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U.S. will climb to No. 3 in the world as LNG export capacity grows

(U.S. Energy Information Administration; Dec. 10) - U.S. liquefied natural gas export capacity will reach 8.9 billion cubic feet per day by the end of 2019, boosting it to No. 3 in the world behind Australia and Qatar, according to the U.S. Energy Information Administration's latest outlook. U.S. LNG export capacity now stands at 3.6 bcf per day, and it is expected to end 2018 at 4.9 bcf as two new liquefaction units go online.

The United States began exporting LNG from the Lower 48 states in February 2016, when the Sabine Pass liquefaction terminal in Louisiana shipped its first cargo. Since then, Sabine Pass expanded from one to four operating liquefaction trains, and the Cove Point LNG facility went online in Maryland. Two more trains — Sabine Pass Train 5 and Corpus Christi (Texas) LNG Train 1 — have recently started production, several months ahead of schedule, and are expected to ship their first cargoes this month.

Two more facilities — Cameron LNG in Louisiana and Freeport LNG in Texas — are being commissioned. First LNG from these facilities is expected in the first half of 2019. Developers expect all three trains at Cameron and two trains at Freeport to be placed in service in 2019. Elba Island LNG near Savannah, Georgia, also is scheduled to become fully operational by the end of 2019. It consists of 10 small modular liquefaction units with a combined capacity of 0.33 bcf per day. Developers expect production from the first train to begin early next year and the nine other trains to follow through the year.

The second train at Corpus Christi is scheduled to be placed in service in the second quarter of 2019. The final two trains of projects currently under construction — Freeport Train 3 and Corpus Christi Train 3 — are expected in service in the second quarters of 2020 and 2021, respectively. Four more Gulf Coast terminals — Magnolia, Delfin, Lake Charles, and Golden Pass — and the sixth train at Sabine Pass have been approved by federal regulators and are expected to final investment decisions in the coming months.

Australia in November tops Qatar as biggest LNG supplier

(Bloomberg; Dec. 6) - The reigns of Qatar as the world's biggest seller of liquefied natural gas and Japan as the biggest buyer have come to an end — for one month at least. In November, Australia was the biggest exporter and China the biggest importer, according to Kpler, an energy research firm that focuses on ship-tracking data. Australia shipped out 6.55 million tonnes during the month, compared to 6.27 million for

Qatar. The start-up of new Australian projects like Inpex's Ichthys LNG have boosted the country's capacity this year as it nears the end of a $200 billion construction boom.

China took in 6.56 million tonnes in November, a 43 percent jump from October, while Japan imported 6.39 million, Kpler said in an emailed report. China's LNG imports have surged in the past two years amid government efforts to clear urban smog by replacing coal boilers with natural gas burners. Chinese buyers also wanted to build up stockpiles ahead of this winter's heating season to avoid a repeat of last year's shortages.

The changes underscore the shifting dynamics in the LNG industry. Among producers, Qatar is undertaking a major expansion project as it competes with growing output from Australia, North America, and Russia. Qatar expects to regain the title as the world's largest LNG producer in the early 2020s with its multibillion-dollar expansion. Global import growth is expected to be dominated by China and new, smaller markets such as Pakistan and Thailand as traditional buyers like Japan see their needs plateau.

Australia supplied 47% of China's LNG in third-quarter 2018

(S&P Global Platts; Dec. 6) – LNG exports from Australia's East Coast in November were the second highest since shipments began at the beginning of 2015, with volumes to China setting a record, data from the Gladstone Ports Corp. showed Dec. 6. A total of 1.92 million tonnes of the fuel was shipped during the month from the Port of Gladstone — home to all three of eastern Australia's LNG export terminals — an increase of 13 percent year on year. The November volumes translate to an annualized rate of 23.40 million tonnes against the terminals' nameplate capacity of 25.3 million.

