Oil and Gas News Briefs
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Alberta had its chance, but spent it

(Bloomberg; Aug. 6) - If any place in North America should have been prepared for the crash in prices, it's oil-rich Alberta, the Saudi Arabia of Canada. Back in 1976, Alberta's government established a special fund to save some of its oil and gas revenue for leaner times when prices dropped or resources ran dry. For decades, royalties poured into Alberta's coffers with the gusher accelerating in the boom of the early 2000s as the province developed its vast oil-sands reserves, the world's third-largest oil resource.

But successive governments failed to stick to the savings plan. Had it set aside more during oil's boom, it could have had a C$575 billion ($433 billion) wealth fund to ease the blows of COVID-19, according to one economist's estimates. Instead, the Alberta Heritage Savings Trust Fund is down to just C$16.3 billion after losing C$1.9 billion because of the pandemic and a wrong-way bet against market volatility.

That's not enough to help much in a province suffering 15.5% unemployment and a falling credit rating. "Many people in Alberta might not even realize the Heritage Fund still exists," said Trevor Tombe, an economics professor at the University of Calgary. His estimate that the fund could have been worth C$575 billion uses the fund's actual investment returns but assumes the province had followed savings and withdrawal practices similar to those that helped Norway amass its $1.12 trillion savings account.

The Heritage Fund, which initially received 30% of Alberta's resource revenue, was meant to transfer the oil wealth to future generations, not serve as a rainy day fund or for diversifying the economy, said Colleen Collins, who worked for the premier when the fund was set up in the late 1970s. In 1987, the government stopped adding resource revenue to the Heritage Fund as low oil prices caused mounting deficits. The fund has limped along since, contributing investment income to the province's general revenue.

The province has Canada's lowest corporate tax rate, relatively low personal income tax rates and is one of the few North American jurisdictions without a sales tax. Even with low taxes, the 1990s' rise of the oil sands allowed Alberta to post 14 straight years of surplus budgets before the streak ended in 2008. Tombe recommends a start by putting a small slice of Alberta's resource revenue into the fund and boosting that over time. The lost revenue could be made up by raising tax rates or implementing a sales tax.

[Oil partnership between Russia, Saudi Arabia may be hard to maintain]

(The Wall Street Journal; Aug. 7) - Saudi Arabia, the dominant force of OPEC, might as well have been herding cats in recent years trying to bring order to the unruly cartel. It wasn't until Russia and others piled in to make it "OPEC+" that the market purred and reversed collapsing prices. But now the expanded group's greatest accomplishment could falter as oil prices stabilize and as Riyadh and Moscow's interests diverge.

After a historic glut — partly of their own making — Saudi Arabia and the rest of the Organization of the Petroleum Exporting Countries, joined by Russia, agreed to slash crude output by an unprecedented 9.7 million barrels a day in April. Compliance has been remarkable. In mid-July, as markets were recovering, OPEC+ agreed to allow production to increase by 1.6 million barrels a day. Yet that very improvement in the market could hobble cooperation between Saudi Arabia and Russia going forward.

"Under $40 [a barrel], they were able to come together. The higher the price, the harder it will be to get Russia to go along with continued production cuts — especially once you get to $50 a barrel for Brent crude," said veteran OPEC-watcher Gary Ross, CEO of Black Gold Investors. Even with markets recovering to the $40s, the Saudis need still higher prices than Russia to cover heavy government spending.

Russia, however, which values market share, faces pressure from its oil companies to allow higher production: Many smaller firms, which account for more than a million jobs, are at risk of bankruptcy — partly because of the way Russia's tax system is structured. Any gains from higher prices tend to go to the state, not the companies, creating an incentive for oil companies to increase their volume at lower prices to generate profit.

[Saudi Arabia scales back crude deliveries to U.S.]

(Bloomberg commentary; Aug. 9) - Saudi Arabia is slashing the amount of oil it's sending to America in an attempt to force down stockpiles in the world's most visible oil market and thereby hasten the rebalancing of supply and demand. Shifts in the flow can have a big impact on U.S. inventories. Riyadh has clearly decided it's time to do its bit to bring them down from the heights of May and June, when the pandemic and the Saudis' own output hike drove the fastest ever surge in U.S. commercial crude stockpiles.

In May and June, tankers full of Saudi crude were arriving off the Gulf and West coasts of the U.S. almost daily, sometimes more than one a day. But in July and August that has dwindled to little more than one a week. That surge in ships briefly drove U.S. imports of Saudi crude close to a six-year high, adding to the upward push on stockpiles and a downward push on prices. But it was short-lived and imports in the last week of July were just 190,000 barrels a day, their second-lowest level in weekly data that extends back a decade. The figure could fall even further in the coming weeks.

