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Biden Looks To SPR Again to Tame Prices

US President Joe Biden this week rolled out plans to sell off 15 million barrels of crude stocks, part of a wider effort by the administration to blunt the economic impacts of elevated oil prices. The latest sale from the Strategic Petroleum Reserve (SPR) rounds out the 180 million bbl already authorized by the administration and comes after Opec-plus' decision earlier this month to cut production by a headline 2 million barrels per day — a move that infuriated the White House. US officials unveiled details on a plan to buy back SPR volumes at a West Texas Intermediate (WTI) price of $67-$72 per barrel, a move meant to offer producers something of a soft floor to buffer demand concerns in the hopes of spurring near-term production. "That means oil companies can invest to ramp up production now … Refining and refilling the reserve at $70/bbl is a good price for companies and it's a good price for taxpayers," Biden said Wednesday. Senior administration officials called the planned fixed-price contracts a "helpful signaling" for stimulating domestic production should WTI prices, which now hover around $85/bbl, fall significantly.

But the SPR buyback is likely to have limited impact on US producers' investment decisions, which continue to be driven largely by investor demands for cash returns. WTI's forward curve does not signal a return to $70/bbl until mid-2024 and it remains in backwardation — with future prices lower than prompt ones, which dissuades hedging for many producers. Energy Intelligence reckons that US shale producers' free cash flow break-even costs are in the $60s, below the buyback level. Even as the boldest draw in SPR history nears an end, Biden has left open the possibility of authorizing more sales. The administration has demonstrated an unprecedented flexiblilty with its SPR policy as it tries

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Opec-Plus Cut Reshapes Oil Sentiment

The political spat over Opec-plus' production cut seems much bigger that its actual impact on oil balances. However, the move did change market sentiment, pushing prices back over the $90 per barrel level the producer group appears to favor. The cut emphasizes not only expectations for a slower economy but also how oil demand is already hurting. Huge downward revisions to demand neutralize the impact of the cut — which should amount to around 1 million barrels per day in real world volumes — on balances, which show stockdraws in the fourth quarter that gets replenished in the first half of 2023, according to Energy Intelligence calculations. The cut looks less dramatic when compared to what oil consumption is up against: war in Europe, rising interest rates, recessions fears, a strengthening US dollar, and China's strict Covid-19 policies and economic woes. Energy Intelligence has cut its demand growth estimate for 2023 by 500,000 b/d to 1.6 million b/d for a total 101 million b/d. Oil consumption in 2022 is now seen growing at 1.8 million b/d, down 400,000 b/d from our previous forecast. China's impact alone is large. Its demand is forecast to drop 400,000 b/d compared to 2021 — the first fall in at least 20 years, and it could turn out to be steeper. China is expected to show growth of 660,000 b/d in 2023. After the Opec-plus decision, balances show a draw of 1 million b/d in the fourth quarter with a surplus of 400,000 b/d in the first quarter of 2023 and 800,000 b/d in the second.

Since September, market rhetoric has shifted from how high oil prices can go to how bad the

Chairman: Raja W. Sidawi. Vice Chairman: Marcel van Poecke. Chief Strategy Officer & Chairman Executive Committee: Lara Sidawi Moore. President: Alex Schindelar. Editor-in-Chief: David Pike. Executive Editor: Noah Brenner. Contact Us: New York: Tel: +1 212 532 1112. London: +44 (0)20 7518 2200. Sales: sales@energyintel.com. Customer Service: customerservice@energyintel. com. Bureaus: Beirut: +961 3 301278. Dubai: Tel: +971 4 364 2607/2608. Houston: Tel: +1 713 222 9700. Moscow: Tel: +7 495 604 8279/78/77. Singapore: Tel: +65 6538 0363. Washington: Tel: +1 202 662 0700. Other publications: *EI New Energy, Energy Compass, Energy Intelligence Finance, International Oil Daily, Jet Fuel Intelligence, Natural Gas Week, Nefte Compass, NGW's Gas Market Reconaissance, Nuclear Intelligence Weekly, Oil Daily, Oil Markets Briefing, Oil Market Intelligence, World Gas Intelligence.* www.energyintel.com

economy can get. Sturdy demand, Russian supply disruptions, and global diesel shortages were expected to support higher prices. So far, however, Moscow's crude exports are holding up. Russia's product exports are already down 800,000 b/d from pre-war levels — but Opec is about crude, not products. Crucially, the product markets may not melt down now that China is mobilizing an estimated 1 million b/d of spare refining capacity. China is likely to buy discounted Russian crude for its rising product exports, which would alleviate the worst fears for the winter months. But this market is not out of the woods. A cold winter and an uptick in fuel switching from high natural gas prices can further squeeze an already tight diesel market, where refiners are struggling to keep up with demand. With EU import bans on Russian crude and products looming, Moscow still must find new markets for 1.1 million b/d of crude by December and 600,000 b/d of products, of which 60% is diesel, by February.

In September, Brent dropped below the $90-$100/bbl price band that Opec-plus' actions suggest it favors. With Brent sliding towards $80, it decided to cut. When Brent last week approached $100, reports appeared that Opec-plus could reverse its decision when it meets again in December, which reduced Brent to the lower $90s. Opec-plus has claimed the cut will stabilize the market by restoring its spare capacity to nearly 3 million b/d. It may have to put this spare into action if oil prices run away again. On the other hand, if prices drop far below $90 again due to persistent economic downgrades, it may have to consider further cuts. The outlook for 2023 is so uncertain. Energy Intelligence sees Russian crude output falling by 1.45 million b/d to 8.3 million b/d by June 2023 from 9.75 million b/d last month. To keep inventories flat, our latest balances suggest Opec must add an average 700,000 b/d to its expected 28.7 million b/d of crude output in 2023.

The Opec-plus cut had its desired impact in the oil futures market. Speculators rushed to cover bets on falling prices by buying futures contracts, driving up crude and product prices rapidly. The producer group has been known to effectively spook short-term speculators at times. Speculative bets on lower Brent prices dropped below 36,000 contracts, or 36 million bbl, by mid-October, the lowest position in three years. At the same time, more money flowed into bets on rising prices for crude and diesel. Total capital committed to net longs on rising prices was the equivalent of $37 billion in mid-October, 25% higher than mid-September.

Russian Oil Industry Braces For Upheaval

With about 1.7 million barrels per day of its crude oil and refined products facing a ban in Europe over the next three and a half months, Russia's oil industry is at risk of considerable upheaval. The transition ahead of these bans will be topsy-turvy. Preliminary information suggests that, with crude under the embargo gun first, Russia will start running refineries hard and export everything from the slate it can. This will last until January, at which point the industry, along with the government, will have to take stock. If alternative clients appear and clean, long-haul tankers for products can be contracted, producers will adapt to new trade patterns and suffer minimal loss in output. But if product sales drop significantly in January and the tonnage is unavailable, as many expect, oil companies will have no choice but to cut — and most likely at refineries. The pressure is already on. The discount for Urals, Russia's chief export grade in the western part of the country, has risen steadily in recent days, and analysts believe it will continue to grow as the Dec. 5 crude ban approaches. EU countries are scaling down their crude intake. Loadings dropped to just over 600,000 barrels per day in the first half of October — or 1 million b/d down from average 2021. The remaining importers are Italy (300,000 b/d), the Netherlands (200,000 b/d) and Bulgaria (100,000 b/d). Hungary, Slovakia, the Czech Republic, Poland and Germany still receive Urals crude via the Druzhba pipeline, and the first three countries are exempt from the ban for a total 250,000 b/d. Russia is selling more crude to India, Turkey and China, but is also sending some to Cuba, the United Arab Emirates, Qatar and EU member Croatia.

Russia's priority will be maintaining output at current levels — about 10.6 million b/d of crude and condensate, or about 9.6 million-9.7 million b/d of crude only. Shutting wells is never a good idea in such a cold country, so assuming producers encounter difficulties marketing the embargoed crude,

they will send as many barrels as needed to refineries. The end of turnaround season this month will facilitate this. Besides, in the run-up to the Feb. 5 product embargo, they will try to capitalize on the attractive netback for some products in Europe, especially middle distillates. Runs in the first two weeks of October were 5.45 million b/d, flat on September, but this could grow by 250,000 b/d-300,000 b/d in November, according to preliminary plans by Rosneft, Lukoil, and others seen by Energy Intelligence. A return to the prewar level of 5.8 million b/d is possible. Product sales to the EU are still relatively robust, amounting to 700,000 b/d in the first half of October, even though this is down nearly 500,000 b/d from 2021. Hard-to-replace diesel loadings ticked up to 375,000 b/d from a low 250,000 b/d in September and average of 600,000 b/d in 2021. Refineries will try to improve on this trend while they still can.

