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Opec Mega-Deal Ends With Micro Move

Opec-plus' agreement this week to increase production by just 100,000 barrels per day in September reflects a confluence of complex political and market factors. A desire not to risk antagonizing key member Russia, coupled with genuine demand fears — reinforced by oil prices that have fallen by almost $20 per barrel since mid-June — prompted Opec-plus energy ministers to opt for caution. September's increase represents one of the smallest supply adjustments since Opec introduced quotas in the early 1980s. That may seem like an anticlimactic way to end Opec-plus' 27-month long pandemic supply response — which initially involved unprecedented cuts of 9.7 million b/d — but it also reflects the limited spare capacity the alliance now has to work with. Indeed, given the widespread failure of members to boost output in response to rising targets in recent months, perhaps only Saudi Arabia, the United Arab Emirates and Kuwait will deliver tangible new supply, amounting to a paltry 44,000 b/d (see table). This latest step may have surprised some observers, but it is consistent with the cautious approach demonstrated by Opec-plus during times of volatility. The group argued that wafer-thin spare capacity "necessitates utilizing it with great caution in response to severe supply disruptions." This capacity crunch was down to "chronic underinvestment" across the oil supply chain, said the communique following the Aug. 3 meeting. Most members' inability to increase supply means that Opec's Gulf core would have to disproportionately bear the burden of any serious output rise, requiring politically sensitive discussions to persuade others in the group of the necessity of such a course.

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West Looks to Opec to Fill Russian Gaps

Both the US and Europe have so far looked to Opec members to help replace the Russian oil they have shunned. But they are pushing the limits on this trade and may find additional replacement barrels harder to come by as tougher restrictions on Russian imports are implemented in the coming months amid dwindling Opec spare capacity. Mideast producers have been sending more heavy oil to the US and Europe, and, along with West Africa, more crude to Europe. This successful rerouting of flows, which includes India and China buying more Russian crude, has helped calm oil markets. Brent has sunk to nearly a six-month low at under $100 per barrel, responding also to wobbly demand from high prices and the prospect of economic recession. But the summer lull could be short-lived. Deadlines looming on EU rules that will ban Russian oil imports and restrict shipping could create havoc beyond Opec's control. US refiners have been replacing banned Russian intermediate fuels with feedstock from Opec members like Saudi Arabia, Iraq, Algeria, Kuwait and the United Arab Emirates, according to the US Energy Information Administration (EIA). US refiners bought nearly 300,000 barrels per day of heavy fuels from Opec members in May — the latest month for this EIA data — up from 45,000 b/d before the war. The same trend is visible in residual fuel oil, where not only Opec but also Latin American producers have stepped up supply to US refiners. EU refiners are buying more Mideast fuel oil. Meanwhile, some of Moscow's discounted fuel oil is moving to the Mideast, allowing

Oil Exports From Russia's European Ports

('000 b/d)	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22	Jul '22
Crude	1,825	1,530	1,781	2,057	2,060	1,977	1,716
Baltics	1,440	1,280	1,363	1,547	1,501	1,503	1,331
Black Sea	385	250	418	510	559	474	385
Products	**2,490**	**2,712**	**2,046**	**2,170**	**1,768**	**2,110**	**2,102**
Baltics	1,553	1,681	1,385	1,495	1,211	1,348	1,332
Black Sea	937	1,031	661	675	557	762	770
Total Exports	**4,315**	**4,242**	**3,827**	**4,227**	**3,828**	**4,087**	**3,818**

Source: Kpler, Energy Intelligence

countries there to export their own fuel at higher market prices. More US, West African and Mideast crude is flowing to Europe.

Since Russia's Feb. 24 invasion of Ukraine, roughly a quarter of Russian crude and product flows to Europe and the US have been rerouted. But that was the easy part. New EU import and shipping bans take effect around the new year and will force some 1 million b/d of products and an equal volume of crude to find new homes. Opec, the US and the North Sea might be able to replace much of the crude needed in Europe if Asia is willing to buy more Russian barrels. But product flows are more complicated. In July, the EU still imported 1.2 million b/d of refined products from Russia's European Black Sea and Baltic ports, shipping data show. The bulk of that must end by Feb. 5, 2023. The EU also imported still 1.6 million b/d of crude, half via ports and half via the Druzhba pipeline. Much of that will come to an end by Dec. 5, 2022. Not all EU imports of Russian petroleum will dry up. Hungary, Slovakia and the Czech Republic are allowed to continue buying pipeline crude. Bulgaria and Croatia have exemptions for imports as well. This might add up to a total 400,000 b/d, mostly crude.

Russian diesel exports will be particularly crucial to markets. Europe still bought 680,000 b/d of Russian diesel in July — more than before the war. If Russian diesel can move to Latin America and the Mideast, US and Mideast flows can become available for Europe — but at a higher price since uncertainty and shipping have their costs.

