Oil and Gas Investor

SPECIAL OGI REPORT

PERMIAN PLAYS

THE MIGHTY MIDLAND

Rebuilding the Most Prolific Paradigm in the US

THE OGInterview

KEEPING UP WITH THE JONES ACT

LNG Renews Repeal Efforts on 104-year-old Law

BRINGING THE KNOW-HOW

Woodside Energy CEO Meg O'Neill Banks on Technical Prowess in the US Gulf of Mexico

DOING MORE WITH LESS

US Production Maintains Oil, Gas Volume Despite Rig Count Plunge

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APRIL 2024

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

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UNDISCLOSED	**$324 MILLION**	**$475 MILLION**	**UNDISCLOSED**	**$155 MILLION**
UNDISCLOSED SELLER HAS SOLD NON-OPERATED WORKING INTERESTS TO IOG Resources Financial Advisor	Atlas Energy Solutions INITIAL PUBLIC OFFERING Financial Advisor	Performance Proppants HAS AGREED TO BE ACQUIRED BY ProFrac Financial Advisor	RAM Energy LLC ASSET DIVESTITURE Financial Advisor	Cheyenne SENIOR SECURED TERM LOAN Financial Advisor
$1.3 BILLION	**UNDISCLOSED**	**$55 MILLION**	**$126 MILLION**	**$307 MILLION**
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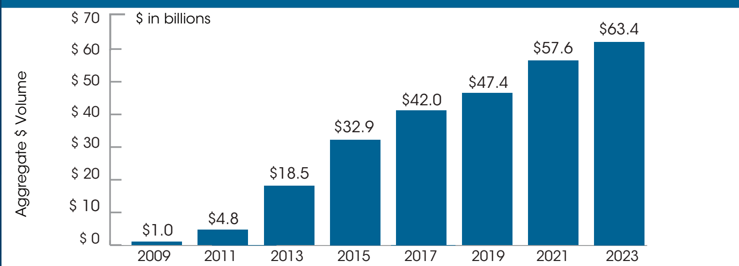
$63+ Billion
Energy Investment Banking Transaction Volume Since 2009

~$300 Million
Average Transaction Size

222
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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The OGInterview

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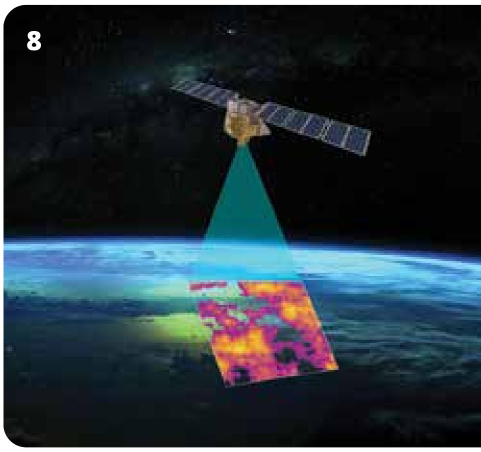
COMMENTARY



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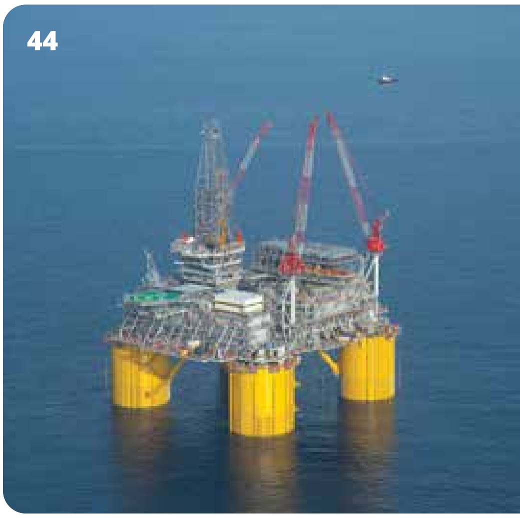

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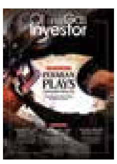
TECHNOLOGY

MIDSTREAM

NEW ENERGIES

GLOBAL ENERGY



ABOUT THE COVER:
Photographer Tom Fox captured this image of Casing Specialties worker DJ Crane making pipe connections on Unit Drilling rig 408 at QEP Resources' University Land well 1125 W5 11SB in Andrews County, Texas.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Get Ready to Renew

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Ah, springtime in Texas. There's a lot to be said for its reliable rhythms. Swaths of bluebonnets emerge in lavender waves along the highways. Daylight saving claims an hour of our limited time. Oil and gas producers weigh commodity prices' wild gyrations. Public companies rehearse for annual shareholders meetings. The air in Houston, warm and thick with moisture by mid-March, feels heavier every day.

And then, there's spring 2024.

The above is all still true. But this year, there's some industry excitement tinged with a sort of "what's can possibly be next?" thrill.

Consolidation is hot throughout the U.S. energy sector, but nowhere does it sizzle with the wild crackle and flame as in the Permian Basin. In this edition of *Oil and Gas Investor*, we're launching a series of in-depth reporting and analysis of the emerging landscape with a story about the mighty Midland Basin. Next month, we'll take a similar approach to the Delaware. In June, our editors will tackle completion strategies and map what's happening in the midstream. A July feature will follow on the remaining family-owned operations.

Not to rely solely on our land legs, this month *OGI* has an exclusive interview with Meg O'Neill, CEO of Woodside Energy, Australia's largest oil and gas independent. Its multi-billion-dollar investments in the U.S. Gulf of Mexico and around the world are driving home the global spending trend in which offshore–and international–is leading capex this year.

But there is trepidation within the industry, too.

In mid-March, the Waha Hub natural gas spot price in the Permian traded at less than \$0.50/MMBtu; 2024 bids parked at negative \$0.77 and 2025 bids at negative \$0.69. That's fine for midstream players, but producers with copious amounts of associated gas in their supply are likely less thrilled by the prospect of paying pipeline operators to haul off low- to no-profit volumes. We'll explore the factors shaping natural gas prices and producer strategies in the May issue.

A steady stream of M&A news flows throughout our coverage in the magazine and on the website. And it's not just in the Permian where companies are–not desperate, but certainly, ardent–in their quest for scope and scale that they are joining forces. Appalachia's EQT Corp.'s play for Equitrans would vertically integrate the U.S.'s largest natural gas producer. While it reads like a logical idea on paper, the deal will likely face intense federal regulatory scrutiny. EQT shareholders reacted to the announcement with a selloff that sent the stock price down almost 8% by market close on March 11.

In short, this spring season of annual renewal will be a fascinating one.

Our team has big plans on the horizon for you, too. I joined *OGI* two years ago this month amid an ongoing redesign with a team that was largely in flux. It's my pleasure to tell you that today we've got one of the strongest teams in the business and the magazine, in my humblest estimation, just gets better every month.

And we're not done yet.

In addition to the mega Permian series we've got on track, we're rebuilding our brand of enterprise journalism, which will be featured in every future edition of this magazine. That's the kind of work most of us get into the business to do, and we're thrilled that our recently returned CEO Rich Eichler is a fan, too, and that he supports these efforts. Watch this space, folks. It's going to get awesome.

But none of what we do succeeds when it's done in a vacuum. We want to know what you like about the magazine–as well as what you think we could do better or differently–so that you look forward to reading it every month. With that spirit, I invite you to shoot over a text to my personal cell phone at 512-619-5473. Let's talk soon. OGI

DEON DAUGHERTY
EDITOR-IN-CHIEF

JOE TO THE WORLD

Is MethaneSAT Watching You? Yes.

EDF's MethaneSAT satellite is the first devoted exclusively to methane and it is targeting the oil and gas space.

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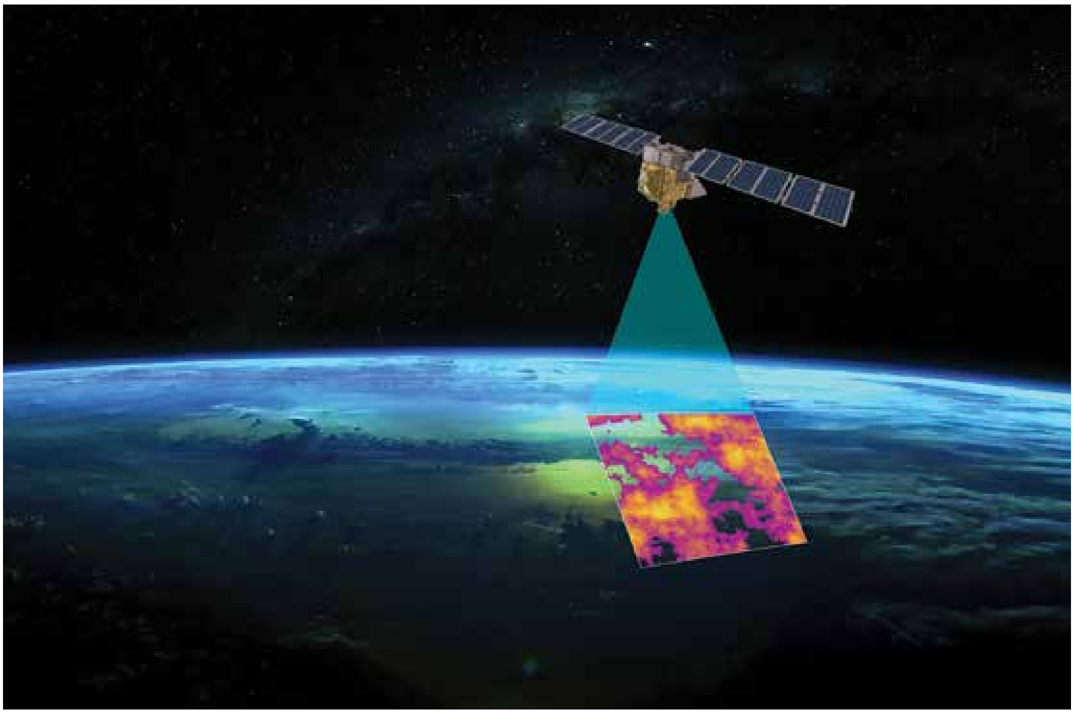


METHANESAT

MethaneSAT will create heat maps that are 200 km x 200 km, focusing on oil and gas basins.

Have the environmentalists placed a narc in the sky to methane shame oil and gas operators? Yes, they have, but there's more to it than that.

On March 4, SpaceX's Falcon 9 rocket streaked toward the heavens carrying MethaneSAT, a refrigerator-sized satellite meant to monitor methane emissions in oil and gas basins. The state-of-the-art tracker can capture enough emissions information to satisfy the collective data cravings of every nerd you've ever known.

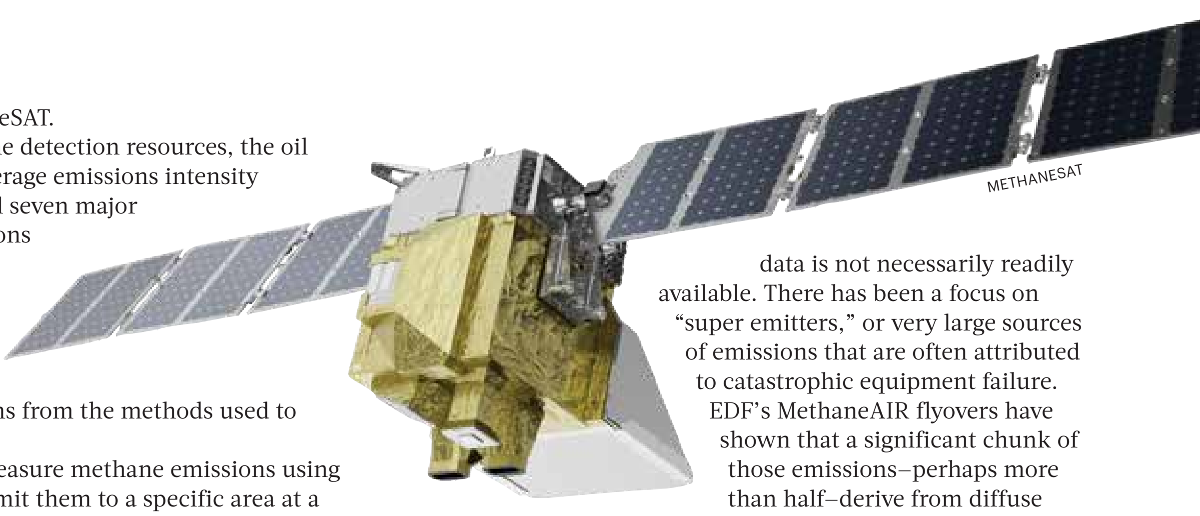
The satellite was developed by the Environmental Defense Fund (EDF), a research team at Harvard University, Ball Aerospace and others. Google will host mission analytics on its cloud and make data available to the public on its Google Earth Engine. Other satellites track greenhouse gases, including the European Space Agency's TROPOMI, and GHGSat, a private company, but MethaneSAT is the only one built exclusively for methane.

Not everyone is thrilled about the prospect of an environmentalist organization's satellite turning its sensors toward a basin's operations and sharing what it knows with the world. And, to be fair, methane outing is part of the mission.

"I'm sure many people think that this is a tool that could be used to name and shame companies who are poor emissions performers, and that's true," said Mark Brownstein, senior vice president, energy transition for EDF during a press event prior to the launch. "But I like to think of it as a tool that can help document progress that leading companies are making in reducing their emissions."

API has already indicated a preference for the Environmental Protection Agency (EPA) to handle that task, rather than relying on third-party data. EPA's new methane regulations that went into effect on March 8 allow third-party input and EDF would be allowed to apply for certification for MethaneSAT.

Using its own methane detection resources, the oil and gas industry cut average emissions intensity by almost 66% across all seven major onshore producing regions from 2011 to 2021, API says. At issue, though, is the accuracy of the data underpinning those numbers.



Some of that doubt stems from the methods used to collect it.

Scientists typically measure methane emissions using planes or cars, which limit them to a specific area at a specific time. The trouble with this method is that methane emissions tend to migrate, so a snapshot at one point in time would not look the same as a snapshot a few days later, making it difficult to determine where the emissions were, how much methane was escaping into the atmosphere, and the change over time.

"We needed to really have some way of looking constantly to take the snapshots of what was happening and turn them into a motion picture, and the only way we could do that effectively was from space," said Steven Wofsy, MethaneSAT's lead scientist and professor of atmospheric and environmental science at Harvard.

EDF's surveys, both in the U.S. and in other global regions, show methane emissions are about 60% higher than what has been reported to the EPA and other regulatory agencies. The industry can't tackle the problem of methane emissions without complete data on the extent of the problem, and data is not necessarily readily available. There has been a focus on "super emitters," or very large sources of emissions that are often attributed to catastrophic equipment failure. EDF's MethaneAIR flyovers have shown that a significant chunk of those emissions—perhaps more than half—derive from diffuse sources.

Larger oil and gas companies may be able to handle the expense of hiring a firm to fly over their operations with a LIDAR device to measure emissions, but many smaller producers would be hard-pressed to do so, especially when sudden drops in the price of WTI cut into margins. Access to MethaneSAT's data, which will likely become publicly available early in 2025, will be a cost-saver in pinpointing trouble spots.

It's a new world, and not just because a rocket booster can zoom into space and return upright to its launch pad. Investors may return to the oil and gas space, but a company identified as a methane emitter that is unwilling to address the problem will have a tough time attracting funds.

Emission control is simply a part of doing business. And if you think you can hide from that reality, then just look up in the sky. OGI

▸ ENERGY POLICY

Belcher: Our Leaders Should Embrace Certified Natural Gas

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Jack Belcher is a principal at Cornerstone Government Affairs, where he focuses on regulatory affairs, risk management and ESG matters within the energy and transportation sectors.

Last month, I was critical in this column of the "temporary pause" issued by the Biden administration on pending decisions regarding exports of LNG to non-free trade agreement countries. The announcement stated the administrative action on LNG would cease "until the Department of Energy can update the underlying analyses for authorizations," primarily the environmental and climate change impact from LNG exports. This action has caused a great deal of consternation from the energy industry and governments around the world that depend on U.S. LNG.

Shortly after the pause was issued, a group of seven Democratic senators, led by Ed Markey (D-Mass.), sent a letter to the Securities and Exchange Commission (SEC) that accused certified, responsibly sourced or differentiated natural gas providers of "greenwashing" and "false burnishing (of) their climate credentials." The letter went on to ask the SEC to investigate and address false or misleading claims of natural gas certifiers, and to update their own guidance to address claims about certified gas.

The highly inflammatory and accusatory letter was a direct shot at the concept of natural gas certification, an ongoing voluntary effort by industry to reduce emissions, increase efficiency and ensure that best practices are being applied to U.S. natural gas production and transport. One certification standard alone, the MiQ standard, has already been applied to more than 20% of U.S. natural gas production, providing a substantial positive impact on the environmental performance of U.S. natural gas.

Recognition gained through gas certification verified by third-party auditors has led natural gas producers and midstream companies to voluntarily comply and often exceed compliance with regulatory requirements, including the EPA methane rule.

EQT, the largest natural gas producer in the United States, has voluntarily committed to certify its gas to demonstrate its commitment to reducing emissions and enhancing its sustainability performance. The majority of its gas production is now certified and audited under both the MiQ standard and the Equitable Origin EO100 Standard for Responsible Energy Development. EQT certification alone accounts for 4.5% of all U.S. gas production. As part of its commitment, EQT spent $28 million to replace or retrofit 100% of its gas-powered pneumatic devices used in oil and gas production, resulting in a 70% reduction in methane emissions. Chesapeake Energy has certified 100% of its natural gas assets that support the production of about 6 bcf/d using the MiQ Standard, the Equitable Origin EO100 standard and Project Canary.

Gas certification is clearly moving the needle in terms of reducing methane emissions and making overall production compliant with the EPA Methane Rule years ahead of the compliance deadline. If there was ever a doubt that the U.S. has the cleanest gas in the world, certification is erasing it.

Importantly, certification is making U.S. natural gas more marketable in the world. Prior to the Russian invasion of Ukraine, Europe was balking at imports of U.S. shale gas, which it deemed as dirty due to hydraulic fracturing. With Russian gas supplies largely cut off from Europe, the United States has been exporting LNG to Europe in record numbers. Even under the pressure of a cut-off of Russian supply, the European Union enacted a law last year that places limits on emissions from imported gas beginning 2030. However, natural gas certification brings U.S. natural gas into compliance with those EU standards, years before they are mandatory.

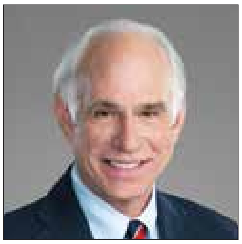
Perhaps the greatest opportunity for U.S. natural gas to make a difference in coal displacement and greenhouse gas (GHG) emissions reduction is in Asia. While Europe and North America are reducing their GHG emissions, countries in Asia including Pakistan, India and China are doing just the opposite. These countries are building new coal power plants and increasing global GHG emissions. China alone is currently constructing 176 gigawatts of new coal capacity, two times the coal capacity the United States has retired since 2005, or one coal-fired power plant per week.

U.S. oil and gas producers want to improve their emissions performance. They want to deliver a clean and reliable product to our allies in Europe. They see the opportunity that U.S. LNG can play in displacing coal and reducing GHG emissions in Asia. Certification is a process that can and does create certainty and transparency that guarantees performance and continued improvement.

Our government should not attack natural gas certification. It should embrace it. OGI

▸ REGULATORY POLICY

Hirs: The SEC's Enhanced Climate-Related Disclosures Are Unnecessary—Even According to the SEC



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The U.S. Securities and Exchange Commission (SEC) has released its rules for enhanced climate-related disclosures, which are due to be phased in following publication in the Federal Register. Across 886 pages, the rules call for companies to disclose material levels of greenhouse gas emissions, the impacts of potential climate-related weather events, and actions taken to reduce emissions and protect against weather events.

To justify the new rules, the SEC cites multiple studies that have found an association between greater climate disclosures and higher stock valuations. The SEC's work has already been done by the market! Following the SEC's logic, those companies seeking greater valuations will make climate-related disclosures.

So, what is the goal of requiring disclosures? In a departure from decades-long tradition, the SEC has not included a standard cost-benefit analysis on these proposed rules. It seems clear that the "cost" of these rules would go far beyond the accounting measures required to produce the reporting and could, in fact, make it easier for climate groups to sue any company over its greenhouse gas (GHG) emissions.

The rules require companies to disclose their Scope 1 and 2 emissions. Under established conventions, Scope 1 emissions are those generated directly by a company's business activities such as transportation fleets, process heat or heating for office buildings. Scope 2 emissions are indirectly generated, such as when a company buys electricity from a fossil fuel power plant. Scope 3 emissions are further removed from direct company control, generated by suppliers and customers. Obviously, a company has much less control over these sources of emissions and as a result, the SEC did not mandate Scope 3 disclosures. In the grand scheme of things, requiring Scope 1 and 2 reporting should provide a complete picture of GHG emissions for the economy.

The SEC states that the new rules will standardize disclosures across issuers for the benefit of professional and retail investors and argues that these disclosure requirements will fall across all public issuers, not just oil and gas producers—but there is a catch. There is little direct guidance for "standardization" of climate risk reporting.

The SEC does not quantify benefits and costs of the new rules for companies, notwithstanding earlier comments to the SEC. These cost-benefit analyses have been required for federal rules and regulations since the Johnson administration in the 1960s. Federal courts may find that the lack of a complete benefit-cost analysis is enough to suspend implementation of the rules.

"In the grand scheme of things, requiring Scope 1 and 2 reporting should provide a complete picture of GHG emissions for the economy."

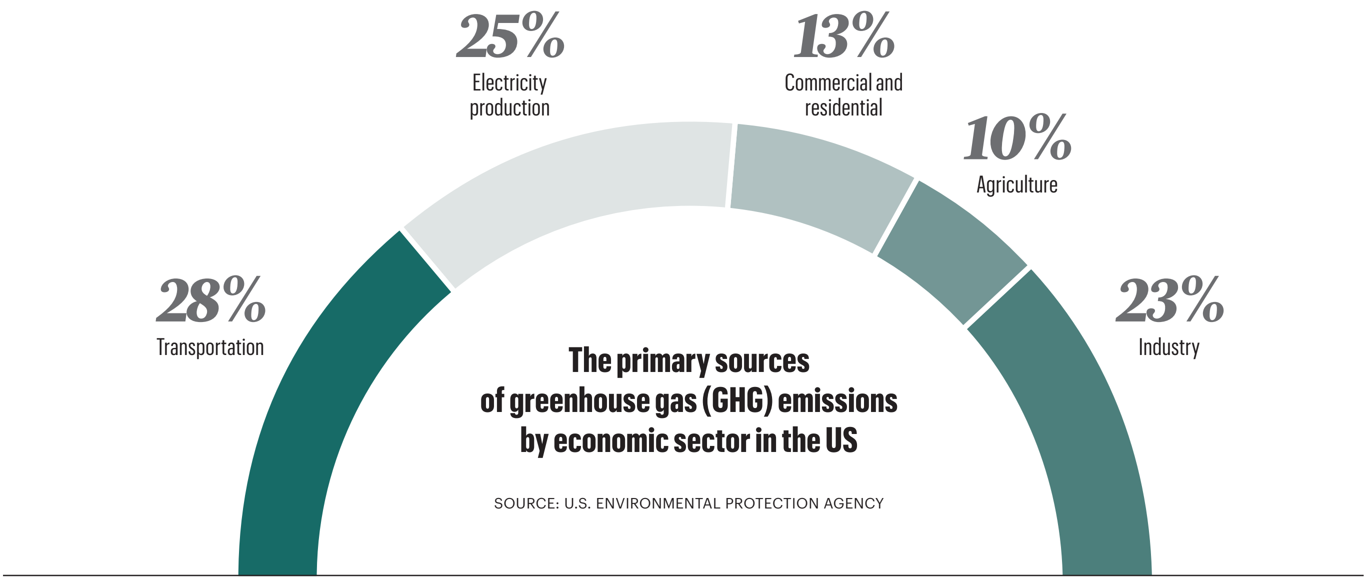
Instead, the SEC argues the benefits of enhanced disclosure are demonstrated by the studies that show "higher level of disclosures are associated with higher valuations." But it is nonsensical to conclude that the entire market would enjoy a higher valuation due to more disclosures. If the cited studies are valid, non-disclosing companies are already penalized.

The SEC is similarly vague about the costs of these disclosures. The SEC omitted real-world examples of the incremental costs incurred by issuers who previously have met or exceeded the new climate-disclosure rules. Why? The subtext is important, also. The SEC states that the enhanced level of disclosures will increase litigation risk for issuers. First, the increased risk will arise because the disclosures will be filings that cannot be misleading under penalty of law. Second, and perhaps more importantly, the enhanced disclosures will make issuers publish data that was only previously available in litigation such as those climate lawsuits filed against Chevron, Exxon Mobil, Eni and other major oil companies.

And oil companies are not the only targets of climate activists.

Agriculture accounts for 10% of greenhouse gas emissions in the United States. "Big Ag" companies know that plowing and tilling fields releases carbon emissions. They also know that planting cover crops during the winter are effective carbon sinks. Livestock emissions—methane from feedlots—can be captured for renewable natural gas. Commercial and residential use accounts for 13% of emissions. Transportation accounts for 28% of greenhouse gas emissions. Separately, cement plants account for 8% of greenhouse gas emissions. Large source emitters will become targets for litigants and, because of the new SEC disclosure requirements, they will be providing the very data needed by the plaintiffs seeking to sue them.

In this particular matter, oil and gas producers can find allies across the industrial spectrum. The SEC's rationale for enhanced climate-disclosure rules is weak and contradictory. If the courts are unable to stop the new rules, then Congress may act by withholding funding from the SEC. It is a high-stakes game for a wasteful, indirect approach to reducing GHG emissions. OGJ



THE OGI INTERVIEW

Bringing the Know-How

Woodside Energy Group CEO Meg O'Neill is relying on technical sophistication to guide the Australian giant as it takes on three challenging projects in the U.S. Gulf of Mexico.

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Woodside Energy Group CEO and Managing Director Meg O'Neill has great expectations for the Australian company's U.S. Gulf of Mexico (GoM) portfolio, where it is flexing its deepwater technical capabilities in three key projects.

Woodside's involvement in the GoM is centered around Shenzi, Mad Dog and Atlantis. O'Neill classifies the three as Tier 1 assets with 1 billion-plus barrels in place that challenge operators with the technical complexity of drilling in deepwater.

O'Neill, during an exclusive interview with *Oil and Gas Investor*, said the difficulties in deepwater revolve around the obvious water depths, which have implications for development plans and design structures to be built. There is also a huge amount of subsurface complexity, as a number of these resources are difficult for seismic devices to build images. Additionally, there's quite a bit of geologic faulting in the structures.

That said, the GoM wells can be extremely productive. They simply require technical sophistication.

2023 SUMMARY
$1.7B
Net profit after tax

"Between both LNG and deepwater, these are higher risk parts of the business [and] you've got a strong process, safety focus. The subsurface work required is at a very high level of sophistication, again with the complex imaging," O'Neill said. "And those are some of the capabilities that we think we bring to the table."

The Woodside-operated Shenzi (72% interest) is a conventional field being developed through a tension leg platform (TLP). It has 16 producers flowing to the TLP and six water injection wells, plus two subsea wells tied back to the non-operated Marco Polo platform.

Shenzi North is a two-well subsea tieback

Meg O'Neill in Her Own Words

Woodside CEO and Managing Director Meg O'Neill joined the company in 2018 and has served in a number of senior executive positions including COO; executive vice president, development; and executive vice president, development and marketing. From April to August 2021, O'Neill was acting CEO until she was formally appointed to the position.

Prior to joining Woodside, O'Neill spent 23 years with Exxon Mobil in a variety of technical, operational and senior leadership roles.

In an exclusive March interview with OGI, O'Neill also shared her perspective on a range of topics spanning from how the Russia-Ukraine conflict and the rally around energy security has helped Woodside, to the U.S. Inflation Reduction Act (IRA), to Scope 1 and Scope 2 emissions, to safety after a recent fatality at an offshore facility, as well as workforce diversity.

Pietro D. Pitts: Russia's invasion of Ukraine in early 2022 turned world leaders' attention to energy security? How has that impacted Woodside?

Meg O'Neill: Actually, it's in some ways done the heavy lifting for us as we engage with customers around the world, and I think we have some recent examples that reinforce this. We're seeing customers who, a few years back, had been willing to take more risk on buying off the spot markets, actually doubling down and saying we want to take long-term volumes. And the two examples I'd point to is the agreement we announced with JERA (Japan's largest power generation company), a strategic agreement, where they're coming into our Scarborough

"As we've been working on our strategy to thrive through the energy transition, we've really focused our efforts on hydrogen and integrated carbon solutions, so things like CCS and carbon offsets."

–**Meg O'Neill**, *CEO and Managing Director, Woodside Energy Group*

WOODSIDE

to the Shenzi TLP. However, production has been below expectations due to reservoir connectivity.

"The next couple of years with Shenzi are very much going to be focused on maximizing value from the assets, updating our reservoir models, making sure we really understand what's going on in the subsurface," O'Neill said.

The BP-operated conventional oil and gas development Atlantis (44% interest) is one of the largest producing fields in the U.S. GoM. The development includes a semisubmersible facility with 28 active producer wells and three water injector wells. Two wells (one producer and one injector) were completed in 2023, alongside an extensive well intervention campaign.

"This is another complex field, and we continue with infill well drilling, and we're continuing to focus on maximizing recovery from that asset," O'Neill said.

At the BP-operated conventional oil and gas development Mad Dog (23.9% interest), Phase 1 of the project includes a spar facility (A-spar) with drilling capability and 10 active producer wells.

$3.3B
Underlying net profit after tax

Mad Dog Phase 2 relates to the southern flank of the field through the new Argos floating production facility. The facility achieved first oil in April 2023, and production ramped throughout the year. After a successful appraisal well was drilled to extend the field to the southwest, the co-owners subsequently sanctioned a three-well subsea tie back.

"[At Mad Dog Phase 2] there was a bit of remedial work we needed to do with some components, things called flex joints, which basically connect the riser to the floating structure. That work was completed over this past winter in December and January. At this point, [the] focus for Argos is really getting to that maximum production," O'Neill said.

The company's overall strategy in the GoM is to be a non-op partner. Woodside only operates the Shenzi project, which saw the start-up of Shenzi North in 2023—ahead of its 2024

development. They've also signed up for additional LNG offtake. LNG Japan late last year came in with a similar LNG offtake deal, a 10% stake in Scarborough, and we just signed a 10.5-year offtake agreement with Korea Gas Corporation (KOGAS). The really high-quality sophisticated buyers in Asia are taking steps to lock in energy security for 20 years. I think the energy security message is really being embraced by many of our core customers in Asia.

PDP: Has the U.S. Inflation Reduction Act (IRA) been a catalyst for you in the United States?

MO: We were working on a hydrogen project in the U.S. in Oklahoma called H2OK, even before the IRA was launched. Now when the IRA came out, it had this promise of a very significant production tax credit for hydrogen, and that is the market that we're targeting. We do see a role for hydrogen to help decarbonize, particularly heavy business, things like ground transportation as well as things like data centers. And a number of corporations in the U.S. have pretty ambitious decarbonization targets. So again, those were the sorts of customers we were targeting. Now, the rules to implement that production tax credit were just unveiled by the Department of Treasury late last year, and they were very restrictive. And again, if we're thinking about, well, what's required to encourage people to change the energy that they use, well, making it more affordable is a great way to incentivize that. We're in continued discussion with the government around how the production tax credit should be implemented to really encourage that uptake of usage. But at the end of the

Three world-class projects in execution

	SANGOMAR	SCARBOROUGH	TRION
			
Advantages	**Oil grade well suited for European refineries** **~$11/boe breakeven operating cash flow in 2025**	**Among the lowest carbon intensity projects for LNG landed in north Asia** **$5.80/MMbtu cost of supply delivered to north Asia**	**Expected carbon intensity of 11.8 kg CO_2-e/boe** **<$50 cost of supply and <4 year payback**
Production capacity	**100,000 bbl/day**	**Up to 8 Mtpa LNG + 225 TJ/day domestic gas**	**100,000 bbl/day**
Cost	**~$4.9B - 5.2B (100% project)**	**~$12B (100% project)**	**~$7.2B (100% project)**
Target start-up	**Mid-2024 (first oil)**	**2026 (first LNG cargo)**	**2028 (first oil)**

SOURCE: WOODSIDE

target, said Omar Rio, North America research analyst at Welligence Energy Analytics.

"Atlantis and Mad Dog are both operated by BP and have significant running room remaining. With the heavy investment phase now over at Atlantis, Mad Dog and Shenzi, Woodside is able to enjoy steady cash flow to maintain dividend payments to their shareholders and fund growth projects in its global portfolio, along with exploration efforts," Rios told *OGI*. "We don't view this strategy changing, as Woodside's GoM portfolio is poised for strong growth in the medium term, plus it is a non-op partner in multiple exploration leases."

Rios said that on the exploration front, Welligence has a line of sight on the Chevron-operated Corvus prospect, which was spud in January. Woodside's farm-in could pay off as the partners are targeting the proven Miocene formation with the hopes of developing the potential resource with its own dedicated infrastructure.

Woodside boasted record production of 187.2 MMboe or 513,000 boe/d in 2023, split between gas (69%) and liquids (31%). Woodside's share of production in 2023 from Shenzi was 10.8 MMboe (29,600 boe/d), Atlantis' share was 12.6 MMboe (34,500 boe/d), while Mad Dog's share was 7.2 MMboe (19,700 boe/d).

"We see quite a bit of running room in the Mad Dog area, particularly with Argos just starting up. We had some appraisal success last year at Mad Dog Southwest and really pleased that the joint venture has already agreed to sanction

day, it doesn't change the fact that the customers we were targeting still have those ambitious decarbonization goals. It just affects the price that we can offer them for that hydrogen.

PDP: Is there a push in Australia to boost renewables usage to free up more gas for export in the form of LNG?

MO: There absolutely is a push to increase renewables in Australia, but Australia is still heavily dependent on coal for power generation. Gas will play an important role and is used in industrial processes; it's used in manufacturing. Gas will continue to be important. It'll be important, in my view, as a firming fuel for renewables as those coal-fired power stations are turned off. But the renewables push is much more around decarbonizing the power sector, which is currently heavily dependent on coal.

PDP: Is the energy industry moving too slow on some of the net zero goals out there?

MO: Well, I'm not sure it's a question for the industry. I think it's a question for the world, and the world is a far more complex place. We spend a lot of time with customers around the world trying to understand what their energy needs are and what their priorities are. And it's perhaps similar to the Senegal discussion. When you go to places like Bangladesh or India, their priority is reliable and affordable energy. Carbon intensity comes third and it's kind of third by a ways because, again, their focus is on figuring out how do they tackle widespread poverty, how do they tackle energy poverty?

Woodside has great expectations for the company's U.S. Gulf of Mexico (GoM) portfolio. Woodside has the capabilities to manage the high level of technical complexities and sophisticated subsurface work needed to make GoM wells productive, CEO Meg O'Neill said. 1. Mad Dog spar in the GoM. 2. The Atlantis Project in the GoM. 3. Shenzi platform in the GoM.

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that further development. I think that is really reinforcing the value of that Gulf of Mexico portfolio, that there's opportunities to continue to add value in that business," said O'Neill, who holds a Masters of Science in ocean engineering from the Massachusetts Institute of Technology.

Woodside After BHP and Santos

Perth-based Woodside, which completed a transformational merger with Melbourne-based miner BHP in 2022, isn't necessarily on the prowl for another acquisition. The company walked away from a plan to acquire Adelaide, Australia-based Santos Ltd. in a deal that would have created a near-$60 billion Aussie powerhouse.

Woodside's early February decision to forgo the Santos deal was simple: it wasn't accretive, O'Neill said. This is true despite the upside it would have given Woodside through three LNG projects—Papua New Guinea LNG, Gladstone LNG in Australia, and Bayu-Undan and Barossa to Darwin LNG—as well as two Australian domestic gas businesses.

Completion of the BHP deal allowed Woodside to merge complementary long-life, high-margin assets with strong growth profiles and a wide range of growth options. The deal boosted Woodside´s production by 105% and also doubled its interest in the North West Shelf (NWS) project in the northwest of Western Australia and acquired interest in Bass Strait in Victoria (southeast Australia) and Pyrenees (northwest Australia) and Macedon (located near Onslow), also in the northwest of Western Australia.

Now, as an energy company, of course, we have a role to play. We need to be a responsible player. We've set our own goals for reducing our net equity Scope 1 and 2 emissions. We've set ourselves some ambitious goals for providing customers with products like hydrogen and carbon solutions that help them reduce their emissions. But we need to make sure that we're thinking about the transition in a balanced way. We think gas has an extremely important role to play. You just have to look at the stats. And I think the International Energy Agency (IEA) issued some stats recently saying, coal use increased last year. So, despite 20-plus years of conversation on climate change, coal use globally is going up and gas is going to have a hugely important role to play to help remove those emissions from the power generation sector.

PDP: Woodside has laid out what is a focused implementation of Scope 1 and 2 emissions reduction opportunities. You've reduced net equity Scope 1 and 2 emissions 12.5%, using an average of 2016-2020 as the base, and are targeting 30% by 2030. What about reaching net zero by 2050 and how are efforts progressing to continue to decarbonize your portfolio?

MO: Just to be sharp, it is our net equity Scope 1 and 2 emissions. We look at our equity share, and again, it's different from what we operate. We want to reflect what we're financially responsible for, and net is an important word because we do use offsets to a certain degree to help with that emissions reduction.

Net zero by 2050 is our aspiration

The BHP deal lifted Woodside into a top 10 global independent energy company based on hydrocarbon production and created the largest energy company listed on the Australian Securities Exchange.

Today, Woodside is a true international company with a diversified, large-scale, low-risk portfolio. The company has operations in Australia, the GoM, the Caribbean, Senegal, Timor-Leste and Canada. However, the bulk of its production comes from Western Australia. In terms of product mix in 2023, LNG dominates by a large margin, followed by crude oil and condensate, piped gas and NGLs.

As of December, Woodside's remaining proved reserves were 2,450.1 MMboe, proved plus probable reserves remaining were 3,757.1 MMboe, while the best estimate contingent resources remaining were 5,902.0 MMboe, according to details in its annual report.

Woodside's change of heart on the Santos buy is testament to the company's capital discipline, O'Neill said. Across Woodside's three main pillars, its capital allocation plan is quite clear.

In the oil space, especially offshore, the company seeks to generate high returns to fund diversified growth amid a focus on high quality resources. The opportunity target is for an IRR that exceeds 15% while the preferred payback period is within five years.

In the piped gas and LNG spaces, the focus is on leveraging infrastructure to monetize undeveloped gas, including optionality for hydrogen. The opportunity target is for an IRR that exceeds 12% while the preferred payback is within seven years.

In the new energy diversified space, the focus is on new products and lower carbon services to reduce customers' emissions; hydrogen, ammonia, and carbon capture utilization and storage. The opportunity target is for an IRR that exceeds 10% while the preferred payback is within 10 years.

In the aftermath of BHP and Santos, O'Neill said the near-term focus revolves around three growth opportunities: in Australia related to a massive liquefaction project at Pluto Train 2, a deepwater project in Mexico at Trion, and another deepwater project in Senegal at Sangomar. All three will come online within the next five years.

"Our goal is to thrive through the energy transition and that means being a resilient, low-cost, lower carbon profitable company. We have a number of top tier high quality assets both in Australia, Gulf of Mexico, and then we've got growth opportunities and projects that are underway," said O'Neill.

"Sangomar, Scarborough, and Trion will come online in a series of reasonably quick successions. Beyond that, we have optionality, that includes options like Calypso in Trinidad and Tobago, Sunrise and Browse here in Australia, as well as a number of new energy opportunities both in hydrogen and CCS [carbon capture and storage]. We've got good organic growth options beyond the projects we're executing today."

$600M
2023 free cash flow

With M&A frenzy in the U.S. featuring mega-deals like Exxon Mobil's $60 billion all-stock purchase of Pioneer Natural Resources and Chevron's $53 billion all-stock deal for Hess Corp. fresh on investor's minds, Woodside at most could divest some assets.

