Oil and Gas News Briefs
Compiled by Larry Persily
September 8, 2022

OPEC+ may find it hard to hold oil prices if world falls into recession

(Reuters columnist; Sept. 6) - It's tempting to dismiss this week's decision by OPEC+ to cut oil production by 100,000 barrels per day in October as a statistical insignificance that will likely have zero real market impact. While it's true that the tiny adjustment to the group's output targets won't make a big difference to the global supply-demand balance, the announcement has significance: It signals OPEC+'s intent to defend oil prices.

While the group doesn't explicitly state its preferred price level, from current and recent actions it's likely the target is somewhere above $90 a barrel. The problem for OPEC+ is that aiming for this level now, as the world economy likely heads into an energy price-led recession, raises the risk of being forced to take stronger action to defend $50 in six months after global demand is smashed. The risk is that by the time mid-winter hits the Northern Hemisphere, the supply, demand and price situation could be entirely different.

Europe is likely heading for a recession as energy costs soar. The surge in natural gas prices has had the flow-on effect of boosting thermal coal to record highs. It has also kept diesel prices elevated as the fuel, used mainly for transport, becomes price-competitive for electricity generation. The full impact of high inflation and rising interest rates generally takes some time to manifest itself. The risk for the global economy is that all the negative factors start to hit home around the same time — this winter.

In addition, the lockdown of Shenzhen and Chengdu last week added to the view that China may remain a soft spot for oil demand. Overall, it's becoming increasingly hard to make the case that oil should be above $90 a barrel by the end of the year. The risk for OPEC+ is that if it does try to force the price to stay at that level by restricting supply, it will provoke a deeper and longer global recession.

U.S. crude falls below $82 a barrel, lowest since January

(CNN Business; Sept. 7) - Oil prices dropped sharply on Sept. 7. U.S. crude tumbled by more than 5% to $81.94 a barrel. That's the lowest since Jan. 24. U.S. crude is now down by more than one-third since briefly hitting $130 a barrel in early March. Brent crude, the world benchmark, closed at $88. Alaska North Slope crude ended the day at $91.75, its lowest in seven months. Fears that slowing global growth could undermine demand have sent prices tumbling. Brent has lost nearly 20% of its value this quarter.

Analysts cited a range of factors behind the losses, including concerns about the health of the world economy and the skyrocketing U.S. dollar. A stronger U.S. dollar tends to weaken demand for oil overseas. "High prices are already starting to weigh on the European economy, and fears of contagion are causing a vicious selloff in oil prices today," said Matt Smith, lead oil analyst Americas at Kpler. The good news is that the drop in oil prices should continue to lower prices for consumers at the gas pump.

But Tom Kloza, global head of energy analysis at the Oil Price Information Service, is skeptical the drop in energy prices will continue — especially given recent threats from Russian President Vladimir Putin and other Kremlin officials, who have said they could retaliate against the West by cutting off energy exports. "Putin has indicated he will do crazy things," said Kloza. "This is an interlude, a buying opportunity. There's a false sense of security."

Private-equity funds dial back investment in oil and gas companies

(The Wall Street Journal; Sept. 1) - Profits from oil and gas production have surged as prices hover at elevated levels, but volatile returns and a fraught political climate have created a divide among the biggest private-equity firms about whether investing in the sector is worth the headache. Many public pension funds and endowments that invest in private-equity funds have put pressure on their managers to stop backing producers of fossil fuels and invest more in cleaner sources of energy. The energy market's boom-and-bust cycles also have translated into poor investment returns over the long term.

That has caused some of the biggest buyout firms to dial back investment in the sector. The aggregate transaction value of private-equity and venture-backed investments in oil and gas has been just $4.4 billion this year, according to data from S&P Global Market Intelligence; at the peak in full-year 2014, it totaled $49.5 billion. Meanwhile, there has been nearly $11 billion worth of investments in renewable energy such as solar and wind this year, the data show, putting it on track to surpass oil and gas for the first time.

