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EU Leaves Hard Work on Russia to Last Minute

Europe's efforts to reduce imports of Russian oil have stalled. Tanker data for August show the EU continues to buy Russian oil in almost a business-as-usual way despite looming embargoes on imports — Dec. 5 for crude and Feb. 5 for products. Shipping data show the EU loaded slightly more crude from Russia in August than in July. The data suggest that EU nations bought far less refined products in August, but many vessels had "unknown" destinations and were pointed toward Europe, which could bring August imports close to July levels. Shortly after Russia's Feb. 24 invasion of Ukraine, European oil majors and traders scaled back their spot buying of Russian crude oil and promised not to renew term contracts. But after a quick reduction of some 600,000 barrels per day of seaborne crude imports and 100,000 b/d of seaborne products imports, the EU has not made much further progress, with seaborne crude and product imports running around 1 million b/d each in recent months. The Druzhba pipeline that delivers Russian crude to Germany, Poland, Slovakia, the Czech Republic and Hungary, has also kept flowing around its pre-war rate of 800,000 b/d.

The EU embargoes aim to reduce Russia's income from oil exports to fund the war. So far, however, higher oil prices — and still robust exports — have kept Moscow flush. The average Brent price of $104 per barrel year-to-date is 40% higher than the same period in 2021, with geopolitical concerns contributing significantly to surging prices. The EU has left much work to be done in a short period of time. Traders are watching Russian flows to Europe closely since the bans would not only re-route traditional oil trading patterns but also potentially disrupt Russian supplies if Moscow cannot find alternative buyers. Russia has already diverted some

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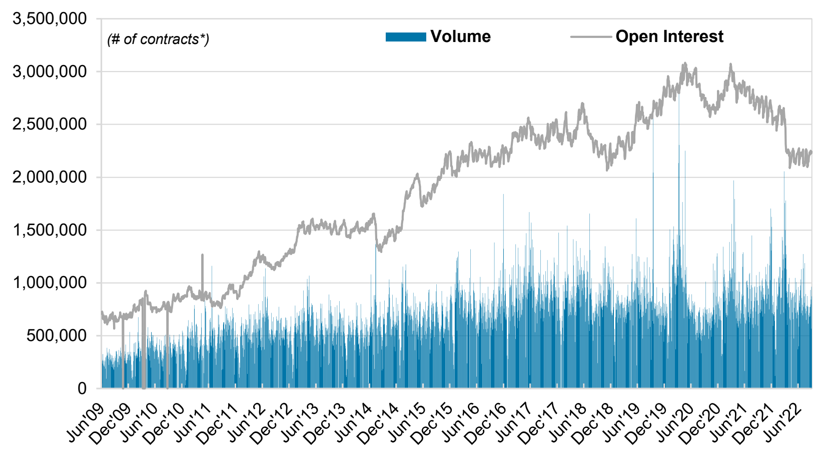
Price Swings Take Speculators for Wild Ride

Speculators in crude oil and product futures contracts are trying to ride the waves of rapidly changing market sentiment — with mixed results. For the past two months, banks and funds were bullish on refined products and bearish on crude oil. After some wild price spikes, sentiment is now pointing south for all. Bullish speculators claim this market is broken, since prices are deflating while the market is still very tight. Bears think the market had this correction coming, since high energy prices will hurt demand and the global economy. Opposing views are fueling price jolts, which are shaking out participants and leading to even bigger price swings. Since early July, banks and investment funds have increased bets that product prices would rise. They saw a bottom of $3.50 per gallon for diesel in the US, which rose to $4 but lost 50¢ the past week. Speculators saw the bottom for US gasoline at around $3.25, but instead of rising again, the price never took off and is now $2.40, causing a hasty retreat. Over the past two months, speculators have been losing faith that crude prices could rally and lowered their bets on rising prices to nine-year lows — only to reverse course after Saudi Energy Minister Prince Abdulaziz bin Salman suggested last week that Opec-plus could cut output to stabilize the market. His comments resulted in a $12/bbl price swing from speculators covering their bets on lower prices by buying futures contracts.

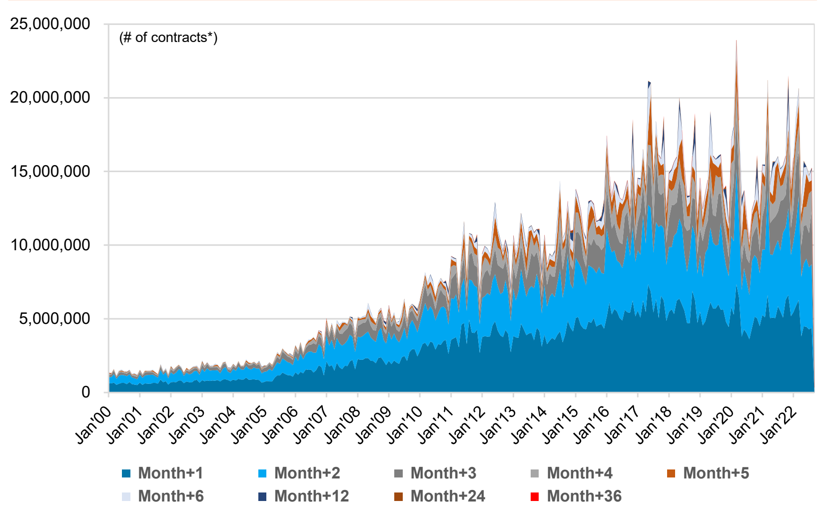
Brent traded volumes remained relatively strong in August, at an average 738,000 contracts,

but open interest has been declining since March 2021. This suggests that fewer investors want to hold an overnight position in a such a fickle market. Volatility has shooed away some market participants that used to keep positions open for more than a single day, including physical hedgers. In the US, the CBOE oil volatility index hovers around 50%, well above its 10-year average of 37.6%. In the Brent options market, implied volatility has stayed at or above 40%. The sheer magnitude of daily price swings has partly deterred hedging, especially when it dovetails with prices in excess of $90/bbl. In addition, exchange data show that liquidity is holding better at the front of the curve than in longer-dated contracts. This is because most speculative investors concentrate their bets in the front months, and more of them settle their positions at market close, meaning that liquidity tends to subside overnight, keeping volatility high. These intraday ebbs and flows dragged Brent below its 200-day moving average, a key support level around which the benchmark has since been hovering. But oil has also followed the rebound in the so-called real asset class — that is, assets producing tangible goods like commodities. Given that inflation may last longer than expected, commodities and oil especially remain the best-performing hedge against higher prices. And with dramatic refined product shortages looming this winter, some investors with deep pockets may still seek higher exposure to energy if they can buy market dips.

