Energy Intelligence

PETROLEUM INTELLIGENCE WEEKLY®

Vol. 61, No. 38 www.energyintel.com September 22, 2022

Qatari Minister: No 'Quick Fix' to EU Gas Crisis

There is not much Qatar can do to alleviate Europe's gas crisis in the short term due to contractual commitments, Qatari Energy Minister Saad al-Kaabi tells Energy Intelligence — but further out, in five to seven years, new Qatari LNG exports to Europe should be significant. In an exclusive interview, al-Kaabi said production from the Golden Pass LNG project in the US, where QatarEnergy partners with Exxon Mobil, is due on stream in 2024 and is "already earmarked for Europe." Up to half of new output from Qatar's 48 million ton per year North Field mega-expansion could also go West of Suez when it starts up from 2026. Al-Kaabi also serves as head of state-owned QatarEnergy, which is in active discussions with customers for the new supplies. Significantly, targeted contract durations are shorter than the 20-year deals seen in Qatar's original LNG expansion, reflecting European reluctance to lock into gas supplies long-term. "I think 10-15-year deals are probably what are most acceptable to both sides. But for us, the long-term deal, it's not just about duration, it's about price," he said. Even with such supplies, al-Kaabi expressed skepticism about Europe's ability to completely wean itself off Russian gas. Europe will find it "very difficult" to completely forgo Russian pipeline gas for more than two winters. Despite storage, fuel switching and active efforts to expand LNG imports, "a quick fix" to the EU's dependency on Russian gas does not exist.

Qatar's North Field expansion is attracting enormous interest from foreign investors, with TotalEnergies tipped to become the first of the Phase-2 partners to be selected later this month. But investors in existing Qatari projects face a rocky ride when contracts on current joint ventures expire, as Exxon and Total discovered when their prized Qatargas-1 contract was not renewed last

(Please turn to p.4)

Slump Puts Russia's Refiners On Brink

Russia's refineries are on the cusp of an existential crisis. The industry is witnessing an acute slump in margins this month and can barely eke out a gain. Middle distillates remain strong and are expected to firm in the lead-up to the EU ban on Russian oil products on Feb. 5, 2023. Beyond that, the outlook is grim, and Russia's refineries, which export about half their output, may have to slash throughput by 15%. Closures are unlikely given the sensitive social ramifications, but smaller facilities without conversion capacity, as well as teapots, could suffer a quiet death. For every three barrels of crude processed, a typical Russian refinery produces two barrels of light products and one of heavier fuels. The latter has been unprofitable for some time, but this was exacerbated by the US embargo earlier this year. The crack spread on a barrel of heavy fuel oil for a refinery near Moscow sunk to minus $43 per barrel this week. Normally, refiners could live with that, but this month gasoline and naphtha returns have also deteriorated. Domestic gasoline sales are subsidized, but the state cut this subsidy so the crack on 92-octane gasoline, the most widely used, has been a negative $1.5/bbl over the past week. At the end of July, it was a positive $40. Meanwhile, naphtha, which is mainly exported, has a negative crack of about $20/bbl since European buyers, who used it as petchems feed, are demanding a steep discount.

Diesel and jet fuel are keeping overall margins in positive territory, but only for the most advanced refineries cranking them out in large volumes. Moscow's decision to mobilize 300,000

Chairman: Raja W. Sidawi. Vice Chairman: Marcel van Poecke. Chief Strategy Officer & Chairman Executive Committee: Lara Sidawi Moore. President: Alex Schindelar. Editor-in-Chief: David Pike. Executive Editor: Noah Brenner. Contact Us: New York: Tel: +1 212 532 1112. London: +44 (0)20 7518 2200. Sales: sales@energyintel.com. Customer Service: customerservice@energyintel. com. Bureaus: Beirut: +961 3 301278. Dubai: Tel: +971 4 364 2607/2608. Houston: Tel: +1 713 222 9700. Moscow: Tel: +7 495 604 8279/78/77. Singapore: Tel: +65 6538 0363. Washington: Tel: +1 202 662 0700. Other publications: *EI New Energy, Energy Compass, Energy Intelligence Finance, International Oil Daily, Jet Fuel Intelligence, Natural Gas Week, Nefte Compass, NGW's Gas Market Reconaissance, Nuclear Intelligence Weekly, Oil Daily, Oil Markets Briefing, Oil Market Intelligence, World Gas Intelligence.* www.energyintel.com

reservists to protect the front in Ukraine, and possibly retake lost territory, will give the domestic market a boost, and Europe also is expected to stockpile ahead of the February embargo. Most importantly, the state subsidy for diesel — approximately $40/bbl in September — means refineries can rejoice with an approximate $70/bbl crack spread on this product. Russian retailers even believe that the domestic market could run short of winter-grade diesel this month and are calling for imports of Belarusian diesel, which used to be exported to Ukraine. This could be premature. Because come February, some 500,000-550,000 b/d of diesel exports to Europe will have to be rerouted, along with 450,000-500,000 b/d of other products. Brazil has suggested it could take some 200,000 b/d, and there is potential for some shipments to Africa and the Middle East. Hefty discounts will be needed to entice new buyers, and even then Russia is certain to encounter sanctions-related shipping risks and a lack of long-haul tankers that can handle clean products. The export parity for diesel will sink substantially, and hence, overall refining profitability.

Without higher subsidies, particularly for gasoline, the product slate will yield a net loss and Russia's refineries will have to cut output next year. Energy Intelligence believes that Russian refining runs will decline by about 600,000-700,000 b/d to 4.7 million-4.8 million b/d in 2023. Product exports will fall by some 500,000 b/d to 2.2 million b/d, tightening a global product market already coping with a refining crunch. Such an outcome would vault India over Russia as the world's third-largest refiner. If the Ukraine war drags on and sanctions remain, Russia's refining sector could see its competitiveness diminished. Refiners need to boost conversion capacity — mainly via hydrocrackers and delayed cokers — and squeeze more value from the bottom of the barrel, but these technologies are mainly Western and therefore under sanction. The sector also is dependent on imported refining catalysts, particularly for hydrogen-related units, although Moscow has prioritized a domestic replacement program. How effective these new catalysts will be remains to be seen. Although products markets will remain tight in the medium term, over the longer term Russia's refineries have little to cheer. Moscow is leading a drive for more vehicles to switch to liquefied petroleum gases and compressed gas (methane), undermining the domestic gasoline market, while the move away from fossil-based transportation fuels in Europe and the US raises questions about the viability of large refining investments.

Stalled Growth Spurs Questions for US Shale

US oil production has rebounded from its Covid-19 lows, but now seems to be bumping up against significant constraints that will limit further growth. Despite strong oil prices, US drilling and fracking activity has flatlined since mid-June, with the oil rig count stuck at about 600. Several market impediments have emerged, while a dramatically changed shale industry, now laser-focused on cash returns, is behaving much differently than before the pandemic. Some experts are scaling back previously aggressive production forecasts. Decent growth is still likely for the next couple of years, but the sector could then stall. Back in April, the US Energy Information Administration (EIA) had expected the US to add 800,000 barrels per day in crude production this year for an average of 12 million b/d, and another 900,000 b/d in 2023. Others predicted growth as high as 1 million b/d this year. These are now being cut back to more modest numbers. Energy Intelligence, by contrast, has consistently forecast the US would add 600,000 b/d this year to average around 11.8 million b/d, followed by a gain of 750,000 b/d in 2023. After recent revisions, the EIA's forecast is now in line with this. Such growth is still impressive, particularly after US output dropped below 10 million b/d at the height of the Covid-19 pandemic in 2020. In addition, the US will add about 450,000 b/d in natural gas liquids (NGLs) this year and roughly the same amount in 2023, with NGLs output expected to exit 2023 at 6.6 million b/d, according to our forecast. Taking into account all liquids, the US remains a force in global supply in the near term.