Come January, if the outlook is bleak, Russian producers will have to choose between cutting at the wellhead or slashing runs. Analysts believe they will opt for the latter. A refinery can be kept on hot circulation, but a shut-in well, especially one with paraffinic oil typical in Western Siberia, will freeze over and in many cases be impossible to restart. President Vladimir Putin has vowed to keep production at current levels, and given the massive financial requirements for the war in Ukraine, there is good reason to believe producers will pull all the stops to keep the barrels flowing. At current price levels, Russian can still make a buck on its discounted oil. A key yardstick for which direction the wind will blow in January will be lighter products such as gasoline and naphtha. The margins on domestic sales of gasoline, some 850,000 b/d, are lousy now that the state has slashed a key subsidy. Refineries are therefore cranking out more straight-run gasoline, a widely used petrochemical feedstock in Europe. But the discount European buyers are demanding for straight-run, or naphtha, means Russian refiners are losing money hand over fist. Russia exports about 80% of its naphtha output of 550,000 b/d this year, and much of that to Europe. But finding alternative buyers and, more importantly, the vessels to ship it long distances, could prove to be an insurmountable hurdle.

Oxy Puts Money Where Mouth Is in Carbon Capture

For all the talk and proposed investment around carbon capture, utilization and sequestration (CCUS), few energy companies have made firm spending commitments, let alone started putting shovels in the ground. That is not the case with Occidental Petroleum, which is moving decisively on its carbon capture plans. Oxy is due to break ground next month on the first of what it now says could be 135 direct air capture (DAC) plants by 2035, pioneering the technology at a scale yet to be matched by any other aspiring carbon capture developer. Bolstered by newfound policy support from the much-lauded Inflation Reduction Act (IRA) in the US, Oxy is cementing its lead in the nascent carbon capture sector, widely seen as indispensable in the race to net-zero emissions. While project sanctions have been slow to materialize, investment is still pouring into the carbon capture sector. Research firm BloombergNEF (BNEF) counts some $3.5 billion invested in the space just this year through September, compared to $7 billion invested from 2018-21. It reckons global capture capacity will hit 279 million tons per year of CO_2 by 2030, a sixfold increase from today's levels. But that would still account for just 0.6% of today's emissions, BNEF says, and is a far cry from the 1.6 billion tons/yr the International Energy Agency says needs to be captured by 2030 if the world has a chance of reaching net-zero emissions by 2050.

Exxon Mobil is trying to position itself as an industry leader in carbon capture, with a much different approach than Oxy. The supermajor plans to make CCUS a cornerstone of its proposed $3 billion spend on lower-emission energy solutions through 2025. But it has been largely silent on what would be one of the world's most ambitious carbon-capture projects, a grand plan announced last year bringing together dozens of the Houston area's biggest emitters to capture some 100 million tons/yr of CO_2. When asked for an update on the hub this week, the company referred all questions to the Houston CCS Alliance, a newly formed local advocacy group. To be sure, Exxon and its peers have been active in their CCUS planning. The Texas giant this year sanctioned a $400 million expansion of existing carbon capture facilities at its LaBarge natural gas project in Wyoming, targeting an additional 1.2 million tons/yr of CO_2 capture, with start-up planned in 2025. It announced plans this year to build one of the world's largest "blue" hydrogen facilities, using natural gas and carbon capture to produce up to 1 billion cubic feet per day of clean hydrogen — a first step in the larger "Houston hub" concept, Exxon says. Meanwhile, some of its proposed hub partners, including Chevron, Linde, Air Liquide and others, are evaluating separate plans for low-carbon opportunities on the US Gulf Coast.

Developers are looking for governments to step in to help finance these CCUS megaprojects, complicating final investment decisions (FIDs). Norway is funding 80% of the sanctioned multibillion-dollar Northern Lights project, led by Equinor, TotalEnergies and Shell. The Porthos project in Rotterdam, involving Exxon, Shell and others, is getting €2 billion ($2 billion) in incentive support from the Dutch government. But the companies behind a C$24.1 billion (US$17.6 billion) carbon capture project in the Canadian oil sands say they can't move forward without public assistance, and have been in discussions with governments for more than a year.

Oxy was already preparing to break ground on its first billion-dollar DAC plant — even before incentives in the IRA enabled it to double down on its already-ambitious plans — financed mainly with cash and carbon-offset credits. It is now looking ahead to a second plant, building a "digital twin" of the first to help optimize designs and reduce costs for what will be near identical subsequent plants. It also has pre-FID point-source CCUS plans in development on the US Gulf Coast. The slow pace of FIDs belies the rate of new CCUS project announcements. The Global CCS Institute says there are currently 196 proposed carbon capture projects in the pipeline worldwide, a 44% increase from a year ago. That's a "conservative" estimate, the institute says, since it does not account for projects that will emerge post-IRA. Its early analysis suggests the IRA alone could increase the deployment of carbon capture by thirteenfold, or "well over" 110 million tons/yr, by 2030 compared to existing policy.

Biden Looks To SPR Again to Tame Prices

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to counter energy inflation. It notes that SPR stocks remain more than half full at over 400 million bbl — "more than enough for any emergency drawdown," Biden noted. The administration will decide in roughly a month about additional releases for January. Separately, the US must also sell off 33.5 million bbl of SPR oil in the fiscal year that runs from Oct. 1 until the end of September 2023, according to a compilation of legislated sales by the Congressional Research Service.

With just under three weeks until US midterm elections, Biden has not ruled out the possibility of further action to cool fuel prices, which have been edging up since reports of Opec-plus' big production cut plans first surfaced last month. US officials have repeatedly stressed that nothing is off the table, but the administration has few good options. Biden's options include restrictions on booming US product exports, although a senior administration official on Tuesday noted any tools used must contribute to a "stable domestic supply" — which analysts argue is not the case for product export curbs. US oil companies, which have clashed with Biden regularly over his ambitious climate agenda, have railed against the notion of export restrictions for months amid warnings from Energy Secretary Jennifer Granholm to US refiners to increase inventories. Some insist that export restrictions could backfire by creating upward pressure on global markets, at a time when the US has pledged to help Europe with fuel shortages. The US also has mechanisms to require industry to add to product inventories, but acting on those may be logistically fraught and would likely draw producers' ire as Biden urges them to increase output. Biden in June also began pushing the idea of a federal gasoline tax holiday, but lawmakers did not pick up the torch, and tax relief requires an act of Congress — currently on recess until after the US election Nov. 8.

The Opec-plus cut provoked fury in Washington, and Biden has vowed to "re-evaluate" the US-Saudi relationship. In the wake of the decision, long-proposed legislation aimed at exposing Opec members to US antitrust litigation resurfaced in Congress and now stands a better chance of passing than ever before. US Sen. Chuck Grassley pledged to move the legislation via a must-pass defense spending bill, but its viability likely won't be clear until after the Senate returns post-election. The US has maintained sanctions restricting Venezuela's oil output since 2019, and the Opec-plus decision and high prices have raised the specter of relaxing those restrictions — but this hinges on political negotiations with respect to Venezuela's elections. An Iran nuclear deal could inject about 1 million b/d to global markets, but that seems unlikely before the elections, and the negotiations remain complicated. A public US-Saudi spat cooled this week, and Opec-plus has indicated that it could restore part of its cut if markets tighten in coming months. But the group has been irritated by Biden's SPR releases and other market interventions, and further releases above 180 million bbl could see it reassess that flexibility.

Global E&Ps Critical for Energy Security

Global independent E&Ps will remain a critical source of new supply growth in the coming years to help meet energy security needs. The energy crisis in Europe has temporarily quieted calls to halt fossil fuel financing and given oil and gas companies more flexibility. While investor pressures to decarbonize and diversify remain, the enterprising spirit that served independents well in the past could help some come through the energy transition intact. Independents, both publicly listed and private companies, have become an important source of supply, and some are starting to wield some political clout. In the UK, for example, over two-thirds of domestic oil and gas is now produced by independent E&Ps, with North Sea-focused Harbour Energy the country's biggest producer. "When the government now has concerns about energy security, they don't necessarily just call the Shells and the BPs, they have to engage with the independent oil and gas community as well," says Harbour CEO Linda Cook. "I think if you ask most people, then at least in this country, we're critical to energy security," she told the Energy Intelligence Forum in London earlier this month.

At the same time, companies seeking growth are becoming more sensitive to the uncertain political risk landscape, including in jurisdictions once thought to be safe investment havens. Independent E&Ps with much greater geographic portfolio concentration than their larger counterparts are particularly exposed to evolving market interventions by host governments, such as windfall taxes and price caps. Australian Woodside Energy has undertaken a strategic review following completion of its merger with BHP Petroleum in May. It now has a significant position in Australia in LNG, as well as in the US Gulf of Mexico, and boasts a much stronger balance sheet. "We're looking for opportunities for growth, and we're seeing behaviors from what you would describe as the traditionally stable nations, where the industry has historically invested, that are a deterrent," Woodside CEO Meg O'Neill told the Forum. O'Neill cited the UK as an example of how investor confidence in a traditionally stable country can quickly sour, noting how surprise changes to the tax regime were imposed with little industry consultation.

