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Fate of Russian Output Becomes Guessing Game

With EU embargoes on Russian crude oil and refined products imports to kick in soon, markets are assessing how much the measures will disrupt Russian production. Scenarios range from a smooth transition to alternative markets, which seems unlikely given the scale, to a temporary disruption that later settles, as seen immediately after the Ukraine invasion, or a permanent, long-term disruption. Shipping is a key factor, as a parallel insurance ban and price cap kick in — and here, there is uncertainty over the exact size and availability of an alternative fleet that could bypass the restrictions. What seems clear is that the fate of Russian crude sales will depend largely on the appetite of China and India to buy more. Energy Intelligence's current forecast assumes that the embargoes prompt a gradual decline that ultimately removes more than 1 million barrels per day from the market. Half of that will materialize as lower crude exports, the other half as lower product exports. Russia must find a new home for the remaining 1.1 million b/d of crude still flowing to Europe subject to Dec. 5 ban. The EU has already reduced its Russian crude imports significantly — by 1 million b/d versus pre-Ukraine war levels, according to October data. Russia, meanwhile, has more than compensated so far through higher crude sales to other markets, mostly India, but also China and Turkey, by offering discounts. Some sources suggest that India could take another 600,000 b/d of Russian crude, while others suggest that volume for Asia as a whole.

Finding new markets for Russian products will be even harder than for crude, as both India and China are long on diesel. The EU has so far lowered its Russian product imports by just 300,000 b/d. That means some 880,000 b/d of refined products still sailing to the EU must find new buyers when the product embargo kicks in on Feb. 5. Russia has so far failed to find alternative markets to replace all

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EU Refiners Back Out Urals But Face Issues

European refiners have effectively replaced seaborne Russian Urals with other crude feedstocks ahead of the EU's Dec. 5 ban. But the process has not been painless, and concerns about diesel yields have emerged. European refiners are using a combination of short- and longer-haul crude to back out Urals. Light, sweet crude, not only from the North Sea, but increasingly from Libya and the US, has been a facilitator, particularly for complex refiners with the ability to process a wider spectrum of grades. The availability of these barrels on the spot market — unlike Mideast crude, which is generally sold on a term basis — has been a boon. Sourcing alternative grades from the Atlantic Basin has also helped refiners mitigate the costs associated with steep Brent backwardation and hedging cargoes whose value is bound to time-decay during long-haul voyages. For complex refiners, the transition has been smooth and faster than expected. The ability to juggle crude slates is also enhanced by integration, which constitutes a natural hedge when crude supply is changing. In Northwest Europe, refineries in the Amsterdam-Rotterdam-Antwerp (ARA) hub are integrated with other downstream activities, including petrochemicals, which increases their flexibility.

For the most part, only European refineries owned by Russia, exempt from the EU ban, or outside the EU continue to buy seaborne Urals — a volume that totaled about 750,000 b/d in October. The market for those abandoning Urals, however, has become less efficient in terms of transportation flows. Some Urals will continue to flow to Europe due to exemptions, but, all told, Russia must still find new markets for about 1.1 million b/d, Energy Intelligence reckons. A typical 6-day journey for a Urals cargo travelling from the Baltic to Rotterdam is now taking longer if crude has to originate from Libya (nine days) or from the US Gulf (20 days), not to mention the Middle East or West Africa. This is why Norwegian medium, sour crude is advantaged and has gained the most market share, especially Johan Sverdrup, which now loads more than 550,000 b/d. Turkey, outside the EU, has gorged on discounted Urals, with more than 75% of its crude diet now comprising Russian barrels.

Phasing out Russian supply has lightened the Europe's average crude slate by 2° API, showing the growing deficit of heavier, sour barrels in the region. Urals used to be a baseload crude for many European refiners—but also the promptest available barrel on the market, loading as soon as 10-15 days after being purchased. Severing ties with Russia remains a big challenge for regional refiners, especially if Russian oil is replaced with lighter alternatives yielding less diesel—the product most in demand now. Running light, sweet crude produces more naphtha and gasoline, which was very profitable during the summer driving season. But naphtha margins are now negative, while the spiking diesel margins in Europe — north of $70 per barrel — show that this market wants more of it. Heavier, sour grades with a density of about 28°-30° API are a much better feedstock to produce high-quality middle distillates in the volumes required by the winter market. With Russian supply of that quality exiting, there is a higher appreciation for the heavier barrel. This trend was reflected in the recent recoil of US light, sweet oil shipments to Europe. US crude exports to Northwest Europe dropped from 1.2 million b/d in September to 800,000 b/d in October, according to Kpler data.

Saudi Arabia and the United Arab Emirates are potential providers of adequate crude replacements going forward, but their volumes are sold under long-term contracts to carefully vetted customers. This is why Iraq, which sells on spot terms, has been able to take a bigger market share in Europe despite wobbly logistics and recurrent production problems. Grades that closely match Urals quality and yield enough diesel are in demand, like Norway's Johan Sverdrup and Grane. Most cargoes of Guyana's Liza and Liza Unity Gold now end up in Europe after being outbid from their natural American market. Brazil is also a strong contender for alternative, medium-sour supply to Europe. Urals volumes displaced to Asia have mostly pushed spot purchases out of the region, which is why more Brazilian crude or Basrah Medium is now available to Europe. None of these grades are new to the market, save Guyana's oil. But some come with different trading cycles and loading schedules, and thus new constraints on shipping and refinery planning.

