russia or Saudi Arabia — would be desperate to find new buyers and may have to undercut the market with low prices, thus further dropping oil prices. The point of all of this is that when it comes to oil, Russia and Saudi Arabia are beholden to China. They need sales to China, but thanks to China's inventory, China does not really need purchases from both of them. On the global stage, it would be hard for Russia or Saudi Arabia to take sides on any issue against China.

Shell's floating LNG plant has not produced since February

(Forbes; June 23) - The world's biggest ship is on the way to becoming one of the oil industry's biggest bloopers. Six times the displacement of the largest U.S. aircraft carrier, it's designed to produce liquefied natural gas and other petroleum liquids. Anchored atop a remote gas field 300 miles off the northwest Australian coast, the 1,600-foot-long Prelude is a bold experiment by Shell. But the hugely expensive floating LNG (FLNG) vessel — technically a barge because it cannot propel itself — is not performing as designed and hasn't produced any LNG since early February.

Safety problems forced the shutdown and a restart date has not been set for the vessel, estimated to have cost $12 billion to $17 billion — Shell has never revealed the exact price. The idea is that remote and smaller offshore gas fields might never be developed using a conventional offshore platform and pipeline to an onshore LNG plant. So rather than take the gas to the onshore plant, FLNG flips the model by taking the plant to the gas with the bonus that the vessel can move to new gas fields as old ones dry up.

It sounds good, except for the technical challenges of squeezing a big LNG facility into a relatively small space. Recent events highlight the challenges Shell has ahead of it with Prelude and plans for sister vessels that were to follow. The immediate issue is to satisfy Australia's oil and gas safety regulator that problems such as the failure of a back-up diesel power unit have been fixed and LNG production can restart. According to analysts at Goldman Sachs, Prelude is the world's most expensive new LNG project, with a "commercial breakeven" cost of almost $20 per thousand cubic feet of gas.

Oil cutbacks ease Canada's shortage of pipeline capacity

(Bloomberg; June 23) - The shortage of pipeline capacity that has hurt Canada's oil producers for years may be over — just not in the way they had hoped. The pandemic-induced oil crash prompted Canadian companies to cut about 1 million barrels of daily output, freeing up space on the country's previously congested pipelines. With that production likely slow to return and as many as three new pipelines slated to be built in the next three years, the industry may have years of cheap, plentiful shipping ahead.

That's a significant turnabout for a country where, until COVID-19 hit, the lack of pipelines out of Western Canada was a central political and economic issue. The pipeline relief came only because oil producers had to adapt to a dramatic drop in demand and low prices that are causing mounting financial losses. Some had spent heavily to ramp up their ability to ship crude by rail and now find themselves stuck with idled tanker cars and loading terminals as they have cut back on oil production.

Enbridge, which typically has to ration space on its pipeline system, had spare capacity in recent months, a rare occurrence. Shipping oil by train, the alternative to pipelines, have plunged as well. April's crude-by-rail exports fell 55% to about 156,000 barrels a day, according to the Canada Energy Regulator. That trend appears to have continued into May with only about 49,000 barrels a day moving by rail, according to Genscape. Until recently, the problem had been just the opposite. The lack of shipping capacity forced producers to sell their crude at wide discounts to benchmark U.S. prices.

Pipeline work will begin to LNG Canada site in Kitimat, B.C.

(Natural Gas Intelligence Daily; June 23) - After surviving protests and the COVID-19 pandemic, Coastal GasLink plans to start laying pipe for the only liquefied natural gas export project underway on the northern Pacific coast of British Columbia. The company said construction employment would roughly triple to peak at more than 2,500 in September as work accelerates along the 416-mile route from northeastern B.C. gas fields to the Shell-led LNG Canada terminal, which is being built at Kitimat.

With a second wave of COVID-19 seen as a potential threat in British Columbia, Coastal GasLink and its contractors are “implementing enhanced project-wide health and safety standards at all worksites and workforce accommodations.” Precautions include fielding about 80 medics from a global health and safety contractor. During the spring thaw, skeleton crews built work camps and cleared the pipeline right-of-way to enable the summer acceleration of construction.