The energy crisis has led investors to take a "more holistic" approach toward independents' energy transition strategies, with more room for fossil fuels. Indeed, some investors are looking for greater exposure to the sector to avoid missing out on the run-up in prices. Yet executives emphasize that capital investment in oil and gas will remain constrained as investors keep up pressure to decarbonize and maintain their focus on shareholder returns. Environmental, social and governance (ESG) issues continue to be a prominent theme in discussions with investors, O'Neill said. But she noted a "greater appreciation that you have to tackle the whole question of energy security, reliability, you have to manage energy cost and manage carbon. That's, I think, positive in that … we can start having a good conversation around how do you execute the transition." Still, investors will continue to scrutinize capital allocation and returns. And Harbour's Cook noted, "no one will give you any value in your share price" for reserves that won't be produced around 8 years from now, versus 15 years previously.

Global E&Ps are working to decarbonize their business models, but with less emphasis on renewable energy and more commitments to lower-carbon barrels, ammonia, hydrogen and carbon capture and storage (CCS). Moreover, Woodside's O'Neill believes they have much to bring to the transition, including an "entrepreneurial spirit" and a willingness to pilot innovative technologies that is baked into the sector's DNA. Woodside sees the potential to export ammonia from Australia to North Asia, building off its strong position in LNG trading and shipping. And it is looking to recycle greenhouse gases such as CO2 and methane into useful products like value-added ethanol. Harbour is meanwhile using its know-how injecting fluids, operating pipelines and drilling wells for injection for CCS in the UK Southern North Sea. It has signed preliminary agreements with several emitters that would be incentivized to cut their emissions through government schemes but would pay Harbour a transport and storage fee.

Petchems Drive Growth in China's Downstream

China, the world's largest petrochemicals consumer, has sought to reduce its dependency on imports by building large, new integrated refining and petrochemicals complexes along its east coast. These have helped transform China into the world's biggest petrochemicals producer. But they have also contributed to the country's refining overcapacity, while raising questions about decarbonization of its massive, still growing petchems sector as China strives for net-zero emissions by 2050. China's refining capacity surged from 12.54 million barrels per day in 2013 to 18.3 million b/d in 2021, according to China National Petroluem Corp. (CNPC), thanks partly to giant projects like 400,000 b/d private Hengli Petrochemical, and the 800,000 b/d private Zhejiang Petrochemical. But China's pledge to peak its carbon emissions before 2030 is prompting it to put the brakes on its refining sector. Beijing has set a strict 20 million b/d cap on China's refining capacity by 2025. The government also recently demanded that new plants produce no more than 40% transportation fuels by 2025, with the rest of the output to go to associated petrochemicals facilities. The cap, which is unlikely to be revised up, means that China may import a maximum of 13 million b/d of crude by 2025 and thereafter, Energy Intelligence calculates. This would be about 2 million b/d above the record-high 10.89 million b/d that China imported in 2020.

Between now and 2025, several major petrochemicals projects are in the pipeline. Most are integrated plants that will add another 1.42 million barrels per day of refining capacity, adding to China's current surplus. This may lead to excess supply for the domestic market unless China ramps up product exports — a potentially profitable prospect given the current global refining crunch. Still, there will be pressure on small refiners, or teapots, to shut down. Beijing recently issued additional product export quotas to some Chinese refiners, as well as the first batch of 2023 crude import quotas, which could provide some relief to tight global product markets. With CNPC expecting China's refining capacity to reach 18.9 million b/d this year and the potential for more projects between now and 2025, this could force the closure of smaller plants. "Most advanced refiners move to petchems, [so] it is time for small refiners to retire," PetroChina International's chief economist, Wu Qiunan, told the Appec conference in Sinapore last month. PetroChina, the listed unit of CNPC, is expected to bring its 400,000 b/d Jieyang refining complex online by the end of this year in the southern Guangdong province. Private Shenghong Petrochemical is also conducting test runs at its 320,000 b/d complex in Jiangsu province. Meanwhile, the 400,000 Yulong development will replace several teapots in the Shandong province by 2024.

China's petrochemicals market will help drive and sustain its petroleum imports as the country moves further downstream from refining to high-value petchems — even in the face of energy transition pressures. How profitable the projects turn out will be closely linked to China's economic performance and global demand. Beijing's zero-Covid-19 policy has hit the domestic economy hard recently. A slump in the real estate sector is also causing a fall in demand for construction materials and fixtures. China's accelerated petrochemicals growth over the past eight years is creating fears of oversupply in some markets. China's ethylene capacity increased by 8.5 million tons/yr in 2021 to 43.7 million tons and is expected to hit 55 million tons by 2025, according to CNPC, potentially reducing China's import dependency to less than 50%. China is already almost self-sufficient in propylene and an exporter of specialty products. Beijing has said little so far about plans to cap carbon emissions in the chemicals sector, which could see growth curtailed if it is included in China's carbon market by 2025, as proposed.

Total in Key Role in Israel-Lebanon Deal

TotalEnergies is set to play a unique role in a US-brokered maritime border deal between Israel and Lebanon that should reduce the threat of conflict in the important East Mediterranean gas play, which Europe has identified as a viable alternative to Russian piped gas. US Energy Envoy Amos Hochstein is due back in the region next week, with hopes rising that a deal will finally be signed. The danger of a miscalculation between Lebanese Shiite militant group Hezbollah and Israel was increasing after Israel's Karish gas field was targeted earlier this year by Hezbollah drones. Moreover, a deal should unlock regional gas cooperation and potentially more upstream investment. All sides have agreed the text of a new deal as Lebanon seeks to elect a new president and Israel goes to the polls in November. The Israeli security establishment has given its approval, but Israel's Knesset has yet to agree to the text. Still, a signing ceremony will likely take place soon at the southern Lebanese border town of Ras Naqoura.

Total now finds itself a crucial cog in a complex mechanism designed to help both states reach agreement on their respective borders. At issue is the Qana prospect in Block 9, located in disputed waters between the two states. Once a deal is signed by all sides, Total and its partner Eni must start exploration of Qana immediately, and if a commercial discovery is made, the French major, without Lebanese involvement, must agree to a separate agreement with Israel to determine the scope of Israel's economic rights in the find. Total will operate Block 9 exclusively for Lebanon but will have sole responsibility for remunerating Israel. "There is no precedent for a state to give an international oil company [IOC] this much power," argues Tibisay Morgandi, a lecturer in energy and natural resources law at London's Queen Mary University. "Lebanon has given an IOC the power to negotiate Israel's share of profits, without Lebanon's involvement, even though this could come at a cost to Lebanon," she says. An Israeli diplomat told Energy Intelligence earlier this year that it was a US proposal to use oil companies as the vehicle to allow commercial development of the find and remuneration of both states. However, a US administration official has insisted that Israel and Lebanon would need to come to terms on their own commercial arrangements. Morgandi warns that "there is an interesting point which could be interpreted as a potential veto — that Israel will have to sign an agreement with Total to determine its rights — but it could take years to do so, leaving Lebanon in a difficult position." Operator Total declined to comment. It has a 40% stake in both blocks along with Eni, which also has 40%. Beirut holds the remaining 20%.

One immediate benefit for Lebanon is that the border deal helps unlock a separate agreement for Egyptian gas to flow to the country to alleviate its chronic blackouts and fragile economy. US officials have insisted the two deals are not linked, but Lebanese officials insist they are. Lebanon, Syria and Egypt in June agreed to a gas supply deal, first mooted in 2021, that would see Egypt transport 650 million cubic meters of gas per year via the Arab Gas Pipeline running from El-Arish on Egypt's Mediterranean coast via Jordan and Syria to the Deir Ammar power plant in northern Lebanon. Egyptian Petroleum Minister Tarek el-Molla told Energy Intelligence this month that with pipelines and contracts set, all that was needed was approval. Deliveries of Egyptian gas via Syria still require the US to find a workaround to its Syria sanctions — both to facilitate World Bank funding for the project and to allow Syria to claim transit fees.

Total CEO Warns of 'Damaging' Effects From Market Interventions

Patrick Pouyanne, chairman and CEO of TotalEnergies, spoke to Energy Intelligence about today's energy crisis and the dangers of government intervention in markets at the recent Energy Intelligence Forum in London. Edited highlights follow.

Q: Let's begin with this Opec-plus production cut that we've just heard about of 2 million barrels per day. At the same point, we're hearing reports out of the US that potentially there could be additional SPR [Strategic Petroleum Reserve] releases in response to this. What are your thoughts?

A: Opec has been quite efficient for maintaining the price above $80 per barrel. I think that's the fundamental behind all of that, but somewhere there is a feeling that the world is entering into a recession. We've seen that the price degraded from $105 to $85. And so Opec is considering that maybe today the market is anticipating, I would say, less demand and it's time to continue to monitor the price.

So, I don't know, it's not public but I'd guess that $85 was considered by some members [who were] probably not willing to get the price going under $80 or $75, somewhere like that. We know that for some producing countries this is a necessity. I think that's what we can say. After that, I will not make any politics, and [as for] the reaction of a consuming country like the United States, we are in election period, you know, so let's see.