There are only six tankers carrying a total of 9 million barrels of Saudi crude currently showing a U.S. destination, according to tanker-tracking data. With a journey of about six weeks from the Persian Gulf to any of the major U.S. oil ports, that's all the Saudi crude that's likely to arrive by mid-September. The leaders of Saudi Arabia and the U.S. both want to see higher oil prices — the kingdom's budget still depends on oil revenues and the U.S. shale industry desperately needs higher prices to recover.

Russia boosts exports of fuel oil to U.S., replacing Venezuela crude

(Reuters; Aug. 6) - Russia has continued increasing fuel exports to the United States, raising them by 16% in July from June, to almost 8 million barrels for the month, replacing crude supplies from Venezuela, Refinitiv Eikon and traders' data showed on Aug. 6. Attractive pricing and lower freight rates have also supported demand for Russian fuel oil.

The U.S. imposed sanctions on Venezuelan oil last year in an effort to squeeze out President Nicolas Maduro. As many U.S. refineries historically process heavy crudes, including from Venezuela, the United States has increased purchases of fuel oil, including from Russia. Supplies by Moscow to the U.S. doubled to 80 million barrels last year from 2018, according to Refinitiv Eikon data.

Refineries in the United States mostly use Russian fuel oil as feedstock for further refining as well as for marine fuel. Russian fuel oil shipments to the United States come mainly from the Baltic Sea port of Ust-Luga, according to Refinitiv Eikon data. In January-July of this year, Russia supplied 47 million barrels of fuel oil to the United States, on track to match record-high volumes of 2019, the data showed.

Reuters reports BP plans to sell more oil and gas assets

(Reuters; Aug. 6) - BP is preparing to sell a large chunk of its oil and gas assets even if crude prices bounce back from the COVID-19 crash because it wants to invest more in renewable energy, three sources familiar with BP's thinking said. The strategy was discussed at a BP executives meeting in July, the sources said, soon after the oil major lowered its long-term oil price forecast to $55 a barrel, meaning that $17.5 billion worth of its assets are no longer economically viable.

But even if crude prices bounce back to $65 to $70 a barrel, BP is unlikely to put those assets back into its exploration plans and would instead use the better market conditions as an opportunity to sell them, the three sources said. Major oil companies typically hold assets for the long term, even when crude prices plunge with a view to start bringing more marginal production online when market conditions improve.

BP's new divestment strategy means there will be no way back for the company once it has offloaded its stranded oil and gas assets. BP did not respond for a comment. The new strategy also sheds light on CEO Bernard Looney's plan to reduce BP's oil and gas production by 40% by 2030, or at least 1 million barrels per day, while expanding into renewable energy. BP has yet to name the other assets it wants to sell. Sources have previously told Reuters that BP has identified Canadian oil sands assets and projects in deep water off Angola as being uneconomical under its new oil-price scenario.

Active U.S. drilling rig count lowest since 2005

(Bloomberg; Aug. 7) - Drillers cut exploration in U.S. oil fields to a 15-year low as billions of barrels from old discoveries became worthless and explorers abandoned growth plans. The number of active oil rigs in the U.S. fell by four to 176, the lowest since 2005, according to Baker Hughes data released Aug. 7. Energy companies have been parking rigs on an almost uninterrupted streak for more than four and half months.

Stung by the pandemic-driven slump in demand and prices, oil explorers are fleeing from the very lifeblood of their business: Drilling for new discoveries. ExxonMobil and Chevron have warned they probably will wipe billions of barrels of reserves from their books because weak prices have made them unprofitable to pump. Instead of searching for untapped deposits of crude, executives are channeling cash into dividends and other shareholder-friendly initiatives to appease investors fed up with years of poor returns.

"North American E&Ps (exploration and production companies) are in a battle for investment relevance, not a battle for global market share," Matt Gallagher, chief executive officer at Parsley Energy, told analysts during a conference call. "Allocating growth capital into a global market with artificially constrained supply is a trap our industry has fallen into time and time again." The rig count is a closely watched metric because it's long been considered indicative of future crude production.

Texas looks to reduce gas flaring at oil wells

(Marketplace.org; Aug. 6) – Texas oil wells produce a lot of excess natural gas, and the Texas Railroad Commission, the agency that regulates oil and gas in that state, said Aug. 4 it's implementing changes in hopes of reducing the amount of gas that gets burned off in flaring. "We're flaring about 1% of U.S. production," said Robert Kleinberg at Columbia University. That doesn't sound like a lot, "but U.S. production is very large, and 1% is the equivalent of supplying something like 7 million homes," he said.

