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Opec-Plus Buys Time to Ponder Future Policy

Opec-plus has bought more time to come up with a production plan for when its current deal expires in September. But it's anyone's guess how the producer alliance proceeds from here given the huge amount of uncertainty in global oil markets. The current deal succeeded in working off surplus inventories from the pandemic. But the challenge now — taming runaway prices — may be greater due to tricky politics and limited spare capacity, as alliance heavyweight Russia is at war and under sanctions, while high oil prices are fueling inflation and threatening global demand. Opec-plus ministers on Jun. 30 decided to stay the course and add 648,000 barrels per day to production in August — as agreed in the previous meeting. Many Opec-plus members have regularly failed to meet their allotted production quotas — especially Angola, Nigeria and Malaysia — and the actual increase will be perhaps just half the agreed volume. Compliance with agreed cuts has shot up to a meaningless 250% or so, and Energy Intelligence reckons the group could be short of targeted levels by around 4 million b/d by end-August.

Oil fundamentals are fraught with uncertainty as both demand and supply could suddenly and drastically change from sanctions, high prices or a recession. Greater market clarity is unlikely to emerge before Opec-plus meets next on Aug. 3, which is shaping up to be a pivotal gathering. Saudi Arabia and Russia, as leaders of the Opec and non-Opec producers in the alliance, are both keen to maintain cooperation, which could result in a "pause" deal after August in which the group kicks the can down the road. Opec sees three demand scenarios that all replenish low inventories and require more oil from Opec. On Thursday, ministers considered all three cases — high, low and base.

(Please turn to p.4)

China Keeps Feasting on Russian Oil

China is importing Russian crude at record rates, and its insatiable appetite for the discounted barrels looks unlikely to wane in the near term. China's imports of Russian crude could exceed 2 million barrels per day in June, and its July volumes already look strong. Chinese national oil companies (NOCs), along with several independent refiners, are most responsible for the surge in demand, snapping up almost all of the East Siberia-Pacific Ocean (Espo) crude on offer while grabbing significant volumes of Urals, too. China imported a record 1.99 million b/d of Russian crude in May. It landed 1.13 million b/d of seaborne Russian crude in May, said Emma Li, a China-focused analyst at data analytics firm Vortexa. That means pipeline crude accounted for practically all of the other 856,000 b/d of imported Russian crude. Seaborne Russian imports arriving at Chinese ports are expected to rise by 72,000 b/d to 1.21 million b/d in June, according to ship-tracking data, Li added. Assuming pipeline imports stay at the same level as May, this would push up China's June-arrival imports to 2.06 million b/d. This forecast could be too low since it likely does not include an Aframax Urals cargo that underwent a ship-to-ship transfer and subsequently arrived in China in June. Aframaxes typically carry around 600,000 barrels or more, equal to 20,000 b/d. China imports Russian crude through two main pipeline systems — the Espo spurs into China, with a capacity of 700,000 b/d, and pipelines running through Kazakhstan. The Kazakh pipelines have a capacity of 400,000 b/d, although a deal to send Russian crude through those lines is for 200,000 b/d. The deal was recently extended for another decade in February.

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

Espo and Urals account for 81% of China's seaborne imports of Russian crude in June. Urals imports are likely to stay relatively stable in July, while Chinese players look set to extend their domination of the Espo spot market. There had been some doubts about whether China would continue buying lots of Espo after Russia's Feb. 24 invasion of Ukraine, but these have been erased. June-arrival seaborne imports of Espo are expected to drop by 23,000 b/d from May to 753,000 b/d in June, according to Li. But only around 757,000 b/d of seaborne spot Espo was available for June loading. Most seaborne Espo spot volumes arrive at Chinese ports within the same month as they are purchased, since tankers take less than a week to get from the Espo export port of Kozmino to Northeast China. June-arrival Urals imports are expected to dip by 4,000 b/d from May to 225,000 b/d, Li added. But data intelligence company Kpler sees higher June-arrival Urals volumes of 264,000 b/d, with July-arrival imports so far at 212,000 b/d. Vortexa's count of Russian imports includes CPC Blend, which is a blend of both Russian and Kazakh crudes. CPC Blend volumes are expected to jump by 98,000 b/d from May to 133,000 b/d in June, Li said.

With Russian crude forced to sell at much cheaper prices, few Chinese players have been able to resist it in this red-hot oil market. The prices are too attractive relative to other, similar crude grades. This could make it difficult for the West to get buyers like China and India on board with any price cap scheme for Russian oil — unless it results in even cheaper prices. China's largest refiner Sinopec, its second-largest refiner PetroChina, China National Offshore Oil Corp. (CNOOC) and Shandong independent refiners are among the likely buyers or traders of Espo arriving at Chinese ports in June, according to Kpler. And so far for July-arrival Espo cargoes, CNOOC and Shandong independents are among the likely buyers or traders, Kpler adds. For Urals, Sinopec, CNOOC and Zhenhua are among the buyers or traders of June-arrival volumes, while PetroChina and Shandong independents have bought or traded July-arrival cargoes, Kpler notes. One notable exception among China's NOCs has been Sinochem, a trader and operator of the 300,000 b/d Quanzhou refinery. Sinochem has been avoiding Russian crude postwar, market sources report.