It can be difficult to get debt financing for companies that produce fossil fuels because banks are wary of lending to them now. The limited pool of willing buyers — not just among investment firms, but among other oil and gas companies, which are consumed with their own energy-transition efforts — means there also are significant hurdles to exiting from such investments. Bankers and private-equity managers say it is nearly impossible to take a fossil-fuel producer public these days. To have any hope of selling an oil or gas asset at a profit, a firm has to have a plan to make itself greener.

China barters smartphones and IT gear for Russian oil

(Nikkei Asia; Sept. 4) - Japan, the U.S. and Europe responded to Russia's invasion of Ukraine with an embargo on Russian crude oil. China has not. Data shows that 46 large oil tankers in July crossed from Russia's Far East to ports in Qingdao and Dongjiakou, in China's Shandong province. That is 1.9 times more than made the journey in January, and the amount of crude oil purchased in July was almost double that of May.

The issue with Western sanctions is payments. Major Russian banks have been cut off from the Society for Worldwide Interbank Telecommunications. So how are Chinese companies getting their payments to Russia? On June 29, a cargo plane full of Xiaomi smartphones and other Chinese information technology gear took off from Xi'an, in the inland province of Shaanxi. Its destination was St. Petersburg, Russia, 6,000 miles away. According to a person with knowledge of the flight, the cargo was used as barter.

China buys Russian oil in yuan, which Russia then uses to buy China-made IT equipment. The transactions are thought to be backed by China's state-owned, oil-related Bank of Kunlun, which frequently interacts with Iran, another target of U.S. sanctions. No matter if Western countries join ranks to shut out their adversaries, China is unaffected. Because of sanctions, Russia is having to lure customers by cutting its resource prices. "We want to reduce losses by using low-priced Russian products," said a senior executive of a privately owned company operating an oil refinery in Shandong.

U.S. LNG export capacity set to grow about 40% by 2025

(U.S. Energy Information Administration; Sept. 6) - The U.S. began exporting liquefied natural gas from the Lower 48 states in February 2016. The U.S. now has more LNG export capacity than any other country, at more than 13 billion cubic feet per day. The seventh and latest U.S. project — Calcasieu Pass LNG — placed all of its liquefaction trains in service by August, ahead of schedule. In addition to the ExxonMobil-Qatar venture, Golden Pass LNG, which started construction in 2019, two more Gulf Coast projects have begun construction. The three will boost U.S. capacity by about 40%.

Calcasieu Pass, which uses mid-scale liquefaction technology, started production 30 months after its final investment decision — the shortest period for any U.S. LNG export project so far. Golden Pass LNG is constructing standard-size liquefaction trains with peak production capacity totaling 2.4 bcf per day. The other projects under construction, Plaquemines LNG, in Louisiana, and Corpus Christi Stage III, in Texas, use a modular technology with mid-scale liquefaction trains, which has a shorter construction timeline.

Plaquemines consists of 24 mid-scale trains for a combined peak capacity of 1.8 bcf per day. Corpus Christi Stage III is on the site of an existing terminal with three liquefaction trains in operation; the 14 new mid-scale trains will have a total output capacity of 1.6

bcf per day. Once completed by 2025, the three projects under construction will expand U.S. peak capacity by a combined 5.7 bcf per day, more than 43 million tonnes a year.

EPA denies exemption from emissions rule for LNG plant turbines

(Reuters; Sept. 6) - The U.S. Environmental Protection Agency said on Sept. 6 it has denied a request from leading liquefied natural gas exporter Cheniere Energy to exempt turbines at its two Gulf Coast terminals from a hazardous pollution rule. The rejection raises questions about whether the company will have to reduce exports of the fuel to install new pollution control equipment at its facilities at a time that Europe is depending on increased shipments of LNG from the United States to offset cuts from Russia.