Lula's Return Spells Change for Petrobras

Leftist Luiz Inacio Lula da Silva's narrow victory over right-wing incumbent Jair Bolsonaro in Brazil's contentious presidential election could lead to significant changes in the country's energy policy and at state oil firm Petrobras. However, significant hurdles remain before his ambitious climate-focused energy agenda could be passed into law, particularly since Bolsonaro's Liberal Party (PL) and its right-leaning allies won majorities in both the upper and lower chambers of Brazil's government. The PL won 99 seats in the 513-member lower house, up from 77, and right-leaning parties allied with Bolsonaro now control half the chamber. This result was replicated in the Senate, where Bolsonaro's party and its election allies won 13 of the 27 seats up for grabs, of the total 81. That means Lula will have to find common ground with a potentially adversarial congress to get new policies and regulations passed into law — a stark departure from his first tenure as president from 2003 to 2010. Making deals with parties such as the centrist Social Democracy Party will be essential for Lula.

Lula's victory means that Petrobras is now likely safe from Bolsonaro's threats of privatization, although reform could now come through a broader energy mandate for the oil company. The president-elect has said Petrobras must diversify and return to "being an integrated energy company" that is better positioned for low-carbon energy, with more emphasis on biofuels production. Some investors fear Lula's plans, which could see Petrobras move back into less efficient operations or absorb more fuel subsidy pain, could reduce profit margins at a time when it appears on track for substantial upstream growth. Under Bolsonaro, the firm has been selling off downstream assets as part of a divestment drive aimed at reducing its massive debt and refocusing its strategy on development of its low-cost pre-salt oil and gas assets. There has been talk in the Lula campaign of reversing those divestments, but any change would require significant outlays at a time when Brazil's budget is already stretched and when Lula is keen on social programs to help the poor. Petrobras reported net income of 54.3 billion reals ($10.5 billion) in the second quarter this year, up 27% from a year earlier, along with a record 87.8 billion real dividend payout. Petrobras last week affirmed its 2022 production guidance of 2.6 million barrels of oil equivalent per day, which would represent 4% annual growth. By 2026, the goal is to reach 3.2 million boe/d, as Brazil is expected to provide critical non-Opec supply growth in coming years. The pre-salt, which contributed 1.94 million boe/d last quarter, is set to do the heavy lifting amid natural declines in mature Campos Basin reservoirs and divestments of shallow water assets.

Climate change activists are welcoming Lula's victory due to his promises to overhaul Brazil's environmental policy, particularly curbing deforestation of the country's Amazon rainforest — which rose to an all-time high — in recent years. But any climate initiatives must also take into account Brazil's sputtering economy, as well as elevated energy prices. Lula has acknowledged that oil will be necessary for some time and would oversee continued increases in production. With inflation set to average 5.8% this year and interest rates near 14% in Brazil, oil will remain a key revenue source for Lula's government as he tries to deliver on promises to improve the economy, create jobs and alleviate poverty. Higher fuel prices will remain a challenge. Petrobras found itself a frequent target of Bolsonaro because of high energy prices, having churned through four CEOs since he took office in 2019.

Under Bolsonaro, Petrobras was able to focus almost solely on oil and gas production — its energy transition activities were focused primarily on efficiency and reducing carbon emissions from operations. But the company could be forced to rethink its position within Brazil's renewable power sector under Lula. The president-elect pledged to return Electrobras, Brazil's largest power company with 42,547 megawatts, or 25%, of Brazil's total generation capacity — mostly in the form of sustainable hydropower stations — back to a state-owned entity. But the sheer financial power required for such a move will likely see it delayed — possibly indefinitely if the company is able to operate successfully as a private firm. That could, theoretically, open an opportunity for Petrobras if Lula seeks greater state participation in renewable power, although he has not explicitly called for this.

Industry Ready to Make Case at Climate Talks

The oil and gas industry should have a significant voice at next week's COP27 climate summit in Egypt thanks to the energy crisis and the venue's location in Egypt, a large gas producer. But whether it can seize the moment and reclaim more of the narrative on the low-carbon energy transition remains to be seen. A greater near-term focus on high energy costs and supply security likely means that COP27 will be less challenging for the oil and gas sector than previous ones — but today's crisis also threatens to accelerate the transition away from fossil fuels, as the International Energy Agency (IEA) predicts. COP27 will prove whether or not stakeholders can remain committed to decarbonization in the face of war, shifting alliances, energy security fears and high prices. In terms of the official agenda, Sharm el-Sheikh is not a landmark summit like the 2015 Paris talks or 2021 Glasgow talks. Yet it's still significant. It has been nicknamed the "implementation COP," meaning it represents an opportunity to achieve decarbonization objectives and beef goals set at previous summits to keep global warming below 2°C compared to pre-industrial levels.