Gladstone, which is in the Australian state of Queensland, is home to Origin-ConocoPhillips Australia Pacific LNG, Santos-led Gladstone LNG, and Shell's Queensland Curtis LNG. Each facility has two liquefaction trains with the first of the lot having come online in January 2015 and the last in October 2016. Energy consultancy EnergyQuest said utilization has increased throughout the year at the three projects.

"Chinese gas demand is growing rapidly as the Chinese government works to reduce some of the world's worst urban air pollution," said EnergyQuest CEO Graeme Bethune, adding that in the July-September quarter China's total LNG imports reached a record of 13.2 million tonnes, of which Australia supplied about 47 percent.

Louisiana LNG project signs preliminary deal pegged to Asian prices

(Reuters; Dec. 6) - Tellurian, which is working to develop a liquefied natural gas export project on the U.S. Gulf Coast, has signed a preliminary deal to supply LNG to global commodities trader Vitol. The deal prices the LNG against Platt's Japan-Korea Marker, the first time the daily assessment of spot LNG prices in northern Asia has been used for a long-term offtake agreement, according to S&P Global Platts.

In the United States, such long-term deals — which are critical to financing export terminals — are priced against the U.S. Henry Hub gas price. Most deals elsewhere are priced against oil, while some are priced against other natural gas hubs such as in the U.K. The memorandum of understanding is Tellurian's first preliminary offtake deal for its proposed Driftwood LNG project. The Federal Energy Regulatory Commission issued its draft environmental impact statement for the project in September.

Vitol aims to buy 1.5 million tonnes of LNG per year from Driftwood for 15 years once operations begin. The export terminal in Louisiana aims to have a capacity of as much 27.6 million tonnes per year and to start operations by 2023. Tellurian's co-founder is Charif Souki, a former head of Cheniere Energy, which operates the largest U.S. LNG export facility at Sabine Pass, Louisiana, and another in Corpus Christi, Texas. Souki is known for taking unconventional approaches toward the Driftwood project.

Louisiana LNG developer taps Kiewit for construction work

(Reuters; Dec. 6) - Venture Global LNG has selected U.S.-based Kiewit as the contractor to build its proposed Calcasieu Pass liquefied natural gas export project in Louisiana, the companies said Dec. 6. Venture Global also said it entered into a $220 million bridge loan with Morgan Stanley Senior Funding and associated lenders to pay for final engineering work and to start site activity for the project. Kiewit will design, construct, and commission the 10-million-tonne-per-year LNG terminal.

Venture Global said construction would start by early next year after the Federal Energy Regulatory Commission issues its authorization for the project. The FERC vote is scheduled for no later than Jan. 22, 2019, the companies said. Venture Global applied to FERC in September 2015. The project is expected to be completed in 2022, according to the developer. Venture Global has signed up several European buyers for the plant's LNG capacity including Spain's Repsol.

Virginia-based Venture Global reported in August it had raised $630 million from institutional investors to support its Calcasieu LNG project and its proposal to build an even larger terminal in Plaquemines Parish, Louisiana, 30 miles south of New Orleans.

U.S. LNG not price competitive in China when oil prices are low

(Bloomberg; Dec. 6) - China may be girding itself to buy more U.S. natural gas and soybeans amid easing trade tensions, but the sums don't add up right now. American supplies would be uncompetitive or unneeded when shipped to China, based on current prices, shipping costs, and other variables. So any resumption in purchases by the world's biggest gas importer and America's top soy buyer is unlikely to be for economic reasons and may be a political gesture by Beijing to smooth relations with Washington.

President Donald Trump's claim this week, following a meeting with his counterpart Xi Jinping, that China would boost purchases was welcome news for U.S. farmers and energy executives who have seen sales to the Asian nation virtually vanish. Chinese officials have been told to take necessary steps to rekindle trade, though it isn't clear if its recent import-stifling retaliatory tariffs would be cut. But China may not have much appetite for any additional gas right now beyond its baseload contracted volumes as its fuel tanks remain near capacity amid forecasts for an unseasonably warm winter.