Supply chain issues, labor shortages, inflation and infrastructure constraints continue to dog US producers after surfacing during the post-pandemic recovery last year. Today, firms also face extreme oil price volatility and the growing threat of economic recession, which could hurt oil demand. Despite global supply tightness, there seem few reasons for shale producers to grow more

aggressively. Publicly-traded firms are holding the line regardless of oil market signals — they did not meaningfully change investment plans when West Texas Intermediate (WTI) breached $80 per barrel in late 2021, nor after the Ukraine war pushed WTI to $120/bbl earlier this year. The subsequent fall in prices, with WTI now back under $85/bbl, makes accelerating growth and depleting drilling inventories even less likely, especially considering uncertain demand. Shale executives say that, even if they wanted to expand faster, tight capacity for oil services would make it almost impossible.

Shale's embrace of capital discipline and cash returns is well-documented. But after years of investor pressure, the ethos is now fully baked into the sector. Executive pay is now tied to financial returns, ensuring that managements stick to the low growth model. Investors still question the sustainability of shale's recent strong returns, while rampant consolidation has put more production in the hands of fewer, larger players — making it easier for Wall Street to exert its influence. Pioneer Natural Resources' executive compensation plan reflects shale's new priorities. For 2021, it was 40% weighted toward corporate returns and free cash flow, 20% toward environmental, social and governance (ESG) and health and safety, 20% toward capital spending and cost control and 20% toward annual strategic goals. That is a big change from 2019, when Permian Basin production and reserves growth (25%) and drilling and completion activity (12.5%) factored heavily. The majors and super-independents that now dominate shale after waves of mergers and acquisitions have created a more oligopolistic sector. These financially-focused firms are less likely to break ranks on low growth.

Longer term, there remain questions about the economics of shale, as well as the scale and viability of the resource. Energy Intelligence reckons that shale's per barrel free cash flow breakeven costs are in the $60s rather than the $30-$40 range that companies advertise. US production should slightly exceed the 13 million b/d pre-pandemic peak achieved in late 2019, according to our forecast, but this would not happen until late 2024 — and upside could be extremely limited from there. Back in 2018, shale pioneer Mark Papa spoke of "resource exhaustion," arguing shale would not grow past 2025 because of inventory degradation. This has since become more the consensus view. At the recent Barclays CEO Energy-Power Conference, Pioneer CEO Scott Sheffield said some operators had started drilling in less productive Tier 2 and 3 acreage. The industry is believed to have exhausted much of its best acreage and drilling inventory during the downturn. A drop in well productivity could lead to more challenging extraction, higher breakevens and less incremental drilling, which add further pressures on US output growth.

Shell to Embark on New Chapter Under CEO Sawan

Supermajor Shell is set to embark on a new chapter following the imminent retirement of Chief Executive Ben van Beurden and the ascension of Wael Sawan to the job on Jan. 1. The announcement of a new CEO was hardly a surprise, given Van Beurden's relatively long nine-year tenure at the helm. The choice of Sawan as successor was well-flagged but nevertheless represents a departure from past Shell leaders. He takes over a company that has recently undergone its most significant strategic shift in decades as it resets its financial framework and approach to the energy transition after the pandemic-driven downturn. At 48, Sawan will be the youngest CEO in Shell's history, and the Lebanese-Canadian executive will be the first non-European to guide Shell in its roughly 115-years of existence. Sources tell Energy Intelligence that Sawan enjoys strong backing at the board level, noting that he is known for being decisive on tough issues. Chairman Andrew Mackenzie praised Sawan's "track record of commercial, operational and transformational success" and noted "his strategic clarity," when announcing the decision.

Sawan comes to the top spot having held a variety of important roles within Shell. Most recently, he headed its mammoth — and most profitable — Integrated Gas, Renewables & Energy Solutions division, but his background has primarily been in key upstream posts, including heading Shell's deepwater division and its operations in LNG giant Qatar. Consensus among analysts is that Sawan is unlikely to dramatically change Shell's course following Van Beurden's comprehensive rethink of the company's strategy in 2020, including a historic recalibration of its dividend. But industry insiders tell Energy Intelligence Sawan has room to maneuver within that framework and could make more substantial changes than some expect. "The shift is likely to be more of a continuation than revolution of the strategy put in place by Van Beurden," RBC analysts said in a note to clients. One insider said there is scope for Sawan to simplify Shell's corporate structure, noting that London-based supermajor's strategy and divisions are more complex and harder to understand than its peers. But any strategic changes would need to gain the backing of a board that endorsed Van Beurden's massive overhaul of Shell less than two years ago. Further, it is unlikely Sawan would unveil anything too ambitious through June 2023, during which time Van Beurden will remain an advisor to the company. "I will not be surprised if there are substantial changes in strategy once Ben has stepped away," said one source.

Where Sawan could look to make his mark remains to be seen. Analysts and industry insiders both noted the potential to quietly reemphasize the upstream part of Shell's portfolio amid today's energy crisis, but this would need to be done within Shell's strategic and financial frameworks. Anything Sawan might like to do in the upstream or downstream could bump up against a requirement to rapidly cut emissions following a 2021 landmark Dutch court decision mandating Shell rapidly accelerated its decarbonization plans. Some sources pointed to the Middle East as one area where Sawan, an Arabic speaker who was born in Beirut and grew up in Dubai, could potentially out-maneuver CEOs of competing Western majors. However, Shell has noticeably pulled back from the region over the last five years after struggling to find its footing in places like Iraq and Libya. Shell is allocating $7 billion to $9 billion to upstream investments this year from its total capital budget of $23 billion-$27 billion. Qatar remains a key investment destination, but there are comparatively few upstream openings in the Middle East. There could be more opportunities in the downstream or retail/marketing, as well as the potential to aggressively expand in transition industries like green hydrogen, which has become a focus for sun-rich countries in the region. The court ruling handed down in The Hague would require Shell to cut all its emissions — including those from the use of its products — by 45% by 2030, rather than the 20% reduction of carbon intensity it had proposed under its initial plan to reach net zero. Shell has since upped its emissions targets but has also filed an appeal against the ruling.

Qatari Minister: No 'Quick Fix' to EU Gas Crisis

(Continued from p.1)

year. Al-Kaabi revealed that QatarEnergy came close to going it alone on the North Field expansion, too. Qatar, which is generating around 1 million barrels of oil equivalent per day of net output for Exxon, Total and Shell alone, is critical for the majors. However, "if there is no value, there is no partnership, very plain and simple," al-Kaabi said. Even if joint ventures are maintained after expiry, terms will be tougher. For Exxon, which has stakes in nine of Qatar's 14 trains, these contract renewals are especially strategic. Qatar knows the value of its LNG will likely drive a hard bargain. "An investment in Qatar is really an important downside-risk revenue maker" for partners, al-Kaabi said.

