Oil and Gas News Briefs
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Goldman Sachs forecasts 15% to 20% drop in oil prices

(CNBC; June 9) - Goldman Sachs sees a correction in oil prices on the horizon even amid a significant recovery in the past month and the recent decision by OPEC and its allies to extend historically large production cuts through July. "With oil now above $40 a barrel, supplies will be incentivized to return, but we believe risks to the downside have increased substantially and are now looking for a 15% to 20% correction," Goldman Sachs' commodities research team led by Jeffrey Currie wrote in an analysis June 9. ***(Oil prices in early trading June 11 were down almost $3 per barrel, about 7%.)***

"Despite the rally, we have been hesitant to recommend a long position this early in the cycle for several reasons," the analysts wrote. For one, they said, it's because surplus inventory still very much exists — an estimated 1 billion additional barrels that have piled up as economic activity and travel worldwide remains largely at a standstill amid fears of COVID-19. Goldman also said the rally has gotten "ahead of fundamentals."

The note added, "This is not to dismiss the current recovery or not acknowledge that it is progressing ahead of expectations, but rather note that prices are ahead of the rebalancing where oil still faces a billion-barrel inventory overhang," the Goldman team wrote. They described oil's current rally as "surprising given the massive inventory overhangs and depressed demand faced by energy and agriculture markets." Some analysts believe it could take until the middle of 2021 to reverse the inventory build.

Analysts worry oil-price recovery too steep, too fast

(The Wall Street Journal; June 10) - Oil prices have shot up from the historic depths hit during the coronavirus shutdown, but analysts and traders worry the rebound has been too sharp and could prove short-lived. Rather than surging on supply and demand fundamentals, oil prices have ridden along with other risky assets, such as stocks, that have been bid up by speculators looking to cash in on the U.S. emergence from the coronavirus shutdown.

"The short-term optimism on the oil market is exaggerated," said Commerzbank analyst Eugen Weinberg. Benchmark West Texas Intermediate closed June 10 at $39.60, with Brent at $41.73. But the prices shouldn't be so high given swollen stockpiles and depressed fuel demand, Goldman Sachs analysts said. They have argued that oil prices have "mirrored the strength of the rally in financial markets, anticipatory assets entirely driven by expectations," rather than trading on supply and demand fundamentals.

Prices nearing $40 have prompted U.S. companies to bring back curtailed production, which in turn has threatened the price recovery. Analysts at Houston's Tudor, Pickering, Holt & Co. estimated that a million barrels a day of curtailed output will return to the market this month and that average daily production will rise by another 750,000 barrels in July. Commercial stockpiles of crude, which excludes oil tucked away in the U.S. Strategic Petroleum Reserve, rose to 538 million barrels last week, up 11% from the same time last year and eclipsing the old high of 535.5 million barrels in March 2017.

ConocoPhillips CEO surprised at swift price recovery

(Reuters; June 10) - ConocoPhillips CEO Ryan Lance on June 10 expressed surprise at the quick rebound in U.S. oil prices that slipped into the negative territory in April, and said he expects prices to remain volatile in the near term. Oil is now trading at near $40 a barrel, almost double the $20 it averaged in April, the same month prices briefly fell to minus $38 due to low demand as nations halted travel to curb the spread of COVID-19.

"We were surprised it came back this strong this quickly," Lance said on a webinar hosted by the Independent Petroleum Association of America. He added that a continued increase in crude storage could, however, drag down prices as more producers reverse some production cuts announced over the past couple of months.

U.S. shale oil producers have begun to reverse production cuts as prices bounce back, while U.S. crude inventories rose by 5.7 million barrels in the week to June 5 to 538.1 million barrels, the highest in history, according to the latest EIA data. Lance also commented that some consolidation in the sector will be a positive for the industry, adding that his company was monitoring the deal activities closely. "We're in the market every day." ConocoPhillips is the world's largest independent oil and gas producer.

World 'awash in diesel' and refiners are paying the price

(Bloomberg; June 8) - In all the hullabaloo of OPEC+ prolonging the deepest production cuts in history, it's easy to overlook ominous signals for prices emanating from the diesel market. The world's largest oil producers agreed June 6 to extend their collective output curbs, keeping 10% of supply off the market another month. While that tightens the global crude market, potentially driving prices higher, it does little to address grim margins that refiners earn from diesel, one of the most important petroleum products.