The oil industry was shut out of COP26 in Glasgow, but it will participate in COP27 and next year's COP28, which will be held in the United Arab Emirates, an Opec member. "We'll be part of those because both of those are in hydrocarbon-producing countries that want oil and gas to be part of those conferences," Occidental CEO Vicki Hollub told Energy Intelligence recently. She said the industry would seek to address an excess of "misinformation" about the transition among conference delegates.

Egypt is perhaps a perfect arbiter between producers and consumers because it straddles both worlds. On one hand, it's an African nation with a large population of low-income consumers, a net oil importer, and a close ally of Washington. On the other hand, it offers a listening ear to oil- and gas-producing nations and industry given its close ties with the heavyweight Gulf Opec producers, and its status as an LNG exporter. While oil and gas players will have more opportunity to make their arguments, they will need to bring strong decarbonization ambition and solutions to the table. State-owned Saudi Aramco last week added to earlier low-carbon initiatives with an announcement that it would establish a $1.5 billion sustainability fund, which will support Aramco's goal of net-zero Scope 1 and 2 emissions by 2050. Oman also recently announced a net-zero 2050 emissions. But both Gulf producers could face pressure on Scope 3 emissions from the hydrocarbons they export. At the same time, producers are keen to show that it is possible — and required — to continue investing in upstream oil and gas in parallel to keep oil and gas affordable. Developing countries that are oil and gas producers also resent past efforts to curtail financing from multilateral development banks and export credit agencies for fossil fuel projects, arguing this creates unfair barriers to their economic development.

COP27 comes as the IEA argues that the crisis and Ukraine war will accelerate the transition if governments make good on recent policy goals. Based on its "announced pledges" scenario, the IEA sees peak fossil fuel consumption in the mid-2020s or, under its more conservative "stated polices" scenario, in the mid-2030s. Both scenarios now foresee a more abrupt end to the "golden age of gas" compared to just a year ago as the world shifts more rapidly to renewables. However, critics argue the IEA, which drew the oil industry' ire with its Net Zero by 2050 roadmap in 2021, is too optimistic about the transition's pace. Despite recent inflation, the IEA sees renewables increasing their cost advantage in power generation due to soaring gas prices. Due to increased use of electric vehicles, the IEA in stated policies predicts oil demand will peak in 2035 at 103.2 million barrels per day and then decline slightly until about 2050. But peak oil demand is much sooner — in 2024 at 98.1 mllion b/d — under announced pledges. The IEA said the crisis can be a "historic turning point towards a cleaner and more secure energy system," citing government responses like the US Inflation Reduction Act, the Fit for 55 package and REPowerEU in Europe, Japan's Green Transformation program, Korea's aim to increase the share of nuclear and renewables, and the ambitious clean energy targets set by China and India. For gas, the IEA's long-term outlook has deteriorated significantly from a year ago. Stated policies has gas demand reaching around 4,400 billion cubic meters in 2030 and staying at that level to 2050. That puts 2050 demand some 750 Bcm lower than projected in last year's forecast. Under announced pledges, gas demand drops 31% from last year's forecast to 2,660 Bcm in 2050 and 36% below actual demand in 2021.

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of these product volumes, with an earlier US import ban affecting sales, too. Total Russian product exports are on average down 500,000 b/d from pre-war levels.

From a Russian perspective, producers will pull out all stops to maximize output since shut-ins will damage wells. Lower exports of crude or lower refinery runs means that producers would have to shut in production. This is harder to revive in Russian conditions, although producers now have more experience with this after complying with Opec-plus output restrictions when the Covid-19 pandemic hit in 2020. Energy Intelligence analysis indicates that Russia's pandemic rebalancing, or shutting in nearly 2 million b/d of crude production, cost some 300,000 b/d in lost output capacity. The country could produce 10.5 million b/d of crude oil before the pandemic, and just 10.2 million b/d after. Producers would want to avoid a repeat of such a scenario.

Countering Russia's desire to keep oil and income flowing is a logistical shipping hurdle — the result of related European restrictions on shipping services. A G7 scheme will allow vessels to carry Russian oil if is traded within a certain price cap. Moscow has vowed not to comply or sell oil directly to anyone complying, but it needs the ships. Shipbroker Braemer has said there seems a "shortfall of 70 Aframaxes and 35 Suezmaxes" to move the Russian volumes entirely. But uncertainties abound, from the size of the Russian fleet to the willingness of Chinese and Indian operators to ply that trade. Since the Ukraine invasion, Indian companies have been buying Russian crude on a delivered basis, putting the onus on arranging freight with the seller. Russian companies could also exercise some discretion, for example over a sale that is priced within the cap but does not refer to the cap. Another complication is that oil is not typically traded at a fixed price, but at a differential to a benchmark — making the actual price hard to determine in advance.