Q: But this reaction from the US — I mean, in a way we've seen discussion at the G7 level of a cap on Russian oil prices. We saw Opec respond with a bigger-than-expected cut. We saw the US come back with the potential for additional SPR releases. What does this say about the relationships between the major producing and consuming countries?

A: I think it means that in fact each of the countries have different roles. One is to try to stabilize the market. Producing countries obviously face also some need for social and economic development. I would say, honestly, I'm not sure that a price or a cap on Russian oil is a good idea. Personally, I don't understand. I think it's a bad idea, in fact, because it's a way to give the leadership back to [Russian President] Vladimir Putin and I would never do that.

Who is buying Russian oil, fundamentally? Europe, 1.6 million b/d; India, which [has gone] up from 500,000 [b/d] to almost 1 million [b/d]; China and Turkey. Turkey is full of Russian oil, so there is no more gap. So where will Russia go with 1.6 million b/d? In India, China? These two countries have a huge bargaining power to [get] themselves a discount. Why not? What does it bring really a cap on the Russian oil price? I don't understand. I'm sure that if we do that, Putin will say then I don't send my oil and then the price will not be at $95 it will be at $150. I would not give that to Vladimir Putin. I would let the market behave. I think that Indian refiners and Chinese refiners will be good to get some discounts and to put a cap for the benefit of the two countries.

I understand that today all Western governments are under pressure from the customers, that's clear. Having said that, those same Western governments were explaining to us not so long ago in Glasgow that we should stop subsidizing fossil fuels, if I remember well — that we should let the price make the transition. It seems that it's more difficult than we expected. So again, I don't think these interventions are very efficient. I think honestly, there is a big discount on Russian oil, and I think Russia will have maybe some difficulty to find buyers for 1.6 million [b/d] without higher discounts.

By the way, there is a reason why Russia is ready to participate in an Opec cut, just because they are not sure to find somebody to buy this oil. So maybe India will benefit from that … What is happening today in India is interesting. There is a discount, but the discount is captured by the state because they put in place a heavy taxation on refiners. So in the end, the Russian discount is finalizing the subsidies of India to this huge population with its energy. Is it wrong? No, it's not wrong. I think it's quite good.

Q: Speaking of market intervention, this global Russian oil price cap proposal is not the only price cap that's being talked about. I mean, here we have the EU talking about capping natural gas prices, whether from Russia or globally. You're a major LNG seller, there's worry that if they cap gas prices that maybe those cargoes won't flow into Europe. What's your view?

A: That's clear. You know, Europe has a deficit of gas, and the gas is coming from the international market. So somebody will have to explain to me how a cap could help Europe solve this supply issue. Or you put a cap linked to the LNG worldwide price higher than the Asian price. We face a clear situation. We need to bring to Europe this year 50 million tons of LNG. I remind you that the [global] market is 400 million tons and if we want to replace all the Russian gas, it's 100 million tons. So it's a huge shock — 100 million tons out of a market of 400 [million tons]. So of course, the only way is to pay a little more than the Asian buyers, and this is what we have done. So I think the only thing which could be done … is if there are some friendly negotiations between Europe and Norway, and Norway accepts — by the way it's not Norway, it's Equinor, which is a listed company, because again, people forget.

What strikes me is that since the beginning of the crisis, it seems to be a state-to-state market, but in fact it does not work at all like that. Sorry to remind everybody that it's a company-to-company market. In between the US and Europe, the power of President Biden is to accept, to say yes I approve this project and I give a license to export for three or four years. But at the end, it's offtakers, our European companies, our international companies and developers, our US private or public companies. That's the reality of this market.

Of course, the states are under pressure from their citizens, from their consumers to take action. But at the end of the day, they should rely on the companies. For example, in Europe, I have been surprised that none of the governments ask the two largest LNG players (Shell and Total) ... to bring LNG, to commit to bring LNG. Nobody came to us. We are doing it by ourselves. It's a strange mechanism because we are there. I have a portfolio of 40 million tons of LNG. So, I'm bringing that according to the dynamic of the market.

So, honestly, I understand the pressure. In fact, something is strange to me. The market was working very well in Europe until this exacerbation because of the stress created by Russia. The mistake we have probably [made] is not to test the stress. Of course, the market today is facing some problems of liquidity because of huge volatility because we have some counterparties, which have margin calls. We have things that are difficult to manage. In fact, my recommendation to the governments is the best thing they could do today is to announce that in these markets if there is a failure of one counterparty there would be a guarantee of last resort either by the [central bank] or state.

If they do that, immediately, you are putting back some liquidity in the market. Today, even our company, we have been obliged to say to our traders, "relax." We received one night an $8 billion margin call. The day after they were in my office and I told them, OK, let's take action, you know, no more. [It's] no problem to find $8 billion because I'm TotalEnergies, but I could imagine other players who could have difficulties.

And again, by the way, a margin call is supposed to be working capital, but if one party defaults then it is cash out. So, we need to find ways to inject liquidity in the market to avoid these incredible high prices. Putting a cap on the gas, I mean, if it's one-sided by Europe it cannot work. We are integrated in the world market. We are interconnected, and we need this LNG. Again, if it's friendly with one country, with Norway, [that's all] well [and] good. But that's diplomacy, it's not a market story.

So, I don't recommend at all to take an action which would be unilateral from Europe because the consequences could be really damaging for the suppliers of the market and for the consumers.

Q: This gets at this broader question of, as we talk about energy security becoming ever more important, who pays for energy security? His Excellency [Saad] al-Kaabi [of Qatar] said I'm happy to bring LNG to Europe, I'm happy to sign those contracts if private companies in Europe are willing to add that premium to bring the LNG in. So, who pays for energy security if it's what everybody is asking for?

A: We speak a lot about energy security today. I'm not sure this concept was in the debate one year ago. Even if we are permanently explaining that basic energy is a matter of reliability, of sustainability and affordability, that's the three components. The lesson of 2022 is that the last element — affordability — is the most fundamental one for either customers or industries. It's their life, it's their purchasing power, it's the way to manage their costs. So, affordability is even more important than sustainability. This is a lesson of today because we subsidize a lot of fossil fuel today. So that's a lesson which we need to keep in mind.

On the security of supply, I mean, this is a real question for Europe now. The best way for Europe to secure the gas supply today is to do like the Japanese did 30 years ago. Japan understood that it's a country which is not blessed with LNG. So, they committed to long-term contracts, with big volumes and no diversion clauses. They want the LNG to come to Japan. When you add that, so you have a good element for the customer, duration where you know the price because we value that, volume is an element of course, and no diversion has a cost. So if Europe today wants to secure some supply, I would invite them to look to what Japan [has done] very well for 30 years, which is engage in 15-year [contracts], large volumes, and if you don't want any diversion clause, because you want to be sure, that has a cost.

And the market is answering to that. It's not diplomacy which will solve the issue. I mean, it's not because you have all the leaders of Europe going to Qatar that it will help to solve the problem. It's important that people realize that the answers are there if we [allow] the normal game, if we accept the game and we understand the fundamentals, and then we'll have the volumes and maybe the price. This year, with the formula in Asia, we sold our LNG, which is more or less half Brent-related, half gas index-related. The average was not $25, $30 or $40 per million Btu, the average was around $15/MMBtu.

With my portfolio there is always this question, should we have Brent or gas? I say 50-50, you know, because I don't know what will happen. Historically, we think that gas was less valorized than oil, and suddenly it's more. So, my answer to all my colleagues is 50-50, and I would give the same advice to buyers. You should have a 50-50 portfolio. Maybe you will win for oil, sometimes you will win for gas because the two dynamics of the markets are not fully correlated. I think that's a lesson.

Our European leaders should go to Japan, they would have good training there.

Q: You mentioned affordability is fundamental, and at today's energy prices, energy is not affordable for much of Europe, particularly consumers. Yesterday, [Shell CEO] Ben van Beurden said he felt like some levies on energy players were inevitable to help cushion the blow to consumers. What is your thinking on windfall taxes?

A: My first answer is we did not expect the debate to begin within TotalEnergies. In March and April, when we announced the first-quarter results, we took the initiative without having the debate, ourselves, to propose a rebate to the French consumer of 10¢ per liter of gasoline. Why? Because we understood that announcing results, which were several billion dollars would create a shock. I was then encouraged in July by the French government, which did not want to put a tax in place because they don't like this idea that when you make a profit you tax. To continue to make the rebate, they encouraged me to increase it. Today, we are so popular in France that we don't have enough gasoline to distribute in our stations, which by the way is interesting because when we move the rebate from 10¢ to 20¢, it has a huge impact on the consumption.

I just want to remind people in the room of two elements which are important. When we look to the results and the cash flow generated by TotalEnergies in 2022 compared to 2012, the price is the same — $100/bbl. I eliminate the surplus of gas. We will generate $15 billion more at the same price just because all the teams of TotalEnergies have worked hard to restructure the portfolio, to lower the break-even to $25/bbl … in the last 10 years. And I'm proud of that.