"We do have a process underway for Pyrenees and Macedon. And we had some inbound interest, a couple of potential players saying they would be interested in those fields and if they are willing to offer something that's compelling for our shareholders, we'd be willing to part with those assets," O'Neill said.

Pyrenees is an FPSO facility off the northwest coast of Western Australia (Woodside operates with a 40% interest in WA-43-L and 71.4% in WA-42-L). Woodside also operates Macedon with a 71.4% interest. Macedon is a gas project located near Onslow, Western Australia and produces piped gas for the Western Australian domestic gas market. Woodside's share of production from Macedon in 2023 was 8.2 MMboe.

"I'm really pleased with the portfolio that we have. From a growth perspective, there's three big gas growth opportunities: Calypso in Trinidad and Tobago, Browse in Australia and Sunrise, which straddles the border between Australia and Timor-Leste," O'Neill said.

187.2 MMboe/d
2023 production volume

Woodside ended 2023 with net debt of $4.7 billion. The company's gearing ratio at 12.1% is at the lower end of its target range, while the company has $7.8 billion in available liquidity to support major capital investments, said Woodside CFO Graham Tiver said during the company's February year-end webcast with analysts. Woodside also has sustained credit ratings of BBB+ or equivalent.

"Looking at our sources of cash in the period 2024 to 2028, we expect a significant increase in our cash generation as each of our three major projects–Sangomar, Scarborough and Trion–come online," Tiver said. "Assuming an oil price of $70 per barrel, we expect to generate cash flow from operations that more than covers our current budgeted capital expenditure and dividends,

and I'll differentiate. For 2025 and 2030 we have targets. So those are commitments. 2050 is an aspiration and it'll depend a bit on how the world is tracking, but philosophically that's where we're headed.

Also, we've got asset decarbonization plans that the teams are working through. We've got a number of activities that we've implemented and activities that we're planning that allow us to bring those emissions down. We've also done work to build up the capability of our carbon team so that we're well-positioned if we need to use offsets, which we expect we will have to, in order to have the high-quality offsets that we want to use to achieve that net emission reduction.

PDP: Some people are saying ESG is dead. What's your take on that statement?

MO: I think everywhere you operate you ask yourself the fundamentals: is protecting the environment important? The answer is yes. We've got to make sure—we operate in sensitive areas—that we're doing our part to make sure that we're protecting those environments. Everywhere we operate we want to make sure that we are actively involved in the communities and doing our part in supporting those communities and having a strong governance and oversight is, I think, important for any corporation. So, whilst the three-letter acronym is probably less in use today, I don't know that the focus on those three items has actually diminished as part and parcel of what we do. We need to make sure that we're, again, playing a role in protecting the environment,

1. The Karratha Gas Plant, North West Shelf Project in Australia. 2. Sangomar FPSO. 3. Pluto LNG project in Australia.

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creating a projected surplus of cash through the period of 2024 to 2028."

Australia, Pluto LNG and Pluto Train 2

Russia's invasion of Ukraine in early 2022 rattled energy markets. Global gas markets started to rebalance in 2023 but remained tight, aggravated by uncertainties around Russian LNG sanctions. Wood Mackenzie's base case scenario forecasts global LNG demand growing 53% by 2033, supported by growth in Europe (until 2029), China and emerging Asian markets, the consultancy said in October.

Woodside is well-positioned on the LNG business side to take advantage of this scenario. Its reliability of gas supply tied to LNG was reported to be 98% in 2023.

Woodside's Pluto LNG project consists of a gas processing facility in the Pilbara region of Western Australia. Woodside operates Pluto LNG and holds a 90% interest. Kansai Electric and Tokyo Gas each hold a 5% interest. Gas from the offshore Pluto and Xena fields is sent through a 180-km pipeline to Pluto Train 1, which has 4.9 million tonnes per annum (mtpa) of processing capacity and is located on the Burrup Peninsula, near Karratha, Western Australia. Woodside has operated the facility since start-up in 2012.

"The Pluto Train 1 actually is running flat out. When it was built, the nameplate was 4.3 mtpa. The team's done a lot of work over the last decade to try to be able to get more gas through and just working through debottlenecking in a very structured manner. The train's actually doing better than it was built to do," O'Neill said.

A brownfield expansion of Pluto LNG will add a second gas processing facility, Pluto Train 2, which will have capacity to process 5 mtpa. Gas from the offshore Scarborough field located in the Carnarvon Basin, 375 km off the Pilbara coast, will be developed through new offshore facilities connected by a

being constructive members of the community, and have appropriate systems and processes for how we run our business.

PDP: Even though you are the CEO of Woodside, the company's workforce is still around 66.4% dominated by males. What efforts is Woodside making to change those statistics and in general increase diversity among its workforce?

MO: I'd say first and foremost, you have to be very deliberate about diversity and inclusion, and those are two important things, but they're different things.

So first off, you need to make sure that you have the systems to understand well, what is your workforce demographics and what are the steps you can and should take to increase the diversity within your workforce demographics?

The second thing is inclusion. And that gets to the question of, well, what are the sorts of things you need to do to enable your workforce to really bring their true selves to work and to thrive over the course of a career. [That] gets to the policy space. Do you have policies that support people as they go through various life stages? Be it having a young family, potentially caring for elderly parents? Do you have policies that support gender balance in caring roles?

And for example, at Woodside, our parental leave policy is the same for both males and females or primary parents and secondary parents. We just try to make sure that as people are going through these family milestones, that the caring responsibility can be shared by all parents. The policy gets

430 km pipeline to the onshore facility. The project is around 55% complete and first LNG cargoes are targeted for 2026.

The Scarborough energy project represents a gross investment of around $12 billion.

Woodside operates the Scarborough energy project in the Scarborough field. However, in August, Woodside entered into an agreement with LNG Japan for the sale of a 10% non-operating participating interest in Scarborough. Woodside has also entered into an agreement with JERA for the sale of a 15.1% non-operating participating interest in Scarborough.

Woodside holds a 100% interest in Scarborough, 51% interest in Pluto Train 2 and 90% interest in Pluto LNG. Upon completion of the transactions with LNG Japan and JERA, Woodside will hold a 74.9% interest in Scarborough, remaining as operator. Woodside expects to complete the transaction with LNG Japan as well as JERA by the second half of 2024.

At Scarborough, eight wells will be drilled initially, with 13 wells drilled over the life of the field. Scarborough will produce around 8 mtpa, of which 5 mtpa of Scarborough gas will be processed through Pluto Train 2, with up to 3 mtpa processed through the existing Pluto Train 1.

"[Due to] the very lean gas that we have from Scarborough, we are making modifications at Pluto Train 1 to enable it to process a blend of Scarborough and Pluto gas. Right now, it's full on Pluto gas, but when we bring the blend in, we're going to curtail Pluto production to allow initially 2 mtpa of Scarborough to flow through it. And then when Pluto field life ceases, then Scarborough gas we can flow through at 3 mtpa," O'Neill said.

"Pluto is more than halfway through its reserve life, so we've produced more than half of the gas we expect to recover from that field. We do expect to see production increase when Scarborough comes online, but there'll be a point in time where Pluto goes offline. Again, a lot of what we're doing is about preparing the business to be resilient in the 2030s when some of our legacy assets start to come offline," O'Neill said.

Scarborough gas has a very low reservoir CO_2 content. That, when coupled with the highly efficient design of the offshore facility and Train 2, will allow Woodside to deliver gas to Asia with a much lower carbon intensity than many competing sources of LNG, O'Neill said, adding it was "a plus for buyers."

While Pluto LNG will soon have two trains, there are no plans for a third.

"When we sort of leased the land for Pluto sites, there were a lot of questions of how big would the trains be and how many could fit? We've ended up building a couple of quite large trains, so the site is full, so there's no Train 3," O'Neill said.

In 2024, Woodside expects 26%-33% of its produced LNG to be sold at prices linked to gas hub indexes. Long-term the percentage is expected to be around 30%, so that the company can sell on the spot market and take advantage of gas price swings or volatility.

$1.40
/share
Full-year dividend

"Our LNG footprint is today largely in Australia, and so we have that proximity to the Asian markets and that's historically been our area of focus and continues to be an area of focus. Now, that said, we [recently] started lifting LNG from Corpus Christi," O'Neill said. "Part of why we signed up for that offtake position was because we saw an opportunity to deliver LNG to European customers and we see an opportunity through our marketing and trading team if we have a position in both the Atlantic and the Pacific to increase value even further to our shareholders. We do have a position in the Atlantic, but it's a smaller position than our Pacific position."

Woodside has been building up the capabilities of its trading teams over the past five years, which sees a lot of value in optimization work.

"[With] our Pacific portfolio between Northwest Shelf, Pluto and Wheatstone, we've got enough kinds of levers in that portfolio plus our shipping position. We've got a number of ships on long-term lease to be able to add value, add incremental value by optimization. Now bringing those additional LNG volumes from Mexico Pacific Limited into that Pacific portfolio just gives us another optimization lever," O' Neill said.

2023
reduction achieved
12.5%
Below starting base
Net equity Scope 1 and 2 emissions

O'Neill continued: "We do see value in being able to offer that North American LNG to our Asian customers. We see additional value by our ability to optimize and to make sure that we get the right cargo to the right customer at the right time, and we think we can generate more value for our shareholders along the way."

In December, Woodside signed a sales and purchase agreement (SPA) with Mexico Pacific to acquire 1.3 mtpa, equivalent to approximately 18 LNG cargoes each year, for 20 years. The SPA is subject to Mexico Pacific taking final investment decision (FID) on the proposed third train at the Saguaro Energía LNG Project. The FID is expected in the second half of 2024 and commercial operations are slated to start in 2029.

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to inclusion, the culture that you set. We've got a strong focus on respect at work, so making sure that we're confronting things like bullying and sexual harassment in the workplace, making sure that we're very deliberate about those conversations.

One area that I'd like to highlight that I'm really proud of is the work we've done to increase women in trades and technician roles. And we've been on a very deliberate journey for the last probably 10 years at Woodside, making sure that as we bring new people into those roles that have historically been very male dominated, that we're trying to bring in more women and more indigenous Australians, and very pleased that last year we broke the 10% mark. So, we're up to 11% women in our trades and technician roles. So that's fantastic. I don't know that there's a whole lot of other organizations that have made that shift and it's taken time. We've got an established workforce, so you only move the needle through hiring and I'm really pleased we're getting close to having a critical mass of women in the plants, particularly.

PDP: On two recent occasions—in your annual report and at the start of Woodside's quarterly webcast with analysts—you've mentioned the aboriginal people of Australia. Why is that so important for Woodside in particular and Australia in general?

MO: A lot of it gets to Australia's context where the settlement of the continent has only happened within the last couple of hundred years, and the indigenous groups that were here, the first nations groups that were here, many of them were displaced. There was

Rendering of planned FPU for the deepwater Trion project in the GoM.

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Woodside's fourth GoM project: Trion

Woodside's project offshore Mexico at the large, high-quality conventional resources Trion development continues to move forward. Trion checks key production, climate and financial boxes for both Mexico and operator Woodside (60% interest) and its partner state-owned Pemex (40% interest).

Trion's $7.2 billion FID was announced in June. It is Woodside's first major investment decision following its merger with BHP. Trion was an asset in BHP's portfolio, and will be Woodside's fourth major project in the GoM, albeit on Mexico's side of the maritime border after Shenzi, Atlantis and Mad Dog on the U.S. side.

Woodside's Trion deal validates growth in its Americas deepwater portfolio from a valuation perspective, Welligence's Rios said, which also includes Trinidad and Tobago.

"The project is a priority for the current administration and will continue to be for the next. The project is still in its early stages, but Woodside seems to be making timely progress on its first oil target," Rios said.

"[Trion is] a big deal for the post-merger Woodside because, again, it really reinforces the upside quality of the BHP portfolio. This is an asset that BHP secured when the Mexican sector opened up, I think we were quite disciplined in how we approached it," O'Neill said.

Production from Trion will be processed through a floating production unit (FPU) with a nameplate capacity of 100,000 bbl/d. The FPU can process up to 120,000 bbl/d when Woodside is producing early in the field's life with no water breakthrough. First oil is slated for 2028. The project continues to award contracts including for the wellheads and subsea line pipe. Procurement activities also commenced for FPU materials and subsea equipment.

Woodside expects Trion will have an all-in breakeven below $50/bbl and then below $43/bbl excluding the Pemex capital

probably a very long history of poor treatment by the settlers. In the last, call it 50 years, there's been increased recognition of the importance of aboriginal Australians, of their long and rich culture. And the places where we operate have a much higher percentage of aboriginal Australians. So as a nation, I think the population is about 3% indigenous or aboriginal Australians. But in Western Australia, the number goes up. And in Karratha, where our operations are, it's closer to 15%. These are very important stakeholder groups for us. They have very strong connections to the country through native title law. They have legal rights over the country. It's important for us to engage with them in a respectful and constructive way.

PDP: In the aftermath of a recent fatality at Woodside's North Rankin Complex facility, you said that "safety needed improvement." Could you expand on that comment and what exactly that improvement entails?

MO: First and foremost, it's making sure that the leadership of the organization, and that's myself through every staff member, recognizes that when it comes to safety, we're all leaders [and have] safety first and foremost in everything we do. So, really reinvigorating our personal commitment across the leadership team. We had an external review team come in last year and take a look at our safety and process safety systems and their conclusion was we have outstanding systems, but a fair amount of complexity. We're taking steps to try to improve the simplicity so that the worker at the front line really has clarity over what he or she needs to do to execute their work safely.

carry. Trion is expected to deliver an IRR that exceeds 16% and excluding the capital carry it is greater than 19%.

Trion's average carbon intensity is expected to come in at 11.8 kg CO_2e/boe during the life of the field, which is lower than the global deepwater oil average.

"The team took a number of steps in the design phase to, we call it, 'design out' emissions. So, the best way to reduce emissions is to never have them in the first place. We're really happy with the work the team did to design out and avoid those emissions," O'Neill said.

The use of the local workforce in Mexico is a priority for Woodside.

"There certainly is plenty of talent. Now, we'll want to, of course, make sure that we're setting up the organization there with the right Woodside culture. We will be bringing in some of our experts from the Gulf of Mexico, potentially also from Australia. Again, just to make sure that when we're setting up that team, that they've got that Woodside mindset and that we're bringing our best technical capability," O'Neill said. "But there will be a lot of focus on local content and doing what we can to support local businesses and local industry as well."

On the financial side, Pemex carries a massive debt load—$106.1 billion at year-end 2023. Over the short term, Pemex has significant debt amortizations looming, Rios said.

"We feel good about the project economics as they stand, and there are mechanisms in the agreements to deal with that situation of a partner not paying their way," O'Neill said when asked whether she had concerns regarding Pemex.

"We've been working very closely with Pemex and the Mexican government to make sure everybody understands the point in time where they will start to get cash calls, the budgetary obligation that is expected. Pemex has assured us, and the Mexican government also clearly understands their obligations. So, I feel good about Pemex and paying their way once we get to that point of cash-calling them here."

Further uncertainty remains in Mexico amid presidential elections in 2024. All indications are the country will have a woman president since both of the front runners from the last two competing parties are female.

"The thing that gives us great comfort in Mexico is, you've got the structures and systems to be robust in terms of defending a foreign investor's interest. Between the legislature, the executive and the court system, we've got a very strong three-branch system of government. So again, we did a lot of work before we took the final investment decision to make sure we're comfortable with the legal framework in Mexico," O'Neill said.

"The best way to reduce emissions is to never have them in the first place."

—Meg O'Neill, CEO and managing director, Woodside Energy Group

Senegal's first offshore oil development: Sangomar

Woodside has been in and out of Africa over the last decade but its Sangomar field development offshore Senegal could be a more enduring footprint for the company, according to O'Neill, who said it represented a significant investment for Woodside and was likewise important for the country.

Offshore Senegal, the Sangomar field development Phase 1 will be that African country's first offshore oil development. Work on the Sangomar field development started in early 2020. The field (formerly the SNE field), is located 100 km south of Dakar and contains both oil and gas.

Sangomar represents a gross investment of between $4.9 billion-$5.2 billion. Woodside operates Sangomar and holds an 82% interest in the Sangomar exploitation area and a 90% interest in the remaining Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) evaluation area. Societé des Petroles du Sénégal (Petrosen) holds an 18% interest in Sangomar and a 10% interest in RSSD.

Sangomar field development Phase 1 includes a stand-alone floating production storage and offloading (FPSO) unit, named *Léopold Sédar Senghor*, with subsea infrastructure and an expected production capacity of 100,000 bbl/d.

The FPSO reached Senegal in mid-February 2024 and first oil is slated for mid-2024. The project was 94% complete at the end of 2023, with 17 of 23 wells drilled and completed.

"It's a very complex field architecture. It's 23 subsea wells that include producers, water injectors and gas injectors. The flow assurance is complex, so we're going to take a measured approach to starting up to make sure that we start up smoothly and that we continue on a positive trend," O'Neill said.

The FPSO was previously a Very Large Crude Carrier (VLCC) that was converted by MODEC into a fit-for-purpose FPSO suitable for the Sangomar field in accordance with agreed specifications under an FPSO purchase deal between MODEC and Woodside.

Woodside continues to focus on local content and has been working with Senegalese small- and medium-sized companies to help them understand what services the company needs in the country while also trying to help them build up their capabilities.

The Sangomar project will go a long way to help the Senegalese government address the west African country's financial stresses. Like other countries in Africa, Senegal's population is young and the government is more fixated on tackling energy poverty first but with an eye on trying to contain emissions.

"The government's message to us is very much focused on this as an important asset for our nation. It's important that we do what we can to build local capability," O'Neill said. "We have conversations around energy transition, but their focus is very much around that revenue security that this investment will bring."

BHP legacy in Trinidad, Calypso Gas

Gas producing and LNG exporting Trinidad and Tobago rounds out Woodside's American assets. In the small twin-island country the Australian energy giant is filling a void once filled by the so-called three Bs: BPTT, which partners BP and Repsol, British Gas and BHP. These three companies were once among the top four, with Shell, over a decade or more. Shell swallowed BG and Woodside swallowed BHP.

"The thing that has impressed me from day one about Trinidad is the government's strong support for and deep understanding of the industry," O'Neill said.

"We've got a couple of assets that we operate now that I would describe as later in their life," O'Neill said. "And the government has been incredibly supportive on working with us to figure out what are the sorts of things we can do to really extend field life to ensure that we continue to create value for all of the stakeholders: and that's ourselves, that's the government, that's the downstream customers who consume our product."

Woodside is in the Greater Angostura field, a conventional offshore oil and gas field located 38 km northeast of Trinidad

Macedon offshore gas field in Onslow, Western Australia.

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that was discovered in 1999, with first oil achieved in January 2005 (Phase 1). Phase 2 started gas sales in 2011, while first gas for Angostura Phase 3 started in September 2016. Ruby is a conventional offshore oil and gas field located within the Greater Angostura Fields. First oil started flowing in May 2021.

Woodside operates Angostura with a 45% interest with partners The National Gas Company of Trinidad and Tobago Limited or NGC (30% interest) and Chaoyang (25% interest). Woodside also operates Ruby with a 68.46% interest with partner NGC (31.54% interest).

Today, Woodside is the third-largest gas producer in Trinidad, trailing only BPTT and Shell, according to recent data published by Trinidad and Tobago's Ministry of Energy and Energy Industries (MEEI). A pending FID and production to come from Woodside's Calypso project, coupled with production to come from Shell's Manatee project, are expected to help Trinidad stabilize its gas production by 2026, Trinidad's Energy Minister Stuart Young told *OGI* in an earlier interview.

Young told attendees at the annual Trinidad and Tobago Energy Conference in February that Calypso is planned to produce around 700 MMcf/d of gas, according to details from the event.

"The government is really phenomenal and Calypso is another opportunity to bring some new gas to market in Trinidad and Tobago. Now it's a deepwater field from a size perspective, it's two to three Tcfs, so not particularly big for the water depths that we're talking about. It's got a bit of complexity, but the government is very engaged and supportive and wants to work with us to figure out what we need to do to be able to move this opportunity forward," O'Neill said.

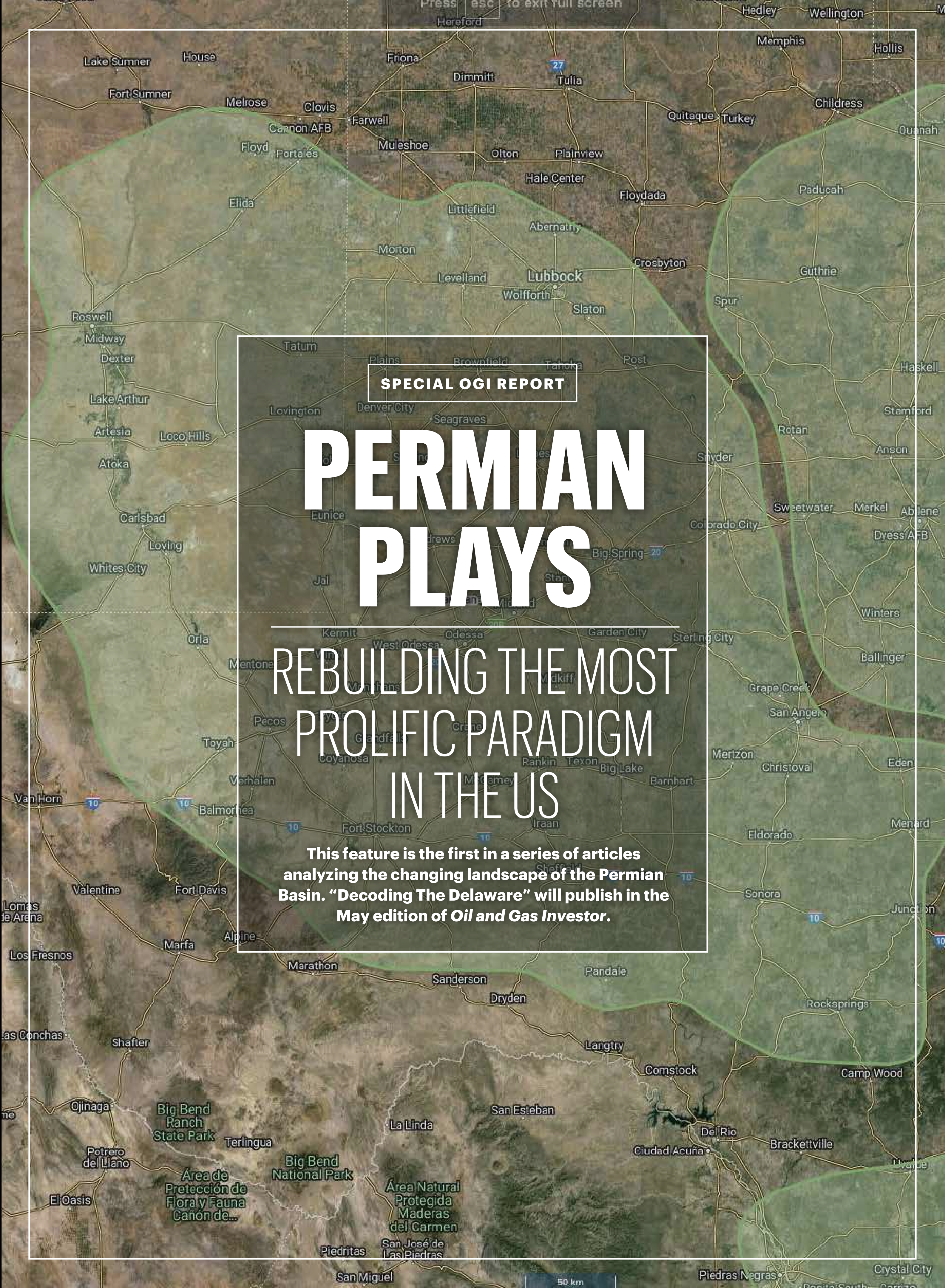
Trinidad, located just off the eastern coast of Venezuela, is home to the four-train 14.8 mtpa Atlantic LNG facility, the first liquefaction plant constructed in the Latin America and Caribbean region (LAC). Trinidad is also home to ammonia and methanol plants even though the bulk of the country's value is generated from its gas derived from the LNG business, according to recent official statements from NGC President Mark Loquan.

However, declining gas production in recent years in Trinidad, coupled with disagreements between Atlantic LNG shareholders BP, the country's largest gas producer, and Shell, the largest shareholder, saw Train 1 initially idled in December 2020. The train is still offline. However, a recent Atlantic LNG restructuring as well as a deal to tap into gas from Venezuela's offshore Dragon fields look to assure the Train returns to operation soon, according to Young.

"The restructuring gives us the opportunity to potentially process Calypso gas through that facility and lift LNG if we so desire. A lot of the work that we're doing right now is understanding the possible outlets for Calypso gas. There's also a very significant petrochemical industry in Trinidad and Tobago. There's a number of different potential customers, and that's a key part of our scope of work in the near term."

Beyond oil and gas, Trinidad is really leaning on IOCs already in the country to assist with the country's energy transition and shift to renewables.

"As we've been working on our strategy to thrive through the energy transition, we've really focused our efforts on hydrogen and integrated carbon solutions, so things like CCS and carbon offsets," O'Neill said. "We do see some opportunities in Trinidad, but renewables isn't a focus area for us. It's not something that particularly matches our capabilities. So, that's not something that we'll be pursuing." OGI



SPECIAL OGI REPORT

PERMIAN PLAYS

REBUILDING THE MOST PROLIFIC PARADIGM IN THE US

This feature is the first in a series of articles analyzing the changing landscape of the Permian Basin. "Decoding The Delaware" will publish in the May edition of *Oil and Gas Investor*.

MIGHTY MIDLAND STILL BECKONS

But only those with the biggest balance sheets can afford to buy in the basin's core following a historic consolidation trend.

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Oil industry insiders have probably written off the dusty, shrub-dotted land surrounding Midland, Texas, more times than you can easily count

But the mighty Midland Basin has persisted—decade after decade, downturn after downturn—to help push U.S. oil production to a new record high.

And as the availability of currently economic onshore drilling locations around the U.S. shrinks, some of the world's top oil producers are paying hefty premiums to get a piece of the action.

Full-year 2023 upstream dealmaking totaled $192 billion, including $144 billion of transactions inked in the fourth quarter alone, according to data from Enverus Intelligence Research.

With high-profile consolidation spilling over into first-quarter 2024, the Permian Basin has seen well over $100 billion in M&A activity get signed in the last 12 months.

That includes the largest deal ever made in the shale oil and gas industry: Exxon Mobil's $64.5 billion acquisition of Pioneer Natural Resources.

In January, Diamondback Energy announced plans to acquire private producer Endeavor Energy Resources for $26 billion—the largest buyout of a private upstream E&P in industry history.

Occidental Petroleum is also getting deeper in the Permian with a $12 billion acquisition of CrownRock, a joint venture between CrownQuest Operating and private equity firm Lime Rock Partners.

Within a matter of months, some of the largest and least-developed pieces of land in the core of the Midland Basin were plucked off the drawing board.

Add onto those megadeals a deluge of smaller transactions, and operators that have yet to ink a deal are suddenly finding a lot less of the Midland to go around.

Today, the vast majority of the lowest-cost drilling locations across the Permian are already held within the portfolios of a relatively small number of public E&Ps, according to a Wood Mackenzie analysis.

E&Ps have realized that to get their hands on top-quality Permian rock, they'll likely have to go out and buy it from one, or several, of their competitors.

As the Midland's core shrinks, where could the next multibillion-dollar deals get signed?

Lateral movement

The feeding frenzy underway in the Midland Basin stands in stark contrast to the 1980s, when big U.S. majors were picking up and leaving matured West Texas fields in search of new oil in international locales, like Saudi Arabia and Russia.

U.S. independents, like Parker & Parsley, used the vacuum left in their wake as an opportunity to scoop up additional Permian Basin leasehold on the cheap.

Parker & Parsley CEO Scott Sheffield—who later led the company's merger with T. Boone Pickens' Mesa Petroleum to form Pioneer Natural Resources—recalls paying "nothing" for those Permian leases during the '90s and 2000s.

Operators were still drilling vertical Permian wells at that point. But advances in hydraulic fracturing and oilfield technologies, like composite bridge plugs, made it possible for vertical wells in the Permian to target several producing intervals underground, said Ron Dusterhoft, technology fellow at Halliburton and a 40-year industry veteran.

Hitting those secondary targets with vertical wells and hydraulic fracturing enabled operators to produce oil economically in the Midland area once again.

"This was, from my perspective, the second life in the Permian Basin when a lot of people had started to write it off," Dusterhoft told *Oil and Gas Investor*.

New technologies breathed a second life into the Permian throughout the 1980s and 1990s. But the Permian's second act had seemingly run its course by the 2000s, when operators struggled to sustain domestic output.

Total U.S. crude oil output fell by over 44% from 8.97 million

$192B
2023 upstream dealmaking

$64.5B
Exxon Mobil acquires Pioneer Natural Resources

$12B
Occidental Petroleum acquires CrownRock

$26B
Diamondback Energy acquires Endeavor Energy

Despite decades of downturns, new drilling techniques and technologies have pushed the dusty Midland Basin to become the site of a M&A frenzy—and there's not much left on the table.

EXXON MOBIL

"I'm not sure that anyone realized that the Permian had the potential that it has demonstrated today, but I remember Pioneer talking about the huge potential of this region very early on."

–**Ron Dusterhoft**, ***technology fellow, Halliburton***

bbl/d in 1985 to just 5 million bbl/d in 2008, bottoming out during the global financial crisis, according to the Energy Information Administration (EIA).

As domestic demand for oil and gas continued to rise, conventional wisdom held that the U.S. would be the world's largest importer of hydrocarbons for the foreseeable future.

It took unconventional risk-taking to break free from that mold.

Horizontal drilling and fracking techniques–pioneered by operators like Burlington Resources, Continental Resources, Lyco Energy and others in the Williston Basin in the late '90s and early 2000s–proved they could be applied to several unconventional targets in the Permian.

8.97M

Barrels of oil produced per day in the U.S. in 1985

5M

Barrels of oil per day produced per day in the U.S. in 2008

Top privately held E&Ps in the Permian Basin

Operator	Oil	Gross gas	Total boe/d
Mewbourne Oil Company	219.8	158.1	377.8
Endeavor Energy Resources*	**227.9**	**118.6**	**346.5**
CrownQuest (CrownRock LP)**	**105.1**	**69.8**	**174.9**
Birch Operations	66.6	37.8	104.4
Kaiser-Francis Oil Company	53.4	36.7	90.1
Surge Energy	57.6	24.5	82.1
BTA Oil Producers	39.9	32.3	72.2
Continental Resources	45.4	17.9	63.3
Fasken Oil and Ranch	35.1	12.4	47.5
Franklin Mountain Energy	37.6	9.7	47.3
Blackbeard Operating	25.5	18.8	44.3
Sequitur Energy Resources	14.7	23.7	38.4
Ameredev	22.3	15.3	37.6
Spur Energy Partners	22.9	13.6	36.6
Discovery Natural Resources LLC	16.0	19.2	35.1
VTX Energy Partners	24.1	9.4	33.5
Permian Deep Rock Oil	24.5	6.2	30.7
Summit Petroleum LLC	18.4	11.1	29.5
Double Eagle IV	23.5	5.3	28.9
Triple Crown Resources	14.2	14.2	28.4
Steward Energy LLC	18.0	8.5	26.5
TRP Energy	20.3	6.1	26.4
Rio Oil And Gas	6.5	14.6	21.1
Maverick Natural Resources	9.1	10.3	19.4
Capitan Energy	6.1	13.2	19.3

SOURCE: RYSTAD ENERGY
NOTE: Values shown are gross operated 2-stream production data by operator in thousand barrels of oil-equivalent per day (boe/d); Average daily production as of 3Q23
*Pending acquisition by Diamondback Energy **Pending acquisition by Occidental Petroleum

Pioneer Natural Resources is currently the largest pure play in the Permian; its acquisition by Exxon Mobil is expected to close this year.

PIONEER NATURAL RESOURCES

First in the Midland Basin, and later in the more western Delaware Basin, Dusterhoft said.

Operators started drilling horizontal Permian wells, complete with longer and longer horizontal laterals extending for miles deep beneath the red Midland dirt.

By January 2007, crude oil production in the Permian region averaged around 843,000 bbl/d, according to the earliest figures published by the EIA. That dwarfed other onshore plays at the time, like the Bakken (~132,000 bbl/d), the Anadarko (~126,000 bbl/d), the Rockies (~113,000 bbl/d) and the Eagle Ford Shale (~54,000 bbl/d).

It wasn't until May 2011 that Permian oil output rose above 1 million bbl/d.

"I'm not sure that anyone realized that the Permian had the potential that it has demonstrated today, but I remember Pioneer talking about the huge potential of this region very early on," Dusterhoft said.

"It's really that sweet spot of a deal that companies are willing to pay up for, where you're both getting a lot of long-term inventory, and you're really getting that core-of-the-core, top-tier inventory that's requiring those higher multiples."

–Matt Bernstein, *senior analyst, Rystad Energy*

Core competency

Scarcity of top-quality drilling locations is now causing acreage in the core of the Midland Basin to sell for a premium.

But if you were to gaze over a tract of "premium" core acreage in Midland or Martin counties, for example, it might not be clear why one dusty, flat acre would be any more or less valuable than the next.

What operators are chasing in the Midland Basin's core is a ton of oil production that doesn't need a ton of money to get it out of the ground.

Companies like Pioneer and Endeavor were two of the largest owners of undrilled land in the core-of-the-core of the play.

Put another way, these companies owned rights to drill wells that can guarantee profitable returns even in a period of low commodity prices.

Counties in the core of Texas' Midland Basin–Midland, Martin, Upton and Glasscock–consistently have some of the lowest breakeven costs across the Spraberry, Wolfcamp A and Wolfcamp B intervals, according to an analysis from Novi Labs.

But the cost curve to drill goes up the further outside of the basin's core you move.

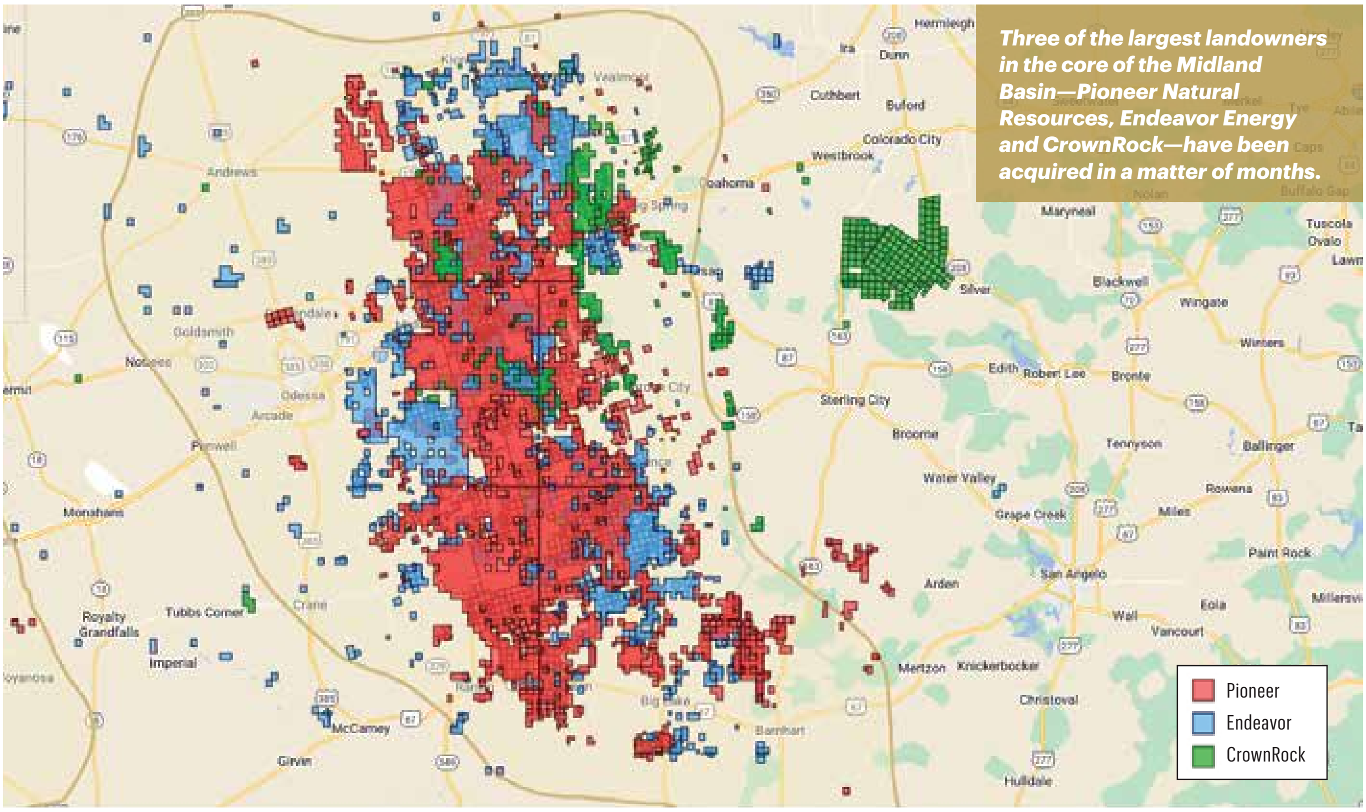
New wells drilled in the core of the play are generally able to break even after two years with oil prices averaging between $55/bbl and $60/bbl.

But new wells drilled in the northern and southern fringes of the play would require average oil prices between $90/bbl and $100/bbl over two years to break even.

That huge difference is why Pioneer, Endeavor and CrownRock sold for a hefty premium between 5-6X their EBIDTA margins.

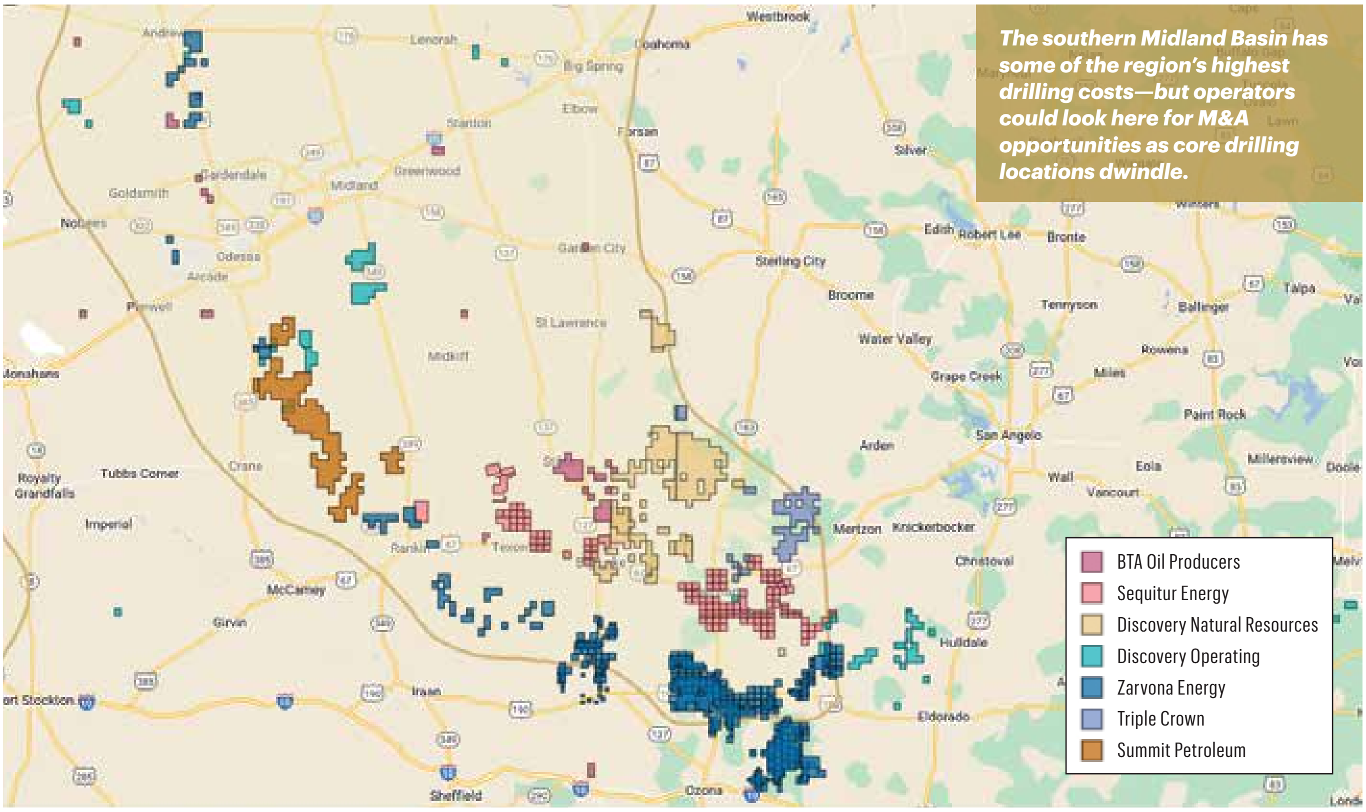
"It's really that sweet spot of a deal that companies are willing to pay up for," said Matt Bernstein, Rystad Energy senior analyst, "where you're both getting a lot of long-term inventory, and you're really getting that core-of-the-core, top-tier inventory that's requiring those higher multiples."

