Energy Intelligence

PETROLEUM INTELLIGENCE WEEKLY®

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Vol. 61, No. 23 www.energyintel.com June 9, 2022

Signs Point to More Gains for Oil Prices

Benchmark Brent crude has surged by more than 50% so far this year to over $120 per barrel, and there are ample reasons to believe it will keep pushing higher. The increase in energy prices over the past two years has been the largest since the 1973 oil crisis, according to the World Bank. And like the 1970s, the market is in a supply-side crisis, which means that prices can still go up even if the global economy slows and demand subsides. With Western embargoes on Russian oil and continued weak upstream investment levels, supply shortages are expected to last well into 2023. Goldman Sachs is now forecasting Brent will average $140 per barrel between July and September, up from its prior call of $125/bbl, and $135/bbl in the second half of the year, up $10 from its previous forecast. "We believe oil prices need to rally further to normalize the unsustainably low levels of global oil inventories, as well as Opec and refining spare capacities," Goldman Sachs strategists wrote this week. Indeed, most analysts think the only way to fend off higher prices is to reduce fuel demand. Energy Intelligence data show that refining Brent crude in Europe yields an average profit of $27/bbl. These record margins will encourage refiners to run at the highest possible levels, but they might not be enough to meet summer demand, let alone replenish already-low inventories. With the summer driving season in full fledge, product stocks are expected to drain even faster. Years of underinvestment in new refineries are now showing. Global refining has lost nearly 4 million barrels per day of capacity since 2019, almost all of it in Europe and the US.

Crude releases from OECD strategic petroleum reserves — mainly from US stocks — have helped mitigate supply shortages. But they are a short-term fix and tend to delay the necessary

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Iraq's Capacity Plans Collide With Constraints

A surge in Basrah crude exports in April raised hopes that Opec's second-largest producer could help ease global supply tightness and cool red-hot prices. But Iraq has reached its limit in southern export capacity, and a bitter row between Baghdad and Erbil is preventing cooperation on boosting exports from northern Iraq. Indeed, it is hard to see Iraqi production rising much above April's two-year high of 4.4 million barrels per day any time soon. Longer term, few doubt the country has the resources to achieve the 8 million b/d target that the oil ministry is eyeing by 2028, particularly with high prices sparking renewed investor interest. But political risk factors, bottlenecks and shifting company priorities are formidable obstacles to realizing the projects needed to get there. Iraq has succeeded in restoring much of the nearly 1 million b/d of production cuts it made two years ago, putting it ahead of many fellow Opec-plus members who are struggling to hit rising output targets. But Iraq's ability to fix its severe oil production constraints is under renewed scrutiny. State oil marketer Somo hit its southern export ceiling of 3.28 million b/d in November. Plans are afoot that should partially alleviate its export constraints at Basrah this year, and field development activity is picking up. Record oil revenues also should help. But the deadlocked government formation process is hampering critical projects that would allow Iraq to pump more than 5 million b/d. Even the oil ministry does not see that happening before 2025.

Iranian forces' May 27 seizure of two Greek-flagged tankers carrying Iraqi oil highlighted

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Iraq's export vulnerabilities. Iraq has for decades dreamed of building a 1 million b/d pipeline to Jordan's Red Sea coast, allowing its shipments to Europe to bypass the Basrah bottlenecks and the Mideast Gulf. But however valuable it would be right now, with Europe scrambling for alternatives to Russian Urals, massive oil infrastructure projects like this, with its estimated cost of around $9 billion and assumed lead time of more than five years, look less likely to advance.

The Basrah oil terminal's outdated infrastructure — from aging pipelines to inadequate pumping facilities and very limited storage — means Iraq's southern exports cannot currently exceed 3.28 million b/d, and officials say those levels can only be sustained with no technical or weather disruptions. Equipment due be installed in the coming months could raise the export capacity of the four single point moorings (SPMs) by up to 250,000 b/d. But the status of more critical infrastructure projects, notably, replacing the two subsea oil pipelines connecting the onshore Fao export hub to the Basrah jetty, remains uncertain. A study completed in 2020 described that as "an urgent necessity due to the advanced deterioration of the existing pipelines," which were laid in 1975. Replacing them, which is likely to take about two years, could add another 300,000-400,000 b/d of export capacity, says a Somo official. The front-end engineering and design has been completed, says another source, but the engineering, procurement and construction tender won't be announced until an official budget is agreed, and Iraq's political deadlock has left the country without one this year. Separately, a third subsea oil pipeline, the so-called Sealine 3 project, would bring a fifth SPM on line and allow loadings to resume at the defunct Khor al-Amaya terminal, adding another 600,000 b/d of export capacity, a senior Basrah Oil Co. official told state media last month. It could be completed by end-2023.