So, it's not coming for nothing. It's coming because we have made some choices about the oil portfolio, to restructure it and to lower dramatically the cost, to be strong in the Middle East when other players were not betting on the Middle East like we have done, to make the choice of LNG, to become among the top three players in LNG — Shell, Total, Qatar — and strongly, heavily when some people were selling their assets, we bought the gas terminal, which today has a value. So, today people are telling us you make too much money, but these choices, I mean, are maybe not as obvious as it is because some people were selling when we were buying, you know, so I think it's a result of the strategy.

Yes, we have a problem, I agree. I made two distinctions in what I explained to the French parliament [during a hearing] … in producing countries, there are some mechanisms in the fiscal contracts where of course when the price is higher they increase the taxation. TotalEnergies will pay in 2022, $30 billion of corporate tax and production tax compared to $15 billion last year. But we pay that to Angola, Nigeria, Abu Dhabi, to the producing countries because this is where between the cost and the international price, it makes a difference.

So, in Europe, when countries like the UK increase the taxation — which I'm not fundamentally against because they were able to lower the taxation when the price was low, so they have a flexibility. Norway does not need to do it because … there is not much [more] to take. So, I make a big difference between the producing countries, and in the EU you have the Netherlands, Denmark, Italy for example, and the refining business. And the refining business, for me, honestly, as I explained, we lost money during the last three years. In 2020 just in France, our loss was €1 billion. Nobody complained at that time, and we did not complain. We never went to any government to ask them to offset this €1 billion. And today, because we are not making €1 billion of profit — I can tell you, it's less than that — it's not acceptable. But who will invest in such a business? We invest, we accept to invest. Refining is not a rent, it's a margin business and it's quite a capital-intensive business.

We accept to invest because we know that we'll have some downside compensated by upside. If when the upside is coming, it's captured, why should we invest in such a business? By the way, I'm asking myself that question today, and that could have some consequences. I mean, I'm not threatening, I'm just saying that at the end of the day, we'll allocate the capital in the constituencies where we feel that we are safe for the capital we invest.

Maybe it will accelerate the shift from refining to biorefining. Europe loves biorefineries. And instead of making losses, we'll make profits. I don't know who will ensure the security of supply of Europe if there are no more refineries in Europe. So frankly, I think that, yes, we can contribute when we produce, but the idea that we should contribute for businesses, which honestly are not super profitable is a strange idea. Having said that, I understand the debate. But what is important as well is that the refining business is a continental business. So, if one country is taking a different stance than others, we can begin to optimize. I have plenty of smart people in my company and so [have] a duty to do it.

So, coordination at a European level is fundamental for a market which is a European one. Refining in Germany, I'm sorry to tell, but they want to tax. But we have decided voluntarily to stop supplying Leuna with Russian oil. With this decision, we did not improve the competitiveness of Leuna because tomorrow the supply to Leuna is more expensive for the Polish system. I didn't go to the German government to tell them you need to compensate us, and they asked us to continue to run Leuna.

So, I know that in these countries we speak about partnerships, but sometimes when we face a situation like today in Europe, where it's a war, we should understand that the only solution must be found together between governments and companies, and antagonizing us against the others will lead us to be more selfish, I think I will say.

We are ready, and I'm absolutely clear, I'm ready to contribute. We are in many countries, to be smart, to understand what are the solutions, but if it is coming with no dialogue and no debate then it will be a mistake. So, to your first question, I prefer clearly to continue to make some voluntary rebates for our customers where they see directly what we do rather than entering into this type of taxation and financing the deficit of the government, the states.

Q: Total increased its capital spending a little bit in its last strategy day, I believe by about $2 billion. But really we haven't seen IOCs [international oil companies] break capital discipline. I mean, it used to be said that the cure for high prices is high prices because high prices unlocked additional investment, but that's not happening globally right now. So, what's the cure for high prices?

A: I will not speak for my colleagues, you know, we have a good question, a good problem, which is yes, we have more cash. Where do we allocate it?

We have decided that it's an opportunity for us to accelerate our strategy of transformation. So, the guidance is up to $18 billion. I know that some people say, oh, they lose the discipline. I'm not sure we lose the discipline to add $2 billion when we have much more cash. You know, I think it's normal, it's logic. Most of it is dedicated to accelerate the new energies transition. This year, we'll spend $4 [billion] out of $16 [billion], and we have announced up to a third. So, this is the correct answer to the windfall tax. The best answer for our industry is not only helping our consumers directly, it is to invest more for cash in the transition. I think this is the right stance.

And from this perspective, I'm very comfortable with the strategy of TotalEnergies, which is to maintain oil that the world needs, to increase LNG, which is becoming a star in the energy debate. So, we'll continue to increase LNG and to invest in electricity, renewables, biofuels, biogas. So, I think we have a right answer to this political debate, and I don't need to have funds or I don't know which subsidies to invest. Let's do it by ourselves. And I think I would invite my colleagues in the industry to do the same rather than having regulations for windfall taxes everywhere.

Oxy CEO Hollub: Low-Carbon Oil Critical to Energy Transition

Since taking over as president and CEO of Occidental Petroleum in 2016, Vicki Hollub has overseen two major transformations of the US-based company. The first came through the acquisition of fellow producer Anadarko Petroleum in 2019; the second, which is still ongoing, is turning Oxy into a leading developer of large-scale carbon solutions, including direct air capture (DAC) and carbon capture, utilization and storage (CCUS). Hollub spoke at the recent Energy Intelligence Forum in London about the company's approach to low-carbon oil, technology investing, and collaboration. Edited highlights follow.

Q: Oxy really has a differentiated approach to the energy transition, with its focus on direct air capture and sequestration hubs. And I definitely want to dig into that a little bit in a minute. But first, can you just give us an overview of how Oxy sees itself contributing to the energy transition, and maybe a little more generally, what role you think oil and gas companies have to play in the transition?

A: Yeah, we've built a strategy that really leverages our core competence of CO2 enhanced oil recovery [EOR], we've been doing it for 50 years, and we're still the largest handler of CO2 for EOR in the world. And we believe that the role that we can fit is leveraging that core competence, leveraging the infrastructure that we have in the Permian, and building direct air capture facilities to extract CO2 out of the atmosphere for sequestration in saline reservoirs, although I think that's a waste, maybe we'll talk about that later. Or we're using it in EOR. We also have the sequestration pumps that will take point source CO2 and sequester it. And we feel like that the role we play is that gap right now, because a lot of companies are going more toward renewables. And that's good, because we need those. And I applaud the infusion of capital that those companies can bring to that effort. But there still has to be carbon capture, and it has to happen in a big way. And then in addition to point source carbon capture, there has to be direct air capture on the atmosphere. And without those two working well, and in a big way, they cannot cap global warming, even at 2º[C].

Q: In your view, what should we be prioritizing in terms of energy production and development in the context of energy security, and what has unfolded in Europe and the rest of the world over the past seven or eight months?

A: Well, I think the important thing is to have a better planned climate transition for the world. I think that what we see in some regions are, there's no climate transition happening. And that's not good. In some areas, there's an acceleration and the climate transition is way ahead of where we really can be, and still have a just transition that doesn't put regions of the world at risk, from a security standpoint, national security, and/or from a leaving people behind standpoint. So, I think that it has to be better planned out, and I think that until there's massive industrial-size batteries that will fit with wind and solar, we've got to really think about how do we make this transition happen. And I think it's going to take quite a bit longer than most people expect.

In addition to that, I think that what's being missed in the world today is the fact that we all should be focusing on emissions, not on the fuel source. And if we focus on emissions, I think there is a way to continue the production of oil and gas for the foreseeable future. And I'm talking 2060-70-80, I'm not talking about ending fossil fuel development in 10 or 20 years. I think we can continue to produce it, if we will deal with the emissions from it. And we have the capability to do that. And I think if the world could realize that, then I think it would also be an affordable transition. I don't think the world can afford $200 to $300 trillion to pay for a transition that currently some people want to drive too quickly.

Q: Carbon removal is probably one of the hottest topics in industry right now. And Oxy is positioning itself as a leader on that front, as you kind of mentioned. But there is a lot of criticism of the spotty track record of CCUS projects to date. And this idea that this money would be better invested in renewables or in widespread electrification. What gives you confidence that this generation of carbon capture and CCUS projects will succeed and be able to meet the levels and the scale that we need to have to really make an impact?

A: I think you hit it with spotty. What's happened in carbon capture has been spotty. And it's been for various needs and various reasons. What I feel like is there hasn't been a consistent effort to improve a specific form of the technology. The ability to separate CO2 from hydrocarbon gases has been around for 50 years, there's technology to separate CO2 from air. But traditionally, it hasn't been at a large enough scale to matter. We're building one that's going to be at large enough scale. But I think that you can't just put these one-offs, there's 20, 30 or 40 around the world, but there isn't a consistent effort to refine the technologies where they are in a better way.

