Oil and Gas News Briefs
Compiled by Larry Persily
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Analysts say Iranian retaliation will determine oil pricing

(CNBC; Jan. 3) - Oil spikes above $100 a barrel may be a thing of the past, but prices are likely to head higher as tensions mount in the Middle East with Citi global head of commodity research Ed Morse forecasting that Brent prices will top $70 in short order. While the market digests the unrest caused by the U.S. airstrike that killed Iran's top commander, the key factor in determining oil's next move is how Iran retaliates.

"We should not think of it as a short-term situation," RBC head of commodity research Helima Croft said Jan. 3. "Their response I think is going to be something we'll be dealing with over the course of 2020. ... I don't believe this is over." International benchmark Brent crude rose as high at $69.50 on Jan. 3, almost a 4% jump.

The price movement — which once would have been much larger on this kind of situation —demonstrates how oil has become resilient to Middle East tensions, in part due to the U.S. shale-driven production surge. Meanwhile, Eurasia Group on Jan. 3 raised its 2020 higher base-case target to $75 per barrel, due to "rising risk to oil infrastructure in the region." If conflict breaks out, which the firm's Middle East and North Africa head Ayham Kamel puts at 30% likelihood, prices could go as high as $95.

"One thing is clear: Iran will respond," analysts at the political risk consultancy said in a research note Jan. 3. "We expect moderate to low-level clashes to last for at least a month and likely be confined to Iraq. … The U.S. will retaliate with strikes inside of Iraq," the research note said. Oil prices "will likely hold" around $70 a barrel, "but could make a run at $80 if the conflict spreads to the oil fields of southern Iraq or if Iranian harassment of commercial shipping intensifies," the Eurasia Group analysts said.

High oil prices depend on actual supply disruption, analysts say

(Bloomberg; Jan. 6) - A flare-up in U.S.-Iran tension may be keeping oil elevated, but an actual disruption to global crude supplies is needed to keep prices at current levels, according to Goldman Sachs Group. Price risks for Brent, which has surged about 6% since the U.S. strike killed a top Iranian general, are skewed toward the downside in the coming weeks without a major supply disruption, Goldman said in a note dated Jan. 6.

Oil was already trading above the bank's projected fundamental fair value of $63 a barrel prior to the attack, buoyed by an "over-enthusiastic December risk-on rally" despite limited evidence of an acceleration in global demand growth, they said. "It is not a given that any potential retaliation by Iran would target oil producing assets," Goldman analysts including Jeff Currie said. "The recent incident at the U.S. embassy in Iraq occurred while there was no disruption to neighboring oil fields."

Brent rallied above $70 a barrel on Jan. 6 as the U.S. warned that there's a "heightened risk" of missile attacks near military bases and energy facilities in Saudi Arabia, while Iran stated it no longer considers itself bound by the 2015 nuclear pact. The rhetoric turned even more hostile after President Donald Trump warned Iran of major U.S. retaliation "in a disproportionate manner," and threatened heavy sanctions on its ally Iraq after its parliament voted to expel U.S. troops from the country.

Mideast uncertainty pushes some Asian buyers to take more U.S. oil

(S&P Global Platts; Dec. 10) - Major energy consumers including India, South Korea, and Japan, as well as multiple Southeast Asian buyers, are increasingly shifting their focus to North American oil to cover growing Mideast supply disruption risks. Asian refiners have been under pressure this year to secure adequate crude supply as geopolitical tensions in the Middle East raised the region's energy security concerns.

The U.S. sanctions blocking access to Iranian crude, as well as a series of attacks on oil tankers and key output facilities in the Persian Gulf, meant many Asian refiners that rely on Mideast sour-crude grades were on edge. South Korea emerged as Asia's biggest customer for U.S. crude oil this year, importing 98.67 million barrels of U.S. crude and condensate in the first nine months, up more than threefold from a year earlier.

South Korea's efforts to diversify its import sources saw the share of Middle Eastern crude in its monthly procurement basket fall below 70% during the third-quarter 2019, compared with more than 85% on average in 2016. As far as crude quality is concerned, Asia has shown interest in a wide variety of U.S. grades in 2019. Lighter and sweeter U.S. crude grades have been among the most popular grades heading to Asia.

