Oil and Gas Investor

MARKET MONETIZATION

Private Equity Exits Hit Five-Year High

STRIKING 'GOLDILOCKS'

Permian Deal Prices Not Too Low, Not Too High

'UNLEASH US LNG'

EQT Chief Toby Rice Solves for Emissions, Security and Accessibility

INSIDE:
SHALE OUTLOOK 2024

THE OGI INTERVIEW

A TIME OF TRANSITION

Pioneer Natural Resources New CEO Rich Dealy on Merging with Exxon Mobil, Managing Expectations for US Energy

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EQUITY PRIVATE PLACEMENT	STRATEGIC PARTNERSHIP	ASSET ACQUISITION	EQUITY PRIVATE PLACEMENT	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Sole Placement Agent	Financial Advisor	Sole Placement Agent	Sole Placement Agent

UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	$350 MILLION
VIKING MINERALS	VIKING MINERALS	**Shadow Creek Minerals**	NOBLE ROYALTIES, INC.	VIPER Energy Partners
ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	FOLLOW ON OFFERING
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Underwriter

$66 MILLION	$104 MILLION	$53 MILLION	UNDISCLOSED	UNDISCLOSED
KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS	**Multi-Basin Minerals Company**	**Multi-Basin Minerals Company**
FOLLOW ON OFFERING	INITIAL PUBLIC OFFERING	FOLLOW-ON OFFERING	ASSET DIVESTITURE	VALUATION ANALYSIS
Underwriter	Underwriter	Underwriter	Financial Advisor	Financial Advisor

MINERALS & ROYALTIES STATISTICS

~$2.4 Billion
Aggregate Transaction Volume Since 2017

15 Closed Transactions Since 2017

PRIVATE FINANCING STATISTICS

~$11.7 Billion
Aggregate Capital Raised Since 2009

37 Closed Transactions since 2009

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COMMENTARY

SPECIAL SECTION

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COMMENTARY

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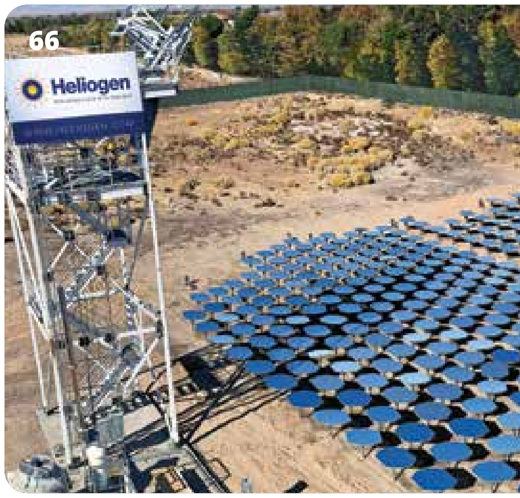

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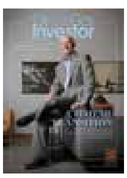
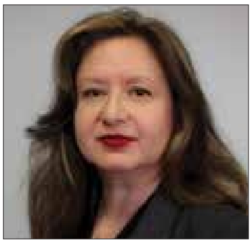


ABOUT THE COVER:
Tom Fox captured this photo of Rich Dealy, CEO of Pioneer Natural Resources, in the company's Irving, Texas, headquarters.

Cause for Consolidation



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Oil and gas producers continue to heed shareholders' insistence on capital discipline. And while the austerity of recent years could be as much a function of the energy transition and supply impacts on price dynamics, it has brought a degree of stability to price and routine cash returns.

U.S. producers largely pledged to keep production growth around 5%. In 2022, deal-making was uneven at best, and described as chaotic in some instances. A slow first half of the year gave way to a second half in which large public U.S. E&Ps struck six megadeals worth a combined $14.6 billion.

The discipline has paid off for the biggest players. Producers generated record profits in 2022—the haul of some $200 billion doubled the sector's previous 12-month returns—and E&Ps returned much of that cash to investors via multibillion-dollar share repurchases and robust dividends.

It was only a matter of time before the industry would chafe at long-term restraint and finally scratch that itch to grow.

Bernstein analyst Bob Brackett said in December 2022 that during the next 12 months, M&A could "pivot from shale bolt-ons to something much grander" as supermajors pull the trigger and target independent shale companies with high-quality inventory.

Brackett named key candidates as Hess Corp., EOG Resources, ConocoPhillips, APA Corp., Devon Energy, Pioneer Natural Resources and Kosmos Energy.

Since October, Exxon Mobil bought Pioneer and Chevron announced its acquisition of Hess, but there still exists a strong but dwindling supply of healthy indies that are ripe for the picking.

Moreover, the shale industry is maturing. The specter of dwindling inventory is very real and likely the catalyst for billions of dollars in asset-level buys in 2023.

"You're constrained by investors. Your asset base is limited. But at the same time, nobody wants to just live status quo," one trusted source told me. "Everybody wants to do better next year than this year, grow results and add value."

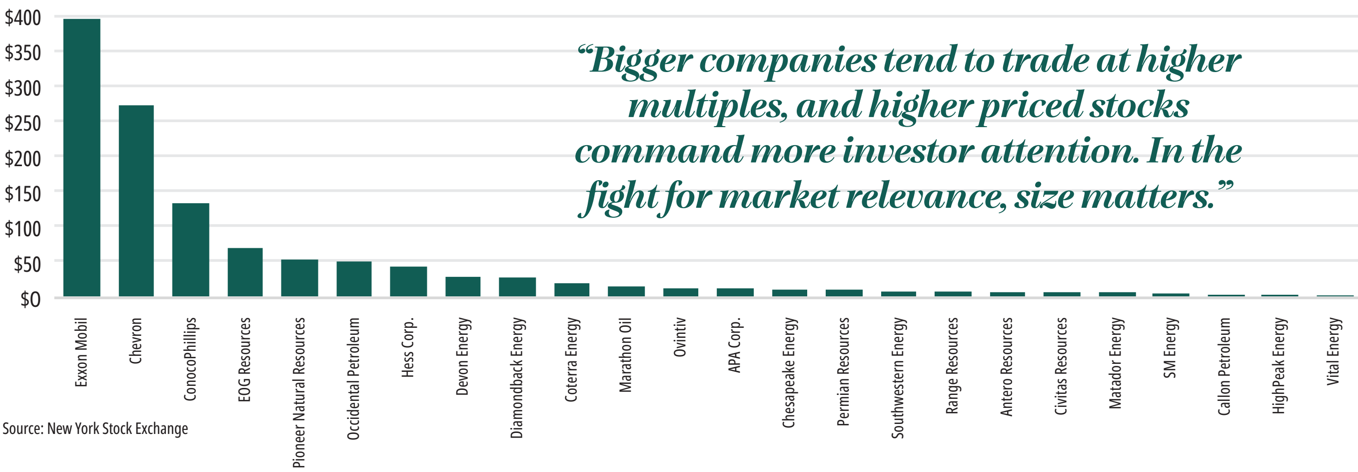
Bigger companies tend to trade at higher multiples, and higher priced stocks command more investor attention. In the fight for market relevance, size matters.

That said, a common lament is the public market's undervaluing of even individual E&Ps and the upstream sector as a whole. On a relative basis, that creates an inexpensive field for M&A and makes an easy case for old-fashioned competition: if you don't buy it now, someone else might beat you to it.

Corporate M&A in 2023 didn't just take out top public independents. Occidental Petroleum's acquisition of CrownRock took a key private Permian Basin producer out of play—and likely boosted the odds that its rival Permian private Endeavor Energy Resources can command the $30 billion price that analysts have floated in recent months. Similarly, when Exxon won the prized Permian player with its Pioneer acquisition, Diamondback's asking price as the biggest Permian pure play probably increased.

"Before all is said and done, my expectation is that [producers] are going to have to come out of basin. That means you are not going to be able to build a $100 billion company in the Permian," an investor told me. "If you're shooting for scale, you're just going to have to be a bigger, more diversified business. And I think the market's going to support that because, right now, they'd rather you grow your earnings with scale via consolidation than see you grow your earnings by being a 25% year-over-year grower on the volume side." OGI

Top producers by market capitalization ($ billions)



Source: New York Stock Exchange

The Future—Believe It or Not

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Attend an oil and gas conference and you'll inevitably hear this mantra: "Oil and gas isn't going anywhere."

It's meant to be an affirmation that fossil fuels will continue to be needed for a long time, not a complaint that pipelines have conked out.

Fun fact: It's true. Oil and gas will continue to be essential for years to come.

Not-so-fun fact: Your oil and gas company might not be around for it.

"Many producers say they will be the ones to keep producing throughout transitions and beyond," the International Energy Agency (IEA) said in a recent special report on the oil industry in net-zero transitions. "They cannot all be right."

Survival is never guaranteed in a free market, of course. For that matter, it's not guaranteed in a controlled one, either.

And while a company the size of ConocoPhillips ($132 billion market capitalization) can afford to double down on its embrace of fossil fuels and be the last one standing in the oil patch, others may face a harsher reality if they choose that strategy. Or not.

The problem is getting a realistic handle on what is to come, and that's not easy.

Mark Finley, fellow in global energy and oil at Rice University's Baker Institute for Public Policy, likes to begin his presentations by quoting Yogi Berra, legendary catcher for the New York Yankees: "It's difficult to make predictions, especially about the future."

There is always a degree of aspiration behind outlooks, Finley told me a few months ago. "You have to consider that when you look at the person producing the forecast."

Finley, former senior U.S. economist for BP, has spent a chunk of his career as that person. He led production of the "BP Statistical Review of World Energy" for 12 years, was responsible for short- and long-term oil market analysis at BP, and contributed key oil market analysis for senior U.S. officials during the Gulf War as an analyst for the CIA.

