Oil and Gas News Briefs
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BP embarks on transformative change to low-carbon energy

(Washington Post; Aug. 4) - With climate change bearing down on the planet and the novel coronavirus upending the fossil fuel business, one of the world's biggest oil and gas companies on Aug. 4 mapped out how it plans to navigate the next decade by radically cutting back on its oil and gas business. BP will transform itself by halting oil and gas exploration in new countries, slashing oil and gas production by 40%, lowering carbon emissions by about a third, and boosting capital spending on low-carbon energy 10-fold to $5 billion a year.

"This makes the BP the first supermajor to spell out, in detail, what the energy transition will actually entail, in practical terms," said Pavel Molchanov, senior energy analyst for the investment firm Raymond James. "We believe our new strategy provides a comprehensive and coherent approach to turn our net-zero ambition into action," BP CEO Bernard Looney said in a statement. "This coming decade is critical for the world in the fight against climate change, and to drive the necessary change in global energy systems will require action from everyone."

The briefing also revealed more of the change at the company once known as British Petroleum. It means an immediate 50% cut in dividends, but that will arm the company with more cash as it reacts to climate change. It's also an admission of profound change in the oil and gas business. A dozen years ago, ExxonMobil set profit records and was the envy of the market. Now the company is no longer in the top tier. Microsoft is worth nine times as much. Exxon, which supplies gasoline to automobiles, is worth $180 billion, not even two-thirds the market value of Tesla, the maker of electric vehicles.

BP expects its oil and gas production to fall 40% over next decade

(S&P Global Platts; Aug. 4) - BP expects its oil and gas production to fall by at least 1 million barrels per day of oil equivalent, or 40%, over the next decade, as it transitions to a lower-carbon energy business, the company said. Under a new strategy announced Aug. 4, BP said it will boost investment in low-carbon projects such as renewables and bioenergy by 10-fold to around $5 billion per year by 2030 as part of plans to become a "net-zero" emitter.

The move will see BP's upstream oil and gas production fall from 2.6 million barrels of oil equivalent per day in 2019 to around 1.5 million, while its refining throughput is expected to fall from 1.7 million barrels per day in 2019 to around 1.2 million. "BP has been an international oil company for over a century, defined by two core commodities produced by two core businesses. Now we are pivoting to become an integrated energy company," CEO Bernard Looney said in a statement.

As a result, BP said it expects emissions from its operations and those associated with the carbon in its upstream oil and gas production to be lower by 30% to 35% and 35% to 40%, respectively. BP had already flagged plans for the "most wide-ranging reorganization in [BP's] history" on Feb. 5, announcing ambitious targets for the oil major to become a net-zero carbon emitter by 2050 or sooner.

BP plans to double volume in LNG portfolio by 2030

(S&P Global Platts; Aug. 4) - BP plans to double the size of its LNG portfolio to 30 million tonnes a year by 2030 as part of its new low-carbon strategy, Chief Financial Officer Murray Auchincloss said Aug. 4. Downstream gas supply remains a key pillar of BP's strategy despite a pledge to cut upstream production sharply in the coming years to focus on low-carbon energy supply including renewables, bioenergy, and hydrogen.

Speaking to investment analysts, Auchincloss said BP's current LNG portfolio is around 15 million tonnes per year, comprised of equity and merchant (trader) volumes in a roughly 50-50 share. The key to expanding the portfolio would be decisions around the mix of equity LNG versus merchant LNG, he said. "That is really the big thing that we'll have to work our way through," he said.

BP has built up its merchant LNG portfolio in recent years by agreeing to off-take from projects where it does not hold equity, such as a deal to buy from the Eni-operated Coral LNG facility under construction for Mozambique. He said the big decision for the coming decade is around how to build out BP's equity LNG position and making projects competitive, citing projects such as Browse LNG in Australia, the Tortue LNG project offshore Mauritania and Senegal, and the Tangguh LNG project in Indonesia.