Midland acreage changing hands



Three of the largest landowners in the core of the Midland Basin—Pioneer Natural Resources, Endeavor Energy and CrownRock—have been acquired in a matter of months.

Southern Midland

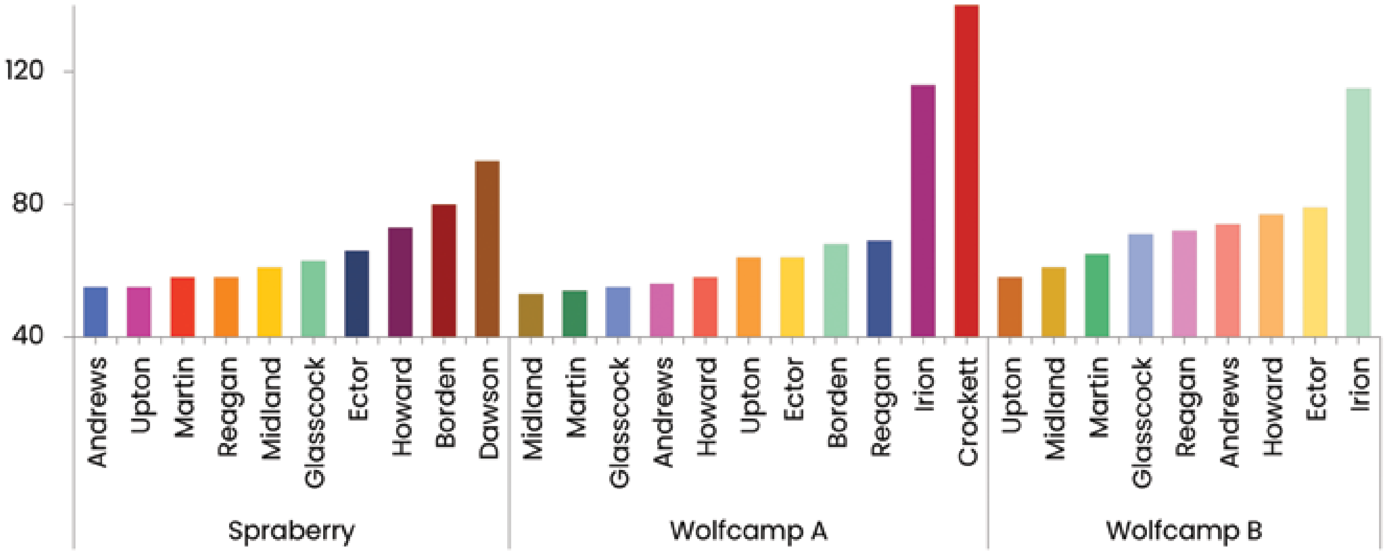


The southern Midland Basin has some of the region's highest drilling costs—but operators could look here for M&A opportunities as core drilling locations dwindle.

SOURCE: REXTAG

Midland breakeven by county

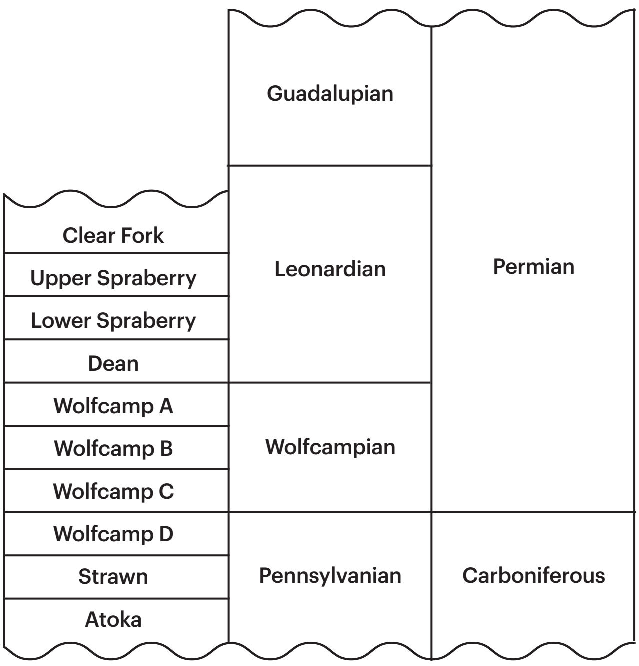
2-Year WTI Breakeven ($/bbl)



SOURCE: NOVI LABS

The core of the Midland Basin has some of the lowest breakeven costs in the region. Costs to drill move up further outside the basin's core to the north and south.

Midland Basin



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, ENVERUS

Some operators are targeting less-developed intervals in the Midland Basin, including the Middle Spraberry and the deeper Wolfcamp D formation, according to Enverus Intelligence Research.

E&Ps located outside of the core, with lower-tier inventory and higher drilling costs, would not fetch similar multiples if they were carved out by a larger player.

They might nab a 3.5x multiple—similar to some of the take-outs of private equity-backed E&Ps early in the 2023 consolidation wave, Bernstein said.

But after a year of historic consolidation, what's left of the Midland Basin's core to be bought?

There are still a handful of private E&Ps with attractive inventory portfolios, including Double Eagle IV, Summit Petroleum and BTA Oil Producers, by Rystad's analysis.

These are the inventory plays: companies with long inventory runways that don't necessarily produce all that much oil and gas right now.

They differ from E&Ps that are producing healthy volumes of oil and gas but don't have attractive inventory depth for the long term—the PDP-centric plays.

Surge Energy and Birch Operations are two of the top private producers remaining in the Permian Basin, according to Rystad, but their assets are located in the northern reaches of the Midland Basin, primarily in Howard, Borden and Dawson counties, where it's more expensive to drill.

"Birch, Surge: these are companies that are producing a lot right now, relatively," Bernstein said. "But again, they're not probably going to get that same type of multiple, or even close to the same type of multiple, that Endeavor or CrownRock got."

There are also several public E&Ps that have grown through Permian acquisitions in recent years that could become targets for acquisition themselves.

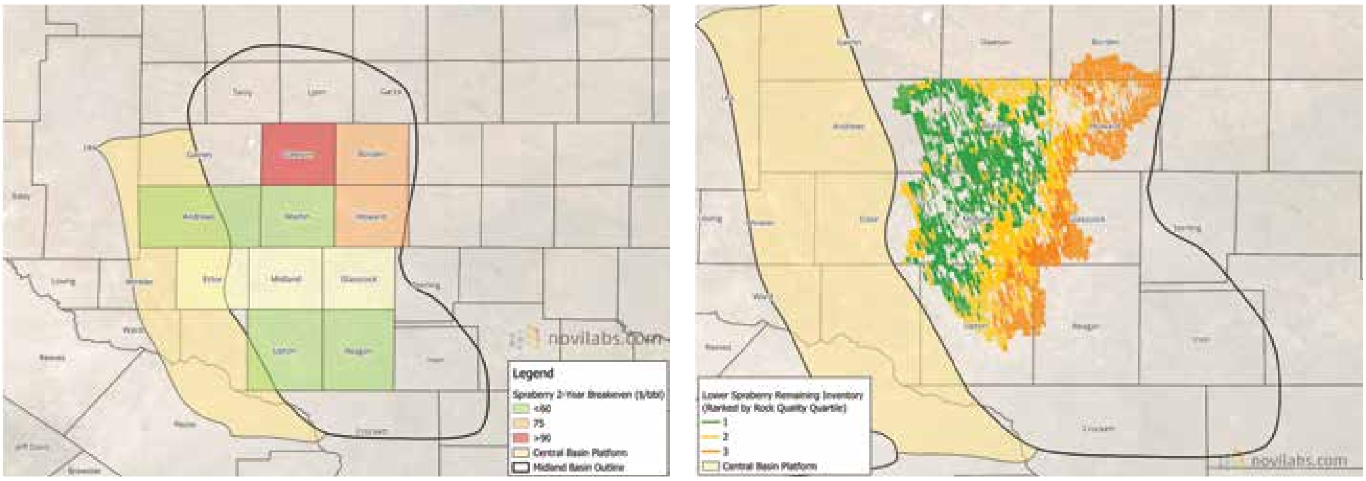
Civitas Resources jumped into the Permian with nearly $7 billion in acquisitions last year. The company's $2.1 billion acquisition of Vencer Energy, backed by commodities trading house Vitol, added acreage in the Midland Basin's core.

Vital Energy—formerly Laredo Petroleum—added to its legacy position in the Midland Basin in deals with private E&Ps last year.

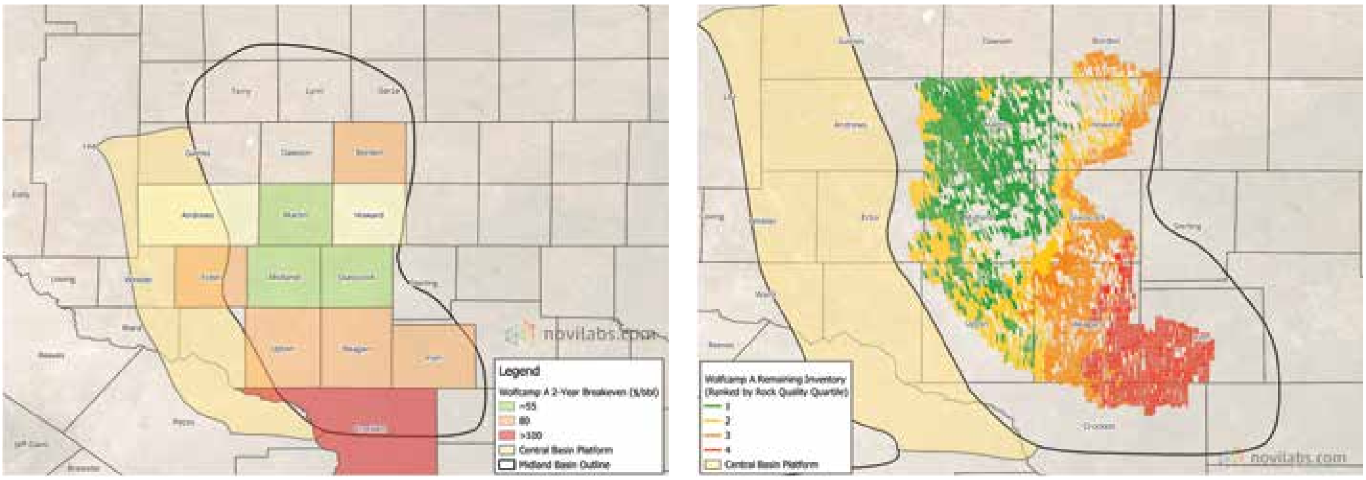
Ovintiv also grew its Midland portfolio by acquiring a package of three EnCap-backed private producers for $4.275 billion.

Permian Resources, which is mostly concentrated in the Permian's more western Delaware Basin, added PDP-heavy assets in the Midland Basin through a $4.5 billion takeover of

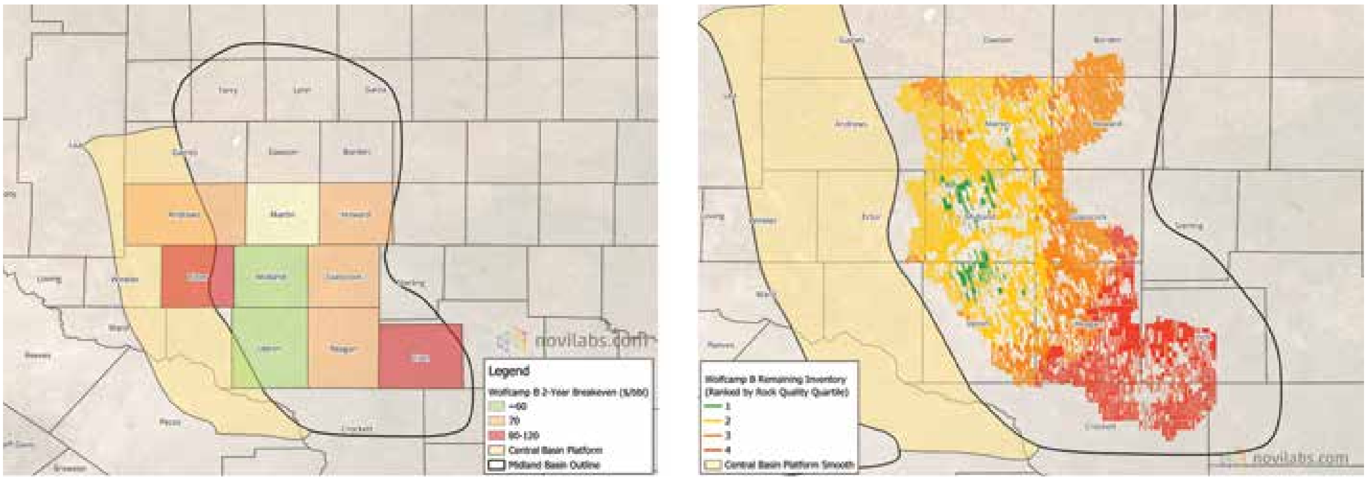
Spraberry



Wolfcamp A



Wolfcamp B



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

The Midland Basin's central core consistently has the lowest breakeven costs to develop the popular Spraberry and upper Wolfcamp intervals.

Earthstone Energy.

"That's kind of what I see as the next chapter of this [industry consolidation]," Bernstein said.

There's also SM Energy, which has operations in the Permian and near the Texas-Mexico border. But SM is getting deeper in the Midland Basin: the company reported increasing its Midland acreage by 37% in 2023.

With a market value of around $5.4 billion, SM appears to be one of the more reasonable acquisition opportunities remaining after this latest wave of consolidation, said Andrew Dittmar,

Most of the Tier 1 drilling locations in the Midland Basin are in the hands of the largest producers.

PIONEER NATURAL RESOURCES

senior vice president at Enverus Intelligence.

"Among remaining SMID caps, for a balance of inventory life and an attractive valuation SM would be near to the top to be positioned for a deal," Dittmar told Hart Energy.

Tier jumpers

After months of major industry consolidation, there are few Tier 1 drilling locations left on the market.

Analysts believe that operators in search of greater inventory depth will have to start moving down the list into Tier 2 and Tier 3 acreage as locations.

And operators believe that by lowering their oilfield service costs, D&C costs and picking up operational efficiencies, they can move some of those Tier 2 locations into Tier 1 status.

As core acquisition opportunities dwindle, "companies needing inventory are likely to take a harder look at the southern Midland," a much more fragmented part of the basin, Dittmar said.

Counties in the southern Midland, like like those in the north generally have higher breakeven costs above the $50/bbl range that public investors prioritize.

An operator buying into the area would then look to drive down those breakevens by lowering drilling costs and optimizing spacing.

It's a story played out across the Permian: spending less money to drill fewer wells with longer horizontal laterals to maintain, or just slightly boost, production.

The southern Midland is also the area that some of the bigger public acquirers from 2023 will likely look toward if they want to sell off non-core portions of their portfolios, Dittmar said.

"Overall, I'd say the southern Midland is one of the remaining bright spots for further consolidation."

Sequitur Energy, Discovery Natural Resources, Discovery Operating and Triple Crown Resources are among the largest producers with significant footprints in the southern Midland Basin.

Dig deeper

Given the chatter about historic consolidation, inventory depletion, scarcity, peak oil demand looming—it might seem like the Permian is nearing the end of its run.

Analysts and industry experts say that's not remotely the case.

"Overall, I'd say the southern Midland is one of the remaining bright spots for further consolidation."

—Andrew Dittmar, *senior vice president, Enverus Intelligence*

The Permian Basin is expected to be the primary driver of U.S. oil production growth for decades to come.

The most common subsurface targets for drilling, the main Spraberry and Wolfcamp intervals, are pretty well developed at this point.

Operators have targeted the Spraberry trend in the Midland Basin with vertical wells since at least the late 1940s, according to the Bureau of Economic Geology at the University of Texas at Austin. The deeper Wolfcamp zones have been targeted more recently.

But once the most popular Wolfberry plays are drilled up and their recoverable resource exhausted, operators will drill deeper.

"The really interesting thing about the Permian Basin is that there are now several horizontal targets, meaning that there is room for a very large number of wells and a massive amount of reservoir contact made possible through horizontal drilling and hydraulic fracturing," Dusterhoft said.

Enverus has identified around 25,000 additional geologically viable locations that imply future upside in more extensional, fringier portions of the Midland Basin.

The average breakeven for these geologically-viable locations is higher—between $70/bbl and $80/bbl—Enverus reported at the end of 2023.

With the primary Wolfberry targets heavily developed, the Middle Spraberry and the deeper Wolfcamp D intervals show the most viable promise in the Midland Basin, according to Enverus' analysis.

"The Permian has proven to be an amazing petroleum system that has been highly productive for close to a century, making it a pretty amazing story," Dusterhoft said.

LIFE ON THE EDGE:

SURGE OF ACTIVITY IGNITES THE NORTHERN MIDLAND BASIN

Once a company with low outside expectations, Surge Energy is now a premier private producer in one of the world's top shale plays.

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Conventional wisdom put little stock in Surge Energy's development plan for the northern Midland Basin when the company launched in 2015. Instability was the rule of oil prices and the startup was buying acreage that was widely known to be expensive to drill.

Nearly a decade later—after a pandemic, an almost-recession and a profound consolidation trend—Surge is one of the top private producers still standing in the Permian Basin.

And as larger E&Ps scour the Permian for low-cost drilling inventory, several of Surge's close neighbors in the northern Midland have recently signed deals to be acquired.

Surge has come a long way since 2015. But CEO Linhua Guan admits that the investment community's skepticism when the company first launched was certainly understandable.

Oil prices were low: average WTI priced at $48.66/bbl in 2015, down more than 47% from $93.17/bbl the year before, according to the Energy Information Administration.

The price environment made it difficult for some of the industry's most adept producers to turn a profit and dozens of E&Ps filed for bankruptcy during the ensuing years.

But while the industry languished, Surge was quietly building its portfolio, albeit in parts of the Permian still largely unproven at that point.

Surge, through subsidiary Moss Creek Resources, made two key acquisitions on the Texas side of the Permian during its first year: a 5,000-acre waterflood asset in Crosby County and a 76,000-acre position in Howard and Borden counties.

There were several areas within Howard County that showed little promise for drilling, Guan told *Oil and Gas Investor*. Borden County, located on the edge of the shelf, wasn't viewed as economic for horizontal development during a period of low commodity prices.

"I think it took the management team of Surge Energy two or three years to persuade [Wall Street] we could produce economically from Borden County," said Guan, who joined Surge as chief business development officer in 2018 before becoming CEO the following year.

Surge's production was coming in at less than 4,000 boe/d when the company launched in May 2015. Oil prices sunk even lower in 2016 and stayed at depressed levels the following year; Surge was burning through a lot of cash, Guan said.

But Surge managed to push through the downturn, growing its northern Midland portfolio with incremental acreage acquisitions in Howard and Borden counties.

And the company kept pushing into the oily fringes of the basin's northern reaches with acquisitions in Dawson and Gaines counties in 2022.

It was in 2022, when WTI prices averaged around $95/bbl—the highest levels seen in nearly a decade—that Surge generated record free cash flow of over $500 million for the year.

A few months later, S&P Global Ratings upgraded its credit rating.

"That pretty much changed everything in how Wall Street viewed Surge Energy," Guan said.

Today, Surge isn't alone in seeing untapped opportunity in the northern part of the basin.

EOG Resources, SM Energy and Callon Petroleum are testing well designs in Dawson and Gaines, neither of which have historically attracted much drilling activity. But permitting is starting to heat up. In Dawson County, just over 250 permits to drill horizontal wells have ever been requested from the Texas Railroad Commission; 60 permits, nearly a quarter of Dawson's total permits, were issued just last year.

By the end of third-quarter 2023, Surge's average output had, ahem, surged up past 65,000 boe/d, the company reported this spring.

"We survived two downturns and kind of turned crisis into opportunity—and continued growing," he said.

Surge aims to continue its growth story in the northern Midland Basin.

After participating in quite a few marketing processes, Surge closed some smaller acquisitions in 2023; nothing large enough to press release, Guan said.

"There was quite a big gap in expectations between sellers and buyers, so we could not close any sizable deals last year," he said. "This year, I hope the bid-ask spread will be narrower."

Surge is open to making acquisitions this year where it makes sense. The company has a few hundred million dollars in its cash war chest and more than $1 billion in liquidity.

And the company is also focused on making organic gains. Surge plans to operate three rigs this year, a similar level of activity compared to 2023, Guan said. But the company also expects to bring its costs down year over year due to deflation in the oilfield services market.

Still, if a buyer were to come knocking, you can never say never to a potential sale, Guan said.

"If the price is right, likely the board of directors could sell Surge Energy," he said.

Surge Energy has grown its footprint in the northern Midland Basin since launching in 2015.

SURGE ENERGY

Inventory scramble

A deluge of M&A activity has washed over the Midland Basin since the summer, and it's being driven by a dwindling number of top-quality drilling locations. As the middle of the basin gets bought up for premium prices, E&Ps are looking at the northern edges for potential deals.

Some of the basin's biggest and oldest producers have been scooped up into the portfolios of larger E&Ps in a matter of months:

The public Permian juggernaut Pioneer Natural Resources agreed to an eye-popping $64.5 billion sale to Exxon Mobil in October.

In December, CrownRock sold to Occidental Petroleum in a $12 billion deal.

Endeavor Energy Resources agreed in February to a $26 billion buyout by Diamondback Energy—the largest acquisition of a private upstream company ever, according to Enverus Intelligence Research.

APA Corp., an Apache subsidiary, is picking up Callon Petroleum—which has acreage in the Midland and Delaware basins—for $4.5 billion.

Several other large private Midland E&Ps—Vencer Energy, Tap Rock Resources, Hibernia Resources, Black Swan Operating, PetroLegacy Energy and Piedra Operating—have been scooped up by public players including Civitas Resources, Ovintiv and Vital Energy.

When it comes to undeveloped inventory, companies like Pioneer, Endeavor and CrownRock were the belles of the Midland ball. These E&Ps held large swaths of premium undrilled land in the core-of-the-core of the basin.

This land is coveted by larger E&Ps because it's cheaper to drill a gushing oil well there than in other places. Take Exxon's massive acquisition of Pioneer: the deal extends Exxon's future drilling runway by about 6,300 net locations that can generate at least a 10% return in a sub-$50/bbl oil price environment.

But prices that low would make drilling new wells uneconomic for many E&Ps with lower-quality inventory. A prolonged period of low prices could sink them—like what happened after the 2014-2015 price downturn and again during the COVID-19 pandemic.

Even before selling to Exxon, Pioneer CEO Scott Sheffield acknowledged that survival through the COVID downturn for many independent E&Ps would require consolidation. The northern Midland Basin still isn't as quality as the core of the basin, analysts say, and companies like Endeavor have some of the most-economic drilling locations remaining across the Lower Spraberry, Wolfcamp A and Wolfcamp B intervals, according to an analysis by Novi Labs.

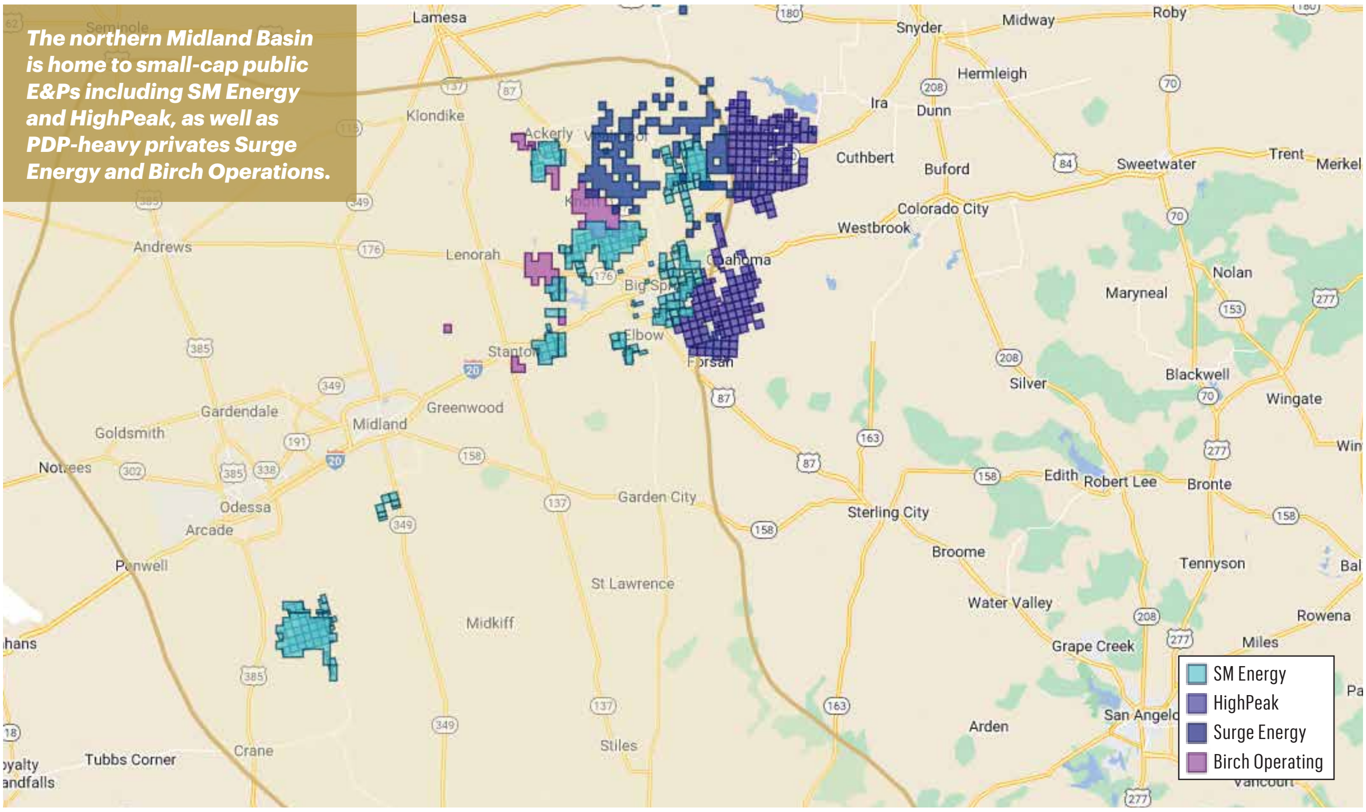
Brandon Myers, head of research at Novi Labs, said many of Endeavor's remaining drilling locations fall into the top quarter of the Midland Basin's most-quality inventory.

Comparatively, the vast majority of Surge's acreage—around 83% of the company's remaining locations—falls into the third quartile of inventory quality, according to Novi's analysis.

"Point being that [Surge] is not going to fetch that [5x-6x] operating cash flow premium that Diamondback paid for Endeavor," Myers told *OGI*.

"A good analogy would probably be Permian Resources and

Northern Midland



The northern Midland Basin is home to small-cap public E&Ps including SM Energy and HighPeak, as well as PDP-heavy privates Surge Energy and Birch Operations.

SOURCE: REXTAG

Earthstone," he said, referring to Permian Resource's $4.5 billion takeover of Earthstone Energy last year.

Living on the edge

The northern edge of the Midland Basin might not be as attractive as core-of-the-core acreage. But the northern Midland is still appealing to major E&Ps hunting for scale and inventory runway.

Ovintiv bought a package of three EnCap portfolio companies—Black Swan, PetroLegacy and Piedra Resources—in a $4.275 billion cash-and-stock deal last year.

APA's $4.5 billion acquisition of Callon Petroleum includes roughly 26,000 net acres in the Midland Basin. The transaction also includes a significant footprint in the Delaware Basin, where Callon holds about 119,000 net acres.

Some of Surge's other publicly traded neighbors say they are open to consolidating.

One is SM Energy, which has holdings in the Midland Basin and in South Texas. During SM's fourth-quarter earnings call, CEO Herb Vogel said the company is agnostic about whether it acquires a smaller player or is itself acquired by a bigger player.

But SM has long been a believer in upstream consolidation, and in the balance sheet accretion and industrial logic M&A can deliver.

"We sit on 10-plus years of inventory, so we don't have to really overpay to get something to just move along," Vogel said. "But if the right deal comes along, we'd be there."

Further to the east, super-oily HighPeak Energy continues to pursue strategic alternatives, including a potential sale.

The company hired Texas Capital Securities and Wells Fargo Securities to "assist us in our pursuit of strategic alternatives," HighPeak reported in fourth-quarter earnings. The E&P's efforts to sell the company in the first half of 2023 didn't materialize.

Fourth-quarter production averaged 50,000 boe/d, 81% oil and 11% NGL. The company's leasehold totals 132,000 net acres.

Privately held Birch Operations has also grown a significant foothold in the area. Birch ranks as the fourth-largest private E&P in the Permian Basin, coming in behind only Mewbourne Oil, Endeavor and CrownRock, according to Rystad Energy.

Surge and Birch are two of the top private producers remaining in the Permian, but from a remaining inventory standpoint, these players wouldn't fetch a premium like Endeavor or CrownRock, said Matt Bernstein, a Rystad senior analyst.

There are other Midland Basin E&Ps that aren't producing as much oil—but have a deeper and more attractive inventory, Bernstein said. These inventory-focused privates include Double Eagle IV, Summit Petroleum and BTA Oil Producers.

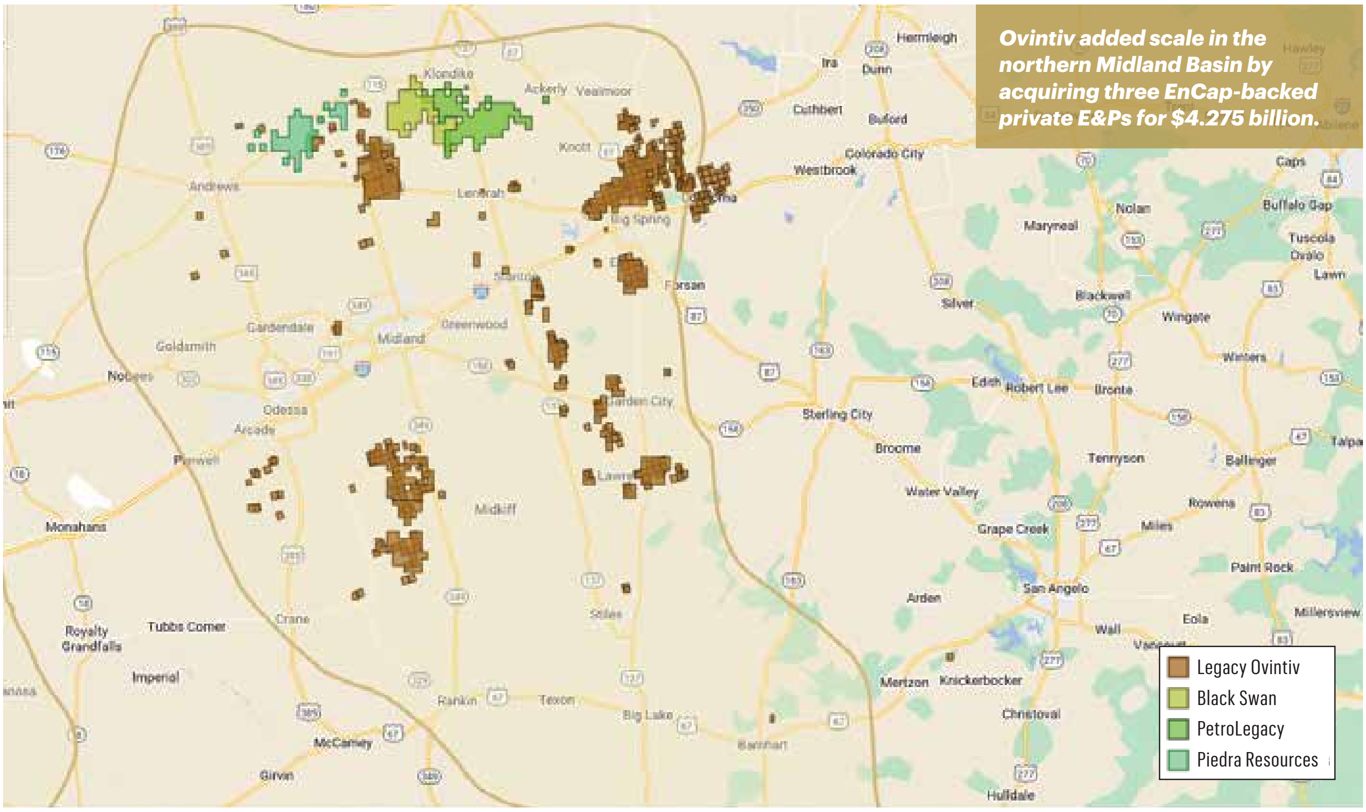
In the current cycle of upstream industry mega-consolidation, there's a widening gap between the $50 billion-plus super-independents and the smaller independents. And there's a shrinking number of companies on the market for a larger producer to score inorganic growth.

Surge and some of its fringy northern Midland neighbors might not be attractive to acquire in one-off deals by themselves, Myers said. A merger between a few of these contiguous landholders might make sense to investors, though.

"Maybe rock quality is Tier 3, but if you can get to a place where you've got best-in-class cash costs and you've got really high netbacks on an operating cash flow basis, you can start to look really attractive from that side," Myers said.

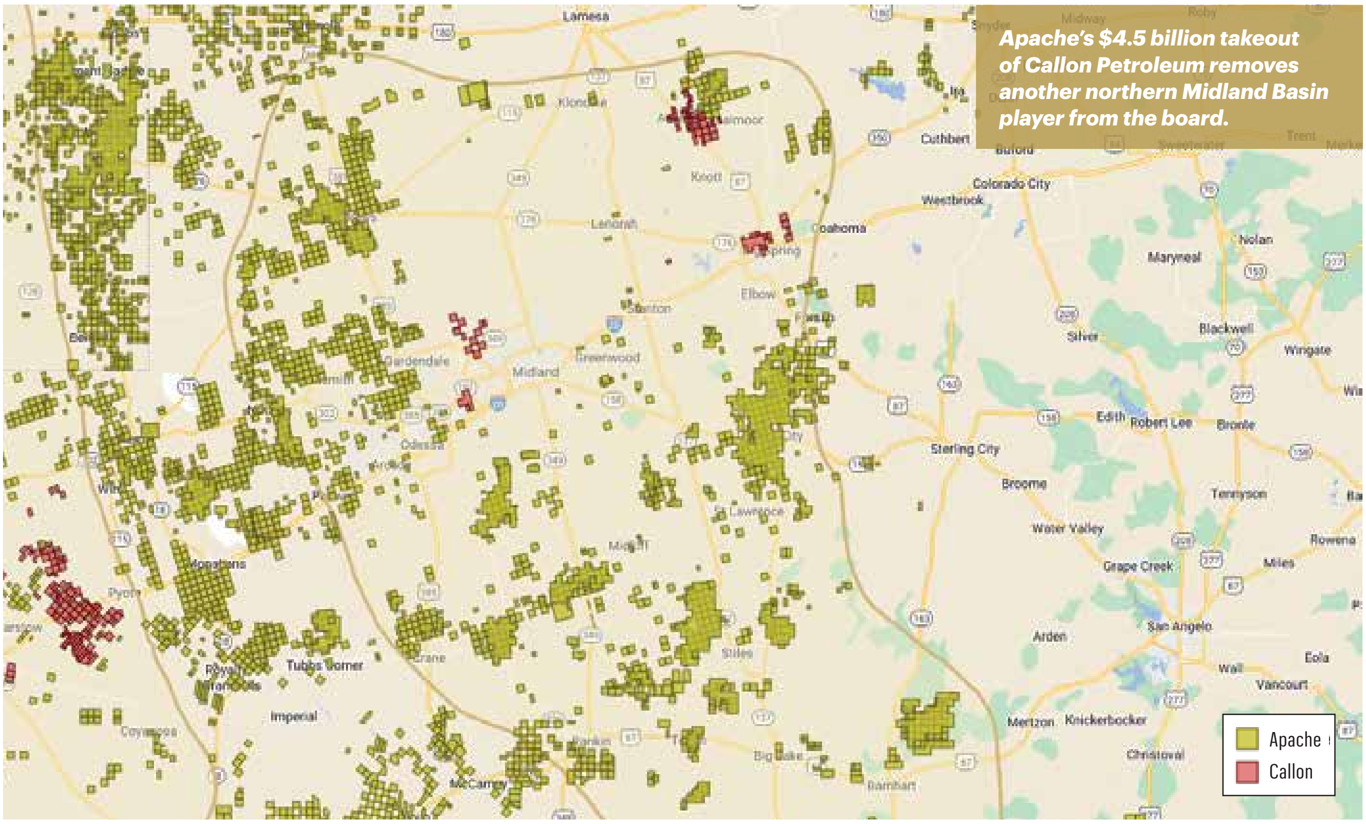
"There could be a role for them if they get big enough." OGI

Ovintiv, EnCap acreage



SOURCE: REXTAG

APA Corp., Callon Petroleum acreage



SOURCE: REXTAG

Kimmeridge Turns Up Heat on SilverBow with New Bid

After asking for additional board seats, the E&P investor followed up with a buyout offer. A deal would make a nearly 1 Bcfe/d Eagle Ford pure-play.

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E&P investor Kimmeridge Energy Management is offering $34 per SilverBow Resources share, asking the South Texas E&P's shareholders to do a deal by April 26.

The bid, a 7% premium to SilverBow's March 12 closing stock price, is elevated from a February request for three board seats that met with a damning reply from SilverBow.

SilverBow shares closed at $31.72 pre-announcement; the company's 30-day average was $28.12. At closing on March 14, after Kimmeridge's offer went public, shares were trading at $33.41 per unit.

On March 13, SilverBow confirmed receiving the Kimmeridge proposal in which it offers to contribute the assets of Kimmeridge Texas Gas (KTG) and $500 million of cash in exchange for shares issued by the combined entity.

"Following the proposed transaction, Kimmeridge would control a supermajority of the combined company, including the shares currently held by Kimmeridge, with the remaining shares held by public shareholders," SilverBow said in a press release.

SilverBow said it would "carefully review and consider the proposal to determine the course of action that it believes is in the best interest of the company and all of its shareholders."

SilverBow noted that it has engaged extensively with Kimmeridge beginning in August 2022. On March 1, 2024, the company disclosed its history of engagement and negotiation with Kimmeridge on Form 8-K filed with the Securities and Exchange Commission (SEC).

Kimmeridge's proposed merger of its South Texas E&P KTG with SilverBow would grow production to 900 MMcfe/d across 370,000 net acres. The combined company would hold 5 Tcfe of proved reserves and 1,600 future well locations.

Separately, Kimmeridge is looking to cover a 267 MMcf/d LNG-supply deal. SilverBow (SBOW) currently produces some 476 MMcf/d. KTG produces 315 MMcfe/d, 85% gas.