Owners and operators of gas turbines in the U.S. had a Sept. 5 deadline to comply with the National Emission Standards for Hazardous Air Pollutants, which the Biden administration put into effect after an 18-year stay. The rule imposes curbs on emissions of known carcinogens like formaldehyde and benzene from stationary combustion turbines, such as those used by LNG facilities.

Cheniere had asked the administration to exempt a specific kind of turbine installed at its LNG terminals from the limits, arguing they would reduce shipments from the top U.S. exporter for an extended period. Cheniere was the only company to request such an exemption, according to the EPA. The company claimed the model of turbine it uses at its Texas and Louisiana facilities is the best technology for withstanding the types of storms that often strike the Gulf Coast, but that the equipment is also exceptionally hard to retrofit, and that engineering and installation of pollution controls could take years.

Cheniere spokesperson Eben Burnham-Snyder said that while the company "strongly disagrees" with the EPA's decision, "we will work with our state and federal regulators to develop solutions that ensure compliance." About 250 U.S. gas turbines are subject to the new rule, according to an EPA list, nearly a quarter of them operated by Cheniere.

Europe faces high gas prices for several years, bank analyst says

(Bloomberg; Sept. 7) - The European Union is set to intervene in energy markets to take the pressure off companies squeezed by a cash liquidity crunch. It will also propose a clawback on excess profits by power and oil companies as it seeks to protect citizens from soaring costs. EU officials are set to meet in Brussels on Sept. 9 to consider next steps. All eyes are on the calendar as the cold season approaches — but this winter may be just the beginning of a prolonged crisis, according to some observers.

Citigroup’s Ed Morse said natural gas prices will be elevated for a while yet. “It’ll be somewhere between 2025 and 2027 that we’ll see the prices in Europe coming back to where they were at the beginning of 2021," Morse, Citi's global head of commodities research, said in an interview. "You can only produce as much LNG as you have liquefaction capacity, and it doesn't grow overnight. That's the reason why Europe is going to have to wait to mid- or later in the decade" for supplies to replace Russian gas.

Europe can't solve its energy crisis just with LNG cargoes redirected to the region, said Dustin Meyer, vice president of natural gas markets at the American Petroleum Institute. Replacing Russian gas can only be achieved if global LNG export capacity increases quickly, he said. "That is a problem that must be solved only through investments in new capacity, new supply," said. "The diversion of cargoes has been very helpful in the short term, but in the long term, we need investment in export capacity."

Long-term contract prices much cheaper than LNG spot market

(Reuters columnist; Sept. 5) - The spot price of liquefied natural gas is poised for another surge with the global market tightening as Russia turns the screws on Europe's supplies of pipeline natural gas. A fresh record high above the all-time peak of $69.955 per million Btu is definitely possible for spot LNG prices, as European utilities will likely be desperate to ensure sufficient gas for the upcoming winter peak demand period.

While any surge in spot LNG prices is likely to grab the media headlines, it masks important shifts in the overall market dynamics. In Asia, only about one-third of LNG volumes are traded at spot prices, with the majority of LNG being priced against crude oil in long-term contracts. Notwithstanding a surge in oil prices in the aftermath of Russia's attack on Ukraine, the cost of LNG priced against oil is now substantially below the spot price, and the discount is the widest ever in Refinitiv data going back to 2012.

Most long-term LNG contracts are priced as a percentage of a benchmark crude, known as the slope, and a typical contract might be pegged at about 14.5% of a barrel of the so-called "Japan Crude Cocktail," which is a price based on the customs cleared cost of crude oil in Japan. As of the end of August, this LNG price was around $16.63, or less than one third of the Japan-Korea Marker spot price of $53.95 on Aug. 31.

That spot-market prices are more costly than oil-linked contract prices is a reversal of the trend for most of the past decade, when spot tended to trade below the oil-linked contract price. This means that buyers that has in the past been able to take advantage of lower spot prices, such as India and Pakistan, are now priced out of the market.