LNG is only part of a multifront, international investment drive now under way at QatarEnergy. Downstream, petrochemicals is a priority, with al-Kaabi touting QatarEnergy's planned US project with Chevron Phillips Chemical as "the largest polyethylene plant." It recently awarded construction contracts for a 1.2 million ton/yr blue ammonia project, also tipped to be the biggest of its kind. But its global upstream drive is most significant. There were doubters when the strategy launched, but QatarEnergy has been vindicated over the past year by major exploration success in Namibia. QatarEnergy, by virtue of sizable stakes in both Total and Shell discoveries, is poised to be the largest reserves holder in a significant new oil province — Total's Venus discovery is described as the largest deepwater find ever. There have also been offshore gas discoveries in Cyprus and South Africa. And in Brazil, output at QatarEnergy's offshore Sepia field is set to more than double to 400,000 barrels per day in the next couple of years.

Despite confidence in long-term gas demand, QatarEnergy is taking steps to ensure its place in the energy transition. It is investing heavily in greenhouse gas emission mitigation technology at projects. Over $250 million is being spent on such measures at the LNG expansion alone — principally carbon capture and storage (CCS) and solar power. Some 11 million tons/yr of CCS is planned by 2035. "From an overall value chain, Qatari LNG will be the least carbon footprint LNG you can get," al-Kaabi said. "We think that our buyers, and our investors that have joined us in [North Field East expansion], see this as the Rolls-Royce of projects." Transition pressures are feeding into the urgency for developing projects. "I am a believer that you need to monetize what you can because the market conditions change, and there is a competitive advantage to go ahead of others," al-Kaabi stated.

China Export Decision May Swing Market

Chinese national oil companies (NOCs) have asked the government for up to 15 million tons of additional quotas to export transportation fuels, potentially offering relief to tight global diesel markets but also threatening to collapse refining margins. Markets are on tenterhooks as Beijing mulls its decision. Such a move would mark a significant turnaround from last year, when China slashed products exports to cap refining runs and carbon emissions in one stroke. Chinese refiners — mainly NOCs and private giant Zhejiang Petrochemicals — have so far received 24 million tons of export quotas for 2022, nearly 40% lower than in 2021. The companies have exported 543,000 barrels per day of gasoline, diesel and jet fuel over the first eight months of 2022, or about 50% below the same period in 2021. Diesel exports have crashed hard, averaging 100,000 b/d against about 460,000 b/d a year ago. Without additional quotas, the companies are left with about 7.65 million tons for the last four months of 2022, a paltry volume at a time when China's oil demand remains sluggish due to Beijing's zero Covid policy. An additional 15 million tons would bring total quotas for 2022 near 2021 levels — but they would remain far below 2019's record exports of 55.4 million tons.

Amid a global refining crunch, China is one of the few countries with significant excess capacity — estimated at over 3 million b/d. Even running at less than 80% capacity, China could produce and export an additional 15 million tons of products in the fourth quarter. Most would likely be diesel, China's main product export until last year, which could help calm markets ahead of the EU's potentially disruptive ban on Russian products on Feb. 5, 2023. The EU embargo presents a potentially lucrative opportunity for China. Diesel refinery margins of $30 per barrel for Asia, $45/bbl for Europe and $55/bbl for the US are off their peaks but remain sky-high. The world could lose a big chunk of Russia's 450,000 b/d of ultra-low-sulfur diesel exports due to the EU ban. Global diesel consumption will only grow from here due to rising winter demand from the Northern Hemisphere. In Europe, diesel substituting in power generation due to the gas crisis will also stoke demand. Diesel and heating oil demand could run 1 million b/d over current levels at the peak of winter. China has ramped up its imports of Russian crude to close to 2 million b/d since May, according to shipping estimates. It could import more once an EU ban on Russian seaborne crude imports comes into effect on Dec. 5. Processing discounted Russian crude into diesel would provide ally Moscow with needed revenues while generating strong profits for Chinese refiners, with some of the product likely making its way to Europe.

On Thursday, expectations were growing that Beijing would allocate quotas for around 10.5 million tons of transportation fuel and possibly 4.5 million tons of very low sulfur fuel oil (VLSFO), whose exports have surged as China positions itself as a bunkering hub. Beijing must balance several considerations, including domestic fuel needs, environmental concerns and how much Russian crude it is willing to import. A new 10 million tons quota would translate into an increase of 800,000 b/d in Chinese exports, according to consultancy FGE. Just two months ago, there was talk of China's products exports stopping by 2025 or even 2023. In August, the ministries overseeing China's energy and environment sectors published a plan calling for new refining projects to be fully integrated with petrochemicals and capping refinery output of gasoline, diesel and jet fuel at 40% of capacity by 2025. Cheap Russian crude may tempt, but Beijing will be careful not to become too reliant on it or supportive of Moscow for political reasons. China also wants to avoid a repeat of last year's diesel shortages at home. As such, Beijing will likely award extra quotas to support Chinese refiners, which have seen products sales fall at home and overseas this year, but will be wary of awarding too much, says a trading analyst.

Mozambique Wants More From Majors to Advance LNG

In the coming weeks, Mozambique will join the club of African LNG exporters when the first cargo is lifted from the $7 billion, 3.4 million ton per year Eni-led Coral South floating LNG project. But the main talking point at a recent conference in the capital, Maputo, was the security situation in the northeastern region of Cabo Delgado, which continues to derail the country's two onshore LNG developments: the $20 billion 13.12 million tons/yr TotalEnergies-operated Mozambique LNG project, which has been under force majeure since April last year, and the $23 billion, 15.2 million tons/yr Rovuma LNG scheme, led by Exxon Mobil, which is no closer to getting the green light than it was two years ago.

At the conference, Mozambique's President Filipe Nyusi urged the LNG developers to advance and said the outlook for Cabo Delgado was improving as the militants, who have wreaked havoc in the region over the past five years, are being chased out. **But the oil companies are much more circumspect, and say more work needs to be done to restore stability to the region.** "We are not there yet," was the assessment of the deputy managing director of Mozambique LNG, Stephan le Galles, who would not be drawn on when the force majeure may be lifted — although industry sources say privately that a resumption is earmarked for early 2023. Exxon's country head, Jos Evens, told the conference that fellow concessionaries for Block 4, which include Eni (25%), China National Petroleum Corp. (20%), Mozambique's state oil company ENH (10%), Korea's Kogas (10%) and Portugal's Galp (10%), were discussing a possible "optimization" of the Rovuma LNG concept and also looking to build a second floating LNG (FLNG) terminal to complement the one at Coral South.

Based on its giant deepwater gas reserves, which lie in the Rovuma basin off Cabo Delgado, Mozambique has the potential to become one of the world's largest LNG exporters at a time when global supply tightness has pushed prices to sky-high levels and as Europe scrambles to find

alternatives to Russian gas. Area 4 alone has proven reserves of around 85 trillion cubic feet, of which around 16 Tcf are at the Coral field, discovered in 2012. Coral South will take up just 5 Tcf of gas, which will come from six wells drilled; according to Eni, there is scope for two more FLNGs for Coral, each with a 2-3 million tons/yr capacity and requiring the drilling of just two wells. Another factor in Area 4's favor is that the gas has a very low CO2 content, which would help allay concerns among banks and other lenders about the potential environmental impact. That said, there is little appetite among banks, who provided most of the funding for Coral South and Mozambique LNG, to increase their exposure to Mozambique: "There's a wait-and-see attitude right now," a Western banker says. "You could get quite a lot of momentum after Coral South starts up."