KTG has an enterprise value of $1.42 billion, according to Kimmeridge. The investment firm would get 32.4 million SilverBow shares for the KTG property.

For the additional $500 million cash investment, Kimmeridge would get 14.7 million SBOW shares. At closing, it would hold 50.3 million. The cash infusion would be used to reduce SilverBow's debt.

Ben Dell, a Kimmeridge co-founder and managing partner, wrote before markets opened March 13, "We believe all shareholders will benefit from the opportunity to participate in the compelling upside of a larger and more resilient company that is uniquely positioned to drive growth and lead the next phase of consolidation in the Eagle Ford."

Kimmeridge holds 12.9% (3.3 million) of SBOW shares currently. Additional large shareholders include Riposte Capital (9.7%), BlackRock (5.9%), State Street (4.15%) and Strategic Value Partners (1.5%), according SEC filings.

KTG holds 148,000 net acres in the Eagle Ford play, neighboring SilverBow in some areas.

"If SilverBow is as committed to hearing the perspectives of shareholders as it purports to be, then it will be open to the following proposed process," Dell wrote.

He added, "Contrary to what the SilverBow board would have you believe, Kimmeridge's focus throughout our engagement has squarely been on putting forward a highly compelling transaction that paves the way for value creation for all."

Kimmeridge said its advisers include Barclays and RBC Capital Markets.

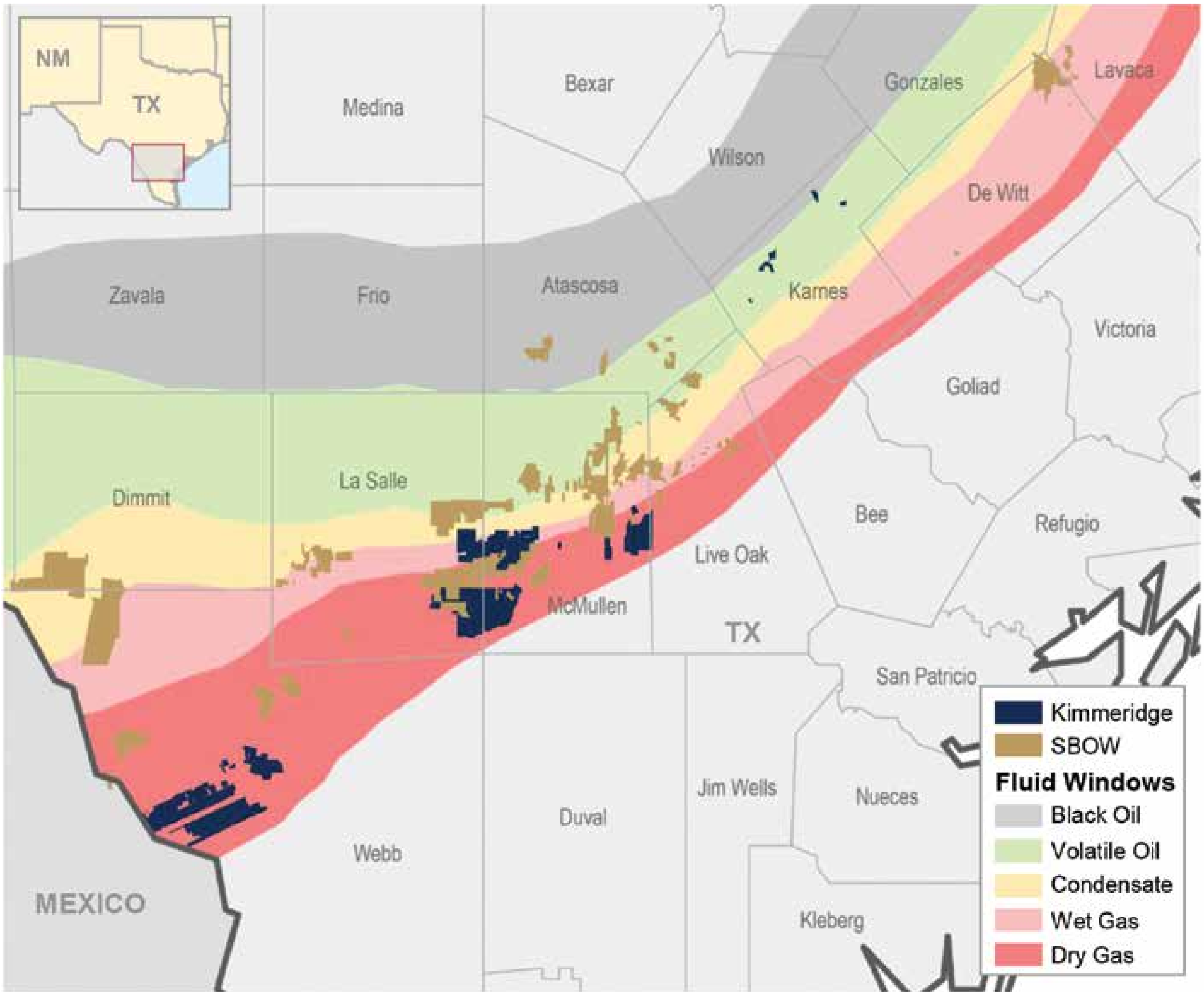
The first offer

Kimmeridge's February ask was for three seats and to remove one board member.

SilverBow's board replied March 1 that Kimmeridge had a "hidden self-serving agenda."

"We believe the launch of this proxy fight is a next step in [Kimmeridge's] nearly two-year effort … to force a merger with KTG on terms unfavorable to SilverBow and its shareholders," the board wrote to investors at the time.

Kimmeridge, Silverbow acreage in the Eagle Ford



SOURCE: KIMMERIDGE ENERGY MANAGEMENT

"We believe all shareholders will benefit from the opportunity to participate in the compelling upside of a larger and more resilient company ..."

–**Ben Dell,** ***co-founder and managing partner, Kimmeridge Energy Management***

On Feb. 29, SilverBow's market cap was $724 million, while the share price was $28.10. The trailing-12-month price-to-earnings ratio was 2.34; price to book, 0.69; profit margin, 86.33%; debt-to-capital, 48.53%; and annual revenue of $652 million, according to Fidelity.

Kimmeridge's year-end 2023 holdings also included California Resources, which is buying Aera Energy; Chesapeake Energy and Southwestern Energy, which are merging; Enerplus Corp., which is merging into Chord Energy and which Kimmeridge's SilverBow board nominee Doug Brooks formerly led; and Civitas Resources.

Kimmeridge wrote March 13 that SilverBow would begin throwing off cash to shareholders in 2025 under its plans for the E&P and Kimmeridge would have five of nine board members.

As an example of Kimmeridge's past E&P consolidation, he pointed to the Kimmeridge-led formation of Rockies and Permian-focused Civitas Resources–an amalgamation of several E&Ps that has grown from a $1.2 billion operator to $7 billion today. OGI

TPH: Lower 48 to Shed Rigs as Gas Plays Rebound

Permian Basin down for the count in the near term, with muted activity into 2025.

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The Lower 48's oil and gas landscape is in for some pruning as rig counts are forecast to fall, especially in the Permian Basin, according to an outlook from TPH & Co., the energy business of Perella Weinberg Partners.

Taking into account fourth-quarter 2023 earnings and upstream operators' 2024 guidance, TPH is reducing its near-term outlook for the Lower 48 with the Permian and Appalachia basins each shedding 10 rigs, and the Eagle Ford Shale losing nine rigs. Those basins are primarily driving the decline into the third quarter, bottoming out at 533 rigs, versus prior guidance of a low of 563 rigs, said Jeff LeBlanc, a TPH analyst.

TPH's outlook is primarily based on the public operators executing on their plans, with guidance indicating a decline of five rigs in the Permian, seven in the Eagle Ford and eight in the Northeast. However, TPH said continued churn should bias private aggregate activity lower over the next six to nine months.

"Year-to-date reductions have been most severe in the Haynesville (-11 rigs), but with a handful of reductions still pending, we expect basin activity to ultimately trough at ~35 rigs (~4 rigs below spot levels)," LeBlanc said in a March report.

Year-over-year, the Haynesville Shale has seen the rig count fall by 29 rigs, with 38 currently running, according to Baker Hughes. The cuts come as E&Ps reduce activity in the face of declining natural gas prices. Gas-focused E&Ps in the Haynesville, Marcellus and Utica shales, including EQT Corp., Chesapeake Energy, Comstock Resources and Antero Resources have announced reductions in drilling and completions. Most recently, CNX Resources said in March it would delay completions on 11 Marcellus wells to "avoid bringing incremental volumes into the current oversupplied market."

Looking further out, TPH is more optimistic about the gas drilling environment in 2025.

TPH expects stronger fundamentals to support a rebound in gas-directed drilling, with rig counts rising from third-quarter 2024 to third-quarter 2025. TPH forecasts rig activity to pick up with additions in the Haynesville leading the way with an increase of 24 rigs. The Anadarko Basin will add 10 rigs, the dry gas Eagle Ford will add seven and the

Major basin rig count as of March 8

Major basin variances	March 4-8	+/-	Feb. 26-March 1	+/-	Previous year
Ardmore Woodford	1	0	1	-1	2
Arkoma Woodford	1	0	1	0	1
Barnett	0	0	0	-1	1
Cana Woodford	21	-1	22	-10	31
DJ-Niobrara	12	0	12	-4	16
Eagle Ford	52	0	52	-20	72
Granite Wash	5	0	5	-2	7
Haynesville	38	-3	41	-29	67
Marcellus	32	0	32	-3	35
Mississippian	2	0	2	-2	4
Permian	313	-2	315	-30	343
Utica	12	0	12	-3	15
Williston	34	0	34	-8	42

SOURCE: BAKER HUGHES

TPH is reducing its near-term outlook for the Lower 48 rig count, predicting a continued decline into third-quarter 2024.

SHUTTERSTOCK

Northeast three rigs, according to the outlook.

In the Permian, 2025 will see a flattening of the rig count. Continued drilling efficiency gains, longer laterals and M&A synergies will dampen the need for incremental deployments and result in basin activity "plateauing below spot levels: ~306 rigs adj. spot, ~302 rigs FY'25 (vs prior ~316 rigs)."

"Specifically, we forecast avg. Permian lateral lengths of ~10,900 ft in 2025 (+7% vs FY'23) with companies realizing double-digit drilling efficiency gains to maintain leading-edge days-to-total depth moving forward," LeBlanc said.

OFS companies optimize

Despite the more bearish outlook for U.S. activity, TPH sees oilfield service (OFS) companies in its coverage—Helmerich & Payne, Patterson-UTI Energy and Nabors Industries—disproportionately benefitting because of their dominance in the drilling rig markets, though still at net negative versus TPH's prior models.

"The emphasis on maintaining and further improving upon today's efficiencies will drive operators to high-grade and standardize their fleets to one to three contractors," LeBlanc said. "Specifically, most operators will look to adopt the highest-quality services, equipment and technologies while trying to optimize standard operating procedures."

Some service companies are likely to expect investors to place a greater scrutiny on their customer base moving forward, in terms of their share of a customer's overall activity and whether their customers are more likely to be among the buyers or the acquired.

Out of the 20 most active producers, H&P holds a roughly 33% market share, while Patterson-UTI has 23% and Nabors has 15%. H&P works with nine of those operators, Patterson-UTI with six and Nabors with two, TPH said, although Nabors holds three sizable majorities at the basin level.

While those companies command higher day rates than some of their peers, the higher costs are unlikely to help much.

"We continue to observe a sizable spread in leading-edge rates with smaller drillers working in the mid-to-high $20k's, PTEN/NBR in the mid-to-low $30k's and HP in the high-$30k's," LeBlanc said. "Public operators continue to suggest higher sticker prices are not an issue for them as they value the reliable, consistent operations top tier contractors can provide."

Companies covered by TPH have maintained pricing discipline for the past nine months, a trend unlikely to change anytime soon.

"However, given the reduction in aggregate U.S. activity and our long-term outlook, we see limited upside to day rates (i.e. ~$1-2k per day) beyond covering any reactivation costs," TPH said. OGI

APA Boosting Permian Oil Production

APA Corp. plans to grow oil production by 10% this year above 2023 year-end volume.

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APA Corp. is on a growth trajectory driven by oil production in the Permian Basin, said CEO John J. Christmann IV.

During a fourth-quarter earnings call with analysts, APA reported average U.S oil production of around 84,000 bbl/d for the period. A targeted 10% increase would boost production close to 92,000 bbl/d by the end of this year.

"This growth will be driven by the Midland and Delaware Basins," Christmann said, adding that Permian production would be weighted toward the back half of the year due to the timing of completions.

The Permian offers APA a short-cycle asset base with predictable capital productivity and strong free cash flow generation, Christmann said.

APA's combined Permian production during the last three months of 2023 was primarily weighted toward oil (37%) followed by gas (34%) and NGLs (29%). During the fourth quarter, APA drilled 29 gross wells (25 net) and reported an average six rigs in operation.

In the southern Midland Basin, APA averaged three rigs and placed nine wells on production. APA plans a Barnett formation appraisal well in the second quarter.

In the Delaware Basin, APA averaged three rigs and placed 20 wells on production. APA plans to test u-zontals, also known as horseshoe wells, in the basin this year.

In addition to running six rigs in the Permian, APA will also pick up five rigs there related to the Callon Petroleum acquisition announced in January.

"We're very comfortable running those 11 rigs and really look forward to being able to integrate the Callon assets into our workflow and our schedules and so forth, but that's going to take a little bit of time," Christmann said. "And we're anxious to jump on their Delaware assets in addition to what we're doing in the Delaware and our Midland Basin".

"We believe [APA's] Permian program that is soon to be among the most active in the play will be key to continued, solid free cash flow generation and shareholder return," Truist said in a recent research note.

For the full-year 2023, APA reported average U.S. oil and gas production of 229 Mboe/d; 144 Mboe/d gross from Egypt (before adjusting for non-controlling interest and tax barrels); and 42 Mboe/d from the North Sea.

In 2024, APA's total gross production is expected to reach between 391 Mboe/d-393 Mboe/d prior to incorporation of Callon's assets compared to 405 Mboe/d in 2023. While APA expects higher U.S. production, it expects lower volumes in Egypt due to activity delays and scheduling constraints associated with limited available workover rig capacity and declines in the North Sea.

"This is an inexpensive toehold in the industry, with M&A clarity (vs. speculation elsewhere) and some long dated (and largely financed) barrels to come from Suriname as time passes," Evercore ISI said following the earnings call. "The quarter-to-quarter volatility one needs to stomach we acknowledge remains the challenge."

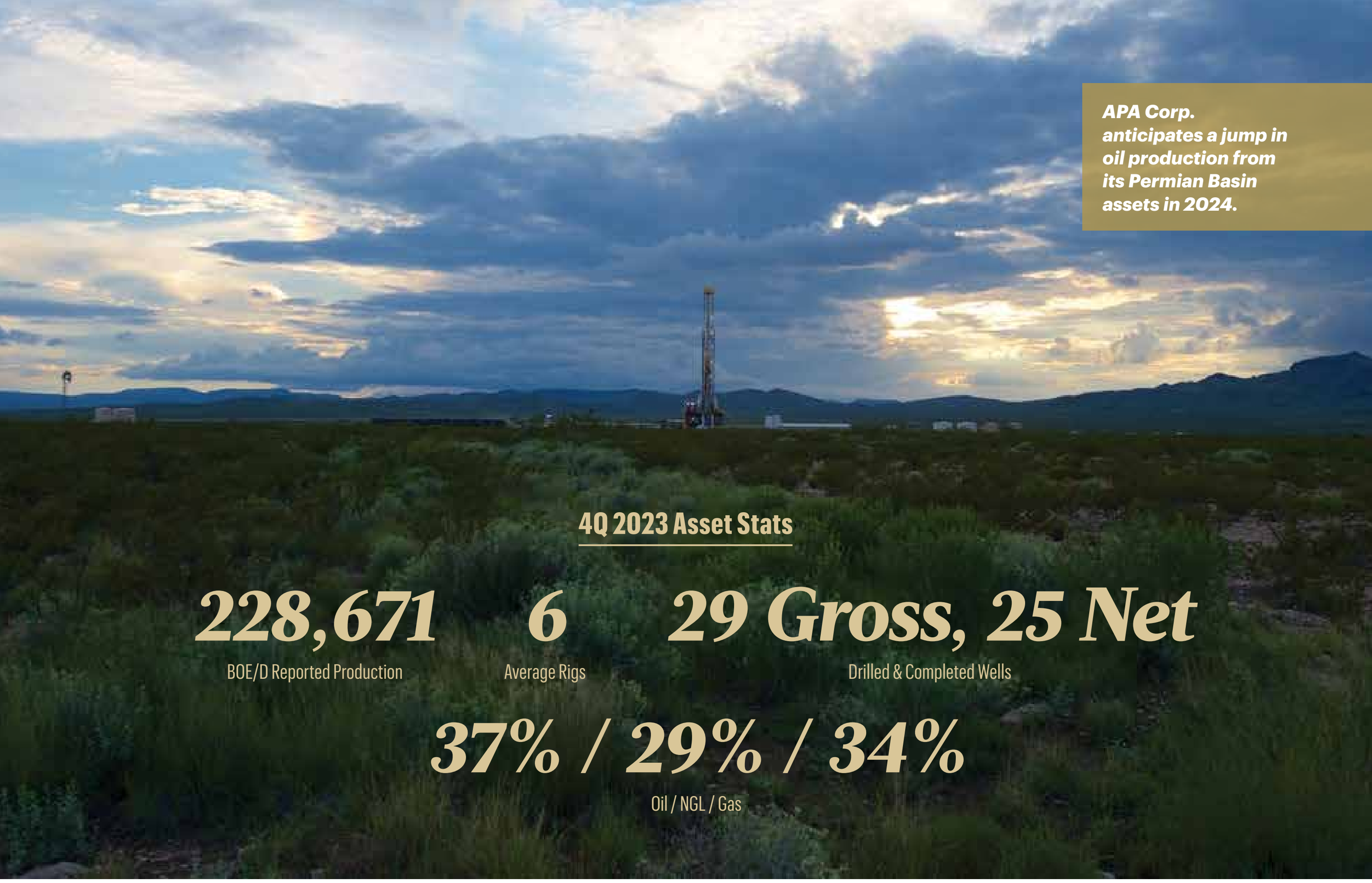
Scaling the Permian

The Callon acquisition brings "scale to our Delaware position and balance to our overall Permian asset base, making it fairly evenly weighted between the Midland and the Delaware upon closing," Christmann said.

APA entered into an agreement in January to acquire Callon in an all-stock deal valued at $4.5 billion, inclusive of Callon's net debt. APA and Callon's combined production is expected to exceed 500 Mboe/d, while the combined company's enterprise value is expected to exceed $21 billion, APA said when the deal was announced.

"While Callon has experienced operational and productivity challenges in the past, more recently, they have begun to make good progress towards demonstrating the upside potential of their acreage," Christmann said. "We expect to further build on their progress, most notably in the areas of capital productivity from well spacing, target zone selection, frac design and drilling, completion and infrastructure efficiencies."

During the webcast, APA President and CFO Stephen J. Riney said the assumption of Callon's debt would increase APA's leverage metrics slightly, but it has not impacted



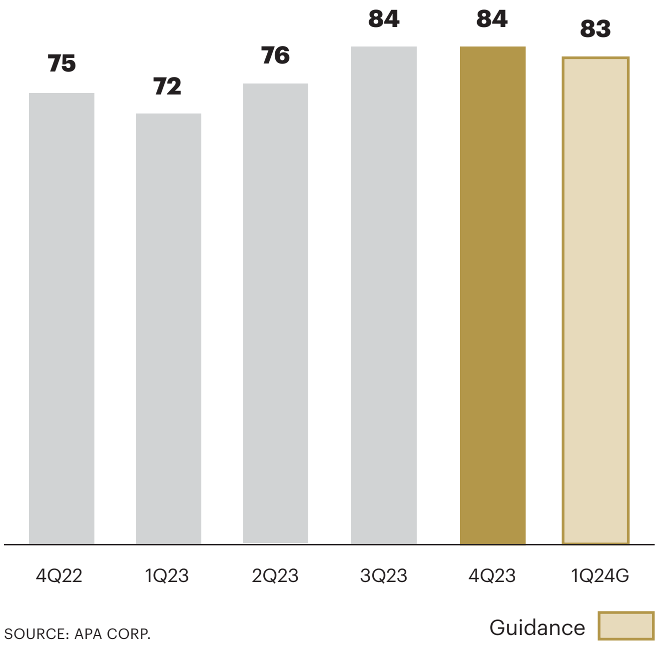
APA Corp. anticipates a jump in oil production from its Permian Basin assets in 2024.

APA CORP.

discussions with rating agencies.

"We continue to target a BBB rating or the equivalent thereof with all three agencies. For this reason, we remain focused on further debt reduction, which will be achieved through the application of cash flow and possible asset divestments," Riney said.

Net oil production, Mbbl/d



SOURCE: APA CORP.

APA added it remained committed to returning at least 60% of free cash flow to its shareholders.

Alaska and Uruguay exploration, Suriname FID

APA's recent entries in Alaska and Uruguay offer large-scale exploration upside, according to the leadership team.

In Alaska, APA expanded its exploration portfolio through the addition of onshore leases. The company has a 275,000 gross acre position on state lands. There, APA holds a 50% working interest in a joint venture with Lagniappe Alaska, LLC (25%, operator) and Santos Ltd (25%). The venture will spud three wells in the first half of the year, and is very close to spudding the first well, according to Christmann.

In Uruguay, APA was awarded two offshore blocks in 2023 although no drilling is planned for 2024.

At the OFF-6 Block (100% working interest, operator), which covers 4.1 million acres, the company has an exploration well obligation.

At the OFF-4 Block, APA has a 50% working interest and is the operator. Shell has the remaining 50%. The block covers 2.5 million acres and APA has a seismic acquisition obligation.

In Suriname's offshore Block 58, no drilling is planned for 2024 as APA envisions a final investment decision (FID) announcement by year-end 2024. APA and French partner TotalEnergies SE have identified an estimated 700 MMbbl of recoverable oil resource at the Sapakara and Krabdagu finds in Block 58 and have already initiated a FEED study. Initial production could commence sometime in 2028.

Truist expects incremental Suriname value once the project reaches FID late this year. OGI

▶ ACTIVITY HIGHLIGHTS

Monthly oil production in the Gulf of Mexico has averaged

48.4 MMBBL

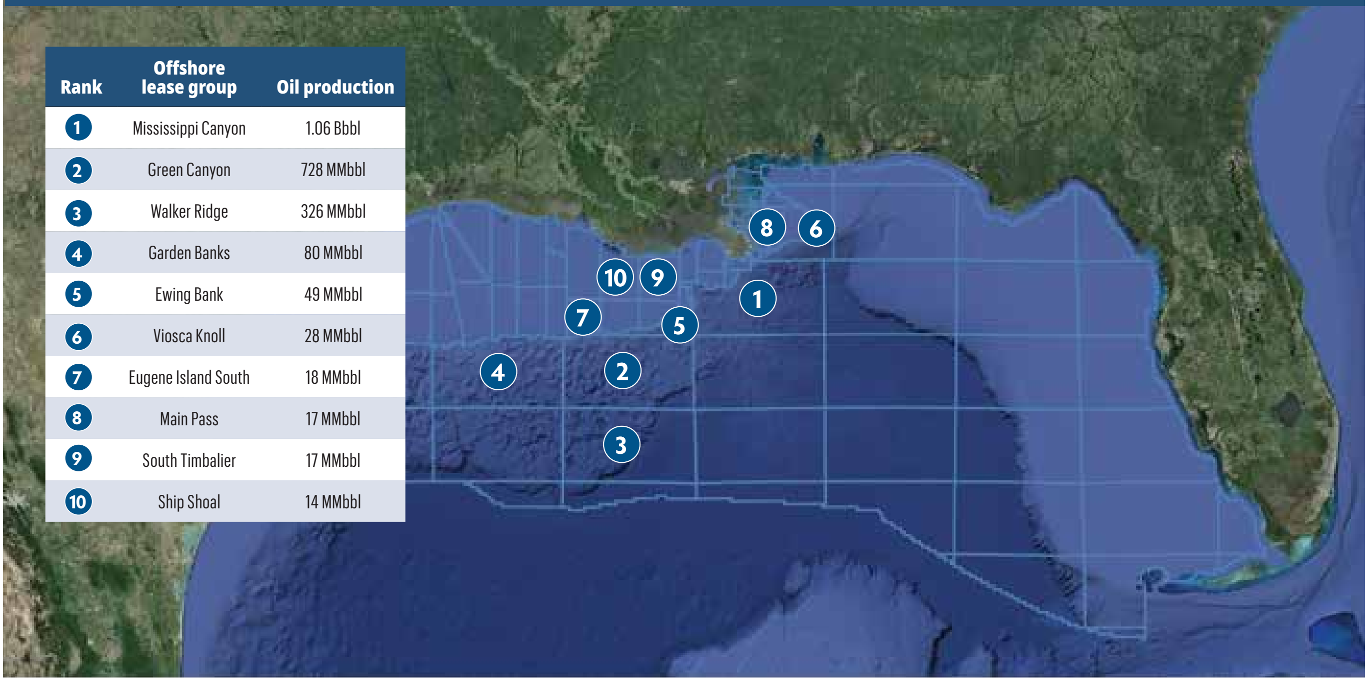
over the last five years.

Photographic Services, Shell International

BASIN FOCUS:
OFFSHORE GULF OF MEXICO

Oil production in the Gulf of Mexico, led by activity in the Mississippi Canyon, has increased steadily since May 2023.

Most productive Gulf of Mexico offshore lease groups during the last five years

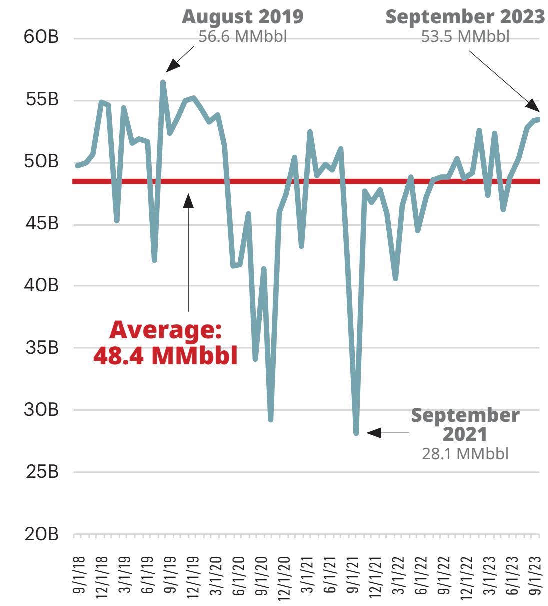


Rank	Offshore lease group	Oil production
1	Mississippi Canyon	1.06 Bbbl
2	Green Canyon	728 MMbbl
3	Walker Ridge	326 MMbbl
4	Garden Banks	80 MMbbl
5	Ewing Bank	49 MMbbl
6	Viosca Knoll	28 MMbbl
7	Eugene Island South	18 MMbbl
8	Main Pass	17 MMbbl
9	South Timbalier	17 MMbbl
10	Ship Shoal	14 MMbbl

SOURCE: REXTAG

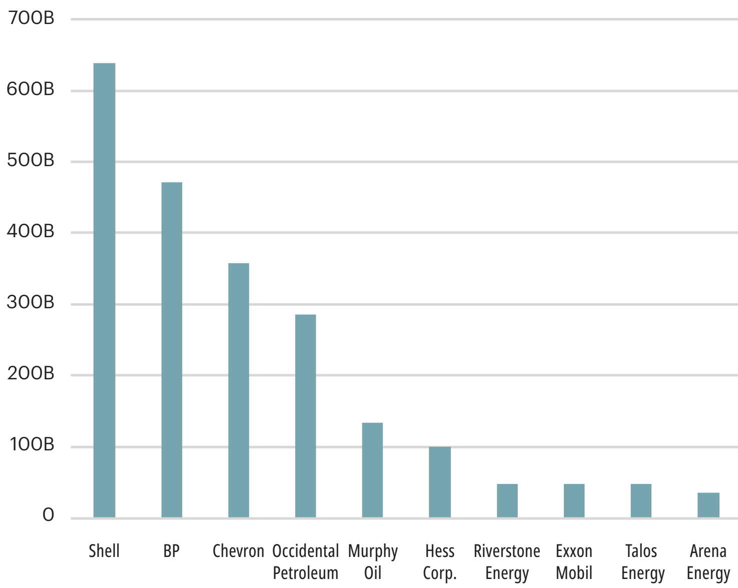
Gulf of Mexico oil production

(monthly, bbl)



Gulf of Mexico oil production by operator

(five years, bbl)



SOURCE: REXTAG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PERMITS

Texas led all states in permit approvals in the past month, but Campbell County, Wyo., led all counties with 44.

Permitted wells by county

Rank	County	Well Count
1	Campbell, Wyo.	44
2	Reeves, Texas	42
3	Upton, Texas	38
4	Weld, Colo.	38
5	Loving, Texas	37
6	Martin, Texas	30
7	Reagan, Texas	27
8	Howard, Texas	22
9	Ward, Texas	21
10	Webb, Texas	21
11	Midland, Texas	19
12	Williams, N.D.	15

Permitted wells by operator

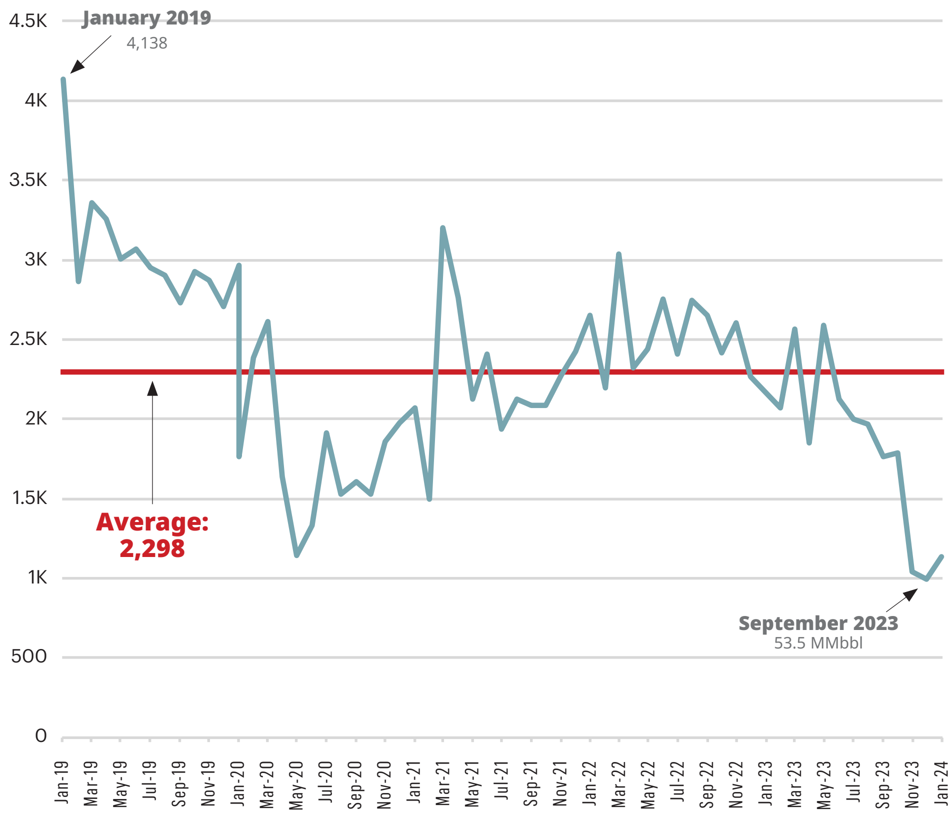
Operator	Well Count
Chevron	49
BPX Energy	39
EOG Resources	36
Anshutz Exploration	26
Crestone Peak Resources	24
Windsor Energy Group	24
Terra Energy Partners	18
Pioneer Natural Resources	17

Permitted wells by state

State	Well Count
Texas	502
Colorado	129
Wyoming	68
North Dakota	54
Oklahoma	22
Louisiana	13

U.S. well permits

(monthly, five years)



SOURCE: REXTAG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EQT's Purchase of Equitrans Faces Steep Challenges

EQT will assume debt of $7.6 billion or more, while likely facing intense regulatory scrutiny.

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EQT Corp.'s $5.5 billion all-stock deal to buy Equitrans Midstream will try to thread the needle with investors as EQT executives make the pitch for creating the U.S.' lowest cost natural gas producer—while adding a mountain of debt.

The initial tradeoff? EQT will sacrifice some free cash flow to pay off Equitrans' debt of between $7.6 billion and $8 billion. EQT will also sell assets to reduce borrowings. Including equity and debt, the deal is valued at roughly $13 billion.

The deal could also face regulatory hurdles.

Investors reacted to the March transaction announcement with a selloff, sending EQT shares down by 7.76% at closing.

The acquisition brings long-term synergies for EQT but also near-term overhang, Gabriele Sorbara, Siebert Williams Shank managing director, said in a report.

"While there is clear industrial logic and long-term benefit from the ETRN [Equitrans] acquisition, it is a mostly dilutive transaction that significantly increases pro forma debt and leverage and carries substantial regulatory uncertainty which we believe will drive continued weakness," Sorbara said.

EQT's rationale for the deal is simple: The company will become the only large-scale vertically integrated U.S. natural gas company. Equitrans' 2,000 miles of pipeline will integrate with EQT's upstream assets to create a company capable of breaking even at natural gas prices as low as $2/MMbtu.

On a call to discuss the transaction, EQT President and CEO Toby Rice said its upstream acquisitions have shared a common theme: pipelines.

"Each acquisition we've done included midstream ownership, which was by design as we recognized early on the strategic value associated with owning integrated midstream infrastructure," Rice said. That includes EQT's $5.2 billion acquisition of Tug Hill and XCL Midstream last August.

"Pro forma for Equitrans, approximately 90% of our operated production will flow through EQT-owned midstream assets, creating unrivaled margin enhancement relative to the rest of the industry," Rice said.

EQT executives said that at prices of $2.75/

EQT-Equitrans overview

> $35 B	**> $23 B**	**> $7.5 B**
Enterprise value	Equity value	Long-term debt target
~ 6.3 Bcfe/d	**>8.0 Bcfe/d**	**~ 90%**
Upstream net production	Gathered volume throughput	Upstream net production
~ $16 B	**~ $6 B**	**~ 30%**
2025E - 2029E cumulative FCF	Annual Adj. EBITDA	2025E - 2029E cumulative FCF

ETRN brings extensive overlap and direct connectivity in core operations area

Gathering: ~1,220 miles

Water: ~200 miles

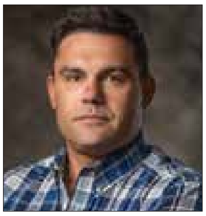
Transmission: ~940 miles

MVP: ~300 miles

SOURCE: EQT

Construction of the Mountain Valley Pipeline, an interstate natural gas pipeline, near Cowen, W.Va.

SHUTTERSTOCK



"Each acquisition we've done included midstream ownership, which was by design as we recognized early on the strategic value associated with owning integrated midstream infrastructure."

–**Toby Rice,** ***President and CEO, EQT***

MMBtu, most of its natural gas peers do not generate "any" free cash flow in maintenance mode without hedges.

By locking in a low-cost price structure, EQT executives said the company would virtually eliminate the need for hedging–a strategy that protects on the downside but, as with the post-COVID-19 price spike, costs EQT more than $5 billion in lost revenue.

"Though the acquisition does not inorganically grow EQT's inventory, the addition of ETRN's midstream assets materially drops the breakeven price of the remaining ~4,000 locations below $3/MMBtu with ~3,000 locations below $2.50/MMBtu," David Deckelbaum, TD Cowen managing director, wrote in analyzing the deal.

Long term, EQT management projects cumulative free cash flow of about $16 billion at strip through 2029, Deckelbaum said.

M&A to solve debt

Near-term, the tension for EQT is that the Marcellus and Utica shale E&P will spend up to 18 months chewing through $5.5 billion in debt after the deal closes.

To tackle the debt, the company plans to sell off $3.5 billion in "highly coveted noncore assets." The rest will be paid through organic excess free cash flow. EQT executives said sales could include Equitrans' Appalachian crown jewel, the Mountain Valley Pipeline (MVP).

EQT CFO Jeremy Knop said assets sales will be focused on some of Equitrans' assets regulated by the Federal Energy Regulatory Commission (FERC).

"MVP certainly could be part of that. It's a very logical divestment candidate, one of the highest quality pipelines in the country with brand new 20-year contracts," Knop said. "We do have that ongoing sale for our non-op assets that I would say that is going very, very well, and we hope to update investors on that in the near term."

The transaction's closing is contingent on FERC authorizing Equitrans' MVP to commence service.

Knop agreed with an analyst's scenario that the company would keep its base dividend while excess free cash flow would go toward debt repayment.

"With our deleveraging plan, the guidance we've gotten from the rating agencies has been post-closing. You typically have 12 to 18 months to complete that plan," Knop said. "And we think with what we have on the table today and what we've outlined … we have really more than two times the number of sale candidates available.

"So, we think that path to be leveraging is very low risk and very high confidence, something we can execute on in pretty short order. But really we're looking at mid- to yearend 2025 is that timeframe to get to that target debt level."

Midstream-upstream behemoth

A combined EQT-Equitrans company would be formidable–EQT is the largest U.S. natural gas producer–but scrutiny from federal regulators is likely to be just as tough.

Transaction summary

Transaction	**> On March 11, 2024, EQT announced the acquisition of ETRN in an all-stock transaction** • 0.3504 shares of EQT stock for each share of ETRN stock, representing an implied value of $12.50 per ETRN share based on the volume weighted average price of EQT common stock for the 3 days ending in March 8, 2024 • Combined enterprise value of > $35 billion
Gathering	**> ~1,220 miles of high-pressure pipeline, ~491,000 HP of compression** • 13-year weighted average firm gathering contracts • EQT directly holds firm capacity of 3 Bcf/d, stepping up to 4 Bcf/d by 2026 and an additional 1.2Bcf/d on Hammerhead
Transmission	**> ~940 miles of FERC-regulated interstate pipelines with 4.4 Bcf/d of capacity, 135,000 HP of compression, and 43 Bcf of working gas storage** • Direct connectivity of 7 interstate pipelines provides access to all major gas demand regions, including local demand • 12-year weighted average firm transmission and storage contracts • EQT holds ~2.3 Bcf/d of aggregate firm capacity
Water	**> ~200 miles of mixed-use water pipelines with ~350 Bbl of above ground storage** • Water network reduces customers' disposal and capital costs while also enhancing safety and environmental attributes • 10-year firm contracts executed with EQT and another producer customer
MVP	**> Mountain Valley Pipeline (MVP) Joint Venture, ~49% expected ownership and operator** **> ~300 mile, 42" diameter FERC-regulated pipeline connecting low-cost Appalachia natural gas to growing demand in the southeast U.S.** • 2 Bcf/d capacity with ability to expand up to ~2.5 Bcf/d • 20-year firm capacity contracts (EQT holds ~1.5 Bcf/d)
Closing	**> Transaction expected to close in Q4 2024, subject to shareholder approvals and regulatory clearances** • Pro forma ownership ~74% EQT / ~26% ETRN **> Transaction closing contingent on FERC authorizing MVP to commence service** **> Upon the closing of the transaction, three representatives from ETRN will joint EQT's Board of Directors**

SOURCE: EQT

Rice was asked twice about the regulatory approval process during a call with analysts.

Rice said he wouldn't speculate on the regulatory process, but he welcomed a chance to talk about the benefits of the transaction for the companies, the Appalachia region and the country.

"We are looking forward to discussing with regulators, especially in this environment where people are talking about energy. It's a political issue," he said. "This is a great opportunity for us to communicate how this transaction is going to make the energy we produce more affordable, more reliable and cleaner."