With it vast, low-cost oil reserves — 145 billion barrels, according to BP — Iraq has a golden opportunity to hike its capacity, if only circumstances allowed it to. The departure of two key players — Exxon Mobil and Shell — from the country's oil sector in recent years has cast a shadow over its future. But BP remains, and TotalEnergies is poised to embark on the first major new upstream project in years, if and when the next government signs off on it. An integral part of the $10 billion project is a major water injection scheme that is deemed essential to Iraq's future production plans. With oil prices now generating revenues of more than $10 billion each month, Iraq can afford to push ahead with those plans. Chinese contractors are already busily expanding their work — bagging contracts in recent months to raise West Qurna-2's output capacity by 200,000 b/d and develop Block 9. Perhaps the greatest threat to its upstream hopes is that Iraq becomes too reliant on Chinese firms — and Russian operators like Lukoil whose ability to finance their projects may be complicated by sanctions — if political turmoil hastens the flight of its remaining Western partners.

Disclosure Drops in Russia's Oil Sector

Western sanctions against Moscow over the war in Ukraine have made publicly traded Russian companies less transparent. Corporations have reduced the amount of information they are sharing with investors and the wider public, including regular financial reports. Moscow's decision to stop circulation of Russian depositary receipts outside the country has also prompted many oil and gas companies to delist from international stock exchanges, including London. The lack of transparency could make it harder to track the performance of Russia's oil and gas sector as the EU and US try to cut off revenues to Moscow through embargoes and other restrictions on its energy flows. Moscow has also allowed Russian companies to delay annual shareholders meetings (AGMs), provided leeway on election of new directors, and permitted them to hold shares repurchased on the open market for up to two years rather than cancel them. Russian energy companies' AGMs will be held behind closed doors this year using absentee votes — the same practice used during Covid-19 lockdowns. Gazprom, its oil subsidiary Gazprom Neft, and Lukoil said they would terminate their American Depositary Receipt (ADR) programs, while independent gas producer Novatek and regional oil producer Tatneft have received exemptions. Russia's state-controlled Rosneft has been tight-lipped on its Global Depository Receipts (GDRs), but US-based investment bank JPMorgan has warned the

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owners of Rosneft GDRs that it has stepped down as the Russian company's depositary starting from May 13. Lukoil said its ADR holders could convert them to the Russian major's ordinary shares until Dec. 30, 2022. ADR holders accounted for 30.6% of Lukoil's charter capital at the end of May 2021. Rosneft's GDRs amounted to only 4.8% of the company's shares.

Even though financial reports for the first quarter have not been released, analysts believe Russian producers generated strong profits on the back of soaring oil and gas prices. According to Sber CIB Investment Research, Russian major oil and gas companies could have generated jointly nearly $43 billion in earnings before interest, taxes, depreciation and amortization and $22 billion in net profit. Analysts of the bank estimate that the combined free cash flow of Rosneft, Lukoil, Gazprom Neft, Tatneft, Gazprom and Novatek could have grown by more than 63% from the previous quarter to $25.2 billion. However, this is before changes in their working capital, which "must become a key factor for the dynamics of the financials" due to problems with logistics and payment transactions related to sanctions. It is "practically impossible" to evaluate correctly the impact of those changes on the companies' financial results, the report said. Russian crude oil exports have kept steady since the beginning of the Ukraine war, although discounts for Russian volumes have gone up to some $35 per barrel. Discounts for Russian oil products could be comparable with those for Urals crude. Still, the surge in the outright prices for global energy commodities has bolstered Russian profits.

International investors from countries Moscow considers "unfriendly," including the UK's BP, are unlikely to benefit from the generous dividends that Russian companies are on track to pay this year. Rosneft is sticking to its policy of allocating 50% of its profits, which totaled 883 billion rubles ($15 billion) in 2021, to dividends. It already paid slightly less than half of the sum in interim dividends last year. Shareholders eligible for the remainder will be determined on Jul. 11. It is unlikely that BP, which still formally owns 19.75% of Rosneft, will receive payments. BP said shortly after the Ukraine war started that it would divest all assets in Russia, including its Rosneft stake. Recently approved Russian legislation allows payments to companies from "unfriendly" countries — but only in rubles and using a special bank account to be opened by a resident with a Russian financial institution in the foreign company's name. Gazprom is to pay 1 trillion rubles ($21 billion) in 2021 dividends. Nonresidents might account for 33%-38% of Gazprom's shares, according to estimates from the BCS brokerage. So far, only Lukoil has postponed a decision on final dividends due to the current instability.

UAE Explores Bigger Capacity Expansion

While most Opec-plus members fret about production capacity issues, the United Arab Emirates offers rare hope. The UAE is exploring the possibility of upsizing its current expansion program and taking its oil production capacity to 6 million barrels per day by 2030, about 1 million b/d higher than previously planned. It may also accelerate the program to complete it two or three years earlier. With oil markets facing a supply crunch and the long-term health of Russia's oil sector now in doubt, the decision could have major ramifications. Energy Intelligence understands that Abu Dhabi National Oil Co. (Adnoc) is conducting feasibility studies to increase its capacity to maximize profits from higher oil prices and address the lack of global spare capacity. If the studies show the move is feasible, reaching the higher target will likely take Adnoc six to seven years, given the long-cycle nature of the required upstream projects and investments. Industry sources think a formal announcement about Adnoc's plans could be made as early as this year. Energy Intelligence estimates the UAE's oil production capacity now stands at around 4.3 million b/d, but it is gradually edging higher as expansion projects are executed.