For the past few decades, folks who have needed to know what's happening next have saved (or could have saved) a lot of time in meetings by simply asking Finley. So, I asked Finley.

My questions were about the trajectory of oil prices, but he also touched on the nature of outlooks, i.e., they are written by real people.

Case in point: A few years ago, I watched Fatih Birol, executive director of the IEA, swat aside a question from a luncheon attendee who didn't much care for the numbers he presented on oil and gas production.

"I cannot change the data," Birol said. "It's not an expectation. It is what has happened."

Seems straightforward enough, but we all know that statistics are in the eye of the beholder.

"How much of [the analysis] is just objective numbers, and how much is what they want to happen?" Finley asked. "I mean, obviously OPEC would want there to be more oil consumption."

In the case of the IEA, Birol presents scenarios of what would need to happen to achieve net-zero climate goals, given the stated goal of the Paris Agreement of achieving no more than a 1.5 C rise in global temperature by 2050.

Topping the list: oil and gas companies would need to cut emissions from operations by 60% by 2030 and arrive at near-zero emissions intensity by the early 2040s. That's not a prediction of what the industry will do, or a dictate of what it must do; it's what the IEA calculates is a necessary step by the industry to keep the world on track to limit global warming.

But back to survival. "The volatility of fossil fuel prices means that revenues could fluctuate from year to year—but the bottom line is that oil and gas becomes a less profitable and a riskier business as net zero transitions accelerate."

The IEA's assessment isn't all negative.

"Some 30% of the energy consumed in a net zero energy system in 2050 comes from low-emissions fuels and technologies that could benefit from the skills and resources of the oil and gas industry," the agency says.

It comes down to oil and gas companies either bumping up annual investment in clean energy projects from $20 billion (2.5% of capital spending) to $400 billion (50%)—on top of Scope 1 and 2 emission reduction investments—or sticking with fossil fuels and preparing to wind down operations over time.

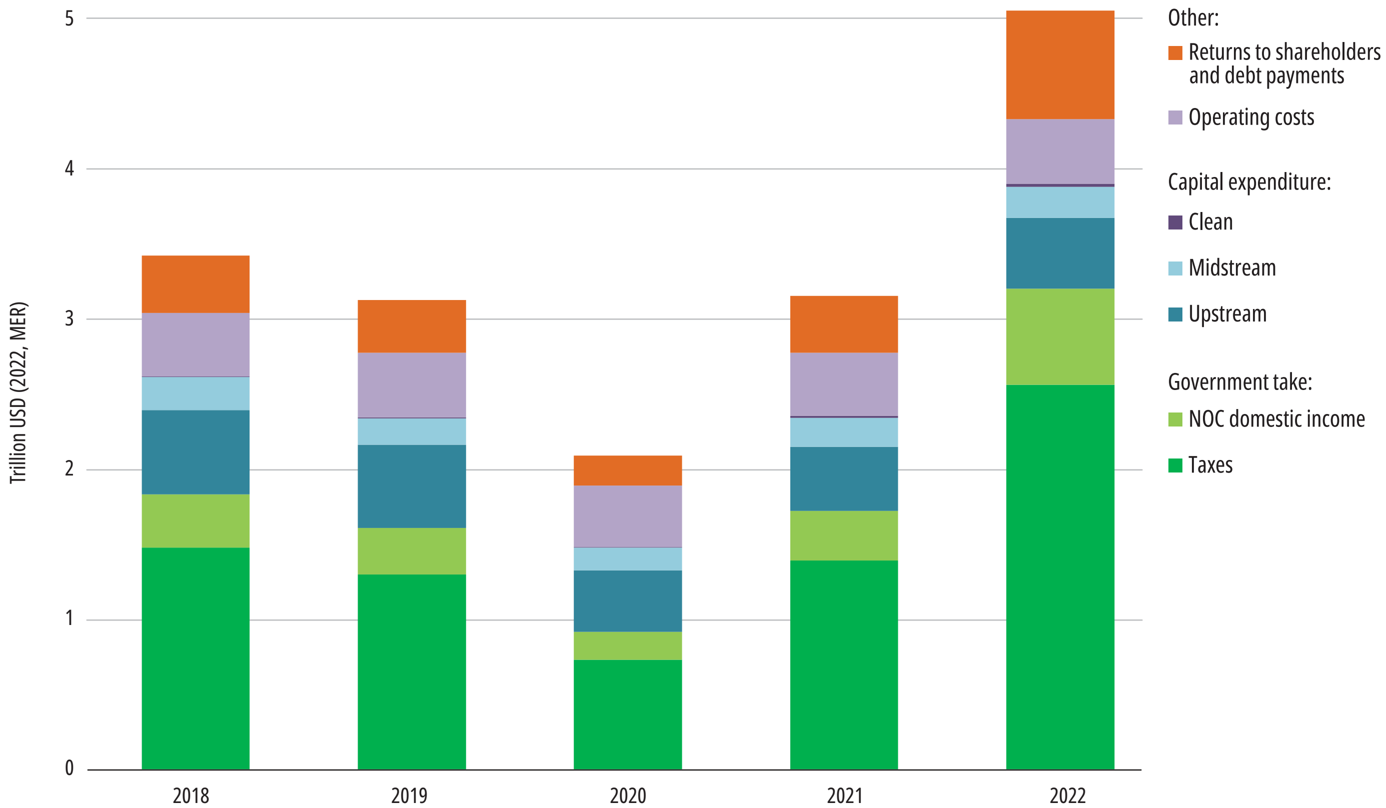
That's a stark choice. Is the IEA correct that a moment of truth is fast approaching? Realistically, the choices to be made are probably going to be somewhere in the middle. The IEA's scenarios are based on the 195 signers of the Paris Agreement actually adhering to the agreement. The likelihood of that is … c'mon, not a chance.

Which brings us to what happens next.

"The baseline expectation should be for a volatile and bumpy ride," says the IEA.

Agreed. OGI

Use of revenue by the oil and gas industry
(2018-2022)



Source: IEA

Hirs: Meet the Old Boss ... 2024

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The 2024 presidential election will have a big impact on oil and gas, but perhaps not what you expect. Energy issues are on the second page of voter concerns behind the economy, abortion, immigration, Social Security, aging candidates and the fate of democracy. The oil and gas industry's best strategy is to support both sides.

What would President Joe Biden's reelection mean?

Oil and gas production under Biden has reached unprecedented highs, at least in part because of his focus on keeping fuel prices down as he runs for a second term, as well as efforts to limit the impact of sanctions on Russia. But there's no guarantee that would continue in a second term. In fact, the industry should expect an increased focus on climate policies and a stronger push to move away from fossil fuels.

Upstream, access to federal lands, onshore and offshore, will be reduced. Midstream, the status quo is about the best that can be expected. Downstream, we can expect more hurdles to secure permits for refineries and petrochemical plants.

If Biden wins and gains Democratic majorities in both the House and Senate, expect a cap-and-trade system for limiting carbon emissions. It is the system most favored by thousands of bureaucrats and the cottage industry it would spawn. It would be better for producers and consumers to have a carbon tax at the wellhead, port-of-entry or coal mine. Even Congress would benefit with another revenue stream to fund pet projects.

With Donald Trump, the question is: could his second act be better than his first?

The first lesson of the Trump presidency was that access mattered. For energy, and oil and gas in particular, it is clear to see that his administration's decisions benefited those with direct access. Today, candidate Trump is chanting "Drill, baby, drill"—not music to the ears of the oil and gas industry because Trump's goal is lower prices, including at the gas pump. Trump lobbied Saudi Arabia for lower oil prices and, in exchange, gave the Saudis a pass for the 2018 murder of journalist Jamal Khashoggi.

Construction of five pipelines was pending when Trump took office. Only one, the Dakota Access Pipeline, was completed, reducing the cost of taking Bakken oil to market. The Keystone XL pipeline did not advance at all—much to the benefit of the Saudis, who continue to export heavy crude to the U.S.

Under Trump, the Constitution and Atlantic Coast natural gas pipelines were canceled. Producers who had planned on greater access to domestic and foreign markets via these pipelines were blocked. So, who benefited? Producers of associated gas in the Permian, Rockies and Dakotas. The Mountain Valley Pipeline project to take gas from West Virginia to the Virginia coast is progressing under the Biden administration.

The Trump administration limited offshore development even more than the Biden administration. The five-year Gulf of Mexico lease plan was not issued by the Trump administration, but subsequently by the Biden team. Trump prohibited oil and gas development off the west coast of Florida and all along the Atlantic seaboard. This protected onshore independents at the expense of the domestic majors.

Their differences in the electricity market are more subtle.

Both Trump and Biden are pursuing similar agendas for electricity markets, albeit from different angles. For decades, the nation has needed to harden its fragmented electric utility systems against extreme weather, keep up with demand growth and repair aging infrastructure. Because wind and solar development necessarily is in rural areas, a massive buildout of transmission must happen. Consumers will question the "free" part of renewable energy, but the transition is upon us.

Proponents of renewables and pro-volatility commodities traders have become unexpected bedfellows, accelerating the transition away from fossil fuels and nuclear power plants at the cost of reliability and much higher prices for consumers. Grid operators warn the public that electricity rationing, or "rolling blackouts," will be the new normal.

Republicans opt out of leadership by calling for "market solutions," a catchy phrase that really means "it hurts my brain to think about the executive leadership that is required." The fact that Republicans tout the Texas grid as a success shows either willful ignorance or enormous disrespect for the electorate. The North American Electric Reliability Corp. points out that the nation's other grids are not secure, either. It is a matter of national security.