Low Carbon Plans Stay in Focus Despite Crisis

This year's global energy crisis has sharpened the challenge for oil and gas companies of investing to meet current and future demand while at the same time reducing emissions and developing green forms of energy. Decarbonizing their operations is a key response to the dilemma. Mideast Gulf national oil companies (NOCs) like Abu Dhabi National Oil Co. (Adnoc) and QatarEnergy have increasingly embraced the effort, while European majors remain resolutely focused on it. But while both recognize the importance of curbing emissions, international oil companies (IOCs) face a different set of pressures and priorities than NOCs. With their naturally low cost, low emissions production, the United Arab Emirates, Saudi Arabia and Qatar can reasonably claim to be best placed to supply the additional oil and gas the world needs. "At Adnoc, we have connected our operations to zero carbon nuclear and solar power," CEO Sultan al-Jaber told delegates at this week's Adipec conference in Abu Dhabi, adding that the company also plans to electrify its offshore operations to cut their carbon footprint in half, and get tougher on methane. All of which helps to justify Adnoc's unofficial plan to raise production capacity to 5 million barrels per day by 2027. Similarly in Qatar, the giant LNG producer, which is forging ahead with its mega-expansion, plans to roll out an 11 million tons/year carbon capture and storage (CCS) project by 2035 to radically reduce the CO2 emissions from its LNG and upstream facilities.

Western IOCs, and particularly European majors, face bigger stakeholder pressures to invest in producing assets that have a low carbon footprint. Shell and TotalEnergies, which both have relatively ambitious emissions reduction plans, were recently the two big winners in Phase 2 of Qatar's 48 million tons per year LNG expansion. Total's presence in Qatar and the UAE — and the recently improved prospect of a major oil, gas capture and solar project proceeding in Iraq — complement its commitment to cut emissions from its operations by 40% by 2030 while increasing its energy supplies by 4% over the same period. "You're not always as lucky as to be in Abu Dhabi [where] you have low cost and low emissions. We are in 130 countries. It's a challenge," Total's senior vice president for the Middle East, Laurent Vivier, told the conference. Indeed, where IOCs work can make a big difference to the carbon intensity of their oil and gas output. Total has set the bar at 20 kilograms of CO2 per bbl of oil equivalent, and Vivier notes that some upstream projects the company sanctioned a few years ago wouldn't get the green light today. Shell, for its part, is pursuing a wide range of emissions reduction strategies, from CCS to hydrogen and biofuels, in line with its Scope 3 commitment to lowering the carbon footprint of its customers. "Our upstream business produces about 0.1 gigatons of Shell's 1.7 gigatons of emissions in absolute terms, which tells you why it's so important that we focus beyond the boundaries of the upstream," said upstream director Zoe Vujnovich.

The energy crisis has emboldened NOCs and Opec countries in the Mideast Gulf that feel vindicated after having warned for years about underinvestment in fossil fuels. The global supply shortages have given them a newfound confidence in extolling the continued importance of oil and gas, which is reinforced by their decarbonization plans. Western IOCs, meanwhile, are under pressure to help alleviate today's crisis with their windfall profits while carrying on with the energy transition apace. Shell counts the Norwegian sovereign wealth fund among its major shareholders, and the fund says it will press companies like Shell to reach their net-zero goal by 2050 by setting "credible" interim targets. Pressures to accelerate the transition and invest more aggressively in renewable and clean energy technologies could grow in response to today's crisis. But as Energean CEO Mathios Rigas noted at Adipec, the start-up last week of its Karish gas field in Israel had helped the country to phase out coal-fired power generation, and sharply reduced the carbon intensity of the London-listed company's output, which was 100% oil four years ago. Going too fast threatens to prevent such projects. "In the madness of going all green from all oil, we've seen a lot of financial institutions pulling out of the industry," he said.

Cash Returns Open Majors to Questions

The five leading Western oil majors are on course to pay out more than $100 billion in shareholder returns for this year — more than their combined annual capital expenditure guidance for 2022 and their combined earnings in 2021. The companies — BP, Chevron, Exxon Mobil, Shell and TotalEnergies — have been making record distributions to shareholders, through dividends and share repurchases, in recent months and announced a fresh round of buybacks with their third-quarter results after generating more bumper free cash flow amid high energy prices. The majors together earned free cash flow of $54 billion last quarter and $152 billion in the first nine months of 2022. The five firms are set to distribute some $104.4 billion in shareholder returns for this year, based on company guidance and analyst estimates, compared with a maximum of $102 billion in combined capex in 2022 and around $89 billion in combined adjusted earnings last year. And it's not just the Big Five that are ramping up returns to shareholders, with Norway's Equinor and regional integrated players such as Spain's Repsol, Italy's Eni and Austria's OMV all either continuing with share repurchase programs or paying out extraordinary dividends, or both.

