Oil and Gas News Briefs
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BP says it's time it went back to work in Gulf of Mexico

(Bloomberg; May 2) - A few years before going down in flames, the Deepwater Horizon oil rig made a sensational discovery. In 2006, the semi-submersible rig — which was on a mission for BP — was drilling in the Gulf of Mexico when it found an enormous accumulation of oil buried so deep that no one had looked there before. That new oil field, named Kaskida, was both stunning and unattractive. It contained billions of dollars worth of petroleum, but the technology needed to develop it didn't exist.

The oil wasn't just far beneath the sea. It was under a thick layer of salt and under such high pressure and temperature that it would gush out into the seabed if tapped. Nothing at the time could have contained it. Just four years after finding Kaskida, the Deepwater Horizon rig exploded while drilling another well. The fire killed 11 workers. The largest oil spill in U.S. history cost BP more than $65 billion in cleanup cost and penalties.

In the wake of the disaster, Kaskida was all but forgotten. The spill essentially closed off the gulf to advanced exploration. The result was stagnation. Today, the part of the gulf under U.S. jurisdiction produces less oil than it did in the months before the 2010 spill — a sharp contrast with the rest of America where output has boomed thanks to shale oil. No one wanted to risk the challenges that came with pioneer work in the gulf. Until now.

"It's time for BP to open that basin up again," Murray Auchincloss, the company's new CEO, told investors recently. "We're really excited about it." If all goes as planned, BP will greenlight Kaskida in the second half of this year. Two other similar fields are likely to follow. The region is about to boom again. Others are joining BP in the geological strata of the gulf, known as the Paleogene. Shell, Chevron and a company backed by private-equity giant Blackstone are all racing to develop their own oil fields there. "The Gulf of Mexico is the gift that keeps on giving," Chevron CEO Mike Wirth said.

Industry expands search for oil in Gulf of Mexico

(The New York Times; May 3) - About 80 miles southeast of Louisiana's coast, 100,000 metric tons of steel floats in the Gulf of Mexico, an emblem of the hopes of oil and gas companies. This hulk of metal, a deepwater platform called Appomattox and owned by Shell, collects the oil and gas that rigs tap from reservoirs thousands of feet below the seafloor. Equipment on the platform pipes the fuel to shore.

Political and corporate leaders have pledged to reduce planet-warming emissions to net-zero by 2050, but companies like Shell are betting the world will need oil and gas for decades to come. To serve that demand, they are expanding offshore drilling into deeper waters, especially in the Gulf of Mexico. Offshore production, oil executives argue, is better for the planet than drilling on land. That's because such operations emit far less of the greenhouse gases that are warming the planet than producing the same amount of oil and gas on land, according to industry estimates.

The greenhouse gas emissions associated with extracting a barrel of oil from the Gulf are as much as a third lower than from producing a barrel of oil from fields on U.S. soil, according to a report last year by the National Ocean Industries Association, an industry group for offshore oil, gas and wind businesses. Oil production in the gulf fell for several years after the 2010 Deepwater Horizon disaster caused the worst offshore spill in U.S. history. But output has been rising over the past decade. Companies favor drilling in the gulf because there is a lot of oil and gas there, especially under very deep waters.

Big money flows into deepwater oil exploration and production

(Reuters; May 5) - As Big Oil returns this week to the industry's annual showcase for offshore energy projects and equipment in Houston, deepwater discoveries off Guyana, Namibia and the U.S. Gulf Coast will take the spotlight. Offshore exploration had dimmed after the U.S. shale boom ushered in new and cheaper-to-tap supplies, and as past offshore cost overruns pushed deepwater projects onto the industry's backburner.

But newer deepwater projects have the attributes oil and gas companies are looking for: longer-term production, lower breakeven costs, big resource potentials and lower carbon emissions, said Pablo Medina, head of new ventures at energy consultants Welligence. "Deepwater is back in vogue," Medina said. Capital spending on all-new deepwater drilling is poised to hit a 12-year high next year, predicts consultancy Rystad Energy. Investment in new and existing deepwater fields could hit $130 billion in 2027, a 30% jump over 2023, it said. The Offshore Technology Conference (OTC) opens May 6.

"The return of offshore and deepwater operations is going to be a big topic at OTC, and Namibia is going to be talk of the show," said James West, senior managing director at financial firm Evercore, referring to the recent series of oil finds off the west African coast. With crude oil prices above $70 a barrel, producers can expect a return on their multibillion-dollar deepwater projects in six years, a relatively short period considering the wells' longer lives compared with shale, explained Matt Hale, vice president of supply chain research at Rystad, at the Rystad Energy Forum in Houston last month.