Complicating matters is that the EU also plans to ban the use of Western tankers to handle Russian oil. Spurred on by Washington, which fears a price spike from disrupted Russian supplies, G7 countries are discussing a remedy: vessels can be used if Russian oil is bought at or below a price cap set by the West. The thinking is that Russian oil will still flow while Moscow gets less income. But the plan is fraught with issues. Traders don't see it working in practice. Russia could cut supply or use a dark fleet of tankers — possibly with the help of allies Iran and Venezuela. But there would still not be enough tankers available. Cap or no price cap, it seems Russian exports, which dropped slightly in July, must fall further later this year, unless the EU changes terms of the ban. Opec, led by spare capacity leaders Saudi Arabia and the UAEs, could produce more, but this would gobble up Russian market share, and members are keen on keeping Moscow in the Opec-plus alliance.

NOC Controversy Clouds Libya's Upstream Outlook

Libya is promising a new foreign investment drive after the controversial replacement of National Oil Corp. (NOC) chairman Mustafa Sanalla with ex-central bank governor Farhat Bengdara last month. Libya's up and down oil production is on the rise again, hitting 1.2 million barrels per day recently, with August exports set to reach 1.01 million b/d. If political stability can hold, long-delayed oil sector investment and reform could be back on the table, improving the outlook for the Opec country's output at a time when oil markets are fretting over dwindling spare capacity. Indeed, Libya is keen to develop its oil wealth before its fields become stranded assets, Libya's Oil Minister Mohamed Oun tells Energy Intelligence. European oil majors have remained significant investors in Libya over the past decade during the country's civil war. Now, amid tight global supply, Libya could be more attractive due to its low extraction costs, infrastructure and geographical location as Europe turns its back on Russian hydrocarbons. After Dbeibeh replaced Sanalla, NOC lifted force majeure declarations on Jul. 15 at Libya's oil fields and loading terminals where petroleum facilities guards and workers had been on strike at eastern ports of Es Sider, Ras Lanuf, Zueitina and Marsa al-Brega over salaries and grievances. Dbeibeh dismissed Sanalla after he refused to step down. Sanallah had accused Dbeibeh of

NOC Production Enhancement Program, 2019-24

Company	Field	Scope	Capacity	Budget ($US)	Schedule
Mellitah Oil & Gas Co.	Wafa Gas Inlet Compressors	New compressors to maintain gas plateau output	NA	100,000	2019-22
	A&E Structures Offshore	Drilling and completion of 30 gas wells and five oil wells, two platforms and subsea system for seven gas wells	760 MMcf/d	8.3 million	2013-24
Zallaf Libya Oil & Gas	Erawin Field NC-200	New field pipeline and surface facilities	4,000 b/d	100,000	2020-21
Nafusah Oil Operations	North Hamada A-47	New field development	10,000 b/d	142,428	2020-21
Waha Oil Co.	NC-98	Drilling of 18 new wells and 20 gas injection wells	80,000 b/d 440 MMcf/d	1.03 million	2018-25
	Gialo-III	Drilling of nine development wells and surface facilities	25,000 b/d, 6,000 boe/d, 30 MMcf/d	159,600	2018-23
	North Gialo Block	Drilling of 45 oil wells and 16 gas injection wells	100,000 b/d, 200 MMcf/d	859,459	2018-25
Arabian Gulf Oil Co.	NC-4	North Hamada new field development	15,000 b/d	93,571	2020-21
	NC-100	New field development	10,000 b/d	NA	2019-21
Sirte Oil Co.	LP 3D	Field development	2,800 b/d	7,140	2020-21

Source: Libya's National Oil Corp.

alleged collusion with the United Arab Emirates over oil supply and services contracts — charges which Dbeibeh has denied.

However, the manner of Sanalla's departure leaves question marks over the future independence of NOC and the morale of its officials, who are responsible for meeting Libya's established oil and gas production targets of 2.1 million b/d and 4.1 billion cubic feet per day by 2024. Dbeibeh sent armed militias to encircle NOC headquarters to force Sanalla out, and when Bengdara first tried to enter the building, NOC executives blocked him, forcing the new chairman to hold a press conference on the steps outside. Asked about morale and how supportive NOC executives would be under Bengdara, Oun insists that despite initial resistance, "when they [officials] feel there is fair treatment and every individual is behaving well, they will support it." The US embassy in Libya initially expressed "deep concern" over the power struggle at NOC. It later added that it was following court proceedings brought by Sanalla against NOC over his dismissal, noting that NOC's "apolitical status … should be maintained to sustain Libya's reputation in the international oil sector." Washington went on to say that it was closely monitoring NOC subsidiaries "and any attempts to appoint unqualified representatives to the boards."