Brent Volume vs Open Interest | 2000-2022 ytd



Brent Volume Distribution by Contract Maturity | 2000-2022 ytd



*Contract size is 1,000 barrels. Source: ICE

Prices are sagging, but the oil market is tight, which Brent's forward curve signals. The Brent prompt premium to deliveries in six months has narrowed to $5.90 in August from $13.30 in July, but it remains still historically strong. A weaker signal comes from the physical market. The spot Dated Brent price has sunk below the front-month future price for the first time since April, after blowing out to an $11/bbl in July. With seasonal turnarounds looming and gasoline season drawing to an end, refiners are buying less crude, and differentials are falling. But the lull seems only temporary. Many speculators think that the risk of oil demand destruction will be largely offset by fuel switching this winter. Oil is far less expensive than either natural gas or coal, which makes burning diesel or fuel oil an economic alternative for power generation. Energy Intelligence estimates that gas-to-oil substitution could reach 1 million b/d this winter, including 300,000 b/d from Europe alone. Oil is also a much easier and cheaper commodity to ship than the LNG that will replace some of the missing Russian gas volumes. Balances signal that refiners will have to run flat out to meet winter demand. Even if an economic recession in Europe deepens and spreads, its effects would be delayed — and eventually compounded — by the demand-boosting subsidies that countries are doling out to shield their taxpayers from the inflation shock. Combined with chronic energy shortages, these policies could backfire and push oil north of $100/bbl again.

Cepsa Embarks on Unique Transition Path

Spain's Cepsa is trying to leverage its industrial footprint and an advantaged location on the Iberian Peninsula as it embarks on one of the more unique transition stories in the oil and gas sector. Led by newly minted CEO Maarten Wetselaar, a former head of the Integrated Gas, Renewables and Energy Solutions division at Shell, Cepsa is trying to build a model based around green molecules — from biofuels to hydrogen. It is derived from the fact that "half of the energy system cannot be electrified," Wetselaar told Energy Intelligence in an exclusive interview. Like the US majors, Cepsa has eschewed the ambitious renewable power drive favored by many European companies due to worries about low margins and lack of competitive advantage. But its upstream approach of running the business to generate cash for transition investments, rather than adding more reserves and production, is more aligned with the philosophy of its European counterparts.

Cepsa, which is owned by Abu Dhabi sovereign wealth fund Mubadala and the Carlyle Group, offers an interesting take on how a downstream-focused oil and gas company can approach the energy transition. Its new model will be structured around two business units, Sustainable Mobility & New Commerce, and Sustainable Energy. The first will focus on electric vehicle charging, powered by a partnership with Endesa, a subsidiary of Italian multinational power giant Enel, and developing a broader business line at its large retail network. Sustainable Energy will focus on selling green hydrogen and biofuels to hard-to-decarbonize industries like aviation, shipping and heavy industry, where electrification is difficult. The company plans to develop 7 gigawatts of solar and wind power — but all of it will be used within its own portfolio. Cepsa will look to use its more than 600 retail locations to build out non-energy offerings in things like food and pharmacies through partnerships with providers and last-mile delivery services. The company will not add to its upstream portfolio, and while it is not actively considering a stake sale or spinoff — as has been rumored at Spanish competitor Repsol — Wetselaar said Cepsa will keep its options open in the future.

But the transformation cannot happen without significant investment. Cepsa will spend between €7 billion ($7 billion) and €8 billion through the end of the decade, with 60% going to transition businesses. For the strategy to be successful, those transition businesses need to perform. The company is targeting more than 50% of its revenues to come from transition activities by 2030, up from 14% today. By 2030, Cepsa plans to have roughly 2 GW of green hydrogen electrolyzer capacity as it looks to supply first its own needs and then regional demand. At the same time, it is ramping up biofuels production to 2.5 million tons per year and shifting its aviation fuels business to supply 800,000 tons of sustainable aviation fuel (SAF). Greenhouse gas emissions are expected to fall as these transition businesses ramp up. Cepsa is targeting a 55% reduction in Scope 1 and 2 emissions (from operations) and a 15%-20% drop in Scope 3 (end-users) by 2030.

How Secure Are Druzhba Oil Supplies?

Russian oil pipeline supplies to Europe have been relatively stable over the past six months since Russia invaded Ukraine on Feb. 24. But recent disruptions could signal that further troubles lie ahead as Moscow looks to protect its interests amid intensifying Western sanctions pressure. The Eastern and Central European nations affected by the recent disruptions to the southern leg of the 1 million barrel per day Druzhba pipeline moved swiftly to resolve the payment issues to get crude flowing again. Moscow is already being accused of using its energy as a weapon, citing various reasons — including payment troubles — for cutting natural gas supplies to Europe. Some analysts suggest the same could happen with Druzhba flows, which could add more volatility to an already-frothy global oil market. Since the mid-1960s, Druzhba has been one of the fastest and cheapest routes for Russian oil shipments to consumers in Germany, Poland, Slovakia, Hungary and the Czech Republic. But supplies face increasing risks as the EU applies more economic pressure on Russia for the its invasion of Ukraine. Moscow, in turn, is looking to find alternative markets for its oil as Europe tries to wean itself off Russian energy. Both sides could use Druzhba supplies as a bargaining tool to achieve their aims. Last month, supplies via Druzhba's southern leg to Slovakia, Hungary and the Czech Republic were briefly suspended after a European bank rejected a payment that Transneft, Russia's national oil pipeline monopoly, made to Ukraine to cover transit fees. The bank was concerned that it might violate EU sanctions against Russia if it completed the transfer of funds for Transneft, although EU officials later clarified that payments to Ukraine's Ukrtransnafta were still permitted. Shipments were only resumed after the European customers stepped in to pay Ukraine for the August transit. Shipments to Germany and Poland via Druzhba's northern leg have so far not run into similar troubles.