The announcement that construction would accelerate on schedule to hit the pipeline’s 2023 completion target date stood out as the second success for the C$6.6 billion (US$4.9 billion) project so far this spring. In late May, sponsor TC Energy closed a sale of a 65% investor ownership share in the pipeline to a partnership of KKR and Alberta Investment Management Corp., while also raising project construction financing from a bank syndicate. An additional 10% ownership stake is on offer to Indigenous groups.

West Virginia oil and gas regulator may need to lay off inspectors

(West Virginia Public Broadcasting; June 24) - The West Virginia state agency tasked with regulating oil and gas permitting, inspections, and the plugging of abandoned wells is facing a major budgetary shortfall and is expecting to cut staff by more than 35%. James Martin, director of the Office of Oil and Gas for the Department of Environmental Protection, said June 23 that permit requests from the industry were down substantially this year. The office receives the bulk of its funding from permitting fees.

“It’s going to be a big change for us,” Martin said. “I’ve never really experienced this, certainly during my time in state government nothing to this kind of degree.” Martin said the office is expecting to cut staff across the board from roughly 40 to about 25 employees. That cut includes inspectors, he said. The revenue shortfall is tied to a decline in new drilling activity. Last year Martin said the agency had between 35 and 40 permit requests. In March and April, the office saw just six and five permits, respectively. The oil and gas industry has been hit hard by the coronavirus pandemic.

Angie Rosser, director of the conservation group, the West Virginia Rivers Coalition, said the agency’s current financial challenges highlight why the Office of Oil and Gas needs to diversify its funding stream. Last year the Legislature failed to pass a series of bills that would have funneled more money toward the office.

Offshore drilling rig companies hit hard by industry slowdown

(Reuters; June 24) - The companies that operate offshore drilling rigs for oil producers face a second wave of bankruptcies in four years amid a historic drop in energy prices that likely will leave surviving drillers more closely tied to big oil firms. A collapse of the offshore industry will have broad impact. Drillers and suppliers have driven innovation that has helped shale and offshore wind companies by pioneering remote monitoring and control, and last year directly generated about 25% of global oil production.

The offshore services business now is the worst performing of the oil field services sector, with shares of the 10 largest publicly traded firms down 77% since the start of the year. Four of the seven largest offshore drillers — Diamond Offshore Drilling, Noble, Seadrill, and Valaris — have sought protection from creditors or begun debt restructuring talks that could lead to bankruptcy. Two others are reaching out to their creditors.

The latest turmoil "is going to change things in many ways," Odfjell Drilling CEO Simen Lieungh said. "Existing players and the existing structures will probably not be there as today," he said referring to companies scrapping rigs. This month the number of floating rigs at work is expected to hit the lowest since 1986 as oil companies cancel or defer contracts, said industry executives and analysts. Offshore service firms may need to scrap up to 200 of the about 800 existing floating rigs to regain profitable lease rates, said David Carter Shinn, head of analysis for rig brokerage Bassoe Offshore.

Michigan goes to court to shut down Enbridge oil line

(Calgary Herald; June 23) - Enbridge, North America's largest pipeline company, says Michigan's request for a restraining order and injunction against a pipeline connecting Alberta oil fields to Midwest refineries is "legally unsupportable" and "unnecessary." The company shut down the twin pipelines through a narrow waterway on the Great Lakes last week when one of the anchor supports at the bottom of the lake shifted.

After inspecting the lines, Enbridge reopened one pipe, which was not damaged, but requires an engineering report and work with the U.S. Pipeline and Hazardous Materials Safety Administration on the other pipe. However, Michigan Attorney General Dana Nessel filed for an injunction June 22, asking a county judge to suspend operation of Line 5, which carries 540,000 barrels of oil per day until an investigation is conducted.

"To date, Enbridge has provided no explanation of what caused this damage and a woefully insufficient explanation of the current condition and safety of the pipeline as a result of this damage," Nessel said in a release. Enbridge fired back with a letter signed by CEO Al Monaco to the governor on June 22, which described efforts by the Calgary-based pipeline company to inspect, repair, and restart a portion of its pipeline through the Straits of Mackinac, the narrow waterway that connects lakes Michigan and Huron.