Oun has instructed NOC to plan a new bid round, but there will be no reform of the oil law or Qaddafi-era exploration and production sharing agreements (EPSA IV) for now. Dbeibeh is keen to encourage more foreign investment in Libya's oil sector but does not want to review current contracts with international oil companies (IOCs), Oun says. European majors TotalEnergies and Eni have both doubled down on Libyan investments during the civil war, which started in 2011, and are eyeing opportunities combining solar power and oil and gas production. But Libya's targets previously required an estimated $60 billion of investment — 82% of which was to come from the private sector, with just 15 billion Libyan dinars ($10.5 billion) coming from Tripoli. Oil fields, pipelines, storage tanks and power plants all need rehabilitation, with the bill running to billions of dollars. Despite North Africa's growing importance to Europe amid the war in Ukraine, IOCs may yet hesitate unless hydrocarbons legislation is adapted to the current international upstream landscape. Libya's previous EPSA contracts featured a punitive government take of roughly 88%. NOC was reviewing the contract terms in 2013 ahead of a planned licensing round, but that work stalled as the civil war took hold. Last year, Sanalla launched a review to create a new EPSA V contract model that would be offered to IOCs. Tripoli was also planning to launch a new auction in partnership with the US Department of Energy to help promote its acreage.

US Climate Bill Seeks Balanced Transition

It's dangerous to count chickens before they hatch when dealing with the US Congress, but if new compromise legislation passes, the US could be close to having an energy policy that addresses both its short- and long-term needs. The landmark spending bill, which has a decent chance of passing in the coming weeks, combines provisions for continued near-term investments in oil and gas with $369 billion in climate and clean energy spending, which would help the Biden administration approach its goal of reducing greenhouse gas emissions by 50% by 2030. Importantly, the bill is a practical manifestation of the "more now, less tomorrow" approach to oil and gas that has gained traction in the Ukraine crisis, involving a balancing act that has challenged policymakers worldwide. The bill, known as the "Inflation Reduction Act," was unveiled last week after swing vote US Senator Joe Manchin announced a surprise deal with Democratic leadership. Manchin, a centrist Democrat from West Virginia, a state that has long relied on fossil fuels, described the bill as a "balance," saying its energy provisions "should knock down [gasoline] prices," streamline energy infrastructure permitting and support clean energy — without forcing an abrupt pivot away from fossil energy. The bill summary maintains it would reduce greenhouse gas emissions 40% by 2030. Passage still faces obstacles in the Senate, where Democrats hold the slimmest majority and need full party support. Chiefly, it requires backing from another centrist Democrat, Arizona's Kyrsten Sinema.

Oil and gas-focused provisions are a mixed bag, as might be expected from a compromise. Perhaps most importantly for the industry, the bill would sound the death knell for President Joe Biden's anti-drilling pledge — a concession that has enraged climate activists. It would revive canceled offshore oil and gas lease sales and lock in new oil and gas sales — which would be tied to future federal auctions for solar and wind rights. However, the bill would also hike oil and gas royalty rates, another Biden priority. Soaring retail gasoline prices and legal challenges had already undermined Biden's January 2021 promise to halt oil and gas leasing on federal lands and waters. The bill would force the US Department of Interior to reinstate previously scrapped lease sales in the US Gulf of Mexico and Alaska's Cook Inlet — and would effectively guarantee lease sales on federal lands and waters for at least another decade. In a nod to the energy security balance, the bill would require new Interior renewable energy auctions to be matched with onshore and offshore oil and gas equivalents. The offshore royalty rate would be set between 16.67% and 18.75%, compared with the current 12.5%-plus, while onshore royalties would rise to 16.67% from 12.5%. Minimum bids for oil and gas leases would jump to $10 per acre from $2/acre. The bill would also substantially raise bonding requirements for oil and gas wells.

The oil and gas industry has concerns about the bill's impact on its costs. But it stands to benefit from increased support for carbon capture and biofuels, areas that form an integral part of US oil companies' energy transition strategies. The bill includes a series of extensions and enhancements to the existing carbon capture and storage (CCS) tax credit known as 45Q, including hiking the value of CO2 captured and stored to $85 per ton, from $50/ton, for industrial and power facilities, and $60/ton for enhanced oil recovery (EOR). Values for direct air capture would range from $130-$180/ton, depending on use. The bill would also offer a multiyear extension of the window for projects to qualify for the credit, and dramatically reduce thresholds for qualification. On biofuels, it would establish an investment tax credit, providing a credit of up to 30% of project capex, and introduce a tax credit of $1.25-$1.75 per gallon for sustainable aviation fuel (SAF).

The bill would enact a less punitive version of the methane "fee" that incensed oil and gas lobbies earlier in the legislative discussions. This version ties the penalty — which starts at $900/ton of methane over a 25,000-ton threshold in 2024 and escalates each year — to compliance with the US Environmental Protection Agency's (EPA) pending methane standards for the oil and gas sector. Once a facility complies with the EPA regulations, the fee would no longer apply.

Can US Sustain LNG Export Growth?