With gas, Moscow has demanded payments in rubles and has cited technical reasons, including

Druzhba Pipeline

Source: EIA

ones related to sanctions, for supply cuts to Europe. With oil, it is also seeking payment in currencies other than dollars or euros, which could become a point of contention for Druzhba supplies as tougher Western sanctions are implemented in coming months. An EU embargo on Russian seaborne crude takes effect on Dec. 5, although pipeline shipments are exempt from the ban — largely because of the high dependence of Slovakia and Hungary on Russian pipeline supplies. Russia in late July cut gas flows to Europe via the Nord Stream 1 pipeline to 20% of capacity before halting them altogether for three days this week, citing the need to perform maintenance. Germany and Poland, which account for roughly 66% of Druzhba oil shipments, plan to end these imports by year's end even though alternative supplies will be more expensive and take longer to ship. Russia's state-controlled Rosneft, which owns 54.17% in the Schwedt refinery in Germany, said recently additional annual costs for replacing Urals with alternative feedstock are "estimated at $20 million." Germany and Poland have other oil supply options, but customers along the southern Druzhba leg have less flexibility, making them more vulnerable and giving Moscow more leverage there.

But the stakes are high for Russia, too. It has shipped roughly 900,000 b/d through the Druzhba pipeline in recent years, and volumes have been around 800,000 b/d recently. Moscow likely wants to keep as much of this established market as it can for as long as possible. Energy Intelligence estimates the EU ban on seaborne imports will force Russia to find new markets for over 1 million b/d of additional crude. Most agreements for Druzhba supplies end this year, and new ones are unlikely to be inked as European majors distance themselves from Russian barrels. The EU could use Russia's desire to keep Druzhba supplies flowing to heap more pressure on Moscow. Customers along the Druzhba line confirmed to Energy Intelligence that they have faced payment troubles at times over the past six months, with some payments being delayed or rejected by European banks. Russia, which is heavily dependent on oil and gas export revenues, is putting on a brave face, saying it will be able to redirect flows to new customers like India and China, but these markets have their limits. On the positive side, a significant redirection of flows would not require additional multibillion-dollar pipeline infrastructure since Russian ports have some spare capacity to accommodate additional barrels.

Opec-Plus to Tread Carefully With Supply

Opec-plus sees a tighter oil market this year, but it is unclear how this will affect its decision on supply policy at its next ministerial meeting on Sep. 5. With so many moving parts affecting oil markets — where extreme volatility persists — the group plans to keep open all its options in deciding its output policy for the rest of 2022, Energy Intelligence understands. One delegate indicated the alliance may keep its previously agreed September production quotas unchanged for another month to give it more time to assess the market. Another suggested the group may discuss another token increase in supply — like the 100,000 barrel per day increment agreed during last month's meeting. In recent months, the Mideast Gulf states that hold the bulk of spare capacity — led by Saudi Arabia and the United Arab Emirates — indicated the need to remain cautious and not max out their production, which could cause the market to panic and drive prices higher. Taking a cautious approach now is a safe bet given today's volatility, which all Opec-plus members view as a threat. This week's report by the group's Joint Technical Committee "acknowledged the importance" of recent comments by Saudi Energy Minister Prince Abdulaziz bin Salman. Last week, he decried volatility and said Opec-plus was prepared to take whatever measures — including possible cuts in output — to stabilize the market. Reaching a high level of consensus ahead of the meeting is important because it safeguards group unity and guarantees smooth meeting. But whipsawing prices in oil futures markets can make that difficult. Benchmark Brent has been under pressure lately, trading in the $90s this week after topping out above $120 per barrel in June.

The latest JTC report sees global oil supply running at an average of 400,000 b/d above demand in 2022. That surplus is down 50% from the group's previous forecast. The new calculations were made using the actual production figures from Opec-plus member states, rather than assuming a theoretical case of 100% compliance. The downward revision reflects a persistent

shortfall in Opec-plus output relative to targeted volumes. Although this has been a problem for Opec-plus since it began hiking output last year, Energy Intelligence understands that quota redistributions will not be up for discussion this year. "Many countries have not reached their required production," the JTC report acknowledged. In July, the 19 Opec-plus members with a quota missed their target by 2.85 million b/d, a slight improvement of the nearly 3 million b/d gap seen in May and June. Overall, the group's production grew by 1.06 million b/d in July compared to June and totaled 44.53 million b/d, according to Energy Intelligence's assessment. Complicating matters, the JTC report shows an average oil supply deficit of 300,000 b/d in 2023. But already there are promising signs the alliance will continue managing the market beyond 2022. On Thursday, Russian Deputy Prime Minister Alexander Novak said Moscow supports the extension of the Opec-plus pact beyond 2022. "We discussed this with our oil companies, and they also support it," he said. Russia remains the most critical non-Opec member of the alliance.

The tightening of the market does not mean Opec-plus producers are more likely to significantly raise output, especially since spare capacity is tight. Another big uncertainty is the fate of Iran's oil exports as negotiations with the West over a new nuclear deal continue. How Opec-plus might handle a surge in Iran's exports remains to be seen, but Iranian officials have said previously they will not accept a production quota before the country's output reaches pre-sanctions levels. On Thursday, French President Emmanuel Macron said he hoped an Iran nuclear deal will be reached "in the next few days," although the sides have looked close in the past also and failed to agree. Geopolitical uncertainty also clouds the production outlook in Russia, Iraq and Libya. On the demand side, Opec-plus forecasts see the need for more oil ahead despite mounting concerns about an economic recession. The JTC report's base case scenario shows the global economy expanding by 3.1% in both 2022 and 2023, with oil demand growing by 3.1 million b/d this year and 2.7 million b/d next year. The report shows OECD commercial oil stocks ending this year at 181 million barrels below their 2015-19 average, with that gap expanding to 225 million barrels below the 2015-19 average by the end of 2023.