The UAE and Saudi Arabia hold most of the spare capacity in Opec-plus, which as a group is struggling to meet its production targets due to operational and investment issues at its weaker members. UAE and Saudi capacity expansion plans are underpinned by the belief that long-term demand for their low-cost oil will remain robust for decades, and expectations are growing that the duo could increase production further when the current Opec-plus deal expires in September. Under Opec-plus' new agreement reached last week, the UAE's production target is 3.127 million b/d, which means it would still have a little over 1 million b/d as spare capacity. In general, sitting on unused spare capacity is expensive and is something producers seek to avoid — especially if there is current demand for their oil. There is a growing expectation, especially among US officials, that both Saudi Arabia and the UAE will further increase their production when the current Opec-plus deal ends. But industry sources from both Mideast Gulf states say it is too early to decide on future output plans. They stressed, however, that group unity remains a top priority. Last year the growing gap between the UAE's Opec baseline target and capacity raised tensions within the producer group. This led to the revision of the UAE's baseline to 3.5 million b/d, which came into effect last month. Given the limited spare capacity elsewhere, Saudi Arabia and the UAE will have the upper hand when it comes to adding future supply, and the leaderships of both states are aligned in terms of preserving the Opec-plus market management structure.

It's still unclear where extra UAE oil would come from. Some contractor sources say it could be unconventional fields, which are generally more expensive to develop. But with global capacity squeezed, this still might make economic sense. Recent capacity additions in Abu Dhabi have come from projects offshore, where output capacity is now estimated above 2.2 million b/d. Upper Zakum's capacity has risen by an estimated 200,000 b/d since 2019, and the field is now capable of pumping 1 million b/d on a sustained basis. Adnoc last month said it had made significant new conventional oil discoveries. Another 500 million barrels of oil were discovered by an exploration well at its 650,000 b/d Bu Hasa field, which has been producing since 1965. The company also said around 100 million bbl of oil in place was discovered in the Occidental Petroleum-operated Onshore Block 3, marking the second find in the concession, which is still in the exploration phase. Another 50 million bbl of light, sweet Murban crude was discovered in the Al-Dhafra concession. In a move that could support the expansion, Adnoc Drilling Co. last week announced plans to fast-track its fleet expansion program. It added that it had signed a deal to acquire two more jackup rigs, bringing its total fleet to 104 owned rigs.

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demand adjustments. Opec-plus is increasing output, which will alleviate some of the price pressure, but its capacity is limited — and the real onus is on refined products supply, not crude. Energy Intelligence estimates Opec-plus spare capacity — that which could be mobilized in short order — at only 2.85 million b/d. Saudi Arabia and the United Arab Emirates hold most, while many Opec-plus members continue to miss their production targets, stoking supply concerns.

Meanwhile, it could take higher prices for a longer period to induce demand destruction in this market. In the Great Recession of 2008, it took prices of $120/bbl to trigger demand destruction. In today's money, factoring inflation, it would require at least $150-$160/bbl, assuming everything else is equal. Aggressive interest rate hikes from central banks are likely to hit the market before that happens, prompting a big but necessary slowdown in demand growth to slay inflation.

The bigger question is how the oil market will address the long-term structural issues on the supply side. Even with today's higher prices, most producers are reluctant to undertake new upstream projects with long lead times due to concerns about future demand and the energy transition. Investor demands for capital discipline are also playing a big role — even in the short-cycle US shale sector, which in the past served as a key swing producer. With Russian oil off the table in the US and Europe, buyers are now vying for the same barrels in a smaller pool of global supply. This is already visible in the recent hike of Saudi crude selling prices to Asia, where higher demand is expected. This is also visible in the US, where diesel prices in New York Harbor have flared up to more than $200/bbl to prevent too much domestic supply from shipping to Europe, where it fetches an even higher price. Russia's crude output is down by 900,000 b/d since its Feb. 24 invasion of Ukraine, but this partly reflects lower demand from domestic refiners. Russian crude exports are in fact slightly higher than prewar thanks to steep discounts of $30-$35/bbl. Lower runs in Russia have lowered its product exports by 600,000 b/d, and this situation is likely to worsen as the EU import ban and shipping insurance restrictions kick in, which will likely add upward pressure on prices.