It's no coincidence that US natural gas prices rebounded to near-record levels above $8 per million Btu in July just as the country took over as the world's largest LNG exporter, according to the US Energy Information Administration. With European gas demand soaring in the wake of the Ukraine war, in-service US LNG terminals are running at full capacity, and new liquefaction trains continue to enter service. Even with the extended outage at Freeport LNG in Texas, nearly 10 to 11 billion cubic feet per day of US production is making its way to foreign markets, helping raise the price floor in an already-tight domestic market. And once Freeport returns to service late this year, add 2 Bcf/d to the tally. But how sustainable is export growth? Many politicians and consumer groups insist the US can't keep expanding LNG exports while containing domestic prices and are calling on the federal government to intervene. They maintain that gas prices at these levels, while good for producers, are inflicting economic pain for industrial, commercial and millions of residential customers — similar to record-high gasoline prices — and threaten to derail an economic recovery.

LNG project developers appear undeterred, with an unprecedented number of investment and offtake deals being inked recently. Since early 2022, buyers have signed up for 48.7 million tons per year of offtake with US LNG developers or with Mexico-based projects exporting US gas via Mexico. That amount surpasses the combined capacity of expansion

projects at Qatar's North Field East (32 million tons/yr) and North Field South (16 million tons/yr) and puts the US in the driver's seat for the first time. Portfolio players, trading houses and Chinese end-users have comprised the majority of US sales and purchase agreements, bolstering existing terminals and breathing life into long dormant projects. Much of this year's dealmaking has occurred in the tight market environment following Russia's Feb. 24 invasion of Ukraine. Offtakers and investors have included some of the world's biggest companies, including Shell, Exxon Mobil, TotalEnergies, ConocoPhillips, Chevron, and traders Gunvor and Vitol. Together, this group has signed deals for 17.4 million tons of destination-flexible US LNG offtake, or 36% of the total.

This flurry of activity comes against the backdrop of a major disruption of US LNG exports in mid-June, when a fire and explosion knocked Freeport offline. US gas prices immediately tanked while overseas gas prices shot higher on fears of a supply shortage from the US, although they have since resurged amid robust summer demand. Some politicians in Washington took notice. Sen. Angus King said it illustrated the direct negative impact the fast-growing LNG export market is having on American consumers. The Industrial Energy Consumers of America — long a critic of shipping domestic gas abroad — said the extraordinary price impact of one terminal being sidelined "should be alarming to federal policymakers." But whether this concern translates into actual policy risk for US LNG seems unlikely, at least in the short run. The Biden administration is already taking the line that instead of proposing additional LNG exports, developers should complete those already approved — but there is no sign of any official policy change. The US Department of Energy has the authority to "claw back" some previously approved export approvals if it is in the public interest, but little has been said suggesting that is in the cards.

Still, final investment decisions (FIDs) for US LNG project have proved largely elusive, with the only FID this year being the 10 million tons/yr Corpus Christi Stage 3 in June. That could be a sign that some future capacity on the drawing board may not materialize as companies weigh the pros and cons of moving forward in a highly volatile global gas market amid the energy transition. The fresh wave of US LNG offtake deals only began in earnest after Russia's invasion of Ukraine in late February, so it may be a case of finalizing details before an FID wave begins. But regulatory concerns remain — even for even existing LNG exporters. Cheniere, for instance, is asking the US Environmental Protection Agency (EPA) to renew a long-standing exemption for some natural gas-fired turbines from air toxics rules, warning that the regulations would impose significant costs and possible operational disruption for its two US Gulf Coast LNG export facilities. The consequences would be bearish for US gas prices if Cheniere is forced to curtail exports from Sabine Pass LNG and Corpus Christi LNG as they represent 45 million tons/yr (6.2 Bcf/d) out of a total US nameplate export capacity of 91.3 million tons/yr.

Majors Running With 'Advantaged' Project Plans

The global oil industry is beginning to usher in a new era of upstream projects as those schemes sanctioned before pandemic-driven downturn come online and companies look to their next tranche of new production. These projects are broadly characterized by attributes such as low cost, low carbon footprint, short development cycle, strong access to existing infrastructure and markets and strategic fit within an integrated portfolio — all attributes Energy Intelligence has defined as "advantaged barrels." More recently, we would add an increasing focus on above-ground risk to the calculation. "Our strategy in oil and gas is to maximize returns and cash flow, creating resilience through lower costs, higher margins and lower operating emissions, focusing on the best barrels," BP CEO Bernard Looney said, noting he expects upstream margins to grow 20% by 2030. The exit of the majors from Russia following its invasion of Ukraine as well as the retreat from places like Myanmar and onshore Nigeria has shown the majors' appetite for political risk is shifting. "We want to be out of onshore oil, no matter how the macro might perhaps change the outlook for those assets," Shell CEO Ben van Beurden said of Nigeria. "And that is a case of risk management and appetite for dealing with the challenges onshore."