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1 million b/d of crude exports to India and China, at large discounts. Russian crude exports are actually higher now than before the invasion of Ukraine. Finding new markets for another 1 million b/d could prove harder, however. For global oil markets, the bigger concern is keeping Russian products flowing given the current downstream crunch. Russia has started selling into new markets like North Africa, the Middle East and Latin America, but the volumes are small. With global refining capacity at its limit and more fuel switching expected away from ultra-expensive natural gas, the world will need Russian products to balance the market. Traders worry that even if Russia finds new buyers for its crude and products, an EU shipping ban that complements the import embargo could prevent Russia from sailing oil. Some traders believe the EU, which is already suffering from record gas prices as Russia holds back supplies, must abort its bans on oil imports and shipping to avoid sky-high prices and "economic suicide." Discussions over a US-proposed price cap on Russian oil exports set by the West have gone quiet recently. Such a cap, traders, say would not work, and Russia could respond by cutting supplies, resulting in higher oil prices.

Some shifts in Russian flows continue beyond the first wave that sent so much more crude to India and a little more to China. New countries are trying small volumes of Russian crude and products, but the traditional flows remain intact — making it hard to predict how changes in trade flows could materialize if the EU follows through with its bans. From the Black Sea, more Russian crude is flowing to Turkey, Bulgaria and India, with more "unknown" destinations, which could mean cargoes are unsold or hiding their destination. From the Baltic Sea, the largest supplier to Europe, small volumes are now making it to Africa, the Middle East or beyond. The number of vessels showing no destinations is rising from the Baltics, too.

EU Imports of Russian Crude Oil, Refined Products

('000 b/d)	Jun'22	Jul'22	Aug'22
Crude	**1,898**	**1,740**	**1,832**
Baltics	504	461	560
Black Sea	305	215	200
Arctic	321	240	317
Druzhba	768	824	755
Products	**1,091**	**1,191**	**878**
Baltics	887	867	667
Black Sea	204	311	197
Arctic	—	13	14
Total	**2,989**	**2,931**	**2,710**

Source: Kpler, Energy Intelligence

After the chaotic fallout immediately following the invasion, Russian production, refining and export data now show a resemblance to pre-war activity. Energy Intelligence data show Russian crude production at at 9.74 million b/d in August, down 31,000 b/d from 10.05 million before the war. Refinery crude throughput was 5.56 million b/d last month, down 27,000 b/d from 5.83 b/d pre-war. When product exports drop, crude production is expected to fall in line. Energy Intelligence reckons Russia's refinery runs could drop to 4.9 million b/d by February 2023.

Australia Reviews Policy to Curb LNG Exports

Supply shortage fears and record natural gas prices have prompted Australia to rethink how and when it might restrict its LNG exports. Canberra recently extended the Australian Domestic Gas Security Mechanism (ADGSM) to 2030 as concerns grow that the country is headed for another power crisis in 2023 due to gas supply deficits. A reform of the mechanism, colloquially known as the "gas trigger," is also in the works to simplify its usage and make it more relevant to address the challenges faced by Australia's power system. The ADGSM gives Canberra the power to restrict LNG exports to ensure enough gas is available for domestic use. But the ruling Labor government says the mechanism is poorly designed and takes too long to produce results after it is invoked due to its bureaucratic complexity. It seeks major changes — including the possibility to activate the mechanism at short notice and if domestic gas prices rise beyond a reference price. The reference price could be determined through a legislated calculation, factoring in international prices, production costs, reasonable profit margins for gas suppliers and gas purchasers' capacity to pay, according to a government consultation paper. Under its current form, the ADGSM can only be activated between July and November if a gas shortfall is forecast to occur the following calendar year. If sufficient gas supply exists but prices rise to unaffordable levels, the gas trigger cannot be pulled. These limitations could be seen during June's crisis, when the loss of some coal-fired power generation, coal supply problems and lower solar energy output prompted a surge in gas demand that resulted in a wholesale gas price spike.

The reform of the ADGSM could ruffle some feathers among Australia's three east coast LNG exporters, which are now waiting to see if the government will activate the mechanism for the first time since its creation in 2017. Indeed, the Australian Competition and Consumer Commission (ACCC) has identified a potential gas shortfall of 56 petajoules (53 billion cubic feet) in 2023 if LNG exporters decide to sell all the gas that is not contractually committed on a spot basis to overseas markets. The east coast is forecast to produce 1,981 PJ of gas in 2023, of which 1,299 PJ, or 66%, is forecast to be exported overseas under long-term contracts by the Australia Pacific LNG plant operated by ConocoPhillips, the Gladstone LNG project operated by Santos and Shell's Queensland Curtis LNG plant. The three LNG exporters are also expected to produce a further 167 PJ over what they require to meet their contractual commitments. LNG exporters expect to export "the vast majority of this gas as spot cargoes or additional LNG sales," the ACCC said. However, Santos does not expect a gas shortfall to materialize, nor does it believe the government will pull the gas trigger. "I believe that we can work again with government to make sure that the supply is available to the [domestic] market," Santos CEO Kevin Gallagher said recently, adding that there is enough uncontracted gas available. "Why would you ever want to go and break into international offtake agreements? There are a few countries that have tried that over the years. Very few have succeeded...and most of them will destroy their export markets in the process," Gallagher said.