All the signs point to the shareholder return boom continuing into next year, with dividends taking greater priority. Still, buybacks, once deployed only occasionally as a tool to reduce the number of outstanding shares and thereby increase earnings — and the dividend — per share, are now becoming the new normal. For Chevron, growing its dividend is the "first financial priority," according to CFO Pierre Breber. Buybacks, meanwhile, are only in fourth place after investment in its traditional and new energy businesses and maintaining a strong balance sheet. Fellow US major Exxon Mobil, which raised its dividend for the fourth quarter by 3.4%, is continuing with its $30 billion buyback program through 2023 and is set to end the year with a cash position of $30 billion. "We're trying to get that balance right," CFO Kathy Mikells said, mindful of the need to keep investing to prepare Exxon for the next downturn. Shell CFO Sinead Gorman said the UK supermajor still views buybacks "very favorably" but will be as disciplined with shareholder returns as it is with capex. For compatriot BP, 4% annual dividend growth in a $60 per barrel oil price environment remains top priority, while buying back $4 billion in shares per year at the same oil price is only priority No. 5, according to CFO Murray Auchincloss.

In the current supply-driven energy crisis, giving shareholders more money than is being invested in the business inevitably raises questions, including from angry politicians and society at large. But majors are unlikely to unleash waves of capex across the board next year — despite near-term energy security concerns and calls to accelerate the low-carbon transition — as firms take the opportunity to strengthen balance sheets in turbulent times. The sector has also found itself in good standing with investors, which for years were put off by Big Oil's poor return on capital employed. Breaking capital discipline — even for low-carbon investments for the future — risks rocking that boat. Chevron, however, is likely to increase spending by about 20% next year, due to cost inflation and increased activity in the Permian Basin and elsewhere, Breber said. Total, which in September said it was within reach of zero net debt, was generating so much cash flow in the third quarter that it was able to reduce gearing to below its 5% year-end target well ahead of schedule. BP, which is using 60% of surplus cash flow for buybacks and the remaining 40% to strengthen its balance sheet, has cut its net debt for 10 quarters in a row.

Energy Inflation Looms Large in US Election

US President Joe Biden this week delivered scathing criticism of oil companies for "outrageous" third-quarter profits in a pre-election counterstrike to Republican messaging blaming his energy policies for high fuel prices. US retail gasoline prices, averaging $3.76 per gallon as of Wednesday, have dropped from their mid-June peak of $5/gallon but are 60% higher than when Biden took office in January 2021. Against a backdrop of broad energy inflation, the runup to the Nov. 8 US midterm elections has been punctuated by some significant energy and climate debate, particularly in oil- and gas-producing states. Energy politics has emerged in gas-rich Pennsylvania's high-profile Senate race, and even historically oil-friendly Oklahoma's gubernatorial race, along with key races in energy powerhouses Texas, Colorado and New Mexico. Biden's calls Monday for the US Congress to levy a "windfall" tax on blockbuster oil company profits aside, any substantial new energy or climate legislation does not seem in the cards even if Republicans win one or both chambers of Congress. An exception may be permitting reform if lawmakers find a path forward on current gridlock that spans both sides of the aisle.

Republicans are heavily favored, according to national polls, to capture control of the US House of Representatives and remain locked with Democrats in a dead heat for the Senate. Ripping up the Inflation Reduction Act, which contains $369 billion in clean energy spending, is high on a GOP-controlled House to-do list should they win control of that chamber, even if Biden's veto power means a straight repeal is unlikely. But if Republicans win both chambers, much could be done to slow implementation given that Congress wields the power of the purse. Clean energy tax incentives are relatively safe, anyway, with oil interests most focused on eliminating a 15% minimum tax on corporate book income, the methane tax on oil and gas operations, and myriad tightening of policies for drilling on federal lands, such as higher bond requirements, according to one Washington-based industry official.

The two US states that have drawn the closest watch from Washington oil lobbyists: Pennsylvania and Ohio, which produced a combined 10 billion cubic feet per day of natural gas last year from shale plays. Two high-profile US Senate races playing out in both states have drawn a lot of attention for their implications for Senate control. In Ohio, longtime US Rep. Tim Ryan (D), who has embraced gas as a "bridge" fuel while backing spending on carbon capture and solar, is squaring off against Republican JD Vance, who has underscored the need to adopt more of a pro-oil and gas federal policy to stabilize prices. In Pennsylvania, Republican candidate Mehmet Oz is neck and neck with Democrat John Fetterman, and hydraulic fracturing has been a flash point in the campaign and in a debate last week. Oz has adopted a pro-gas platform that closely mirrors the "energy dominance" strategy embraced by former US President Donald Trump and vowed to keep cash flowing to oil and gas companies. Fetterman, meanwhile, is a strong supporter of renewables and has been frequently called out for pivoting his position on fracking to cater to voters. Oz has faced similar criticism, albeit less intense.

Also worth keeping an eye on are possible major political shake-ups in key energy states Oklahoma, New Mexico, Colorado, and in states where a gubernatorial or legislative flip could mean a reversal of climate policy, such as in Oregon and Arizona. In Oklahoma, for example, the sixth-biggest oil producer, incumbent Republican Governor Kevin Stitt is slightly trailing Democratic challenger Joy Hofmeister. In ruby red Oklahoma, a Democratic victory might not translate into radical policy swings on energy — Hofmeister is a former Republican who has a reputation for supporting oil and gas, but it will raise eyebrows as a possible bellwether of shifting dynamics in the state.