Fundamentals Signal Extreme Price Outcomes

Oil prices have reached an inflection point, with the threat of recession now grappling with supply concerns in battle that will decide the commodity's trajectory. Supply and demand shocks have defined oil markets over the past two years, and it looks like there will be more to come. Western sanctions and efforts to punish Russia for its war in Ukraine could have the most impact on supply balances in the rest of 2022. The risk is that significantly lower Russian supply drives Brent higher, well beyond current levels near $114 per barrel. But new shocks are also possible for oil consumption. Higher prices coupled with a recession could decimate product demand and prompt a price crash. Uncertain oil market fundamentals for 2022 only seem to deliver extreme outcomes. Oil traders say the market is focused on the present since the future throws up so much uncertainty. Russian oil exports have held up against dire forecasts of collapse, thanks to robust discounts. Global crude inventories rose for three consecutive months in March, April and May, partly thanks to huge releases from consuming nations' strategic petroleum reserves. Demand is set to rise sharply over the next few months as consumers drive and fly more freely than ever before since the start of the pandemic in 2020. Energy Intelligence balances now show a slight crude surplus in 2022 and a bigger one in 2023 — but this assumes some measure of market normalcy, which has been rare since 2019. Product markets, on the other hand, look set to remain tight. After a seasonal lull in the fall, demand should rise again in winter. High prices and economic downturn pose a threat to demand, but this could be partly offset by fuel switching away from higher-priced natural gas and rising demand for heating oil this winter. Energy Intelligence sees supply in 2022 at 99.6 million b/d, narrowly above demand at 99.4 million b/d.

Extreme prices are nothing new for oil markets, but the combination of a pandemic, a war, a gas/power crisis and an energy transition make the situation more challenging to sort out. Shorter-term factors like Covid-19 lockdowns in China, production outages, Russia's export ability, rising inflation and the prospect of recession are up against factors that structurally change

how the world produces, consumes and trades oil. Seasoned oil traders have seen their fair share of price volatility. 2008 saw Brent soar to a high of $147/bbl before crashing to $40. Typically, periods of extreme volatility have been followed by some stability. But since US benchmark West Texas Intermediate went negative for the first time in history in April 2020, the crude price has been on a consistent upward trajectory. Opec-plus' concerted effort to drain surplus inventories after the pandemic's initial demand collapse helped was the first catalyst. Fear that underinvestment in new upstream projects could cause crude shortages lent more support. The gas crisis of late 2021 then stoked product prices, which were goosed further by the growing realization that refiners would struggle to meet rising demand after closing 4 million barrels per day of capacity during the pandemic. The start of the Ukraine war in February then pushed all these fears into overdrive.

The war is creating new trading paradigms and alliances in oil markets, with Russia forced to lean more heavily on Asia. The short-term impact on balances might well draft the blueprint for what is to come. But the fundamental outlook can drastically change from the impact of new shocks. For now, front and center is the EU's ban on 90% Russian crude and product imports by year's end. The ban and other Western measures will rewrite trade maps for 2 million b/d of products and 2.5 million b/d of crude that Russia used to sell to the OECD. This is resetting alliances for supply security, making Asia more dependent on Russian energy. It is also speeding up the EU energy transition — and the world's move to a low-carbon economy, which could bring peak oil demand forward. BP chief economist Spencer Dale calls today's shocks to the energy system the biggest since the 1970s, referring to an "energy trilemma" in markets due to the simultaneous need for energy security, affordability and lower carbon. So vast is the uncertainty in markets that Citigroup believes Brent could fall to the $80s by the fourth quarter, while Goldman Sachs sticks with its "supercycle" call and thinks it will average $135 in the second half of 2022.

Has Biden Really Come Round on Natural Gas?

The Biden administration has been seen in recent months as warming to natural gas as an interim fuel after taking a more tepid position in its early days. White House officials have taken on more vocally supportive overtones on gas, and especially LNG exports, after Russia's Feb. 24 invasion of Ukraine. The more positive rhetoric is considered a welcome shift by US gas and LNG interests, considering an icier tenor toward the fossil fuel in favor of aggressive climate policies when Biden took office in January 2021. But the gas industry remains wary, saying the verbal backing has yet to translate into more granular policy changes that could help boost gas supply and exports as prices continue to rise. The Ukraine war and Europe's commitment to wean itself off Russian gas forced the administration to reconsider its position on gas. The White House quickly pledged to send 15 billion cubic meters of US LNG to Europe this year and as much as 50 Bcm/yr by 2030. But Dena Wiggins, president of the Natural Gas Supply Association, said there is "still something of a disconnect" when it comes to bridging support for boosting LNG exports to Europe with policy revisions needed to boost capacity. Earlier this year, the US Department of Energy approved additional exports from Cheniere Energy's Sabine Pass, Louisiana and Corpus Christi, Texas, terminals to countries that do not have free trade agreements with the US, including all of Europe. But lobbyists note that while the administration points to capacity expansion among fully approved projects, two-thirds of the current capacity is under contract, and conditions that allowed for diversion of cargos meant for Asia this year may not be the case next year. While "rhetoric has changed pretty dramatically, there are still mixed messages" when it comes to policy support, said Charlie Riedl, director of the Washington-based Center for LNG.