The activation of the ADGSM would send shockwaves through Asia since it would reduce supply in an already tight LNG spot market. It would also stoke more volatility in global gas markets, which have been roiled since the start of the Ukraine war in late February. Australia's reputation as a reliable, low-cost LNG supplier would also be threatened, the three east coast LNG exporters warn. Spot LNG traders are bracing for some complicated months ahead as winter restocking accentuates the market's recent erratic behavior. Spot markets are on the boil due to extra stiff competition for cargoes from European countries, which are aiming to lift EU storage capacity to 80% by November and reduce reliance on Russian gas. The imbalance in LNG supply/demand is already having a huge impact in Asia. The Japan Korea Marker, Asia's de facto benchmark, broke a new record last week, crossing the $70 per million Btu threshold after Norway announced that planned maintenance would take place up until Sep. 7. Just days earlier, concerns that gas flows from Russia via the Nord Stream 1 pipeline could permanently cease after Gazprom announced a three-day maintenance outage had sent prices above $60/MMBtu, a first at the time. At this time of year, spot LNG prices have historically been in the single digits.

CEO: New Energy System Demands New Strategy

Spain's Cepsa has unveiled a new strategy to reposition the company to thrive through the energy transition. Under the plan, the privately held player will dramatically boost investment into activities like electric vehicle charging, biofuels and green hydrogen to slash emissions and garner some 50% of its income from sustainable businesses. Energy Intelligence caught up with Cepsa CEO Maarten Wetselaar for an exclusive interview. An edited transcript of the discussion follows.

Q: Can you explain why you chose to reorient the company in this way?

A: It starts with the realization that just about 50% of the energy system needs a molecule. Today, molecules versus electrons is 80-20. But if you look at how much can we electrify of the molecule usage, most studies end about 50%, maybe 55%, if you push the boundaries. So it leaves about half of the energy system that cannot be electrified. That is an important conclusion, because electrification is a very good and useful and important way to drive the energy transition, but there are all these energy uses like steelmaking, cement-making, but also air transport, long-range shipping and trucking that are very, very difficult — heavy industry — very difficult to electrify. And the green molecules have been ignored by science and by investments, etc. The ranges and the cost curves and the government policy have all been about electrons. I think the competitive space is better at the green molecule side. There's been less development, less attention on it and it's also because it's more complex. A second generation biofuel molecule or green hydrogen molecule is just a more difficult thing to produce, a more difficult thing to handle and to scale up. So in a way, for companies that like doing difficult things, this is more promising space. You know, windmills and solar panels are very, very commoditized. It's hard to find a competitive advantage in them.

Q: Where does Cepsa see its competitive advantages relative to your peers?

A: We've been handling molecules for 100 years, including hydrogen molecules, but molecules in general. So it's our business. There is a lot of crossover between the current molecules of the energy system and the new molecules of the energy systems. We are large users of hydrogen, so the initial green hydrogen we produce we can simply consume ourselves. We can be our own customer. And we are a large seller of aviation fuel and for a long time that will be a blend of sustainable aviation fuel and normal aviation fuel. And so having the two — being in that market, being a significant player, I think will yield important synergies for us. We're not the only ones in this space, but it's a much less contested space than green electrons.

Q: If it's much less contested, will green molecules have a higher, more defensible margin than green power?

A: That is certainly the implication of it. I think there will also be more opportunity for infrastructure to play a key role in keeping returns reasonable. There's not going to be that many hydrogen lines. There's not going to be that many energy parks where you can actually produce this stuff. A second generation biofuels plant or green hydrogen plant is a real industrial installation. If you are already an industrial location with permits with land with utilities, there are very important advantages that are defensible against competition, whereas a solar farm or wind farm more or less anybody can get into this.

Q: How will conversions of your refineries into energy parks that produce hydrogen and biofuels work? Will you have to give up the ability to make traditional fuels — which enjoy high prices now — to move ahead?

A: That will be very market driven. The way we are configured we can scale up the hydrogen and sustainable aviation fuel and biofuel production whilst keeping the traditional fuels running at the same level. Particularly in markets like Europe where liquid demand is not growing, it's simply substituting one for the other. This development will over time start to drive down the demand for hydrocarbons and then for us it will be relatively easy to say, OK, we have six distillation columns that currently distill crude oil. At some point we might shut down one of these distillation columns and then the second one. You will always look at the economics of this. We have some advantage in being able to export relatively easily to North and West Africa. It is possible that our refineries will be producing into Africa for a while if the European demand starts to fall away. But in principle we would over time be planning to take out crude distillers and continue to build the biofuels and hydrogen.

Q: Your strategy talks about participating in a green energy trade between the Middle East, North Africa and Europe. How do you see those hydrogen markets developing?

A: There will be three stages to this and all with their different timelines. Initially, you can see local hydrogen consumption being displaced by locally produced green hydrogen. That's a logical first stage because the logistics are simple. As a stage one, production and consumption is relatively local. In stage two, it becomes a pipeline industry where local production serves regional consumption. The EU has already published its plan for pipelines in Europe for how we're going to connect the major centers of supply to the major centers of demand. That has a pipeline in it that goes through the south of Spain to the north of Europe to the German consumption center. Then thirdly, there will be an international trade. So, although you can get going with locally produced hydrogen and then you can make the next step with, let's say European hydrogen produced for Europe, in 15 years, maybe 20, you will need Middle Eastern and North African hydrogen to come into Europe and Middle Eastern and Australian hydrogen to come into Japan in order for the energy system to truly be green. You could build a pipeline between Morocco and Spain and get green hydrogen into the European market. But in the Middle East, where you have some of the cheapest conditions to make green hydrogen, you will end up liquefying, which is not trivial. Today, as you know, liquefied natural gas has become the commodity of the day in the world — that's minus 162° C. Liquefied hydrogen is minus 260° C. That's even more intense process of liquefaction and it needs an even higher grade of steel to contain the hydrogen. But it's going to happen. So the Middle East will be liquefied hydrogen and North Africa will likely be by pipeline. All of that will be needed in order to get Japan, Europe and other places like China to net zero.

Q: With the technical challenges of transporting hydrogen and the immense amount of renewable energy needed to make it, wouldn't it be more efficient to use that green power directly rather than convert it into hydrogen?

A: If you have a green electron, use it and as much as you can, use it for energy. There's a false discussion going on about, is it green electrons or is it green hydrogen? They don't compete. If you can use green electrons to drive your Tesla or electric vehicle, go ahead. Don't go through the trouble of converting it to hydrogen and back to electricity because you lose more than 50% of the energy content. The green hydrogen molecule addresses energy demand that cannot be electrified. Therefore, it doesn't really compete with green electricity but you're absolutely right, the amount of green electrons that will be needed to first of all electrify the system and then make all this green hydrogen is staggering.