Chevron sees LNG growth opportunities in U.S., Mediterranean gas

(S&P Global; Sept. 6) – Chevron wants to grow its liquefied natural gas business as part of a strategy to expand in oil and gas more generally, and sees the U.S. and the East

Mediterranean, both where it holds significant gas assets, as key growth opportunities. Chevron's vice president for midstream, Colin Parfitt, told S&P Global Commodity Insights that the company had become a more global LNG player, with Europe an obvious target for more of the fuel as it looks to replace lost Russian gas.

"Our global footprint has changed, and we're trying to enable some of that supply to Europe where it is clearly needed at the moment," Parfitt said in an interview on the sidelines of the Gastech conference in Milan. "The U.S. has plenty of gas — it's just a question of liquefying it and transporting it — while the East Mediterranean is close to Europe. Those are the obvious places to help Europe with its supply need," he said. Chevron traditionally focused its LNG business on supplying volumes from its northwest Australia projects to North Asia, but has set its sights on becoming more global.

In June, it signed two major U.S. LNG deals, taking volumes from U.S. liquefaction plants operated by Cheniere Energy and Venture Global. Combined, the two agreements will see Chevron take 4 million tonnes per year of U.S. LNG. "We're now becoming a more global player. We're enabling gas from the U.S. to come through as LNG," Parfitt said. Chevron has gas production assets in the Permian Basin and is looking at LNG exports as an outlet for those volumes.

Japan making plans to restrict gas use, support LNG purchases

(Reuters; Sept. 5) - Japan plans to introduce measures to restrict use of city gas and support fuel procurement in the event of a large-scale disruption to liquefied natural gas imports amid lingering fears about energy supplies from Russia. The scheme has been discussed since July by a group of external energy experts. Resource-poor Japan faces a historic energy security risk amid the growing threat of gas cutoffs from the Sakhalin-2 LNG project in Russia at a time when global supply is tight and prices are sky-high.

A report on city gas compiled on Sept. 6 by the working group under the industry ministry includes a scheme enabling state-run Japan Oil, Gas and Metals National Corp. (JOGMEC) to buy LNG on behalf of city gas providers in case the companies become unable to purchase the fuel. Such a scheme was added to the Electricity Business Act which regulates the power sector about two years ago, but it is not included in the Gas Business Act which regulates the gas sector. The scheme has never been used, according to the industry ministry.

Gas companies are advised to make preparations in advance so that alternative procurement and purchases from other LNG buyers, including electricity utilities, can be conducted smoothly in the event of supply disruptions, the report said. On the demand side, Japan may also make necessary legal amendments to force city gas users to restrict the use of the energy during severe supply crunches. Such a scheme already exists for the electricity sector, but not for the gas sector.

China imports 9 cargoes of Russian LNG in August

(S&P Global; Sept. 5) - China's LNG imports from Russia reached a 22-month high of about 611,000 tonnes in August, shipping data from S&P Global Commodity Insights showed, due to China's continued reliance on Russian cargoes despite Western sanctions following its invasion of Ukraine. China imported six LNG cargoes from Russia's Yamal LNG terminal in the Arctic and three cargoes from the Sakhalin-2 LNG terminal in the Far East, according to the shipping data.

The Yamal cargoes are estimated to be mostly term contract volumes, while the Sakhalin cargoes were bought in the spot market via tenders, market sources said, adding that the latter were likely purchased at a high discount to spot LNG prices. The Sakhalin cargoes were shipped to state-owned Sinopec's Tianjin LNG terminal in North China, PetroChina's Rudong LNG terminal in eastern Jiangsu province, and state-owned CNOOC's Ningbo terminal in eastern Zhejiang province, shipping data showed.

China’s LNG importers have mostly cut back on their purchases in the spot market in 2022 as prices became too expensive for many downstream buyers to afford and domestic demand was well supplied by cheaper pipeline gas and term contract volumes, sources said. But strong demand from gas-fired power plants because of hot weather in eastern China has pushed LNG terminals in the region to boost prompt LNG inflows at a time when the national oil companies are stocking up for winter supply.