Where does that leave us? Still on the second page of voters' concerns. Support both sides. Someone will win, and the only losers will be those on the sidelines. OGI

Belcher: What to Expect in 2024

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A new year brings with it new opportunities and new realities. In the world of energy, it is enormously complicated. In the U.S., the political situation makes it even trickier.

Here at home, amid a spate of retirements and an expulsion, the Republican grip on power in the U.S. House of Representatives has diminished as its majority has gotten even smaller, while Democrats cling to the narrowest of majorities in the U.S. Senate. These slim margins, while perhaps useful at times in preventing actions that would be adverse to the energy sector, also represent a constant threat to the passage of legislation that could be beneficial.

These tiny margins are resulting in gridlock. Given the current dynamics, where it will be hard enough just to pass a bill to keep the government open, no one should expect much in 2024 in the way of major legislation. Although Senate Energy and Natural Resources Committee Chairman Joe Manchin (D-W.Va.) and Ranking Member John Barrasso (R-Wyo.) remain hard at work on a bipartisan permitting bill, reaching consensus will be difficult. Furthermore, even if an agreement is made on the substance of such a bill, there will be few, if any, opportunities to find legislative vehicles for moving it.

Prior to their adjournment in December, House Republicans were focused on policy initiatives that would bring new life to oil and gas production on federal lands, while Democrats focused on legislative solutions that would address the nation's aging transmission grid. Both sides are seeking permitting reform, but focused on different sectors of the energy complex.

Additionally, 2024 is a presidential election year, which will further highlight major differences between the two parties on energy and environmental policy as they seek to lock up their respective political bases, further complicating prospects for the passage of energy legislation.

International events, such as the war in Ukraine, Russia's influence in OPEC and the Middle East, and China's global ambitions, are setting the stage in terms of energy's role in geopolitics. This tension, and the need to support our European allies with LNG supplies, helps make the case for the continued U.S. production of record amounts of oil and gas for the world.

At the same time, the commitments made by the United States and other countries at the COP28 climate conference, while falling short of phasing out fossil fuels altogether, attempt to set a course for significantly reducing consumption and production of oil and gas. This sets up a real conundrum for the U.S., which is setting records for oil and gas production, and LNG and crude oil exports. In fact, U.S. exports are countering the impacts of OPEC+ production cuts and are softening the effects of the cutoff of Russian natural gas supplies to Europe.

This creates a tricky situation for President Joe Biden, who is suffering from some of the lowest poll numbers of his career. How does he satisfy his climate-focused Democratic base voters and support continued U.S. oil and gas production and exports, which are thus far preventing a surge in oil and fuel prices?

Assuming that both parties' current front-runners are nominated, energy and climate can be expected to be dominant themes. Donald Trump will emphasize the need for U.S. "energy dominance" and focus on offshore and onshore federal leasing, pipeline permitting and regulatory reform. He, along with Republicans running for Congress, will also seek to paint Biden and the Democrats as weak on domestic production, and attack their climate and environmental policies as hurting U.S. production and helping U.S. adversaries like China, Russia and Iran. Expect Republicans to highlight decisions to nix the Keystone XL Pipeline and nearly eliminate oil and gas leasing in the Gulf of Mexico.

Biden will call for weaning the nation off of fossil energy, and focus on renewables, the benefits of the Inflation Reduction Act and being a global leader in addressing the climate crisis. However, Biden will need to be more nuanced in his approach to oil and gas, so as not to make himself vulnerable to attacks about high energy prices.

The most likely outcome is a close presidential election, won in a few key battleground states, and continued tight margins in the House and Senate. Along the way, we can expect a rigorous debate about oil and gas, and climate and the environment. One thing is for near certain, however: the state of the American economy and prices on goods and services in the months ahead will play a major role in the election outcome. OGI

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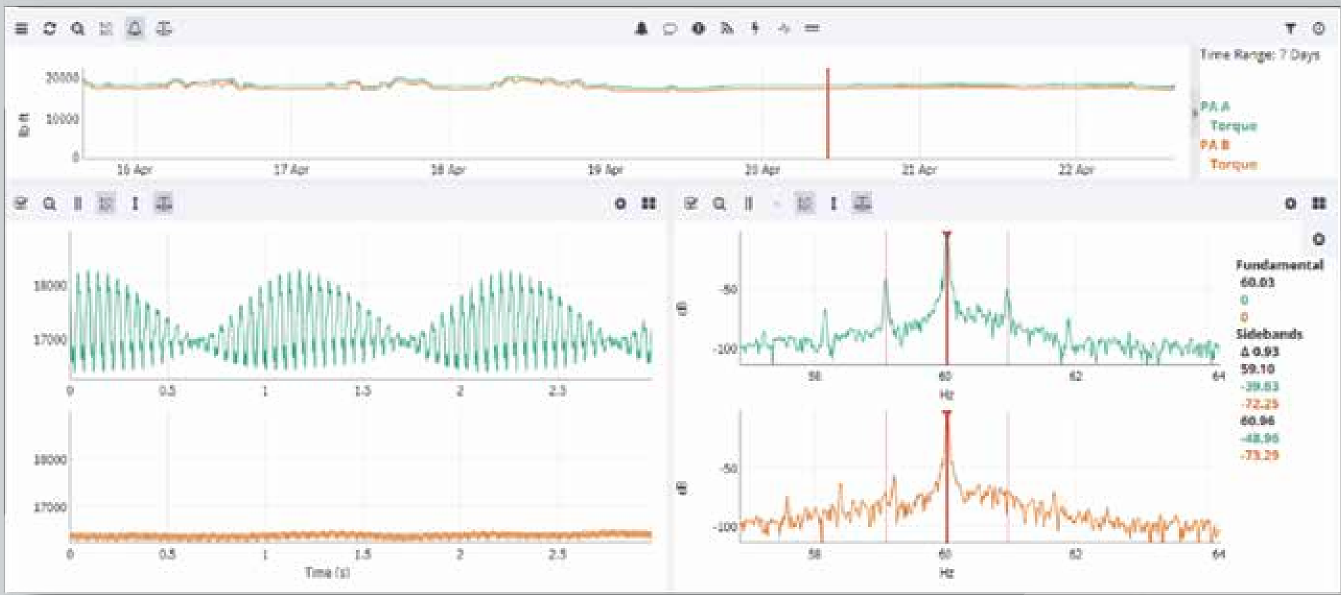

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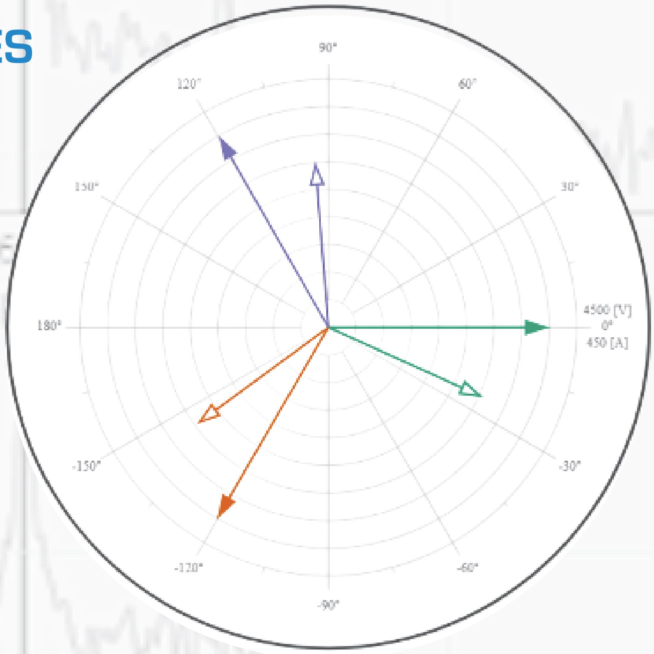