Expanded Trans Mountain line can carry more oil than Keystone XL

(Financial Times; May 2) - Canada's oil industry lost a promising outlet for its crude when the controversial Keystone XL pipeline south to the U.S. was cancelled in 2021. This week it gained another route. A newly expanded Trans Mountain pipeline started commercial operations on May 1, funneling oil from landlocked Alberta toward tanker berths on the Pacific coast in British Columbia. It has also almost tripled the system's capacity to 890,000 barrels a day — more than Keystone XL was supposed to carry.

The most expensive infrastructure project in Canada's history, the C$34 billion (US$25 billion) pipeline expansion was first proposed a dozen years ago. After lawsuits, permitting delays, vast cost overruns and a federal government takeover, its price tag nearly quintupled from a forecast of C$7.4 billion in 2017. The government bought the line to ensure the expansion would be completed, planning to sell off the asset when the job was done. Ottawa will "launch a divestment process in due course," said Katherine Cuplinskas, press secretary for Canada's deputy prime minister and finance minister.

Rory Johnston, a Canadian energy analyst, said he expects the pipeline to sell for roughly half the C$34 billion in construction costs. The pipeline runs through many Indigenous communities and the government is planning to sell ownership stakes to these communities and provide access to capital to help finance their purchase. While some groups remain stridently opposed to the project, almost 70 Indigenous communities have signed benefit agreements regarding the pipeline.

Port constraints may limit export cargoes fed by new Canadian oil line

(Reuters; May 1) - Logistical constraints at the Port of Vancouver mean waterborne oil exports from the Trans Mountain pipeline expansion may only be around half what the Canadian government-owned corporation has forecast, traders and shipping sources said. The C$34 billion (US$24.82 billion) project to nearly triple the flow of crude from Alberta to Canada's Pacific Coast to 890,000 barrels per day opened for business on May 1 after years of regulatory delays and construction setbacks.

Trans Mountain says it has capacity at the dock to load 34 Aframax ships a month, but ship brokers and analysts have pegged the likely number at less than 20, citing concerns about pilot and tug boat availability and loading restrictions. "Theoretically they can handle the volumes, but auxiliary or secondary services are not ready for huge volumes," said Rohit Rathod, senior oil market analyst at ship tracking firm Vortexa.

Vessels leaving the dock must pass through a busy narrow shipping channel that runs beneath two major bridges to reach the open sea. To manage high traffic in the channel, the Port of Vancouver has restrictions including daylight-only transit for Aframax tankers and transit times based on tidal currents, said Sean Baxter, the port's acting director of marine operations. Aframaxes typically transport up to 800,000 barrels but at the oil dock they will be limited to loading around 550,000 barrels because of draft restrictions.

Tankers carrying Trans Mountain crude will have to be accompanied by a pilot and a tug boat for longer on each voyage, as part of new regulations imposed on the expansion project. Shipping crude on an Aframax to China will take about 18 to 20 days and cost about $17.42 a barrel, including pipeline tariffs, according to ship broker BRS. Larger tankers are more economical, but the Vancouver port cannot accommodate the bigger ships. Voyages to California refineries will take just two or three days.

OPEC+ meets June 1; speculation points to no change in production

(Reuters; May 2) - OPEC and its allies have yet to begin formal talks on extending voluntary oil output cuts of 2.2 million barrels per day beyond June, but three sources from OPEC+ producers said they could keep their cuts in place if demand fails to pick up. OPEC+ has implemented a series of output cuts since late 2022 amid rising output from the United States and other non-member producers and worries over global oil demand as major economies grapple with high interest rates.

OPEC+, which includes the Organization of the Petroleum Exporting Countries, Russia and other non-OPEC producers, next meets on June 1 in Vienna to set output policy. The OPEC+ group is currently cutting output by 5.86 million barrels per day, equal to about 5.7% of global demand. The cuts include 3.66 million barrels per day by OPEC+ members valid through to the end of 2024, and 2.2 million of voluntary cuts by some members expiring at the end of June.

Oil prices have found support this year from the conflict in the Middle East, although concern about economic growth and high interest rates has weighed on prices. Brent crude hit a seven-week low on May 1 and settled at $83.44 a barrel. The three sources from countries which have made voluntary supply cuts said an extension by OPEC+ was likely. The cuts could be extended until year-end, said one source, while another said it would take a surprise jump in global demand for OPEC+ to make any changes.