The administration still appears hesitant to endorse new infrastructure, with officials regularly pointing to US LNG projects that the government has already approved, rather than trying to accelerate yet-to-be approved projects. But commercial interest does not entirely align with approved projects, and that alignment could get worse, slowing down US LNG export growth. One test could come as Exxon Mobil seeks help from the Biden administration in navigating the thicket of federal agencies to stay on schedule building the Golden Pass LNG export terminal, due to start operations in 2024. Exxon and partner QatarEnergy are seeking permission to increase the onsite workforce and want quicker approvals for routine construction modifications.

Lines of communication between the gas sector and the White House have improved in recent months. But time frames and obstacles for getting new pipelines and LNG infrastructure approved remain befuddled by complex regulatory obstacles and multitiered environmental reviews, long a complaint of US oil and gas companies. The Biden administration has also taken a more robust approach to calculating climate impacts from energy projects than the Trump administration. While the White House did step into the fray in walking back to draft form the US Federal Energy

Regulatory Commission's (FERC) pending overhaul of its gas approval process, the commission's Democratic majority is still pursuing a process that appears "overly complicated and cumbersome," according to a lobbyist. Although speeding up major gas projects would not boost near-term LNG supply to Europe or help cool prices, the industry says the administration's unwillingness to remove those obstacles is hurting the investment climate. For example, the Biden administration recently proposed giving states more flexibility to object to major pipeline projects over water quality concerns.

This is currently playing out with a major gas pipeline in the Northeast. Despite FERC approval five years ago, Mountain Valley Pipeline (MVP) has been unable to complete the project thanks to courts rejecting downstream approvals from other federal agencies, including the US Fish and Wildlife Service, the US Army Corps of Engineers and the Bureau of Land Management. As a result, MVP this week asked for a four-year extension to complete the pipeline, delaying a major takeaway route for Marcellus and Utica Shale gas. The administration also is yet to issue a waiver under the Jones Act, which mandates domestic maritime trade take place on US-built, owned and crewed vessels. Doing so would allow domestic LNG to ship to constrained US Northeast markets.

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(Continued from p.1)
Crucially, Opec oil would help fill low OECD inventories, in all three scenarios. This would push OECD oil inventories up in the second, third and fourth quarters of 2022, and fill tanks with another 60 million bbl or 120 million bbl, depending on the scenario. But stocks in the fourth quarter would still be below the five-year 2015-19 average. Inventories have been rising in April, May and June for first time since the huge draws that absorbed the pandemic surplus. Rising Opec-plus production should rebuild the inventory buffer that helps cushion supply and demand surprises, which in turn would help lower prices.

If the group would decide on a total production volume — without individual quota allocations — it would create more flexibility to keep the market well supplied, as both Saudi Arabia and the United Arab Emirates, the key producers with spare capacity, could cover shortfalls elsewhere. It has been done in the past. The flipside is that Saudi Arabia and the UAE might have to open taps so wide that the market gets worried about available leftover capacity — or would refuse to open taps since Western buyers are boycotting oil imports from ally Russia. Energy Intelligence balances foresee no danger of running out of spare — even with Russia dropping 1.8 million b/d from current levels below 8 million b/d by the end of 2023 and without a resumption of the Iran nuclear deal. Iranian Oil Minister Javad Owji told reporters after the meeting that the market would be less volatile if Iran could export more oil. Saudi Arabia could produce 11.1 million b/d in that scenario and the UAE 3.4 million b/d. In uncertain times, Opec-plus tends to take its guidance from the oil price. After deciding to lift output faster than planned on Jun. 2, the Brent price has fallen $5 to around $115 per barrel. On Thursday, traders continued their recent focus on potential demand destruction. Prices for crude and especially refined products kept sliding from recent highs.

Russia Hints at Direction of Energy Policy

Russia will not engage in formal discussions on a new energy policy until September, but recent statements by Russian officials may indicate how Moscow is thinking about its future under Western sanctions. Comments suggest there are no plans to significantly cut oil and gas production, so long as Russia can continue to find buyers. This is already facilitating a massive shift toward Asia-Pacific markets, which Moscow will more fully embrace. Russian Energy Minister Nikolai Shulginov opposes the idea expressed by Lukoil's major shareholder Leonid Fedun, who believes that Russia should cut its production by about 30% to 7 million-8 million barrels per day and sell less oil at higher prices rather than continuing to sell it at discounts of 30%-40%. Deputy Prime Minister Alexander Novak says the discounts — which can reach as high as $40 per barrel — would disappear with resolution of export logistics problems. Novak also believes Russian oil sales will remain stable, even if crude and gas condensate production could fall to 10.02 million b/d this year from 10.5 million b/d in 2021, because of reduced refining volumes. Russia produced close to 10.7 million b/d in June. Novak said longer-term production would not suffer much because of the EU's oil embargo, which will come into force at the end of 2022, because by that time Russia will have redirected its exports. However, Russia's economic development ministry envisages a bigger production decline — to 9.53 million b/d in 2022 and even lower in 2023.