A good example is the Permian and in the shale revolution. The shale revolution happened because we were developing technologies and consistently refining those technologies over time. But we didn't do it by drilling 10 wells. We didn't do it by drilling 20 wells. It took hundreds of wells, and then almost thousands of wells to get the technology to the point where it was repeatable, and at a level where the revolution could take place and could be done economically.

So, I think that what's going to happen today is, more and more companies are interested and more and more companies are starting to do it — we have to do it consistently. And what we're going to do with our direct air capture is we're going to build a digital twin, as we're building the first train of the first plant. So, we'll build a 500,000 ton per year facility in the

Permian. We're doing the site preparation right now. And we'll start construction on the facility itself by the end of the year, and having a digital twin as we're building it, to use to optimize it, and then make it better and make the next generation, which will be the next year. And basically, because of this acceleration, we're going to be able to advance that technology a lot faster.

Wind and solar reduced their costs by 80% over a 10-year period, but they didn't have the benefit of the kind of technology that we have today. From a modeling standpoint, they didn't have digital twins back then. So, they had to just build and modify and build and modify. We can modify on the fly, and then make step change differences from the first to the second, third, fourth units. So, I think there's going to be a difference in the way carbon capture, use and sequestration technologies develop today.

Q: You mentioned that you're going to start construction on that by the end of the year. I believe you said previously, third quarter was when groundbreaking was due. What's the latest on DAC 1 in the Permian?

A: DAC 1, we're doing site prep. We've announced that we'll have the groundbreaking on Nov. 29. It is a big deal to a lot of people, there are already 250 people that want to be there for the groundbreaking. So, it is an important technology that we have to build. I think someone said earlier that currently the largest direct air capture facility in the world is Climeworks, and it extracts 4,000 tons/yr out of the atmosphere. And I applaud Climeworks, I think that was their fourth or fifth unit. And that unit is performing well, they are a company that is doing that repeatable development, and they are having success. So, that's an important technology. But it's not scalable yet. They're working to make it in a way that ours is scalable. And we expected to build 70 of these by 2035. So that's 70 million tons/yr that we'll extract out of the air, we'll be doing that before 2035. And actually, the IRA [Inflation Reduction Act] bill in the US has helped us to get to the point to accelerate, because we'd like to go to our more advanced model, which would be 135 plants before 2035.

Q: You mentioned the Inflation Reduction Act and some of the incentives that it provides to help accelerate some of these technologies. I think it triples the amount of tax incentive for direct air capture, in particular. But all the same, 135 plants sounds very ambitious, in really any scenario, but what do you need to see happen to actually get those in the ground? I mean, is it even more policy support, cost reductions, technology advancements?

A: The policy support from IRA is what's going to help us be able to accelerate because that is stackable with selling the credits, so that's going to be helpful. And it's also going to take partnerships, it's going to take now having others become a part of the projects and help to finance and build these. So, there's going to be a lot of collaboration that needs to happen. But we're getting a lot of interest in this because the reality of where the world is today is there are not enough certifiable CO2 credits for the more than 2,500 corporations that have committed to net zero. So these CO2 offsets are going to be in high demand.

Q: This is going to require a massive amount of capital. And in any event, you're talking, at least for the first one, $800 million to $1 billion for that one. How do you think Oxy will finance the construction of these plants?

A: Certainly, the first one is likely to be a combination of our cash plus potentially a partner coming in on that. And we've already begun to sell the CO2 credits. That'll happen with the first one. Once we prove the technology on the first one, we'll be able to access project financing going beyond that, and/or partnerships. But in any case, what IRA does is, it lets you take the credit for the CO2 that's provided as a part of that bill. And you can also then sell the CO2 credits from it. So we expect that we will be getting sufficient revenues from the sale of the CO2 credits to help with the additional units that come after.

Q: And would you expect all or most of those plants to be tied to enhanced oil recovery projects like DAC 1?

A: Now, that is the issue. I do consider putting CO2 into a saline reservoir a waste of a valuable product, because CO2 can be used, it can be useful, and it could be useful for the transition if we use it in a CO2 EOR project. And there's a dual benefit from that. So, if you take CO2, put it in a reservoir to generate more oil, that oil is either carbon neutral, or carbon negative because it takes at least as much or more CO2 injected into the reservoir than what the barrels produced from that injection will generate when used. And that's an important point. Because that oil being carbon neutral or negative can then be turned to convert it to fuel for maritime, jet fuel for aviation. And it provides those hard-to-decarbonize industries a way to have zero-carbon fuels.

But the other part of that is injecting CO2 into an oil reservoir enables you to recover more from that oil reservoir. If you can recover more from that reservoir, you will be doing it with infrastructure that's already been installed. So you don't have to go out and get more steel for the facility, or more rare minerals for the controls and all that. So you have that same footprint that you've already paid for that already exists, you don't have to go duplicate it. I think it's more important to get more oil out of the reservoirs that we produce today, rather than going into the remote areas of the world to develop incremental oil, especially if it's in pristine areas that we want to protect. So, that part of it is incredibly important. And for us, we've got a reservoir in the Permian, that we've gotten up to more than 70% of the oil in place. So, I think the last barrel of oil produced in the world should come from a CO2 EOR project.

Q: I think you've made a pretty clear argument as to how this equates to low-carbon oil or carbon-neutral oil. But there is obviously still a lot of criticism around this idea of using captured CO2 to produce more oil. It is somewhat of

a hard concept to grasp. Do you think that message can resonate or is resonating with people who might not be quite ready to accept it?

A: It resonates more with people who can put aside some of the paradigms that exist out there. And I know it's initially hard to get, but ultimately we're only going to be supplying the oil that is demanded by the world. So, to get the oil out of the CO2 EOR reservoir doesn't mean you're over time producing more oil than the world demands, you're just meeting demand. So, it's better to meet that demand with a lower-carbon oil, or a no-carbon oil.

Q: I want to shift gears a little bit and talk about Oxy Low-Carbon Ventures and some of the technologies and opportunities that you see coming out of that. I feel like, more often than not, I come across some start-up with some new technology, and Oxy is behind it somehow or involved somehow, whether it's through a partnership or an investment. So, how would you say that the Low-Carbon Ventures unit reflects on Occidental's broader strategy around technology and the energy transition? And are there any especially cool technologies that are coming out that we should be paying attention to?

A: Well, it's not a venture capital kind of strategy that we have, we only invest in technologies that we think will be complementary to our strategy, and that we will actually consider building or funding to be built, or partnering so that it becomes a part of our operations or supplemental to our operations. So, I think Cemvita is a great one because we're not just an oil and gas company. We have a chemicals business and Cemvita is a Houston-based entrepreneurial company that is working to convert CO2 to bioethylene, and our chemical plants use a lot of ethylene. So, to have bioethylene is incredibly important.

A second technology is Lanzatech, and Lanzatech converts CO2 directly into fuels, and that technology is really interesting. We also are working with a company that can convert CO2 to put it in clothing. We want to pursue the opportunity to convert, to put CO2 not just in cements but to put it in construction materials too. So that you have a way to build a stronger house or stronger office building and use the CO2 for that. But NET Power, I believe, is going to be transformational for the power industry, especially in the United States where there's a lot of gas. NET Power combusts hydrocarbon gases with oxygen instead of air. So, as a part of the process, it separates out with CO2, which drives the turbine to produce the electricity, and then it spits off a pure stream of CO2 that's excess. And you can take that CO2 then and do any of the number of things that I've just mentioned. So, I think those are the most exciting technologies that we have today.

Q: We talked about EOR, and that's obviously going to be part of the business. But do you see some of these emerging technologies as taking up a larger share of the CO2 that you capture?

A: Yeah, I think over time we want to help people understand, let's not put it in saline reservoirs, let's put it to use for other, better things. And so I think that over time, as a lot of these companies start getting better at what they do — and I think there are more start-ups happening all the time, and there's a lot of innovation happening around our world, and a lot of it is around CO2. So, as we know, people are making diamonds with CO2. So, I think there's a lot to be done with CO2, we just need to figure that out and work that a little harder, and support the companies that are doing that. And I believe there will be more of that coming.

Q: I just wanted to get back to this idea of low-carbon oil, and specifically the US Gulf of Mexico. This is an asset that Oxy acquired in the Anadarko deal. And in my opinion, anyway, it is maybe one of the more underappreciated assets in Oxy's portfolio. We've heard a lot about how the US Gulf has some of the lowest-emissions-footprint oil globally. So you are one of the largest infrastructure owners in the Gulf of Mexico. So, how do you see that asset fitting into these larger questions around energy security, and for Oxy in particular?

A: Well, the Gulf of Mexico is really important to us because of what you've said. It's lower-intensity carbon, and it's one of our higher-margin assets. So it will continue to be a big part of what we do. The other part of it is that future development will continue to be lower intensity with respect to CO2, because we'll be able to use the infrastructure that we have. We just put in a subsea pump system that actually expands the trajectory of how far out we can develop wells and still get it to the existing infrastructure. And wherever we can, that's what we're trying to do, is not build new things that we don't need to build, because that does create a bigger carbon footprint. So, we're trying to utilize the infrastructure every way that we have to meet and minimize what we use from the carbon standpoint.