When Coral South lifts off, there will be a gap of several years before the next project starts up. Even if work resumes early next year, Mozambique LNG will not come on stream until 2026 — two years later than planned, while Rovuma LNG is unlikely to see the light of day before 2030. In Maputo, there is an expectation that the LNG bonanza will transform Mozambique's depressed economy and improve living standards and services across the country. "There is quite a lot of impatience, and expectations are probably too high," says an industry source in Maputo who works closely with ENH. At the same time, the oil companies recognize that more needs to be done to assist with the development of Cabo Delgado and convince the local population that they are forces for good. Total, which entered Mozambique only three years ago, has launched a "massive" campaign to carry out humanitarian projects in the region.

US Flexible With SPR Ahead of Price Cap

When it comes to strategic oil stocks, the Biden administration is keeping some in reserve — which could help it cope with potential price spike in coming months. The US Department of Energy (DOE) this week announced the sixth installment of emergency stock sales this year, offering 10 million barrels of oil from the Strategic Petroleum Reserve (SPR) for delivery in November. That means the administration has some 15 million barrels left of the 180 million authorized by President Joe Biden in March as market players begin to nervously eye the G7's implementation of a "price cap" on Russian oil slated to come into effect in early December. Officials originally envisioned selling the 180 million barrels over six months at a rate of up to 1 million barrels per day. But not all of the oil on offer in June and July was bought up, and officials now appear to be extending the timeline, with planned deliveries in November and further authorized volumes still available. There could yet be more, with an agency official saying this week that the administration is tracking global supply, the types of crude refiners need, and what the SPR has available when offering up barrels.

The administration is trying to transform the SPR into a more flexible tool that can be used to take the edge off uncomfortable prices. The DOE is simultaneously trying to change how it can replenish its coffers: in August, the administration proposed changes that would allow it to make fixed price contracts to purchase oil to refill the SPR. From the start, administration officials have been keenly aware of concerns that SPR sales could serve as a signal to producers to keep output in the ground — precisely the opposite of what they want in the near term. Instead, they have framed the largest-ever sale of strategic stocks as a "wartime bridge" to get the US to higher output. The move to fixed-price contracts is meant to be a signal to producers that there will be demand for their output at higher prices. Officials haven't publicly commented on a price at which they would repurchase oil, although Bloomberg last week reported discussion around $80 per barrel for refill purchases. While US crude production looks like it will fall short of some bold forecasts that had predicted growth of 800,000 b/d to 1 million b/d this year, it will still post a strong advance. Indeed, US crude output of around 12 million b/d today is some 600,000 b/d higher than where it started 2022 despite growing concerns about a recession that threatens oil demand.

With the heavy use of the SPR, its volumes are lower than they have been since Oct. 1984, at 434.1 million barrels. That worries some market watchers, but more active use of the reserve is also in line with the "central bank of oil" vision some early architects of the reserve had in mind. The lower SPR volumes also come as the US is more secure in its position as a producer. The US is obligated as an International Energy Agency (IEA) member to maintain stocks equivalent to 90 days of net imports in publicly-held or commercial reserves. As of August, US stocks amounted to 2,552 days worth of net imports, according to the IEA. Moreover, average US retail gasoline prices of $3.65 per gallon today are down sharply from over $5/gallon in June. This has provided some relief to consumers and eased some political pressure on Biden. But with inflation still running at a 40-year high and the price cap threatening to disrupt Russian supplies, the White House remains cognizant of the threat from another potential oil price spike.

Qatar's Al-Kaabi: Crisis Changes Outlook for Gas

The current energy crisis has generated massive interest in LNG and its potential role in addressing supply concerns, both today and in the energy transition. This has heightened scrutiny of the plans and strategy of LNG superpower Qatar. Energy Intelligence recently spoke with Saad al-Kaabi, Qatar's Minister of State for Energy Affairs, and President and CEO of Qatar Energy, in his Doha office. An edited transcript of the interview with 2022's Energy Executive of the Year follows.

Q. With Europe and Russia escalating into an all-out energy war, we are heading into a very difficult winter for European customers. As the largest LNG producer in the world, how do you see the market developing? Is there going to be enough LNG supply to replace Russian gas?

A. It is a very difficult question to answer. A lot of countries and companies have reached out to us, and I have consistently said the same thing: Europe was always dependent on Russian gas as the major supplier from pipelines. The majority of Europe, especially the north, was not set up for LNG imports. Now, of course, the situation has changed. You see Germany going from zero LNG import terminals to four to five terminals, starting in the first quarter next year. And other European countries are trying to take a similar approach. From what you hear, the Europeans have really tried to fill up storage capacity. Storage will help for sure. But if it is a very strong winter, there could be a problem — maybe not in winter, but beyond winter in the season when you are going to have to replenish storage for the next winter. There will be some LNG coming in from the US, other places. [For Qatar,] the majority of our customers have long-term contracts. We have committed not to move anything away from Europe or divert any volume. And we have lived up to that. But in the end, this is a small volume in comparison with the huge volume that is coming from Russia that Europe depended on.

Q. Do you think Europe will be able to wean itself off Russian gas?

A. No. They are going to have come back. I am hoping that at some point there is an end to this crisis, or a mediation that would bring peace to Europe and hopefully bring some of that Russian gas back to support Europe. If you look at a situation where zero Russian gas comes to Europe for more than two winters, I think it is going to be very difficult.

Q. Shell CEO Ben Van Beurden's recently said Europe is facing "a number" of bad winters. So unless there is a political solution to bring back Russian gas, it sounds as if you agree?

A. There isn't a quick solution. A quick fix is not available. It will take a lot of collective efforts to logistically get some volume into Europe. There is a lot of fuel switching due to the high prices, and that could help slightly alleviate that. But I think it is important that legislators and governments understand that they need to have their minds set on what they need for the long term. And it can't be narration of: 'We need to go green, green, green,' without talking about the transition. I still hear some people promoting that, saying we need to invest heavily in green energy, which I completely support. But we should not forget that gas, specifically, is very important for that transition for continuity of supply and for having a fuel that can be your baseload with no intermittency for a long time. When you couple gas with CO2 sequestration, some renewable energy to power that, it is the most powerful fuel we have. It serves both purposes. Gas is fundamentally needed for decades to come.

Q. You have said that Qatar does not have supplies to replace Russian gas in the short term, but what can you do in the medium term?

A. In the five- to seven-year horizon, we have much more capability to support Europe, because volumes are going to start coming from two of our projects. One is 16 million tons per year Golden Pass LNG coming on stream from 2024. It is already earmarked for Europe. It could go to other markets too, but Europe would be the first choice. In addition, just a couple of years after that we have the huge North Field expansion. When you combine our US and Qatar projects, QatarEnergy and its partners alone will bring around 65 million tons/yr into the market.

Q. There have been calls by EU politicians to phase out the use of gas altogether as soon as 2030. Do you see Europe as a reliable market for Qatar in the future?

A. Europe is definitely going to be a very important gas market no matter what happens. If you look at what we're doing, as far as all the investment in the 32 million tons/yr North Field East (NFE) and Phase-2, the 16 million tons/yr North Field South (NFS), when it's all said and done, I would expect us to have 50% East of Suez. It could be skewed to 40/60, either way depending on supply and demand.

Q. You have had a lot of conversations with governments and policymakers over the last couple of months. Do you detect any change in their willingness to have gas be part of the energy mix in the quest for energy security?