Rig Counts Swell Across US Shale Plays

Surging commodity prices are lifting drilling activity across US shale basins, reinvigorating some plays that went quiet during the pandemic. The powerhouse Permian Basin continues to drive the recovery that has occurred over the past year, but the resurgence is spreading to other major shale plays, as well as some marginal ones, in response to soaring prices for crude, natural gas and natural gas liquids (NGLs). The US oil and gas rig count now totals 727, down less than 10% from the roughly 800 rigs that were operating in the final months of 2019, before the pandemic hit, according to Baker Hughes. Rig activity has been particularly robust this year in the Eagle Ford of South Texas, which is on the verge of reaching its pre-pandemic rig count level. And while the Williston Basin of North Dakota's Bakken Shale is nowhere near its pre-pandemic rig count of 53, it has recovered from a 2020 low of nine to 38. On the marginal side, the Powder River Basin of Wyoming and Colorado is set to grow output by 40,000 barrels per day in the next 10 months, according to Rystad Energy's head of shale research, Artem Abramov. Elsewhere, Enverus has noted an uptick in several previously sidelined plays: The Mancos shale in Colorado's Piceance Basin recently had five active rigs, something that hasn't happened since December 2014.

Benchmark Henry Hub gas prices have traded around $7-$9 per million Btu over the past two months, and all US gas plays are generating attractive economics at current strip pricing, according to JPMorgan. The plays that screen at the low end of the cost curve have also been bolstered by the strength in NGL and condensate prices. The US gas rig count has risen by about 50% since a year ago and now stands at 151, slightly above the roughly 130 operating in late 2019. The Haynesville play of Louisiana, with a rig count of 69, has led the way, but the Barnett shale had as many as 11 rigs running in February, which hasn't happened in five years, according to Enverus. In the Anadarko Basin, operators are still struggling to grow on the oil side, but natural gas output is picking up in the region, and the "pace of growth is set to accelerate" in the second half of 2022, says Abramov.

Inflation and supply-chain issues are hitting producers everywhere in the US, but they are hurting Permian operators most. According to JPMorgan's recent estimates, shale break-evens have risen by 7% to $56 per barrel due to inflationary pressure and rising commodity prices. Those estimates place the Denver-Julesberg Basin of Colorado at the low end of the cost curve at $45/bbl, helped by higher gas and NGL prices. Meanwhile, some areas of the Eagle Ford sit at the lowest end of the US cost curve. Overall, however, the Eagle Ford Shale and the Permian subbasins of the Delaware and Midland follow the DJ "in a tight range" of $48 to $49/bbl.

The US oil rig count now stands at 575, or about 100 fewer than in the final quarter of 2019. While the Permian will continue to be the biggest contributor to US oil production this year by far, Energy Intelligence anticipates growth in all the major basins. Still, capital discipline will keep overall US output growth in check in 2022. Energy Intelligence forecasts crude production growth of about 600,000 b/d this year to 11.8 million b/d but sees continued steady growth to around 13.5 million b/d in 2025. This year, we see the Eagle Ford and Niobrara each contributing 25,000 b/d, with the Bakken of North Dakota contributing 18,000 b/d. Another 68,000 b/d should come from other areas like Gulf of Mexico, Alaska and conventional development, while the rest is expected to come from the Permian. On the gas side, growth is expected in all the major plays, although the Permian will stay far behind Appalachia as the top producer. We see US gas output rising by about 2 billion cubic feet per day this year to 93.9 Bcf/d and steadily expanding to 103.6 Bcf/d in 2025.

Can India, China Keep Russian Oil Flowing?

The noose around Russian oil has tightened after the EU's agreement to ban imports of Russian seaborne crude. India and China have so far prevented a major collapse in Russian crude flows, with the former dramatically stepping up purchases of discounted Russian oil and the latter maintaining its robust imports. But whether they can sustain or increase these volumes as Russian flows to Europe drop further as the year progresses remains an open question. Preliminary shipping data indicates that Indian imports of Russian crude, the bulk of it Urals, could hit 840,000 barrels per day or more for June, according to data analytics firm Vortexa. This would be relatively stable with May arrivals of 850,000 b/d but would mark a big surge from 360,000 b/d in April. In 2021, India's imports of Russian crude averaged below 50,000 b/d. Indian refiners are thought to have signed semi-term Urals contracts for the second half of 2022 with volumes totaling an estimated 400,000-600,000 b/d. China bought up to 780,000 b/d of May-loading seaborne Russian East Siberia-Pacific Ocean (Espo) crude and is believed to have snapped up nearly all of the June-loading Espo cargoes totaling 757,000 b/d.

India and China appear to have solved at least some of the logistical, insurance and payment difficulties associated with Russian crude. This is helping Russia place about 800,0000 b/d that is bypassing Europe. But as the EU ban takes hold over the coming months, Russia will need to find a market for another 1.1 million b/d of crude. At least some Urals crude is being shipped to India on tankers owned by Russian state-controlled shipping company Sovcomflot in what appears to be a government-to-government arrangement, traders said. China, on the other hand, has been using its Cosco tankers to bring Espo crude "on milk runs" to Chinese ports, sources said. Going forward, Indian imports of Russian crude could rise even further, said an Indian trader. And China plans to buy oil for its strategic reserve in coming months, which could increase its appetite for Russian crude, at least temporarily.