Flaring gas is a waste. Companies flare because gas is cheap, and figuring out a way to use it is often more costly than just burning it. "If you're way out in West Texas with no convenient pipe, or if pipeline transportation costs are higher than what you get at the marketing hub, then you'd flare it because there's no economic driver for saving it," Kleinberg said. The Institute for Energy Economics and Financial Analysis found that oil companies in the Permian Basin of West Texas wasted $750 million of gas in 2018.

"Increasingly, you're seeing third-party, data-collection operation through drones, satellites and flights, which are collecting and beginning to make public very, very granular data," said Varun Rai, director of the Energy Institute at the University of Texas at Austin. On Aug. 4, Texas regulators told oil companies they must offer more thorough justifications for why they need to flare. In part, that's to curb damage to the environment. Flaring emits carbon dioxide, methane and other pollutants into the atmosphere, contributing to climate change and poor air quality.

North Dakota disputes producers' royalty expense deductions

(Inforum; North Dakota; Aug. 10) - Several oil and gas producers are behind on bills owed to North Dakota for school funding, according to the state Department of Trust Lands. Twelve firms operating in western North Dakota, including top producers Hess, Continental Resources and Whiting, owe millions of dollars to the state after taking improper deductions from their royalty payments, Land Commissioner Jodi Smith said.

Continental, the state's top royalty payer, is locked in a three-year legal battle over the deduction dispute. North Dakota Petroleum Council President Ron Ness said the companies believe they have been paying the right amount and the department is unfairly demanding too much. More than 30 companies owe tens of millions of dollars in gas royalties, and the disputed oil royalties are "significantly more," Smith said.

Most of the money funnels into the Common Schools Trust Fund, which supports K-12 education. The friction between the state and industry over gas royalty payments is well-publicized, but the feud over underpaid oil royalties has taken place mostly behind the scenes. The companies contend that they should be permitted to take deductions to cover post-production costs, like removing impurities from oil and transporting it. The state said that violates the companies' state leases, while Ness said the department is being "a bit greedy" by disallowing transportation costs and other back-end expenses.

Opponents sue Utah over state grant for private oil rail line

(Public News Service; Aug. 7) - Conservation groups have sued a Utah state agency, claiming illegal use of public money to construct a private oil-and-gas rail line. The Utah Permanent Community Impact Fund board awarded a $28 million grant to help the Uinta Basin Railway move crude oil to refineries in border states. The suit, filed by the

Center for Biological Diversity and the nonprofit Living Rivers, claims the project will bring a significant increase in oil extraction and environmental damage.

John Weisheit, co-founder of Living Rivers, said the state's Community Impact Fund is there to repair damage from the fossil fuel industry, not to subsidize it. "These are public funds and they're supposed to be helping public communities," said Weisheit. "The Community Impact Fund board has discretion on which direction it goes, and they chose not to help communities as much as they are helping oil corporations."

The suit alleges the proposed 85-mile Uinta Basin Railway would increase oil drilling and fracking, strain public facilities and services, worsen the climate crisis, and harm public health. The project, originated in 2014, was intended to move oil from the Uinta Basin to a refinery complex near the Port of Oakland. But California officials denied a permit for the project because of its potential to cause environmental damage, leaving its backers to seek new sources of funding and a new destination for the rail line.

BLM approves 4,250-well expansion in Wyoming

(Casper Star Tribune; WY; Aug. 7) - An energy venture received approval to drill 4,250 additional wells in central Wyoming under a final decision released Aug. 7 by the Bureau of Land Management. The bureau's record of decision allows Aethon Energy and Burlington Resources Oil and Gas to drill 4,250 additional wells as part of the closely watched Moneta Divide project. Aethon and Burlington applied to drill 4,250 new wells throughout 327,000 acres of land — a checkerboard of private, state, and federal land — about 40 miles east of Riverton, Wyoming.

The companies aim to produce 254 million barrels of oil and 18.16 trillion cubic feet of gas over the project's estimated 65-year life, according to BLM. The company's request to expand was met with widespread protest from conservationists and nearby landowners. Many feared the contaminants in the briny water would pollute Alkali and Badwater creeks or eventually flow into the Boysen Reservoir Basin. The BLM decision comes months after state regulators decided to deny the company's request to release higher volumes of discharged wastewater as part of its proposed expansion project.