China was the biggest buyer of U.S. crude oil in Asia in 2018, but U.S. crude sales to China have been rather small this year as the two countries are locked in a trade war. China imported 15.45 million barrels of U.S. crude in the first half of 2019, down 76.2% from the same period a year earlier, according to China's customs.

More than $40 billion in shale oil and gas debt matures this year

(Wall Street Journal; Jan. 1) - The bill is coming due for the shale industry's price war with OPEC. North American oil-and-gas companies have more than $200 billion of debt maturing over the next four years, starting with more than $40 billion due in 2020, according to Moody's Investors Service. It's a tab that North American producers, pipeline operators and oil field service companies have run up battling the Organization of the Petroleum Exporting Countries for global market share.

It's unclear how they will repay it all. Shareholders and private-equity investors, which used to be willing funders, have been burned in recent years attempting to buy at the bottom. Banks are in retreat. Bond markets have shown little indication that they are open to any but the most attractive oil-patch borrowers. Analysts are predicting and investors hoping that the specter of debt maturities will prompt companies to do what low oil prices and prodding from shareholders haven't: Stop drilling so many wells.

"Capital markets are putting enormous pressure on companies to behave like real economic vehicles," said Ian Nieboer, managing director at consulting firm RS Energy Group. Easy credit and enthusiastic investors fueled the shale boom that flooded the world with oil and gas. Average daily U.S. output has risen 34% since November 2014, reaching about 12.5 million barrels this past fall. The U.S. sector "has spent too much capital for too long with meager returns," Bank of America Merrill Lynch analysts wrote in a note to clients. "This golden era of unlimited capital availability has now ended."

[Rapid growth in U.S. shale oil output could be over]

(Reuters; Jan. 1) - Vastly slower U.S. oil growth this year and the prospect of a plateau for the world's top oil-producing nation have signaled a new and unfamiliar era of self-restraint for the go-go shale industry. Spending cuts and production declines common to shale wells mean U.S. output growth is expected to brake from 2019's pace that pushed domestic production close to 13 million barrels per day. Some analyst forecasts for next year call for growth to slow, potentially to a rate of just 100,000 new barrels a day.

Over the past decade, the shale revolution turned the U.S. into the world's largest crude producer and a force in energy exports. Yet the revolution did not translate to higher stock prices. The S&P 500 Energy sector only gained 6% for the decade, far less than the 180% return for the broader market. The decade-long oil expansion failed to boost profits, which has discouraged investors. The shale industry was squeezed by an OPEC price war that began in 2014, sending U.S. crude below $30 per barrel at one point.

Production temporarily slowed but accelerated into the end of the decade as companies cut costs and grew more efficient. Now with investor returns flagging, the industry no longer believes in drilling its way to success, even at higher prices. "Our view is that (rapid growth) is kind of over," said Raoul LeBlanc, an analyst with consultancy IHS Markit. Because shale output drops off quickly, wells require constant, costly drilling to keep output steady. All that drilling costs money, which the industry is trying to avoid.

Permian gas venting and flaring ‘here to stay’ until pipelines added

(OilPrice.com commentary; Jan. 1) - There was a time when natural gas was a welcome byproduct of crude oil drilling and Permian producers enjoyed the consolation prize — at least when gas prices were on the rise. All good things come to an end, though, and the volume of gas now exceeds the capacity to get rid of it. With pipelines full and gas prices squarely in the red, Permian Basin drillers are faced with three lousy choices: burn off the gas, pay to have it removed, or slow oil drilling to staunch the gas flow.

Crude oil and gas are like two peas in a pod: When you find oil, you often find gas. As crude is pumped out of the well, a small amount of gas almost inevitably comes with it. But over time this ratio changes: less oil, more gas. Now there is simply too much gas, and drillers in the American shale patch must face the not-so-pleasant music with only one question remaining: Which shale drillers can hold on until more gas pipeline capacity comes online?