Despite the Russian crude flows into Asia, the region's main Mideast crude market remains strong. Increased European competition for Mideast crudes has contributed to a spike in spot price differentials for July-loading cargoes of competing medium, sour Mideast grades, trading sources said. July spot Upper Zakum, a medium, sour crude from Abu Dhabi, traded at premiums ranging from around $5.40 per barrel to $5.60/bbl to the Dubai benchmark price, a huge jump from the previous month, when June-loading spot Upper Zakum had sold at premiums ranging from $2.50/bbl to $3.30/bbl to Dubai, sources said. The grade's strength was largely due to Asian demand recovering as many of the region's refineries return from maintenance — although European competition also contributed. Europe had already started to buy more Mideast sours before the EU ban, in anticipation of it being agreed, sources said. But later in the trading month for July loaders, spot Upper Zakum deal premiums softened to around $5/bbl to Dubai as demand ran out of steam due to Indian and Chinese buying of Russian crude capping their spot crude appetite, a refiner source said.

The EU's Russian crude ban is likely to provide a boost for this month's Mideast spot market for August-loading cargoes, especially with the Dubai benchmark price weakening massively relative to the Brent benchmark that prices seaborne crudes in the North Sea and the Mediterranean. Increased European demand will stiffen competition for Mideast spot crude with Asian market players, traders note. The Brent-Dubai Exchange of Futures for Swaps (EFS), which is a gauge of how much more expensive Brent is relative to Dubai, has strengthened dramatically. The monthly average EFS spiked by $2.83/bbl from April to $9.28/bbl for May. By Jun. 8, it stood at $11.21/bbl, making Dubai-priced Mideast crudes extremely attractive to European market players. Ultimately, how expensive August-loading spot Mideast crude ends up this month could again depend, at least partly, on how much Russian crude India and China take.

As Deadline Nears, Fate of US Lease Sales No Clearer

The Biden administration recently announced that a new, five-year offshore leasing proposal is on the way, with the US Interior Department pledging a draft by the end of the month. But while that may quell some uncertainty given that the current Outer Continental Shelf 2017-22 plan expires Jun. 30, it raises more questions about the substance of the proposal. Biden's strategy for revamping policies governing leasing and access to federal lands and waters for drilling has been a moving target since day one and still looks unsettled. Lease sales have ping ponged on and off the books, as early executive orders canceling any planned during the Trump administration were later scrapped by a court ruling in Louisiana. A different court later nixed the November US Gulf Lease Sale 257, which drew nearly $192 million in total high bids across 308 blocks. The administration has since canceled the proposed lease sale for Alaska's Cook Inlet and two auctions in the US Gulf of Mexico — Sales 258, 259 and 261. In the latest move in the push-pull legal battle, a federal court in Washington sent Interior back to the drawing board on roughly 2,000 existing oil and gas leases between 2015 and 2020 over environmental concerns.

But politics has contributed to the chaos. Biden campaigned on a promise to end all new oil and gas leasing on federal lands, where roughly 20% of US production takes place. With US midterm elections drawing near and Democrats on the back foot over inflation and sky-high fuel costs, Biden doesn't appear to be backing too far from that pledge, which is part of his bold climate agenda. White House officials continue to draw a distinction between current high oil and gas prices — even as they make the case for ramping up production — and the need for new leasing, arguing that 9,000 application-to-drill permits have been approved for onshore. Testifying before a US Senate energy panel last month, Interior Secretary Deb Haaland declined to guarantee that new acreage will be on offer in the forthcoming offshore leasing plan. The uncertainty of future access to acreage in the US Gulf spells trouble for deepwater companies. While major producers like Shell, BP and Chevron have collected more undeveloped leases with the time frames necessary to wait out a gap in fresh leasing and hope for a shift in the White House, any future administration would have to propose and finalize its own five-year plan first, a time-consuming process.

What exactly will be on offer looks to be slim pickings, absent another major 180 court ruling. One legal source suggested that Interior could offer as few as one sale per year over five years and holds wide discretion over the amount of acreage per sale. Comparatively, the current Obama-era plan for 2017-22 envisioned 11 lease sales, and a Trump-era plan that was never finalized would have seen 47 sales in 2019-24. The Interior department is not "committing to any specific lease sales or areas yet, since the final program still has to be developed," cautioned Justin Williams, a spokesman for the National Ocean Industries Association, the US offshore lobby group. In other words, producers are braced for a very light leasing sale schedule. Greens, meanwhile, are making the case that the administration has the authority to complete a five-year plan that locks in place zero lease sales through 2027. However, there exists scarce legal precedent for that, and oil lobbyists point out that the governing statute requires a plan that best meets national energy demand. That demand threshold means that current high fuel prices will play an outsized role in Interior's analysis and may make it more difficult to justify a slimmer sale schedule.