A. Absolutely. There has been a big shift, a fundamental shift in how governments perceive gas and want to publicly speak about gas. I think a lot of it was discussed previously but it is much more public due to energy security now. I think they realized that gas was absolutely needed, but they couldn't be as vocal as they are today in my view. You need all fossil fuels. We have to make sure we have strict environmental regulations, so that everybody in the oil and gas industry has the same standards.

Q. Contract duration seems to be a key stumbling block as regards new supply to the EU. Currently where do we stand on this?

A. I think everybody wants stability. A buyer wants stability of supply, and a seller wants a buyer that is stable and can buy for the long term. But the fundamental issue in Europe, in my view, is that governments talk about buying additional gas but they can't because most European countries do not have a vehicle to buy gas through.

The majority of the purchases of LNG is through private companies. It's the private sector that buys. That's the mismatch. Is the government going to pitch in to bridge that gap for the risk of the private sector or not? I'm not sure. I think 10- to 15-year deals are probably what are most acceptable to both sides. But for us, the long-term deal, it's not just about duration, it's about price.

Q. Is there any possibility of accelerating the start-up of Golden Pass?

A. No. I think it is very difficult. If you look at contractors' situation, steel prices, shipping , logistics — everyone is challenged. I don't think anybody is going to be able to do that.

Q. We would be very interested in hearing your views on prices. Do you see danger of long-term LNG demand destruction?

A. As far as the gas prices and what's happening in [Dutch] TTF and [UK] NBP and so on, that is actually ridiculous. It has already destroyed demand. You have seen companies shut down fertilizer plants. It really did have a big effect. Destruction of demand is the biggest enemy for our business, in my view. It will need time to correct itself.

Q. We are hearing a lot of talk about capping the price of Russian oil and gas into Europe. What are your views on this?

A. Like you, I read about the price caps. I don't think it's a good idea to try and control the market. Not because I want higher prices, I'm just saying it won't solve the problem. It will be creating something that is unprecedented and could worry investors for future investments. Because if the Europeans decide to have a price cap and I'm investing billions of dollars, what guarantees me that that price cap is not lower than my break-even [price] at some point in the future.

Q. To follow up, are you concerned that high gas prices mean you could move from coal directly to renewables and skip gas, especially in Asia?

A. I don't see that at all happening, if people are serious about the environment. You are doubling the emissions when you use coal instead of gas. So, if you are willing to double that emission, you definitely are not going to get to net zero by 2050. Coal cannot do everything. Coal cannot run CNG (compressed natural gas) buses, cannot run shipping. And even the coal that they are talking about, they need the ammonia to try and reduce the carbon as one way to make it less carbon intensive. And you need gas to do that. So, I don't buy into that argument at all.

Q. It would be interesting to hear your views on green LNG. What sort of premium do you see for it?

A. Buyers today are looking for LNG. Period. They are not looking really for green LNG, to be honest with you. But as a responsible company striving to ensure sustainability, we have used solar, the best machinery you can buy for reduction of emissions of nitrogen oxide, sulfur oxide, all the emissions. We have invested in the best technologies — more than $250 million dollars — just for the CO2 sequestration and storage and everything that we need to do to reduce the emissions. And a couple of weeks ago, QatarEnergy announced the start of construction of two new new solar power plants in the industrial area, to generate for 800 megawatts of power. This will partially supply power to the new LNG trains in Qatar to reduce the carbon footprint. In addition, all the ships that we've ordered — around 70-plus ships — are going to be run by LNG-fueled engines, using the most efficient engines available today. Basically, from an overall value chain, Qatari LNG will be the least carbon footprint LNG you can get. We think that our buyers, and our investors that have joined us in NFE, see this as the Rolls Royce of projects. We're not asking for a huge price premium. But there is an appreciation for what we can supply as far as reliability and sustainability as a package.

Q. Once the supply situation gets better post-2025, do you see green LNG becoming a bigger selling point?

A. I think it's a great selling point for us. There's no question. I mean, we have invested a lot in it. We were working on this many years before people were talking about CO2 sequestration.

Q. There seems to be a shift towards greater Qatari ownership of your assets, for example with taking full ownership of upstream oil concessions and Qatargas-1 from foreign partners. Is that what's going to happen as the other LNG projects expire? Will they automatically revert to QatarEnergy operatorship?

A. We are not saying that we don't want the partnership model — as evident by what we did in NFE. NFE partnership is similar to joint venture models that we've had in the past with some of the same partners. The new joint ventures in NFE are going to be in effect until 2055. It's not a shift in strategy. But we were prepared to [go solo for NFE]. And I was serious. I said this before.

Q. That wasn't a bluff?

A. It wasn't a bluff. We awarded all the EPC contracts and we went ahead. It was all done.

Q. With all the design work done, the contracts awarded and enough capital to self-fund the expansion, why did you bring in any partners?

A. There are benefits of having them in. If we didn't like the offers we got, we would not have brought them in. Period. We have a great relationship with our partners. They are very much a value-add to Qatar's gas industry and to our business. That's why we have them. We are very proud of our partners. [But] going forward, QatarEnergy needs to present to my country that we are bringing a value proposition for having a partner take a piece of that action. If there is no value, there is no partnership, very plain and simple.

Q. But when you have partners, you can bring them with you for other things?

A. Yeah, that is definitely there. There is an element of having that partnership that is important. The relationship with these companies is important; the relationship with their countries is also of added value. You look at all that. You look at the offers they bring in. They bring a wealth of expertise. They're going to spend capital here so they're bringing in 25% of the capital in some NFE ventures, for example. That of course is a big support. Its foreign direct investment into the country. In addition to that they bring a marketing offer. Part of that is there is an offtake agreement by them. That is a win-win. You need to have a partnership that can outlast CEOs. You can't have a partnership where it's lopsided and you think you got the best of them or vice versa. It has to be balanced for both sides. It has to be, as much as possible, fair. And also the way our projects work, and how we've structured the deals, it has a lot of downside risk protection on price. These projects, even at a very low oil price, would actually make good money.

Q. For all partners?

A. Yes. An investment in Qatar is really an important downside-risk revenue maker. When the Covid pandemic hit, I know for some companies, the only real money maker was their investments in Qatar. That's because of the low-cost resources, the excellent operational efficiency and also the structure of the deal.

Q. You have said in the past that you want QatarEnergy to look more like an IOC than an NOC. Can you give us an update on your vision on what you're trying to do with the company?

A. I consider that we already made the shift from being a national company to being an international company, evident by what we are doing internationally. It is very methodical. It's been ongoing, even in the downturn of the business. We have more than 30 blocks around the world and there are wells being drilled as we speak. We are not stopping. People are saying, 'What are they doing? Why are they going and investing internationally?' We were consistent, and we were just staying the course. It takes a lot of good work and some good luck. And we've been quite successful in our exploration, whether it's in Cyprus, or in South Africa. The biggest was Namibia, where we had two big finds with our colleagues from Total and Shell. In addition to that, we bought into the Sepia oil field in Brazil, which is a producing asset, and we were fortunate to join the project at a good time. On the petrochemicals side, we've announced in the US that we are going to build the largest polyethylene plant in the world. And we are getting close to moving ahead with that. If you are asking what QatarEnergy will look like in the future, it will be a much bigger producer. Some part of its production is going to be from outside Qatar. What percentage that is will depend on the success of the exploration drilling. But it will be a substantial income for the country and for the company. In addition to that, our announcement of the 1.2 million tons/yr blue ammonia project was a big surprise to everybody. It is something that we need for the future from a transition point of view. We went to EPC. The contractors are in place. And in a few years, we will have first production. It's coupled with carbon capture and sequestration. It has solar power for some of its requirement and it is the largest in the world.