“The world’s awash with diesel,” said Alan Gelder, vice president for refining, chemicals, and oil markets at consultants Wood Mackenzie. “There’s just loads of it everywhere.” Away from Europe, where diesel often powers cars, the fuel is also widely consumed by industry to move goods, as well as in construction and agriculture. Less economic activity, less demand for diesel. The bigger problem, though, is too much supply.

Refineries — particularly in Europe and the U.S. — are trying to make as little jet fuel as possible because demand from the aviation industry still remains far below where it was before the pandemic struck. But that means producing more diesel from the barrels. Similarly, refineries cannot meet a recovery in gasoline consumption without boosting their overall processing rates — and that too brings more diesel. U.S. diesel stockpiles have grown for nine straight weeks to sit at the highest since 2010 and refinery margins on producing the fuel in the U.S. are hovering near a 10-year low.

Forecast shows U.S. oil production losing 2.2 million barrels per day

(S&P Global Platts; June 9) – U.S. oil production will continue to decline until bottoming out at 10.63 million barrels per day in March 2021, about 2.2 million below the record high set in November 2019, the Energy Information Administration said June 9. EIA now predicts U.S. oil output to average 11.56 million barrels per day in 2020, a downward revision of 130,000 from last month's forecast, with 2021 output averaging 10.84 million. This year will mark the first decline in U.S. oil production since 2016.

Global oil demand is on track to shrink 8.3 million barrels per day year on year to average 92.53 million in 2020, a slight reduction from last month. EIA sees 2021 global oil demand averaging 99.71 million, still 1.2 million barrels a day below 2019 levels.

Saudi price hike could drive Asian buyers to U.S. crude

(Reuters commentary; June 8) - Saudi Arabia’s decision to jack up the price of its July oil exports to Asia may have opened the door for U.S. producers to boost sales to the region that consumes more crude than anywhere else in the world. State-controlled producer Saudi Aramco hoisted its official selling prices to all regions for July-loading cargoes, but the biggest hikes were for Asia, which takes the bulk of Saudi exports.

Saudi Energy Minister Prince Abdulaziz bin Salman told a news conference on June 8 that the strong official prices are a sign that global oil demand is returning. The price increase came after OPEC+ agreed to extend their output cuts to the end of July, prolonging the measure that was in place for May and June. However, an additional voluntary cut of 1.18 million barrels per day by Saudi Arabia, Kuwait, and the United Arab Emirates will not continue beyond June, Prince Abdulaziz said.

With the July price increase, the Saudis are trying to boost the amount of crude they are selling from May and June's higher output levels, while simultaneously earning more for the smaller volume they can deliver in July. It's a fine line to tread. The risk is that refiners, particularly in Asia, will buy as little Saudi crude as they can in July and boost purchases from producers outside the OPEC+ agreement — including those in the U.S.

Price crash hits Bakken hard; Permian expected to continue growth

(The Wall Street Journal; June 9) - As the U.S. shale industry slowly recovers from a historic crash in oil prices, it is poised to grow in fewer places than before. Even before prices fell into negative territory in April, investment in once-booming oil fields in North Dakota and South Texas was waning while producers drilled through many of their sweetest spots. Now the Permian Basin straddling Texas and New Mexico is securing its spot at the center of U.S. oil production as drillers focus on the richest targets.

The Permian is set to return to growth next year and continue through 2030, consulting firms Rystad Energy and Wood Mackenzie estimate. Among those expanding in the Permian are ExxonMobil and Chevron, which have each detailed plans to increase output to one million barrels a day by 2024. By contrast, the Eagle Ford region of South Texas is unlikely to top its 2019 output until 2024 and then will decline, the firms said. Rystad projects North Dakota's Bakken will not reach last year's average until 2026.