What's New Around the World

GENERAL

EARNINGS — Saudi Aramco reported that its third-quarter net income rose 39% to $42.4 billion versus the same period of last year, but that fell short of the $48.4 billion it earned in the second quarter of this year. The Saudi oil giant's average realized crude oil price dipped to $101.70/bbl in the third quarter of this year from $113.20 in the second, while its downstream business posted a loss in the third quarter as it lowered the value of its inventories in line with a softening of prices for refined products. In a brief commentary accompanying Aramco's earnings report, CEO Amin Nasser reiterated his confidence about oil's role in the global energy mix. "While global crude oil prices during this period were affected by continued economic uncertainty, our long-term view is that oil demand will continue to grow for the rest of the decade given the world's need for more affordable and reliable energy," he said. Capital spending of just over $9 billion for the third quarter brought the total for the first nine months of this year to just shy of $26 billion, which appears to put Aramco on a trajectory that would fall short of full-year guidance of $40 billion-$50 billion.

M&A — US producer Marathon Oil has agreed to shell out $3 billion in cash for privately held Eagle Ford operator Ensign Natural Resources. The deal will more than double Marathon's footprint in the Eagle Ford Shale from 130,000 net acres to nearly 300,000, and add 67,000 boe/d in production. Marathon said that it produced 90,000 boe/d in the Eagle Ford in the third quarter, two-thirds of which was crude oil. Ensign's assets lie across the condensate, wet gas and dry gas windows of the Eagle Ford and are near Marathon's existing position. Operators have faced pressure from investors to stem growth and maintain capital discipline even as commodity prices have ascended to multiyear highs. Deals like Marathon's acquisition of Ensign allow them to grow production without adding rigs or frack crews, which have become more costly as inflation soars. The transaction, which is expected to close by the end of the year, would also add to Marathon's drilling inventory. By Marathon's estimates, Ensign's acreage holds around 600 undrilled locations, representing about 15 years of drilling inventory.

COUNTRIES

INDIA — With Indian refiners continuing to lift cheap discounted barrels, Russia is likely to have surged ahead of Saudi Arabia and Iraq to become India's top supplier in October, according to shipment tracking data. While Vortexa estimates India's oil imports from Russia averaged 936,000 b/d in October compared with 876,000 b/d in September, its rival tracking agency Kpler data shows Russia's imports last month were 925,000 b/d versus 835,000 b/d in September. Vortexa said imports from Iraq stood at 889,000 b/d last month, compared with 807,000 b/d in September, and from Saudi Arabia at 747,000 b/d in October versus 937,000 b/d in September. The imports from Saudi are likely to have fallen due to due to high official sales prices for Mideast barrels into Asia, Viktor Katona, head of crude analysis at Kpler, said. It could be a challenge to maintain imports from Russia at over 900,000 b/d as a G7 price cap enters the picture on Dec. 5 along with an EU ban on Russian seaborne crude imports. India's Petroleum Minister Hardeep Singh Puri told Energy Intelligence this week that his country is happy to buy additional volumes from Russia if the price is right.

JAPAN — Japan's imports of Emirati crude jumped by 190,000 b/d from August to 1.24 million b/d in September, the highest level in Energy Intelligence records dating back to 2008. Compared to September 2021, inflows spiked by 345,000 b/d, according to data from the Ministry of Economy, Trade and Industry (Meti). The increase from August was mainly driven by a 148,000 b/d jump in Abu Dhabi medium, sour Upper Zakum crude and a 94,000 b/d leap in Abu Dhabi light, sour Murban crude. Japanese imports of Saudi crude plunged by 270,000 b/d from August to 921,000 b/d in September, with medium, sour Arab Light inflows tumbling by 172,000 b/d and light, sour Arab Extra Light imports dropping by 60,000 b/d. Japanese refiners likely pulled back from Arab Extra Light term volumes partly due to the grade's official formula price shooting up to a record high a few months ago. Total Japanese crude imports tumbled by 225,000 b/d from August to 2.76 million b/d in September.

Japan's Top Crude Suppliers

('000 b/d)	Sep '22	Aug '22	Chg.	Sep '21	Chg.	Jan-Sep '22
UAE	1,240	1,049	190	895	345	1,019
Saudi Arabia	921	1,191	-270	855	66	1,031
Qatar	251	221	30	208	43	221
Kuwait	127	310	-183	199	-72	210
Ecuador	55	73	-18	46	9	53
Bahrain	50	5	45	83	-33	32
Oman	33	42	-9	17	16	32
Vietnam	20	8	12	19	0	7
Angola	16	0	16	0	16	2
Neutral Zone	15	0	15	30	-15	8
Others	30	83	-54	116	-86	100
Total	**2,757**	**2,981**	**-225**	**2,467**	**289**	**2,716**

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

QATAR — Qatar has surprised industry watchers by selecting ConocoPhillips over dominant LNG investor Exxon Mobil to take the final equity position — a 6.25% stake — in the second phase of its giant North Field LNG expansion. Several weeks ago, QatarEnergy had stated that "three new partners will be entering" the 16 million ton/yr North Field South (NFS) project in addition to TotalEnergies. The assumption was that this would be Exxon Mobil, Shell and either Eni or ConocoPhillips, the other two short-listed firms. Exxon had won a stake in the North Field East (NFE) project, the 32 million ton/yr Phase 1 of the expansion, in June. Exxon is a heavyweight in Qatar. The US major pioneered the 7.8 million ton/yr megatrains and QatarMax tankers that helped revolutionize Qatar's LNG industry. In addition to being one of the three biggest international investors in the Phase 1 NFE, Exxon is also partnered with QatarEnergy in the 18.1 million ton/yr Golden Pass LNG project in Texas. The NFS news comes hard on the heels of a decision to separately market Golden Pass LNG volumes, doing away with a specially created joint marketing vehicle, Ocean LNG, that QatarEnergy and Exxon had created.