Q. It sounds like your model is very much, you build it and then you figure out the market later. Is that fair to say you don't need to have all the buyers lined up before you invest?

A. When we are confident about the demand in the future about any product, we invest. When we talked in 2016 or 2017 of the LNG expansion, people were doubting us. Why would you do the huge expansion project NFE/NFS and go solo? Everybody, even us, thought that there will be an oversupply in 2022 and 2023. But nobody thought that it would come to what we have today.

Q. Are there still ongoing discussions for Asian clients to join NFE?

A. Yes. The discussions are still ongoing and it's really an open discussion, if you will. We don't need them. If they come that's great. There isn't a timeline.

Q. Are you still offering 5% equity in the project?

It depends. It won't be higher than 5%. But if there is a percentage that's given to somebody that's willing to buy LNG from us for 26 years, and at a price that we accept for that duration, then they would come in. That can happen one day before the production starts and it can happen today. We're in no rush. But we're talking to many Asian customers.

Q. On NFS, have the partner selection discussions begun?

A. We are almost done. I can't tell you who it is. Before I come to receive the Energy Executive of the Year on Oct. 4, we will have an announcement. I know that at least one is beyond the finish line.

Q. How much do associated liquids make up of your profits?

A. It depends on the oil price, of course. I actually don't have a number to give you now, but it's substantial. It's 40% or 30%, it depends. We produce about 700,000 barrels per day of condensate. And condensate is at $90/bbl plus. We're producing LPG. We're going to be the largest or one of the largest producers in the world.

Q. After NFS is done, you have 108 years of production left in the North Field, according to your bond prospectus last year. What are your next steps for the North Field?

A. If you look at the evolution of Qatar and LNG and what we have done, there is something we don't talk much about by the way, which is very important. All the trains of LNG that we built in the past did not extract ethane. None of them. This project, NFE, is the first that actually extracts ethane. It tells you that we're actually ambitious on chemicals. We have a very set plan, and the plan is very meticulous. We know where we're going, and we know what we're going to do. I don't have to think about it. It is done. Every year we update our strategy or our path, just to make sure. [We might say,] okay, a little bit to the right guys, a little bit to the left, but it's really the same strategy. We haven't changed our strategy in almost anything.

Q. Even through the pandemic?

A. It has not changed at all. The only thing that actually kept getting delayed was the award of the North Field expansion to IOCs, and it was intentional. We didn't like what they offered us.

Then we awarded everything (all EPC contracts) alone as QatarEnergy. We de-risked NFE and asked our friends that were in the race to enter NFE to submit a new bid that took into account the new risk profile.

Q. How many rounds of negotiations were there? How close were you to going by yourself?

A. After we awarded the EPC contracts and everything was set in stone from a cost perspective — we knew the the actual capital cost of the project — then I said, if I don't get offers within this kind of threshold, we are not going with anybody.

Q. How did the foreign partners feel about the deal that you finally gave them?

A. I think they feel they should have gotten better terms but understand that this is a de-risked project and very good portfolio protection for the low side. And it has quite a robust high side. I think they are very happy to be in the best LNG project in the world from a carbon footprint point of view.

Q. What are your plans for further North Field development beyond the North Field South project?

A. It depends on technical information. Once the technical information is in, it will either tell us yes or no. We would like to develop more. We are working on it. We haven't stopped appraising the field. Does that result in saying that we can potentially do more? Possibly. The issue to me is technical. If something materializes that shows there is potential, we would not hesitate.

Q. I note that from NFE to NFS, there's a slight drop in quality of the reservoir.

Q. True. The cost [per unit] of NFS is going to be higher than NFE. Yes, for sure. You see there is a difference. If in our international exploration program we find something one tenth as good as the quantity/quality of NFS, I'll be making headline news. Now, with NFS to NFE, I'm comparing a Rolls-Royce to a Bentley, or a Bentley to a BMW, or a BMW to a Mercedes. It is just one step below NFE, but it is still a world class asset. Now if we go to another area of the field, it could be better than NFS not worse.

Q. Is there still a lot of work to do, to know the next stage for North Field development?

A. We will know soon enough.

Q. Next year?

A. In the next couple of years.

Q. Has the mindset changed at all in Qatar about the urgency to develop resources? Should you monetize your assets quicker?

A. If there are reserves that can be developed economically with good reservoir engineering practice in mind, it will be developed. That's always been the mindset. I am a believer that you need to monetize what you can because the market conditions change and there is a competitive advantage to go ahead of others. And I think NFE proved that we were right in the decision. We don't look to compete with others. We are focused on our strategy.

Q. Let's discuss new technologies and how the oil and gas industry can play a role in removing carbon from the energy mix. You have been skeptical on hydrogen. But you mentioned the large ammonia project, so you clearly see value in clean hydrocarbons. What is driving this investment?

A. People don't understand that the oil and gas industry understands ammonia and hydrogen very well. We have dealt with it for years. We produce or use hydrogen in a lot of our facilities. We are one of the largest urea producers in the world. You need ammonia to produce urea. Everybody is saying, 'ammonia and hydrogen, hydrogen.' But for hydrogen, you need to go to minus 260°C to transport it in liquid form to far away markets. That is a very difficult proposition. Ammonia is transported as liquid at minus 30°C. It is doable, much easier than for hydrogen. Ammonia can be a carrier for hydrogen, which is one way of doing it. People are trying to say that or testing ammonia as fuel directly. Ammonia can be used to reduce the CO2 emissions from coal. When you're burning coal, you bring in ammonia with it and you burn the two in power plants and you reduce the CO2 emissions substantially.

Q. Are you looking at more regas capacity internationally?

A. Yes. Pakistan is being considered. We are looking at terminals all round the world. If it helps us monetize our gas, we would participate. We bought capacity into regas terminals in Zeebrugge, Montoir-de-Bretagne, the Isle of Grain. People were saying, 'What are these guys doing?' We were targeting the EU and also that was the closest point to Germany, and that's the biggest industrial nation in the EU. The UK is second.

Q. Can you talk about any highlights of your international portfolio, for instance Namibia?

A. Namibia is a very substantial find. Both [our] fields are quite large oil fields with some gas. Now we are further appraising these fields with our partners. We are the biggest holder of reserves in Namibia as QatarEnergy because we have two blocks with TotalEnergies and Shell.

Q. How big are the Namibia reserves?

A. I would say it's around 10 billion bbl of oil In place with upside.

Q. So you've actually got quite a large production in Brazil. What is your strategy there?

A. In Brazil we have many exploration blocks. We are partners in the Sepia field, which produces somewhere in the range of 180,000 b/d and it's going to go up to 400,000 b/d in the next couple of years. In Cyprus, we've made a good discovery and we took additional acreage. We are shooting seismic next year.