"The Bakken was well on its way to being a 2-million-barrel-a-day oil field," said Kelcy Warren, CEO of pipeline company Energy Transfer, which operates the Dakota Access Pipeline and transports Bakken crude. "If we had $70-a-barrel crude and kind of a normalized business again, I think we'll get back on track for that, but it's going to be a while." The Energy Information Administration expects the Bakken to generate 1.1 million barrels of oil a day this month, down from about 1.5 million barrels last fall. Major producers of Bakken crude have been among the hardest hit in the industry downturn.

Oil spill could increase focus on Russia's Arctic activities

(S&P Global Platts; June 9) - Risks from climate change to Russia's oil infrastructure and its plans to drill in the Arctic may come under closer scrutiny after the leak of about 150,000 barrels of gasoil into waterways in Siberia. The major spillage from an industrial storage site May 29 — although a relatively common occurrence in Russia — prompted President Vladimir Putin to declare a state of emergency and demand tougher rules.

Nornickel — the mining company that owns the storage site — blamed the leak of highly sulfurous "winter gasoil" on soil subsidence and thawing permafrost. Melting subterranean ice has been flagged as a risk to oil pipelines and infrastructure globally, especially in oil-rich Arctic areas from Alaska to Siberia. "Generally warmer permafrost means less ability to support infrastructure," said Dmitry Streletskiy, associate professor of geography and international affairs at George Washington University.

The oil industry is coming under pressure globally to reduce its role in climate change. Putin only recently acknowledged the risks late last year in his annual press conference addressing the impact of thawing permafrost on towns in arctic regions. Still, Russian oil and gas arctic production has increased over the past decade. Production in the Arctic accounted for 11.8% of overall output in 2007, rising to 17.6% in 2017, and is projected to grow to 26% by 2035, according to the statistical arm of Russia's energy ministry.

Oil spills are common in Russia. Natural resources supervisor Rosprirodnadzor estimates there were 819 leaks in 2019, covering a total area of 230 acres. Russia's biggest onshore leak is thought to have happened in 1994 when over 800,000 barrels of oil escaped from a pipeline in the Komi region, according to BCS Global Markets.

Russian agency wants fuel tanks drained before another Arctic spill

(The Barents Observer; Norway; June 10) - The Russian Environmental Control Authority has called on Nornickel and its subsidiary Norilsk Taymyr Energy Co. to close down a major fuel storage park and empty the tanks of diesel oil. The storage is used for the mining company's power station. The warning from Rosprirodnadzor comes after last week's leak of more than 150,000 barrels of diesel oil into the local Taymyr Peninsula tundra and adjacent lakes, rivers, and creeks.

According to Rosprirodnadzor, the catastrophe happed after the concrete foundation under the tank began to sink and the bottom of the tank detached from its walls and the fuel spilled into the surroundings. The reservoir park is owned by the Norilsk-Taymyr Energy Co., a subsidiary of mining and metallurgy major Nornickel. It was built in 1985 and the reservoirs reportedly underwent inspection and repair in 2017-2018.

There are four similar reservoirs at the site, three of which are in operation. They are now a major subject of concern for environmental inspectors. In a letter to Norilsk Taymyr, Russia's environmental watchdog warns that the other reservoirs could fall to the same fate as the first collapsed tank. The reservoirs together could hold more than 400,000 barrels. The agency proposes that the company pump all the diesel fuel out of the reservoirs by Aug. 9 and carefully study the technical condition of the facilities.

Britain has gone two months without any coal-fired power

(Reuters; June 9) - On June 10, Britain reach two months in a row without using electricity from coal-fired power stations for the first time since its 19th-century industrial revolution, according to the country's National Grid operator. Britain was home to the world's first coal-fueled power plant in the 1880s, and coal was its dominant electric source and a major economic driver for the next century.

However, coal plants emit almost double the amount of carbon dioxide — a heat-trapping gas blamed for global warming — as gas-fired power plants. Britain plans to close its coal plants by 2024 as part of the efforts to reach the country's net-zero emissions goal by 2050. Low power prices amid weak industrial demand due to measures to contain the novel coronavirus, and levies on carbon emissions, have made it increasingly unprofitable to run coal plants.