Less supply of heavy crude in Atlantic basin drives up refiner costs

(Reuters; May 2) - Mexican export cuts and a rerouting of Canadian output are shrinking already limited supplies of heavy crude in the Atlantic basin, driving up refiners' costs with a likely knock-on effect to industries ranging from shipping and construction to Mideast power plants. Prolonged OPEC cuts and international sanctions on Venezuela, Iran and Russia had already led to shortages of heavier crude, with the refineries built to process it, such as those in the U.S. Gulf, struggling to find cheap supplies.

Heavy-sour crudes yield more residual fuel oils that are either upgraded into higher-value road fuels or converted into marine fuels and bitumen. "The combination of tighter heavy crude and fuel oil supplies, as well as the seasonal rise in power generation demand is expected to push up fuel oil cracks in the weeks ahead," said Vortexa analyst Xavier Tang, referring to the spread between the price of crude and the refined product.

More marine fuel oil is needed by ships making longer voyages around Africa to avoid the Red Sea area, while Saudi Arabia burns more fuel oil for air conditioning in the summer and demand also increases from construction and roadbuilding activity. Mexico cut crude exports in April to promote more domestic refining as it seeks to end a costly dependency on fuel imports. That further threatened sour supply in the Atlantic basin where refiners have been preparing for this month's opening of the Trans Mountain pipeline expansion that will divert more heavy Canadian crude to the Pacific market.

China's Sinopec in talks for equity and gas from Canadian project

(Reuters; May 6) - China's Sinopec is in discussions with Pembina Pipeline for a liquefied natural gas offtake agreement and equity stake in the Canadian company's proposed Cedar LNG project in coastal British Columbia, two sources told Reuters. A joint venture between Haisla First Nation and Pembina, Cedar would be Canada's third LNG export terminal, costing roughly $4 billion. It would produce 3 million tonnes of LNG a year after completion in 2028, pending a final investment decision by mid-2024.

Together with the larger Shell-led LNG Canada project, which is under construction in Kitimat British Columbia, and the similarly sized Woodfibre LNG north of Vancouver, the three terminals would provide access for Canadian gas to Asian markets, reducing reliance on export sales to the U.S. Sinopec is in talks to purchase 1.5 million tonnes annually of Cedar LNG production under offtake capacity held by Pembina, the sources said, declining to be named as the talks are not public.

Cedar LNG announced in April separate 20-year offtakes with Canadian gas producer ARC Resources and Pembina for 1.5 million tonnes each. The world's largest refiner by capacity, Sinopec has slowed its investment in upstream oil and gas in the decade since the 2014/15 oil price rout and as Beijing increased its scrutiny of national oil companies' finances. With slowing oil demand growth but increasing gas use in China, Sinopec is looking to expand its global portfolio by investing in refining and petrochemical projects in Sri Lanka and Saudi Arabia and gas projects in Qatar and Canada.

Project delays likely to postpone global LNG oversupply to 2026

(Bloomberg; May 6) - A wave of new liquefied natural gas projects that was supposed to flood the global market starting next year now looks like it might not emerge until at least 2026. The main reason is that the build-out of new export plants across the U.S. Gulf Coast is at risk of taking longer than expected. That means the current supply tightness — a hallmark of the market since Russia’s invasion of Ukraine in 2022 — will be around for a bit longer.

QatarEnergy’s Golden Pass LNG facility in Texas may miss its first-half 2025 start-up date due to a shortage of workers. And while Cheniere Energy said last week that its Corpus Christi, Texas, expansion work will start this year, traders are anxious about any hiccups. The Arctic LNG 2 project in Russia, meanwhile, is likely to ship its first cargo to China this summer when ice levels in the Northern Sea Route recede. The plant is unlikely to operate at full capacity, however, as long as U.S. sanctions remain in place.

And Australian exports are slated to drop next year due to legacy production declines, while Egypt and Indonesia are also contending with falling output and higher domestic consumption. Expectations of a tighter 2025 are showing up in the futures market. The European benchmark contract for next year has jumped by around 17% since March. Make no mistake — the LNG market will still be oversupplied later this decade. Qatar’s massive expansion is on schedule, while potential U.S. project delays won’t last forever. But in the shorter term, be prepared for another year of heightened prices and volatility.

Start-up of LNG Canada could reduce gas exports to U.S.

(Reuters; May 3) - The start-up of LNG Canada, the country's first export terminal, is likely to strain its natural gas supplies for multiple years and force producers to reduce exports to the U.S., where demand for the fuel is at a record high, companies said. Shell-led LNG Canada has begun testing its C$40 billion Kitimat, British Columbia, terminal ahead of commercial operations starting in mid-2025. The terminal will process up to 2 billion cubic feet per day, representing 11% of current Canadian gas output.