What's New Around the World

GENERAL

MARKETS — Saudi Aramco CEO Amin Nasser says the world is facing an energy crisis of its own making because it underinvested in oil and gas, failed to create sufficient availability of alternative energy and did not prepare a back-up plan. "When historians reflect on this crisis, they will see that the warning signs in global energy policies were flashing red for almost a decade," Nasser told the Schlumberger Digital Forum in Luzern. Nasser said industry players had warned for years that a sustained decline in oil and gas investment would lead to a lag in supply growth, with repercussions for markets and the global economy. At the same time, unrealistic scenarios and flawed assumptions had undermined energy transition planning because they had been "mistakenly" viewed as facts, he added. "These are the real causes of this state of energy insecurity: underinvestment in oil and gas, alternatives not ready and no back-up plan. But you would not know that from the response so far," Nasser said. Saudi Arabia is pressing ahead with plans to raise its oil production capacity to 13 million b/d by 2027 and potentially increase its gas capacity 50% by 2030, allowing it to phase out the use of liquid fuels for power generation.

COUNTRIES

ARGENTINA — French supermajor TotalEnergies said it would proceed with a $706 million offshore gas project in southern Argentina as the nation aims to become a major gas exporter in the region. First gas from the newly sanctioned Fenix project is expected in early 2025; at its peak, the development is slated to reach around 10 MMcm/d. One analyst said the project would be the "most relevant" Argentinean project outside the Neuquen Basin, home of the prolific Vaca Muerta Shale. "It will take advantage of existing infrastructure and help provide supply security for the country," said Rystad Energy analyst Vinicius Romano. The plan calls for the drilling of three horizontal wells in 70 meters of water from a new unmanned platform in the Fénix field, some 60 kilometers off the coast of Tierra del Fuego. The gas would then travel 35 km through a pipeline to Total's platform at Vega Pleyade and its plants at Rio Cullen and Canadon Alfa. Total will operate the project with a 37.5% interest via its affiliate, Total Austral. Germany's Wintershall Dea and Argentina-based Pan American Sur are partners and will maintain a 37.5% and 25% interest, respectively.

AUSTRALIA — Shell has restarted production at its floating Prelude facility offshore Western Australia, ending a standoff with Australian unions, which lasted more than two months. The operator said Monday that LNG cargoes have resumed from the Prelude facility. This follows the cancellation of protected industrial action after an in-principle enterprise agreement was reached with the Australian Workers' Union (AWU) and Electrical Trades Union on Aug. 23. The Offshore Alliance, a partnership between AWU and Maritime Union of Australia, said its members have voted 94% in favor of a new Prelude enterprise agreement, which "close out the bargaining process after 76 days of industrial struggle." The new agreement is expected to come into effect in early October. The strike, which started on Jun.10 and extended several times, has led to a shutdown of the 3.6 million ton/yr Prelude due to work bans. Prelude's restart would help ease global LNG supply tightness as winter approaches which has boosted buyers' stockpiling in Asia and Europe.

IRAN — Iran's crude and condensate exports continue to hover around 900,000 b/d, the bulk of which still goes to China, even though the Asian giant has been buying more deeply discounted Russian crude. A senior Iranian oil official told Energy Intelligence that crude and condensate exports are estimated to have remained at levels of around 700,000 b/d and 200,000 b/d respectively in recent months. Most of that continues to head to China — Iran's only major buyer — via clandestine channels, including ship-to-ship transfers. Smaller volumes also go to Syria, while some condensate is shipped to Venezuela. The official said he believed Iran was unlikely to be offering discounts of more than $1/bbl versus discounted Russian crude because "the quality of our crude is better than Urals." Some media reports have suggested that Iran may be offering discounts of $5-$7/bbl to Russian crude. Iran is estimated to have more than 90 million bbl of crude in floating storage that it could release swiftly if an agreement were reached to revive the 2015 Iran nuclear deal and lift sanctions on its oil.

RUSSIA — The head independent producer Russneft has suggested that Russia could continue to export oil profitably under the G7 nations' plan to impose a price cap on overseas sales of Russian oil — as long as certain conditions are met. Russneft CEO Yevgeny Tolochek said the scheme could work for Russian producers if the value of the dollar was strong relative to the ruble and if the cap was set around $69/bbl. Tolochek said the price cap proposal "indirectly proves that the market won't be able to do without Russian oil." Russneft produces around 140,000 b/d, or slightly more than 1% of Russia's total production of crude oil and condensate. Tolochek said Russneft's 2022 budget is based on a price of $65/bbl for Russia's Urals crude oil export blend. The company's budget calculations for 2023 are likely to be set around $69/bbl. "If the price cap is set at about this level, exports would remain efficient, also under a high exchange rate of the US dollar," he said. Tolochek said Russian producers would need an exchange rate of around 80 rubles to the dollar. The current rate is less than 60 rubles per dollar.

UNITED STATES — US legislators want a say in the forthcoming price cap on Russian oil. Republican Sen. Pat Toomey and Democratic Sen. Chris Van Hollen announced a sanctions bill that has broader powers to enforce the proposed price cap on Russian oil than what the Biden administration is currently advocating. The senators' proposal threatens to block companies from the US financial system if they buy oil priced above the cap, a structure known as "secondary sanctions" that have been controversial in the past when used in other sanctions programs, such as that on Iran. The legislation is meant to act "as a complement to the administration's effort, a backstop," Van Hollen said in a Senate Banking Committee hearing Tuesday. But Treasury Department officials have seemed comfortable with the idea that Russia may be able to sell some oil above the cap. They've largely framed the idea that Russia is forced to sell at steep discounts as the price cap looms as a success. Their objective is to reduce revenues — and steep discounts do that. The Biden administration is also balancing its concerns over Russia's revenues with those of oil market supply.

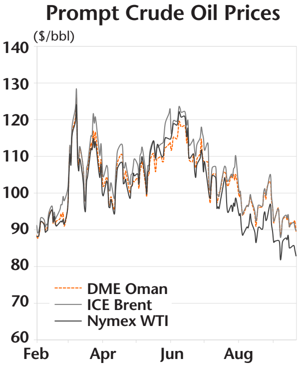
UNITED STATES — US shale giant Chesapeake Energy has formed a strategic partnership with Houston-based Criterion Energy Partners to deploy and develop technologies for geothermal energy projects. Chesapeake's involvement in the partnership includes an investment to assist in the planning and preparation for an initial geothermal test well. The news comes as excitement builds around emerging geothermal technologies that could potentially greatly expand the availability of clean baseload power supplies. Hundreds of millions of dollars in new funding from both the private and public sectors has shined a spotlight on new approaches to geothermal, and raised hopes that the abundant "always on" energy source could one day be a key tool in global decarbonization efforts. Like other oil and gas companies, Chesapeake has identified geothermal as an attractive fit with its existing skillset and energy transition ambitions, although details of the company's investment in Criterion have not been disclosed. Most of the interest in geothermal from the oil and gas industry so far has stemmed from the services sector, with few E&Ps publicizing their involvement to date.

Marketview

Diesel on the Floor

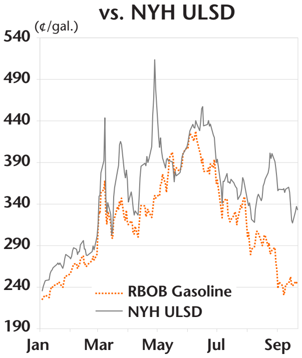
Global benchmark Brent crude dropped below $90 per barrel again this week but promptly rebounded above that threshold. Technical traders say Brent remains well above its next key support level — in fact, the front month contract is closer to resistance than support. For all the bearish sentiment and fears about a recession driving prices, expectations of a tight market — especially for heating fuels during winter in the Northern Hemisphere — seems to be putting a floor under oil.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex Prompt Gasoline vs. NYH ULSD



Several factors serve as a brake on further selling. First and foremost, the continued and intensifying displacement of Russian petroleum by the EU keeps the market tight. Opec-plus actions and strained spare capacity also serve as supports, as do the tapering of big US Strategic Petroleum Reserves (SPR) sales, although the Biden administration is keeping its SPR policy as flexible as possible.