Use of renewable power, such as wind and solar, has soared over the lockdown period, helped by lower running costs than fossil fuel producers and favorable weather conditions. May saw the greenest ever month for electricity production in Britain with the lowest average carbon intensity on record at 143 grams of CO_2 per kilowatt hour, National Grid said. Carbon intensity is a measure of how much carbon dioxide is emitted for each kilowatt hour of electricity produced.

IEA forecasts global natural gas demand to drop 4% this year

(Reuters; June 9) - The coronavirus crisis and a mild winter in the northern hemisphere have put global natural gas demand on course for the biggest annual fall on record, the International Energy Agency said in its annual outlook June 10. Global gas demand is expected to fall by 4% this year — twice the size of the drop following the 2008 global financial crisis. Major gas markets have experienced record low prices as lockdowns and reduced industrial output due to the COVID-19 pandemic have stunted demand.

For the full year, more mature markets across Europe, North America, and Asia are forecast to see the biggest drops in demand, accounting for 75% of the total fall in 2020. "Global gas demand is expected to gradually recover in the next two years, but this does not mean it will quickly go back to business as usual," said Fatih Birol, IEA executive director. "The COVID-19 crisis will have a lasting impact on future market developments, dampening growth rates and increasing uncertainties," he added.

The IEA forecasts 2.6 trillion cubic feet of lost annual demand by 2025 — the same amount as the increase in global demand in 2019. After 2021 most of the increase in demand will be in Asia, led by China and India where there is strong policy support. Liquefied natural gas is expected to remain the main driver behind any growth, but it faces the risk of prolonged overcapacity as the build-up in new export capacity from past investment decisions outpaces slower than expected demand growth, the IEA said.

Demand losses set back global LNG growth rate

(S&P Global Platts; June 9) - LNG market growth is set to decelerate sharply in 2020 on the back of pandemic-driven demand losses, with most analysts cutting their forecast for the year and some predicting an outright year-on-year contraction in LNG trade. This is likely to be the market's sharpest growth deceleration in years and contrary to expectations that 2020 was to have been one of strongest growth years for LNG with the addition of new U.S. liquefaction capacity, which is now expected to be worst hit.

Global LNG trade in 2019 amounted to 354.73 million tonnes, which was an increase of 13% from 2018 and the sixth year of consecutive growth, according to the International Gas Union, a Barcelona-based gas industry trade group. But brokerage Poten & Partners expects Poten expects LNG demand in 2020 to fall below the 2019 levels by almost 2%, and even that view may not be bearish enough. It could be almost 4%, or almost 14 million tonnes, due to risks of secondary waves of the pandemic and economic recessions, said Jason Feer, Poten's global head of business intelligence.

Feer said that demand declines are spread across India, Pakistan, Bangladesh, Thailand, Kuwait, and Singapore, among others, while China and some European countries will show marginal growth. Consulting firm Wood Mackenzie has cut its 2020 estimates and now expects demand essentially unchanged from 2019. But research director Robert Sims said there is the chance that low LNG prices could trigger Indian industrial demand, and boost coal-to-gas switching demand in Japan and South Korea.

LNG demand in China, India will depend on price and coal policies

(Reuters commentary; June 9) - The latest International Energy Agency report on the global gas market makes somber reading, especially for current and would-be suppliers of liquefied natural gas. No doubt much of the commentary on the report, issued June 9, will be around the headline forecast that global gas demand will drop by 4% in 2020, or 5.3 trillion cubic feet, as consumption takes a hit from COVID-19's economic impacts.

The IEA forecasts a gradual demand recovery in 2021 and 2022, but the impact of the coronavirus will be long lasting, increase uncertainties and dampen growth rates. Any recovery is likely to be led by Asia, the IEA said. This may sound encouraging for the LNG industry, but there are some caveats around the IEA's forecasts for Asia. The chief concern is that much of the rebound in demand is to come from China and India, but the optimistic scenarios are dependent on whether Asia's two fastest-growing major economies continue with gas-friendly policies, or whether they backslide and favor coal.

The future of China's coal-to-gas switching policies remains uncertain, after previous strict moves in favor of gas in order to reduce air pollution were relaxed last winter. China has also allowed the planning and construction of new coal-fired power plants to proceed, and even accelerate, as part of plans to boost the economy. India, too, wants to use more gas over coal, but getting the gas at an affordable price is key.