UAE — Abu Dhabi National Oil Co. (Adnoc) and India's state-owned gas pipeline utility Gail India have signed an initial pact to explore short and long term LNG sale agreements. The companies also agreed to explore optimization of LNG trading activities and joint equity investments in renewables and the monitoring of greenhouse gases for LNG cargoes to support low carbon LNG supplies. India, the world's fourth-largest LNG importer, has been struggling to get term suppliers to commit to long-term deals. India currently does not have a term deal with the UAE but the Middle Eastern nation accounted for 14% of India's imports for the January-August period of the current year, according to Indian federal commerce ministry data. Gail, which has an LNG portfolio of 14 million tons a year from the US, Qatar, Australia, and Russia, is struggling as its term deal with Gazprom's German subsidiary has been disrupted after it was taken over by Germany. It has been scouting for an immediate term deal for at least 1 million tons/yr.

UNITED STATES — Midstream and logistics giant Enterprise Product Partners says that despite perceived slowdowns in oil production and concerns about investment, US supply is set to significantly ramp up through next year. Anthony Chovanec, senior vice president for fundamentals and commodity risk assessment at Enterprise, said activity in the Permian Basin is speeding up and getting more sophisticated, despite supply chain, labor and logistics challenges. "We've got 60-rig increase in the Permian Basin year-to-date," said Chovanec. "And if you think about what those rigs look like, compared to say 2019 or 2020, there is some efficiency [that's] 30% greater — this is not a small number." Chovanec said that government data puts year-to-date US oil production growth at some 400,000 barrels per day. For full-year 2022, Enterprise is estimating that incremental domestic crude output will grow by 500,000-600,000 b/d, with another 600,000-800,000 b/d coming next year, he added —almost entirely driven by activity in the Permian. "Any other increases when we look at oil are relatively small," said Chovanec. "So think Permian."

Marketview

Trapped

Brent is trapped in the mid-$90 per barrel range and seems unable to break through higher, even if some analysts think Opec-plus producers want to see a $100/bbl floor on their oil.

While a tight middle distillate supply underpins the current price strength, the timing of an imminent recession has kept market bulls on a tight leash.

Investors are busy reading central banks' body language and trying to figure out what sorts of credit risk and growth damage may stem out of monetary tightening. The US Federal Reserve dropped the hammer on Nov. 3, raising its short-term borrowing rate by a historic 0.75 percentage points to a 3.75%-4% target range. A similar decision by the Bank of England brought rates to 3%.

These aggressive hikes — the fastest since the 1980s — are meant to root out inflation: 8.2% in the US in October, 10.1% in the UK, 10.7% in the Euro area. But they pose a risk to investment in new oil and gas supplies when more is needed to fill the vacuum left by a decade of underinvestment and now the effects of the Ukraine war.

This does not bode well for oil, as given the current shortages, demand erosion will be the only way out.

On one hand, governments need to raise interest rates to fight inflation because there is not enough real goods to go around. On the other, if more investment is required to solve that problem, raising borrowing costs will be an issue.

Two months ago, Saudi Oil Minister Prince Abdulaziz bin Salman said that historical data pointed to weak causality between recessions and oil demand contractions. The last time prices strayed too far north of $100/bbl, however, Opec-plus made a token gesture and raised output by 100,000 b/d. This shows that if the recent decision for a 2 million b/d cut was a cold shower for the oil market, the group is still concerned that given adverse economic conditions, too high a price may still erode demand for its crude.

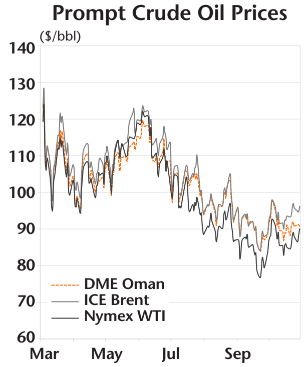
Meanwhile, an oil price closer to $70/bbl would be preferred by both OECD and non-OECD consumers, if only to fend off energy inflation and ease the pain. Central banks cannot print oil.

And then, there is uncertainty about China, one of the biggest engines of global oil demand.

China is poised to register its first annual drop in crude demand in 20 years, in large part the consequence of Beijing's zero-Covid policy. China deceleration looms large in the global growth outlook. The country's marginal withdrawal and rising resource nationalism may signal an inflexion point in its relationship with the West, and one that may partly affect the trajectory of its future trade relationships and energy consumption.