Flaring has increased exponentially in recent years as the gap between gas production and pipeline capacity increased. Venting and flaring may be the cheapest option for producers, but it’s also the most harmful to the environment by adding to greenhouse gas emissions. There are pipelines in the works set to increase the gas takeaway capacity in the region, which will alleviate the burden on oil drillers. But until such time as the pipelines come into service, venting and flaring in the Permian is here to stay.

Judge says Indigenous law not automatically part of Canadian law

(The Financial Post; Canada; Jan. 2) - The Supreme Court of British Columbia has ruled that indigenous law is not necessarily Canadian law, enabling construction on the C$6.6 billion Coastal GasLink pipeline despite some First Nations opposition. Justice Marguerite Church ruled Dec. 31 that Coastal GasLink suffered irreparable harm after protestors built blockades and camps to stop work crews from accessing parts of the gas pipeline route to the LNG Canada plant under construction in Kitimat, B.C.

Church granted an injunction and an enforcement order to keep the pipeline route clear of the blockades. She took issue with various First Nations groups and some hereditary chiefs claiming that indigenous laws give them legal rights to blockade crews trying to access the area. The justice noted that indigenous laws do not become part of Canadian common or domestic law until they are enshrined through treaties, court declarations, statutory provisions, or other means.

The overlap between Canadian law and indigenous law has not been settled, and courts across the country have had different opinions, said Dwight Newman, a law professor at the University of Saskatchewan and a researcher in indigenous rights and constitutional law. “I think there are some interesting tensions to be sorted out,” he said. “In terms of this particular decision, the judge is also saying that there wasn’t very good evidence in terms of what the indigenous law was," Newman said. The judge found multiple groups claiming rights over land amid conflicting claims of hereditary lineage.

Hereditary chiefs serve 'eviction notice' on gas pipeline work

(The Canadian Press; Jan. 5) - TC Energy will be forced to halt construction on a section of its C$6.6 billion 415-mile Coastal GasLink pipeline this week amid an escalating dispute with indigenous hereditary chiefs. Construction workers, who have been away on holidays, are scheduled to return to work Jan. 6, but won't be able to gain access because of a blockage along a remote logging road. The pipeline would deliver gas to the Shell-led LNG Canada project under construction in Kitimat, British Columbia.

On Dec. 31, a B.C. Supreme Court judge extended an injunction against Coastal GasLink protesters, saying the project has been harmed by the Wet'suwet'en Nation's blockades. But hereditary house chiefs disagreed with the ruling and issued their own "eviction notice" on Jan. 4 on the Wet'suwet'en's territory near Houston, B.C. "Over the past year, Coastal GasLink has operated on our territories despite our opposition to the project," said the letter endorsed by eight men who serve as hereditary house chiefs.

"We must reassert our jurisdiction over these lands, our right to determine access and prevent trespass under Wet'suwet'en law," the letter said. TC Energy (formerly known as TransCanada) expressed disappointment at the letter. The project was approved by all 20 elected First Nation councils along the route, but hereditary chiefs say indigenous authority rests with hereditary and not elected leaders over the Wet'suwet'en's traditional territory, in which 28 percent of the pipeline route would cross.

Pakistan's power plants shy away from costly LNG imports

(The Express Tribune; Pakistan; Jan. 2) – The high price for liquefied natural gas from Qatar has started affecting Pakistan's power producers, which are not willing to sign purchase deals with import suppliers beyond 2025 — the next time the two countries are scheduled to hold a price review of their long-term contract. Power producers believe their LNG-based power plants are not economical to run because of high fuel prices, which is why many of the power plants stay shut most of the time.

However, consumers still are bound to pay capacity charges to the power plants if they are not operated at full output, and import terminal operators also collect charges even if they're not run at maximum capacity due to low offtake by power producers. In a new development, a 1,263-megawatt LNG-based power plant near Trimmu Barrage has backed off from its commitment to take gas beyond 2025 due to the fuel's cost.