Overall, the prospects for LNG seem inextricably linked to whatever policies are implemented by Beijing and New Delhi, as well as keeping prices low enough to act as an incentive to demand growth, especially at the expense of coal.

Enbridge plans transition to more natural gas, renewable energy

(Calgary Herald; June 8) - Enbridge, North America's largest pipeline company, is shifting its asset mix to reflect the energy transition underway across the world. Al Monaco, CEO of Calgary-based Enbridge, said it is taking a "gradual" approach to energy transition. While it will continue to invest in oil pipelines, the company will also invest increasingly larger proportions of its capital in natural gas and renewable energy projects as consumers around the world demand lower-emitting forms of energy.

"If you look at the energy supply/demand balance globally, we as a company kind of mirror that. We have a meaningful part of our business in renewables — the base is probably 5% of our assets," Monaco said in an interview with the Financial Post. Currently, 55% of the company's earnings are generated from its liquids pipeline business, roughly 40% from its gas transmission and storage business and 4% from renewables, which consist primarily of offshore wind projects in the U.K. and Germany.

The company has identified a number of renewable opportunities off the coast of France. Enbridge has identified offshore wind opportunities in North America as well. "There's still lots of runway for oil and natural gas, but it makes sense for us to mirror that global supply picture. I think you'll find most companies, or the vast majority of companies in our sector, are not positioned in that way," Monaco said. "We think having a diversified approach, having a gradual approach to the transition through natural gas and renewables makes a lot of sense," he said.

Mid-sized LNG carriers a good fit for emerging markets

(Bloomberg; June 9) - The new Saga Dawn liquefied natural gas carrier shuttling between Singapore and Humen in eastern China is a sign that the fastest-growing fossil fuel is permeating into markets once thought inaccessible. A so-called mid-sized tanker, the ship can travel up the Pearl River to access inland markets, extending LNG's reach beyond traditional coastal facilities. The emerging trend could unlock access to cleaner-burning fuel for remote buyers, while helping exporters grow demand in new markets.

And with LNG spot prices at record lows amid a global oversupply, it's also a cheaper solution for end-users. The mid-size vessels, with capacity between 20% and 60% of a full-size LNG carrier, are being tapped for deliveries to smaller Asian buyer that don't require a full shipment of the fuel and might just have bare-bone storage and distribution infrastructure. Besides, larger vessels, the backbone of the LNG trade, often cannot enter waters near cities where demand is emerging the strongest.

"Especially in Asia and India where you have shallow waters, they cannot have large tankers going up and down these rivers," said Sarah Behbehani, former senior vice president for LNG at JERA Global Markets in Japan. With capacity one-third that of a full-size LNG carrier, the Saga Dawn can unload at Jovo Energy's new terminal in Dongguan, one of the cities comprising the Pearl River Delta metropolis in China. Singapore's Pavilion Energy and India's Venerable LNG are also looking at such vessels, which can help LNG replace dirtier fuels in smaller, inland markets.

Canada's Inuvialuit propose LNG plant to serve the far north

(CBC; Canada; June 10) - The Inuvialuit have an ambitious plan to produce liquefied natural gas to bring energy independence to Canada's remote Northwest Territories. The Inuvialuit Petroleum Corp. is teaming up with Ferus Natural Gas Fuels to advance the Inuvialuit Energy Security Project. Ferus is owned by a Houston-based investment fund. According to a June 9 news release, the plan is to tap into the Tuk M-18 well and build a plant to liquefy the gas so that it can be trucked to Inuvik and other communities.

The well was drilled by Devon Energy and Petro-Canada almost 20 years ago. It's part of the gas reserves left stranded when Esso and its partners abandoned their proposed Mackenzie Gas Project to serve North American markets. The companies said the well has more than 200 billion cubic feet of recoverable gas. Though Inuvik, population 3,200, is the area's biggest town and key to the project's success, LNG could be sent to other communities by truck or barge to reduce greenhouse gas emissions and provide a cheaper alternative to diesel, said Doug Matthews, an energy analyst and consultant.