Q: I just had a question around a new lower CO2 oil — it will come with some additional cost, I would think. Are your buyers willing to pay a premium for lower CO2 oil? I know you have done a deal before, but are you seeing continued appetite given energy inflation from your customers?

A: Yes. We've had conversations with companies that are united, clearly as expressed, that they either will invest in the direct air capture, or they'll pay a premium for the oil. One of the two, SK Group, has come on board, is wanting to get low-carbon, carbon-neutral oil, and they're willing to pay a premium for it. Other companies are now expressing the same thing. So, I do think it will command a premium. And I think we'll be able to get that — I don't know how much, that's still open right now.

Q: You said you think that the energy transition is going to take a lot longer than some people think. By what year would you think is a realistic goal for net-zero emissions? And do you think that the global governments are going to

have to revise up the goal in the Paris Agreement to limit warming to well below 2ºC?

A: Yeah, I think that without much, much better collaboration, we're not on the path to achieve 2º, we're just not there. Because we're not collaborating with other industries. We're trying to. Oil and gas companies were not allowed in any of the meetings at COP26. We're already working right now on COP27 and COP28. In both of those we'll be a part of the discussions because both of those are in hydrocarbon-producing countries that want oil and gas to be a part of those conferences. And so I think we'll get in to have that discussion. But the problem is, there's too much misinformation out there about the transition. Too many, I would say, high-profile people just don't have the right data. I don't know why they don't have the right data, but they don't have the right data; the message that they're delivering is not creating a cohesive enough environment for us to be able to partner across sectors to be able to make this happen … And if we can't pull together to fight this together, then there's something wrong with the world. There's something wrong with people who won't be in the same room with an oil and gas company to talk about how do we fight this together.

Q: Just follow up on that. You've talked about the need for a price on carbon in whatever form that takes. What do you think is the most effective way to implement something like that?

A: We don't think that a carbon tax right now works very well, because it's really better to have incentives to develop technology. And then the price of carbon needs to be established at that point. Because if you apply the price of carbon early, then you don't provide for the way to actually build and make the technology better. But we know that there is a price being developed by the voluntary compliance market today. And we're seeing some of that. And as we talk to people about providing them CO2 offsets, we're seeing prices being developed. And you see prices being developed in some of the systems here in Europe. But I think it would be incredibly difficult for there to be a carbon tax, or carbon price applied around the world in an equitable way. I think that would be too difficult and too much to expect.

Q: And as you talk to some of your peers, do you think that is a shared belief among other people in your position?

A: I know that a lot of people want a carbon tax. But again, the carbon tax is likely to provide too much burden on certain parts of the world, certain regions, and it wouldn't be applied uniformly across the board. So there are issues with the carbon tax. And so that's why I like it when the markets can develop the prices, because when markets can develop prices, at least there's some consistency in how it's done. And then it can be applied uniformly across the world.

What's New Around the World

BIOFUELS — UK major BP plans to more than double its renewable natural gas production by 2030 following the acquisition of US landfill gas specialist Archaea Energy. BP will pay $3.3 billion — $26 per share — a 38% premium to the 30-day average share price. It will also take on $800 million of Archaea debt, taking the overall enterprise value of the deal to $4.1 billion. Archaea brings BP about 6,000 boe/d of biogas production from 50 facilities across the US. Most of Archaea's facilities sit atop landfill sites where methane produced by the buried waste is captured before it can escape into the atmosphere. The global oil majors are ramping up their presence in an array of biofuel businesses including synthetic and renewable gases as well as liquid fuels like biodiesel and sustainable aviation fuel. Earlier this year, Chevron announced the $3.15 billion purchase of biodiesel specialist Renewable Energy Group. BP CEO Bernard Looney said that integrating Archaea into BP's trading and supply operations and taking advantage of the many state and federal green energy credits for renewable fuels could augment the already "double-digit" returns anticipated from the business. BP estimates that Archaea will produce $500 million in annual free cash flow by 2025 and about $1 billion by 2027.

CORPORATE — North Sea-focused Ithaca Energy has confirmed plans for a London stock market listing to take advantage of a surge of investor interest in the region as a result of the European energy crisis. The company said on Tuesday that it plans to become a "key player in providing energy security to the UK." It noted that it holds stakes in six of the top 10 largest UK offshore fields, including the two biggest undeveloped discoveries — Cambo and Rosebank. However it did not provide details about the timing or size of its planned initial public offering (IPO) of shares. High oil and gas prices have led to a new wave of interest in exploration of the UK North Sea after years of declining investment. The UK government wants to increase domestic fossil fuel production, and Ithaca's controversial Cambo oil field is on a list of priority projects. Ithaca has been an active buyer in the North Sea, where it has picked up assets from Chevron, Sumitomo, Mitsui and Marubeni. In April it agreed a $1.46 billion deal to buy private-equity backed Siccar Point Energy as part of a plan to prepare for an IPO and raise output to 80,000-90,000 barrels of oil equivalent per day for the next decade from an average of 56,000 boe/d in 2021.

CORPORATE — The board of directors of oil and natural gas producer Continental Resources has accepted the latest offer from founder and chairman Harold Hamm to take the company private. Continental said Monday that its board had reached an agreement in which Omega Acquisition, an entity that is owned by Hamm, will purchase all outstanding shares of the company's common stock that are not already owned by the Hamm family at a price of $74.28 per share. That represents a 15% premium over Continental's Jun. 13 closing price of $64.50/share, just before Hamm made his initial buyout offer of $70 per share. Hamm has long lamented the lack of "freedom" that public companies enjoy compared to their private peers, which don't have to cater to the demands of investors or certain SEC disclosures. While analysts largely believe the privatization of Continental will be a one-off event rather than a bellwether for US E&Ps, the odds of other privatizations in the US shale sector have grown larger over the last year or so due to companies using windfalls from elevated commodity prices to buy back significant amounts of their shares.

CANADA — The Canadian oil sands industry's ambitious plan to capture and sequester carbon emissions from their heavy industrial operations in Alberta will cost an estimated C$24.1 billion (US$17.6 billion), according to the companies involved. In a project update, the Pathways Alliance, a coalition of the six largest oil sands producers, said the first phase of the carbon capture and storage (CCS) scheme would require some C$16.5 billion of planned investment by 2030, plus another C$7.6 billion for other emissions-reductions projects. The group offered no further details about how it intends to finance the project. Members have been in discussion with federal and provincial government officials for more than a year focused on potential incentive programs that the companies say are necessary to move the project forward. The groups, which represent more than 95% of Alberta's oil sands production, aim to reduce annual emissions from oil sands operations by 22 million tons by 2030, with a goal of "net-zero emissions" by 2050. The plan centers around a 400-kilometer pipeline that would connect more than 20 oil sands facilities in northern Alberta to collect CO2 emissions and send them to an underground storage site near Cold Lake.

INDONESIA — Exxon Mobil is looking at the Masela Block's data, Indonesia's upstream regulator SKK Migas told Energy Intelligence. Masela contains an estimated 10.7 Tcf of gas which is due to feed the long-delayed 9.5 million tons/yr Abadi LNG project. Exxon declined to comment, but the US supermajor's interest is understood to be recent. Exxon is moving ahead with liquefaction projects in the US, Qatar and Papua New Guinea, but it has watched the timeline for its Rovuma LNG project in Mozambique slide, which might potentially leave room for other project interest. Tutuka Ariadji, the energy ministry's director of oil and gas, told Energy Intelligence in September that state-owned Pertamina is the only company looking at the Masela Block's data. Ariadji said this during the Indonesian Petroleum Association conference. That said, Indonesia's minister of energy, Arifin Tasrif, told reporters at the conference that local firm MedcoEnergi is considering buying a 10% interest in the Masela Block. Shell opened a data room back in 2020 with a view to selling its interest in the block. The European major has a 35% stake in Abadi; Japan's Inpex is operator with the remaining 65%.

RUSSIA — India's ONGC Videsh has decided to retain its 20% stake in the Sakhalin-1 oil and gas project in Far East Russia by participating in a new operating company for the project that was recently registered in Russia. Japan's Sodeco consortium is also expected to retain its 30% stake in Sakhalin-1, but US major Exxon Mobil is expected to exit the project. Analysts say Russian oil giant Rosneft is likely to pick up Exxon's stake, raising its own interest to 50%. A member of the ONGC Videsh board who requested anonymity told Energy Intelligence that the company will retain the 20% stake in Sakhalin-1 that it originally acquired in 2001. Sakhalin-1 accounted for 23% of the Indian company's total production of around 247,000 boe/d in the fiscal year to Mar. 31, 2022. Russia has emerged as a major supplier of crude oil to India this year, with its refiners taking advantage of deeply discounted prices as other countries shun Russian crude because of Moscow's war in Ukraine. In previous years, India imported only modest amounts of Russian crude, but its September imports from Russia were estimated at around 870,000-900,000 b/d, exceeded only by its imports from Saudi Arabia.