Exxon says low prices threaten up to 20% of its oil and gas reserves

(Bloomberg; Aug. 5) - ExxonMobil warned that low energy prices may wipe as much as one-fifth of its oil and gas reserves off the books. If depressed prices persist for the rest of the year, "certain quantities of crude oil, bitumen, and natural gas will not qualify as proved reserves at year-end 2020," the company said in a regulatory filing Aug. 5. A 20% hit would impact the equivalent of almost 4.5 billion barrels of crude, or enough to supply every refinery on the U.S. Gulf Coast for 18 months.

The company's massive Kearl oil sands mine in Alberta was the only specific asset singled as a potential victim of any year-end revision. Imperial Oil, which is about 70% owned by Exxon and run as a subsidiary, said in a separate filing that an undetermined portion of Kearl's reserves may be imperiled. Exxon isn't waiting until the traditional end-of-year reserves reassessment. After slashing its drilling budget by $10 billion to cope with the virus-driven market collapse, the company on Aug. 5 said it removed about 1 billion barrels from its books. Most of that involved shale fields, according to the filing.

Separately, Chevron said Aug. 5 that it expects to revise its reserves downward by about 10%, mainly in the Permian Basin and Australia. Shell, BP, and Total have written off billions of dollars in reserves in recent weeks as the pandemic destroyed oil demand and prices, making some fields unprofitable to drill. Exxon had been the sole holdout during the current crisis, having not revised anything lower until now.

Exxon shifts and will impose more spending cuts, project delays

(Bloomberg; Aug. 3) - ExxonMobil is ripping up its debt-fueled, $30 billion-a-year plan to rebuild an aging worldwide portfolio after cash flow evaporated and threatened the company's vaunted dividend. The shift by the Western world's premier oil explorer represents an about-face after more than two years of doing pretty much the opposite of its biggest rivals, which have been shrinking and looking to a future beyond fossil fuels. As recently as March, the Texas giant had pinned its future to huge capital spending on oil and natural gas at a time when peers were exploring ways to decarbonize.

CEO Darren Woods' plan was to lean on Exxon's impeccable balance sheet to drill for gushers and still cover almost $15 billion in annual dividends. If cash flow fell short, its stellar credit rating would allow it to borrow its way through lean times, or so the thinking went. But the global pandemic that smashed energy demand amid a stubborn glut of crude overwhelmed Woods' ambitions. Cash flow fell to zero in the second quarter, Exxon said July 31, and one of the CEO's top lieutenants announced all bets were off.

The company is pursuing "significant potential" budget cuts and some managers may find themselves out of a job as a result, Senior Vice President Neil Chapman said in a conference call with analysts. Those cuts would be in addition to ongoing efforts to trim its U.S. workforce by as much as 10% and a $10 billion scale-back in capital outlays. More striking was Chapman's announcement that work on Exxon's five marquee developments — deepwater oil in Guyana and Brazil, Permian Basin shale, gas exports from Mozambique and Papua New Guinea — will all be curtailed or delayed.

Exxon wants to truck stranded crude oil in California

(Santa Barbara News-Press; CA; Aug. 4) - Allowing ExxonMobil to transport crude oil on Highway 101 and State Route 166 in California faces considerable pushback from local environmental groups, though the corporation insists it is a safe practice that will bring considerable economic benefit to Santa Barbara County. The Santa Barbara City Council approved a resolution Aug. 4 opposing the plan.

Last month, the county released an environmental impact report on ExxonMobil's proposal to transport crude by tanker trucks as an early step toward restarting its three offshore platforms that were shut down in 2015 after a pipeline ruptured and led to a large oil spill. The proposal would allow for seven-days-a-week, 24-hour trucking of crude oil with a maximum of 70 trucks within a 24-hour period. Each truck would transport about 160 barrels of crude for a daily average oil production rate of 11,200 barrels, about a third of the production rate before the pipeline shut down.

The trucks would be loaded at the ExxonMobil Las Flores Canyon facility and would deliver to the Phillips 66 Santa Maria Pump Station, or the Plains Pentland Terminal in Kern County. Trucking would cease after seven years or once a replacement pipeline is installed, whichever is shorter. The county planning commission will hold hearings on the project on Sept. 2 and 9 with opponents planning to speak against the proposal.