What's New Around the World

COUNTRIES

QATAR — QatarEnergy could be poised to announce the long-awaited first awards for prized equity stakes in Qatar's 48 million ton/yr LNG expansion. The state-owned gas giant has invited international media to attend "an important signing ceremony" on Jun. 12 in the presence of Energy Minister and QatarEnergy CEO Saad al-Kaabi. The company did not provide any further details on what would be signed at the event. However, two sources told Energy Intelligence in May that equity stakes in the expansion's 32 million ton/yr first phase, dubbed North Field East, had been awarded, making an official signing possible. QatarEnergy previously announced a signing event scheduled for May 26 but this was canceled on short notice. A Bloomberg report on Tuesday signaled Exxon Mobil and TotalEnergies were in pole position to be awarded stakes. This would mesh with Energy Intelligence soundings. One source said one of two awards in May was to a new investor. Both Exxon and Total are existing investors. Short-listed firms include Exxon, Shell, ConocoPhillips and Total, which are all existing investors, plus Eni and Chevron. QatarEnergy has also been speaking to some of its existing Asian customer base about taking equity stakes.

VENEZUELA — The US is easing a restriction on Venezuelan oil exports, allowing European giants Repsol and Eni to export oil from the South American country as payment for debt. The decision comes amid a tight oil market — especially for the grade of heavy crude Venezuela produces — and diplomatic wrangling around renewed political negotiations between the government of de facto President Nicolas Maduro and the disparate Venezuelan opposition. The US State Department is reversing its earlier position of threatening sanctions against Repsol and Eni for exporting Venezuelan crude, a senior administration official confirmed to Energy Intelligence. Under the new arrangement, both Italy's Eni and Spain's Repsol will be able to offtake Venezuelan crude as repayment for past investments in the country and export it overseas. The Biden administration has offered some limited sanctions easing over the last month, first giving Chevron a license to negotiate with state-held Petroleos de Venezuela (PDVSA) over the future of the US giant's license in the country. The administration now appears to be paving the way for some oil to come to market — even if the revenues don't flow to PDVSA. But more comprehensive sanctions relief may be difficult absent progress in political negotiations.

Opec-Plus Supply Gap Widens

The 19 members of Opec-plus with a quota managed to raise production in May by 235,000 b/d to 37.68 million b/d, according to Energy Intelligence's assessment. Kazakhstan led the gains, lifting output by some 175,000 b/d after previous terminal difficulties in the Black Sea, while Russia managed to lift production by 92,000 b/d after the staggering 850,000 b/d decline in April. Saudi Arabia added another 115,000 b/d to post total output of 10.52 million b/d. Still, the gap between output and targets widened further, amounting to 2.7 million b/d in May. Russia accounted for nearly half the deficit. The shortfall is expected to grow this summer despite the agreement last week to raise monthly increases to 648,000 b/d.

Compliance With Opec-Plus Production Cuts

Opec	Base	May Ceiling	May Production	Target	Compliance Rate
Saudi Arabia	11,500	10,549	10,519	-30	103%
Iraq	4,803	4,461	4,305	-156	146
UAE	3,500	3,040	3,030	-10	102
Kuwait	2,959	2,694	2,694	0	100
Nigeria	1,829	1,753	1,178	-575	857
Angola	1,528	1,465	1,229	-236	475
Algeria	1,057	1,013	1,019	6	86
Congo (Br.)	325	312	249	-63	576
Gabon	187	179	165	-14	NA
Eq. Guinea	127	122	102	-20	506
Opec 10	**27,815**	**25,588**	**24,490**	**-1,098**	**149**
Iran	3,296	NA	2,550	NA	NA
Venezuela	1,171	NA	715	NA	NA
Libya	1,114	NA	690	NA	NA
Opec 13	**33,396**	**25,588**	**28,445**	**-1,098**	**149**

Non-Opec	Base	May Ceiling	May Production	Target	Compliance Rate
Russia	11,500	10,549	9,246	-1,303	237
Mexico*	1,753	1,753	1,734	-19	NA
Kazakhstan	1,709	1,638	1,649	11	85
Oman	883	846	849	3	92
Azerbaijan	718	688	578	-110	466
Malaysia	595	571	391	-180	850
Bahrain	205	197	168	-29	463
South Sudan	130	124	142	18	-211
Brunei	102	98	88	-9	316
Sudan	75	72	79	7	NA
Non-Opec 9	**15,917**	**14,783**	**13,190**	**-1,593**	**240**
Combined 19*	**43,732**	**40,371**	**37,680**	**-2,691**	**180**
Opec-Plus 23	**51,066**	**NA**	**43,369**	**NA**	**NA**

In '000 b/d. Opec and non-Opec compliance based on crude oil only. Mexico no longer has a quota but nominally is a member of the non-Opec alliance. Source: Opec, government data, Jodi, Energy Intelligence.

Global Supply Pushes Higher in May

After a steep fall in April, the world supply of hydrocarbon liquids jumped by almost 680,000 b/d in May to reach 99.3 million b/d — just 200,000 b/d shy of March's level. Non-Opec-plus countries, turbocharged by output of Brazilian biodiesel, added 500,000 b/d, while Opec-plus itself only provided 100,000 b/d of new supply. Russia and Kazakhstan, which together suffered a massive drop of over 1 million b/d in April, managed a joint increase of 340,000 b/d, although this was offset by setbacks in Opec-plus members Libya and Gabon.