EQT's Tug Hill/XCL acquisition won approval after more than a year of review by the Federal Trade Commission. The FTC ultimately allowed the deal to proceed by preventing "entanglements" between EQT and seller Quantum Energy Partners.

Likewise, other large proposed transactions, including Exxon Mobil's proposed acquisition of Pioneer Natural Resources and Chevron's deal to buyout Hess Corp., have been put under the microscope as congressional Democrats raise anticompetitive concerns.

Pro forma, EQT would boast 27.6 Tcfe of proved reserves across about 1.9 million net acres, with 6.3 Bcfe/d of net production and more than 8 Bcfe/d of gathering throughput across 3,000 miles of pipeline. Some of that infrastructure serves third-party producers that may be EQT competitors.

Combined, EQT and Equitrans would have an estimated market cap of $23 billion and add pipeline infrastructure that have "extensive overlap with EQT's core upstream operations and existing midstream assets."

Under the terms of the merger agreement, each outstanding share of Equitrans' common stock will be exchanged for 0.3504 shares of EQT common stock, representing an implied value of $12.50 per Equitrans share based on the volume weighted average price of EQT common stock for the 30 days ending on March 8. The transaction suggested a 12% premium compared to Equitrans' March 8 closing price of $11.16.

After the deal, EQT shareholders would own 74% of the combined company, and Equitrans shareholders the remaining 26%.

The companies said the merger would create $250 million in annual synergies, including lower financial and corporate costs; uptime and production optimization; and reduced capital and operating costs. EQT has also identified an "upside pathway" to another $175 million in additional yearly synergies. OGI

▸ ACQUISITIONS & DIVESTITURES

Will Coterra Join the Consolidation Frenzy?

CEO Tom Jorden is keeping an eye out for acquisition opportunities.

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As the U.S. upstream sector consolidates at a quickening pace, Coterra Energy is keeping its M&A plans close to the vest.

Formed by the all-stock merger between Cabot Oil & Gas and Cimarex Energy in 2021, Coterra spent just $10 million on leasehold and property acquisitions in 2023. By comparison, U.S. upstream M&A activity totaled $192 billion last year, including a whopping $144 billion transacted in the fourth quarter alone, according to Enverus Intelligence Research.

The Permian Basin—where Coterra has deployed the bulk of its drilling operations—has been the epicenter of the dealmaking deluge:

- Pioneer Natural Resources agreed to a nearly $65 billion buyout by Exxon Mobil, including Pioneer's net debt;
- Diamondback Energy's $26 billion acquisition of Endeavor Energy Resources was the largest buyout of a private upstream company ever; and
- Occidental Petroleum is acquiring private E&P CrownRock for $12 billion to add scale and inventory runway in the Midland Basin.

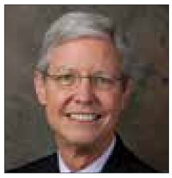
Some of the Permian's oldest and largest oil producers have been scooped up by large producers in a matter of months. Many of the top private equity-backed E&Ps in the Permian have similarly been acquired by smaller operators, such as Civitas Resources, Vital Energy, Ovintiv and Matador Resources.

There's a feeding frenzy afoot across the U.S. shale patch. Coterra Chairman, President and CEO Thomas Jorden acknowledged as much.

"I think The Wall Street Journal should have a weekend breaking story that says, 'Flash: Everybody Looking at Everybody Else in E&P Space'—because that's what we have," Jorden said during Coterra's fourth-quarter earnings call.

Coterra hasn't deeply engaged in evaluating M&A opportunities that have come and gone, Jorden said. But the company definitely isn't ruling out inorganic growth.

"We remain deeply curious about what consolidation could offer for Coterra owners," Jorden said, "but the bar is very, very high."



"We remain deeply curious about what consolidation could offer for Coterra owners, but the bar is very, very high."

–Thomas Jorden, *Chairman, President and CEO, Coterra Energy*

Lease line look-around

The bulk of Coterra's operations and production are in the Permian's Delaware Basin. The company also has operations in the Midcontinent's Anadarko Basin and in Appalachia's gassy Marcellus Shale play.

Given the weak macro environment for natural gas, Coterra will allocate most of its capital spending toward liquids-rich assets in 2024. The company plans to reduce drilling activity in Appalachia this year, and the Anadarko is attracting a small fraction of Coterra's overall capital spending budget.

The company plans to use most of its development spending—an estimated $1 billion—on drilling and completion activity in the Permian this year.

So, if Coterra wants to deepen its Permian Basin inventory, what might the E&P be able to digest? And what does the market still have to offer?

The remaining prospects out there in the basin are extremely limited after the past six months of M&A, said Matt Bernstein, Rystad Energy senior analyst.

On the private side, Mewbourne Oil and Continental Resources are the most attractive remaining private E&Ps with sizeable portfolios of undrilled locations.

"It's really Mewbourne and Continental and then everybody else right now as far as inventory goes," Bernstein told *Oil and Gas Investor*.

Small- to medium-sized public operators have also gained a strong foothold in the Delaware Basin in recent years.

Permian Resources grew in the Delaware—and

COTERRA ENERGY

Coterra's acreage position spans across the Permian Basin, Marcellus Shale (pictured) and Anadarko Basin.

"It's really Mewbourne and Continental and then everybody else right now as far as inventory goes."

—Matthew Bernstein, *senior analyst, Rystad Energy*

gained some oil production in the Midland Basin—through a $4.5 billion acquisition of publicly traded Earthstone Energy last year. Permian Resources, though, has become more expensive for a potential takeover. The company's market valuation is around $12 billion, compared to Coterra's roughly $21 billion market cap.

There's also Matador Resources, which grew in New Mexico last year with the $1.6 billion acquisition of Advance Energy Partners from private equity firm EnCap Investments. Matador has a market valuation of around $7 billion.

After the whirlwind of Permian consolidation over the past year, analysts expect a robust market for non-core divestitures as E&Ps parse through their portfolios.

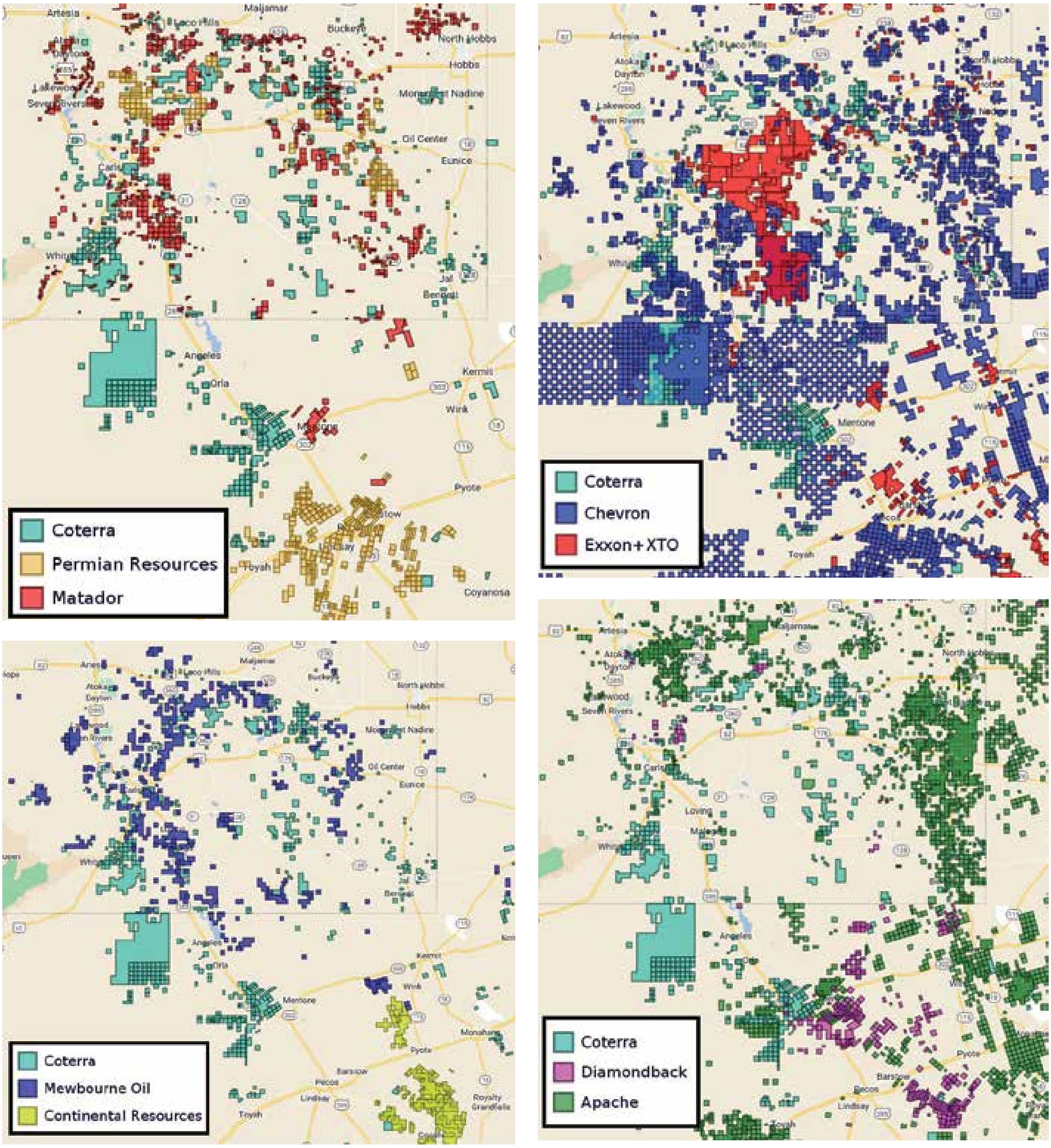
Diamondback doesn't feel compelled to sell off non-core assets as the company integrates its $26 billion acquisition of Endeavor. But non-core asset divestitures could happen eventually as the company works to reduce debt after the deal, CFO Kaes Van't Hof said during the company's recent earnings call.

APA Corp., parent company of Apache, also has a sizable footprint in the Delaware. APA recently inked a $4.5 billion takeover of publicly traded Callon Petroleum.

Then there are the majors, Exxon Mobil and Chevron, which are each engaged in massive acquisitions of their own.

Exxon and its subsidiary XTO Energy have acreage across the Permian's Midland and Delaware basins. But Exxon will become much more Midland-weighted after its nearly $65 billion acquisition of Pioneer.

Looking over the fence



SOURCE: REXTAG

Coterra's Delaware operations are nearby several private and public producers.

Chevron acquired Hess Corp. last year for roughly $60 billion, giving it a foothold offshore Guyana, in the Bakken Shale of North Dakota and in the Gulf of Mexico. The Hess deal didn't include Permian acreage, where Chevron already has massive operations.

Gas woes

Coterra churns out large volumes of natural gas from Appalachia, the Permian and the Midcontinent. But the company wants to reduce gas production this year amid prolonged low natural gas prices. Coterra plans for gas output to be between 2.65 Bcf/d and 2.8 Bcf/d in 2024; gas production averaged 2.97 Bcf/d during the fourth quarter.

2024 capex is expected to range between $1.75 billion and $1.95 billion, down 12% year-over-year at the midpoint, due in part because of lower activity planned in the Marcellus.

"In the Marcellus, we are currently running two rigs and one frac crew, with plans to go to one rig and lower our frac activities," said Blake Sirgo, Coterra's senior vice president of operations. OGI

Civitas, Prioritizing Permian, Jettisons Non-core Colorado Assets

After plowing nearly $7 billion into Permian Basin M&A last year, Civitas Resources is selling off non-core acreage from its legacy position in Colorado as part of a $300 million divestiture goal.

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Civitas Resources divested $85 million of non-core acreage in the Denver-Julesburg (D-J) Basin during the fourth quarter as part of its pivot toward the Permian Basin. The primarily non-operated interests provided minimal production, the Denver-based company said.

Civitas remains on track to reach a $300 million divestment target by the middle of the year.

Civitas has been cleaning up its portfolio in Colorado and plans to deploy roughly 60% of its total investment into the Permian this year, with the remaining 40% earmarked for the D-J Basin.

Last year, Civitas made a splashy entrance into the Permian with nearly $7 billion in M&A.

The first pair of deals with NGP-backed privates Hibernia Energy III and Tap Rock Resources delivered assets in the Delaware Basin. Civitas agreed to pay $4.7 billion in cash and stock.

Civitas announced a second Permian deal in October—a $2.1 billion acquisition of Vencer Energy, backed by global commodities trading house Vitol. The Vencer transaction adds interests in the Midland Basin.

"As our D-J Basin asset continues to outperform, we were successful in strategically expanding our portfolio over the last year by capturing accretive acquisitions that provide us with important scale and diversification in another world-class unconventional basin, the Permian," Civitas CEO Chris Doyle said in the company's fourth-quarter earnings release.

D-J Basin production averaged 173,000 boe/d during the fourth quarter; Permian Basin volumes averaged 106,000 boe/d for the quarter.

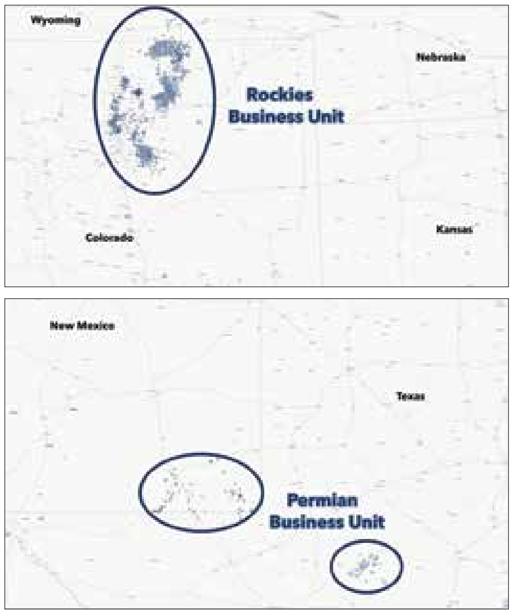
Civitas plans to drill and complete 130-150 gross Permian wells in 2024. In the D-J, the company plans to complete between 90-110.

Civitas was created in 2021 through the combination of three Colorado E&Ps: Bonanza Creek Energy, Extraction Oil & Gas and Crestone Peak. At the time of the merger, Civitas was the largest pure-play producer in Colorado.

As Civitas sought to scale through M&A, it needed to look outside of Colorado, Doyle told Hart Energy in an exclusive interview last year. Most of the quality D-J Basin acreage was already owned by a small group of public E&Ps, including Chevron, Occidental, PDC Energy and Civitas itself.

The D-J consolidated even more when Chevron bought PDC for $6.3 billion last year. OGI

Civitas Resources acreage



SOURCE: CIVITAS RESOURCES

Civitas plans to deploy roughly 60% of its total investment into the Permian this year with the remaining 40% earmarked for the D-J Basin.

"As our D-J Basin asset continues to outperform, we were successful in strategically expanding our portfolio over the last year by capturing accretive acquisitions that provide us with important scale and diversification in another world-class unconventional basin, the Permian,"

–Chris Doyle, *CEO, Civitas*

▸ ACQUISITIONS & DIVESTITURES

Buffett Loves Oxy But Will Pass on Owning It

But Berkshire Hathaway's co-founder has an 'ominous' outlook for the U.S. electric power situation.

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Berkshire Hathaway "has no interest in purchasing or managing" Occidental Petroleum, though "we very much like our ownership, as well as the option," co-founder, chairman and CEO Warren Buffett told Berkshire shareholders in February.

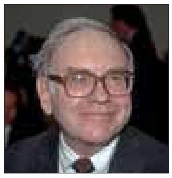
The conglomerate owns 27.8% of the $53 billion market cap oil and gas producer, he noted in his annual letter to shareholders, and has warrants that "give us the option to materially increase our ownership at a fixed price."

That price is $59.62/share, derived from a $10 billion cash investment in Occidental in 2018 that helped the company fund its purchase of Anadarko Petroleum.

Shares were trading at $60.67 in late February. The stock was about $85 at the time of the 2018 deal announcement—falling after to as little as $10 during the 2020 pandemic—and settling in the $55-$75 range since early 2022.

'Hallelujah!'

Buffett also made a shout-out to U.S. shale oil and gas explorers, who, "Hallelujah!" he wrote, made producing oil and gas from super-tight rock profitable this century. The result:



"Now, U.S. production is more than 13 MMBoe/d and OPEC no longer has the upper hand."

–Warren Buffett, *co-founder, chairman and CEO, Berkshire Hathaway*

"Our energy dependency ended," he wrote.

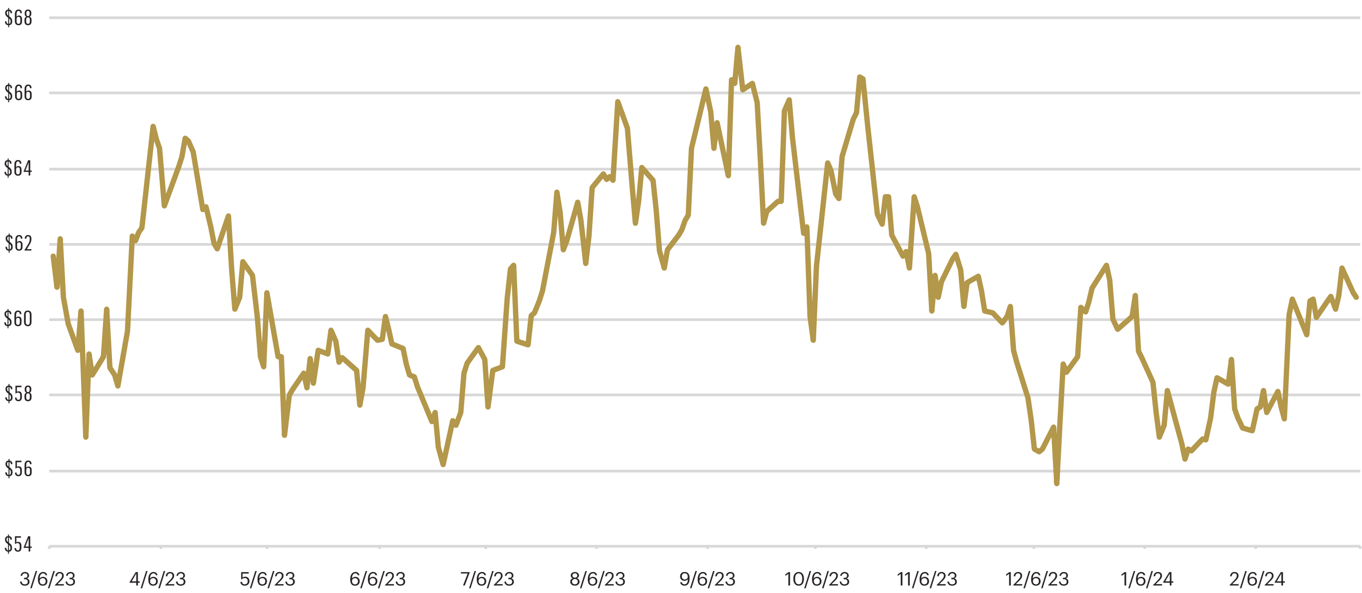
"Now, U.S. production is more than 13 MMBoe/d and OPEC no longer has the upper hand."

Occidental alone produced 1.2 MMboe/d in December. The annualized rate of just the oil component is nearly as much as the U.S. has in the Strategic Petroleum Reserve, Buffett said.

The SPR's year-end 2023 oil in storage was 354 MMbbl, according to the U.S. Department of Energy.

"Under [President and CEO] Vicki Hollub's leadership, Occidental is doing the right things for both its country and its owners," Buffett

Occidental Petroleum stock price, March 2023-March 2024



SOURCE: OCCIDENTAL PETROLEUM

CEO Vicki Hollub's uncommon talent is valuable to her shareholders and her country, Buffett said.

OCCIDENTAL PETROLEUM

wrote. "No one knows what oil prices will do over the next month, year or decade.

"But Vicki does know how to separate oil from rock and that's an uncommon talent valuable to her shareholders and to her country."

Buffett added in his letter that Berkshire Hathaway likes Occidental's "leadership in carbon-capture initiatives," but that "the economic feasibility of this technique has yet to be proven."

Berkshire Hathaway holds 244 million Occidental shares, according to its 13F-HR report for year-end 2023. At that time, it also owned 126 million Chevron shares, it reported.

In contrast, at year-end 2014, Berkshire Hathaway held shares of ConocoPhillips (11 million), Exxon Mobil (41 million), National Oilwell Varco (9 million), Phillips 66 (27 million; spun out of the 2002 combination of Conoco and Phillips Petroleum) and Suncor Energy (13 million).

'Ominous' power future

As for the Berkshire Hathaway Energy (BHE) business unit, he wrote he "erred … in my expectations" for 2023.

Besides an earnings disappointment in its railroad holding, an "even more severe earnings disappointment last year occurred at BHE."

The unit performed as expected, "but the regulatory climate in a few states has raised the specter of zero profitability or even bankruptcy–an actual outcome at California's largest utility and a current threat in Hawaii."

He has an "ominous" outlook for future electric-power supply.

"When the dust settles, America's power needs and the consequent capital expenditure will be staggering."

CARBON ENGINEERING LTD.

Direct air capture facilities under development by Occidental subsidiary 1PointFive and Carbon Engineering Ltd. Berkshire Hathaway co-founder, chairman and CEO Warran Buffet told shareholders in February that the company likes Occidental's leadership in carbon capture initiatives, but the economic feasibility of the technology waits to be proven.

Across 11 U.S. states, BHE utilities have 5.3 million power and natural gas accounts. Generating capacity, including in the U.K. and Canada, in 2023 was 36,000 megawatts, including capacity under construction.

BHE also operates some 21,000 miles of pipe, carrying 21 Bcf/d, along with 22 gas storage caverns with working capacity of 516 Bcf, plus the Cove Point, Md., LNG import, export and storage facility. OGI

Oxy May Divest Non-core Permian Assets Post CrownRock Closing

Occidental Petroleum President and CEO Vicki Hollub said plans to divest non-core Permian assets would come after the close of the recent $12 billion purchase of Midland-based CrownRock.

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Occidental Petroleum will consider divesting non-core Permian Basin assets, but not until after its $12 billion deal to acquire CrownRock LP eventually closes.

Infrastructure, however, may be a different story. Reports emerged in late February that Occidental is considering a sale of its interests in Western Midstream Partners, which is valued at almost $14 billion.

Oxy owns a controlling 49% of Western Midstream.

"By virtue of all the M&A that's happening, there's a lot of appetite for companies to try to get into the Permian and we do have properties in the Permian that are not core to us but could be core to others, and some of it is just where they're placed in the Permian geographically," said Oxy CEO Vicki Hollub during the company's fourth-quarter earnings call in February.

The cash-and-stock acquisition of CrownRock, announced in December, is not expected to close until the second half of 2024 because of delays from extended federal regulatory reviews.

"The divestitures, I believe, will go well," Hollub said. "What we won't do, though, is we've decided not to make any divestitures until we close the CrownRock acquisition and then we'll start a proactive process more aggressively at that point."

But reports that Occidental is exploring the sale of its share of Western Midstream could generate substantial proceeds to reduce debt. Occidental ended 2023 with long-term debt of $18.5 billion. That doesn't include the additional $1.2 billion in CrownRock debt that Occidental will assume when the deal closes. Occidental is leaning on $9.1 billion in new debt and $1.7 billion in common equity to finance the deal.

In a statement, Western Midstream said, "WES has not launched a sales process nor has it engaged bankers or other advisors with a view toward doing so. We are aware, as has been publicly stated, that Oxy has expressed interest in divesting assets. We cannot speak to the composition of the assets Oxy may seek to divest, and any questions regarding Oxy's ownership interest in WES should be directed to Oxy."

> *"We're trying to minimize the cash flows sold to ensure that we can maintain our cash flow."*
>
> **Vicki Hollub,**
> ***Oxy President and CEO***

Hollub has minimized the possibility of big deals to come once Oxy closes on CrownRock.

"Anything that's material, we wouldn't likely do," Hollub said. "We're trying to minimize the cash flows sold to ensure that we can maintain our cash flow. With that said, there will be some cash flow going, because it's hard to sell any assets out here that we haven't already at least done appraisal work on to generate some cash flow."

Hollub classified the CrownRock acquisition as strategic since it added "high-margin, low-breakeven inventory." Incremental cash flow would be used to support Occidental's plan to deliver a sustainable and growing dividend with deleveraging and share repurchases after reducing the company's debt to $15 billion.

Occidental aims to repay $4.5 billion in debt within 12 months of transaction close and eyes $4.5 billion to $6 billion of after-tax divestiture proceeds to be realized within 18 months of transaction close, Occidental said when it announced the CrownRock acquisition.

TD Cowen's investment thesis on Oxy sees the producer benefitting from multi-year deleveraging efforts. An attractive asset base is expected to "deliver outsized returns of capital to shareholders in the coming years, supported by a superior asset base in the Permian, DJ [Denver-Julesburg Basin], GoM [Gulf of Mexico] and international, in addition to value enhancing opportunities via Occidental Low Carbon Ventures," analysts said.

Hollub said Occidental was working constructively with the U.S. Federal Trade Commission (FTC), which is reviewing the

CrownRock deal. Oxy CFO Sunil Mathew said additional requests from the FTC would impact the timing of the closing. However, he said Oxy still expects to receive regulatory approval and close the acquisition later this year.

"While total shareholder returns are likely to decline nearer-term to focus on debt repayment, we forecast the payout by 2026 (or sooner) should be better than ever," Truist Securities wrote in February.

Debt reduction priority

Oxy aims to use its excess cash flow to reduce long-term debt as it looks to rebalance its enterprise value to the liking of common shareholders, according to recent financial details revealed by company executives.

Occidental's debt reduction will target lowering expenses and improving the balance sheet.

"Once we get our debt back down to $15 billion, that's going to be a key part of helping us then to start the resumption of a more robust share purchase program of both the common and ultimately the preferred," Hollub said.

"We're going to accumulate cash flow as we continue to work toward closing the CrownRock deal, because a part of cash flow will be used to help pay down both the term loan and our debt maturities that are coming," she added. "So, cash flow would not be used for share repurchases until we get to the point where we've achieved those goals."

Occidental remains focused on its sustainable and growing dividend, while its share repurchase plan supports capital appreciation and per-share dividend growth, executives said.

"Post-CrownRock, the Occidental game theory has become harder. We had been convinced the cycle of free cash flow generation plus preferential pay down would leave shareholders disadvantaged over a longer period," Evercore ISI analysts wrote in a recent research note.

"With the changes to preferential redemption, now clearly pushed to end of decade (incremental debt from CrownRock the first priority), one is left with a relatively disadvantaged shareholder return vehicle and a long road to deleveraging, with a … better-than-most asset position in the global upstream," Evercore said.

CrownRock and EOR opportunities

CrownRock adds to Oxy's inventory in the core of the Midland Basin with a rich and understood subsurface. The company also plans to expand unconventional EOR opportunities to follow on its Midland pilot success.

Over the next five to 10 years, EOR will be a significant part of Oxy's portfolio development. Hollub said Oxy had 2 Bbbl of resources remaining to be developed and that its Direct Air Capture (DAC) facilities, which will remove CO2 from the atmosphere, would result in "the most sustainable barrels in the world."

"We have high-quality, short-cycle, high-return oil and gas shale development in the U.S., along with conventional, lower-decline oil and gas development in Permian EOR, GOM, Oman, Algeria and Abu Dhabi," Hollub said.

In 2024, Occidental is eyeing capex between $5.8 billion and $6 billion. The bulk of the spending–between $2.5 billion and $2.7 billion–will flow into the Permian Basin, where Occidental will run 10 net rigs. Capex for low-carbon ventures is expected to be $600 million. OGI

Earnings season proves producers earn stronger efficiencies, profits

The 2024 outlooks largely surprise to the upside with conservative budgets and steady volumes.

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Saying you're going to "do more with less" typically rings as an empty platitude spouted by cost-cutting executives. But even prosaic phrases can prove true on occasion, and that's occurring with the productivity of energy producers in 2024.

The potentially fleeting phenomenon is playing out in real time because of a confluence of events, or, to borrow another hackneyed cliché, a perfect storm.

The combination of industry consolidation, technological advancements, efficiency gains, services deflation and a focus on the best remaining acreage are allowing many producers to churn out more oil and gas from wells while drilling and completing them more quickly and cheaply.

This was the main theme emanating from the fourth-quarter earnings season that focused heavily on 2024 outlooks, said Gabriele Sorbara, managing director of equity research at Siebert Williams Shank & Co.

"You're seeing companies target their best acreage and have more efficient capital budgets," Sorbara said. "It's really about capital allocation being dedicated to the most efficient and most core areas.

"The core stuff is more mature. You're just crushing it and executing."

The U.S. drilling rig count plunged 17% in a year, but domestic crude production continues to hover near a record high of 13.3 MMbbl/d, according to the March 8 rig count report from Baker Hughes. Drilling is even down nearly 10% in the booming Permian Basin, while Permian volumes approach new highs of 6.1 MMbbl/d.

The story is different for pure-play natural gas producers because of weak pricing, but top players such as Chesapeake Energy and EQT Corp. are curtailing volumes and winning praise. Optimism exists after the calendar eventually flips over to 2025 and new LNG infrastructure starts driving up demand.

And it is proving helpful—at least in the short term—to set relatively low bars for performance goals.

"The best way to attract institutional investors is to provide conservative guidance and beat it quarter over quarter," Sorbara said. "There's more optimism now that you're going to see continued beats. Efficiencies are getting better and they're outperforming on the productivity front."

"There's more optimism now that you're going to see continued beats. Efficiencies are getting better and they're outperforming on the productivity front."

—Gabriele Sorbara, *managing director of equity research, Siebert Williams Shank & Co.*

M&A on steroids

The industry is consolidating at a rapid pace and most companies have realized they either need to buy or capitulate.

Scale is critically important for longer-term survival both for inventory and to satiate investors. But consolidation and scale also equate to greater efficiencies and cost savings.

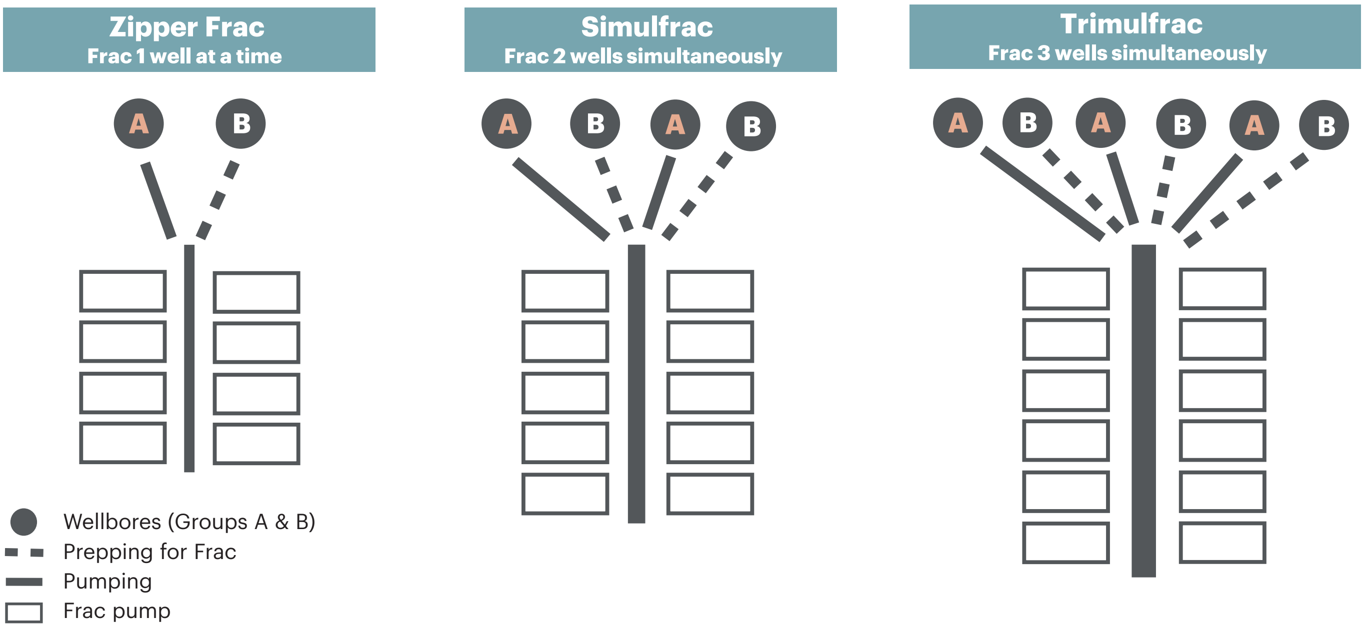
Scale means more leverage on negotiating with services companies. Scale means more knowledge and technological gains from combining operator teams. And scale creates the ability to drill longer and more productive laterals from wells because of the larger blocks of acreage created from dealmaking.

U.S. upstream M&A activity totaled $192 billion last year, including a whopping $144

"We're switching a little bit more to 'Moneyball,' which is 'Let's spend [via] testing new zones and get wells-not for free, but almost for free.'"

—Jason Pigott, *CEO, Vital Energy*

Applying an innovative development approach at scale



SOURCE: OVINTIV

"It's culturally ingrained not only to rigorously examine our own internal results, but also spend intellectual capital on looking across the barbed wire fence at what others are doing."

–**Travis Stice**, ***CEO, Diamondback Energy***

billion transacted in the fourth quarter alone, according to Enverus Intelligence Research. Of course, the massive jump at the end of the year came from Exxon Mobil scooping up Pioneer Natural Resources and Chevron acquiring Hess Corp. And not to be outdone, Occidental Petroleum swept in at the end of the year with a deal for private Permian player CrownRock.

The A&D market isn't slowing down in 2024 either, and it's not just the supermajors doing all the buying. Diamondback Energy won the top Midland Basin prize, privately held Endeavor Energy Resources. And, in the merger of natural gas players, Chesapeake is gaining Southwestern Energy in an all-stock deal. Those two deals alone add up to nearly
$40 billion in sales in just two months. Meanwhile, Apache Corp. is buying Callon Petroleum in the Permian and Chord Energy is acquiring Enerplus in a Williston Basin consolidation.

Diamondback President and CFO Kaes Van't Hof touted the benefits of the pending Endeavor deal and of overall competitor research in an earnings call.

"We spend a lot of time looking at ourselves. We also spend a lot of time looking across the fence line at what other people are doing, either through the M&A process or just general competitor analysis," Van't Hof said.

For instance, competitor learnings have helped Diamondback add the Wolfcamp D and Upper Spraberry benches into more of FANG's core development plans, he said. And acreage that was previously deemed Tier 2 becomes closer to so-called Tier 1 assets.

Diamondback CEO Travis Stice agreed, arguing the company has historically done a "really good job of checking our egos at the door" when integrating acquired companies "and finding out what's really working.

"It's a culture of seeking first to understand as opposed to being understood," he added. "It's culturally ingrained not only to rigorously examine our own internal results, but also spend intellectual capital on looking across the barbed wire fence at what others are doing."

And M&A brings on a lot of scale that also de-risks the company, Stice said. If Diamondback did one or two big drilling projects each quarter, then that puts a lot of pressure on each individual project.

"But here we can have four, five, six of these coming on every quarter. And that allows us operational flexibility to move around and plan our business. And that's just one of the other benefits of size and scale that will only be magnified with the potential of the Endeavor merger," Stice added.

There's also small-ball M&A. The Permian's Vital Energy, for instance, paid a combined nearly $2 billion last year to scoop up the bulk of acreage from Driftwood Energy, Forge Energy, Henry Resources, Tall City and Maple Energy.

The deals added 88,000 net acres, 465 gross oil-weighted locations and 280 future well locations. And Vital added another 185 via new geology and geophysics evaluation, improved economics and higher well performance.

"We're switching a little bit more to 'Moneyball,' which is 'Let's spend [via] testing new zones and get wells–not for free, but almost for free,'" Vital CEO Jason Pigott said.

Efficiencies galore

A few years ago, many companies struggled with too-tight well spacing and interference as the shale game evolved. But most of those mistakes are now in the past and drilling and completions practices are becoming increasingly efficient.

There is more refined cube development and ever-longer laterals with more drilled four miles long. There are more precise completion designs and higher-intensity fracs with additional sand and water.

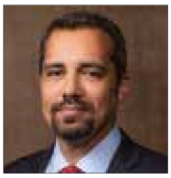
The projects are larger and producers are working with the same drilling and completions crews for longer periods of time, maintaining consistency and knowledge.

Simulfracs became a big deal a few years ago to complete wells more quickly and, now, so-called “trimulfracs” are in vogue–stimulating three wells simultaneously–led by Ovintiv and others.

“We are constantly looking for ways to improve cycle time and reduce the number of days on location,” said Ovintiv COO Greg Givens, arguing that the company’s average completion speed of more than 4,000 feet per day with trimulfrac wells was 9% faster than in 2022. Ovintiv pumped nearly 30% more slurry and increased equipment utilization almost 15% for an average of 18 pumping hours a day, he said.

“We expect to utilize trimulfrac on more than half of our program this year,” Givens said. “This approach yields a 15% savings and completions cost per foot, and essentially doubles the completed fee per day versus a traditional zipper frac.”

Vital also praised its frac design on gains, said Kyle Coldiron, vice president of new well delivery.



“We actively avoid falling into manufacturing mode where one well design is stamped out across a basin. Rather, we adhere to the discipline of continuous improvement such that the latest learnings get embedded into the next well and transferred to the next basin.”

–Ezra Yacob, *CEO, EOG Resources*

“We put a high-intensity, tight cluster-spacing, high proppant-loading completion design on these wells, and we think that certainly contributes,” Coldiron said.

Exxon Mobil leans heavily on cube development in the Permian and likes to tout its “manufacturing approach.” For Exxon, that also means building up a bigger backlog of drilled but uncompleted DUC wells in 2024, said CEO Darren Woods during an analyst call.

Having a backlog of strategically located DUCs helps maintain manufacturing consistency when you’re overseeing a complex system of drilling and fracking, Woods said.

“It is a very paced continuum of work and production,” Woods said. “So, there are constraints that you hit as you’re doing that consistently across all that acreage, and having some DUCs available to us allows us, when we run into an issue with what we’re doing in the immediate vicinity, to have some other opportunities to continue the production. So we use it like any other inventory.”

On the other hand, EOG Resources CEO Ezra Yacob specifically criticized relying on a manufacturing system in the Permian, although he didn’t name any companies. So there’s no cookie-cutter approach that works for every company.

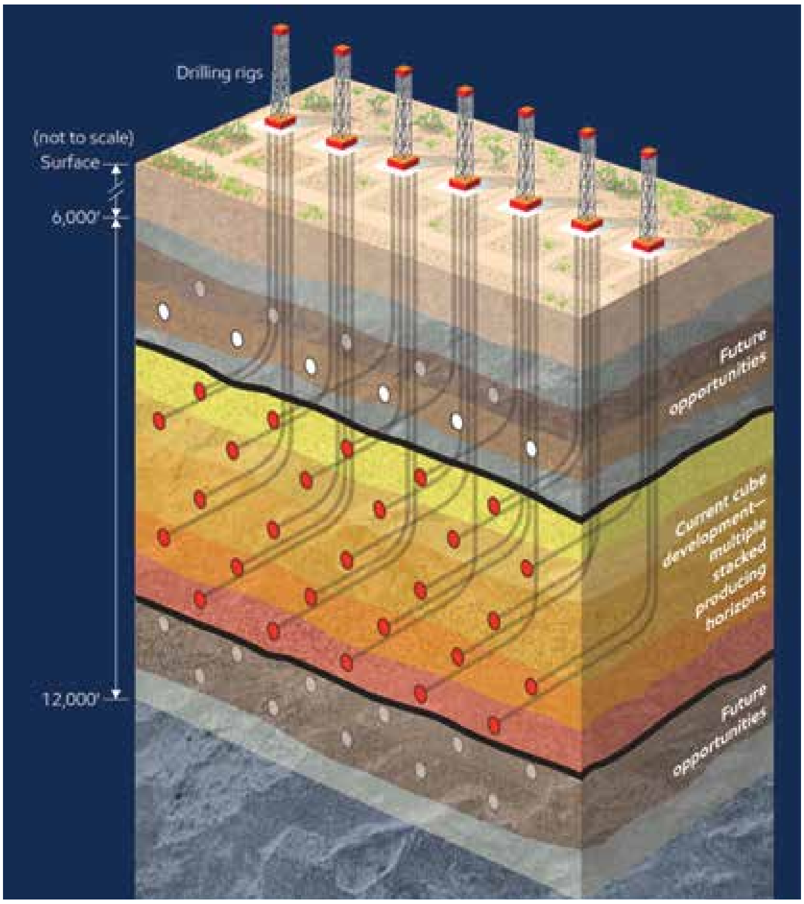
“We actively avoid falling into manufacturing mode where one well design is stamped out across a basin,” Yacob said in a call. “Rather, we adhere to the discipline of continuous improvement such that the latest learnings get embedded into the next well and transferred to the next basin.”