Q: Your retail strategy goes well beyond selling energy and extends to food and pharmacies and a host of other activities. How is an energy company going to develop the ability to operate in these unrelated businesses?

A: That definitely needs development of competence, but also development of partnerships. One of the very interesting developments that took off during Covid was (multi-purpose) kitchens. These are kitchens that will produce for up to 15 brands of food and they are the base from which these brands of food deliver to the home. The companies that are good at this were essentially space-constrained for places that had permits to make food, which had a bit of space, etc. We have retail sites that have very open-ended permits to produce food and very often have space to do this activity. For me to say, OK, I am going to be the world's best operator of (multi-purpose) kitchens would be relatively risky. But luckily the world's best operators of (multi-purpose) kitchens dream of having access to the footprint that we can bring and the same goes for the best operators in the world of the last mile delivery of goods. So what we're saying is, these locations, these permitted square meters that we own — very often close to a community or even in a community — have been underutilized dramatically over the last decades. We've been treating them as places to sell our diesel and gasoline from rather than a place to serve a community from. I think that's the whole philosophy change. It's about building partnerships with people who are the best in the world at doing this and then leveraging our infrastructure because it dramatically lowers their costs.

Q: You're giving your upstream business more autonomy within this strategy. What does autonomy mean?

A: Giving it autonomy is simply, I think, the logical consequence of realizing there's very little integration value. We don't use our own oil. We sell it and then we buy oil from others and we process it. So there's very little integration value. We've made clear we're not developing new upstream positions. For now, the role of the business is to produce cash, to sustain itself but then also to allow us to invest in the greener business.

Q: Some competitors have looked at spinning off their upstream business or taking on selling a portion of it. Is that a possibility?

A: We haven't decided to go down that path at this point in time, but these strategic options are open to us. Having it more autonomous creates an option more clearly.

Q: What is the impact of high energy prices on your strategy?

A: There are areas where we benefit from high energy prices. There are also areas where there are costs. We are a large consumer of natural gas and natural gas in Europe is unbelievably expensive today. And of course it dampens economic growth and dampens people buying our products. Altogether, I'm not the biggest fan of high energy prices. What is interesting though is that today the cost of gray hydrogen produced from natural gas is higher than the cost of green hydrogen. So in a way, it gets oxygen to all these green alternatives. The cost of the alternatives — they are not so crazy anymore. It proves that the world can live on a green diet without falling apart.

Q: How should governments respond to address the current high prices?

A: I think what governments are clearly doing, and they should be doing, is taking some radical decisions. I think it's wise for people to say let's not shut (nuclear plants). I think they should be more willing to apply the same slightly more radical thinking to going quicker on the green front. They've been increasing targets, but you know we have enough targets. We need action on the ground, and there it's been a bit more I would say traditional. Governments could use this moment to push the transition agenda with more force and with a bit more imagination. The industry and certainly Cepsa is ready for it.

What's New Around the World

GENERAL

CARBON CAPTURE — Exxon Mobil has gotten the green light from the US Department of the Interior for permanent underground carbon storage on federal land for the expansion of its LaBarge carbon capture and storage (CCS) facility in Wyoming. The project, which Exxon says will add up to 1.2 million tons/yr of CCS capacity to the 6 million-7 million tons/yr currently captured at the site, is the first of its kind to win approval under a nascent Interior policy for managing some aspects of CCS on federal lands. Interior called the approval a "significant milestone" in the Biden administration's efforts to combat climate change, and it precedes the department's plans to unveil leasing regulations governing US Gulf of Mexico leases for carbon capture later this year. The $400 million expansion marks the first CCS project to be sanctioned under Exxon's Low-Carbon Solutions Division. The proposal includes a carbon dioxide disposal well pad and pipeline, which, once completed, will provide the opportunity for permanent underground storage of CO2 produced along with natural gas at the existing Exxon Mobil Shute Creek plant.

COUNTRIES

INDIA — Reliance Industries set out its plans to invest in petrochemicals and green energy during its annual shareholder meeting. Chairman Mukesh Ambani said Reliance will invest 750 billion rupees ($9 billion) over the next five years to expand production of petrochemicals as it seeks to maximize the conversion of crude oil into chemicals. Reliance owns the 1.2 million b/d Jamnagar refinery in India, which already transforms a large portion of the crude it processes into petrochemicals. By 2026 the company plans to complete construction of a purified terephthalic acid (PTA) plant with a capacity of 3 million tons/yr and a polyethylene terephthalate plant with a capacity of 1 million tons/yr. Reliance said it will also triple its current polyvinyl chloride (PVC) capacity with expansions at Jamnagar and in the United Arab Emirates, which will make it one of the world's top five PVC producers. Reliance has sought to shift its refinery output toward petrochemicals because it anticipates that demand for diesel and gasoline will be eroded by growing sales of electric vehicles. Reliance plans to invest 750 billion rupees in the coming years to build four factories to make solar panels, electrolyzers, fuel cells and energy storage systems. Ambani said the company will consider doubling that investment when the initial plans are completed.

IRAQ — Deadly unrest in Baghdad on Monday night fueled fears that Iraq could be edging toward civil war before powerful Shiite cleric Moqtada al-Sadr helped calm the situation by ordering his supporters to withdraw from the streets. Nevertheless, the Iraqi capital was rocked by the worst violence in years, sparking protests in the country's southern oil heartlands, leading to a nationwide curfew and laying bare the dangers of the country's deepening political crisis. Oil production and exports in Basrah remain unaffected for now, but protests related to Iraq's political crisis have taken place in Basrah and at oil fields in the south, an oil ministry official told Energy Intelligence. "There has been no effect on production and exports until now. Yes, we have some protests in front of some fields in Basrah … There were big protests in Basrah," he said. The official declined to say which fields had been targeted, but access to the giant Halfaya oil field was recently blocked by protesters who blamed operator PetroChina for using too much water at a time of extreme heat and scarce water supplies.