Pakistan State Oil and Pakistan LNG are under contract to take 800 million cubic feet of gas as LNG per day on a take-or-pay basis — they have to pay the cost of gas even if they don't take all the fuel. Other sectors like compressed natural gas filling stations and fertilizer manufacturers want to import LNG themselves and are not willing to take costly supplies under the long-term oil-price-linked deal with Qatar. Pakistan LNG has found supplies on the spot market at one-third less than the contract price with Qatar.

Nova Scotia LNG project still looking for gas suppliers and customers

(CBC Canada; Jan. 2) - A proposed liquefied natural gas terminal in Point Tupper, Nova Scotia, that was originally supposed to come online in 2019 still doesn't have any signed contracts with gas suppliers or LNG customers, but the company behind the project says it is confident about its prospects. Bear Head LNG hopes to import gas from Western Canada or the United States, liquefy it at the plant near Port Hawkesbury and then ship it to European customers.

The challenge for the company is that LNG buyers are unwilling to commit until they know where the gas is coming from, and gas suppliers are unwilling to build a pipeline to Point Tupper until LNG customers come on board, John Baguley, Bear Head LNG's chief operating officer, said from Houston. "You've kind of got this catch-22," he said. "We're … trying to advance them both in parallel so we can get to a point where we can solve these two issues simultaneously and Bear Head can go forward," Baguley said.

Bear Head recently asked the Nova Scotia Utility and Review Board for a three-year extension to its construction permit, which was set to expire Dec. 31, 2019. The board granted the extension to 2022. The company was granted a construction permit in 2006 and received its first extension in 2015. "I think many people felt that Bear Head, perhaps, was a wildly optimistic project," said Larry Hughes, who teaches energy systems analysis at Dalhousie University in Halifax, Nova Scotia.

OPEC output declines, but not all members are doing their share

(Bloomberg; Jan. 2) - OPEC's output declined last month as several Persian Gulf producers stepped up their implementation of cutbacks aimed at balancing global oil markets. Saudi Arabia, Iraq, and the United Arab Emirates reduced production in December, the final month of a round of restrictions by the cartel before it presses on with new — and even deeper — curbs this year.

OPEC-member production fell by 90,000 barrels a day to 29.55 million in December, according to a Bloomberg survey of officials, ship-tracking data and estimates from consultants. The campaign by OPEC and its allies to tighten supplies shored up global crude markets in 2019, pushing Brent prices up 23% despite a flood of new U.S. shale oil and fragile fuel demand around the world. The coalition agreed early last month to deepen its curbs to prevent a new surplus forming in the first quarter of 2020.

The survey showed that Saudi Arabia, OPEC's biggest member, is already making strides toward its new target. With 9.83 million barrels a day of production, the kingdom has cut more than twice the amount pledged under last year's deal, and is well on its way to the new, self-imposed quota of 9.7 million barrels. The performance of other nations has been less exemplary. Iraq made a token gesture at fulfilling its commitments, and Nigeria remains slightly higher than the baseline for its 2019 cuts.

Legislation proposes higher oil royalty rates in Nigeria

(OilPrice.com; Jan. 2) - Nigeria has long been known for its oil riches. Angola too, but decades of entrenched corruption have chased foreign investors away from both countries. Now Namibia is joining the African oil conversation with one of the most oil-friendly regimes on the continent. It's offering 5% royalties on what might just be a very productive shale play in the 6.3-million-acre Kavango Basin.

Emerging markets are where oil upside might be found these days but navigating them is a challenge. Nigeria is Africa's largest oil producer, but the party is coming to an end from an investor's standpoint. Nigeria is home to about 37 billion barrels of reserves. And while it's got some 32 active rigs, only 81 wells were completed last year — down from 141 in 2014. Nigeria produced an average 2 million barrels a day in 2018.

Since oil prices started tumbling in 2014, the government has been taking more from oil companies with back taxes and new legislation. Now it wants Chevron, Shell, and Total to pay around $62 billion. Nigeria claims it was shortchanged under a revenue-sharing agreement dating back to the 1990s. Chevron is seeking to sell several Nigerian oil fields, and Exxon and Shell have both been reducing their footprint in the country.