EOG recently hit the milestone of producing more than 1 MMboe/d in overall volumes.

EOG President Billy Helms touted the company’s “motor program” for reducing downtime, yielding a 15% improvement in footage drilled per rig.

For completions, EOG continues to expand its super-zipper operations, reduce frac fleet move times and decrease stage pump times due to increased horsepower for frac fleet, resulting in a 7% improvement in completed footage per frac

Majors’ year-on-year and average exploration spending



SOURCE: EXXON MOBIL

More refined cube development techniques, among other innovative drilling techniques, have increased drilling and completion efficiency compared to a few years ago.


Producers are hesitant to cut rigs and lose access to reliable crews.

SHUTTERSTOCK

fleet in 2023. "And we expect to continue seeing the benefit of those gains throughout 2024," Helms added.

Crews shedding tiers

The results may be a bit more subjective, but crew consistency is another big reason for efficiency gains, Sorbara said.

Companies are hesitant to add drilling rigs and scare off shareholders with rising spending. But they also are afraid to cut drilling rigs, including their crews.

"Most producers are maintaining the status quo," Sorbara said. "You don't want to lose a crew that's operating faster and faster.

"It's a more refined approach now," he said. "There's less experimentation overall. Even if it's Tier 2 acreage, you're just upsizing your completion."

Most companies are keeping production relatively flat in 2024, but they're doing so without adding to their expenses either. Any time you add a rig, you risk bringing on either older equipment or inexperienced crews, and the hard-won efficiency gains can start to slip away, he said.

And, for companies with multiple-basin strategies, they can shift spending from gassy plays to more liquid ones to avoid adding overall costs.

Coterra, for instance, will increase spending in the Permian for 2024, but the overall capital budget is down 12%. That's because it is cutting its Marcellus Shale capital budget by more than 50%.

EQT said in early March it started to cut gross production by about 1 Bcf/d in "response to the current low natural gas price environment." EQT expects to maintain the curtailment through March and then reassess.

And EQT isn't alone. Gas players Chesapeake, Comstock Resources and Antero Resources all said they would notably cut back production or pull back because of the low natural gas pricing environment.

Chesapeake lowered its previous capex guidance by about 20%. Antero said it expected its gas production to decline by 3% in 2024, and that its drilling and completion capex budget would plunge 26%. Comstock plans to cut two rigs in the Haynesville Shale.

And, while gas prices remain low, some producers, such as Chesapeake, are building up their DUC backlogs for a sunnier pricing environment.

"They can just flip the switch in 2025," Sorbara said.

Still, these efficiency gains can't last forever. Deflation is temporary and the core acreage zones only have so much life left in them.

"There's not a lot of the core left," Sorbara said. "They're all acquiring and depleting assets. It's just tough to pinpoint when we're going to see a decline."

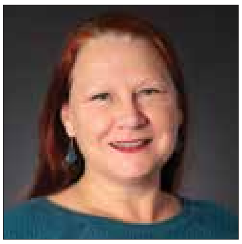
And the industry has a history of surprising to the upside when it comes to innovation, especially as more machine learning and artificial intelligence continue to enter the fray.

"Every time you think capital efficiency has peaked, then it just keeps getting better and better," he said. "Every time you think you hit a technical limit, you just keep pushing forward. The technology keeps making life easier." OGI

Hart Energy editors Nissa Darbonne, Jennifer Pallanich and Chris Mathews contributed to this report.

Drilling Destination: Deepwater

The upstream majors are diving into deeper and frontier waters in 2024, despite flat exploration budgets.



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Even as operators tighten budgets, they are earmarking funds for deepwater, ultra-deepwater and frontier drilling.

Rystad Energy expects operators to be quite active on the drilling front in 2024. Frontier regions, in particular, are fueling optimism for drilling activities this year, especially deepwater projects in the Atlantic Margin, Eastern Mediterranean and Asia, Rystad said.

Offshore optimism was a recurrent theme in fourth-quarter earnings calls with analysts.

During his company's call, Transocean President and COO Keelan Adamson expressed optimism about expected rig contracts for drilling operations in Brazil, the Gulf of Mexico and West Africa.

TechnipFMC Chairman and CEO Doug Pferdehirt observed that operators are shifting more capital to offshore projects this year.

And SLB CEO Olivier Le Peuch said offshore rig counts are rising in response to a strong pipeline of final investment decisions (FIDs) for both shallow and deepwater.

"We think across this wide base load of activity, a significant portion is taking place offshore, where capital expenditure will continue the growth momentum in 2024," Le Peuch said.

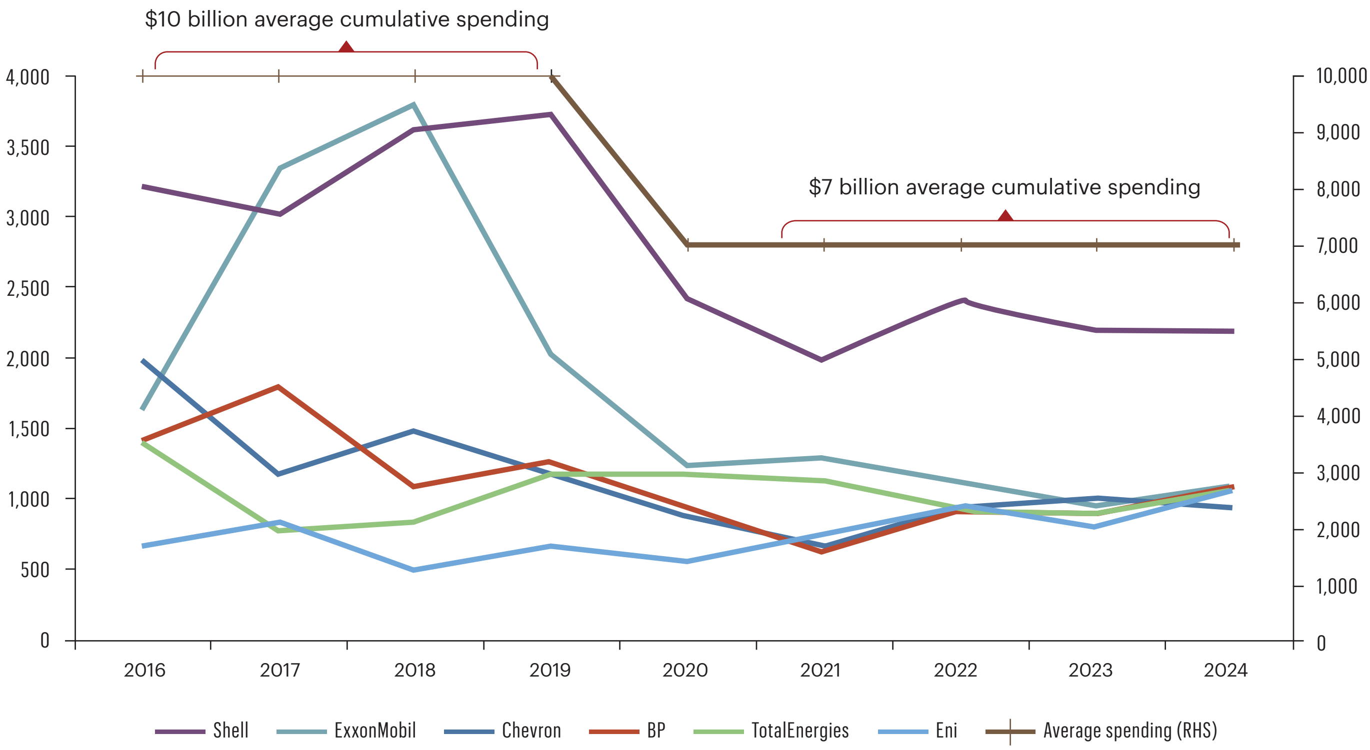
He noted there has been an "explosion" of activity offshore.

Jeff Miller

"It is broad and it's here, in my opinion, to stay because the economics of offshore have improved significantly over the last couple of cycles," he said.

Halliburton CEO Jeff Miller said his company is seeing an increase for 2024 and beyond in "service intensity everywhere we operate—whether it's longer laterals in North America, smaller and more complex reservoirs in mature fields or offshore deepwater—customers

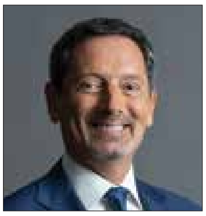
Majors' year-on-year and average exploration spending
USD million



SOURCE: RYSTAD ENERGY

TechnipFMC's Deep Energy pipelay vessel is designed to operate in the North Sea, Atlantic Basin and intercontinental projects.

TECHNIPFMC



"It is broad and it's here, in my opinion, to stay because the economics of offshore have improved significantly over the last couple of cycles."

–**Olivier Le Peuch,** ***CEO, SLB***

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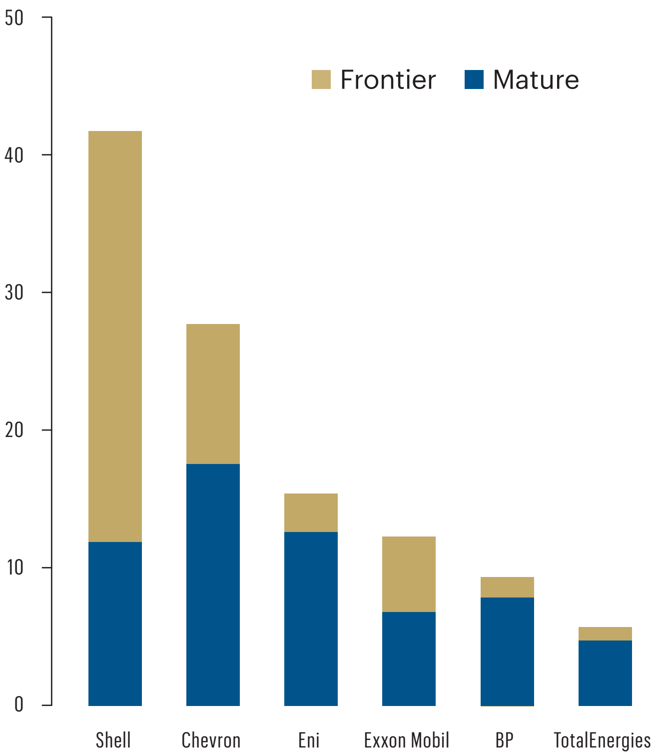
Rystad expects operators to venture abroad with increased deepwater, ultra-deepwater and frontier drilling in 2024.

TECHNIPFMC

TechnipFMC's Subsea 2.0 tree, deployed offshore Brazil.

Upstream acreage allocation by majors and maturity

Thousand square kilometers



SOURCE: RYSTAD ENERGY

require more services to develop their resources, not fewer."

Clay Williams, NOV chairman, president and CEO, said that 2023 saw continuing momentum in offshore and international markets underpinning the steady upcycle that he believes will continue to unfold over the next several years.

Clay Williams

Throughout 2023, operators renewed deepwater activity and exploration in places like Namibia and Suriname, along with brownfield developments offshore Norway and West Africa and in the Gulf of Mexico, and greenfield developments offshore Brazil, Guyana and Australia, he said.

"There are so many areas that look so strong," he said.

Between 2020 and 2024, Exxon Mobil, Shell, Chevron, BP, TotalEnergies and Eni will have spent, on average, a combined $7 billion each year, according to Rystad. That is a drop from the previous four-year period, during which average total spending was $10 billion, Rystad said

Going deeper

During 2023, 112,000 sq km of offshore acreage was awarded to major players, with 39% of that acreage on the shelf, 28% in deepwater and 33% in ultra-deepwater. The acreage awarded to majors in 2023 was 20% higher than acreage awarded to them in 2022.

Rystad suggests this trend represents a significant push into deeper waters, and the firm predicts about 50 more deepwater and ultra-deepwater exploratory wells to be drilled in 2024 compared to 2023. About 27% of all offshore exploration wells drilled in 2023 were deepwater or ultra-deepwater, and for 2024, Rystad expects that percentage to rise to around 35%.

Familiar and frontier acreage

Santosh Kumar Budankayala, senior upstream analyst at Rystad, said majors are "cautiously" venturing into deeper waters and re-evaluating their approaches to frontier exploration.

"While we anticipate them to appraise and mature their frontier acreages, we also expect them to continue to focus on familiar territory–regions with established expertise and existing infrastructure that offer quicker monetization with lower risks," he said in a press release.

Rystad noted that frontier basins generated 45% of 2022's discoveries, but only 20% of 2023 discoveries. Additionally, the firm said, conventional discoveries dropped in 2023, with majors finding 1 Bboe, compared to 3 Bboe in 2022.

In the face of that trend, Rystad suggested the future of oil and gas exploration might lie in venturing beyond the familiar into frontier and underexplored basins. Exploration in mature basins typically yields smaller finds that can quickly transition from discovery to start-up by using existing infrastructure, while frontier and underexplored areas hold the allure of large, geographically concentrated prospects, the firm said.

Past frontier exploration yielded the discovery of gas in Area 1 and Area 4 off Mozambique between 2010 and 2013, gas finds off the coast of Mauritania and Senegal between 2015 and 2017, the Liza oil discovery offshore Guyana in 2015 and the Sakarya gas field in Turkey's Black Sea sector in 2020. The Brulpadda and Luiperd discoveries offshore South Africa in 2019 and 2020 and Venus and Graff offshore Namibia, both in 2022, have led to the opening of new hydrocarbon plays.

2024 plans

Shell secured 42,000 sq km of frontier acreage offshore Uruguay in 2023. Rystad noted Shell has significant projects in Southeast Asia, Africa and the Americas slated for this year. Currently, Shell is drilling the ultra-deep prospect Pekaka on Block SB 2W offshore Sabah, East Malaysia. This prospect shares similarities with the 2022 Tepat discovery in deepwater Block M and holds substantial potential for a gas-condensate discovery, aligning with Shell's gas-focused portfolio strategy in Malaysia, the firm said.

Following Pekaka, Shell is expected to pursue more ultra-deepwater exploration on Block SB X with the Bijak prospect, Rystad said. Shell secured these blocks in Malaysia's 2021 bid round. Additionally, exploration drilling is anticipated in the shelf region of Sarawak, East Malaysia. Shell is also continuing appraisal activity in Namibian waters to further prove the extent of its discoveries there, including Graff, Rystad said.

BP's deepwater exploration plans in Africa and the Americas comprise of multiple wells in Egypt, including appraisal drilling at the Raven gas and condensate field, as well as wildcat exploration drilling in the King Mariout offshore concession in the Western Mediterranean, Rystad said. BP's Pau-Brazil well marks its first operated well in the Santos Basin off Brazil, expanding its presence beyond the Campos Basin, where it was previously a non-operating partner with Petrobras.

Additionally, Chevron and Shell are collaboratively spearheading plans to drill off the coast of Suriname in Block 42, which contains the Walker carbonate prospect. Rystad said a discovery in Block 42 has the potential to catalyze further exploration efforts in Suriname.

Argerich-1, Argentina's first offshore ultra-deepwater well, in which Shell has a 30% non-operating stake, if successful, also could spur deepwater exploration in that region, Rystad said. OGI

Kissler: OPEC+ Likely to Buoy Crude Prices—At Least Somewhat

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BOK FINANCIAL SECURITIES

Dennis Kissler is senior vice president of Trading for BOK Financial Securities. He is based in Oklahoma City.

Although oil prices fell slightly after OPEC+ announced that it would keep its voluntary production cuts in place until midyear, the market's initial reaction probably isn't a harbinger of what's to come as we move through the first half of the year.

OPEC+'s decision to extend its output cuts of 2.2 MMbbl/d into the second quarter was widely expected, especially given the concerns about global growth that have been circulating. However, within the announcement, Russia's decision to cut its oil production and exports by an extra 471,000 bbl/d in the second quarter was a surprise to many—and, looking forward, it just might be one of the factors that supports higher oil prices.

What's the 'sweet spot' for prices?

At the same time, it's important to temper expectations. I'm not talking about a surge in prices; rather, the sweet spot for price equilibrium in OPEC+'s mind is likely between $85/bbl and $88/bbl for Brent, or approximately $78-$82 per barrel for WTI. As of mid-March, those figures were around $82 for Brent and $79 for WTI, so even in the case of Brent, the price increase probably won't be large.

Any prices we see below those ranges could easily push OPEC+'s production cuts into the end of the year—and that's a possibility. The near-record production numbers coming out of the U.S.—at 13.3 MMbbl/d—has been a thorn in OPEC's side. Without OPEC+'s continued production cuts, crude futures could easily be priced in at between $5/bbl and $8/bbl lower.

Oil demand will be key

At the same time, oil demand has been better than most analysts expected, which could push prices higher. This increased demand is mostly led by higher global consumption of jet fuel, which is up 11.1% from the level of consumption a year ago. Also keep in mind that distillate/diesel inventories in the U.S. stand at 11 MMbbl below the five-year average. Any novice economist can tell you that tighter supplies with elevated demand will keep an upward bias to the pricing curve.

However, one wildcard is China. As I've written about before, much of the concern surrounding global oil demand has been stemming from China's economic struggles post-COVID. Although China's economy grew

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by 5.2% in 2023 and the government's growth target for 2024 is a healthy 5%, the country still faces property market struggles, a declining population and insufficient demand.

Given that China is the largest manufacturing economy in the world, any growth struggles that they have tend to bring down oil demand. Still, as of this writing, the Hang Seng Stock Index has been making a nice recovery, and oil demand looks to be improving in most of Asia, especially India. If these improvements continue, that would also push oil prices higher.

Yet as we look forward through the next few months to midyear, another question is what will happen with U.S. interest rates. Previously, some experts anticipated that the Federal Reserve could cut rates as soon as March. However, now many experts do not expect the first rate cut to occur until June or July, with an anticipated total of three rate cuts in 2024. However, none of that is an absolute certainty: inflation remains on the Fed's watch list, and the path toward the Fed's goal of 2% inflation probably won't be a straight line. If the Fed does end up having to keep rates higher for longer, that would be a headwind for crude prices and would most likely keep the U.S. dollar elevated against world currencies.

The bottom line

By keeping the voluntary production cuts for longer than what was originally expected, OPEC+ is sending a clear signal that oil prices need to be sustainable for both producers and consumers. However, again, it's important to keep our expectations in check. While OPEC+ members will most likely be attentive to crude prices, they also have a checkered past in staying with compliance when prices get elevated. OGI

Qnergy Tackles Methane Venting Emissions

Pneumatic controllers, powered by natural gas, account for a large part of the oil and gas industry's emissions. Compressed air can change that.

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Natural gas-powered pneumatic devices have been identified by the EPA as one of the biggest sources of vented methane emissions in the U.S. oil and gas industry. Some look to replacing natural gas with compressed air technology as a way to tame methane venting.

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As oil and gas companies look for ways to tame methane emissions from operations and strengthen existing programs, some are turning to clean dry air to eliminate methane venting.

The technology aims at natural gas-powered pneumatic devices, which have been identified as one of the biggest sources of vented emissions from the oil and gas industry, according to the U.S. Environmental Protection Agency (EPA). Pneumatic devices are typically powered by pressurized natural gas to operate valves or control pressure, liquid flow, temperature or other processes.

"It's very easy to control the flow of gas, separate gas from water, from oil, with those pneumatic valves. The problem is that every time a valve opens, some methane is emitted," Qnergy CEO Ory Zik told Hart Energy. "That's on the pneumatic devices side. On the vented side, there is another big deal, which is water tanks [on gas fields]… They accumulate methane vapor, and this methane vapor, every time it's over pressured, is emitted through the air."

The EPA estimates the oil and gas industry is responsible for 30% of U.S. methane emissions, or about 240 MMmt of CO_2 equivalent emissions in 2021. To combat emissions, the EPA announced a final rule in December 2023, which had been in the works since President Joe Biden took office, targeting the so-called "super pollutant."

The rule phases in a requirement to eliminate routine flaring of natural gas produced by new oil wells, establishes standards for emissions reductions from high-emitting equipment and mandates comprehensive monitoring of methane leaks from well sites and compressor stations, among other requirements. It also mandates conversion of pneumatic controllers to zero-emitting technologies and the elimination of associated gas venting.

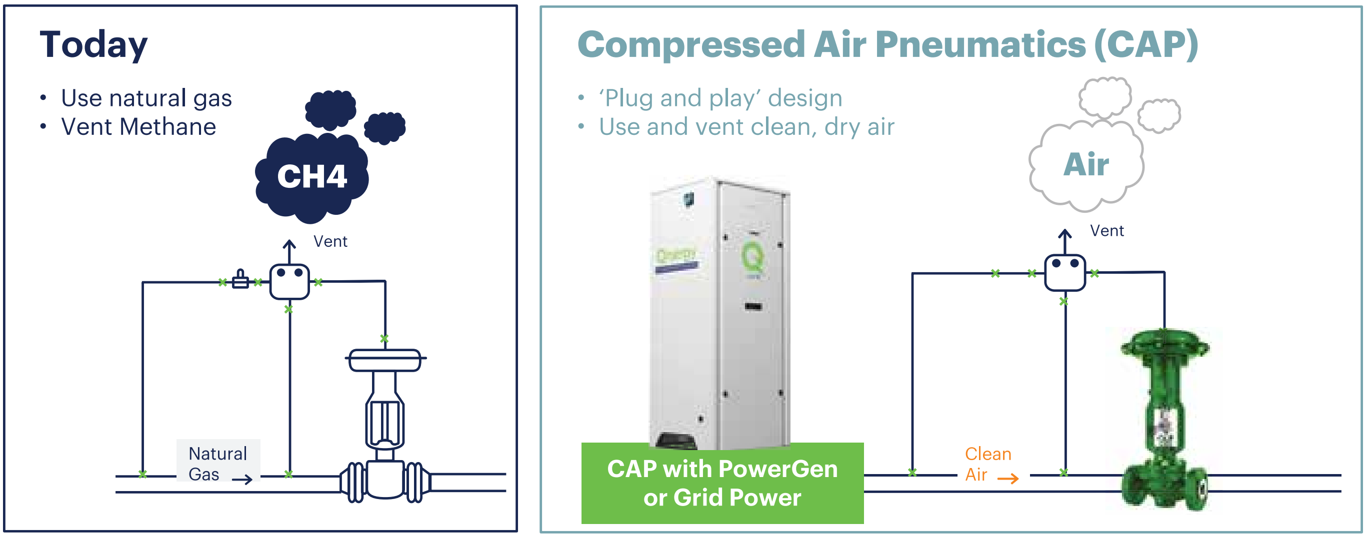
With cost-effective and innovative technologies, the EPA said the rule could prevent an estimated 58 million tons of methane emissions from 2024 to 2038, the equivalent of 1.5 billion metric tons of CO_2.

Managing methane

Since the final methane rule was released, Zik said Qnergy has seen increasing interest in some states in its technology using compressed air pneumatics, instead of natural gas, in combination with grid power or its PowerGen generators.

"The compressor package does something very simple. It takes electricity to compress air and replaces natural gas as a source of pressure with compressed air. So now, instead of having natural gas as a source of pressure and vent methane, you vent clean, dry air," Zik said. "The site is cleaner. There's no methane venting. It's safer because there's no methane vapor in the air. And, it's

Replacing methane venting with clean, dry air



SOURCE: QNERGY

very affordable. People are now deploying them in massive amounts."

Increased interest in the technology post-final methane rule has varied by state, he said. The EPA's rule establishes guidelines for states for enforcement. In the rule's new subpart OOOOc, states may adopt the standards set in the guidelines for an existing source or develop their own. Subparts OOOOa and OOOOb regard new activities, sites and installations.

"States have about five years to implement the OOOOc for existing installations. So, as you can imagine, Texas is taking its time and Colorado and New Mexico are jumping all over it," Zik said.

Some smaller companies are awaiting to see how regulations will be implemented at the state level. And, natural gas prices are playing a role.

"We see less activity than was expected because of the low gas prices of about $1.50 per MMBtu. People are just slowing down," Zik said. "So, we expect as it will roll up to $2, $2.50, $3 per million BTU, those activities that fall under OOOOb will pick up."

However, some bigger oil companies have jumped into action.

TotalEnergies is among the companies using the technology, as part of Qnergy's corporate program geared toward companies needing large installations.

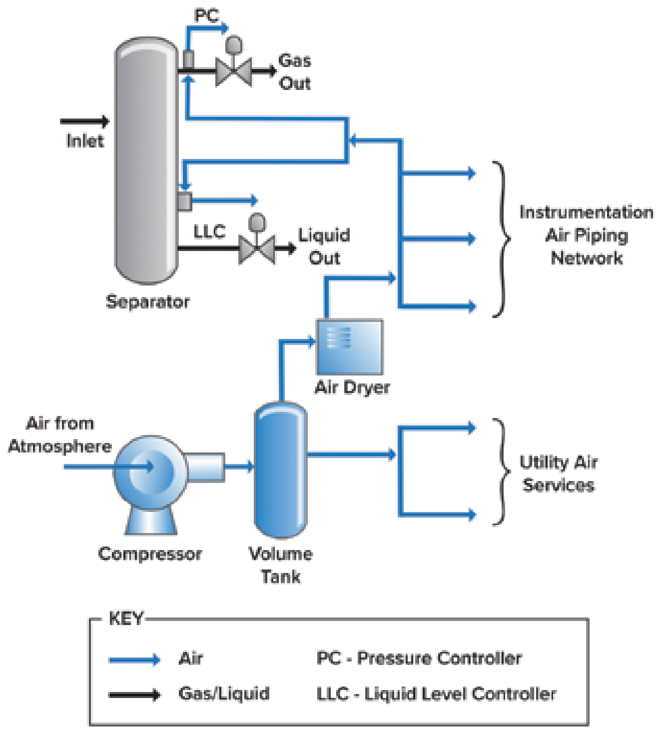
"They ordered about 100 units out of about 400 [units] that are required in their activity in the Barnett. And then they found out that, using these units, they eliminated immediately nearly 100%, or 98%, of their emissions," Zik said. "So, they turned and ordered the rest of these 300 units. The deployment of this entire project is about to end in two weeks."

Bigger ambitions

Qnergy has also taken its PowerGen technology to landfills, capturing methane and transforming it into electricity. The company has a pilot project underway in Utah and hopes to carry out similar projects capturing methane at hundreds of landfills in the U.S.

"The beauty of this model is that these 10,000 closed landfills are now a liability from the environmental standpoint and from the financial standpoint for the owner," Zik said. "They need to measure the emissions and they need to deal with it and that costs money. So, we turn this liability into an asset. Instead of costing you money, we eliminate the pollution and we share the revenue."

Typical instrument air control system



SOURCE: U.S. ENVIRONMENTAL PROTECTION AGENCY

The methane abatement can also qualify for carbon credits. With the Utah pilot project, carbon credits have been registered with the American Carbon Registry, the generator has been tested and the plant is being erected, Zik said.

Collecting methane in pipes for conversion into electricity can also be carried out at dairy farms, particularly at those sites where renewable natural gas production is not economic, he added.

"We have a pilot that we're running in Mexico, and probably in 2025 we will start deployment of this solution," Zik said. "People overlook the fact the methane is a distributed problem that needs a distributed solution. Our solution is very small, relatively, and it can be deployed all over the country in a distributed fashion." OGI

▸ TECHNOLOGY

Cyber-informed Engineering Can Fortify OT Security

Ransomware is still a top threat in cybersecurity even as hacktivist attacks trend up, and the oil and gas sector must address both to maintain operational security.

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As the cybersecurity landscape shifts with an increasing number of successful "hacktivist" attacks, the combination of process, automation and network engineering tools can address operational security (OT) risks, according to industry experts.

About 80% of the successful cyberattacks on industrial operations in 2022 were ransomware-related and roughly 15% were led by hacktivist groups. The expectation is that future hacktivist efforts will continue to target high-profile targets and infrastructure, according to Andrew Ginter, vice president of industrial security at Waterfall Security Solutions.

Andrew Ginter

While the oil and gas industry hasn't borne the brunt of cyberattacks, it has weathered a few onslaughts, including the 2021 Colonial Pipeline ransomware attack and a trio of early 2022 ransomware attacks on ports that delayed the loading and unloading of oil tankers.

But Ginter worries that might change.

"There are distressing trends, one of which is the trend towards increased hacktivist activity," he said. "The thing about hacktivists is that they're politically motivated. They don't have a financial agenda and are politically motivated."

And he believes hacktivists are "quite happy" to target critical infrastructure, including energy, and the bigger the better because of resulting impacts. So, if hacktivist activity continues to increase, it increases the likelihood of attacks on critical infrastructure.

Fuzzy risk picture

With the low number of successful attacks on the oil and gas industry, he said, some might consider playing the odds when it comes to cybersecurity.

They might ask how likely they are to have nation-state grade ransomware attacking their pipeline or refinery in the coming year, he said.

"That's the wrong question. I mean, imagine that the refinery goes down for 10 days. How much have you lost? Do the math? It's a lot of money," Ginter said. "If your answer is, 'Hey, we knew that if this grade of ransomware attack came after us, we'd go down. We knew that. We just didn't think they'd pick on us this year.' That's the wrong answer."

Even with the rise of hacktivist attacks, Ginter said the pervasive threat to critical oil and gas infrastructure is nation-state grade ransomware.

"We need to take really strong measures to protect our system against that network-based threat," he said.

Part of designing cyber protection has been protecting against worst-case consequences, but there's no consensus in the industry as to how to assess cyber risk, he said.

Ginter said the International Electrotechnical Commission standard for secure industrial automation and control systems touches on the process of risk assessment without spelling out step-by-step instructions on how to conduct one.

"All this thing talks about is the process," he said. "It says, first you should do a preliminary, and you should use the result of that to make a decision. And then you should talk about network segmentation, and then decide if you need to do a detail. It doesn't actually tell you how to do the preliminary; it just says that you should do one. Yet we could not get anyone to agree on a methodology for connecting threats and consequence into risk. That's left to the reader."

Ginter also argues that worst-case consequences should determine the required strength of a system's security program.

"But even that is controversial," he said.

Defending OT systems

Yet the worst-case consequence in oil and gas is usually unacceptable, he said, due to the public safety threat involved.

Fortunately, he said, new approaches for addressing such threats are being created, such as the Idaho National Lab's Cyber Informed Engineering approach, which uses engineering-style mitigations for cyber risk.

Such mitigation strategies are what "cyber-informed engineering is all about," he added.

"The new thinking is, wherever practical, put electro-mechanical safety in to eliminate the cyber threat to safety," he continued. "Still use all the cyber stuff. You want a second and third line of defenders, but your last line of defense basically takes the threat off the table." OGI

▸ TECHNOLOGY

Cash Flow Assurance

Service companies combine processes and techniques to mitigate the impact of paraffins, asphaltenes, hydrates and scale on production – and keep the cash flowing.

JAXON CAINES
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Despite what people might believe about themselves and their individual abilities, it is generally accepted as universal law that most things are easier to accomplish with a team. No one is great at everything. Whether it's completing a project for work or studying for a graduate exam, it's hard without help and the benefits that come when complementary skills work together. This axiom also holds true in the oil and gas field. In flow assurance, it takes multiple processes working in concert to get the job done.

There are a number of reasons a well could stop flowing smoothly. Both organic and inorganic material can block a pipe and pose risks to safety, the environment and an operator's bottom line.

"Our customers, which are mostly E&P-type companies, are making these massive investments on the drilling and exploration side. And overall, production is kind of the cash register. Without flow assurance, we risk that revenue flow," Randy Guliuzo, flow assurance global product line manager at Baker Hughes, told *Oil and Gas Investor*.

Typically, flow is restricted by one or a combination of four things: paraffin,

Randy Guliuzo

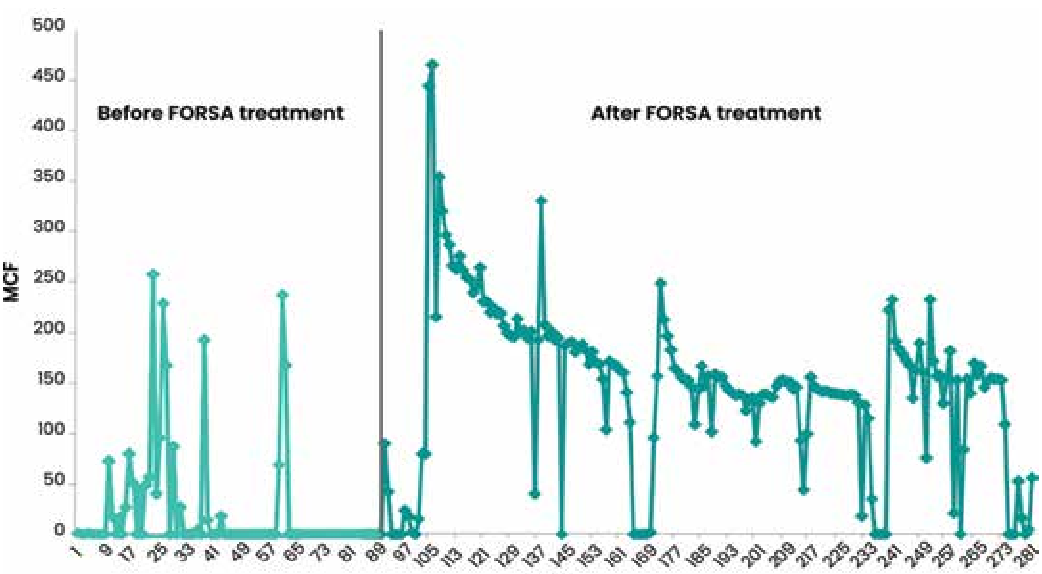
asphaltene, hydrates and scale.

Paraffins are waxes derived from the fatty components of crude oil and appear when the temperature in the pipe decreases to a certain level, restricting flow within the pipe and increasing the viscosity of crude oil. Asphaltenes are the dissolved solids components of crude oils and, despite being important in the oil field, they can foul well perforations, tubing valves and heat exchanges, as well as cause wellbore reservoir damage due to permeability or wettability challenges.

Hydrates–compounds in which gas molecules are trapped within a crystal structure–occur in environments with high pressure and low temperature. They can plug tubing and flowlines and also lead to frozen wellheads. Scale, which is similar to mineral buildup on a bathroom faucet, appears when waters with incompatible chemistries are mixed and temperature and pressure changes. It can lead to near-wellbore reservoir damage and permeability changes, fouling of perforations,

Gas production

Super-charged methanol (FORSA HIW5557 LDHI and methanol, 10:90 ratio) initiated day 90



SOURCE: BAKER HUGHES

Baker Hughes' FORSA HIW5557 was able to boost production 530% and increase client revenue by $20,000 per month.

PARA-Window captures paraffin deposition at a more realistic temperature gradient (5°C) between the bulk oil and surface temperature using a near-infrared optical probe.

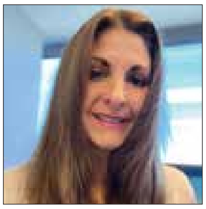
CHAMPIONX

Asphaltenes (pictured), paraffin, hydrates and scale can lead to billions of dollars of lost revenue from slowed down or delayed production.

well tubing, and valves and production decline.

Each of these obstacles can appear during oil and gas operations and cause billions of dollars' worth of damage.

"Deferred production costs companies billions of dollars per year. So, if we can prevent deferred production by just preventing these sources of deposition and flow, that's going to be very profitable for our customers," Rebecca Lucente-Schultz, chemical technologies director of flow assurance at ChampionX, told *OGI*.



Rebecca Lucente-Schultz

To defeat the "Four Horsemen" of Flow Assurance, it takes a combined effort. Baker Hughes, ChampionX and other service companies are developing an array of inhibitors, dispersants and other chemicals that can kill two, three, or even four birds with one stone.

"A really big area for flow assurance is developing combined, multifunctional products," said Lucente-Schultz. "Logistically, it's important because sometimes you don't have a place to store two or more separate volumes of chemicals. And so, multifunctional products allow you to have the same, or sometimes better, functionality in a smaller space."

ChampionX is able to develop these combination chemicals or multifunctional products through what Lucente-Schultz calls the most "critical" part of her work—testing.

"If you're not using the right test method, then you have no idea if the product you're developing is going to get you the right performance in the field," she said.

The different tests determine which flow management system to employ in conjunction with others, whether it's dispersants that aid in breaking up solids and liquids or inhibitors that can deter paraffin and corrosion, which is another prevalent problem.

"We produce chemicals, and part of what makes that challenging is making sure that the chemicals we're producing here in the lab are going to perform in the field," Lucente-Schultz said. "There are aspects from the field that we're incorporating into the test methods we develop, such that we can make sure the products that are performing in our lab tests are also going to perform in the field."

Lab and field

Lucente-Schultz's thought process is evident in ChampionX's PARA01975A solution, a combination paraffin and corrosion inhibitor, which was developed by eschewing the commonly used, but outdated "cold finger test" in which a metal "finger" simulates the pipe's inner wall, in favor of developing paraffin inhibitors and instead adopting the new PARA-window method.

"[PARA-window] allows us to look at paraffin fouling in real time as it's occurring rather than relying on the end of the test," Lucente-Schultz said. "It allows us to look at more realistic test conditions, and that allows us to look at the very first layer of paraffin that's forming, which is really critical in the deposition process. We believe that's one of the reasons why it's so effective."

While in-lab testing is important to Baker Hughes, engineers have a slightly different view on what the most valuable portion of their flow assurance projects are: all on-site monitoring is typically focused on putting the product in the field and learning and adjusting once it is there.

"In-field monitoring and the testing associated, once the application has begun, generally circles around is the product working to meet the KPIs [key performance indicators] that us and the customer have agreed to and is it being injected at the right dosage or do we need to adjust?" Guliuzo said.

Baker Hughes' FORSA suite of solutions is a part of this line of thinking. The FORSA chemicals have been used in a number of operations both on and offshore.

In the Bakken/Three Forks, an operator experiencing scale problems used FORSA's SCW8225 scale inhibitor to successfully treat more than 360 sucker rod lift wells in this field. The inhibitor was also used on the electrical submersible pump (ESP) systems in this field. There were no scale-related failures on the sucker rod lift wells or the downhole ESP equipment in this field during the more than four years of treatment with SCW8225 scale inhibitor, according to Baker Hughes.

Baker Hughes also used FORSA in southwest Wyoming to assist an operator having hydrate issues. After various attempts at methanol injection failed to control the problem, resulting in high maintenance costs and poor production output, Baker Hughes assessed the problem and used its FORSA HIW5557 low-dosage hydrate inhibitor (LDHI) in conjunction with the methanol. This combination resulted in a super-charged methanol/LDHI that boosted production 530% and increased revenue by $20,000 per month, Baker Hughes said.

While the oil and gas industry is normally slow to adapt, these combination chemistries appear to herald an evolution in flow assurance, providing a more efficient and sometimes quicker solution. Lucente-Schultz said ChampionX aims to innovate in "a way that is necessary to our customers if we're going to provide the most value to our customers." OGI

Midstream Builds in a Bearish Market

Midstream companies are sticking to long-term plans for an expanded customer base, despite low gas prices, high storage levels and an uncertain political LNG future.

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Natural gas prices have tanked and gas storage levels remain well above average.

Still, most energy companies plan to spend their 2024 midstream money to bring even more natural gas to market.

According to a study by East Daley Analytics (EDA), energy companies have budgeted more than $10 billion in capex to upgrades and expansions of their gas infrastructure.