To accommodate bigger exports to Asia-Pacific, Russia aims to use additives to increase oil flows via the East Siberia–Pacific Ocean (Espo) pipeline already this year. Moscow also views the Caspian Sea as a key transportation route to new markets, bypassing "unfriendly" Europe. Shipments via the Espo pipeline to the Pacific port of Kozmino could grow by 140,000 b/d this year to

842,300 b/d, according to Novak. Russia's broken ties with Europe and its need to nurture new markets have also increased Moscow's interest in the North-South corridor plan, a multimode network of ship, rail and road routes for moving freight between India, Iran, Afghanistan, Azerbaijan, Russia, Central Asia and Europe. Speaking at the Caspian states summit this week, Russia's President Vladimir Putin said that to develop the 7,200 kilometer route from the St. Petersburg ports to Iran and India, Moscow has adopted a 2030 national strategy of Caspian ports development, including road and railways to service it. Test shipments of cargoes have already started. Novak during his recent visit to Tehran discussed the revival of the Caspian swap scheme, which envisages Russia delivering oil to refineries in northern Iran in exchange for picking up equivalent volumes from southern Iranian ports.

Russia is not backing down from its low-carbon ambitions, including ambitious hydrogen plans. But it must reorientate its green targets and forge new partnerships to replace Western firms pulling out of Russia. Moscow is amending rules for both departing and incoming investors. Russian officials insist that a 2060 carbon-neutrality target remains intact. According to Shulginov, Russia views its hydrogen plans as important but must amend them since they assumed Western partnerships. The hydrogen development concept document approved in August 2021 targets 2 million-12 million metric tons per year of exports by 2035 and 15 million-50 million tons/yr by 2050. But even partners from friendly countries will have to act under new rules. Putin just signed a law stating that only legal entities established in accordance with Russian legislation can be the ultimate owners of Russian subsoil licenses. Foreign companies that own such licenses must reregister them under the new rules. The move is designed to protect Russian hydrocarbon licenses at a time when foreign oil majors are leaving Russia. On that front, Finance Minister Anton Siluanov this week cast some light on departure terms. He said the government would allow asset sales to Russian buyers at discounts of no less than 50% of current market value or one-third of earnings before interest, taxes, depreciation and amortization.

European Majors See CCS Sweet Spots in US, Asia

European oil majors have embraced carbon capture and storage (CCS) in their transition strategies and are participating in some of the world's biggest projects. While renewable power remains at the center of European majors' transition plans, they see CCS as a critical way to tackle their own Scope 1 and 2 (operational) emissions and to abate emissions from sectors with no feasible alternatives to fossil fuel use. The technology is also being used to improve the carbon intensity of LNG, which European majors view as a critical transition fuel. US majors Exxon Mobil and Chevron, which have eschewed big investments in renewable power, have made CCS more central to their transition strategies than European rivals. However, BP, Shell and TotalEnergies have recently been more active in the space. They have entered early-stage agreements to develop CCS or CCUS (carbon capture, utilization and storage) projects in several countries outside Europe, with an emphasis on the US and Asia. Projects under consideration or moving forward are in the US, China, Singapore, Indonesia, Malaysia and Japan. Some of these schemes, announced since 2020, are moving slowly though because they lack sufficient regulatory and policy support mechanisms. Some are in countries that lack carbon pricing, presenting financial challenges.

BP recently inked agreements to study the potential of CCS projects in Texas and is moving forward with a project in Indonesia to reduce carbon emissions from LNG production facilities. The latter could make Indonesia's Tanguuh facility one of the lowest carbon intensity LNG plants in the world, project partners say. In May, BP entered an agreement with industrial gas company Linde to study CCS projects in the Texas Gulf Coast region, for the production of low-carbon hydrogen and the storage of carbon dioxide emissions from other industrial facilities. BP will concentrate on the storage side of the CCS equation, plus the supply of renewable electricity and natural gas for facilities within the cluster hub. Operations could commence in 2026 and eventually store up to 15 million tons per year of CO2 at multiple storage sites. BP is also a partner in a proposed enhanced gas recovery and CCUS project at the Tangguh LNG project in Indonesia. Damian Johnson, vice president for gas and low-carbon energy growth at BP Asia, said recently that a front-end engineering and design study would happen "in the middle of 2022" and that a final investment decision (FID) is targeted by end-2023. Construction could start in 2024 and operations in late 2026 or early 2027.