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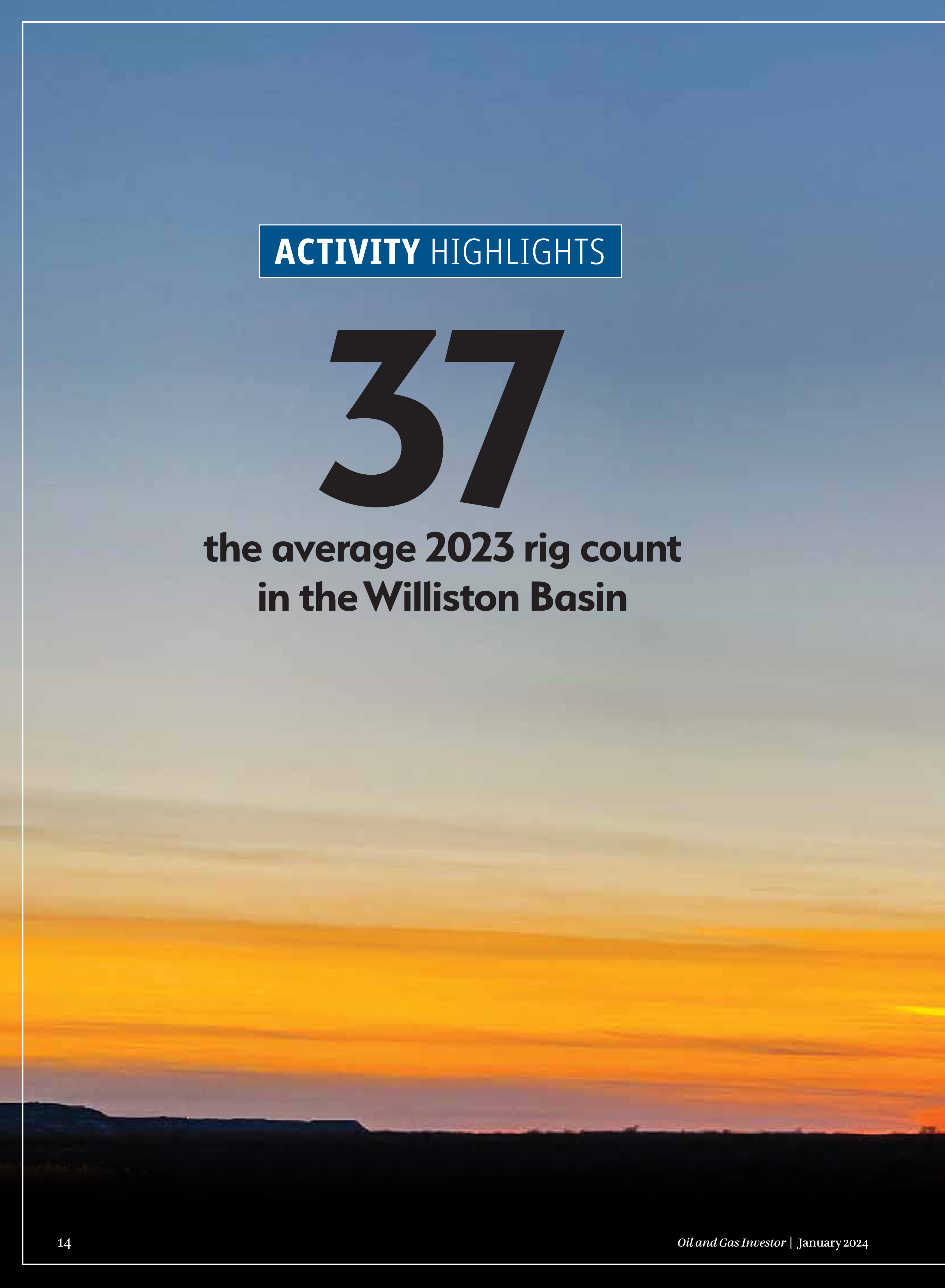

ACTIVITY HIGHLIGHTS

37

the average 2023 rig count in the Williston Basin

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FOCUS ON: WILLISTON BASIN

The Permian Basin might be the hottest play in the U.S., but E&Ps continue to source significant crude volumes from the Williston Basin.

The Williston, which sprawls across large swathes of North Dakota, South Dakota and Montana, is home to the Bakken Formation—the second-most productive shale basin behind the Permian, according to the U.S. Energy Information Administration (EIA)

Bakken output was expected to average 1.27 MMbbl/d during December 2023, per the EIA's most recent forecast.

The Williston Basin is home to some of the nation's most adept operators: the top producer over the past 12 months was Oklahoma City-based Continental Resources, which helped pioneer the Bakken Shale during the advent of the fracking revolution.

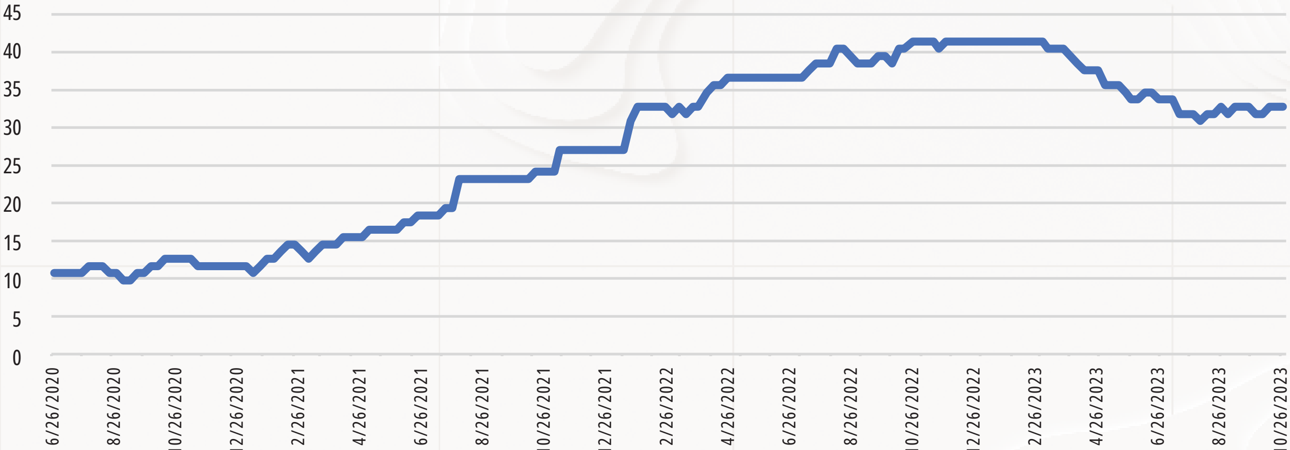
Exxon Mobil and Marathon Oil rank behind Continental as the Williston's second and third most prolific oil producers

During the summer, Chord Energy strengthened its position in the Williston Basin with an agreement to acquire core acreage from Exxon subsidiary XTO Energy and affiliates for $375 million cash.

Hess Corp. is another top oil producer in the Williston. In October, Chevron agreed to purchase Hess in a $53 billion mega-deal; Chevron will enter the Williston for the first time through the acquisition.

Williston rig count

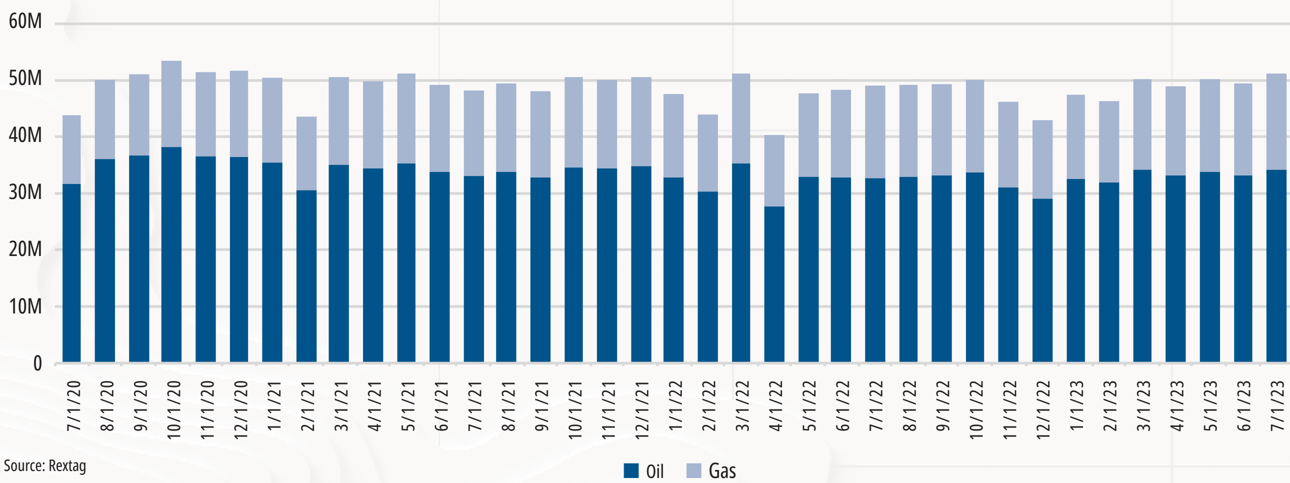
weekly, June 2020-October 2023



Source: Baker Hughes

Williston oil and gas production

monthly, July 2020-July 2023



Source: Rextag

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Hilton America's - Houston

In recognition of International Women's Day on March 8, 2024, Hart Energy's *Oil and Gas Investor* will hold its 2024 Women in Energy luncheon on at the Hilton Americas - Houston downtown.

International Women's Day is a global day celebrating the historical, cultural, and political achievements of women. This is the day to appreciate their efforts! The gala lunch will showcase the accomplishments of distinguished women who have influenced all aspects of the oil and gas industry.

Mark your calendar and join us as we raise a glass and toast these amazing women.

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▶ **ACTIVITY** HIGHLIGHTS

PERMITS

E&Ps continue to plan drilling projects in the Permian Basin at a high clip, drilling permit data show.

Texas saw the most well-permitting activity with 617 permits issues in November, according to Rextag.

Martin County, Texas, in the core of the Permian's Midland Basin, had the most well permits for the same period, at 68.

Midland County, Texas, also saw a lot of activity, with 56 drilling permits issued.

In Loving County, Texas, in the Permian's Delaware Basin, operators filed for 42 well permits.

Another part of the Delaware—Reeves County, Texas—saw 41 permits filed.

Colorado, home to the Denver-Julesburg (D-J) Basin, also saw notable activity. E&Ps filed for 123 well permits in that state.

Weld County, Colo.—the state's most active oil and gas drilling region—saw 20 drilling permits filed.

Campbell County, Wyo., in the heart of the Powder River Basin, also got in on the action, with 32 well permits filed.