World Crude Oil and Other Liquids Supply

('000 b/d)	Apr '22	May '22	Chg.	Crude May	Other May
Non-Opec-Plus	**45,289**	**45,791**	**503**	**31,971**	**13,820**
US	19,108	19,156	48	11,750	7,406
Canada	5,613	5,711	97	4,400	1,311
Brazil	3,531	3,945	414	2,937	1,008
Colombia	748	708	-40	690	18
Norway	2,124	2,055	-69	1,845	210
UK	888	848	-41	765	83
Egypt	634	652	17	543	109
Qatar	2,125	2,131	6	607	1,524
China	4,117	4,132	16	4,028	105
India	753	736	-17	561	175
Indonesia	778	788	9	609	179
Other Non-Opec-Plus	4,868	4,930	62	3,237	1,693
Opec-Plus	**51,124**	**51,228**	**104**	**43,369**	**7,859**
Opec	**33,917**	**33,727**	**-190**	**28,445**	**5,282**
Saudi Arabia	12,744	12,844	100	10,519	2,325
Iraq	4,456	4,370	-86	4,305	65
Iran	3,384	3,391	7	2,550	841
UAE	4,067	4,087	20	3,030	1,057
Kuwait	2,836	2,867	32	2,694	173
Nigeria	1,349	1,415	66	1,178	237
Libya	1,005	749	-256	690	59
Algeria	1,435	1,381	-54	1,019	362
Angola	1,184	1,266	82	1,229	37
Other Opec	1,456	1,356	-101	1,231	125
Non-Opec	**17,207**	**17,502**	**294**	**14,924**	**2,578**
Russia	10,631	10,772	141	9,246	1,526
Kazakhstan	1,726	1,926	200	1,649	277
Azerbaijan	724	705	-19	578	127
Mexico†	1,917	1,976	59	1,734	242
Oman	1,056	1,063	7	849	214
Malaysia	584	563	-21	391	172
Other Non-Opec	570	497	-73	477	20
World Supply	96,413	97,020	607	75,340	21,679
Refinery gains	2,214	2,285	71	0	0
Total World	**98,627**	**99,305**	**678**	**75,340**	**23,965**

*Other liquids include natural gas liquids, biofuels, gas-to-liquids, coal-to-liquids, refinery additives. †Mexico nominally is a member of the Opec-plus alliance but has no production quota. Source: IEA, EIA, Jodi, government and trade data, Energy Intelligence.

Marketview

Smoke on the Water

The Russian oil trade has been smoke and mirrors since the first raft of Western sanctions on Moscow after its invasion of Ukraine on Feb. 24, but it is about to get less transparent and more confusing for oil market observers.

Despite formal US and EU restrictions, buyer self-sanctioning initiatives and lofty calls to action, Russian oil exports have continued unhindered since the start of the Ukraine war. They even rose in March and April as Moscow responded to higher Brent prices with larger volumes.

But how much of this oil has found actual buyers is unclear, as volumes of Urals crude on the water have steadily risen since March.

The EU oil embargo will displace 82% of the 2.2 million barrels per day of crude that Russia previously shipped to Europe, as well as a large chunk of the 1.15 million b/d product exports to the bloc. In total, nearly 3 million b/d of crude and products will have to find a new home.

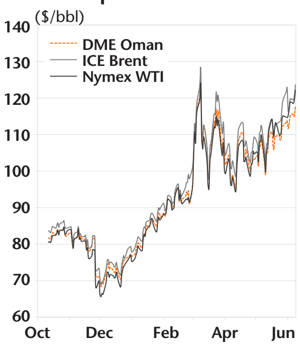
An average 800,000 b/d have already shipped to India and China since the beginning of the year.

It is unclear if these buyers will maintain or step up the pace, although Russia's steep discounts for its oil certainly make it attractive in this red-hot oil market in which Brent is now trading around $123 per barrel.

More Urals cargoes are tied up in longer journeys to Asia, rather than Rotterdam or Augusta in Europe.

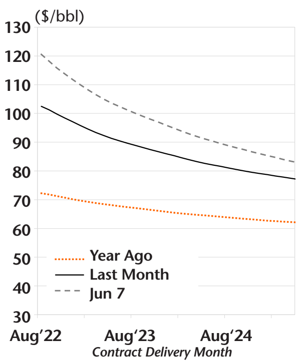
That partly accounts for the higher volumes of floating Urals.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



From an average 13.5 million barrels at sea between Jan. 1 and Feb. 20, the count is up to 60.5 million bbl, with a spike to 63.6 million bbl in late May.

But half of that oil (29.7 million bbl) is floating without a buyer or final destination, Kpler data show.

Given the lack of onshore storage in Russia, more crude will have to go in floating storage, much as Iran has done in recent years.

But Iran owns the world's largest fleet of very large crude carriers (VLCCs). In comparison, the Russian VLCC fleet is small and some capacity will be monopolized in a longer intermediation chain to Asia. Instead of taking a week or less to reach Europe, it will now take up to 60 days to move oil to consumers in China.