Shell and Exxon this week inked a memorandum of understanding (MOU) with a Chinese partner to study CCS solutions at the Dajawan industrial petrochemical plant in China's Guangdong province. Earlier this month, Shell also signed MOUs with Japanese LNG buyers Tokyo Gas and Osaka Gas about decarbonization solutions including CCUS. In May, Total said it was working with project partners Sempra, Mitsui and Mitsubishi to develop the Hackberry Carbon Sequestration (HCS) project at the Cameron LNG facility in Louisiana. The project could eventually store 2 million tons/yr of CO_2 in a saline aquifer roughly 10 kilometers from Cameron LNG.

Smaller European oil companies have also been active in the space. Italy's Eni has set some especially big CCS targets. It aims to build from roughly 1 million tons/yr of CO_2 gross capacity in 2025, to 10 million tons/yr by 2030, 35 million tons/yr by 2040 and 50 million tons/yr by 2050. Beyond existing projects and plans in the UK, Italy and Norway, Eni is developing CCS and CCUS schemes in the United Arab Emirates (Gasha), Libya (Bahr Essalam), Egypt and East Timor. A small storage project in Egypt at the Meleiha field seems to be making progress, too. Norway's Equinor has no current plans to develop CCS projects outside Europe or North America, but is aggressively pushing projects in Norway and the UK, where alongside BP, it received a license in May to store CO_2 in the Southern North Sea.

Eastern Canada Stages Unlikely Upstream Revival

It wasn't long ago that the fate of eastern Canada's offshore province was looking grim. Large projects were stalled, investment interest was anemic amid pandemic spending cuts and some feared the basin might never recover. But sharply higher oil and gas prices and calls for new supply since Russia's invasion of Ukraine have revived its fortunes. At least three major offshore projects are back in play, with more exploration and a fresh bid round also on the agenda. Despite its harsh, frigid environment, the area's relatively low-carbon production profile is ticking an important box amid corporate decarbonization plans. Relatively low break-even costs and a supportive, flexible regulatory regime are also nudging opportunities into the advantaged column. Newfoundland & Labrador Premier Andrew Furey notes that the project revivals appeal to Canadian energy transition objectives, too, providing "responsible supply" to the world while keeping Canada on track for its 2050 net-zero goal. While volumes under discussion are not massive at just under 300,000 barrels per day — mostly hitting later this decade — they would help to backfill flattening production, and exploration offers further upside.

BP's commitment to the area demonstrates its allure. A recent swap agreement worth up to C$1.2 billion (US$929 million) with Cenovus Energy brings BP a 35% share in the Equinor-operated Bay du Nord project, adding a new deep-pocketed partner to a scheme already on the upswing. The UK supermajor leaves behind its stake in the Sunrise oil sands project for a new upstream venture — a rare move given its plan to reduce oil and gas production by 40% by 2030 under its energy transition strategy. Bay du Nord, which developed finds over the past decade, had been in something of a holding pattern, but recently saw uplift from positive resource upgrades and approval from a stringent environmental review in line with net-zero goals. Although sanction is still pending, strong climate credentials were no doubt attractive for emissions-conscious BP. According to Equinor, Bay du Nord project's emissions profile is five times smaller than the average Canadian project and 10 times smaller than the average oil sands project. Its larger scale — the project is targeting a 200,000 b/d floating production, storage and offloading (FPSO) vessel, with first oil in the late 2020s — is also appealing. Relatively low break-even costs are another draw. Wood Mackenzie puts them at $40 per barrel, but says cost inflation could raise them to $45/bbl.

The Cenovus-operated West White Rose project is also moving ahead after being put on ice early in the pandemic. Partner Suncor had even written off the project in early 2021 despite construction being two-thirds complete. Vital to its revival were rising prices and provincial flexibility on royalties, which culminated in a new agreement to protect project economics should commodity prices dive again. First oil is now scheduled for the first half of 2026, with a production peak of 80,000 b/d by end-2029. Woodmac models the project's go-forward Brent break-even at US$48/bbl. Mature fields are not off the radar either — and keep on giving. Cenovus and Suncor said they reached a deal to extend the life of the mature Terra Nova field in the Jeanne d'Arc Basin by a decade, revamping the once-troubled project after US majors Exxon Mobil and Chevron exited. The expansion at Terra Nova targets first oil in late 2022, with output peaking at a gross 29,000 b/d in 2023 after its FPSO unit completes a seven-month refit in Spain. Regulators also said recently that the Exxon-operated Hibernia field has seen a 168 million barrel resource upgrade, with new drilling helping extend the life of the field.

Exploration is also shaping up for an interesting slate, as are results from Newfoundland's ongoing bid round, closing in November. Reliable leasing activity may also take on fresh importance with acreage access in once-reliable jurisdictions like the US Gulf no longer a foregone conclusion amid government climate action. Equinor kicked off a two-well appraisal program near Bay du Nord, which could inform sanction timing. Exxon and QatarEnergy's three-well exploration program in the Flemish Pass Basin is kicking off this summer, with Exxon telling a recent conference that it is gearing up for more activity after a Covid-19 hiatus. BP is also targeting a five-year exploration program starting next year, with the multibillion-barrel Ephesus prospect among the targets.