Louisiana shale producer selling fields for 10% of what it paid in 2016

(Bloomberg; Aug. 4) - Range Resources is selling its Louisiana shale fields for about one-10th of what it paid for them just four years ago as depressed natural gas prices hammered the heavily indebted driller. Range agreed to sell the assets that it acquired in its 2016 takeover of Memorial Resource Development to Castleton Resources for $245 million, according to statements by both companies Aug. 3. Range stands to reap an additional $90 million in the future contingent on higher commodity prices.

The $335 million potential total value compares to the approximately $3.3 billion Range originally paid in an all-stock deal for the fields. The biggest-ever deal for Range turned into a bust when the company's geologists and engineers soured on the quality of the rocks in early 2018. Range is also cutting 100 jobs, or about 17% of its workforce, mostly as a result of the sale, Chief Financial Officer Mark Scucchi said during a conference call with analysts on Aug. 4. Castleton Resources is owned by Castleton Commodities International and Tokyo Gas.

[OPEC+ in 'high-wire balancing act' to keep supply in check]

(CNBC; Aug. 3) – OPEC and its allies need to find a balance between supporting oil prices while keeping U.S. crude production at bay and risk oversupplying the market, a strategist told CNBC this week as the oil-producing group starts to roll back its supply cuts. The alliance's historic production cuts of 9.7 million barrels per day expired July 31. Starting in August, the cuts will be tapered to 7.7 million barrels per day.

"I think we're witnessing kind of a high-wire ... balancing act that OPEC+ is trying to execute here," said John Driscoll, chief strategist at JTD Energy Services. "Now they've restored the balance, prices have recovered, but they have to be very careful because they don't want to be the victim of their own success," he said Aug. 3. "If prices were to zoom past $45 a barrel, $50 a barrel on the back of these cuts, that may be waving the red cape in front of the U.S. … producers," he said.

"This is a very delicate, fragile balancing act and there's this cloud of uncertainty overhanging all of it on the pace of recovery," Driscoll said, adding that it is difficult to predict how quickly the global economy can recover. He also is "very skeptical" about where oil demand is going to come from, given that travel plans are still being canceled this summer. "It's hard for me to imagine anything approaching a rosy scenario on demand recovery when you look at those blighted sectors like commercial aviation."

[Regulators look into trading on the day U.S. crude went negative]

(Bloomberg Businessweek; Aug. 3) - On April 20, the price of a barrel of oil for delivery in May plummeted $40 in an hour, settling at negative $37. It was the first time crude had ever crossed into negative territory. Regulators, oil executives and investors have struggled to understand how a commodity at the heart of almost every aspect of global trade had fallen so far that buyers had to pay counterparties to take it off their hands.

A tiny trading firm called Vega Capital London pocketed as much as $500 million that day, according to people familiar with the matter, who spoke to Bloomberg on condition of anonymity. Vega's jackpot involved about a dozen traders aggressively selling oil in unison before the West Texas Intermediate contract for May settled, the people said.

It's a tactic Vega used regularly, according to another person familiar with the firm's strategy, but that day its trading coincided with a period of unprecedented volatility, when demand for fuel was wiped out by the coronavirus pandemic while storage in Cushing, Oklahoma, where buyers take physical delivery of oil, had all but disappeared.

Regulators at the U.S. Commodity Futures Trading Commission, the U.K.'s Financial Conduct Authority and the owner of the New York Mercantile Exchange where the trading took place are examining whether Vega's actions may have breached rules on trading around settlement periods and contributed to oil's precipitous fall that day.

The plunge, however brief, created big losers. They include thousands of Chinese and American retail investors who, lured by oil's recent slump, had piled into instruments whose value was pegged to the contract's April 20 settlement price. "Regulators need to objectively and thoroughly investigate what happened," said Joe Cisewski, special counsel to Better Markets, a lobbying group that advocates for tougher regulation.