Oil and diesel stored at sea caught up in Singapore lawsuits

(Reuters; June 24) - Millions of dollars of oil and diesel stored in tanks and ships in Asia and Europe has become caught in a web of lawsuits related to trade and financing deals by Singapore's Hin Leong Trading, according to court documents and shipping data. A report filed this week in Singapore's High Court and reviewed by Reuters found Hin Leong obtained financing from various banks for cargoes of oil which did not exist, complicating the competing claims of ownership.

The oil inventories that Hin Leong did have include diesel on three tankers that arrived fully loaded in Europe last month, and which have since been floating off the U.K. and France, shipping data on Refinitiv's Eikon showed. The ownership of the fuel on four floating storage units off Malaysia is also in dispute, the report said. Hin Leong, one of Asia's largest oil traders, was placed under judicial management in April owing $3.8 billion to 23 banks as oil prices crashed and the coronavirus swept across the globe.

The report by interim judicial managers from PricewaterhouseCoopers Advisory Services (PwC) found that Hin Leong's total oil inventory stood at $212 million as of May 20, less than a third of the $646 million owed to banks that provided inventory financing. Hin Leong's oil inventories "are likely to be subject to multiple claims by creditors," according to PwC. The accountancy firm plans to sell some of the inventory, which is currently incurring storage costs, to minimize costs.

Partnership may change at 31-year-old Australia LNG project

(Bloomberg; June 23) - After three decades, the project that kick-started Australia's push as a liquefied natural gas powerhouse faces a shake-up. Woodside Petroleum on June 23 reiterated that it would consider buying Chevron's stake in North West Shelf and indicated that other partners could be looking to exit too. It may be the end of a delicate balance at Australia's biggest LNG project, where six international partners hold equal stakes and as the plant needs to find new gas supplies to keep on humming.

As operator, Woodside is viewed by many in the industry as the logical buyer for Chevron's stake in the 31-year-old plant. Chevron announced last week it would start a formal marketing process, though the other five partners have pre-emptive rights. "You don't want your neighbors to put up the 'For Sale' sign and then get the wrong people move in next door," Woodside CEO Peter Coleman said at an energy conference June 23. "We'll look at it. Whether we participate or not is really going to depend on price."

The stake could be worth as much as $3.7 billion, said Saul Kavonic, a resources analyst at Credit Suisse. Chevron said the time is right to consider a sale as the 31-year-old terminal moves toward becoming a third-party tolling facility, processing gas from non-partners for a fee. That transition means the asset is more likely to appeal to infrastructure investors rather than oil and gas players, Coleman said. North West

Shelf, which has loaded over 5,000 cargoes, is looking to sustain output as its foundational gas fields begin to run dry. Woodside wants to take gas from its own Browse project.

Seasonal LNG contracts may be an option

(S&P Global Platts commentary; June 23) - The LNG market has clung tenaciously to traditional contracting structures, but so many of the justifications — the rationale for oil-price indexation, limited LNG supply, and lack of spot gas trade or benchmark prices — no longer pass the sniff test. The market needs different options. Sellers still need some long-term commitments to provide financial security to shareholders, and buyers still need security of supply to assuage concerns regarding economic vulnerability.

That said, these concepts for buyers and sellers desperately need to evolve, and now is the perfect time to move on. Shifting the focus from "how much" and "how long" to "when" and "what period of the year" provides a better solution to what currently ails the market for LNG contracts. Taking the LNG contract to the next level involves better defining when — more specifically what time of the year — having an LNG contract is an absolute necessity, and when it is more of an option.

Here's where seasonal LNG contracts could come into focus. This new type of contract supports the goals of buyers and sellers, while also simultaneously reducing risks. In a seasonal contract, a long-term deal could be struck with both sides agreeing to a specific period of the year when the LNG is most and least valued. For most buyers in the Northern Hemisphere, this would be during the fourth and first quarters, when cold weather can increase consumption by two to three times the annual average.

During the second and third quarters, one of two things would need to happen: Either the buyer takes no volume and it's not part of the contract at all, or the buyer takes volume that is discounted versus the benchmark price. Finding a long-term buyer is harder than ever, so securing one for at least part of the year is the next best outcome.