Like Canada, the U.S. is building more liquefied natural gas terminals as it produces more gas than it consumes. However, even as the world's top gas producer, the U.S. does not drill enough to meet both its domestic consumption plus rising export demand. Western Canadian producers historically have been able to raise average production by up to 0.5 bcf per day year-over-year, indicating a temporary supply gap for U.S. and Canadian markets at the outset of LNG Canada's full operations, said Jamie Heard, vice president of capital markets at Tourmaline Oil, Canada's biggest gas producer.

"It's going to take, in our view, up to four years to satisfy the pull that LNG Canada by itself is providing to the market," Heard said. Canada exported about 8 bcf of gas by pipeline to the U.S. in 2023, compared with an average of 7.5 bcf per day over the prior five years, according to the U.S. Energy Information Administration. ARC Resources, Canada's third-largest gas producer, expects periods of lower Canadian exports to the U.S. when supply and demand are mismatched, but those periods are likely to be short-lived as the market rebalances, CEO Terry Anderson said in an email.

[Exxon expects decision on Mozambique LNG by end of next year]

(Reuters; May 2) - ExxonMobil is "optimistic and pushing forward" with its delayed Rovuma liquefied natural gas project in Mozambique and expects a final investment decision at the end of next year, a company official said on May 2. ExxonMobil and its partner Eni are developing the gas project in offshore Area 4 in northern Mozambique, with Exxon leading construction and operation of the onshore liquefaction and related facilities, while Eni concentrates on the floating production and upstream operations.

When TotalEnergies declared force majeure on its own gas project in 2021 due to an offensive by Islamic State-linked insurgents that threatened construction crews at its Mozambique work site, ExxonMobil was also affected due to development of shared facilities, such as a jetty for LNG carriers. "We recognize there are challenges. … We recognize that those challenges can be overcome if we work together," Arne Gibbs, general manager at ExxonMobil Mozambique, told an energy conference in Maputo.

"My message is quite simple. … We are optimistic, we are pushing forward," Gibbs said of the Exxon project expected to enter the front-end engineering and design phase in a few months. The project, initially slated for a production capacity of 15 million tonnes per year, has been redesigned to a new modular, electric-powered liquefaction plant at 18 million tonnes, offering more flexibility and producing fewer emissions, Gibbs said. He added that the company recognized that the security situation had improved due to the intervention of a regional military force as well as military support from Rwanda.

[Japanese LNG importers look to expand business in Southeast Asia]

(Nikkei Asia; May 2) - Southeast Asian countries' transition to liquefied natural gas and the expected surge in demand for the fuel is spurring Japanese companies to expand their LNG business in the region as their home market shrinks. In Southeast Asia, "a realistic energy solution for lower carbon emission is to reduce coal-fired power generation and shift to gas-fired (power plants) along with renewable energy," Michiaki Hirose, former president of Tokyo Gas, told Nikkei Asia in an interview.

Gas is becoming an important resource for Southeast Asia. Vietnam and the Philippines began importing LNG in 2023 to fuel gas-fired power plants. Tokyo Gas and Philippine energy company First Gen are expected to start jointly operating an import terminal in the Philippines as soon as they get government approval. The terminal will provide gas to a power plant. The Asia Zero Emission Community in Tokyo is intended to facilitate financial and technical support to help members transition to less-polluting energy.

Tokyo Gas has been importing LNG in Japan since 1969. "Japan became an LNG powerhouse over half a century," said Hirose. "The 'LNG era' will also come to Southeast Asia." According to an International Energy Agency projection, gas demand in Southeast Asia will about double by 2050 from 2020 numbers. Meanwhile, Japan's LNG imports have fallen since 2018 by 20% to 67 million tonnes, the lowest level in a decade, and the country's large consuming companies will have a growing surplus of contracted LNG supplies through 2030. Tokyo Gas is seeking to expand its business.

With declining gas production, Egypt rents floating LNG import unit

(Reuters; May 2) - Egypt's Natural Gas Holding Co. has struck an agreement with Norway's Hoegh LNG to rent the Hoegh Galleon floating storage and regasification unit for liquefied natural gas, the Egyptian petroleum ministry said on May 1. The unit will be leased "to secure additional needs for domestic consumption during the summer," the ministry said. Egypt is expected to ramp up LNG imports during the summer months to meet heavy demand that had led to a wave of rolling blackouts last summer, shocking Egyptians who had grown used to a decade of reliable power from gas production.

The government bought at least two LNG cargoes in April and is expected to purchase up to 20 over the spring and summer to prepare for increasing power demand, sources told Reuters. Returning to imports would reverse the most populous Arab country's position as a gas exporter in recent years.