North Asia's gas buyers, which are well stocked for winter, are awaiting colder weather before increasing spot purchases. And even if China were to seek short-term deals, it would be easier to turn to Australia or Malaysia. Oil-linked cargoes from those suppliers are currently cheaper than U.S. LNG shipments, which are priced off the Henry Hub benchmark gas price that is hovering near a 5-year high, according to Bloomberg calculations. "The key question is regarding Chinese buyers' appetite to underpin long-term U.S. LNG contracts for new projects, which they may still be hesitant to do until the truce proves sustaining," said Saul Kavonic, an analyst at Credit Suisse Group.

India could repeat China's coal-to-gas switch to clean up its air

(Bloomberg; Dec. 6) - China's dramatic increase in liquefied natural gas imports the past two years may have hogged the headlines, but India may well emulate its neighbor in switching to the cleanest and fastest-growing fossil fuel. As China's shift to natural gas from dirtier burning fuels such as coal and fuel oil helps improve air quality, India's cities are rising in pollution rankings. That may increase pressure on lawmakers in India to boost imports of LNG or face "civil unrest," Paul Wogan, chief executive officer of LNG ship owner and operator GasLog, said at an industry conference in London Dec. 5.

"It used to be if you look at the 50 most polluted cities in the world, 30 of them would be in China," he said. "If you now look at the 50 most polluted cities in the world, most of them are in India, and the Indian government is looking at this in the same way that China did." China surprised the industry with the strength of a government-led push to convert to gas, which led to a doubling of LNG imports over the past two years.

India's gas demand is seen rising 4.9 percent annually to 2040, outpacing growth of 4.7 percent in China, according to the International Energy Agency. The Indian government is keen to boost the use of gas to combat air pollution and is promoting the expansion of gas infrastructure, including four LNG receiving terminals under construction.

Analysts doubt easing of pollution rules will help coal power plants

(Bloomberg; Dec. 6) - The Trump administration is removing a key barrier to constructing new coal-fired power plants in the U.S. — but don't expect any utilities to actually build them. The Environmental Protection Agency on Dec. 6 is set to propose easing Obama-era limits on carbon dioxide emissions from new and modified coal power plants that effectively required the use of expensive carbon-capture technology.

Although that regulatory mandate was one obstacle to building coal power plants, economic and market realities have created much higher hurdles, which analysts say will endure no matter what the Trump administration does. "It's doubtful the proposed policy change will make much of a difference to any potential coal power plant developers," said Rob Barnett, an analyst with Bloomberg Intelligence.

"The economics of building a new coal plant just don't make sense given the availability of abundant and cheap natural gas" that has helped make new coal plants "among the most expensive electricity options at this point," Barnett said. Two years into Trump's presidency, despite regulatory steps to improve coal's fortunes, U.S. producers are still losing domestic customers as environmental regulations and economic pressures encourage utilities to embrace cleaner-burning gas and zero-emission renewables.

Since 2010, power plant owners have closed or have plans to close at least 630 coal plants — nearly 40 percent of the U.S. fleet, according to an industry group. "Coal plants are being challenged by low-cost gas and renewables," said Toby Shea, vice president at Moody's Investors Service, "an easing of regulations won't change that."

B.C.'s climate change plan has an 'LNG gap,' critic says

(CBC News; Canada; Dec. 6) - British Columbia's new climate plan has an "LNG-sized gap" in it, according to one environmental group, which argues there can be no more liquefied natural gas export projects if the province is to meet its lofty environmental goals. Many business and environmental groups and advocates are lauding the government's Clean B.C. greenhouse gas reduction plan announced Dec. 5 but some, like Peter McCartney of Wilderness Committee, are raising concerns.

"I still haven't heard an answer as to what their plan is to make sure these [natural gas] proposals don't blow their targets out of the water completely," McCartney said. The Clean B.C. plan includes, among other measures, tax breaks for home retrofits and zero-emission vehicles and incentives for the province's biggest industries to clean up their operations — including pushing the oil and gas industry to run its operations on electricity, not oil or gas. It's all part of the province's efforts to cut greenhouse gas emissions by 40 percent by 2030, 60 percent by 2040, and 80 percent by 2050.