What's New Around the World

GENERAL

CORPORATE — State-controlled PetroChina is looking to sell its upstream assets in Australia and Canada following a buying spree in those countries. The last decade has yielded disappointing results for the Asian giant. Sources confirmed that the assets are being considered for sale, although it was not yet clear if PetroChina, the Hong Kong-listed arm of China's largest energy player CNPC, has started marketing them to potential buyers. The assets, mainly acquired between 2009-13, comprise coalbed methane and offshore gas assets in Australia and oil sands stakes in Canada. Sources familiar with the portfolio said it may be difficult for PetroChina to find buyers for at least some of the assets. It was also not immediately clear what value PetroChina assigns to them. PetroChina bought these assets at a time when Chinese national oil companies (NOCs) were on a global hunt for reliable and safe energy supplies within OECD countries. PetroChina and state rival China National Offshore Oil Corp. spent heavily in Australia, Canada and the US. More recently, Chinese NOCs have been given limited overseas budgets and have been asked to focus more on domestic upstream projects.

MARKETS — Leaders who gathered at the G7 meeting in Europe are reviewing the specifics of a potential "price cap" on Russian oil as Western countries attempt to limit both the energy-related revenue flowing to Moscow and the economic pain in the rest of the world. G7 leaders are going to "acknowledge that the path forward is to urgently direct ministers to work on achieving a price cap, which can, in our judgement, best achieve both of those objectives simultaneously," a US official told reporters. Russia is likely to see higher revenues from energy sales this year, according to a recent Energy Intelligence analysis, although revenues could fall dramatically in 2023. The US official focused on the services that firms in Western countries provide to transport Russian oil, although advocates of a price cap have suggested different mechanisms. One could involve applying secondary sanctions on importers that pay more than a specified level for Russian crude. Another recent suggestion involves modifying the EU's forthcoming prohibition on providing shipping insurance for Russian crude to only prohibit such transactions if they breach a certain price level. To have the effect Western officials are looking for, a price cap would require participation from countries like China and India, enforced by the threat of sanctions.

OPEC — Opec petroleum revenues shot up by some 77% last year, rebounding to $561 billion after dropping severely in 2020, with product exports making up a larger proportion of sales, according to Opec's latest *Annual Statistical Bulletin*. The revenue surge eclipsed 2021's 68.5% jump in Opec basket prices, which averaged $69.89/bbl as the producer group recovered from its lowest annual revenue haul since 2003 in 2020. Still, a combination of lower output and significantly lower export levels meant revenues still fell short of 2019 levels. Asian markets continued to dominate Opec sales in 2021: "The bulk of crude oil from Opec member countries — 14.24 million b/d, or 72% — was exported to Asia," the report said. While crude exports were basically steady compared to 2020 — even falling in Saudi Arabia's case — 2021 product exports rose by 550,000 b/d, or almost 16%, compared to the previous year. The bulletin does not give data for production capacity, but steep falls in output among African members last year highlight the challenges these states are facing in meeting their quotas. Production in both Nigeria and Angola was down by more than 11%.

COUNTRIES

INDIA — The world's third-largest oil consumer will allow explorers to sell domestically produced crude to any refiner of their choice in the local market effective Oct. 1, junking the existing rule that requires them to sell to state refiners according to quotas fixed by the government. The marketing freedom will help explorers negotiate prices and sell to the highest bidder. The explorers, however, still do not have the permission to export crude. The move is another step by Prime Minister Narendra Modi's government to entice private players to explore India's oil and gas basins to cut dependence on imported crude. Imports now account for 85% of the country's oil demand, making India's economy highly vulnerable to swings in crude prices. Domestic oil production, which is largely dominated by state-owned Oil and Natural Gas Corp., declined 2.6% to 596,000 b/d in the fiscal year ended Mar. 31.

IRAQ — Pressure is growing on the Kurdistan region of Iraq's oil and gas sector amid news this week that top oil-field services companies have decided to wind down operations there at Baghdad's request. The moves by the contractors come as rocket attacks targeting the Khor Mor gas field continue. In a letter addressed to Iraq's Oil Minister Ihsan Ismael, Schlumberger said that it would not apply for any tenders in the Kurdistan region's oil and gas sector. In the event of any existing contracts there, Schlumberger said it would "make every effort to resolve the same." Schlumberger was responding to a letter sent by the state-run Basrah Oil Co. (BOC) on Jun. 12. BOC's letter, sent on behalf of Iraq's oil ministry to "all lead contractors and subcontractors," had ordered firms to end their existing contracts in the Kurdistan region within three months and pledge not to work on contracts or projects there that were at odds with a Baghdad court ruling in February. It threatened to blacklist companies that failed to comply. Iraq's federal government has been escalating its efforts to bring the largely autonomous Kurdish region's oil and gas sector under its control, after the Supreme Court's Feb. 15 ruling that rejected the Kurdistan Regional Government's right to manage the oil resources within its territory.