If the project goes ahead, it will be the first resources enterprise spurred by the new all-weather Inuvik-to-Tuktoyaktuk Highway. "The local market … isn't big enough to cover the costs of developing that field. With the road, you can reach other markets, which changes the economics of the project quite significantly," Matthews said. The plan is to complete the design work this fall and then develop cost estimates. If all goes well, LNG deliveries could start in 2022. The territories' former premier said the project could cost C$400 million to build and could be financed if the government pledged to buy the gas.

IRS examining, disallowing some carbon-capture tax credits

(Houston Chronicle; June 10) - Two years ago, Congress enlisted oil companies to help develop an underground carbon storage system to aid in the fight against climate change. Oil producers had for decades pumped carbon dioxide underground to increase output, steadily filling depleting oil reservoirs with the climate-warming gas. To get oil companies to pump more of the greenhouse gas underground, a bipartisan group of senators championed legislation that doubled tax incentives for oil companies using carbon captured from the smokestacks of power plants and other industrial sites.

But since the carbon storage program began in 2008, oil companies have taken the tax credit without providing evidence that the carbon dioxide is staying underground and not leaking into the atmosphere, as required under the law. The Treasury Department's inspector general recently reported that of the $1 billion in carbon-capture tax credits claimed between 2010 and 2019, almost $900 million — 90% — went to oil companies that never offered any proof they are storing the amount of CO_2 claimed on tax forms.

The findings followed a report by the group Clean Water Action, which found that the tax credits being exceeded the amount of carbon the Environmental Protection Agency reported going into storage. Companies are required to set up monitoring programs to verify they are storing as much carbon as claimed, in part because not all the carbon dioxide pumped into oil reservoirs stays there — some escapes. The IRS is examining the filings of 10 companies that account for more than 99% of all the claims and, so far, has disallowed almost $600 million, about 60%, of the credits due to lack of monitoring.

Nigerian LNG cargo headed to import terminal in Savannah, Georgia

(Reuters; June 10) - A ship carrying liquefied natural gas from Nigeria is expected to unload its cargo in Georgia as energy firms look for a place to store the fuel with prices higher in the United States and stockpiles nearing full capacity in Europe. The ship, the Madrid Spirit, does not have a destination listed, according to data from Refinitiv, but is located a day or two away from Kinder Morgan's Elba Island LNG plant in Savannah.

A unit of Shell chartered the ship, sources said. Shell, which has a long-term contract to use Elba, declined comment. The United States, which is the world's third biggest LNG exporter behind Australia and Qatar, does not receive a lot of LNG imports, but they do occur. Analysts said it makes sense for some energy firms to store LNG in the U.S. because U.S. gas prices have traded mostly higher than in Europe since late April.

So far in 2020, the U.S. received at least 10 LNG deliveries with seven going to Exelon's terminal in Massachusetts and three, including one this week, to Dominion Energy's plant in Maryland, according to federal and Refinitiv data.

NYC investment company takes over proposed Louisiana LNG project

(Houston Business Journal; June 10) - New York-based investment platform Glenfarne Group is the mystery buyer of a Houston company's proposed liquefied natural gas project in Louisiana. LNG Ltd. said last week that it sold its flagship project, Magnolia LNG, to a newly formed entity called Magnolia LNG Holdings for $2 million. The latest deal came on the heels of two earlier failed transactions to sell the development amid a restructuring of LNG Ltd., which is technically based in Australia with offices in Houston.

Now, Glenfarne Group — a developer, owner-operator and industrial manager of energy and infrastructure assets — has made its own announcement that it completed the acquisition through the newly formed subsidiary. "Magnolia LNG is a well-known and high-quality project to which Glenfarne brings its funding, marketing, development, and construction expertise to take it to final investment decision, and then construct and operate," Brendan Duval, founder and managing partner of Glenfarne, said June 9.

Magnolia's 115-acre site is near Lake Charles in southwest Louisiana. The project is proposed for 8 million tonnes annual capacity, and has completed the Federal Energy Regulatory Commission approval process. But it lacks sufficient capital, customers and financing to reach a go-ahead decision at this time. Glenfarne has another subsidiary that is the majority owner of Texas LNG in Brownsville, also at the proposal stage.