However, the Dec. 5 reductions only fulfill 75 percent of the 2030 target. The province said the remaining 25 percent will be worked out in the next 18 to 24 months. The province's ambitious LNG plans — with new emissions from gas production and the liquefaction process — may be a reason it can't fully meet its 2030 target, McCartney said. A consortium led by Shell announced last month that it will build a C$40 billion LNG export project in Kitimat, B.C. The plant is scheduled to start up in 2024-2025.

Tokyo Gas signs up to develop LNG import project in the Philippines

(Reuters; Dec. 5) - Philippine power company First Gen Corp. and Tokyo Gas on Dec. 5 said they had signed a preliminary agreement to jointly develop a liquefied natural gas import terminal in the Philippines. Tokyo Gas will take a 20 percent interest in the project, which will be located in First Gen's complex in Batangas province, south of the capital Manila, the Philippine company said. No financial details were disclosed.

First Gen operates four of the country's five gas-fired power plants with total capacity of about 2,000 megawatts, all of them in Batangas. The Philippines is expected to start importing LNG to feed its gas-fired power plants as domestic supply from its Malampaya gas field is set to run out in 2024.

South Korea company may build LNG import terminal in Australia

(Reuters; Dec. 4) - A South Korea-based company has proposed building a receiving terminal on Australia's East Coast for liquefied natural gas, the fifth proposal for an import project in the world's No. 2 LNG exporter. The proposals have come after three new LNG export plants on the coast have sucked gas out of the southeastern market and nearly tripled wholesale prices in places such as Sydney over the past two years. Supporters of the import projects hope the new supply could lead to lower prices.

Credit Suisse analyst Saul Kavonic said there was not enough of a market for all five LNG import projects to go ahead. Nor is it certain that importing LNG will necessarily be cheaper than competing with exports for domestic gas supplies.

EPIK, a newly formed LNG floating storage and regasification unit (FSRU) development company, said Nov. 5 it had signed an agreement with the Port of Newcastle to do preliminary work on the project that it estimated would cost up to $430 million, including onshore infrastructure. "We are confident that by importing LNG via a new, low-cost FSRU terminal, we will be able to provide … a cost-efficient source of alternative gas supplies to the region," EPIK Managing Director Jee Yoon said.

B.C. regulator shuts down fracking after 4.5 earthquake

(CBC News; Canada; Dec. 7) - The B.C. Oil and Gas Commission has shut down oil field fracking operations for at least 30 days in northeastern British Columbia while it investigates earthquakes that occurred there on Nov. 29. The regulator said the seismic events, which measured between 3.4 and 4.5 magnitude, occurred near hydraulically fractured wells about 12.5 miles southeast of Fort St. John by Calgary-based Canadian Natural Resources.

The commission said the company immediately suspended work Nov. 29 and will not be allowed to resume without the commission's written consent. Six companies in or close to the area have also suspended fracking operations. The area closed off is about 7 miles by 4 miles in size, the regulator said. According to Natural Resources Canada, the 4.5 magnitude earthquake did no damage. It was followed by two smaller aftershocks.

Fracking involves injecting large amounts of water, sand and chemicals into a well to break up tight rock underground and allow trapped oil and gas to flow. The technology has been linked by the B.C. commission to previous incidents of "induced seismicity." The earthquake last week came close to matching the world's largest fracking-induced earthquake which occurred a little further north in 2015 and registered magnitude 4.6. Natural Resources Canada said there is still not complete certainty the Nov. 29 earthquake was caused by fracking, although the activities seem strongly correlated.

New rules in Texas could limit underground wastewater disposal

(Bloomberg; Dec. 6) - Texas is considering new restrictions on how shale explorers dispose of wastewater from oil drilling as earthquakes rattle the largest oil-producing state. The new rules would target how much and at what pressure briny water that emerges from oil wells is injected back into the ground, Jared Craighead, chief of staff for the Texas Railroad Commission, said Dec. 6. The rules haven't been finalized amid ongoing talks that include representatives from academia and the shale industry.