Exacerbating the issue is the high price of natural gas in Europe. Gas is needed to desulfurize oil products, but its rich price is adding to already steep regional operating costs. That has two implications; Europe must import more oil products, and it can export less.

Tightness is largely focused on the middle of the barrel products, especially diesel. Refinery economics reflect the concern about adequate availability of diesel — in the US, Energy Intelligence's downstream model suggests a complex Gulf Coast facility processing incremental Brent realizes a diesel crack of $54.99 per barrel. Singapore cracks against DME are also high at $30.17/bbl. Even in the challenging European environment, refiners running incremental spot Brent see diesel cracks of a whopping $47.14/bbl.

There is little relief for diesel supplies on the horizon. Crack spreads are already incentivizing maximum diesel yield in most regions, and refiners in the US are running flat out at 93.6% and have been keeping utilization at a frenetic rate, upping the chances of outages. Indeed, BP's Toledo, Ohio is now shut down after a fire that killed two employees. Refiners in the West simply cannot do much more to feed the diesel market, while in China exports of products remain curtailed.

As supply runs into obstacles, demand might soon start perking up. Diesel futures have been sliding on and off this week amid persistent and growing concerns about a recession. Weaker growth would curb manufacturing and other industrial activity, eating into demand, and Europe's transportation sector also runs off diesel — a recession and high prices themselves could hurt consumption.

But a reversal could easily be in the cards as cold weather approaches. This is especially true as high natural gas costs not only impede Europe's refinery operations but also hurt consumers; the prospects for fuel switching are high, a development that would boost diesel demand. Should the winter be cold, prices (and cracks) will get even hotter. The International Energy Agency sees as much as 700,000 barrels per day in incremental oil demand stemming from potential fuel switching, and the global downstream sector has little wiggle room or capacity to meet that. Strained supply and potentially higher demand come against a backdrop of low inventories as well. There is virtually no cushion.

Spill Highlights Iraq's Export Problems

Crude exports from southern Iraq have returned to normal levels after a brief disruption caused by a leak that halted loadings from the aging Basrah oil terminal, which has recently been operating at a rate of around 1.3 million b/d.

The incident at the ABOT (Al-Basrah Oil Terminal) highlights the decrepit state of Iraq's export infrastructure and the struggles it faces in trying to raise oil production. State-run Basrah Oil Co. (BOC) said on Saturday that engineers had dealt with the spill and that export operations at ABOT had returned to "normal rates" after a 24-hour hiatus. Iraq has recently been exporting very close to 3.28 million b/d from Basrah as it tries to hike its oil output.

PIW Market Indicators

($/barrel)	Sep 19-	Sep 12-	Aug 22-
Spot Crude	**Sep 21**	**Sep 16**	**Aug 26**
Opec Basket	$96.02	$97.13	$102.64
UK Brent (Dtd.)	89.91	91.65	99.00
US WTI (Cushing)	84.67	87.24	94.47
Nigeria Bonny Lt.	92.51	94.48	102.51
Dubai Fateh	91.87	92.83	97.86
US Mars	83.87	86.61	92.69
Russia Urals (NWE)	66.21	68.10	74.51
Crude Futures			
Brent 1st (ICE)	90.82	92.69	99.65
Brent 2nd (ICE)	89.62	91.59	98.56
B-wave (ICE)	91.01	93.00	99.02
WTI 1st (Nymex)	84.37	86.76	92.89
WTI 2nd (Nymex)	83.91	86.35	92.52
Oman 1st (DME)	90.69	92.54	99.23
Oman 2nd (DME)	88.16	89.77	97.38
Murban 1st (ICE)	92.48	94.23	100.00
Murban 2nd (ICE)	90.35	91.98	98.59
Forward Spreads			
Brent (1st-Dtd.)	+$0.91	+$1.04	+$0.65
Brent (2nd-1st)	-1.20	-1.11	-1.09
WTI (2nd-1st)	-0.46	-0.40	-0.37
WTI (3rd-2nd)	-0.74	-0.66	-0.66
Oman (2nd-1st)	-2.53	-2.77	-1.85
Oman (3rd-2nd)	-2.25	-2.52	-2.23
Murban (2nd-1st)	-2.13	-2.25	-1.42
Murban (3rd-2nd)	-2.62	-2.49	-2.02
Grade Differentials			
WTI-Brent (1st)	-$6.74	-$6.34	-$6.74
WTI-LLS	-2.37	-2.15	-2.68
WTI-Mars	+0.80	+0.63	+1.78
Brent(Dtd)-Dubai	-1.96	-1.18	+1.14
Brent(Dtd.)-Urals	+23.70	+23.54	+24.49
Brent(Dtd.)-Bonny Lt.	-2.60	-2.84	-3.51
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$91.50	$94.24	$99.82
Arab Lt.-Europe (Med)	95.71	97.70	104.12
Arab Lt.-Far East (f.o.b.)	102.57	104.30	109.08
Nigeria Bonny Lt.	95.82	97.56	105.46
Arab Light Gross Product Worth			
Rotterdam	$93.77	$96.23	$112.28
US Gulf Coast	98.69	100.50	114.83
Singapore	90.32	93.56	108.04
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$104.58	$107.63	$112.96
UK Brent Margin	+12.64	+15.04	+12.63
US Gulf Coast			
Mars GPW	93.26	95.35	108.82
Mars Margin	+9.29	+8.64	+16.03
Singapore			
Oman GPW	90.54	93.33	106.52
Oman Margin	-4.43	-3.96	+3.79
US Nymex			
WTI 3-2-1 Crack	+$31.42	+$29.41	+$41.97
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$828.30	$832.46	$912.28
Gasoil (0.1%)	974.42	1008.00	1151.10
Fuel Oil (0.5%)*	600.00	640.95	690.50
US Gulf Coast (¢/gal)			
RBOB Gasoline	242.85¢	241.13¢	265.93¢
ULS Diesel	326.59	332.41	386.55
Fuel Oil (0.5%, $/ton)	$653.33	$678.60	$728.20
Singapore ($/bbl)			
Naphtha	$73.10	$72.02	$73.68
Gasoil (0.05%)	119.61	123.63	146.32
Fuel Oil (0.5%, $/ton)	693.33	693.60	771.80

*ARA fuel oil prices for 1% sulfur fuel oil (LSFO) have been discontinued as the market becomes increasingly illiquid. The new 0.5% sulfur fuel oil (VLSFO) specs reflect the transition to new emissions standards set by the International Maritime Organization effective Jan. 1 2020. Latest week's data are preliminary. For GPW and margin calculations, see Refining Profitability Methodologies on the Energy Intelligence website in Reference Tools Publication Methodologies. Spot prices from Thomson Reuters. Opec basket source, Opecna. 3-2-1 crack spread for 3 parts crude, 2 parts gasoline, and 1 part heating oil. PIW Numerical Datasource subscribers can download all indicators in Excel worksheets.