The EU insurance ban on all ships carrying Russian oil will compel sellers to disguise the origin of their oil, using multiple ship-to-ship transfers to evade scrutiny. It takes several shipments from smaller tankers to fill a VLCC, which means more Russian crude is likely to be floating at sea at any one time, at least in the short term.

Longer term, transporting oil to Asia will take up to four months to finance: 60 days for a VLCC journey out and 60 days back.

Filling up those VLCCs will hence cost more money, and more notional borrowings for much longer terms.

It is unclear how long Russia could afford that with discounts for Urals grade running around $35/bbl and without losing customers from Asia.

Vitol: More Iran Oil Could Hit Market

Mike Muller, the head of Vitol Trading in Asia, thinks that if oil prices don't fall in the coming months, the administration of US President Joe Biden may allow Iran to export more of its sanctioned crude to boost global supply.

"I think most analysts now don't have any [unsanctioned] Iranian oil coming back this year," Muller told a Gulf Intelligence podcast on Sunday. But he said there is more than 100 million barrels of Iranian crude and condensate in floating and onshore storage, which is "ready to go now" and could be released to help cool oil prices ahead of the US midterm elections in November. Muller said Washington could turn a "somewhat greater blind eye" to sanctioned barrels flowing out of Iran.

PIW Market Indicators

($/barrel)	Jun 6-Jun 8	May 30-Jun 3	May 9-May 13
Spot Crude			
Opec Basket	$120.52	$118.66	$110.27
UK Brent (Dtd.)	127.45	123.81	107.21
US WTI (Cushing)	119.92	116.36	105.00
Nigeria Bonny Lt.	133.26	131.03	109.51
Dubai Fateh	115.89	112.75	104.68
US Mars	114.10	111.25	103.16
Russia Urals (NWE)	91.66	89.43	72.91
Crude Futures			
Brent 1st (ICE)	121.22	119.63	106.98
Brent 2nd (ICE)	118.67	115.76	105.54
B-wave (ICE)	120.72	119.02	107.17
WTI 1st (Nymex)	120.01	116.42	105.04
WTI 2nd (Nymex)	117.65	113.79	103.46
Oman 1st (DME)	116.89	113.41	103.93
Oman 2nd (DME)	113.45	110.19	101.75
Murban 1st (ICE)	120.19	116.79	106.39
Murban 2nd (ICE)	116.63	113.74	104.32
Forward Spreads			
Brent (1st-Dtd.)	-$6.23	-$4.19	-$0.22
Brent (2nd-1st)	-2.55	-3.86	-1.45
WTI (2nd-1st)	-2.36	-2.63	-1.58
WTI (3rd-2nd)	-2.63	-2.81	-1.88
Oman (2nd-1st)	-3.43	-3.22	-2.18
Oman (3rd-2nd)	-4.21	-2.73	-2.25
Murban (2nd-1st)	-3.56	-3.06	-2.07
Murban (3rd-2nd)	-2.85	-3.09	-2.11
Grade Differentials			
WTI-Brent (1st)	-$3.57	-$4.64	-$3.53
WTI-LLS	-1.55	-1.75	-2.26
WTI-Mars	+5.82	+5.11	+1.84
Brent(Dtd)-Dubai	+11.56	+11.06	+2.52
Brent(Dtd.)-Urals	+35.79	+34.38	+34.30
Brent(Dtd.)-Bonny Lt.	-5.81	-7.22	-2.30
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$121.23	$118.38	$110.29
Arab Lt.-Europe (Med)	122.62	120.92	112.07
Arab Lt.-Far East (f.o.b.)	121.05	116.82	113.98
Nigeria Bonny Lt.	127.45	123.81	109.15
Arab Light Gross Product Worth			
Rotterdam	$141.63	$140.93	$126.06
US Gulf Coast	152.03	147.41	137.47
Singapore	132.35	129.21	120.57
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$156.23	$153.20	$121.67
UK Brent Margin	+27.74	+28.46	+13.13
US Gulf Coast			
Mars GPW	145.81	141.52	131.66
Mars Margin	+31.61	+30.17	+28.40
Singapore			
Oman GPW	131.39	129.41	121.62
Oman Margin	+13.57	+16.91	+16.43
US Nymex			
WTI 3-2-1 Crack	+$57.98	+$58.28	+$53.98
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$1442.77	$1450.93	$1188.08
Gasoil (0.1%)	1341.33	1274.10	1094.05
Fuel Oil (0.5%)*	910.17	854.00	749.80
US Gulf Coast (¢/gal)			
RBOB Gasoline	422.70¢	412.41¢	366.75¢
ULS Diesel	433.17	415.51	394.61
Fuel Oil (0.5%, $/ton)	$945.67	$924.20	$833.40
Singapore ($/bbl)			
Naphtha	$92.04	$93.57	$100.10
Gasoil (0.05%)	169.06	159.48	143.66
Fuel Oil (0.5%, $/ton)	1115.00	1117.00	851.60

*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.