For those following the natural gas market, the move should not come as a surprise.

"Although natural gas prices have come crashing down in recent weeks, the long-term demand for gas infrastructure has not faltered," Ajay Bakshani, EDA director of midstream company financials, wrote in the study.

Infrastructure for natural gas is needed for an LNG export market expected to double in size by 2030, and to support the power generation needed as coal plants retire and domestic electricity demand continues to increase.

Hinds Howard, portfolio manager at the CBRE Group, noted that overall capex spending is not expected to rise much in 2024. Companies spent about 25% more in capex in 2023 than in 2022, he said, while forward statements in 2024 show about an 8% increase. However, the focus on the midstream market shows a dedication to longer-term investments.

"The bigger picture is that midstream is a longer-cycle business," Howard said.

"Although natural gas prices have come crashing down in recent weeks, the long-term demand for gas infrastructure has not faltered,"

–Ajay Bakshani, *director of midstream company financials, East Daley Analytics*

"Upstream has become increasingly short cycle. They can look at prices in the next year or 18 months and say, 'We've got to slow down or else we're not going to make any money.' Midstream announces projects and there's a little bit of a lag effect."

According to a January outlook from S&P Global, infrastructure for LNG export and moving natural gas out of West Texas will be the main focus of the industry for the next several years. Gas-to-oil ratios continue to rise in the Permian, driving the need for more gas pipeline capacity toward the Gulf Coast.

EDA forecasts about $2.6 billion will be spent on gathering and processing plants in the

Waha NatGas Prices Go Negative

Conditions make for a strong LNG export market, according to an Enterprise Partners executive.

The Waha Hub natural gas spot price in the Permian Basin traded below the psychological benchmark of $0.50 per MMBtu on March 14 and briefly dipped into negative territory, executives discussed at an industry lunch later in the day.

At 9 a.m., Andrew Fletcher, KeyBank National Association senior vice president for commodity derivatives, wrote in an email that Waha 2024 bids were at negative $0.77 and 2025 bids at negative $0.69.

"Don't worry about it, we have the gas," Tony Chovanec, an Enterprise Products Partners executive vice president, told a lunch crowd at the Greater Houston Port Bureau Commerce Club. "Natural gas, today in Waha, Texas, is trading negative. That means you had to pay me to take your natural gas. You had to pay me somewhere between 50 [cents] and 75 cents to take it."

The Waha Regional Hub is located outside of Fort Stockton, Texas, in the Permian Basin. The Henry Hub price for natural gas rose by 5.73% and closed March 14 at $1.75.

The Waha Hub price is challenged thanks to its connection to Permian Basin oil production and constrained gas processing and pipeline capacity from the region. According to the U.S. Energy Information

An expansion of natural gas infrastructure is needed to support the LNG export market.

SHUTTERSTOCK

Permian. Enterprise Products Partners and Targa Resources are leading the pack with plans to add 2 Bcf/d of new processing capacity in the area.

TC Energy, Enbridge, Williams Cos. and Kinder Morgan will spend the most on pipelines, with about 40% of their capex slated for pipeline modernization projects and maintenance, EDA estimated. About $1 billion in capex will go toward projects in the Mideast, such as Equitrans' Mountain Valley Pipeline, slated for completion in the second quarter.

In the short term, natural gas prices are expected to remain low. The U.S. Energy Information Administration's weekly release of gas storage figures on March 6 showed a decline of 40 Bcf in the U.S., thanks to continuing mild weather. The amount in storage, approximately 2.3 Tcf, was well above the five-year average. Henry Hub prices on March 8 were holding at about $1.80 per MMBtu, despite news at the beginning of the month that EQT and Chesapeake Energy planned to temporarily cut production. OGI

Administration (EIA), the Waha price fell below zero for the first time this year on March 4 and was trading at -$0.25/MMBtu by March 6.

Negative prices happen when supply exceeds regional demand and the capacity to ship to another market. The EIA noted that the El Paso Natural Gas Co. pipeline system, operated by Kinder Morgan, had been undergoing scheduled maintenance that restricted takeaway capacity.

Chovanec said gas production in the Permian remains high because the region's producers are focused far more on crude production. Currently, each barrel from Permian crude production will contain about 25% NGL and 25% natural gas.

The weather conditions in West Texas can also greatly affect the price, thanks to the region's extremely developed wind turbine and solar facilities.

"It happens when the weather is mild or when the wind is blowing because there's so much wind generation out in West Texas," he said. "So, you take the gas load off."

The National Weather Service monitored strong winds in the Texas Panhandle on March 14, reaching up to 30 miles per hour.

Chovanec pointed out the readiness of the LNG export market to drastically expand in the near term. The market is expected to provide an outlet for natural gas exports and improve prices as Gulf Coast facilities come online.

The export capacity of U.S. LNG is expected to more than double by 2027 to 24.3 Bcf/d, according to the EIA. Some industry critics have said the expansion is overbuilding for the U.S. natural gas supply.

An Old Law That Keeps Sailing

Keeping up with the Jones Act is a burden for the energy industry, but efforts to repeal the 104-year old law may be dead in the water.

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In physics, there is no such thing as a perfect insulator. And therefore, an LNG tanker may not make two consecutive stops at U.S. ports.

Confused?

While the logic may be tough to follow, it's absolutely rational according to the Jones Act, the 104-year old law that governs domestic shipping.

"It's like a bad penny, it keeps showing up," said Gary Kruse, managing director of research at Arbo, an analytical firm that specializes in government energy policy. "And it comes up in really weird contexts. People are like, 'What, I can't do that? For what reason?'"

The 1920 Jones Act requires cargo shipped between U.S. ports to be moved on vessels that are U.S.-built, U.S.-owned and U.S.-crewed. In over a century of regulation by the U.S. Customs and Border Protection Agency (CPB), the rule has often come into conflict with the goals of the energy industry and its customers.

The Jones Act occasionally causes headlines when bottlenecks appear in times of emergency or when government regulations cause unusual situations. Few energy analysts or political commentators expect the law to change any time soon. As noted in a recent analysis by the libertarian Cato Institute, the opposition to the Jones Act tends to be dispersed and distracted, while its supporters are concentrated and passionate, defending a rule they say supports a vital industry and a way of life for thousands of U.S. citizens.

LNG spotlight

In the above case involving the LNG tanker, the CBP ruled in November 2023 that a foreign-owned LNG cargo vessel could not pick up a partial load in one U.S. port and then fill up at another. CBP reviewed the scenario at the request of Reed Smith, a Houston-based law firm that specializes in business and government affairs.

"Foreign-owned LNG tanker" is a redundancy, as no Jones-Act compliant LNG tankers currently exist, according to Reed Smith.

LNG tankers keep their cargo cool through refrigeration powered by the ship's engines. When a ship comes into port, some of the engine power may be reduced. That causes a small amount of the LNG to vaporize, which is then vented to keep the tanker's pressure at safe levels.

The released gas may waft onto shore, thus delivering cargo and violating the Jones Act, the CBP ruled.

"CBP noted in the ruling that the release of vapor at the second terminal is necessary for safety reasons but emphasized that the Jones Act does not contain any exception for safety considerations," wrote Alice Colarossi, a Reed Smith attorney, in an analysis of the decision. Colarossi also noted the ruling could apply to LNG tankers at a single U.S. port going through warmup and cooldown operations.

Customs and Border Protection has dealt with LNG often in the past, as the writers of the Jones Act didn't have to deal with cargo that could easily change into a different form of matter.

In 2002, the CBP ruled that regasification did not create a new and different product. Therefore, LNG could not be shipped from California to Mexico, turned into natural gas and piped back to the U.S.

The ruling was amended in January 2024 to make an exception for small transport ships that carry bunker fuel for ship propulsion.

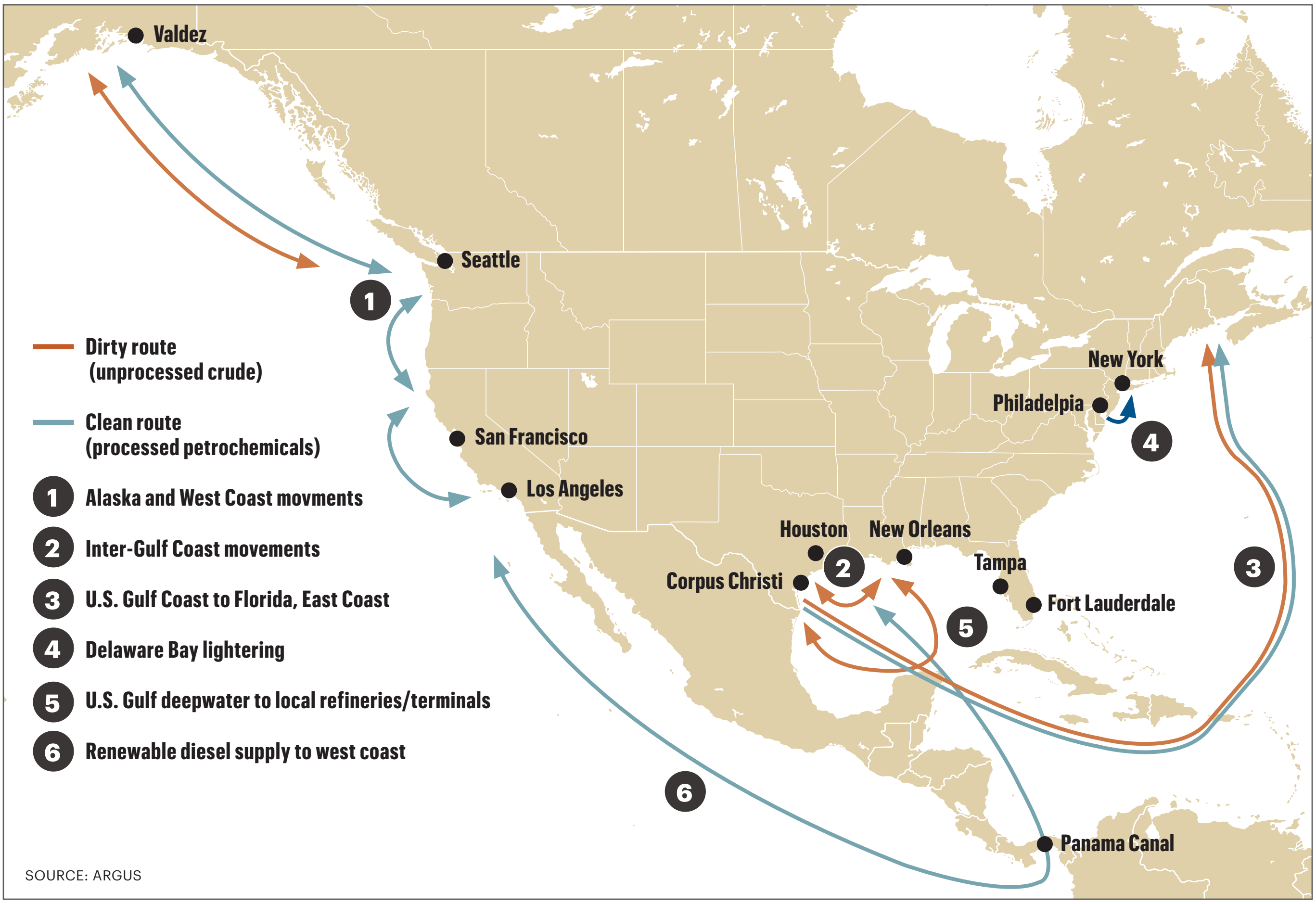
"We expect to see more CBP rulings on the Jones Act compliance of LNG operations as LNG production and export activities are intensifying in the United States," Colarossi wrote.

The country has been politically grappling with LNG and the Jones Act in far more public forums.

After large-scale LNG exports began in 2016, businesses and politicians in production areas begin to lobby for an LNG exemption. In 2018, Texas Railroad Commissioner Wayne Christian sent an open letter to the U.S. Congress asking for a change to the current system.

"Many parts of the Northeastern United States are forced to import their natural gas from Russia instead of purchasing from domestic sources, like Texas," Christian wrote. "Very much similar to the ban on crude oil exports, this is bad public policy for a number of reasons, but primarily because it

Primary routes for Jones Act vessels



"[The Jones Act is] like a bad penny, it keeps showing up. And it comes up in really weird contexts. People are like, 'What, I can't do that? For what reason?'"

–**Gary Kruse**, ***managing director of research, Arbo***

increases our reliance on foreign sources of energy."

Puerto Rico politicians spoke up at the same time, requesting a 10-year Jones Act waiver to deliver LNG. The territory is about a week's ride by tanker from the U.S. Gulf Coast, but the majority of the territory's LNG is provided from Trinidad and Tobago off the northern coast of South America, and Nigeria in Africa, according to the U.S. Energy Information Administration.

Trump had granted Puerto Rico a temporary reprieve from the Jones Act after Hurricane Maria devastated the island in 2017, but ultimately turned down both requests in 2019 after an intense lobbying effort by GOP representatives in Louisiana and other states with Jones Act-dependent industries.

"After talking to President Trump, I am confident that he realizes how important the Jones Act is to Louisiana's maritime industry and that no changes will be made," said Sen. John Kennedy (R-La.), according to Reuters. "It would be foolish to push aside those jobs in favor of foreign-made and foreign-crewed ships."

In 2022, six New England governors requested an exemption from President Joe Biden's administration. In the winter, LNG is considered a backup fuel for the region during extreme cold spells, but its usage is extremely limited.

"The Russian invasion of Ukraine has exacerbated the pricing of nearly all energy commodities which is directly impacting energy consumers in our respective states," the letter read. "The increase in global liquified natural gas (LNG) pricing has been particularly acute–while global petroleum prices increased by 50 percent over the last year, global LNG prices have increased by almost 300 percent."

There is one LNG import facility in the northeast, in Everett, Mass., and it is scheduled for retirement in May. The Federal Energy Regulatory Commission warned as recently as November that shutting down the facility would threaten New England's energy stability. The facility owner, Constellation Energy, listed the high cost of importing foreign LNG as one of the reasons the facility is no longer economically viable.

(A new customer, National Grid, came forward in February and requested a six-year supply deal through the terminal, meaning the facility may be able to stay open, Bloomberg reported.)

On Sept. 8, 2022, Energy Secretary Jennifer Granholm responded to the governors that the Department of Energy could not issue "blanket waivers."

On both sides of the political aisle, the free trade movements of the 1990s and 2000s have largely shifted, Kruse said.

"It goes with how radically trade policy has changed in the last five years, six years and how both parties have kind of come to the same place," Kruse said, "Which is much more of an isolationist perspective than the trade policies we had before then."

On Jan. 25, 2021, five days after President Joe Biden's inauguration, the new administration released an executive order on "Ensuring the Future is Made in All of America by All of America's Workers."

The Jones Act was specifically mentioned in the order as a law that would be protected.

"I've long said that I don't accept the defeatist view that the forces of automation and globalization can keep union jobs from growing here in America," Biden said at a news conference before signing the order.

Winds of non-change

More recently, the Jones Act has made its way onto the list of challenges facing the developing offshore wind energy industry.

In October, Ørsted backed out of the Ocean Wind project planned for the New Jersey coast. The Danish firm stated that the decision was based on "high inflation, rising interest rates, and supply chain bottlenecks."

Later, Reuters reported that decision was also based on delays for a ship needed to build the project. There are no Jones Act-compliant wind turbine installation vessels. The further development of offshore wind projects in America is currently waiting for the construction in Brownsville, Texas, of the WTIV Charybdis.

Dominion Energy, the owner of the vessel, reported in November 2023 that the vessel would not be ready until late 2024 or early 2025, a year after the expected delivery date.

According to the Department of Energy, there are two offshore windfarms in operation off the U.S. coast today. The Jones Act was heavily involved in defining how the facilities would be installed and maintained, according to Kruse.

Kruse's firm, Arbo, conducted a study on offshore wind in 2022, "Regulatory Decisions and Proposed Legislation Make Offshore Wind Even Less Likely." Unsurprisingly, Jones Act-approved crews and boats are required to maintain the wind turbine installations, he said.

However, the Jones Act also regulates the installation of the facilities, down to the placing of foundations. Arbo found that the first layer of rock at the site could be laid by any type of ship. Any more rock, and a Jones Act ship has to be involved.

0
Jones Act compliant LNG Tankers

10
Current global place of U.S. shipping

1920
Year the Jones Act passed

1
Number of Jones Act-compliant wind turbine installation vessels (currently under construction)

650K
U.S. jobs connected to shipping, according to American Maritime Partnership

100ft
Length of Canadian railroad track used to exploit "loophole" in Jones Act

$350M
Year the Jones Act passed

The foundation

The history of shipping law in the U.S. provides answers as to how the Jones Act became so entrenched in the American shipping industry. The rule that the Jones Act is most cited for–U.S.-built, U.S.-owned, U.S.-crewed–predates the Jones Act by more than 100 years. The U.S. government has sought to protect its shipping and shipbuilding industry since the federal government was founded, a Department of Homeland Security report notes.

Laws giving an advantage to coastwise U.S. trade go back to at least 1789, when the 11th Act of Congress established a documentation system for U.S. vessels, which the Coast Guard used to determine if a vessel could be endorsed for domestic shipping.

The requirement that domestic shipping be restricted to U.S.-owned, -built and -crewed ships dates to 1817. The Jones Act, however, was originally focused on building a competitive merchant fleet to keep up with foreign powers.

Prior to the Civil War, American shipping went toe-to-toe with its primary rival, Great Britain. Ships were made of lumber, and America had plenty of it close to coastal shipyards.

Britain had the advantage, however, once the primary ingredient for ship production changed to metal, which the U.K. could produce far more cheaply than the U.S. By the onset of World War I, Britain had four times the tonnage in steam ships as America, according to "The Jones Act in Historical Context," a study by Philip Hoxie and Vincent Smith for the American Enterprise Institute.

World War I would have a massive impact on the U.S. shipping industry. Preparing for conflict, the government ordered 1,460 merchant steel ships in 1916.

It takes a while to build that many ships. By the end of World War I in 1918, only 5% of the contracted vessels had been completed or even started. Instead of cutting the program back, some leaders in Congress saw an opportunity. Outstanding shipbuilding contracts were therefore honored for the creation of the Jones Act. The legislation was named for Sen. Wesley Jones (R-Wash.), who was a leader of the movement.

The rules requiring American ships and American crews were put into the new shipping code as part of general update of maritime law.

Protected sea turf

Since then, the U.S. shipping industry has been built around the provisions of the Jones Act, and several organizations have formed to protect the legislation.

The *Jones Act Enforcer* is a boat by the private Offshore Marine Service Association. The trade association represents 60 firms that operate marine service vessels, which repair, maintain and supply U.S. ships.

Painted Navy Gray, the boat travels up and down America's coastline, surveilling for and recording "the dangerous practices playing out in American waters by documenting foreign vessels skirting U.S. law," according to the group's website, which features a picture of the boat with the caption "We'll Be Watching" in large, white letters.

The American Maritime Partnership is another organization dedicated to keeping the Jones Act in place, saying the industry supports 650,000 U.S. workers and is essential to U.S. security. The organization regularly disputes claims made by opponents or critics of the Jones Act.

In July 2023, the organization posted a critical note of celebrity chef Padma Lakshmi, who said that Puerto Ricans pay more than necessary for their food because of the high costs of shipping from American ports. The AMP cited a 2013 report from the U.S. General Accounting Office that found that higher costs in Puerto Rico could not be attributed to the Jones Act.

Politicians with connections to districts that rely on the Jones Act remain strong supporters. Last National Maritime Day, designated as May 22, Rep. Clay Higgins (R-La.) wrote a letter that appeared in trade publication "Dredging Today."

"Maritime infrastructure plays a significant role in South

The Jones Act Enforcer, operated by the Offshore Marine Service Association, travels the U.S. coastline and documents violations by foreign vessels.

SHUTTERSTOCK

Louisiana's economy," Higgins wrote. "Our district is a testament to the importance of the maritime industry in preserving our heritage, bolstering our national security, and supporting thousands of good-paying American jobs."

Voices for change

On Jan. 30, a group of 24 congressional lawmakers, including Sens. John Cornyn (R-Texas), Mark Kelly (D-Ariz.), Tammy Duckworth (D-Ill.) and Marco Rubio (R-Fla.), submitted a letter to Biden calling for the creation of a Maritime Policy Czar.

"America is–and will always be–a maritime nation. But after years of neglect, changing the trajectory of our shipbuilding and shipping industries is a task that will be measured in decades, not days, months, or years. We stand at an inflection point. We must act now–before it is too late–to reinvigorate American and allied maritime power on the seas."

The intent of the letter was to request the creation of the position of presidential point person for all things maritime, including military, civilian and commercial traffic.

The U.S. Navy is dealing with a shrinking fleet and is currently stretched thin attempting to protect shipping lanes in the Middle East.

"U.S. maritime infrastructure is aging, including in our naval and commercial shipyards, which once produced the world's finest ships," the letter states, without mentioning the Jones Act. "We have allowed the U.S. flagged international trading fleet to decline precipitously, underinvesting in our Merchant Marine and maritime workforce to man our ships and shipyards."

The American merchant fleet handles about 2.8% of the world's shipping capacity, ranked 10th in the world, trailing Bermuda, according to Joseph Guyer, a senior financial writer for U.S. Global Investors.

Energy on the sidelines

Hinds Howard, a portfolio manager for CBRE, said one of the primary factors in favor of the Jones Act is simple inertia. The law's been in place for over a century and is considered part of the legal landscape, he said.

"People just sort of don't believe it can be changed," Howard said. "I'm not really sure what the roadblocks are, but the level of urgency around it is not high among management teams that I've talked to."

A repeal of the Jones Act could even hurt some energy companies financially. Midstream leader Kinder Morgan has a fleet of 16 Jones Act-compliant tankers for crude, condensate and other products. The company entered the tanker business in 2014.

However, studies have shown that a repeal could benefit the entire industry and its customers in a fairly significant way, depending on where they live.

In "Impacts of the Jones Act on U.S. Petroleum Markets," economists Ryan Kellogg and Richard Sweeney, found that the primary beneficiaries of a repeal would be populations on the East Coast, which would see their overall fuel costs fall by $802 million annually.

"Eliminating the Jones Act would have reduced average East Coast gasoline, jet fuel, and diesel prices by $0.63, $0.80, and $0.82 per barrel, respectively, during 2018-2019," the study, published in 2023, found.

However, the decrease in price diminishes closer to the shipping centers on the Gulf, and people in those areas would see gasoline prices rise by about $0.30/bbl.

"These distributional impacts potentially speak to the politics around the Jones Act," the authors wrote.

Kruse said he could see the energy industry driving an eventual change in the law, but it would take far more organized opposition than currently exists, and it's hard for many industry leaders to see much of a payoff.

"You could say that generally incumbents want the status quo because they're organized around (the Jones Act), and they're in long-term contracts to deliver energy with existing routes," Kruse said. "And so, if you throw in something that throws that awry, that could be disruptive." OGI

▸ MIDSTREAM

Squashing Midstream

What does the next level look like for the sector?

HINDS HOWARD
CRBE INVESTMENT MANAGEMENT

Hinds Howard is a portfolio manager at CRBE Investment Management, where he evaluates listed infrastructure and transportation companies in North America and coordinates research of listed transportation companies globally. He is based in Wayne, Pa.

My children are competitive squash players. We travel around the country playing tournaments against the same 50 or so kids in each age group in this country wild enough to do the same. Each match (and even each game within a match) gets heavy scrutiny in our household. At times it seems like nothing is working in a game or one of them loses to a player they beat easily just a few weeks prior. Post-match debrief sessions devolve into hand-wringing over regression despite weeks of practice and expensive lessons.

At those times, at least one parent has the responsibility to pull the lens out to a wider focus on progress that's been made over a longer time horizon. Progress is not always linear, especially when the other players are trying just as hard to improve. It's easy to get bogged down in day-to-day struggles, the short term, and extrapolate that into the future.

Similarly, in the stock market, intense focus on the scoreboard rarely extends beyond a single day or week, much less the multi-year horizon many investors purport to use when underwriting stock investments.

The good news for midstream stocks and MLPs is they are performing well over both short and long terms, essentially since the pandemic bottom. Midstream has not kept pace with the S&P 500 and its tech-fueled expansion, but midstream has outperformed energy stocks and income-oriented stocks like utilities, infrastructure stocks and REITs.

Following this analogy a bit further (if you'll indulge me): there is a major difference between being a top 15 junior squash player in a given age division and being a top five junior squash player. The same could be said for many sports, of course. Through daily practice, one to two instructional lessons per week and some athletic ability, most every 11-year-old can go from starting at a ranking around 200 in the country down to 20 before they turn 13. Progress after that is slow, and you may start to bump up against a physical ceiling that comes down to genetics (or you just may lose interest).

In the same way, through reasonable dividend policy, focused leverage reduction and decently positioned assets, most every midstream company was able to post great stock price performance since the pandemic. But from here, the stock price performance will rely on being not only good, but better than other stocks starting at a higher baseline trying to do the same thing. Progress also could be limited by the quality or geography of the company's assets.

What does my next level look like?

In recent squash history, the most successful and respected college and pro squash coach is a kindly older British man named Mike Way. He is the head coach of Harvard and is the primary coach of the top-ranked squash professional Ali Farag. He tends to focus on the mental side of the game.

Part of Mike Way's philosophy centers around how players can visualize improvements in their game over time. He has players ask themselves, "What does my next level look like?" There's always room for improvement: players will reach a level and plateau for a bit, and asking this question is designed to help players shorten that plateau period before they improve further, reach a new level.

Last year, a big overarching theme was a slowing of new investment opportunities for midstream companies. The general activity deceleration manifested in two main ways: (1) M&A, both asset acquisitions and mergers; and (2) return of capital through higher dividends and buybacks.

In this new environment where fewer large producers exist, visibility into future bottlenecks and investment opportunities has never been higher. Savvy midstream management teams have keyed on the clarity and a new trend is emerging across the sector: multi-year guidance.

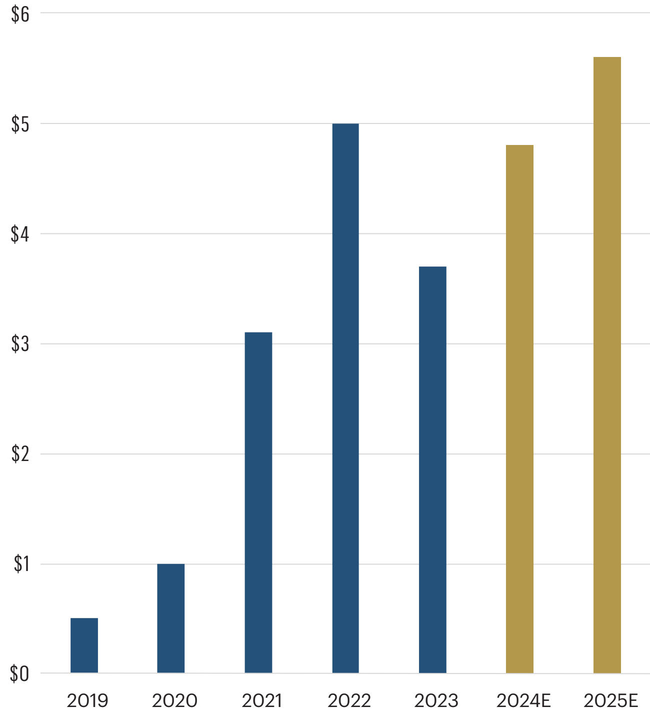
Medium term growth rates: I can see clearly now

Midstream companies recently have begun extending their forward guidance beyond just the current year. Multi-year guidance for EBITDA and capex, and medium term growth rates are becoming more commonplace these days. Three midstream companies initiated three-year guidance for the first time: EPD, TRGP and DTM. EPD only provided capital expenditure guidance, but that's more than we've had before.

One company that already had multi-year guidance is Enbridge, which recently held its analyst day and updated that guidance. ENB expects three-year growth CAGR for 2024-2026 of 7%-9% for EBITDA, up from 4%-6% for its 2023-2025 prior guidance. ENB management attributed the uptick to the impact of utility acquisitions, various base business improvements and growth in its

Midstream buybacks

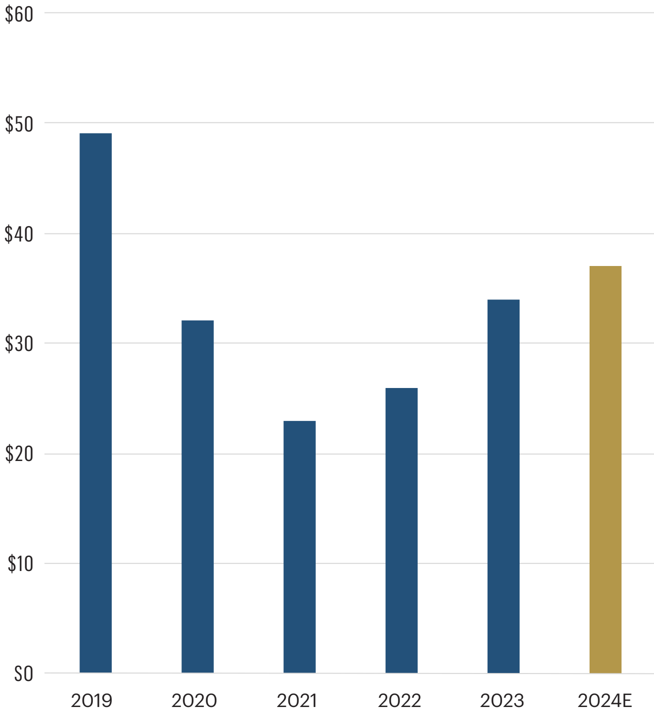
($ billion)



SOURCE: WELLS FARGO RESEARCH

Midstream growth capex

($ billion)



SOURCE: WELLS FARGO AND CBRE RESEARCH

growth project backlogs.

The reasons midstream companies are now offering this extended view on the future include:

• More restrained activity from a more consolidated group of producers.

• Lower growth outlook in 2024 for most companies relative to 2025 when a known catalyst or project completion will drive better growth. Better to convince the market to look past 2024 as a transition year.

• Asset risk profile has improved with less exposure to commodity prices, and in some cases more regulated assets than before, e.g., ENB adding gas utilities.

• Better balance sheets, higher margin of safety related to dividend payments.

• Desire to compare to utilities that tend to provide guidance of three to five years for EPS growth.

Midstream's next level could be trading at a more utility-like EBITDA multiple if the sector can provide and execute on multi-year growth guidance. While midstream has performed well, there is still a valuation gap between midstream and utilities. If midstream can't change perception all the way to utility levels of visibility, this multi-year outlook trend should help keep midstream valuations above other energy stocks.

Enterprise value to EBITDA multiples

Midstream	2/29/2024	5-Year Avg	10-Year Avg
Corporations	9.4x	9.7x	10.4x
MLPs	8.7x	8.0x	11.7
Energy			
Producers	5.6x	5.4x	6.8x
Refiners	5.2x	6.3x	5.9x
Intergrated Oil & Gas	5.0x	5.4x	5.4x
Oilfield Services	8.0x	8.7x	9.0x
Income Stocks			
Utilities	10.2x	10.5x	10.0x
REITS	16.5x	17.9x	11.7x
Market			
S&P 500	14.2x	12.9x	11.7x

SOURCE: FACTSET AND WELLS FARGO RESEARCH

Form breakdown

One final squash analogy to wrap up. Bad habits can be hard to break. Once a bad swing gets ingrained, it can be hard to change. Even when it does change, a player can revert to poor technique when under pressure or fatigued late in a match.

Above, I mentioned the slowing pace of new investment opportunities for midstream companies, but in 2023 growth capex was up 25% over 2022. That uptick in spending reflected to some degree the execution of capital projects announced in years prior. So, growth capital spending was up, but the growth "pipeline" got smaller as those projects were placed into service.

Early indications from initial 2024 guidance announcements point to a small uptick in growth capital spending in 2024 over 2023. There is a lag effect in midstream spending, but if capex continues to creep, midstream stocks will come under some pressure. The market will accept some level of growth spending, but in the face of slowing activity across onshore basins, more growth spending announcements from here would be met with skepticism. Eliminating bad habits like overspending has been a painful lesson that some midstream companies have learned better than others. OGI

► NEW ENERGIES

John Cockerill Americas Building Hydrogen Expertise

Nicolas de Coignac, president of Americas for John Cockerill, recently spoke with *Oil and Gas Investor* about the company's role in scaling electrolytic hydrogen in the U.S.

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John Cockerill is developing an electrolyzer gigafactory in Baytown, Texas

JOHN COCKERILL GROUP

Q&A

The John Cockerill Group is no stranger to the U.S., having been here for decades installing heat-recovery steam system generators, steel-processing lines and manufacturing other equipment.

However, the private Belgium-based company is new to the North American hydrogen scene.

In late 2023, the company announced it acquired a brownfield site in Baytown, Texas, home to a bustling industrial community of petrochemical giants, such as Exxon Mobil and Chevron, near the Houston Ship Channel. When complete, the revamped facility will become the first gigafactory in the U.S. to produce alkaline electrolyzers.

Lured to the U.S. by incentives included in the Inflation Reduction Act (IRA), coupled with growing interest in strengthening the hydrogen sector, the global electrolyzer manufacturer is bringing its expertise to the U.S.

Globally, John Cockerill has a production capacity of about 500 megawatts that will reach 1 gigawatt by year-end 2024. It is commissioning a plant in Europe this year and broke ground on another gigafactory in India.

Hydrogen is seen as a solution to climate woes, serving as a route to decarbonizing hard-to-abate sectors and reduce reliance on fossil fuels used in transportation. While it can be produced via a variety of feedstock, including natural gas, electrolytic hydrogen uses electrolyzers powered by renewable energy to split water molecules into hydrogen and oxygen.

Nicolas de Coignac, president of the Americas for John Cockerill, recently spoke with Hart Energy's Velda Addison, senior editor, energy transition, about the company's role in scaling electrolytic hydrogen in the U.S.

"We're a super excited about bringing this technology to the U.S. We think that it's a missing piece of the puzzle that the country will need for its decarbonization agenda," de Coignac said.

Velda Addison: It's been about two months since John Cockerill celebrated the groundbreaking of its Baytown facility. What is the status of the project? And, are you on track to start producing the first electrolyzer by the end of the year?

Nicolas de Coignac: We called it the groundbreaking when it was closer to a ribbon cutting because we acquired a brownfield. All the buildings are there, all the bones and the infrastructure are there. What we've done so far is we've cleaned up the site. We've prepared it to be able to welcome the equipment that we have [and] placed the orders now for the first equipment. We have to prepare the site so that we can position equipment when they land here in Houston. So, this will take probably another six or seven months before the equipment is installed. This is in line with our target, which is to be able to produce our first electrolyzers by end of this year.

VA: Why did John Cockerill consider the U.S. an attractive place to start developing electrolyzers?

NDC: We're very active in the hydrogen space, manufacturing electrolyzers. We're the world leader for alkaline electrolyzers. But we tend to develop, of course, where the demand is the strongest. And, up to now, it was essentially Asia, Middle East and Europe. Since [the] IRA came out in August of 2022 … there certainly was a surge of interest for green hydrogen. Six months earlier, no one really cared about green hydrogen—at least at scale. You had some demand, but for smaller volumes, more probably dedicated to mobility and largely on the West Coast. But, for industrial use, [there] was no such interest. The IRA has changed this quite dramatically because of the potential to close the gap in price between the targeted green hydrogen price and the current gray hydrogen.

So, suddenly a huge appetite for green hydrogen appeared here in the U.S. Based on my experience in the country, having experienced the surge of shale oil and gas, I know that things can go very, very quickly. And this is where we've decided we need to go. We don't want to address this market with imports. We want to be a local player in the U.S. Actually, we want to be a local player in every large market. We want to be fully integrated to the local economy, where the market is large enough to justify such an approach, of course. And, due to the scale of the United States and the potential need for green hydrogen and the level of ambition that the government has set for 2030 and beyond.

VA: As you know, the U.S. is working to stand up hydrogen hubs across the nation. What role do you anticipate the company playing in those hydrogen hubs?

NDC: We are a supporter of HyVelocity in Houston. … (S)everal of our prospects are members of some of the other hydrogen hubs. We have decided that our first gigafactory will be based in the Houston hub because we know that this will be one of the most active hubs in the country, and I knew the place pretty well. As soon as we have a backlog that is large enough to use all of the capacity of our plant here, we will target opening several other plants in the country.

"We don't want to address this market with imports. We want to be a local player in the U.S. Actually, we want to be a local player in every large market."

Nicolas de Coignac, ***president/Americas,*** ***John Cockerill***

VA: So, you mentioned before, John Cockerill is one of the leading equipment manufacturers of electrolyzers. What learnings or experiences can you bring to the U.S. as it strengthens its hydrogen industry?

NDC: We are offering only one of several technologies that exist for electrolyzers. We are offering pressurized alkaline. The other one that has a maturity level that is sufficient to scale up is PEM [proton exchange membrane], which is a technology offered by Cummins or Plug Power, for example. There's space enough for both technologies to grow. The potential for growth is such that I'm not really very worried about the fact that one technology will win over the other one. In the U.S., the only technology that exists in terms of local manufacturing is PEM. There is no large player for pressurized alkaline. We will be the first one.

VA: How would you characterize the state of the hydrogen market today, and how do you see that changing both in the near term and in the longer term?

NDC: A year ago, there was huge enthusiasm and billions of dollars were just dumped into green hydrogen. Everyone saw this as the new El Dorado. Today, we're facing some skepticism again. Some clouds are appearing and some saying, "Maybe we were hoping for too much," which is normal when you've been shooting too high. If you look at the market cap of many of our competitors that are listed companies, they've lost between 50% and 80% of their market cap in the last six or nine months. So, this appetite has disappeared.

But, I was with DOE [U.S. Department of Energy] this week and met [with] a lot of the customers. The need and the willingness to build those plants of green hydrogen are still there. Everybody thought that would ramp up … [with] 10 million tons of green hydrogen available within five years from now. It will not be five years. It might be eight years or 10 years. I'm still very optimistic. We just have to be flexible enough, agile enough, to live through those bumps.

VA: Do you think more is needed to incentivize demand for green hydrogen, which will in turn help electrolyzer manufacturers? What is needed to encourage gray hydrogen users to switch to green?

NDC: There have been some decisions recently to incentivize demand and … I think it is extremely relevant. Actually, other countries have done this. Japan has done this, for example. Turning to the U.S., for a lot of the projects that are mature enough and are not so much impacted by the guidance of Treasury on IRA, their next hurdle is to secure offtake.

If you have an additional chapter of IRA to support demand, I think this will close the last gap that is missing, and people will be ready to commit to offtake. In turn, [this] will help the developers to say, "Now I can move to the final investment decision," and, in turn, this will become, of course, an opportunity for us.

VA: Which parts of the IRA are you planning to take advantage of?

NDC: Essentially the one that is called [tax credit] 48C, which are subsidies for the investment. Depending on hundreds of criteria that you have to clear, it can support up to 30% of the value of the equipment. So, we are currently applying to this one. Also, linked to the IRA is the Loans Program Office of DOE that supports investment. We are also applying for a loan guarantee from the government, which will help us raise some funds here from banks with the guarantee from the administration.

VA: Is there anything you want to share as far as the R&D or technology part of the electrolyzer? Are you working on anything to help bring the cost down?

NDC: We're pretty advanced in some significant breakthrough on the technology—the core of the electrolyzers. We're talking about the materials. We're talking about the electrodes. We're talking about the diaphragm. All of this will improve. First, the efficiency of the electrolyzer itself, the consumption of power and then the materials, which will reduce the costs significantly. Between now and the next five, six, seven years, we'll see efficiency probably improved by 30% at least, and the cost probably reduced by 30% to 50%. OGI

Transition in Focus

CARBON MANAGEMENT

Weyerhaeuser, Lapis Energy Enter Carbon Sequestration Exploration Pact

Timberlands owner Weyerhaeuser Co. partnered with carbon capture company Lapis Energy to explore carbon sequestration on 187,500 acres across Arkansas, Louisiana and Mississippi.