BLM moves closer to approving 5,000-well development in Wyoming

(S&P Global Platts; Aug. 3) - After more than five years in the making, several producers moved a major regulatory step closer to developing a potential 5,000-well oil and gas project on federal land in Wyoming, but current market realities may get in the way. Occidental Petroleum, Chesapeake Energy, Devon Energy, EOG Resources and Northwoods Energy collectively submitted the proposal in 2014 to develop oil and gas wells on 1.5 million acres in Converse County, Wyoming, over the Powder River Basin.

The federal Bureau of Land Management opened a public comment period on July 31 for its final environmental review and resource management plan amendment on the massive project. A 60-day Governor's Consistency Review also began July 31. Upon resolution of the reviews, the BLM will issue a record of decision. If approved, the final environmental impact statement and resource management plan amendment would allow the five oil and gas companies to drill about 500 wells each year.

Although drilling activity and production had been on the rise in the Powder River Basin over much of the past year, operators quickly halted development following the commodity price collapse and onset of demand destruction related to the coronavirus in March. That month operators averaged a total of 20 rigs across the basin, which is located primarily in northeastern Wyoming and southeastern Montana, according to S&P Global Platts Analytics. The count plummeted to one rig in May and zero by June.

Carbon-capture system that served Hilcorp field shuts down in Texas

(Houston Public Media; Aug. 3) - Electricity company NRG and JX Nippon Oil and Gas Exploration have suspended operation of their much-hyped carbon-capture system at NRG's W.A. Parish coal power plant near Sugar Land, Texas. The Petra Nova system was opened to great fanfare a little more than three years ago. It captures CO2 from coal-fired power generation and pipes it to Hilcorp's West Ranch oil field 80 miles away, where it's used to extract more oil — a method called enhanced oil recovery.

The oil is supposed to pay for the expensive operation. But with the market crashing this year, that's not happening. On top of that, Petra Nova did not supply enough carbon dioxide to the oil field to extract a profitable amount of crude, said Ramanan

Krishnamoorti, chief energy officer at the University of Houston. Krishnamoorti said the plant would likely benefit from more sustained government subsidies.

"If we only want to work with the free-market way of doing it, we're going to end up with these sorts of pauses," he said. "Things get started up, things get stopped, things get shut down." Petra Nova cost $1 billion to build. It was supported with a $190 million grant from the U.S. Department of Energy. NRG said it plans to reopen it "when economics improve." Krishnamoorti said the companies should use that time to improve the carbon-capture system. "It might actually prove to be a blessing in disguise," he said. "Because when it comes back, it probably would be more efficient than it was."

U.S. shale producers focus on minimizing output decline

(Bloomberg; Aug. 5) - America's most prolific shale drillers are accepting a fate once anathema to an industry obsessed with growth: Drilling just to ward off production drops. The pandemic and subsequent plunge in crude prices has forced U.S. crude explorers to scrap plans to expand supplies amid investor skepticism toward the shale business model. For some of the biggest names in the Permian Basin, that has meant vowing restraint as long as oil lingers at price levels too low to justify a new boom.

The pledges come on the heels of the worst crude crash in the 161-year history of the petroleum industry. Explorers are disclosing just how deeply their balance sheets were wounded by a quarter that included the unheard-of phenomenon of negative prices. "These guys have all just had a near-death experience," said Raoul LeBlanc, an analyst at IHS Markit. "It will take some time to get themselves back in a better position."

"Certainly, we're not seeing any signals that growth is needed," Travis Stice, chief executive officer at Diamondback, said during a conference call Aug. 4. "Growth in today's world is pretty much off the table." Drillers are focusing shrunken capital budgets on minimizing the steep output declines unique to shale wells, which start out as gushers before quickly declining to trickles. U.S. production will likely end the year close to 10.1 million barrels a day, about 20% lower than at the start, said IHS. Production will only increase by 350,000 barrels per day next year, according to the firm's analysts.

Court allows Dakota line to continue operating while appeal underway

(Reuters; Aug. 5) - A U.S. appeals court on Aug. 5 said the Dakota Access Pipeline does not have to be shut and drained per a lower court order while the legal battle continues over the federal permit that allowed the line to be built. U.S. regulatory officials may still need to issue another environmental assessment before deciding if the

570,000-barrel-per-day oil pipeline can keep operating, the U.S. Court of Appeals for the District of Columbia said.