Some of these advantaged principles have been pieced into place at existing projects already and will be applied at a much larger scale through phased redevelopments where access to existing infrastructure increases margins. Others are being combined into wholly new development concepts. The results are challenging conventional wisdom about what is possible in an oil and gas development. BP flagged advances in seismic processing, revealing as many as seven previously unseen exploration targets around its existing Thunderhorse hub in the US Gulf of Mexico. In the US, supermajors Exxon Mobil and Chevron are completing production hubs in the Permian Basin that incorporate renewable power and integration with refinery operations. Chevron built 40 tank batteries to process production from its first 800 wells in the Permian Basin. Looking further ahead, Italy's Eni is pioneering a set of fast-track oil, gas and LNG developments offshore Africa that aim to deliver a moderate volume of production as quickly as possible to capture high margins from near-term prices. The Baleine oil discovery could begin to flow through a small early production system later next year — 18 months after discovery. France's TotalEnergies is spending another $1 billion this year on short-cycle oil and gas opportunities, including partnering with BP, Eni and Chevron on the first gas-specific development in Angola to take advantage of capacity at Angola LNG.

The results from this advantaged approach are starting to become evident in the strong performance of the global oil majors, particularly in their upstream divisions. In the first half of this year, crude oil prices averaged $108 per barrel, a level last seen in 2013. But in the second quarter this year, the five global supermajors combined to produce $58.6 billion in net income compared to $22.1 billion in the same period in 2013. Executives credit not only their newfound capital discipline as the difference between the two results but also their refined approach to choosing which projects to develop and how to do it. The new world of upstream oil projects looks different and so far companies like what they see. Eni CEO Claudio Descalzi said his company would look to replicate its concept of modular floating LNG development offshore Congo-Brazzaville in Mozambique to add a second floating unit at Coral in as little as four years, "accelerating the time to market" and "reducing financial exposure." Shell executives estimated that the company's production had fallen 21% from 2013 levels but at the same time cash flow per barrel was up 74%. By 2026, Chevron plans to more than double its cash flow per barrel compared to 2019 levels, while cutting both methane intensity and Scope 1 and 2 emissions.

Opec Mega-Deal Ends With Micro Move

(Continued from p.1)

The politics behind Wednesday's decision make for compelling reading. A year of consumer appeals for more supply culminated last month in the first visit by US President Joe Biden to Saudi Arabia, a country he had previously described as a "pariah." The Biden visit yielded only a vague joint declaration, but consensus was the relationship was on the mend. This, coupled with the US announcement on the eve of the producer meeting of major arms sales to both Riyadh and Abu Dhabi, sparked some speculation that a material output hike might be in the cards. What the US received was a token gesture. Whether connected or not, Washington and Tehran have now restarted talks aimed at breaking the deadlock in their nuclear dispute and lifting sanctions against Iranian crude exports. Repeated failures to break the sanctions justify skepticism about a breakthrough. Tehran's foes in Washington, notably the Israel lobby, remain powerful. Iran does itself no favors, with its protégé Hezbollah currently threatening war with Israel over offshore gas exploration. Even if a deal were reached, it could easily be scuppered by events. But countering these negatives is the incentive of transformational change that an agreement to lift sanctions could unlock — Energy Intelligence's Research & Advisory division projects a 1 million b/d increase in Iranian output within nine months. For Washington, this is not just about oil price relief, welcome tonic though it would be. It is also about undermining Russia's most potent weapon, energy exports, and easing Opec-plus' stranglehold on oil markets.

For all the concerns over demand and recent price declines, Opec-plus' view on short-term fundamentals remains relatively bullish. Global oil demand will grow some 2.7 million b/d from August to December to hit 103.3 million b/d in the year's final month, according to base-case views of an internal report distributed ahead of the meeting and seen by Energy Intelligence. By contrast, non-Opec-plus supply will fall by 100,000 b/d, theoretically allowing for more Opec-plus supply than called for in this week's decision. Indeed, the report sees Opec-plus output up by 500,000 b/d in August. And in all scenarios, OECD stock levels at year-end would be below the 2015-19 average. Under its official quota, Saudi Arabia added 170,000 b/d in July and is due to increase by another 171,000 in August, putting the modest September increase in perspective. Data firm Kpler estimates that Saudi crude exports last month were up by more than 450,000 b/d over the May, June, July three-month average. Wednesday's Opec-plus adjustment only covers September output, and Opec-plus meets again on Sep. 5 to decide its next steps. At that time, 2023 will be on producers' horizons, with demand set for its seasonal slip in the first quarter.

What's New Around the World

GENERAL

CORPORATE — Gulf of Mexico operator Talos Energy is reportedly in "advanced" talks to buy private equity-backed rival Enven Energy in a move that could dramatically increase Talos' E&P asset base as it attempts to diversify its business strategy. Citing unnamed sources, Reuters reported that Talos and Enven are discussing a potential deal for the private player, priced at around $1 billion. Talos would likely primarily use its own stock to fund the purchase, according to Reuters. Energy Intelligence was unable to confirm the rumored talks or any details around the potential deal. If such a deal were to materialize, it would be one of the largest M&A deals in the Gulf so far this decade and the largest corporate combination in the region since Kosmos Energy bought Deep Gulf Energy for more than $1.2 billion in 2018. A merger between Talos and Enven would make strategic sense for both companies. Enven's assets include six operated production platforms and around 44 deepwater leases on their primary terms. Production is projected to average 23,000-26,000 boe/d in 2022, according to a March presentation posted on Enven's website.