The acreage includes five potential carbon sequestration sites, Lapis said in a news release. As part of the two-year exclusive exploration agreement, Lapis will determine the sequestration potential of each site.

The agreement was reached amid continued efforts to reduce greenhouse gas emissions. Carbon capture and storage technologies are expected to play a critical role in lowering emissions, including from large-scale industrial emitters north of the Gulf Coast.

Lapis, which is building a portfolio of carbon capture and storage projects across the U.S., will have the option to move the sites into full-scale development agreements and complete the work required to permit, build and operate permanent CO_2 sequestration sites, following the completion of technical and commercial assessments, according to the release.

HYDROGEN

Chevron Plans First Solar-to-Hydrogen Project in California

Using non-potable water from existing assets at the Lost Hills Oil Field in California and solar power, Chevron said it plans to develop a 5-MW hydrogen production project, marking the first of its kind for the company.

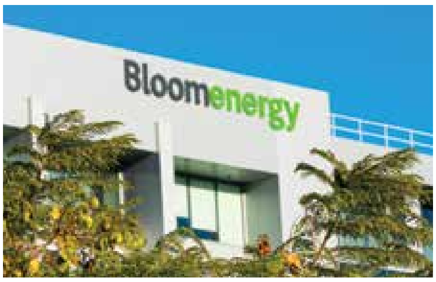
CHEVRON

Bird's-eye view of the Lost Hills Field in California.

Located in Central Valley, the solar-to-hydrogen production facility will be designed to produce 2 tons of hydrogen per day, aiming to support a hydrogen refueling network, Chevron said. The company will use the electrolysis process, splitting water molecules into hydrogen and oxygen to produce hydrogen.

The start of commercial operations depends on factors that include supportive legislative and regulatory energy policies, final engineering design, timely permitting and obtaining the necessary materials, the company said.

Chevron currently produces about 1 million tonnes per year of hydrogen through its traditional business.



SHUTTERSTOCK

Bloom Energy is teaming up with Shell to develop large-scale, solid oxide electrolyzer systems to produce clean hydrogen.

Shell Taps Bloom Energy's SOEC Technology for Clean Hydrogen Projects

Bloom Energy is partnering with Shell to study decarbonization solutions, utilizing Bloom's proprietary hydrogen electrolyzer technology, according to a press release.

The companies will collaborate with the goal of developing large-scale, solid oxide electrolyzer (SOEC) systems that would produce clean hydrogen for potential use at Shell's assets. Bloom's SOEC technology can augment or replace existing fossil fuel-powered gray hydrogen supplies.

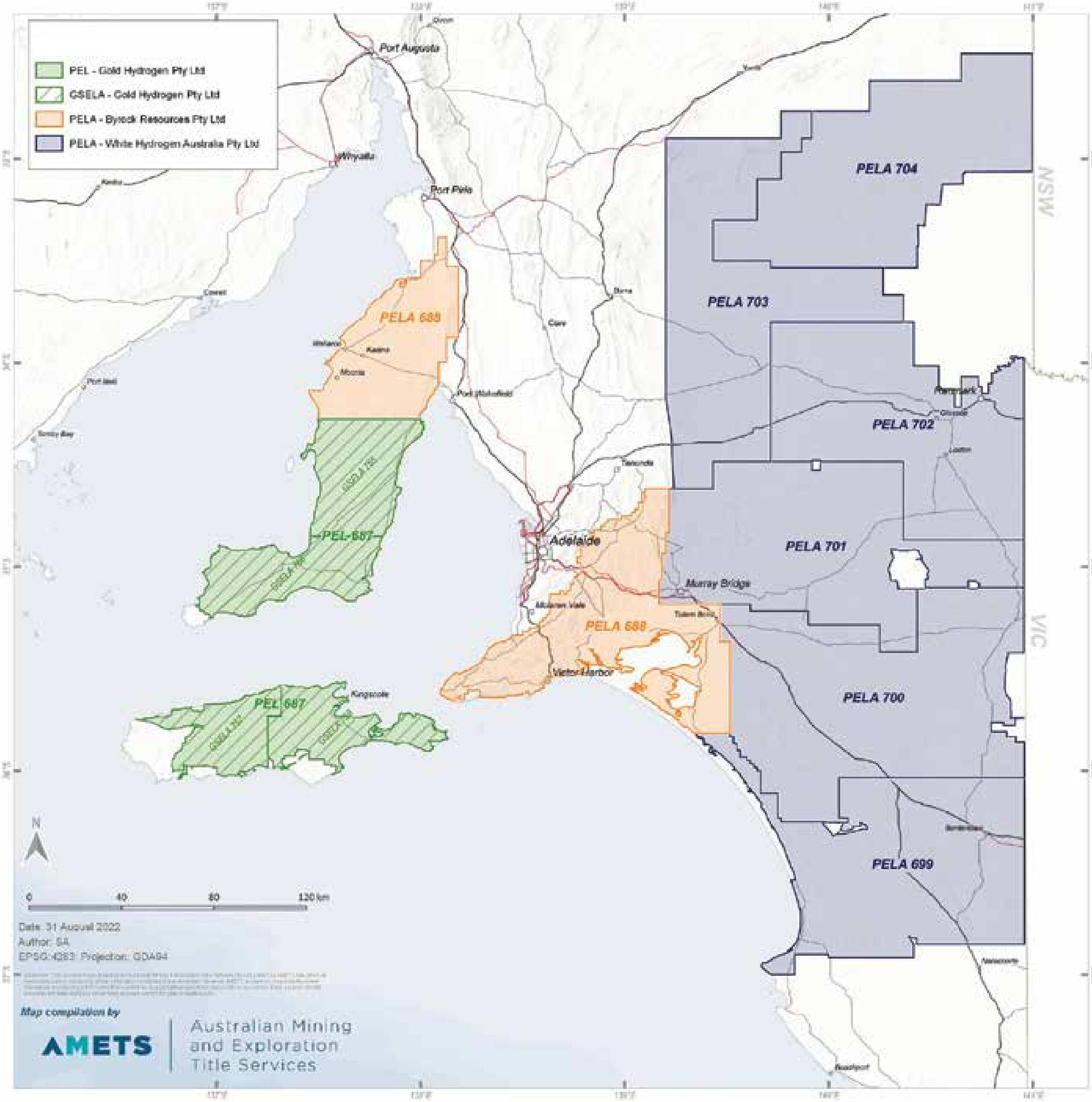
"This technology could represent a potentially transformative moment."

–KR Sridhar, ***founder, chairman and CEO, Bloom Energy***

Gray hydrogen is produced at refineries by high CO_2-emitting steam methane reformation—a process in which high-temperature steam is used to produce hydrogen from a methane source. Clean or green hydrogen is produced from water electrolysis, using renewable energy, the release said.

"This technology could represent a potentially transformative moment for opportunities to decarbonize several

Australian regions for naturally occurring hydrogen and helium



hard to abate industry sectors," said KR Sridhar, founder, chairman and CEO of Bloom Energy.

Bloom has also staged its 4-megawatt (MW) solid oxide electrolyzer, where it produced 2.4 metric tons of hydrogen per day at the NASA Ames research facility in Mountain View, Calif. The project is expected to commence in May.

Gold Hydrogen Begins Well Testing for Ramsay Hydrogen, Helium Project

Australia-based Gold Hydrogen has started exploration well testing focused on naturally occurring hydrogen and helium in a non-petroleum system in South Australia.

The company said its Ramsay 1 and Ramsey 2 wells drilled in late 2023 found natural hydrogen with up to 86% purity and helium at up to 6.8% of raw gas.

"The objectives of the exploration well tests are to obtain more samples of both natural hydrogen and helium for further specialist analysis in world-leading laboratories, and to extract both natural hydrogen and helium to surface," the company said in a news release.

Preliminary technical results from testing are expected by April and will help inform future drilling and well completion designs, a future pilot program and longer-term commercialization planning, Gold Hydrogen said.

The company believes the area, which stretches across Yorke Peninsula and Kangaroo Island on petroleum exploration license 687, could hold an estimated 1.3 million tonnes of natural hydrogen. OGI

Exxon Versus Chevron: The Fight for Hess' 30% Guyana Interest

Chevron's plan to buy Hess Corp. and assume a 30% foothold in Guyana has been complicated by Exxon Mobil and CNOOC claims that they have the right of first refusal for the interest.

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Chevron's plans to acquire Hess Corp. in a $53 billion all-stock deal have reached a major snag. The dispute centers over Hess' 30% interest in the prolific Stabroek Block offshore Guyana. Partners Exxon Mobil and China National Offshore Oil Corporation (CNOOC) believe they have a right of first refusal over the interest.

Speculation has run rampant since Chevron went public with Exxon's claims that the squabble could kill Chevron's deal to buy Hess.

"What is certain is that the Stabroek acreage was the real driver in this acquisition, and if that's no longer available the rest of the portfolio becomes far less attractive," W. Schreiner Parker, senior vice president and head of Latin America at Rystad Energy, told *Oil and Gas Investor*.

Texas-based Exxon, which recently announced a $60 billion all-stock deal merger with Pioneer Natural Resources, is engaged in conversations with Hess and Chevron.

"We owe it to our investors and partners to consider our pre-emption rights in place under our Joint Operating Agreement (JOA) to ensure we preserve our right to realize the significant value we've created and are entitled to in the Guyana asset," Exxon said.

New York City-based Hess deferred to Chevron for comments on the matter. While the California-based oil giant did not respond to *OGI's* questions about Exxon's and CNOOC's claims, Chevron did provide ample details about the noise around Stabroek and Exxon in its February filing with the U.S. Securities and Exchange Commission (SEC).

"Hess, Chevron, Exxon and CNOOC have been engaged in constructive discussions regarding the Stabroek right of first refusal (ROFR), and Chevron and Hess believe these discussions will result in an outcome that will not delay, impede or prevent the consummation of the merger," Chevron said in the filing. "In the event such discussions do not result in an acceptable resolution, either Hess or Chevron could elect for Hess Guyana Exploration Limited, [a wholly owned subsidiary of Hess], to pursue arbitration to resolve the matter."

Either Chevron or Hess can terminate the merger agreement if it hasn't been completed by Oct. 22, 2024. The initial close by date was April 18, 2024, but Chevron and Hess each waived the right to exercise any termination right available with respect to that date.

"What is certain is that the Stabroek acreage was the real driver in this acquisition, and if that's no longer available, the rest of the portfolio becomes far less attractive."

–W. Schreiner Parker, *senior vice president and head of Latin America at Rystad energy, told Oil and Gas Investor.*

However, if Hess stockholders don't adopt the merger agreement or the merger is not completed for any other reason, Hess may be required to pay Chevron a termination fee of $1.7 billion, according to the filing.

Chevron acknowledged that the Stabroek JOA contained a Stabroek ROFR provision. Chevron said the provision "if applicable to a change of control transaction and properly exercised, provides the Stabroek Parties [Exxon and CNOOC] with a right to acquire the participating interest in the Stabroek block held by the Stabroek Party subject to such transaction."

Chevron said the value of the interest would be based on the "portion of the value of the change of control transaction that reasonably should be allocated to such participating interest and is increased to reflect a tax gross-up only after, and conditioned on, the closing of such transaction."

In terms of the Stabroek ROFR, Exxon and CNOOC believe it applies to the Chevron-Hess merger announced in October, while Chevron and Hess don't due to the structure of the merger and provisions language.

"As operator of the Stabroek block, Exxon

Exxon's Liza Phase 2 development involves FPSO Liza Unity.

EXXON MOBIL

Guyana Offshore Stabroek Block FIDs

FID Date	Project	FID US $B	FPSO	Initial Capacity (bbl/d)*	Start Date
April 2023	Uaru	$12.7	Not yet named	250,000	2026
April 2023	Yellowtail	$10.0	*ONE GUYANA*	250,000	2025
Sept. 2020	Payara	$9.0	*Prosperity*	220,000	Late-2023
May 2019	Liza Phase 2	$6.0	*Liza Unity*	220,000	Mid-2022
June 2017	Liza Phase 1	$4.4	*Liza Destiny*	140,000	Late-2019
Stabroek FIDs		**$42.1**		**1,080,000**	

*NOTE: INITIAL NAMEPLATE CAPACITY BEFORE DEBOTTLENECKING.
SOURCE: EXXON MOBIL AND HESS CORP.

Mobil has an obligation to ensure the rights and privileges of the Guyana government, as our host, are honored," Exxon said. "We are not going anywhere—our focus remains on developing the resources efficiently and responsibly, per our agreement with the Guyanese government."

John B. Hess, the CEO of Hess, is "against any acquisition proposal or proposal made in opposition to or in competition with, or that would reasonably be expected to prevent, materially delay or materially impede the consummation of the merger or any other transactions contemplated by the merger agreement," Chevron reported in its SEC filing.

Why Stabroek matters

English-speaking Guyana, home to around 800,000 people, just started producing oil from its Stabroek Block in December 2019. The small country—located in northern South America, between Venezuela on its west and Suriname on its east—is on track to become one of the largest oil producers in the Latin America and Caribbean region. The country is poised to surpass Colombia and the region's lone member of OPEC, Venezuela. Brazil and Mexico are currently Latin America's top oil producers.

Guyana's rising oil production has grabbed the attention of investors in the region and others from around the world, including the Middle East—and rightly so.

Stabroek covers 6.6 million acres, or 26,800 sq km. The block holds over 11 Bboe of estimated gross discovered recoverable resources, Exxon and Hess have reiterated on in their most recent press releases. Energy pundits covering Guyana speculate the ultimate recoverable resources could easily be twice that size.

Exxon expects gross combined production from its first offshore project, Liza Phase 1 (using the *Destiny* floating production storage and offloading offloading (FPSO) vessel; the

An FPSO idles offshore Guyana. By the end of 2027, Exxon and Hess expect Stabroek will have six FPSO vessels online with a gross capacity of over 1.2 MMbbl/d. There is potential for up to 10 FPSOs to develop the current resources, according to the two U.S. companies.

SHUTTERSTOCK

second project, Liza Phase 2 (using the *Unity* FPSO); and the addition of the third project, Payara (using the FPSO *Prosperity*), will be around 620,000 bbl/d in the first half of 2024.

By the end of 2027, Exxon and Hess expect Stabroek will have six FPSO vessels online with a gross capacity of over 1.2 MMbbl/d. There is potential for up to 10 FPSOs to develop the current resources, according to the two U.S. companies.

Exxon operates Stabroek with a 45% interest. Other partners in the block include Hess (30%) and CNOOC (25%). Chevron's deal to acquire Hess would move it into the consortium and team up the top two U.S. energy companies.

Currently, three offshore developments are operating in Stabroek, and more are expected.

The offshore oil project is lifting Guyana's economy, which is expected to grow 34.3%, exceeding growth of 33% in 2023, as Stabroek oil production rises, the country's finance minister, Ashni Singh, said in early January. Projected growth in 2024 will represent the fifth consecutive year that the Guyanese economy has grown over 20%, and will result in Guyana growing at an annual average of 38.8% over that five-year period, Singh said.

Exxon on damage control

Guyana's government under President Irfaan Ali is interested in fast-tracked development of its newfound oil resources as well as associated gas.

In October, after the Chevron deal to acquire Hess was announced, Guyana Vice President Bharrat Jagdeo said the country welcomed having two major U.S. oil companies in its waters.

"We believe they have deep pockets, and they can fund the investment programs necessary to move us to peak production at the earliest point in time," he said, according to Chevron's SEC filing.

Jagdeo, who labeled Chevron as a "good partner too in Guyana," seemingly would be happy even if Exxon were to assume Hess' 30% interest, according to a February Reuters report.

However, as Exxon has taken most credit for the success in Stabroek as skipper of the consortium, it hasn't been immune from criticism on a number of fronts.

In early 2020, a controversial report suggested the Guyanese government of then President David Granger signed a so-called "sweetheart" deal with Exxon, which suggested his government negotiated ineptly with the U.S. energy giant.

In late 2020, Exxon attracted more attention to its leadership in Stabroek over gas flaring as it confronted gas compressor issues on its initial FPSO on the block.

Most recently, Venezuela Vice President Delcy Rodríguez has accused the Guyanese president of following orders from Exxon and the U.S. Southern Command regarding claims to the disputed Essequibo territory located between Venezuela and Guyana.

Venezuela still has issues with Exxon even after the company quit the country in the mid-2000s.

Then, the administration of Exxon Mobil differed with the government of Venezuela's late President Hugo Chávez over a forced joint venture migration process. The process mandated that state-owned Petróleos de Venezuela (PDVSA) operate new joint ventures and hold a majority interest, which in effect relegated bigger and better financed IOCs to the back-seat. Houston-based ConocoPhillips also quit Venezuela for similar reasons and around the same time. Numerous other companies also left Venezuela and many continue to pursue lawsuits for compensation for wrongful asset expropriations.

As it stands, Chevron is the lone U.S. company still operating in Venezuela. And Chevron's presence in Venezuela coupled with its presence in Guyana could work to the betterment of discussions between both governments, pundits in Caracas tell Hart. OGI

Paisie: Dutch Fleet Foreshadows Structural Shifts

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

In last month's article, we put forth our reference outlook for 2024 with respect to the crude oil market, which, in summary, includes the following:

- Based on the economic outlook coupled with the outlook for alternative fuels and EVs, we are expecting oil demand to increase at a moderate pace, in the order of 1.30 MMbbl/d, and despite the struggles of China, Asia-Pacific will represent the bulk of increased demand.
- From a supply perspective, we are expecting that OPEC+ will attempt to be proactive in managing supply to support oil prices. We also think that OPEC+ still has the ability to influence the oil market, despite the growth in non-OPEC supply. However, to convince oil traders to adopt a more bullish sentiment, OPEC+ will need to adhere closely to its supply targets and be willing to make additional cuts, if needed, to support oil prices.
- We are forecasting that the price of Brent crude will increase during the second and third quarters of this year and move toward $90/bbl.

We are still holding to this outlook as our reference case, even though, as we highlighted last month, there are upside and downside risks to the forecast. It is still possible that the geopolitical situation could spin out of control and result in oil prices spiking. Alternatively, oil prices could tumble if growth in oil demand disappoints or if OPEC+ loses control of the oil supply.

In addition to our ongoing assessment of the short-term dynamics, we have recently updated our long-term outlook pertaining to hydrocarbons, including the production outlook for crude oil, natural gas and NGLs. Our reference forecast considers the macro-level factors, as well as the structural changes, including the evolution of the vehicle sector. An example of the extent of the change is indicated by the forecast of Netherlands' vehicle fleet.

The light-duty vehicle (LDV) ownership level in Netherlands stood at 587.3 vehicles per 1,000 people in 2022, which is similar to most developed markets. By 2030, the Netherlands' ownership ratio grows to 610.2 before reaching 643 by 2050. LDV fleet growth is thus expected to outpace population growth in the Netherlands over the forecast through 2030. Gasoline vehicles currently make up the largest portion of the Dutch LDV fleet, although diesel vehicles still covered about 19.3% of the fleet in 2022.

Thanks to the exponential growth in battery electric vehicle (BEV) sales experienced in recent years, the domestic BEV fleet reached a share of 3.7% in 2022. In the outlook to 2030, the BEV fleet is expected to see a four-fold growth to account for 16.7% of the national fleet, significantly outpacing the broader regional 2030 BEV penetration of 7.7% in Europe. In the longer term, and as aging internal combustion engine (ICE) vehicles are gradually retired, the BEV fleet in the Netherlands could reach a market share of 75.7% by 2050.

> *"We are expecting oil demand to increase at a moderate pace, in the order of 1.3 MMbbl/d."*

Conventional vehicles in the LDV fleet face the greatest displacement threat from BEVs over the 2022-2030 period, with these vehicles seeing growth of 1.44 million units. As growth accelerates over the later part of the forecast, BEVs are projected to increase by another 6.89 million units in the 2030-2050 period. Besides BEVs, other low-emissions alternative powertrains also see significant growth in Netherlands, although their penetration remains more limited overall.

In particular, conventional and plug-in hybrids are projected to see a strong increase in their vehicle pool in the medium term, although they will be increasingly displaced by BEVs in the longer term. After their relatively strong growth in the early 2020s, zero-emission vehicle (ZEV) sales mandates are likely to constrain a stronger growth of plug-in hybrids (PHEVs), which are expected to reach a more moderate market share of 6.2% by 2030. Despite multiple efforts to boost sales by expanding refueling infrastructure, hydrogen-powered vehicles are not expected to have a significant impact on the domestic LDV fleet, remaining uncompetitive against BEVs.

The expanding role of BEVs will be supported by the development of associated supply chains, as indicated by our forecast of global EV battery production capacity. OGI

▸ GLOBAL ENERGY

Pitts: Battle Brewing Between US Supermajors in South America

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The two largest oil and gas companies in the U.S.—Exxon Mobil and Chevron—are engaged in a battle of the behemoths for a tantalizing South American prize: a 30% interest in Guyana's Stabroek Block.

The asset is currently owned by Hess Corp., which Chevron agreed to buy in October for a cool $53 billion. The theory goes that while Hess certainly has attractive assets in the Bakken, Stabroek was the selling point.

Exxon and Chevron are already producing in the region, but given the industry appetite for offshore international drilling, Guyana is largely viewed as the "next big thing."

The excitement incited by boxing ringmaster Michael Buffer's iconic "Let's get ready to rumble!" accelerates when you consider the epic scenarios that are set up here: the No. 1 and No. 2 oil companies in the U.S. prepare to duke it out; it's the wildcatting Texas oilmen matched up against the (perceived) fancy folks who are California dreamin'; the squaring off of two extremely successful engineers for the bragging rights of their rival alma maters with Woods representing Texas A&M University and Wirth's University of Colorado.

Exxon took the initial punch, pushing forward on its front foot with both fists raised to defend its right of first refusal (ROFR) for the Hess interest. A quick glance of the regulatory filings that are quickly piling up suggests Chevron won't back down.

Exxon is operator in the Stabroek consortium with a 45% interest; the rest includes Hess' 30% and CNOOC's 25%. Recoverable resources are estimated at more than 11 Bboe.

Production, which started in December 2019, is already slightly over 600,000 bbl/d from three floating production storage and offloading (FPSO) units. Exxon and Hess estimate production from six FPSOs will exceed 1.2 MMbbl/d by the end of 2027. Both say 10 FPSOs will be needed to develop the current resources.

But that may not be the half of it.

Top officials from the government of Guyana say that based on analysts' reports and comments, they believe the resource in Stabroek is easily twice current estimates.

A question for the lawyers with both international oil companies relates to the ROFR details in the original joint operating agreement for Stabroek.

The Stabroek JOA ROFR provision gives the partners a right to buy the participating interest in the block held by a partner but only after, and conditioned on, the closing of such transaction.

To date, Chevron and Hess continue to argue the ROFR doesn't apply to their planned merger while Exxon and CNOOC believe the ROFR applies to the merger. All four companies continue in discussions related to the ROFR, but there is the possibility that either Hess or Chevron could elect for Hess' Guyana affiliate to pursue arbitration to resolve the matter.

One needs to look at what's really at stake for Chevron, Hess and Exxon as it relates to Guyana.

At stake for Chevron is losing a foothold in one of Latin America's hottest exploration plays, which is Guyana and not Brazil, at least not any more since the latter country is now in the development stages of recent discoveries offshore.

A Chevron position in Guyana would give the company an enviable position in northern South America which could span from Colombia, Venezuela and Guyana to Suriname.

For Hess, it's easy. Exxon's surprise blow is ruining John B. Hess' "exit strategy." The Hess CEPP is eying potential payments and benefits in connection with the Chevron-Hess merger of around $56 million as part of his compensation package spelled out in Chevron's S-4.

At stake for Exxon is losing an opportunity to grab an additional 30% interest in Stabroek and all the upside that entails. Maybe that uptick is only 15%, assuming CNOOC took the other half by exercising its ROFR.

Could Exxon make a counter offer to Hess? That can't be ruled out, but it would likely require a premium above a premium to stick. Reuters has reported that Guyana's Vice President Bharrat Jagdeo isn't against the idea. Analysts say everyone is waiting to see what Exxon will do next, which is hard to guess.

Maybe this is Exxon's in-the-ring poker face as it tries to gain even more leverage—sorry, revenue—in Guyana. Maybe that's the $53 billion question. OGI

Around the World

North America

ConocoPhillips CEO Lance Comments on US M&A Environment

ConocoPhillips Chairman and CEO Ryan Lance said more M&A deals are likely to come as part of needed consolidation. The Wall Street Journal reported in February that ConocoPhillips was a bidder for Endeavor Energy, which ultimately reached a $26 billion agreement with Diamondback Energy.

Lance made the comments during the company's fourth-quarter 2023 webcast with analysts. He said that ConocoPhillips' deal making approach hasn't changed.

"Our approach is we think about cost of supply. We think about the framework that we've laid out to the market over the last four or five years, and that's how we've executed some of our M&A activities. So again, it's got to fit that financial framework, how we think about mid-cycle price. It's got to make our 10-year plan better."

The company's M&A would also be driven by a diverse asset base, he said.

"So, we've got to see a way to make that plan better through any inorganic M&A. And then finally, we've got to see a way to make the asset better, and that's really dictated how we've approached M&A over the last number of years. As we think about it going forward, that approach is consistent," Lance said.

"Our approach is we think about cost of supply. We think about the framework that we've laid out to the market over the last four or five years, and that's how we've executed some of our M&A activities. So again, it's got to fit that financial framework, how we think about mid-cycle price. It's got to make our 10-year plan better,"

–**Ryan Lance**, ***chairman and CEO, ConocoPhillips***

BPX Shale Production Rising

BPX, which comprises BP plc's onshore oil and gas operations in the Lower 48, continues to boost production. The company produced 406,000 boe/d in the fourth quarter of 2023, up 28% compared to 318,000 boe/d in fourth quarter of 2022.

For 2023, production averaged 366,000 boe/d with BPX averaging 11 operated rigs, up 13%. By comparison, in 2022 production averaged 325,000 boe/d with 9 rigs. In 2023, BPX ran five rigs in the Permian Basin and three each in the Eagle Ford and Haynesville shales.

And, BPX intends to bring online two new central processing facilities in the Permian: Checkmate and Crossroads.

"Checkmate is tracking well to be online this year, and the final one comes online next year," BP CFO Kate Thomson said during the company's fourth-quarter webcast with analysts.

Thomson said BPX was spending about $500 million to complete the infrastructure buildout.

"And then we'll be able to take that capital and use it to put into our effective production drilling activity, rather than using it to carry on completing the infrastructure," Thomson said. "So that's kind of the way to hold it, is we're going to be able to fill those gathering units and then we're going to be able to redirect that capital to more productive uses as well."

Shell Brings Deepwater Rydberg Subsea Tieback Onstream

SHELL

The Rydberg subsea tieback is producing to the Appomattox semisubmersible through a single insulated 12-mile flowline.

Shell subsidiary Shell Offshore started production at Rydberg, a subsea tieback to its operated Appomattox production hub in the Gulf of Mexico.

Rydberg, located in the Mississippi Canyon Block 525 area, is expected to produce 16,000 boe/d at peak, Shell said in February.

Rydberg is in about 7,450 ft water depth and holds an estimated 38 MMboe of recoverable resources. While Rydberg was originally discovered in 2014, Shell didn't reach final investment decision on the project until 2022.

Shell developed the field using two production wells that produce through a single insulated 12-mile flowline to Appomattox, along with a dynamic umbilical.

The Appomattox production semisumbersible went online in 2019.

"Rydberg will further boost production in the Norphlet Corridor at Appomattox, which is consistently one of our highest producing assets," Rich Howe, Shell deepwater executive vice president, said in a press release.

Shell operates the leases containing the Rydberg discovery with 80% interest on behalf of partner CNOOC with 20% interest.

Shell operates Appomattox with 79% interest on behalf of CNOOC with 21% interest.

Ecopetrol, Occidental Permian JV Generating Positive Results

Ecopetrol SA's joint venture with Occidental Petroleum in the Permian Basin continues to generate outstanding operational and financial results for the Colombian state-owned energy giant.

Ecopetrol's net production from the JV averaged 66,400 boe/d in 2023, up 76% compared to 2022, while EBITDA was

Ecopetrol Rodeo JV with Occidental in the Permian

	2019	2022	2023	23 v 22 Chg	23 v 19 Chg
Net production, before royalities (boe/d)	900	37,800	66,400	76%	7,278%
EBITDA ($ millions)	$1.4	$644.0	$799.0	24%	56,971%
EBITDA margin (%)	69.8%	87.0%	88.0%	1%	26%
OPEX ($/boe)	$4.50	$3.80	$5.40	42%	20%

SOURCE: ECOPETROL

$799 million in 2023, up 24% compared to 2022. Ecopetrol said gross production from the JV reached a record of 103,000 boe/d on Dec. 9.

The so-called Rodeo JV was officially launched in 2019 and Occidental owns 51%, while Ecopetrol owns the remaining 49%.

Ecopetrol's overall production, which comes mainly from Colombia, was 737,000 boe/d in 2023 compared to 709,000 boe/d in 2022 and 724,000 boe/d in 2019, the company reported in its fourth-quarter 2023 financial press release.

Investors Purchase Exxon's Ursa Interest

Esperanza Capital Partners and Andros Capital Partners LLC are buying Exxon's Ursa and Princess Field assets in the deepwater Gulf of Mexico (GoM), Andros announced in February

The companies are also forming a strategic joint venture focused on acquiring and developing upstream and infrastructure assets in the deepwater GoM.

The acquisition of Exxon Mobil's 15.96% interest in Ursa includes current production of about 8,500 boe/d net to Exxon's interest as well as associated infrastructure. Shell operates Ursa.

Coast Guard Confirms Amplify's Platform Elly Unrelated to California Oil Sheen

Amplify Energy Corp. said it's continuing to monitor the status of the oil sheen reported in March off the coast of Huntington Beach, Calif.

The U.S. Coast Guard said in a March press release that the spill appeared to be about 2 ½ miles long.

While Amplify reported a minor discharge of produced water from Platform Elly, Amplify remains confident that the sheen is not related to its operations.

The Coast Guard said that "the characteristics of the produced water from Platform Elly do not align with what was observed from the sheen. Currently, we do not believe the sheen and the discharge are related."

The Coast Guard also noted that offshore recovery assets would be demobilized following an overflight that "did not observe any sheen offshore."

Amplify's Beta field operations in Southern California and development program have not been disrupted.

US Expected to Supply 30% of LNG Demand by 2030

The U.S. will meet about 30% of total global LNG demand by 2030, although reliance on four key Lower 48 basins could create midstream constraints, Shell revealed in its "Shell LNG Outlook 2024."

The London-based company warned that the global gas market is increasingly exposed to U.S. risks–particularly a reliance on U.S.-based liquefaction plants that source LNG feed gas from four basins: Appalachia (which includes the Marcellus and Utica shales), the Permian and Haynesville Shale in the U.S. and the Montney in Canada, according to Shell's February annual industry update.

The U.S. emerged as the world's largest LNG exporter in 2023, shipping 86 million tonnes (MMtonne). The second largest exporter was Australia, followed by Qatar, Russia and Malaysia.

However, U.S. LNG exporters have been plagued recently by outages at Freeport LNG and offtake issues related to Venture Global LNG, as well as the recent Biden administration's pause on approving U.S. LNG exports.

Shell said global LNG trade reached 404 MMtonne in 2023, up 2% compared to 397 MMtonne in 2022, with tight LNG supplies constraining growth while maintaining prices and price volatility above historic averages.

Despite a well-supplied global market in 2023, the lack of Russian pipeline gas supply to Europe–and a limited amount of LNG supply growth over the last year–means that the global gas market remains structurally tight, Shell said.

In 2024, U.S. supply and Asian demand will lead LNG market growth. Europe will also rely on LNG to meet its natural gas supply needs, despite a consensus for falling gas demand.

Deals with the Qataris and Americans dominate long-term contracting as Brent and Henry Hub indexation underscores three commercial structures: Henry Hub prices indexed LNG, oil price indexed LNG and spot price LNG, according to Shell.

Despite LNG Permitting Risks, Cheniere Expansions Continue

In 2023, the U.S. exported 86 million tonnes per annum (mtpa) of LNG. Cheniere Energy expects the domestic market will be the first to surpass the 200 mtpa mark by 2040.

For the LNG and natural gas industry, the potential snag is the much-maligned decision by U.S. President Joe Biden to pause on approvals related to pending LNG projects.

But Cheniere executives, speaking during a February webcast, are undaunted, although a prolonged delay in resuming approvals could halt planned expansions at the company's Corpus Christi, Texas, facility, potentially keeping millions of tonnes of LNG off the market. The company's current plans could add 33 mtpa of liquefaction capacity.

"We are confident that Cheniere will be able to navigate whatever comes out of the Department of Energy (DOE) and continue to prosecute expansions on our timeline," Cheniere CCO Anatol Feygin said.

The company will deal with whatever comes from the U.S. Department of Energy's review of the export permitting process, including its assessment of LNG's effects on the climate, Feygin said.

"A lot of the things that we have been doing for the last four years or five years on our life-cycle assessment and on our environmental science and tracking the emissions profiles, providing the cargo emission tags, are all things that are new in the equation," Feygin said. "And then, of course, just the quantum of LNG exports from the U.S. and gas dedicated to LNG exports is a new component in this equation."

Biden's pause, announced in late January, calls for an assessment of LNG export deals with countries that do not have a free-trade agreement with the U.S. Countries with an agreement are already approved by current law. The order impacts all LNG export projects yet to receive approval.

Cheniere continues to view long-term LNG fundamentals as robust and supportive of approximately 200 mtpa of new capacity expected by 2040, the company said in its quarterly financials. OGI

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2024				
MCE Deepwater Development	April 9-11	Amsterdam	Hôtel Mövenpick Amsterdam City Centre	mcedd.com
International Partnering Forum 2024	April 22-25	New Orleans	Ernest N. Morial Convention Center	oceantic.org
World Energy Conference	April 22-25	Rotterdam, Netherlands	Rotterdam Ahoy	worldenergycongress.org
2024 Women's Energy Network Conference	April 28-30	Atlanta	Atlanta Marriott Marquis	womensenergynetwork.org
2024 AGA Operations Conference & Spring Committee Meetings	April 28-May 2	Seattle	Hyatt Regency Seattle	aga.org
Offshore Technology Conference	May 6-9	Houston	NRG Park	2024.otcnet.org
SUPER DUG	**May 15-17**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**hartenergy.com/events**
IADC Drilling Onshore Conference & Exhibition	May 16	Houston	Hyatt Regency Houston West	iadc.org
10th Mexico Gas Summit	May 16-17	San Antonio	St. Anthony Hotel	mexicogassummit.com
2024 AGA Financial Forum	May 18-21	Palm Desert, Calif.	JW Marriott Desert Springs Resort and Spa	aga.org
ASES Solar 2024	May 20-23	Washington, D.C.	GW University	ases.org
Louisiana Energy Conference	May 28-30	New Orleans	The Ritz-Carlton	louisianaenergyconference.com
Global Energy Show Technical Conference	June 11-13	Calgary, Canada	BMO Centre at Stampede Park	globalenergyshow.com
URTeC	June 17-19	Houston	George R. Brown Conv. Ctr.	urtec.org/2024
IPAA Leaders in Industry Luncheon	June 18	Houston	Petroleum Club of Houston	ipaa.org
CIPA 2024 Annual Meeting	June 20-23	San Diego	TBD	cipa.org
Carbon Management Americas Conference	June 25-27	Denver	The Ritz-Carlton	commodityinsights.spglobal.com
IAEE International Conference	June 25-28	Istanbul, Turkey	Boğaziçi Üniversitesi	iaee2024.org.tr
SPE Artificial Lift Conference and Exhibition	Aug. 20-22	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
IMAGE	Aug. 25-30	Houston	George R. Brown Conv. Ctr.	aapg.org
New Energies Summit	**Aug. 27-28**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
IADC Advanced Rig Technology	Aug. 27-28	Austin, Texas	Hyatt Regency Hotel	iadc.org
Forty Under 40 Awards	**Sept. 6**	**Houston**	**TBD**	**hartenergy.com/events**
Gastech	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
SPE/ATCE	Sept. 23-25	New Orleans	Ernest N. Morial Convention Center	atce.org
Energy Capital Conference	**Sept. 25**	**Dallas**	**TBD**	**hartenergy.com/events**
A&D Strategies and Opportunities Conference	**Sept. 26**	**Dallas**	**TBD**	**hartenergy.com/events**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-TIPRO Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

‘Brownsville, We Have LNG Liftoff’

The world’s attention is on the far south Texas Gulf Coast, watching Starship liftoffs while waiting for new, secure LNG supply.

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As SpaceX was igniting its first successfully launched Starship (although the vehicle was lost upon reentry) at Boca Chica, Texas, a westerly neighbor along the 17-mile Brownsville ship Channel was putting the final touches on a press release.

Starship broke the sound barrier that morning. (And the live feed didn’t break X, much to the X team’s relief.)

A couple of hours later, a SpaceX Starbase neighbor, Glenfarne Energy Transition, announced it had broken through a critical stage in its Texas LNG project.

Enough banks have expressed interest in financing the 4 mtpa (192 Bcf/year) plant’s construction, thus Glenfarne can “move to the execution phase,” it reported.

While the White House’s “pause” on approving more LNG export projects has confounded allies, putting a de facto cap on the number of plants and their already permitted expansions, it is fast-tracking uptake for those already having permits.

Boom.

Boom.

First LNG exports from the Brownsville plant, Texas LNG, are expected in 2028. The banks that are behind the next phase–project execution–are well familiar with LNG developments, “having participated in approximately $44 billion of project finance debt to the U.S. LNG sector alone over the last 24 months,” Glenfarne reported.

Some of the facility’s end-product will be 0.5 mtpa (24 Bcf/year) processed for an EQT Corp. customer.

Another neighbor of Starbase is the Rio Grande LNG plant, owned by NextDecade, and underway along the ship channel. Already under construction, it will ship 4.7 mtpa (226 Bcf/year).

Each of the projects will remove more Eagle Ford and Permian associated gas out of the Henry Hub market, providing some price relief to Haynesville and Appalachian producers at the Louisiana hub.

Also expected to take more Permian gas out of the Gulf Coast market are new Pacific Coast export plants in Mexico. One of these, Energia Costa Azul LNG in Baja, will ship an average of 0.4 Bcf/d and is already under construction. A planned expansion will send out an additional 1.6 Bcf/d.

Sempra Infrastructure is the owner/developer. The site also hosts import infrastructure, which found lack of demand after the advent of U.S. shale gas development this century.

SHUTTERSTOCK

Starship SN15 and SN16 at SpaceX Starbase in Boca Chica, Texas.

Three additional export facilities on Mexico’s West Coast are proposed: Saguaro Energía LNG, Salina Cruz LNG and Vista Pacifico LNG, according to the U.S. Energy Information Administration (EIA).

Houston-based private equity firm Quantum Energy Partners has an interest in the Saguaro project, which is also known as Mexico Pacific LNG. The developer signed a third contract in January with Exxon Mobil. The newest one is for volumes from a third train. And Exxon Mobil took an option for an additional 48 Bcf/year in a fourth train.

“These [western Mexico] projects would use relatively low-cost natural gas imported from the United States for LNG exports to Asian markets,” the EIA reported.

Including Canada’s LNG export projects underway, projections are that North American capacity will be 24.3 Bcf/d by 2027, the EIA estimates.

From the U.S., exports are some 14 Bcf/d of LNG currently and, via pipe, some 7 Bcf/d to Mexico.

Meanwhile, some of the largest U.S. gas producers–particularly EQT Corp. and Chesapeake Energy–are curtailing output as the Henry Hub price was below $2/MMBtu in the first quarter.

The gas-directed rig count was 115 in March, down from 153 a year earlier, according to J.P. Morgan Securities data that cites Bloomberg Finance and Baker Hughes. Cuts largely came from the Haynesville, falling from 67 rigs in mid-March 2023 to 37 this year, Arun Jayaram, analyst for J.P. Morgan, reported March 15.

“We believe the impact of the 2024 production curtailments and activity reductions should help improve the outlook for 2025 natural gas balances.” OGI