China’s biggest energy companies are selling surplus LNG

(Bloomberg; Sept. 5) - China’s biggest energy groups are diverting more liquefied natural gas away from their languishing home market, offering some relief to desperate buyers suffering supply shortages in other parts of the world. CNOOC is offering to sell an LNG cargo for November loading from the North West Shelf export project in Australia, according to traders with knowledge of the matter. That comes after other major shippers, including Sinopec and PetroChina, sold several LNG shipments from U.S. projects to energy-starved Europe throughout the year, traders said.

The supplies should provide modest respite for gas markets rocked by Russia halting a key pipeline to Europe. Gas prices in Europe and Asia are trading at an all-time high for this time of year, forcing governments to consider unprecedented steps to protect businesses and consumers. China was the world’s top LNG buyer in 2021, but the nation’s strict COVID-zero policies and economic slowdown have cut demand by more than 20% this year. Even smaller Chinese LNG importers, such as ENN Energy and JOVO, have been actively offering to sell cargoes for delivery around Asia, traders said.

German utility signs LNG deal with Australian producer

(Bloomberg; Sept. 5) - German utility Uniper signed a long-term deal with Australia-based Woodside Energy to bring in more cargoes of liquefied natural gas to energy-starved Europe. Uniper, which used to be a big buyer of Russian gas, on Sept. 5 said it struck an agreement with a trading unit of the Australian energy giant to buy as many as 12 LNG cargoes a year. The supplies will start in January and could run through 2039.

While not the biggest LNG deal for Europe this year, it's welcome news for the market after Russia's decision to keep the Nord Stream pipeline shut indefinitely. Russia's move sent gas and electricity prices surging on Sept. 5, with European governments racing to stave off an energy catastrophe this winter. Uniper is the biggest corporate casualty of an unprecedented squeeze in energy, with its survival hinging on handouts from the government as the cost of replacing Russian supplies leads to huge losses.

The deal between Uniper and Woodside equates to about 35 billion cubic feet of gas per year. That's about a month of Russian supplies through the Nord Stream pipeline at the curtailed levels that Germany saw before the halt — one-fifth of the line's normal capacity. Woodside will supply LNG from its global portfolio.

Conoco partners with Japanese firm on U.S. hydrogen project

(Reuters; Sept. 6) - ConocoPhillips, one of the largest U.S. independent oil producers, will provide natural gas and manage a carbon-capture and storage facility for a proposed U.S. hydrogen gas project to be jointly developed with Japan's largest utility, JERA, the companies announced Sept. 5. The agreement to supply gas for hydrogen, a potential clean fuel for electricity production, marks a new avenue for gas producers.

A study to determine the project's feasibility could be complete by year-end, according to JERA, the Japanese gas and electricity firm behind the project. The project aims to produce hydrogen from natural gas and convert it into ammonia for sale in the U.S., Europe and Asia. "JERA and ConocoPhillips will be a low-cost ammonia supplier to domestic and international markets," said JERA Americas CEO Steven Winn. The plant could be in operation within five to eight years at a site along the U.S. Gulf Coast.

Conoco declined to discuss the company's role and the size of any potential investment. JERA Americas, a U.S. arm of JERA, said the company, along with German utility Uniper and ConocoPhillips aim to initially produce 2 million tonnes of ammonia per year and could expand to 8 million tonnes Ammonia typically is used to make fertilizers but offers a low-carbon fuel that could be burned to produce electricity. JERA is considering several Gulf Coast sites for the hydrogen, ammonia and carbon-sequestration site, a spokesperson said, powered in part by JERA's U.S. renewable energy operations.

Repsol sells 25% of its exploration and production division

(Bloomberg; Sept. 7) - Spanish oil and gas giant Repsol is selling a quarter of its exploration and production division for $3.4 billion to a U.S. private equity firm, in a dramatic downsizing of its exposure to fossil fuels. The deal is Repsol's second divestment in recent months as the Madrid-based oil producer raises funds to help pay for low-emission projects while also reducing its cost of capital. Repsol was the first of the large oil companies to announce a strategic push into renewable power.