COUNTRIES

BRAZIL — Brazil's state oil giant Petrobras is on track for future production growth as it prepares to bring new domestic offshore fields on line. It also reported a new natural gas discovery in Colombian waters. In a quarterly earnings update, Petrobras continued the industry trend of massive profits from higher commodity prices. It reported net income of 54.3 billion reals ($10.5 billion) in the second quarter of 2022, up 27% from a year earlier, and a record 87.8 billion real dividend payout. Petrobras CFO Rodrigo Araujo Alves said the results "show the resilience and solidity of the company." Adding to the positive news, Petrobras said it had confirmed a gas discovery at the deepwater Uchuva-1 exploration well on the Tayrona Block offshore Colombia that could open up a new producing region in the country. Petrobras noted several projects offshore Brazil that are due to start up this year and next. Its strategic plan foresees production growth of around 500,000 boe/d, hitting around 3.2 million boe/d by 2026 after divestments. Petrobras reported second-quarter production of 2.65 million boe/d, down 5.1% annually. It still expects output to average around 2.6 million boe/d this year.

CHINA — The energy sector accounted for about $11.9 billion or almost 43% of China's total economic engagement with other countries under Beijing's Belt and Road Initiative (BRI) in the first half of this year. The initiative was launched by President Xi Jinping in 2013 to promote overseas investment in infrastructure by Chinese companies. The energy sector has been the biggest beneficiary of such investment in most years since its launch. The BRI is tracked by the Green Finance and Development Center at Shanghai's Fudan University, which defines "engagement" as the combined value of direct investment by Chinese companies and construction contracts awarded to them. Engagement in natural gas accounted for 56% of the energy subtotal during the first half of this year, while oil and solar/wind each grabbed an 18% share, according to the center's latest report. "Many of these energy and resources projects include massive construction demand, from energy facilities to logistics infrastructures," risk consultancy Verisk Maplecroft's head of energy and resources Kaho Yu told Energy Intelligence. "They are not merely about securing energy supplies, but also about advancing the infrastructure connectivity in the BRI."

JAPAN — Japan's crude imports slumped by 324,000 b/d from May to 2.28 million b/d in June, their lowest level since last July, according to data from the Ministry of Economy, Trade and Industry (Meti). Imports from the United Arab Emirates, which is dominated by Abu Dhabi grades, led the decline, falling by 263,000 b/d from May to 904,000 b/d in June. Japanese refiners cut purchases of light, sour crudes considerably, with combined imports of Abu Dhabi Murban, Das and Umm Lulu tumbling by 234,000 b/d from May to 752,000 b/d in June. Japanese refining runs slumped significantly in June, with weekly run rates ranging from 68.6% to 70.6%, according to data from Petroleum Association of Japan (PAJ). In May, weekly run rates ranged from 71% to 82.8%.

Japan's Top Crude Suppliers

('000 b/d)	Jun '22	May '22	Chg.	Jun '21	Chg.	Jan-Jun '22
Saudi Arabia	912	873	39	715	196	1,041
UAE	904	1,166	-263	648	256	964
Kuwait	190	179	11	204	-14	206
Qatar	152	179	-27	214	-61	213
Ecuador	46	66	-20	42	3	51
Mexico	35	32	3	0	35	22
US	34	0	34	0	34	6
Australia	5	12	-8	6	-2	8
Thailand	1	1	0	0	1	1
Others	0	46	-46	92	-92	139
Total	**2,279**	**2,603**	**-324**	**1,938**	**340**	**2,682**

Source: Ministry of Economy, Trade and Industry (Meti)

RUSSIA — Russian gas giant Gazprom said its production during the first seven months of this year fell by 12% compared with the same period of last year, reflecting a slump in exports to Europe since Moscow sent its troops into Ukraine in February. Gazprom said it produced 262.4 Bcm of gas in January-July — which was 35.8 Bcm lower than in the same period of last year. According to Energy Intelligence calculations, the company's gas production in July alone stood at 24 Bcm — down from 37.4 Bcm in July of last year and also less than the 27 Bcm produced in June of this year. Gazprom halted exports via the Nord Stream 1 gas pipeline to Germany for 10 days of maintenance work in July of this year and in the same month of last year. The company said its combined gas exports to Europe (including Turkey) and China, totaled 75.3 Bcm in the first seven months of 2022, which was down by 34.7% from the same period of last year. Gazprom's exports to Europe have declined because the company has cut off or reduced supplies to several countries and companies, and because European countries want to reduce their dependence on imports of Russian gas.