In July, the U.S. District Court for the District of Columbia ruled the U.S. Army Corps of Engineers violated federal environmental law when it granted an easement to Energy Transfer to construct and operate a portion of the pipeline beneath South Dakota's Lake Oahe, a crucial drinking-water source for the Standing Rock Sioux tribe. That judge said the line, controlled by Energy Transfer, would have to shut down by Aug. 5. The Appeals Court decision allows the line to remain running while the appeal will continue.

"We will need to run the course with this litigation. … We believe our legal positions are strong," Energy Transfer's chief legal counsel said on an earnings call. The District Court must make additional findings before the pipeline can be shut, said Earthjustice attorney Jan Hasselman, who represents the Standing Rock Sioux. "The bottom line is that the fight continues," she said. The line's construction spurred months-long protests by activists and Native American tribes. The pipeline came into service in mid-2017.

Global utilization rate at refineries lowest in 37 years

(The Wall Street Journal; Aug. 3) - U.S. refiners slashed production during the second quarter as they reeled from a historic decline in demand for gasoline and jet fuel. Long a bright spot in the oil patch, refiners such as Valero Energy, Marathon and Phillips 66 pumped the brakes as the coronavirus pandemic kept people off the roads and out of the skies, crushing demand for the fuels they produce.

U.S. consumption of gasoline and distillates including diesel has rebounded from its April low to about 90% of year-ago levels, U.S. Energy Information Administration data show. But demand for jet fuel remains anemic, at little more than half of last year's level, a sign that global oil demand is likely to remain depressed for years. Worldwide, fuel makers have coped by processing far less crude, shutting down some facilities and constraining spending. This year's average global refinery utilization rates are expected to be the lowest in 37 years, according to the International Energy Agency.

Refiners typically make less money when they operate well below capacity because the cost of operations doesn't decline by much. U.S. refiners' second-quarter results give a glimpse of challenges ahead as new fuel-efficiency requirements and electric vehicles threaten their businesses. That's the reality already facing refiners in Europe, where demand for transportation fuels had fallen even before the pandemic. "The pandemic is a harbinger of the coming energy transition more broadly, where oil demand declines year after year," said Kurt Barrow, a vice president at analytics firm IHS Markit.

Indonesia will allow oil and companies to choose contract structure

(Reuters; Aug. 2) - Indonesia announced over the weekend that it had made revisions to a 2017 law that will give oil and gas investors more flexibility when choosing their contract options for exploration and production. The revisions, which took effect July 16, now allow companies to choose between different production-sharing contracts including the "cost-recovery" and "gross-split" systems in an effort to boost investment.

Indonesia adopted the gross-split scheme for oil and gas production deals in 2017, in which companies shoulder the cost of exploration and production in exchange for retaining a bigger portion of the oil and gas they recover. That represented a shift from the cost-recovery structure used previously, in which the government reimbursed the exploration and production costs borne by the companies in exchange for the government taking a larger share of oil and gas earnings.

"The government, through the Ministry of Energy and Mineral Resources, is officially allowing flexibility for investors to choose the form of oil and gas cooperation contracts," the energy ministry said in a statement Aug. 1. "This change is to provide legal certainty and increase investment in upstream oil and gas business activities," it said. Under the revised law, expiring contracts no longer have to be converted to gross-split production-sharing contracts from cost-recovery contracts if a company would rather not.

China far short of meeting target to buy U.S. oil, LNG and coal

(Reuters; Aug. 3) - China bought only 5% of the targeted $25.3 billion in energy products from the United States in the first half of 2020, falling well short of its trade deal commitments at a time when relations between the two top economies are already sour. China's imports of crude oil, liquefied natural gas, metallurgical coal, and other energy products totaled around $1.29 billion this year through June, according to Reuters calculations based on China customs data.