Permitted wells by state

State	Well Count
Texas	617
Colorado	123
Wyoming	96
North Dakota	57
Louisiana	49
Oklahoma	27

Permitted wells by operator

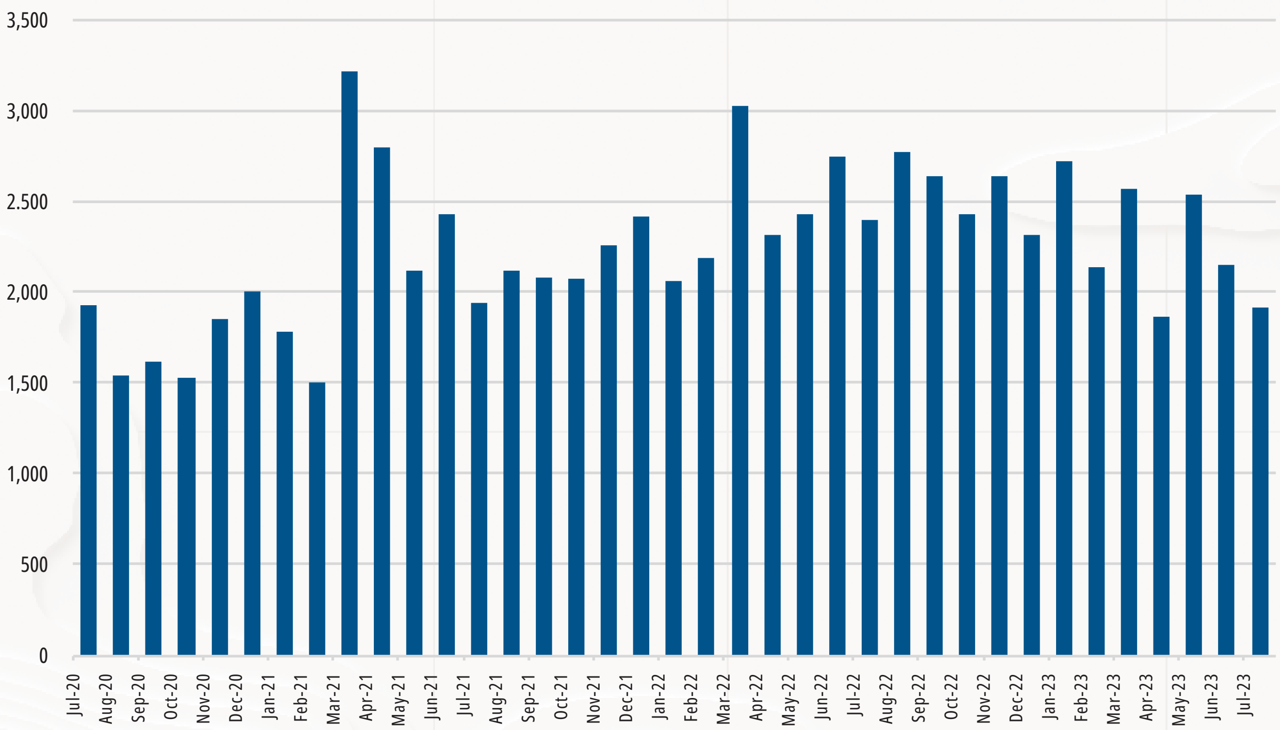
Operator	Well Count
Endeavor Energy Resources	46
Anshutz Exploration	45
EOG Resources	44
Occidental Petroleum	42
Continental Resources	26
Petro Operating	23
ConocoPhillips	19
Pioneer Natural Resources	18
Marathon Oil	18

Permitted wells by county

County	Well Count
Martin, Texas	68
Midland, Texas	56
Loving, Texas	42
Reeves, Texas	41
Campbell, Wyo.	32
Upton, Texas	30
La Salle, Texas	28
Atascosa, Texas	26
Dunn, N.D.	26
Johnson, Wyo.	26
Converse, Wyo.	25
Howard, Texas	25
Reagan, Texas	25
Caddo, La.	20
Weld, Colo.	20

U.S. permits

monthly, July 2020-July 2023



Source: Rextag

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After CrownRock Deal, Which Oxy Assets Are for Sale?

After weeks of speculation, Occidental announced plans to acquire private E&P CrownRock for $12 billion.

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Occidental Petroleum is getting longer in the Midland Basin and adding deeper Barnett drilling targets through a $12 billion acquisition of **CrownRock**.

CrownRock, a joint venture between **CrownQuest Operating** and **Lime Rock Partners**, holds one of the most attractive acreage positions among private E&Ps in the Permian Basin, analysts say.

The deal includes more than 94,000 net acres of stacked pay assets and a runway of 1,700 undeveloped drilling locations across the core of the Midland Basin.

Scooping up CrownRock will also add approximately 170,000 boe/d of unconventional production in 2024, Occidental said in mid-December.

Occidental sees significant upside potential from CrownRock's undeveloped acreage inventory, President and CEO Vicki Hollub said on a conference call with analysts.

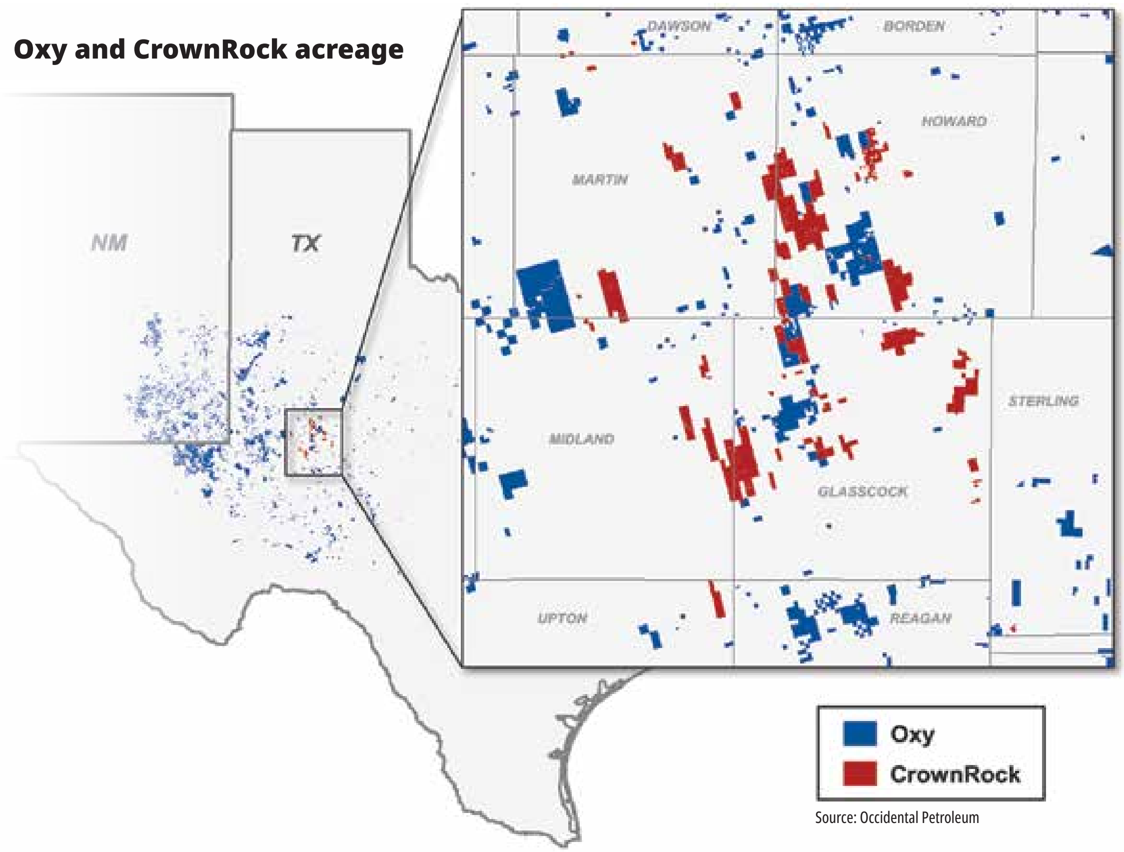
Around 80% of the CrownRock inventory is located within largely clean and undeveloped sections.

But Hollub said the key driver behind the transaction was the significant cash flow accretion Occidental can realize by adding CrownRock's assets to its portfolio.

The deal is expected to generate immediate cash flow accretion, including $1 billion in the first year after closing, based on a $70/bbl WTI price.

Cash flow upside from the CrownRock deal will enable Occidental to pay down at least $4.5 billion in its debt principal within 12 months of closing; the company expects to maintain its investment grade credit ratings.

The significant cash flow accretion also gives



Source: Occidental Petroleum

Occidental confidence to raise its quarterly dividend over 22% to $0.22/share, beginning with the February declaration.

Midland moves

Before the CrownRock acquisition, Occidental had most of its highest quality drilling inventory in the Permian's more western Delaware Basin.

About 80% of the company's inventory at a sub-$40/bbl WTI breakeven price was located within the Delaware prior to the CrownRock deal, said Richard Jackson, Occidental's president of U.S. onshore resources and carbon management operations.

"We now would have 60% Delaware Basin and 40% Midland Basin, balancing this Tier 1 inventory," Jackson told analysts. "Also, the Midland Basin production would move from 9% to nearly 30% of our total Permian unconventional production, based on 2023 estimated and combined totals."

$12B
CrownRock purchase price

Occidental's acquisition of CrownRock is the latest in a deluge of high-profile—and expensive—Permian Basin M&A activity this year.

In October, **Exxon Mobil** announced plans to acquire **Pioneer Natural Resources** and its premier Midland Basin position in a $60 billion acquisition. Several other smaller public E&Ps, including **Civitas Resources**, **Vital Energy**, **Permian Resources** and **Matador Resources**, have added scale in both the Midland and Delaware basins through M&A.

Scarcity of top-quality drilling inventory in the Permian, America's hottest oil play, is driving up prices for acreage and assets across the basin.

Occidental is paying more than $50,000 per acre after discounting for the value of existing production. Andrew Dittmar, senior vice president at **Enverus Intelligence Research**, said the purchase price "shows valuations have fully reclaimed the highs last seen during a frenzy of buying in 2017 [through] 2019 and are inching towards records."

Occidental was also an active M&A participant during that period when it acquired **Anadarko Petroleum** for $38 billion in 2019.