LIBYA — Additional shutdowns of ports in Libya are looking increasingly possible amid political unrest, potentially impacting crude production and exports from the Opec member. State-run National Oil Corp. (NOC) declared force majeure Tuesday at the eastern Ras Lanuf port, according to sources. A Libyan shipping source also confirmed that the planned arrival of tanker *MT Ohio* at Es Sider, also in the east, has been canceled. Force majeure has not yet been imposed at Es Sider, Energy Intelligence understands, and NOC has yet to formally announce force majeure at either port. It was not immediately clear why the ports would be closed, but it could be linked to local protests that have kept the separate eastern ports of Zueitina and Marsa al-Brega shut since late April. Further reductions in Libya's roughly 700,000 b/d output could cause more tightness in an already stretched global oil market and potentially push prices higher. The twin ports of Ras Lanuf and Es Sider account for roughly 560,000 b/d of Libya's export capacity. Libya's export volumes, which are normally around 1.1 million b/d, roughly halved in May to 20.2 million bbl, or 651,612 b/d.

MEXICO — Private oil companies operating in Mexico topped 101,000 b/d in crude oil production in May, according to Mexican oil regulator CNH, marking the first time that private output in the country has crossed the 100,000 b/d threshold. Data from CNH showed that 21 firms, notably Italy's Eni, Fieldwood Energy and Mexican firm Hokchi, contributed to May's private production peak. The Mexican government will receive an average of 74% of all the income generated by the private oil contracts, according to the Asociacion Mexicana de Empresas de Hidrocarburos producer group. While the 101,000 b/d output average for May was relatively small in the grand scheme — the CNH said it represented just 6% of Mexico's total crude output for the month — it represents a significant achievement for private producers in the country. Private operators have not made significant contributions to Mexico's oil production since they snapped up large swaths of development blocks in bid rounds held since the country's energy reforms ended state firm Pemex's monopoly in 2013. They have faced an even steeper uphill climb since Mexican President Andres Manuel Lopez Obrador took office in 2019 and began pushing a more nationalist energy agenda.

Marketview

Demand Fears Hit Oil Prices

Crude oil has come under increased pressure in the last week, registering early signals that could be the harbinger of a demand slowdown.

Monthly US gasoline consumption looks poised to fall for the first time since November 2021. Its four-week average fell to its lowest seasonal level since 2014, data from the US Energy Information Administration showed.

Despite tight supply, refined product prices have been falling twice as fast as crude prices over the past three weeks.

ICE low-sulfur gasoil futures have recoiled from their Jun. 9 high by 17%, to $1,155.25 per ton. In the US, Nymex gasoline futures are also down 16.5% at $3.57 per gallon after straying north of $4/gallon for more than two weeks.

In comparison, the Brent front month price shed about 7%, to $114.62 per barrel, but remains stuck in a wide $110-$120 range.

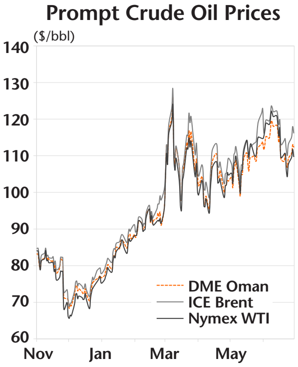
At this point, it is difficult to tell how much fears of demand erosion have played in the selloff. The price dip also coincides with a fair bout of profit-taking by investors as the second quarter ended on Jun. 30.

Adding to the disturbance, the ICE August future contract was expiring on Thursday, and the lack of liquidity in the paper market helped exacerbate the daily up and down moves. The CBOE oil volatility index is at 49.25%, while Brent implied volatility in the option market is still hovering around 45%.

Wild price gyrations are causing large moves in the future exchanges' mark-to-market process, forcing traders to post more maintenance margin on their daily positions. And exchanges are asking for more initial margin to shield themselves from the risk of default. The credit lines of smaller trading companies are being strained, reducing their ability to hedge and slowly reducing liquidity in the paper market.

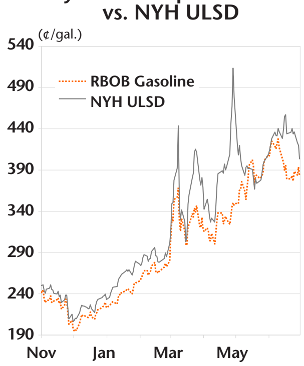
But the middle distillate market is still screaming for supply, meaning that demand erosion will take time to rebalance this market. Stellar refining margins have kept rising to new record highs, with diesel earning $64/bbl in Europe and $82/bbl in the US, Energy Intelligence data showed. The market is short of 800,000 barrels per day of distillates that Russia used to supply, and current refining capacity is struggling to catch up.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex Prompt Gasoline vs. NYH ULSD



"Despite volatile oil prices, refined product prices remain exceptionally elevated, implying a still undersupplied product market, and for now this is going to underpin oil prices", said Jamie Maddock, equity research analyst at Quilter Cheviot. The capacity problem will continue to keep prices high and incentivize refiners to run as hard as they can. The Brent premium for prompt barrels compared with deliveries in six months is more than $15/bbl.