SAUDI ARABIA — Saudi Arabia plans to quadruple the volume of oil that it allocates to petrochemicals production to 4 million b/d by 2030 in order to add value to its hydrocarbon sales, according to energy ministry data. The kingdom currently allocates roughly 1 million b/d of oil to petchems, but the plans call for an additional 1.6 million b/d to be allocated to domestic projects and 1.4 million b/d to overseas projects, the data show. Sources familiar with the matter say that China and India are being considered as target markets for Saudi Arabia's overseas petchem expansion. State-controlled Saudi Aramco has emerged as one of the world's largest petchem producers since its acquisition of Saudi Basic Industries Corp. (Sabic) in 2020. Investing in petchem capacity abroad would be one way for Aramco to lock in long-term oil demand, while also adding value to its hydrocarbons. It could also shield Saudi Arabia from a decline in global consumption of transportation fuels in the years ahead as the result of a shift to electric vehicles, biofuels and hydrogen.

UNITED STATES — A slew of Permian Basin operators said they plan on raising capital budgets to counter the effects of rising costs. But they also plan to continue rolling out rich rewards to investors as cash flows balloon. Devon Energy, for instance, raised its expected 2022 capex by 10% at midpoint to $2.2 billion-$2.4 billion. Meanwhile, Coterra Energy increased capex by 10% above previous guidance to $1.6 billion-$1.7 billion, largely to combat oilfield inflation. While those companies also have operations outside the Permian, pure-play Pioneer Natural Resources has also boosted capex 7% to a range of $3.6 billion-$3.8 billion. Another pure-play, Diamondback Energy, expects to spend 2% more this year than previously planned. Inflation, especially in the Permian, continues to bite, with the companies seeing significant cost increases for both fracking and drilling. "We still haven't been able to offset all of the fixed pricing increases we've seen," said Diamondback CEO Travis Stice during his company's Q2 call. Like nearly every other independent, the Permian players reported billions of dollars of free cash flow. However, not much of this is expected to go to new production.

Marketview

Brent Breather

Brent has shed more than $10 per barrel over the past week, losing momentum on confused market signals and responding primarily to red flags about global demand. But this could be the lull before the storm, as the refined product market is still pointing to higher consumption and tight supply this winter.

Strong demand for incremental refinery runs has boosted the light, sweet crude market in Europe and kept the Dated Brent spot price more than $5/bbl above the future price. At more than $7/bbl, a wide spread between Brent and West Texas Intermediate (WTI) has also drawn sizeable volumes of US crude to Europe.

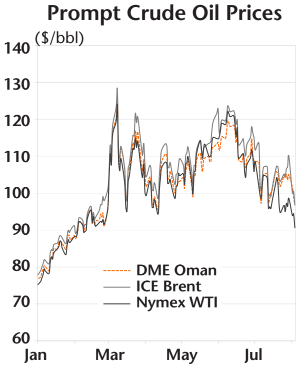
Economic trends in manufacturing are weakening, contributing to the prompt price correction.

US weekly inventories also came in far stronger than expected on Aug. 3, pointing to a slight dip in refinery runs and lower exports to Europe. The Brent time spread between the first and second front months deflated from $6.04/bbl on Jul. 29 to $1.50/bbl on Thursday.

This makes sweet crude cheaper, but the problem is that too much naphtha and gasoline are being produced from running it. Naphtha is the lowest-margin product in Europe, owing to the lack of comingled petrochemical capacity that would allow converting it into more profitable products. Gasoline is also a big threat to refinery margins going forward, because once the summer driving season is over, there will be less demand for it and margins could start to falter.

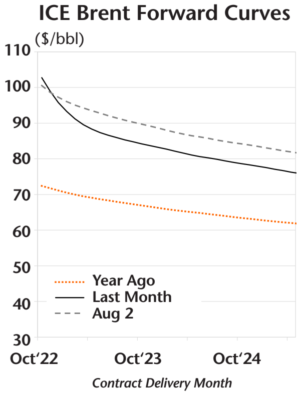
With an EU oil embargo due to come into full effect on Dec. 5, more diesel supply will be needed to make up for the huge Russian shortfall. Europe needs to import more than 20% of its giant diesel demand, and half of that — or about 600,000 b/d — previously came from Russia. Simple refineries with less conversion capacity to maximize diesel yields could face difficulties if they cannot produce enough this winter. But at the current margin levels, they will still run hard to try, with gasoline as an inevitable byproduct.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



This risk was reflected last week in the weaker margins for light products like naphtha and gasoline. The threat of higher gas prices has put more pressure on product cracks, as hydrogen is a workhorse of fuel desulfurization. Meanwhile, electricity prices have also gone through the roof, with some refineries reporting 10-fold increases.

Italian refiner Saras says the market looks "extremely constructive," but the impact of the Russian product ban is still to come. "My view is that this is just a pause in a strong market," said Saras CEO Dario Scaffardi, commenting on the recent dip in margins. Although demand destruction due to recession is a possibility, Saras said they haven't seen any signs of that yet.