And it might get worse. Nigeria is proposing new legislation that would increase taxation on the oil industry, adding an additional 3 to 10 percent to royalty rates at prices between $50 and $80 per barrel. Nigeria's current system gives the government between 60 and 70 percent of all deepwater revenues, which includes taxes and royalties along with state-run Nigerian National Petroleum Corp.'s share of production.

Mexico hedges 2020 oil at $49 a barrel

(Reuters; Jan. 3) - Mexico has completed its annual oil hedging program for 2020 at $49 a barrel, the finance ministry said Jan. 3 at a time when the finances of both the sovereign and state oil company Pemex are particularly vulnerable. The oil-hedging program, the world’s largest financial oil deal, is designed to protect Latin America’s second-largest economy against oil price crashes.

Mexico’s creditworthiness came under increasing scrutiny in 2019 as two rating agencies flipped their sovereign outlook to negative, while another downgraded its rating. One ratings agency already has Pemex bonds at “junk” status. It was unclear how many barrels were hedged or how much was spent. While the finance ministry has previously withheld information about how many barrels are covered, this is the first time since at least 2001 that it did not disclose the program’s overall cost.

The hedge price is notably lower than 2019, which was hedged at $55 per barrel, but in line with the oil price set out in the 2020 budget. Mexico typically hedges using options, which gives it the right to sell oil at a predetermined price, even if the price on the market is lower. Mexico remains the only country that has completed an oil hedging program of that scale. The economy is heavily reliant on oil revenues.

Scaling up hydrogen production could cost $250 billion by 2030

(S&P Global Platts; Dec. 23) - Japan’s Kawasaki Heavy Industries last week launched the world’s first oceangoing liquid hydrogen tanker, symbolizing the emergence of hydrogen as a potentially transformative fuel as the world pursues cleaner energy. Japan is dreaming big that hydrogen derived from coal in Australia will help it lower its carbon emissions. Hydrogen is not without its challenges, however.

Nearly all hydrogen today — already widely used in industry — is produced from fossil fuels. Using carbon capture and storage could lessen emissions in its production, while other methods using renewable energy to produce hydrogen would emit zero carbon dioxide. But it won’t come cheap. Scaling up the hydrogen economy will require investments of $20 billion to $25 billion each year through 2030, potentially totaling a quarter-trillion dollars, the Hydrogen Council industry group said.

And there is not much of a market for hydrogen. Trade is localized between supplier and end user. Currently, roughly 95% of hydrogen is produced on-site. For example, refiners will contract with a hydrogen supplier to build a hydrogen production facility on the refining site, to produce so-called “on-purpose hydrogen.” Hydrogen does not exist alone in nature. Rather, it combines with other elements to form well-known compounds such as water, natural gas, and petroleum. Once separated, hydrogen is a colorless, odorless, and highly combustible gas that can be used as a fuel.

First power from Russia’s floating nuclear plant lights up Christmas

(OilPrice.com; Jan. 2) - Last week Russia made history by flipping the power switch on the Akademik Lomonosov, a cutting-edge nuclear power plant afloat in the Arctic. While the project has been highly criticized by opponents with some referring to the Akademik Lomonosov as “Chernobyl on Ice,” the plant’s first week has been successfully uneventful with the first electricity produced by the plant used to light a Christmas tree.

The floating plant will serve the tiny Arctic city of Pevek in the northeastern Chukotka Autonomous Okrug Region of Russia, which has a population of under 5,000 and will enjoy heating from Akademik Lomonosov within the next year, no small gift in a town where “the average high temperature there is minus 11 Fahrenheit in January and February,” according to Forbes.

The Akademik Lomonosov was launched with the intention of phasing out coal-powered energy in the region and replacing it with zero-emissions nuclear in addition to replacing the aging Bilibino nuclear plant nearby which serves the same power grid as the new free-floating station. Now, however, it looks like that goal has been postponed, as the Bilbino plant’s license has been extended another five years by Rosteknadzor, the Russian Federal Agency for Ecological, Technological and Nuclear Supervision.