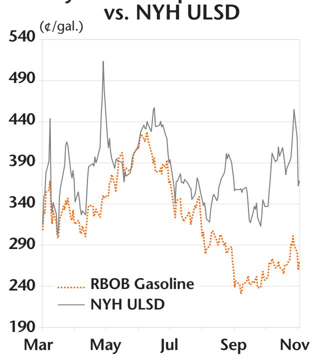
China's Covid-19 vaccination program, which has eschewed Western vaccines, has failed to properly immunize its aging population, resulting in continued lockdowns. Chinese President Xi Jinping's re-election for a third mandate removes optimism for change, meaning oil demand could face continued threats from lockdowns in the world's largest oil importer, in addition to recessionary pressures.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex Prompt Gasoline vs. NYH ULSD



Russian Gas Output Falls

Russia's natural gas production continues to fall as a result of the steep drop in its gas exports following its invasion of Ukraine earlier this year.

The country's October gas output of 53 Bcm was down 19% versus the same month of last year, according to sources with access to the data. Production for the first 10 months of 2022 fell 11.2% to 556.3 Bcm compared with the same period of 2021, reflecting a sharp drop in pipeline gas exports. Moscow has recently forecast that gas production will decline by around 10% this year from last year's record of 762.3 Bcm, but experts say it will likely fall by 10% to 15%.

PIW Market Indicators

($/barrel)	Oct 31- Nov 2	Oct 24- Oct 28	Oct 3- Oct 7
Spot Crude			
Opec Basket	$94.63	$93.10	$94.02
UK Brent (Dtd.)	94.98	93.36	94.95
US WTI (Cushing)	88.27	87.86	88.22
Nigeria Bonny Lt.	97.71	95.45	98.07
Dubai Fateh	90.98	91.20	91.17
US Mars	83.30	83.10	87.01
Russia Urals (NWE)	71.71	69.40	70.97
Crude Futures			
Brent 1st (ICE)	95.21	95.04	93.27
Brent 2nd (ICE)	93.34	93.11	91.39
B-wave (ICE)	94.97	94.57	92.48
WTI 1st (Nymex)	88.30	86.96	87.80
WTI 2nd (Nymex)	87.15	85.80	86.80
Oman 1st (DME)	91.01	90.60	92.58
Oman 2nd (DME)	89.79	89.40	90.17
Murban 1st (ICE)	94.06	94.16	94.89
Murban 2nd (ICE)	93.38	92.65	92.27
Forward Spreads			
Brent (1st-Dtd.)	+$0.23	+$1.68	-$1.68
Brent (2nd-1st)	-1.87	-1.93	-1.89
WTI (2nd-1st)	-1.15	-1.15	-1.00
WTI (3rd-2nd)	-1.33	-1.31	-1.27
Oman (2nd-1st)	-1.22	-1.19	-2.42
Oman (3rd-2nd)	-2.23	-2.48	-2.53
Murban (2nd-1st)	-0.68	-1.51	-2.61
Murban (3rd-2nd)	-2.93	-2.32	-2.40
Grade Differentials			
WTI-Brent (1st)	-$7.69	-$8.08	-$6.48
WTI-LLS	-2.70	-2.30	-2.64
WTI-Mars	+4.97	+4.76	+1.21
Brent(Dtd)-Dubai	+4.00	+2.16	+3.78
Brent(Dtd.)-Urals	+23.27	+23.96	+23.98
Brent(Dtd.)-Bonny Lt.	-2.73	-2.09	-3.12
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$90.93	$90.73	$94.64
Arab Lt.-Europe (Med)	97.67	97.27	95.18
Arab Lt.-Far East (f.o.b.)	97.53	97.56	97.84
Nigeria Bonny Lt.	96.89	95.27	96.86
Arab Light Gross Product Worth			
Rotterdam	$102.45	$105.19	$111.10
US Gulf Coast	108.07	115.62	109.63
Singapore	93.92	93.36	92.65
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$114.76	$119.07	$113.99
UK Brent Margin	+16.77	+24.38	+17.80
US Gulf Coast			
Mars GPW	100.62	106.90	102.68
Mars Margin	+17.22	+23.70	+15.56
Singapore			
Oman GPW	93.62	92.86	91.44
Oman Margin	-0.02	-0.62	-2.42
US Nymex			
WTI 3-2-1 Crack	+$40.94	+$52.53	+$38.30
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$923.10	$925.68	$922.82
Gasoil (0.1%)	1082.08	1124.25	1091.55
Fuel Oil (0.5%)*	596.67	602.70	610.05
US Gulf Coast (¢/gal)			
RBOB Gasoline	260.55¢	278.84¢	271.19¢
ULS Diesel	390.26	422.49	373.60
Fuel Oil (0.5%, $/ton)	$660.00	$664.00	$653.60
Singapore ($/bbl)			
Naphtha	$75.23	$74.69	$74.87
Gasoil (0.05%)	133.22	133.79	130.56
Fuel Oil (0.5%, $/ton)	701.67	709.00	726.40

*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.