The Wyoming Department of Environmental Quality has not yet issued a final discharge permit for Aethon. BLM missed an opportunity to include more stringent safeguards for water in its final decision, said Alan Rogers, communications director for the Wyoming Outdoor Council. "Given the long history of polluted wastewater flowing from Moneta Divide into Boysen Reservoir, this seems like a missed opportunity," he said.

U.S. pipeline gas exports to Mexico up 11% first-quarter 2020

(Natural Gas Intelligence; Aug. 5) - Pipeline natural gas exports from the United States to Mexico averaged 5.3 billion cubic feet per day during the first quarter, up from 4.8 bcf per day, or 11%, in the year-ago period, according to the U.S. Department of Energy's latest quarterly report on the gas trade balance. Mexico accounted for 64.6% of total pipeline gas exports from the U.S., with the other 35.4% going to Canada.

Two pipeline transit points — Rio Grande City, Texas, and Brownsville, Texas — accounted for 46.2% of the total flow to Mexico. Brownsville is the starting point for TC Energy and Sempra Energy's Sur de Texas-Tuxpan subsea pipeline, which began flowing commercial volumes to Mexico last September. The line can carry up to 2.6 bcf per day. Flows from West Texas to Mexico are expected to continue growing as well, following completion of Fermaca's Waha-to-Guadalajara pipeline system in Mexico.

U.S. LNG exporters still moving along with several projects

(Reuters; Aug. 7) - U.S. liquefied natural gas producers made small steps to add export capacity this week, even as global energy demand destruction from the coronavirus pandemic has made it difficult for new projects to move forward. U.S. LNG exports were on track to rise for the first time in six months in August as the amount of pipeline gas flowing to the plants climbed from a 21-month low in July when buyers canceled dozens of cargoes.

Cheniere Energy, the nation's No. 1 LNG producer, said it plans to complete Train 6 at its Sabine Pass terminal in Louisiana in the second half of 2022. Previously, Cheniere said Sabine 6 would enter service in the first half of 2023. The company also said it remains on track to finish Train 3 at Corpus Christi, Texas, in the first half of 2021. Kinder Morgan said the ninth of 10 units at Elba Island in Georgia would be ready for service Aug. 10. The company has said all units at the plant will be ready this summer.

Sempra Energy said it continues to work with Mexican regulators to get a 20-year export permit for the first phase of its proposed Costa Azul LNG export plant. Sempra has said it planned to make a final investment decision in 2020 on Costa Azul, on the Baja California Peninsula. The company also said it still plans to make an FID on its LNG export terminal in Port Arthur in Texas in 2021.

Chevron brings experience to developing Israel's offshore gas field

(Reuters; Aug. 6) - Chevron's entry into Israel's Leviathan natural gas field will help deliver the technical and marketing smarts to turn the project into a global supplier, said the CEO of Israeli company Delek Drilling, the energy giant's new regional partner.

Chevron became the first major to enter the Israeli market when it agreed last month to buy Texas-based Noble Energy, which has stakes in Israel's offshore gas fields.

It's the first big energy deal since the coronavirus crisis, which has crushed fuel demand and added to doubts about the fossil fuel industry's future as pressure mounts on energy companies to shift to renewable sources. Chevron has said the acquisition strengthens its regional position and, over the long term, it expects population growth to drive demand for natural gas, which is less carbon intensive than some fossil fuels.

Leviathan, Israel's largest gas field, began production last year and exports to Jordan and Egypt, as well as supplying the local market. Majority partners Noble and Delek had been keen on tapping into the global liquefied natural gas market at a second stage, although Israel has no liquefaction plant. Options under study are piping the gas to liquefaction terminals in Egypt, or building a floating LNG terminal. "Chevron brings a significant LNG capability into the Leviathan project," said Delek CEO Yossi Abu.

Decision soon on controversial coal-seam Australia gas project

(Bloomberg; Aug. 6) - A key battle over the future of fossil fuels and climate change will soon be decided in a sleepy corner of Australia. After a decade-long struggle pitting a mix of farmers, grandmothers, and activists against oil producers and local and federal governments, a panel will decide by early next month whether to approve a A$3.6 billion (US$2.6 billion) natural gas project. The answer will arrive amid growing global opposition to fossil fuels and as traditional energy producers pivot toward green power.