RUSSIA — Russia's second biggest oil producer, Lukoil, is reportedly considering an overhaul of its trading business as it seeks to minimize the impact of EU sanctions on its operations. Under the plan, the Geneva office of Lukoil's Swiss-registered Litasco trading subsidiary would be responsible for supplying the company's refineries in Europe with non-Russian crude, Bloomberg reported. Litasco's Dubai office would handle Russian crude, with a focus on supplying refineries in Asia, the news service added. Lukoil owns refineries in Bulgaria, Romania and Sicily, which will be barred from buying Russian crude under an EU embargo on seaborne imports from Russia that takes effect on Dec. 5. Lukoil also also holds a 45% stake in a refinery in the Dutch province of Zeeland that is operated by French major TotalEnergies. Sources tell Energy Intelligence that they are aware of the restructuring plan, which they describe as an effort by Lukoil to keep its trading business running under challenging conditions. Neither Lukoil nor Litasco are directly targeted by Western sanctions, but market players say that anything linked to Russia is highly toxic these days and a potential source of problems. This could prompt Lukoil to sell Litasco to the company's management, an option that was first raised several years ago.

Marketview

Get on the Floor

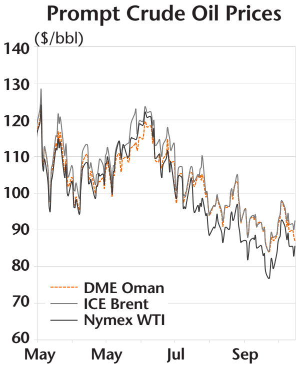
Oil prices are running back and forth in no-man's-land, stuck between consumers and producers who have identified their own acceptable floors. There is a roughly $20 per barrel gap between the levels suppliers seem to deem appropriate and what major consumers have, in some cases quite explicitly, identified as bearable. Within that zone, volatility is high as myriad crosswinds buffet prices.

Following months of downward momentum, Opec-plus stepped into the elevator and slammed the "up" button with a headline production cut of 2 million barrels per day. The bloc seems to be looking at keeping global benchmark Brent crude above the $90/bbl mark.

Initially, prices rose in the wake of the cut. But momentum proved difficult to maintain. Not only does oil face significant macroeconomic headwinds, experts say Opec and its allies are unlikely to be able to cut that much supply. Indeed, the bloc is already underproducing by a significant amount. Some say the actual cuts will likely amount to just 1 million b/d or so.

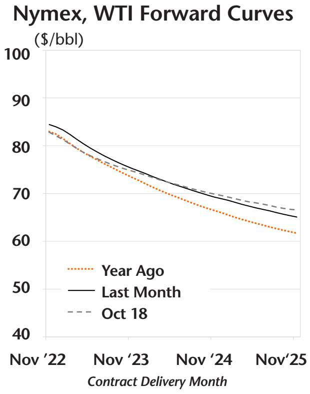
Consumers, naturally, would like a lower price. And earlier this week, US President Joe Biden's administration clarified where that price should be. While announcing the release of 15 million barrels of crude from the Strategic Petroleum Reserve (SPR) — a sale that completes the 180 million bbl release announced after Russia's invasion of Ukraine — the White House also pegged buyback prices at between $67 and $72/bbl. The US remains the world's largest economy and oil consumer; its acceptable crude price can be seen as where the broader consumer base can function. Oil prices climbed in the aftermath, in part because no new releases were announced, but the fact remains that the administration has drawn a line in the sand.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex, WTI Forward Curves



Contract Delivery Month

The $70 mark is below US benchmark West Texas Intermediate's (WTI) forward curve through mid-2024. However, the proposed price band also fits with the hedging patterns of US shale producers. When WTI breeches that level, upstream players are less likely to sell future production via financial instruments such as futures and prefer to increase exposure to the spot market. The higher WTI climbs, the less appetite for hedging. For example, WTI moved above $70 in June of last year, and producers sold 760 million bbl of future production forward. But by this July, with WTI over $100, that volume had dropped to 399 million bbl.

Whatever Opec-plus or the US would like to see, the market is navigating choppy waters. Oil is in extreme flux, facing myriad variables that have sent volatility soaring. Sticking solely to oil itself, these include: the EU's embargo on Russian crude and products and the resulting realignment of trade flows; the G7's price cap on Russian petroleum; a potential dearth of tanker capacity needed to accommodate both of those developments; the recent rationalization of downstream capacity in North America and Europe; and low inventories — a hangover from the Covid-19 pandemic which, whatever behavioral patterns suggest, is still ongoing.

More broadly, fears of recession, high inflation and central banks' moves are all weighing on demand. Major forecasters have slashed consumption projections even as supply concerns come into focus amid Opec-plus cuts and slowing US production growth.

China Awards More Crude Import Quotas

China's Ministry of Commerce has allocated more crude oil import quotas for the remainder of this year to privately owned Zhejiang Petrochemical (ZPC), and state-owned ChemChina, industry sources told Energy Intelligence. The news comes as markets look for a recovery in Chinese oil demand.

The latest allocations add up to at least 13.56 million tons — around 100 million barrels — and will be welcomed by crude sellers. However, that volume works out at a rate of 1.21 million b/d for the rest of the year, which seems too high for all that crude to be bought and delivered in such a short period of time. The news has therefore prompted speculation that the two refiners may have started buying additional crude before the latest quotas were announced.

PIW Market Indicators

($/barrel)	Oct 17-Oct 19	Oct 10-Oct 14	Sep 19-Sep 23
Spot Crude			
Opec Basket	$90.76	$95.62	$95.25
UK Brent (Dtd.)	90.83	94.36	88.97
US WTI (Cushing)	84.95	88.94	83.46
Nigeria Bonny Lt.	93.18	99.08	91.98
Dubai Fateh	88.10	93.29	91.12
US Mars	81.38	86.61	82.28
Russia Urals (NWE)	66.18	71.28	65.44
Crude Futures			
Brent 1st (ICE)	91.35	93.83	89.81
Brent 2nd (ICE)	89.78	92.15	88.68
B-wave (ICE)	91.20	94.18	90.24
WTI 1st (Nymex)	84.61	88.49	83.07
WTI 2nd (Nymex)	83.71	87.29	82.60
Oman 1st (DME)	88.36	92.40	89.86
Oman 2nd (DME)	87.15	90.48	87.46
Murban 1st (ICE)	90.83	95.07	91.51
Murban 2nd (ICE)	89.19	92.89	89.45
Forward Spreads			
Brent (1st-Dtd.)	+$0.52	-$0.54	+$0.84
Brent (2nd-1st)	-1.57	-1.68	-1.13
WTI (2nd-1st)	-0.90	-1.20	-0.47
WTI (3rd-2nd)	-0.97	-1.31	-0.74
Oman (2nd-1st)	-1.21	-1.92	-2.40
Oman (3rd-2nd)	-2.66	-2.60	-2.75
Murban (2nd-1st)	-1.64	-2.18	-2.06
Murban (3rd-2nd)	-1.76	-2.20	-2.56
Grade Differentials			
WTI-Brent (1st)	-$7.65	-$6.53	-$6.92
WTI-LLS	-3.48	-3.21	-2.38
WTI-Mars	+3.57	+2.34	+1.18
Brent(Dtd)-Dubai	+2.73	+1.08	-2.15
Brent(Dtd.)-Urals	+24.65	+23.08	+23.53
Brent(Dtd.)-Bonny Lt.	-2.35	-4.72	-3.01
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$89.01	$94.24	$89.91
Arab Lt.-Europe (Med)	93.90	96.88	94.94
Arab Lt.-Far East (f.o.b.)	95.12	100.17	102.05
Nigeria Bonny Lt.	92.74	96.27	94.88
Arab Light Gross Product Worth			
Rotterdam	$106.75	$108.96	$96.78
US Gulf Coast	106.27	109.17	99.17
Singapore	92.77	94.44	90.05
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$121.24	$123.01	$98.27
UK Brent Margin	+28.03	+26.75	+8.31
US Gulf Coast			
Mars GPW	98.26	101.21	93.73
Mars Margin	+16.78	+14.50	+11.35
Singapore			
Oman GPW	91.60	93.03	90.32
Oman Margin	-0.19	-3.35	-4.36
US Nymex			
WTI 3-2-1 Crack	+$44.07	+$41.10	+$32.46
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$891.93	$954.42	$820.90
Gasoil (0.1%)	1142.08	1132.10	977.35
Fuel Oil (0.5%)*	604.33	613.50	597.75
US Gulf Coast (¢/gal)			
RBOB Gasoline	250.16¢	259.35¢	244.92¢
ULS Diesel	393.25	400.19	326.34
Fuel Oil (0.5%, $/ton)	$646.33	$671.80	$649.20
Singapore ($/bbl)			
Naphtha	$71.19	$73.75	$73.14
Gasoil (0.05%)	133.74	136.23	119.93
Fuel Oil (0.5%, $/ton)	719.33	746.20	692.40

*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.