The North African country, which faces growing demand for gas from its population of 106 million, has been seeking a regional supply role as an exporter but has made few large discoveries since the giant Zohr field in 2015. In 2023, Egypt's total gas production fell 11.5% year-on-year to about 2.1 trillion cubic feet, the lowest since 2017.

Gazprom reports $6.84 billion loss; first since 1999

(Bloomberg; May 2) - Russia’s state-controlled gas giant reported its first annual net loss since 1999 on falling shipments to Europe and lower prices for the fuel. Gazprom Group, which also includes oil and power businesses, posted a 629 billion-ruble ($6.84 billion) loss last year compared with net income of 1.23 trillion rubles in 2022, according to an earnings report published May 2.

The company’s shares fell as much as 4.4%, the steepest decline in more than a year, amid market concerns over its dividend prospects. Gazprom’s biggest shareholder is the Russian government, whose budget is under pressure amid rising military spending and Western sanctions. The net loss follows restricted gas flows to Europe — historically Gazprom’s biggest market — amid the Kremlin’s retaliation for Western support of Ukraine after Russia’s invasion in 2022. Meanwhile, plunging gas prices amid mild weather, sluggish demand and brimming inventories contributed to Gazprom’s loss.

Revenue from gas fell by 40% to 4.88 trillion rubles, according to the report. While Gazprom continues to ship pipeline gas to several European countries, last year its flows to Europe fell to the lowest since the early 1970s, according to International Energy Agency estimates. This year Russia expects its gas shipments via pipelines to foreign markets will increase 18% to 3.8 trillion cubic feet compared with 2023, as the Power of Siberia link to China gradually reaches its full nameplate capacity. But even as more supplies head to China, it can't offset the loss of the European market.

Foreign ships sanctioned for helping Russian oil and gas projects

(Barents Observer; Norway; May 2) – U.S. authorities continue to lash out against Russian gas company Novatek and its LNG projects in the Arctic. An updated sanctions list made public by the U.S. Treasury on May 1 includes a number of ships of major importance for Russian Arctic shipping. On the list are all the heavy-lift ships that have been involved in transporting production modules for the Arctic LNG 2 project under construction, among them the Hunter Star, Nan Feng Zhi Xing, Audax and Pugnax. The last two are owned and operated by Singapore shipping operator Red Box.

The two Red Box ships were on the Northern Sea Route from the Chinese port of Penglai to Belokamenka near Murmansk mid-winter this year. On board were large modules for Novatek's project. With their high ice-class rating, Audax and Pugnax were custom-built to provide transport services for Novatek's Arctic LNG projects. In April, the Hunter Star arrived in Belokamenka with a similar module — it was the 14th of its kind and will allow Novatek to complete a second production unit for Arctic LNG 2.

The sanctions include a number of cargo ships actively used by Russian companies engaged in industrial development along the Arctic coast. Russian firms Transstroy and Eko are included in the sanctions. The same goes for the Chinese company CFU Shipping. The new sanctions will make it harder for Novatek to continue development of Arctic LNG 2. The latest sanction package also targets Russian oil company Rosneft's ability to complete construction of its Vostok Oil project. For the past two years dozens of vessels have carried supplies to build port facilities and other infrastructure at Vostok.

FTC allows merger but bars high-profile shale executive from board

(Bloomberg; May 2) - The Federal Trade Commission's allegations that U.S. shale trailblazer Scott Sheffield tried to collude with OPEC to prop up crude prices is unnerving U.S. oil executives pursuing more than $100 billion in deals. While the green light May 2 from the FTC for ExxonMobil's $60 billion takeover of Pioneer Natural Resources provided some relief to an industry undergoing unprecedented consolidation, a key condition of the approval is triggering shockwaves.

Sheffield, Pioneer's founder and a high-profile figure in the shale industry, has been barred from joining Exxon's board, according to the agreement reached between the companies and the FTC. That represents a change for the U.S. antitrust agency, which in the past usually sought asset sales before assenting to deals, legal observers say. “It’s definitely avant-garde antitrust,” said Jeffrey Oliver, a partner at law firm Baker Botts and former FTC official. “It’s way for them to appear tough on a deal that they couldn’t find a route to try and block on any other grounds.”

Exxon closed its acquisition of Pioneer on May 3. Chevron, Occidental Petroleum, Diamondback Energy and Chesapeake Energy are among the companies with pending transactions currently under FTC review. The notion of the FTC scrutinizing individual executives has some companies with pending deals reviewing their regulatory-review strategies, as they are uncertain what the agency could throw at them next, according to people familiar with current deals. The FTC hasn’t sought to block an oil or gas deal outright in recent memory, preferring to reach settlements.