Europe's oil and gas giants, flush with cash from soaring prices, are considering whether to turbo-charge their transition to clean energy. The sale of assets by Repsol contrasts with the approach of other oil majors, which are so far resisting pressure to sell off parts of their traditional businesses. The proceeds from the sale will further Repsol's strategic aim of having low-carbon businesses account for 45% of capital employed by 2030. Repsol holds a 49% stake in the proposed Pikka oil development in Alaska, which the developers have promoted as a low-carbon project.

Repsol's sale came after an unsolicited approach by EIG Global Energy Partners, a Washington, D.C.-based private equity firm that focuses investments largely on energy and infrastructure globally. The transaction comes after the Spanish firm agreed in June to sell a 25% stake in its clean-energy unit to a joint venture of Energy Infrastructure Partners and French lender Credit Agricole for 905 million euros. It has also sold stakes in individual renewable energy projects. In late 2019, Repsol wrote down the value of its oil assets by 4.8 billion euros and targeted net-zero carbon emissions by 2050.

Imperial Oil looks to low-carbon hydrogen to make renewable diesel

(Financial Post; Canada; Sept. 6) - Calgary-based Imperial Oil said Sept. 6 it will use low-carbon hydrogen from a proposed plant near Edmonton, Alberta, if it builds a renewable diesel facility at its nearby Strathcona refinery. Imperial said it signed a long-term contract to source more than 80 million cubic feet per day of low-carbon hydrogen from a proposed C$1.6 billion plant that Pennsylvania-based Air Products and Chemicals hopes to start building this fall, according to a press release.

Both projects face hurdles and unanswered questions, but the deal shows that traditional energy players in Alberta are publicly considering investments outside of fossil fuel production. Imperial said it plans to make a final decision on whether it will build a proposed C$500 million renewable diesel production facility by the end of the year. It plans to combine hydrogen with feedstock from vegetables, such as canola or soy, to produce 20,000 barrels per day of low-carbon diesel at its Strathcona refinery, which already produces 200,000 barrels per day of gasoline, jet fuel and other fuels.

Air Products did not provide any interviews, but last year shared many details of its plans to build a low-carbon hydrogen facility near Edmonton. The company has said it could use natural gas to produce hydrogen, and would invest in carbon-capture technology and a steam turbine to eliminate or offset most of the greenhouse emissions produced. Construction is set to begin in the fall, and the company said in June it was still negotiating to receive government incentives.

Drought cuts into China's hydropower, forces more reliance on coal

(Reuters; Sept. 6) - China's drought has sent coal prices surging as traders anticipate the lack of hydroelectric generation will force it to burn more coal to meet electricity demand this winter. It marks a significant turnaround from the first half of the year when heavy rainfall and plentiful hydro generation enabled China to reduce coal use and rebuild depleted inventories. During the first six months of the year, southern China, where most hydro generation is concentrated, received the highest rainfall since 2016, as monsoon rains arrived early and the region was hit by a series of massive floods.

As a result, China generated a record 729 billion kilowatt-hours of hydroelectricity in the first seven months of the year, easily surpassing the previous peak of 651 billion kWh in 2019. Massively increased hydro generation supplied almost all the increase in total electricity demand compared with last year. There were also significant increases in generation from wind and solar, and a slight rise in nuclear output.

In the past two months, however, low rainfall has sent the entire process into reverse and threatens renewed coal shortages later this year. Precipitation at Yibin since the start of July has been just 5.3 inches, compared with an average of 18.26 inches in 2014 through 2021. Hydroelectric power generation has fallen sharply and likely to remain depressed throughout the remainder of 2022 and into 2023. Increased coal combustion will have to cover the shortfall, putting more pressure on stockpiles and requiring long rail journeys from the northern coal fields to generators in the south.