The restrictions may be released within weeks, Craighead said. A side effect of the shale boom has been a huge increase in the amount of contaminated water disposed of in so-called injection wells. In cases where those wells touch fault lines, earthquakes have flourished. Neighboring Oklahoma began clamping down on injection wells in recent years after a massive increase in the number and intensity of quakes. Oklahoma forced explorers to reduce the speed and volume of wastewater disposal after quakes measuring at least 3.0 surged from two in 2008 to about 900 seven years later.

In the Permian Basin, where America's busiest oil patch produces enough dirty water in a year to cover Rhode Island nearly a foot deep, the costly treatment and disposal has given rise to a more specialized water-handling industry. At the same time, earthquakes measuring at least 2.5 in the Permian region of West Texas and New Mexico have tripled to more than 60 in a year, according to the U.S. Geological Survey. The new rules in Texas are likely to impose conditions on drilling that could limit an injection well's pressure and volume, but that will be done case-by-case, Craighead said.

Falling oil prices will test economics of U.S. shale producers

(Wall Street Journal; Dec. 5) - The rapid fall in U.S. oil prices will test the claim of fracking companies that they can prosper at $50 a barrel or less, a price they have found challenging in the past. For years the companies behind the U.S. oil and gas boom have promised shareholders that they have thousands of wells that they can drill profitably even at $40 a barrel. But most haven't made much, if any, money at those prices. From 2012 to 2017, the 30 top U.S. shale producers lost more than $50 billion.

Last year, when oil prices averaged about $50 a barrel, the group as a whole was barely in the black, with profits of roughly 1.3 percent of revenue, according to FactSet. The disconnect between the figures cited by companies and their corporate returns lies in the widespread use of a metric called a break-even, often defined as the selling price frackers say they need to generate a small profit on individual wells or projects.

Break-evens, however, generally exclude such key costs as land, overhead and, at times, transportation. Estimates by consulting firm R.S. Energy peg break-evens excluding land costs and overhead at about $37 for the Permian Basin of West Texas and New Mexico, $42 for the Eagle Ford in South Texas and $47 for the Bakken in North Dakota. But companies require much higher prices in order to come out ahead if more of those expenses are taken into account. All-inclusive break-evens are about $51 in the Permian, $57 in the Eagle Ford, and $64 in the Bakken, according to R.S. Energy.

Historically, the break-even number has helped executives decide whether to drill a new well — given that funds may already have been invested in land and infrastructure.

Chevron will focus 2019 investments on U.S. shale

(Bloomberg; Dec. 7) – Chevron has raised its capital budget for the first time since 2014 even as crude prices plummet, doubling down on U.S. shale plays. The world's third-largest oil producer by market value will increase investments by 9.3 percent to $20 billion next year, according to a statement Dec. 6. The U.S. will account for 38 percent of the spend, the highest portion in at least a decade, as Chevron seeks to expand its foothold in the Permian Basin of West Texas and New Mexico.

Chevron is the first of the supermajors to detail its 2019 spending plans, which are being set during a period of considerable price volatility — crude has lost about a third of its value since early October. Saudi Arabia and Russia are orchestrating production cuts to boost prices as OPEC and its allies meet this week. Chevron CEO Mike Wirth's decision to raise spending while oil is in free fall shows how the industry has become more comfortable operating at lower prices after cutting costs in recent years.

Chevron's U.S. spend will focus on the Permian, which will receive $3.6 billion, a 9 percent increase over this year. Growth has been rapid in the region that now accounts for about one in every 10 barrels the company pumps worldwide. The Tengiz megaproject in Kazakhstan is also a key growth area for Chevron. The company's share of production at Tengiz in 2017 averaged 272,000 barrels of crude oil per day, 400 million cubic feet of natural gas and 21,000 barrels of natural gas liquids.