Meanwhile, G7 countries were meeting in Germany to discuss a potential price cap on Russian oil to choke off Russia's war funding and help fend off inflation. Beyond the difficulty of implementing this mechanism, the market is questioning its usefulness in restoring balance if more cheap crude is made available to a market that will lack the capacity to process it. Refiners would still have a feast selling products at even higher margins, which would dubiously help slay inflation.

Iran Nuclear Talks to Restart in Doha

Iran and the US are set to imminently resume indirect talks in Doha aimed at reviving the 2015 nuclear agreement more than three months after they were suspended.

There have been unverified reports that Tehran may agree to compromise on its insistence that the US remove the Revolutionary Guard from its list of foreign terrorist organizations — a major sticking point in the stalled negotiations. High oil and gas prices are a key driver behind the Western push to at least get Iran back to the negotiating table. Spiraling inflation in Iran, meanwhile, and the threat that discounted Russian crude poses to its market share in China — by far the largest buyer of sanctioned Iranian oil — likely figure in Tehran's calculations.

PIW Market Indicators

($/barrel)	Jun 27-Jun 29	Jun 20-Jun 24	May 30-Jun 3
Spot Crude			
Opec Basket	$116.69	$112.79	$117.85
UK Brent (Dtd.)	120.88	116.52	124.26
US WTI (Cushing)	112.05	108.34	116.37
Nigeria Bonny Lt.	128.23	124.06	131.42
Dubai Fateh	112.47	107.97	112.75
US Mars	106.92	99.98	111.25
Russia Urals (NWE)	87.95	82.16	89.82
Crude Futures			
Brent 1st (ICE)	116.44	112.74	119.63
Brent 2nd (ICE)	112.41	109.47	115.76
B-wave (ICE)	116.40	112.19	119.02
WTI 1st (Nymex)	110.37	107.18	116.42
WTI 2nd (Nymex)	107.43	104.89	113.79
Oman 1st (DME)	111.98	108.65	113.41
Oman 2nd (DME)	108.91	105.12	110.19
Murban 1st (ICE)	119.66	114.20	116.79
Murban 2nd (ICE)	111.92	108.46	113.74
Forward Spreads			
Brent (1st-Dtd.)	-$4.43	-$3.78	-$4.63
Brent (2nd-1st)	-4.03	-3.27	-3.86
WTI (2nd-1st)	-2.94	-2.30	-2.63
WTI (3rd-2nd)	-2.95	-2.46	-2.81
Oman (2nd-1st)	-3.07	-3.54	-3.22
Oman (3rd-2nd)	-4.23	-3.27	-2.73
Murban (2nd-1st)	-7.74	-5.74	-3.06
Murban (3rd-2nd)	-3.98	-3.15	-3.09
Grade Differentials			
WTI-Brent (1st)	-$6.07	-$5.49	-$4.64
WTI-LLS	-1.53	-0.42	-1.74
WTI-Mars	+5.13	+8.36	+5.13
Brent(Dtd)-Dubai	+8.41	+8.55	+11.51
Brent(Dtd.)-Urals	+32.93	+34.36	+34.44
Brent(Dtd.)-Bonny Lt.	-7.36	-7.54	-7.16
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$114.05	$107.11	$118.38
Arab Lt.-Europe (Med)	118.30	114.09	120.92
Arab Lt.-Far East (f.o.b.)	117.06	112.92	116.82
Nigeria Bonny Lt.	122.54	118.18	125.92
Arab Light Gross Product Worth			
Rotterdam	$132.53	$134.91	$145.00
US Gulf Coast	144.93	143.60	147.39
Singapore	130.16	131.85	129.21
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$147.29	$149.09	$142.27
UK Brent Margin	+24.60	+30.94	+17.50
US Gulf Coast			
Mars GPW	139.13	136.71	141.51
Mars Margin	+32.11	+36.63	+30.17
Singapore			
Oman GPW	129.58	130.88	129.41
Oman Margin	+16.25	+21.39	+16.91
US Nymex			
WTI 3-2-1 Crack	+$56.07	+$60.89	+$58.28
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$1341.43	$1302.82	$1450.93
Gasoil (0.1%)	1283.92	1345.10	1274.10
Fuel Oil (0.5%)*	866.33	836.80	854.00
US Gulf Coast (¢/gal)			
RBOB Gasoline	386.54¢	382.37¢	412.35¢
ULS Diesel	414.14	433.74	415.45
Fuel Oil (0.5%, $/ton)	$896.67	$883.40	$924.20
Singapore ($/bbl)			
Naphtha	$90.51	$86.56	$93.57
Gasoil (0.05%)	164.86	171.41	159.48
Fuel Oil (0.5%, $/ton)	1096.67	1069.00	1117.00

*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.