India extends deadline for coal power plants to reduce emissions

(Reuters; Sept. 6) - India has extended a deadline for coal-fired power plants to install equipment to cut sulfur emissions by two years, the government said in a notification on Sept. 6, marking the third pushback on a commitment to clean up dirty air. Indian cities have some of the world's most polluted air. Thermal utilities, which produce 75% of the country's power, account for some 80% of industrial emissions of sulfur and nitrous oxides, which cause lung diseases, acid rain and smog.

India had initially set a 2017 deadline for power plants to install flue gas desulfurization units to cut sulfur emissions. That was later changed to varying deadlines for different regions, ending in 2022, and further extended last year to 2025. Only 40% of India's total coal power capacity has been awarded bids for installing the cleaning units, while just 4% have installed it, according to government data. The Sept. 6 order said power plants will be forcibly retired if they do not comply with sulfur emissions by end-2027.

The federal power ministry had pushed for an extension, citing higher costs, lack of funds, COVID 19-related delays and geopolitical tension with neighboring China, which has restricted trade. The delay will be welcomed by operators of coal-fired utilities including private companies, which have long lobbied for less severe requirements.

Gazprom produces first LNG at small-scale terminal on Baltic coast

(Bloomberg; Sept. 6) - Gazprom has produced its first liquefied natural gas at a small-scale facility on the Baltic coast near the start of the shuttered Nord Stream pipeline to Germany. Two production lines at Portovaya LNG have produced some 30,000 tonnes of the fuel, Gazprom Deputy CEO Vitaly Markelov said at the Eastern Economic Forum in Vladivostok. One tanker is already moored near the facility while another is expected to arrive soon, Markelov said, providing no comments on the destinations.

The LNG plant is located near the Portovaya compressor station, the starting point of the Nord Stream pipeline under the Baltic Sea that failed to return from maintenance on Sept. 3, exacerbating Europe’s energy crisis. Earlier this year, the facility was in the spotlight after NASA satellites detected flaring on Russia’s Baltic coast, raising concerns that the gas giant was burning fuel rather than supplying it to Europe amid sanctions over the war in Ukraine. Flaring is a normal part of the commissioning of LNG facilities.

Portovaya LNG has an annual capacity of 1.5 million tonnes, or less than one-sixth of the nameplate capacity of the country’s first LNG terminal, the Gazprom-led Sakhalin-2 site in Russia’s Far East. Portovaya is set to supply the fuel to Russia’s Kaliningrad region, sandwiched between Lithuania and Poland, and to increase Gazprom’s portfolio.

Shell and Malaysia’s Petronas decide to develop new gas field

(Argus Media; Sept. 5) – A venture of Shell's Malaysian subsidiary Sarawak Shell and Petronas Carigali, a subsidiary of Malaysian state-owned oil firm Petronas, has taken a final investment decision to develop the Rosmari-Marjoram gas project in Malaysia’s Sarawak state. The gas fields are about 150 miles off the coast of Bintulu, Sarawak. The project is designed to produce 800 million cubic feet per day. Gas production is expected to start in 2026, Shell said on Sept. 5.

The development is also meant to ensure a sustained supply of gas to the Petronas LNG complex in Bintulu, which has capacity to produce 30 million tonnes of LNG per year. The additional gas is essential, especially in light of a series of production issues at the Pegaga gas field offshore Sarawak which also supplies gas to the Bintulu LNG plant. The field restarted production March 21.

Rosmari and Marjoram are deepwater sour-gas fields that were discovered in 2014. The project consists of a subsea tie-back, an unmanned wellhead platform, a 130-mile pipeline to shore and an onshore gas plant. South Korea's Samsung Engineering said in July that it had won an engineering, procurement, construction and commissioning contract to build the onshore plant. Operations will be primarily powered by renewable energy, Shell said. The offshore platform will be powered by 240 solar panels.