The price for CrownRock nears the level of the Anadarko deal, which valued Anadarko at nearly $60,000 per acre, Dittmar said.

Drilling deeper

The CrownRock acquisition adds top-tier, low-breakeven drilling opportunities to the Occidental portfolio—but it also adds greater upside from target zones deeper underground.

Occidental plans to continue developing its deep horizon Barnett well performance on the CrownRock asset.

Though Occidental is still in the early days of developing Barnett opportunities, the company is "seeing really strong results" from its work so far: new Barnett well production was 34% above the basin average, Jackson said.

The company is also evaluating opportunities in other deep zones like the Strawn, Woodford and Devonian formations.

Occidental also sees potential for EOR with CO_2 injection on the CrownRock asset. The company has overseen a CO_2 EOR pilot in the Midland Basin for several years.

Chopping block

Analysts at Truist Securities believe Occidental is able to pay more than others for CrownRock, assuming oil prices remain stable and drive material free cash flow accretion in the near term.

But proceeds generated through Occidental's new asset divestiture program are also expected to support the purchase.

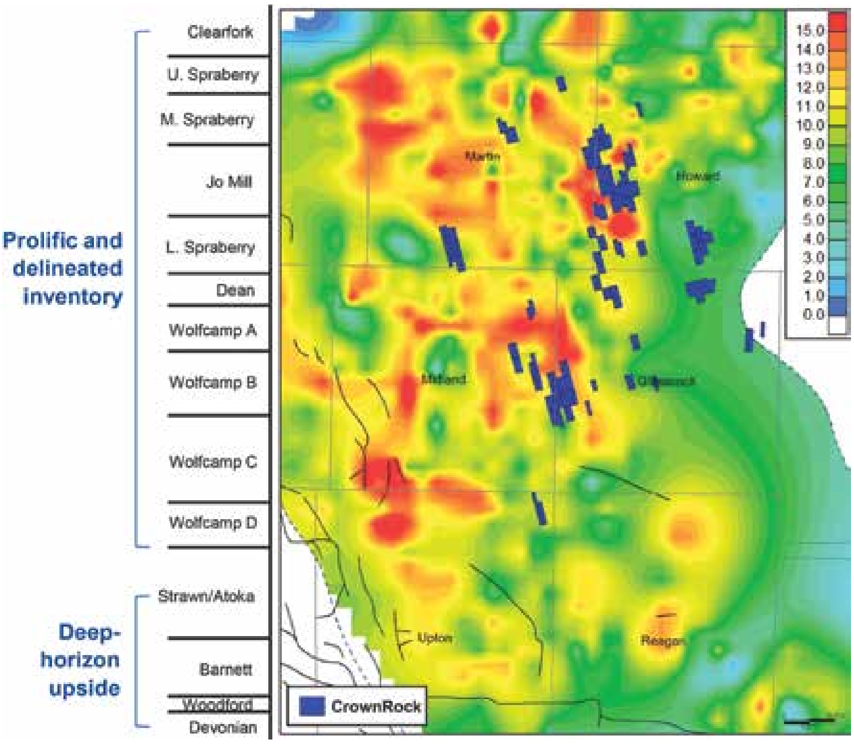
In conjunction with the CrownRock deal, Occidental announced plans to divest between $4.5 billion and $6 billion of less competitive assets. Hollub emphasized that all of the newly divested assets will be from the company's domestic U.S. portfolio.

"Just because we're divesting of something doesn't mean that it's not a quality asset," Hollub said. "It just means that it doesn't fit with our development plans and where we are, and doesn't deliver the margins that we might need but might work for someone else."

Occidental CFO Sunil Mathew said the company is confident it can meet its divestiture targets to support deleveraging its balance sheet. OGI

—Chris Mathews, Senior Editor, Shale/A&D

Productivity (6-Month cumulative oil - bo/ft)[1]



Source: Occidental Petroleum

[1]Production data sourced from Enverus; Clearfork through Wolfcamp D wells since 2021; 6-month cumulative oil associated with prolific and delineated inventory.

SilverBow Closes Deal for Chesapeake's South Texas Assets

New inventory will be developed with an expanded capital program in 2024.

SilverBow Resources closed its acquisition of **Chesapeake Energy's** oil and gas assets in South Texas for $700 million in late November.

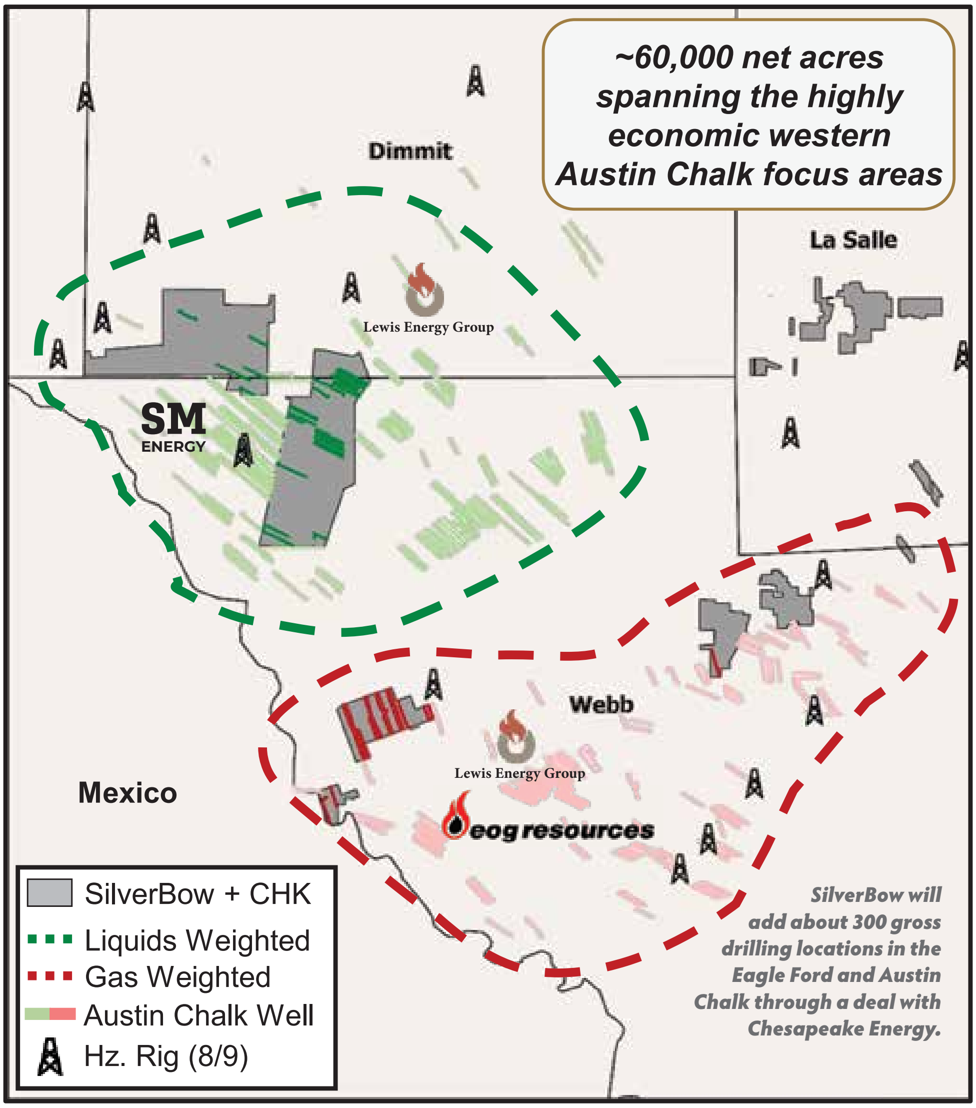
SilverBow's deal, announced in August, includes a $650 million upfront cash payment paid at closing and an additional $50 million deferred cash payment due 12 months after closing, subject to customary adjustments. Chesapeake may also receive up to $50 million in additional contingent cash consideration based on future commodity prices.

The payment was funded with cash on hand, borrowings under the company's credit facility and proceeds from the sale of additional second lien notes.

The deal with Chesapeake included around 300 gross drilling locations in the Eagle Ford and Austin Chalk plays. About two-thirds of the incremental inventory is located in the Chalk; one-third is in the Eagle Ford.

SilverBow also believes there are more benches within both the Eagle Ford and Austin Chalk that it can target beyond the 300 future locations, he said.

Premier Austin Chalk position in the South Texas core



SilverBow will add about 300 gross drilling locations in the Eagle Ford and Austin Chalk through a deal with Chesapeake Energy.

Source: SilverBow

"Our differentiated growth and acquisition strategy has positioned us with a stronger balance sheet, a broader commodity mix and a portfolio of locations across a single, geographically advantaged basin," Sean Woolverton, SilverBow CEO, said. "The acquired Chesapeake assets further enhance our optionality to continue allocating capital to our highest return projects and will immediately compete for capital."

To develop its newly acquired Chesapeake inventory, SilverBow plans on expanding its capital program in 2024, running two rigs on its liquids properties and one rig on dry gas properties, Woolverton said. SilverBow does not plan on any incremental capex on the acquired assets.

In 2024, SilverBow expects oil production to increase approximately 70% year-over-year and average 25,000 bbl/d, with a full-year production mix at more than 40% oil/NGL, the company said in the release.

—Chris Mathews, Senior Editor, Shale/A&D

Feds Dig Deeper into Megamergers

The FTC issued 'second request' notifications for information from Chevron and Hess, as well as Exxon Mobil and Pioneer Natural Resources.

Chevron and **Hess Corp.** said they would promptly respond to an early-December "second request" notification from the U.S. Federal Trade Commission (FTC) for additional information about the $53 billion merger they announced in October.