Australia's path forward may illustrate how communities weigh the economic benefits of gas against environmental damage. Santos says its Narrabri project, about 311 miles northwest of Sydney, is essential for the country to move from coal-fired power toward a cleaner network based on wind and solar. However, "it's wrong to suggest that projects such as Narrabri are some sort of short-term bridge," said Simon Corbell, CEO at renewables-focused consulting firm Energy Estate. "It's not a short-term bridge, it's a long-lived investment that exposes us to significant environment and climate risk."

Narrabri has the potential to supply enough gas to meet half the demand in New South Wales, Australia's most populous state, and will help kick-start the nation's economic recovery from COVID-19, said Santos. But farmers that worry drilling through layers of rock and sandstone could compromise the hydrogeological structures that maintain vast aquifers used to supply water for livestock and crop irrigation, leading to water loss or contamination for farms that share the resource. There are also questions over the disposal of hundreds of thousands of tons of salt the coal-seam project will produce.

Energy traders look to profit from Japan’s deregulated market

(Bloomberg; Aug. 6) - Some of the world’s biggest energy traders are looking to get ahead in Japan’s nascent deregulated power market. From Shell to German utility RWE, companies are hiring, reassigning staff and building relationships with Japanese firms to profit in the $136 billion market. After building mature markets in Europe and the U.S., they have their sights on the third-biggest economy, which is taking shape the way European energy trading did 20 years ago.

While western markets are increasingly dominated by renewable energy and shrinking profits, the potential for price volatility and arbitrage in Japan are a trader’s dream: It has four distinct seasons, a growing supply of intermittent renewables, an uncertain future for its massive nuclear fleet and two separate power grids, not to mention a heavy reliance on imports of natural gas, which many of the new entrants already trade.

“I’m confident Japan will be the next big market,” said Steffen Riediger, a director at European Energy Exchange, which launched a service to clear futures trades in May. European companies are adopting various strategies. Swedish utility Vattenfall plans to hire a futures trader, while RWE has established a subsidiary in Tokyo. From there, the German company plans to be active in the physical and financial trading. Of 13 foreign firms seeking to trade Japanese power products, four have opened or are planning to open an office in Tokyo, according to traders and company spokespeople.

Australian regulators order inspection at Gorgon LNG plant

(Reuters; Aug. 7) - Chevron was ordered on Aug. 7 to inspect the propane heat exchangers on two of the three trains at its Gorgon liquefied natural gas plant in Australia following safety concerns raised by a trade union. Western Australia’s industrial safety regulator said the inspection orders were for Trains 1 and 3 and had to happen before Aug. 21. It was not immediately clear whether Chevron would have to shut down the liquefaction trains at the 15.6 million-tonnes-per-year plant, one of the world’s largest LNG projects, to conduct the inspection and any necessary repairs.

Last month Australia’s Department of Mines, Industry Regulation and Safety said it would inspect the plant following calls by a trade union to shut it down, after the company reported it had found a weld problem in the propane kettles on Train 2 while the unit was undergoing maintenance. The department’s Dangerous Goods and Petroleum Safety Director Steve Emery said in a statement that the nature of reported cracking in Train 2 could mean “there may be similar defects in Trains 1 and 3.”

“We are working closely with the regulator in planning and implementing repair work at Gorgon,” the company said in an email. Chevron said it planned to restart Train 2 in early September after completing repairs. Gorgon is 47.3% owned and operated by Chevron. ExxonMobil and Shell each own 25%, and the rest is held by Japanese firms.

India’s oil demand not expected to recover until March 2021

(S&P Global Platts; Aug. 6) - Hope that India's oil demand will recover in the second half of this year is fading fast as some provinces implement partial lockdowns to battle the COVID-19 pandemic, prompting refiners to start planning for lower crude runs in order to prevent oversupply at home. India, one of the fastest-growing oil markets in Asia in recent years, is expected to end 2020 with its oil demand slipping into the red, a trend not seen for nearly two decades, said government officials and oil analysts.

The last time India witnessed negative growth in oil demand was in 2001. India's oil demand took a big hit in the first half of this year when it implemented a countrywide lockdown. Even with partial lockdowns, according to S&P Global Platts Analytics, India's oil demand is expected to be down 115,000 barrels per day, year on year in the second half of 2020. Demand for the full year will be down an average of 405,000 barrels a day.

Petroleum Ministry officials said Aug. 5 that India's oil demand is expected to remain subdued and is unlikely to reach pre-pandemic levels until March 2021. The expectation is based on the latest re-imposition of lockdowns by many states to combat the community spread of the coronavirus. Indian Oil Corp., the country's largest state-run refiner, has reduced its run rate to 75% from as high as 93% during the first week of July, according to company officials.