More anecdotal evidence points to the surprising resilience of demand. Saudi Aramco this week increased the September selling price of its flagship Arab Light to $9.80/bbl to Dubai quotes, a 50¢ hike from August, which reflects continued confidence in the strength of demand despite still high prices. Meanwhile, Germany is mulling scenarios to make up for the Russian gas supply shortfall, which points to significant gas-to-oil switching this winter. Other countries in Eastern Europe and in Asia are likely to follow.

Russian Oil Output Steady in July

Russia's combined production of crude oil and condensate showed a miniscule increase in July compared to June, according to sources familiar with the country's official data.

However, exports fell for a second straight month, with the July total coming in 2.2%, or 112,000 b/d, lower than in June. Output of crude oil and gas condensate averaged 10.738 million b/d in July, or 11,800 b/d higher than in June. Energy Intelligence estimates Russia's production of crude alone (excluding condensate) at around 9.8 million b/d, or about 1 million b/d lower than its July Opec-plus quota. Refinery runs were 5.6 million b/d for much of July, down 200,000 b/d from pre-war levels.

PIW Market Indicators

($/barrel)	Aug 1-Aug 3	Jul 25-Jul 29	Jul 4-Jul 8
Spot Crude			
Opec Basket	$105.28	$109.09	$110.14
UK Brent (Dtd.)	104.46	109.64	113.78
US WTI (Cushing)	95.41	99.55	103.32
Nigeria Bonny Lt.	114.17	119.39	120.11
Dubai Fateh	99.33	103.95	104.67
US Mars	95.09	97.21	99.50
Russia Urals (NWE)	72.67	77.09	81.30
Crude Futures			
Brent 1st (ICE)	99.12	106.66	105.73
Brent 2nd (ICE)	97.26	101.42	102.00
B-wave (ICE)	100.07	106.54	105.96
WTI 1st (Nymex)	92.99	96.80	101.39
WTI 2nd (Nymex)	91.78	94.80	98.07
Oman 1st (DME)	98.83	104.47	101.14
Oman 2nd (DME)	95.10	100.20	96.99
Murban 1st (ICE)	99.63	105.65	106.55
Murban 2nd (ICE)	96.53	101.80	101.33
Forward Spreads			
Brent (1st-Dtd.)	-$5.34	-$2.98	-$8.05
Brent (2nd-1st)	-1.85	-5.24	-3.73
WTI (2nd-1st)	-1.21	-2.00	-3.32
WTI (3rd-2nd)	-0.88	-1.54	-3.15
Oman (2nd-1st)	-3.73	-4.27	-4.14
Oman (3rd-2nd)	-1.63	-3.56	-3.87
Murban (2nd-1st)	-3.11	-3.85	-5.22
Murban (3rd-2nd)	-1.77	-3.58	-3.47
Grade Differentials			
WTI-Brent (1st)	-$7.33	-$9.87	-$5.71
WTI-LLS	-2.98	-2.78	-1.64
WTI-Mars	+0.32	+2.34	+3.81
Brent(Dtd)-Dubai	+5.12	+5.69	+9.11
Brent(Dtd.)-Urals	+31.79	+32.55	+32.47
Brent(Dtd.)-Bonny Lt.	-9.71	-9.75	-6.33
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$102.22	$104.34	$106.63
Arab Lt.-Europe (Med)	103.97	110.44	109.86
Arab Lt.-Far East (f.o.b.)	110.18	112.54	111.24
Nigeria Bonny Lt.	109.41	114.59	118.73
Arab Light Gross Product Worth			
Rotterdam	$105.06	$110.61	$123.43
US Gulf Coast	111.52	122.62	127.09
Singapore	102.17	104.78	115.73
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$116.21	$123.47	$126.19
UK Brent Margin	+9.27	+12.78	+11.21
US Gulf Coast			
Mars GPW	107.57	117.91	122.03
Mars Margin	+12.38	+20.59	+22.43
Singapore			
Oman GPW	102.29	104.42	115.13
Oman Margin	-0.79	-4.38	+9.82
US Nymex			
WTI 3-2-1 Crack	+$38.47	+$49.83	+$42.90
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$985.17	$1051.20	$1188.22
Gasoil (0.1%)	1053.83	1103.00	1195.25
Fuel Oil (0.5%)*	684.92	720.30	785.00
US Gulf Coast (¢/gal)			
RBOB Gasoline	281.70¢	329.23¢	341.39¢
ULS Diesel	336.40	359.21	365.40
Fuel Oil (0.5%, $/ton)	$773.67	$809.40	$848.00
Singapore ($/bbl)			
Naphtha	$81.20	$82.83	$90.55
Gasoil (0.05%)	125.99	131.12	145.76
Fuel Oil (0.5%, $/ton)	812.00	877.20	1061.00

*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.