The FTC solicitation came just days following a similar request to **Exxon Mobil** and **Pioneer Natural Resources** regarding their $60 billion deal, also announced in October. Both firms intend to fully cooperate, according to regulatory filings.

Rich Dealy

Pioneer's incoming CEO Rich Dealy told Hart Energy that the firms had anticipated heightened FTC scrutiny of their transaction based on the transaction's size and scope. At close, the deal will give Exxon control of 15% of Permian Basin production, 5% of U.S. production and 3% of global production.

"We anticipated that would be the case," Dealy said in an exclusive interview.

"Clearly, the combined company still doesn't set commodity prices," he said. "At the end of the day, we are going to be very transparent and provide all the information, and it'll be fine.'"

Consolidation is entering the U.S. domestic political sphere as an election year looms and the FTC has recently scrutinized high-profile deals in oil and gas, technology, aviation and health care.

Senate Democrats led by U.S. Senate Majority Leader Chuck Schumer (D-N.Y.) are taking clear aim at the oil and gas industry. Schumer and 22 colleagues fired off a letter in November, asking the FTC to specifically investigate whether the Exxon-Pioneer and Chevron-Hess mergers violate antitrust laws.

Both acquisitions are all-stock transactions.

The deal value of Houston-based Exxon's purchase of Pioneer, which is headquartered in Dallas, is nearly $59.5 billion, or $253 per share. Terms of the agreement grant Pioneer shareholders 2.3234 shares of Exxon stock for each Pioneer share at closing. Including net debt, the approximate total enterprise value of the deal is $64.5 billion.

The deal between San Ramon, Calif.-based Chevron and New York-based Hess is worth roughly $53 billion, or $171 per share. Agreement terms assign Hess shareholders 1.0250 shares of Chevron for each Hess share. The total enterprise value of the deal, including Hess's net debt, is $60 billion.

—Hart Energy Staff

ProPetro Buys Permian Cementing Business

Par Five Energy Services will be integrated into the existing cementing team.

Midland, Texas-based **ProPetro Holding Corp.** acquired cementing company **Par Five Energy Services**—part of the services player's strategy to add scale in the Permian Basin market.

Par Five will be integrated within ProPetro's existing cementing and operating team and brand, the companies said.

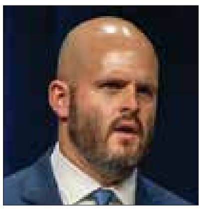
"The transaction is also highly complementary to our current cementing operations, led by Beau Tenney, our vice president of cementing operations, and will allow us to serve both the Midland and Delaware Basin areas of the Permian," said Sam Sledge, CEO of ProPetro.

ProPetro said it anticipates the acquisition will increase their 2024 adjusted EBITIDA by approximately $10 million and convert approximately 80% to 90% of that into free cash flow.

ProPetro is smaller than some of its competitors in the oilfield services space, like **Halliburton** and **SLB**.

But the company thinks its singular focus on the Permian Basin, America's top oil-producing region, helps set ProPetro apart from the competition in the shale patch, Sledge said during Hart Energy's Executive Oil Conference in November.

ProPetro is working to add scale in certain areas of its operations: Last year, ProPetro acquired **Silvertip Completion Services Operating**, a wireline perforating and pumpdown services provider, in a transaction valued at $150 million.



Sam Sledge

"That was a service line we weren't previously in until we made that acquisition, and that was both a scale and integration play for us," Sledge said. "And we've been very inquisitive for other opportunities to add more scale, integration and operating density to what we do here in the Permian Basin."

Drilling down on demand

Headwinds from upstream consolidation to slacking equipment utilization are bearing down on the frac service market.

But as customers increasingly demand cleaner, next-generation equipment, ProPetro is seeing new growth opportunities across the Permian Basin.

Oilfield service supply and demand dynamics have been volatile as the sector emerged from the COVID-19 pandemic, Sledge said.

Drilling activity collapsed when the oil market crashed early in the pandemic in 2020. Service companies eventually gained a better footing on contract pricing as commodity prices increased into last year and drilling activity ramped back up.

But oil and gas prices have come down from the sky-high levels seen in 2022. To that end, drilling activity has also cooled off.

With a dip in activity earlier this summer, ProPetro is seeing new challenges in the frac services sector again.

"I think it's safe to say approximately 20% of rigs and frac crews have been parked or come off the market throughout the back half of this year," Sledge said.

But where things get a bit more interesting is the emerging next-generation equipment market, Sledge said.

ProPetro is seeing strong demand for its dual-fuel frac equipment—which use both diesel and natural gas as fuel—and its electric frac equipment.

ProPetro commissioned its first electric frac fleet during the third quarter; the company recently deployed its second electric fleet, Sledge said at the conference.

"If you're playing in that next-generation market, it's a very good place to be today," Sledge said. "The savings, the incentives and the motivations for our customers to burn more gas and less diesel are very much there, and we're playing head-first into that at ProPetro."

ProPetro sees an opportunity to save on maintenance costs with its electric equipment. The company operates an around-the-clock maintenance operation with hundreds of employees—and most of those efforts are going toward maintaining pieces of diesel equipment.

As the company gets deeper into electric-powered equipment over time, ProPetro aims to cut down on its maintenance spend.

"So it creates more internal efficiencies as well," Sledge said.

—Chris Mathews, Senior Editor, Shale/A&D

BP Buys Remaining Lightsource Stake for $320 Million

BP will take ownership of Lightsource BP by acquiring an additional 50.03% interest in the company, which the supermajor described as a world leader in developing and operating utility-scale solar and battery storage assets.

BP has agreed to take full ownership of solar company **Lightsource BP** by acquiring the company's 50.03% remaining interest, the company said in late November.

Under the agreement, BP will acquire the remaining stake in Lightsource from the company's founders, management and staff. The parties agreed on a base equity value of £254 million (US$321 million) for the 50.03% interest, according to the release.

For full-year 2022, Lightsource BP reported underlying EBITDA of £287 million (US$ 362.9 million). On the transaction's effective date of Dec. 31, 2022, the company had corporate level debt adjusted for cash of £1.5 billion (US$1.9 billion), excluding project finance. The transaction is anticipated to close mid-2024.

As part of the deal, BP will consolidate Lightsource BP's net debt and an existing $900 million loan guarantee issued by BP related to Lightsource BP will be removed from BP's reported adjusted debt.

BP said it structured and priced the acquisition terms to be "highly competitive," reflecting market conditions and with a consideration structure that is "biased to performance." In time, BP may also look to unlock further value by bringing a strategic partner into the business.

"We will continue to scale this successful business and also apply its capabilities and expertise to help meet BP's growing demand for low carbon power from our transition growth engines," said Anja-Isabel Dotzenrath, BP's executive vice president for gas and low carbon energy.

BP added that integration is expected to underpin and de-risk delivery of company targets for its energy transition growth initiatives in hydrogen, EV charging, biofuels and power trading.

Lightsource BP operates a "capital-light, develop, engineer, construct and farm down business model" that creates value through selling majority interests in assets it has developed to

Shutterstock

strategic partners. The model has "built a track record of delivering renewables projects with equity returns in the mid-teens."

BP said full ownership will enable the company to further scale up Lightsource BP and create additional value by applying complementary capabilities and strengths—including in finance and trading—to the business. BP will continue to target double-digit equity returns from the business.

Following the deal's completion, BP intends to maintain Lightsource's independent brand and organization. In early 2024, Joaquin Oliveira, who now serves as BP's senior vice president of finance for gas and low carbon energy, will take on the role of co-CEO of Lightsource. Oliveira has been a non-executive director of Lightsource BP for more than two years.

"This is a natural evolution of the partnership we have built over the past six years—now we will be able to take Lightsource BP to the next level of profitable growth and performance," Dotzenrath said.

—Hart Energy Staff

UPSTREAM

Suncor Energy closed its purchase of **TotalEnergies EP Canada** for CA$1.47 billion (U.S.$1.1 billion), effective April 1, 2023, both companies announced in November.

Including adjustments, TotalEnergies received a closing cash payment of CA$1.83 billion (U.S.$1.3 billion).

Suncor's acquisition of TotalEnergies' upstream Canadian assets include the remaining 31.23% working interest on the Fort Hills oil sands mining project and associated midstream commitments. Suncor now wholly owns the Fort Hills Project in Alberta.

TotalEnergies also completed the sale of its 50% participation in Surmont and associated midstream commitments to **ConocoPhillips** in October and received a cash payment of CA$3.7 billion (U.S.$2.75 billion), with future contingent payments of up to CA$440 million (U.S.$330 million).

"With these two divestments over the last couple of months, TotalEnergies effectively exits the Canadian oil sands, focusing our allocation of capital to oil and gas assets with low breakeven," said Jean-Pierre Sbraire, CFO of TotalEnergies. "The company has hence received more than US$4 billion from these sales during the fourth quarter 2023, out of which, as previously announced, US$1.5 billion will be shared with shareholders as buybacks in 2023."

• **Northern Oil and Gas** is entering the Ohio Utica Shale and expanding its Permian Basin footprint with approximately $174 million in M&A.

Minneapolis-based NOG inked an agreement with a private party to enter the Ohio Utica Shale through acquisition, scooping up non-operated interests in Jefferson, Harrison, Belmont and Monroe counties, Ohio. The primary target zones are the Point Pleasant Formation and the Utica Shale.

The acquired assets include 0.8 net producing wells and 1.7 net wells in process. Current production is approximately 23 MMcfe/d, or around 3,800 boe/d (~100% gas). NOG expects production from the Ohio assets to average slightly higher in 2024.