While Chinese purchases of U.S. products accelerated recently, analysts say weak energy prices and worsening relations means Beijing may well undershoot its full-year goal in the Phase 1 deal agreed in January. "China is unlikely to fulfil its Phase 1 commitments as they were overly ambitious to begin with," said Michal Meidan, a director at the Oxford Institute for Energy Studies, adding that she expected Beijing to step up purchases to show goodwill.

Failure to meet the target could further strain U.S.-China relations. U.S. crude had been expected to feature prominently in China's imports. But a surge in freight rates coupled with a collapse in fuel demand, as COVID-19 spread, made U.S. oil relatively costly for refiners in China. China imported only 45,603 barrels per day of U.S. oil in the first half of 2020 compared with 85,453 barrels per day a year ago. Sushant Gupta, research director at consultancy Wood Mackenzie, said that to meet the trade deal target, China would need to import 1.5 million barrels per day of U.S. crude in 2020 and 2021.

FERC will decide by Dec. 2 on using Kenai LNG terminal for imports

(Reuters; Aug. 5) - U.S. energy regulators said Aug. 5 they plan to make a decision on Marathon Petroleum's plan to convert the Kenai liquefied natural gas export plant in Alaska into an import terminal by the end of the year. The Federal Energy Regulatory Commission said it planned to issue an environmental assessment by Sept. 3 and make a final decision by Dec. 2. The federal authorization deadline comes 90 days after the environmental assessment.

In April, FERC delayed an earlier plan to issue an environmental assessment by April 24 since it had to wait for the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration to make a decision on the company's plan for a vaporizer, used in regasifying LNG for delivery into a pipeline. PHMSA said in May that it had no objection to the planned location of the vaporizer.

The Kenai LNG export plant entered service in 1969. It was the only LNG export facility in North America until Cheniere Energy's Sabine Pass export terminal in Louisiana entered service in February 2016. Nearly all of the LNG from Kenai went to Japan. ConocoPhillips, the operator at Kenai, mothballed the facility in 2015 before selling it to a unit of Andeavor in February 2018. Marathon Petroleum completed its purchase of Andeavor in October 2018.

Global coal-fired power plant capacity declines in first half 2020

(Bloomberg; Aug. 3) - Global coal-fired power capacity edged down for the first time on record in the first half of 2020 as plant retirements accelerated amid the pandemic while new projects were put on hold. The closing of plants, especially in Europe and the U.S., outpaced the start of new units, more than 60% of which were in China, according to a report by Global Energy Monitor. Regardless whether plants have closed, many are running at far less than full capacity as cheap natural gas cuts into coal's market share.

The net decline of 2.9 gigawatts may be small, at just over 0.1% of the world's coal generation capacity, but marks a turning point in the burning of the dirtiest fossil fuel to produce electricity. "The COVID pandemic has paused coal plant development around the world and offers a unique opportunity for countries to reassess their future energy plans and choose the cost-optimal path, which is to replace coal power with clean energy," said Christine Shearer, program director for coal at Global Energy Monitor.

As developed economies in Europe and North America increasingly shift toward cleaner energy sources, coal mining companies are looking to fast-growing Asian countries to shore up demand for the heavy polluting fossil fuel. Still, world coal demand is set for its biggest annual drop since World War II as economic activity plunges due to coronavirus lockdowns, the International Energy Agency said in April. The pace of new coal construction in Asia is slowing, with countries including Bangladesh and Vietnam considering restricting or deferring new plants, according to Global Energy Monitor.

South Korea company expands LNG supplier business

(Reuters; Aug. 4) - South Korea’s Posco International is set to become a liquefied natural gas supplier to Pakistan LNG, two sources familiar with the matter said. Posco has offered lowest bid of a 7.9673% “slope” to the Brent benchmark price of a barrel of crude for supply of an LNG cargo Sept. 25-26, the sources said. It’s unusual for Posco to participate in Pakistan’s LNG import bids and could mean that the Korean company is trying to expand its third-party trading activities, according to an industry source.

At an almost 8% slope to crude prices, the LNG delivered to Pakistan would cost about $3.20 per million Btu at current Brent prices, though the actual price would depend on the time period selected for the oil-market linkage.