LEBANON — Russia's Novatek plans to exit an offshore upstream project in Lebanon where it has a nonoperating 20% stake, a source close to the project confirmed to Energy Intelligence. Novatek is quitting a TotalEnergies-led consortium to develop offshore Blocks 4 and 9 in the Mediterranean Sea. It has informed the Lebanese authorities and expects to complete the exit by Oct. 22, the source said. The consortium, which also includes Italy's Eni, won a tender for the two blocks in late 2017. Lebanon's energy ministry first said that the privately owned Russian gas and LNG producer would be withdrawing from the project due to economic and financial reasons as well as political risks. The ministry also said Total and Eni remained committed to extending the exploration period for the project. The consortium started drilling in Block 4 in 2020 but efforts came up dry. Drilling in Block 9 has been delayed because of a maritime border dispute between Lebanon and Israel. It is not clear whether international sanctions against Russia over its invasion of Ukraine played a role in Novatek's withdrawal. Last week, Total quit a joint venture with Novatek developing the Termokarstovoye gas field in West Siberia, following accusations that condensate production from the field was aiding the Russian military.

MOZAMBIQUE — Mozambique's Coral South floating LNG plant is understood to have suffered technical issues, which could delay the start-up of the project, potentially further squeezing an already tight global LNG market. "Serious issues [were] reported at Coral FLNG with one critical distillation column (demethanizer) suspected of having internal damage. Shutdown is required for inspection and repair, which will delay the start-up schedule by several days, if not weeks," a source told Energy Intelligence. The 3.4 million ton/yr project, located in Area 4 of the Rovuma Basin offshore Mozambique, is operated by Italian major Eni, with partners ExxonMobil, China's CNPC, Galp, Kogas and Mozambique's state-controlled ENH. It is the only export project in the East African country which was expected to come on line on time, with the onshore Mozambique LNG and Rovuma LNG projects facing multi-year delays due to security issues in the region.

RUSSIA — The head of Russia's Gazprom Neft, the country's third-largest oil producer, shrugged off impending EU sanctions on Russian crude imports, saying his company "is prepared" to deal with them. Gazprom Neft head Alexander Dyukov declined to comment directly on the forthcoming EU oil embargo, which will ban purchases of Russian seaborne crude starting from Dec. 5. However, Dyukov said that Gazprom Neft "will work within the new realities." Speaking ahead of the Sep. 5 meeting of the Opec-plus producer alliance, Dyukov endorsed continued cooperation between Opec members and Russia in order to stabilize volatile oil markets. The Gazprom Neft chief praised the impact that Opec-plus has had on global oil markets and said that it would be positive "if this agreement, this mechanism continues working." Oil fundamentals are well-balanced today and high prices are being driven by geopolitical factors, Dyukov said. He also shrugged off the potential return of Iranian barrels. "If the Opec-plus agreement is sustained, then it has already demonstrated that it is able to keep the market in balance and to meet the needs of consumers for affordable prices and maintain a price level necessary for oil companies to continue investments in crude production," Dyukov said.

UNITED STATES — US supermajor Exxon Mobil confirmed that it plans to divest its natural gas-prone Fayetteville Shale assets in Arkansas to private equity-backed Flywheel Energy for an undisclosed amount. The assets to be sold include about 850 operated and 4,100 nonoperated wells as well as related midstream infrastructure spread across 381,000 net leasehold acres, an Exxon spokesperson said via email. The move follows Exxon's decision earlier this year to exit the Barnett Shale, another mature dry gas basin. More recently, Exxon sold its acreage in the Utica Shale of Ohio to Ascent Resources for $270 million. Exxon and its fellow majors are putting their weight behind low-cost, low-risk upstream investments with lower carbon footprints. For Exxon in the US, that means increasing its focus on its Permian Basin acreage. But it is also turning to better economics in other shale gas plays as well. The Haynesville Shale in East Texas and northwest Louisiana tops the list. The company has 200,000 net acres there and has more than doubled production since 2018, to 424 MMcf/d last year — and rising. By comparison, Exxon had over 800,000 net acres across the Barnett, Fayetteville and Freestone dry gas plays that were understood to be written down with plans to be sold.

Marketview

Bad Romance

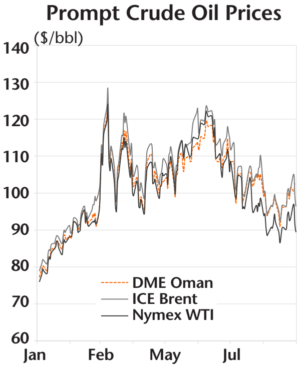
Oil prices have run out of steam, failing to consolidate their initial rebound after Saudi Energy Minister Prince Abdulaziz bin Salman said Opec-plus may cut oil output last week. His intent was to close the gap with the physical market and calm the wild price swings. But it only contributed to more volatility.

Brent initially bounced off its 200-day moving average to $105.09 per barrel. But in less than three days, the benchmark gave up nearly $12/bbl and has since been trawling around this key support level, with too little momentum to snap back to $100-plus levels.

The European gas and power markets are also plagued by volatility, some of which has seeped through to oil prices in a complicated and erratic relationship. The reason is that higher natural gas prices incentivize fuel switching for heat and power generation. Gas-to-oil substitution is already happening, especially in Germany where industrial users have been warned of potential gas outages and are trying to burn fuel oil or even diesel instead. Benchmark Dutch TTF gas in Europe is still hovering around €250/MWh, which gives an oil equivalent of $422/bbl.