USGS estimates Permian Basin field holds 46 billion barrels

(Reuters; Dec. 6) - The largest oil field in the U.S. holds as much as 49 years worth of oil at current production rates, according to a report Dec. 6 by the U.S. Geological Survey. In its first assessment of the Delaware portion of the Permian shale field that spans West Texas and New Mexico, the USGS said it contains about 46.3 billion barrels of oil and 281 trillion cubic feet of gas. The estimates include all underground oil and gas that is technically recoverable but may not be economic at current prices.

The estimate is twice the size of the country's next largest shale reserve the Midland, which is another portion of the Permian. In 2016, that was found by the USGS to have about 20 billion barrels of oil and 16 trillion cubic feet of gas. Survey results "demonstrate the impact that improved technologies such as hydraulic fracturing and directional drilling have had on increasing the estimates," said Walter Guidroz, an official in the USGS Energy Resources Program.

The Permian Basin, which includes both shale regions, is expected to pump 3.7 million barrels of oil a day this month, up 30 percent from a year ago, according to the U.S. Energy Information Administration. The Delaware and Midland basins combined would take 49 years to produce if all the oil was profitable to recover, according to the EIA.

Qatar's decision to leave OPEC and focus on gas makes sense

(Al Jazeera opinion column; Dec. 6) - Qatar's decision to end its nearly 60-year membership in OPEC caught many observers by surprise this week. Explaining the motivation behind the decision, Saad Sherida al-Kaabi, Qatar's minister of state for energy affairs and president of Qatar Petroleum, said Qatar's exit "is not political, it was purely a business decision for Qatar's future strategy toward the energy sector."

Given that the decision was taken in the context of the ongoing Saudi-led blockade on Qatar, many commentators interpreted it as a political act and as a rebuke of an organization increasingly seen as a tool of Saudi power projection. This assessment is too simplistic and does not reflect Qatar's long-term economic strategy. What defines the country's energy sector is not its oil production but its capacity and global presence in the gas sector. Qatar's exit from OPEC should be seen through the lens of its long-term economic vision and its divergence from the oil cartel's business trajectory.

Qatar began to strategically cultivate its gas sector in 1987 at a time when many in the industry hardly saw any potential in gas. This decision paid dividends many times over as Qatar has emerged as the world largest exporter of liquefied natural gas, gas-to-liquids products, and helium. It recognizes that LNG has a brighter future than oil, given the global trend toward cleaner fuels, and Qatar is determined to maintain its leadership position in LNG while also ensuring that the global market for LNG grows. In the context of this strategy, Qatar saw its membership in OPEC as a legacy of a bygone era.

Prices rise as OPEC and Russia agree to oil production cutback

(Bloomberg; Dec. 7) - OPEC finally broke an impasse over production curbs, agreeing on a larger-than-expected cut with allies after two days of fractious negotiations in Vienna. The cartel and its partners agreed Dec. 7 to remove 1.2 million barrels a day from the market, with OPEC shouldering 800,000 barrels of the burden and the rest falling mostly on Russia. Iran emerged as a winner from the contentious talks, saying it secured an exemption from taking any cuts as it suffers the effects of U.S. sanctions.

Crude surged on the news Dec. 7 by as much as 5.8 percent in London, raising the risk that the deal could anger President Donald Trump, who had urged OPEC to keep the taps open and prices low. The breakthrough at the Organization of Petroleum Exporting Countries’ secretariat followed a series of bilateral meetings convened by non-OPEC member Russia, which emerged as the key broker between arch rivals Saudi Arabia and Iran. OPEC has been under increasing pressure, leaving it ever more dependent on Russia’s support while also subject to vehement opposition from Trump.

The deal is a surprise, since discussions had earlier centered on a proposed cutback by OPEC and its allies of about 1 million barrels a day, with OPEC cutting 650,000 barrels of the total, according to delegates. “Given how much expectations were downplayed around the outcome of this meeting, this result comes as a welcome surprise,” said Harry Tchilinguirian, head of commodity markets strategy at BNP Paribas. “OPEC has given the oil market a rudder that appeared largely absent yesterday.