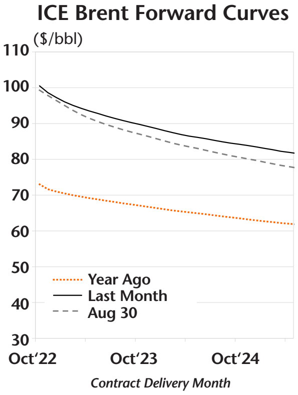
Since natural gas usually sets the price of European power, electricity prices in Europe are surging, including a brief but sharp spike to more than €1000/MWh ($993/MWh) for the German one-year forward power prices on Aug 29. The problem is that higher prices entail lower market liquidity, which in turn gives more leverage to speculators with big enough credit lines to play this market.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



"Trigger happy speculators with deep pockets have been able to drive prices to levels unjustified by current fundamentals, only to dump positions once panic buying dried up," Saxo Bank said.

The late reversal in European gas prices has likely rippled to oil markets and temporarily reduced pressure on fuel switching. If anything, oil volatility does not encourage substitution, especially for industries that may still be reluctant to make expensive adaptations to their current fuel-burning equipment. With refiners heading into seasonal turnarounds, there is also a lull in spot crude demand and a resulting dip in crude physical differentials. Crude supply is therefore not an issue — at least for now.

But the refined product market remains tight and further tightness is looming this winter, especially when the EU ban on Russian product comes to full effect on Feb. 5, 2023. This could coincide with the peak of winter demand and put product inventories under strain if they have not filled up ahead of the seasonal spike. The same is true for both the oil and gas market. Storage filling levels are being eagerly monitored, but storage is only one part of the winter equation.

Europe is trying to lease and install floating regasification units in a rush to import LNG this winter, but some of that infrastructure will not be operational until next year. And given the cost of transporting LNG, burning oil — even expensive winter diesel — may still come out as the best option. Fuel subsidies will sustain product demand, even at higher prices. And with an oil market trading about 28 times more paper than physical oil, more forward product demand can only attract speculators and push oil prices higher.

Gazprom Halts Nord Stream Gas Flows

Gazprom stopped flows of Russian gas to Germany via the Nord Stream pipeline on Wednesday for three days of maintenance work. The shutdown had been announced beforehand, causing a sharp rise in European gas prices last week, with the front-month Dutch TTF gas futures contract soaring well above €300 per megawatt hour. Prices retreated somewhat at the beginning of this week, reflecting relatively high gas storage levels in Europe and support within the EU for for intervention in the market to curb sky-high energy prices. But there are concerns that state-controlled Gazprom may not resume gas supplies via Nord Stream after the scheduled three-day outage, with Moscow perhaps opting instead to cut off supplies to try to undermine Europe's support for Ukraine in its war with Russia.

PIW Market Indicators

($/barrel)	Aug 29-	Aug 22-	Aug 1-
Spot Crude	**Aug 31**	**Aug 26**	**Aug 5**
Opec Basket	$104.10	$102.33	$103.41
UK Brent (Dtd.)	98.33	99.00	102.18
US WTI (Cushing)	93.09	94.45	94.01
Nigeria Bonny Lt.	102.79	102.51	111.50
Dubai Fateh	100.38	97.86	97.67
US Mars	91.62	92.69	93.12
Russia Urals (NWE)	74.79	74.51	70.40
Crude Futures			
Brent 1st (ICE)	100.30	99.65	97.28
Brent 2nd (ICE)	98.80	98.56	95.49
B-wave (ICE)	100.58	99.02	98.04
WTI 1st (Nymex)	92.73	92.89	91.30
WTI 2nd (Nymex)	92.13	92.52	90.20
Oman 1st (DME)	99.15	99.23	96.95
Oman 2nd (DME)	98.13	97.38	93.25
Murban 1st (ICE)	101.04	100.00	97.80
Murban 2nd (ICE)	99.05	98.59	94.67
Forward Spreads			
Brent (1st-Dtd.)	+$1.97	+$0.65	-$4.90
Brent (2nd-1st)	-1.49	-1.09	-1.78
WTI (2nd-1st)	-0.60	-0.37	-1.11
WTI (3rd-2nd)	-0.86	-0.66	-0.84
Oman (2nd-1st)	-1.02	-1.85	-3.70
Oman (3rd-2nd)	-0.98	-2.23	-2.33
Murban (2nd-1st)	-1.99	-1.42	-3.13
Murban (3rd-2nd)	-2.20	-2.02	-1.71
Grade Differentials			
WTI-Brent (1st)	-$7.56	-$6.74	-$7.08
WTI-LLS	-2.50	-2.70	-2.79
WTI-Mars	+1.47	+1.76	+0.89
Brent(Dtd)-Dubai	-2.05	+1.14	+4.51
Brent(Dtd.)-Urals	+23.55	+24.49	+31.78
Brent(Dtd.)-Bonny Lt.	-4.46	-3.51	-9.32
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$98.75	$99.82	$100.25
Arab Lt.-Europe (Med)	105.68	104.12	103.14
Arab Lt.-Far East (f.o.b.)	109.73	109.08	108.82
Nigeria Bonny Lt.	104.79	105.46	108.64
Arab Light Gross Product Worth			
Rotterdam	$106.34	$108.99	$105.92
US Gulf Coast	112.62	114.84	109.16
Singapore	105.42	108.04	100.94
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$118.12	$120.88	$105.96
UK Brent Margin	+18.02	+20.56	+1.99
US Gulf Coast			
Mars GPW	106.69	108.83	105.44
Mars Margin	+14.97	+16.04	+12.22
Singapore			
Oman GPW	103.78	106.52	100.80
Oman Margin	+2.29	+3.79	-1.26
US Nymex			
WTI 3-2-1 Crack	+$36.99	+$41.97	+$37.55
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$862.15	$912.28	$958.76
Gasoil (0.1%)	1134.42	1151.30	1033.10
Fuel Oil (0.5%)*	675.50	690.50	675.15
US Gulf Coast (¢/gal)			
RBOB Gasoline	259.74¢	265.98¢	275.59¢
ULS Diesel	378.00	386.60	329.24
Fuel Oil (0.5%, $/ton)	$740.33	$728.20	$761.00
Singapore ($/bbl)			
Naphtha	$71.80	$73.68	$79.80
Gasoil (0.05%)	145.16	146.32	125.85
Fuel Oil (0.5%, $/ton)	759.00	771.80	786.60

*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.