Nearly all the acquired Ohio assets are operated by **Ascent Resources**.

The Ohio Utica acquisition was expected to close in the fourth quarter with an effective date of Nov. 1. NOG anticipates capex of around $14 million on the Ohio assets in 2023 and $8 million in 2024.

EOG Resources has also been actively consolidating acreage in the region. Houston-based EOG added 25,000 net acres to its Ohio Utica footprint so far this year, the company said in third-quarter earnings. At the time, EOG had around 430,000 net acres in the Ohio Utica, predominately in the volatile oil window of the play.

Delaware Basin M&A

NOG is also expanding its position in the Permian's Delaware Basin through a separate transaction.

The company is bolting on non-operated interests across about 3,000 net acres in the northern Delaware Basin, primarily located in Lea and Eddy counties, New Mexico. The company owns existing interests in approximately 90% of the leasehold.

The northern Delaware acquisition includes 13 net producing wells, one net well in progress and approximately 26.3 net undeveloped locations. Privately held **Mewbourne Oil**, one of the Permian's top oil producers, is the largest operator and controls about 80% of the assets.

Current production from the assets is approximately 2,800 boe/d (2-stream, ~67% oil). The company anticipates output to average around 2,500 boe/d during 2024 before ramping up to more than 3,500 boe/d from 2025 through 2030.

Capex for the northern Delaware assets are expected to range between $25 million and $30 million in 2024.

"After closing, our Permian lands will approach ~40,000 net acres and definitively become our most active and largest basin in terms of activity and production," said NOG President Adam Dirlam in November.

• **Baytex Energy** is divesting some of its crude oil assets in Western Canada, the company announced in November.

Calgary-based Baytex agreed to sell a portion of its Viking assets, located at Forgan and Plato in southwestern Saskatchewan, for nearly US$113 million (CA$153.8 million).

Production from the assets is approximately 4,000 boe/d (100% light and medium crude oil).

The transaction is expected to close before the end of the year. The buyer was not disclosed.

Proceeds from the sale are expected to be applied toward repaying Baytex's outstanding bank debt, the company said.

Baytex had total debt of US $1.98 billion (CA$2.7 billion) and a debt-to-EBITDA ratio of 1.1x as of Sept. 30, the company reported in third-quarter earnings.

Baytex has a $1.1 billion revolving credit facility with a maturation date of April 1, 2026. The company repaid a $150 million term loan during the third quarter.

Scale in South Texas

The third quarter was also Baytex's first full quarter of combined operations after closing its acquisition of Eagle Ford Shale E&P **Ranger Oil Corp.**

The $2.2 billion acquisition added 162,000 net acres and 741 undeveloped drilling locations in the crude oil window of the Eagle Ford—which complemented Baytex's existing non-operated position in the Karnes Trough.

Third-quarter production in the Eagle Ford averaged 87,311 boe/d (85% oil and NGL).

Baytex's companywide production averaged 150,600 boe/d during the third quarter, up 81% from an average of 83,194 boe/d during the same quarter a year ago.

• After recently closing a $70 million acquisition in California, **Berry Corp.** is hunting for more scale through M&A—and it's eyeing deals outside of the Golden State, in particular.

Dallas-based Berry Corp. closed its acquisition of **Macpherson Energy**, a privately held E&P in Kern County, Calif., in mid-September.

Berry agreed to pay $70 million in cash to acquire Macpherson—$50 million of which was paid upon closing. The remaining $20 million will be paid out in July 2024, per the terms of the deal.

Berry CEO Fernando Araujo reported in the company's third-quarter earnings that Macpherson's business has successfully integrated, and that the combined company began implementing efforts to reduce costs and boost free cash flows.

"When we announced this acquisition, we said that we expected these assets to enhance Berry's free cash flow by 15% to 25% in 2024," Araujo said during the company's third-quarter earnings call. "Based on our cost savings opportunities implemented so far, we now expect to exceed these free cash flow estimates."

After closing the Macpherson deal, Berry is searching for more opportunities to grow through acquisition.

The company noted that it is "aggressively pursuing scale through accretive M&A, especially outside of California, in all cases to enhance our ability to generate sustainable free cash flow."

"We're looking for scale," Araujo said.

Berry is still scrutinizing California for opportunistic bolt-ons—similar to the Macpherson deal in its own backyard in Kern County.

But Berry is also focusing on accretive assets outside of California where the E&P can maintain a flat production profile and deliver sustainable free cash flow for years to come, Araujo said.

"In terms of basins, initially, we're focusing in the Western Rockies—basins like the Uinta, Piceance, Powder River," he said. "But in reality, we're basin agnostic."

The vast majority of Berry's total production comes from the Golden State: California production contributed an average 20,500 boe/d, or 81% of Berry's total quarterly output.

The company also has upstream assets in the Uinta Basin in Utah, according to regulatory filings.

• **Freehold Royalties** entered into agreements with two private sellers to acquire Permian Basin mineral and royalty interests in the Midland and Delaware basins for CA$112 million ($US82.5 million), the company said in December.

The assets, primarily in Martin County, Texas, consisted of 2,670 net royalty acres that the Canadian company said were primarily in the "core of the Midland Basin." Freehold forecast the assets will add an average 600 boe/d in the U.S. in 2024 and generate CA$15 million (US$11.05 million) in funds from operations at current commodity prices.

The deal increases Freehold's Permian position by 40% and its U.S. drilling inventory by 25%, Freehold said.

More than 40% of the acquired assets' net royalty acres are undeveloped, providing significant future potential for development, Freehold said. Overall, the Permian production will increase Freehold's volumes in the basin by approximately 30% and, in the U.S. overall, by 12%.

The company described the acquisition as adding more than 2,000 gross development locations to its inventory. That would bring Freehold's reported U.S. inventory to more than 10,000 gross locations, the company said.

"This implies approximately 17 years of drilling inventory based on 2022 drilling levels," Freehold said.

Freehold will fund the acquisitions using its existing credit facility. The transactions are expected to close in January, the company said. Freehold will provide an update on its 2024 guidance as part of its 2023 year-end operating and financial results.

• **WhiteHawk Energy** said it will acquire additional Marcellus Shale natural gas mineral and royalty assets for a total purchase price of $54 million, increasing its ownership in its existing 475,000 gross acre position by 100%.

The seller of the interests was not disclosed.

WhiteHawk said its Marcellus assets are primarily located in Washington and Greene counties, Pa., and represent "some of the highest quality natural gas reserves" in the U.S.

"These assets include all the ideal mineral and royalty attributes—diversified acreage positions in the core of well—established basins, operated by best-in-class companies, generating significant cash flow with no additional capital expenditures," said WhiteHawk CEO Daniel C. Herz. "Since acquiring our initial mineral and royalty interests in the Marcellus Assets in 2022, the assets have performed very well and we are pleased to increase our ownership under some of the best natural gas operators in the world.

"WhiteHawk's Marcellus assets capture production from approximately 1,315 horizontal shale wells and the company owns mineral and royalty interests in 72 wells-in-progress, 64 permitted wells and nearly 900 undeveloped Marcellus locations. The assets include additional potential from the underlying Utica Shale.

As a result of the acquisition, WhiteHawk said it will double its net revenue interest in each well across its Marcellus Assets. Approximately 95% of production, cash flow and present value associated with the assets are operated by **EQT Corp.**, **Range Resources** and **CNX Resources**.

In January, WhiteHawk agreed to acquire natural gas mineral and royalty assets in the Haynesville Shale, covering approximately 375,000 gross unit acres, for $105 million. Combined, WhiteHawk owns interests in approximately 850,000 gross unit acres within core operating areas of the Marcellus and Haynesville shales, with interests in more than 2,550 producing horizontal wells.

The company's Haynesville Shale assets, as well as its Marcellus assets, are actively being developed by multiple operators. The diversified position benefits from sales points in both the Northeast and Gulf Coast regions with combined operator market capitalization of approximately $50 billion, the company said.

MIDSTREAM

Canadian midstream company **Enbridge** announced a CA$3.1 billion ($US2.29 billion) agreement to sell its interests in the Alliance pipeline and Aux Sable, which operates NGL fractionation facilities in Canada and the U.S., to fellow Canadian pipeline company **Pembina.**

Enbridge owns 50% of the Alliance pipeline, a 2,391-mile natural gas line that runs from Northwestern Canada to Illinois. The line has a capacity of about 1.7 Bcf/d. Enbridge owns a 42.7% stake in Aux Sable, which has extraction rights on the Alliance pipeline.

Pembina is the operator of the Aux Sable facilities and will become the operator of the Alliance pipeline when the deal is approved. The deal has an effective date of Jan. 1, 2024. Closing is expected in the first half of 2024, Enbridge said.

"From an asset standpoint, the assets are highly contracted and highly utilized, with ARC Resources and Ovintiv as the largest customers on Alliance and total utilization remaining above 90%" over the past three years," TPH Analyst Zack Van Everen wrote in mid-December. "On a macro level, sustained WCSB supply growth resulting from TMX and LNG Canada projects, coupled with higher U.S. demand from upcoming projects in the USGC LNG corridor, Alliance should remain highly utilized in the foreseeable future."

POWER

TotalEnergies had acquired three startups as the Paris-based company looks to accelerate its electricity business.

The businesses were part of the "TotalEnergies On" acceleration program based at STATION F, a startup campus in Paris.

TotalEnergies said it acquired:

- **Dsflow**, which adds multi-site, electricity-intensive B2B customers with an innovative Software-as-a-Service solution (SaaS) to pilot their asset in real time and optimize their procurement strategy;
- **NASH Renewables**, a software platform developed to optimize the design and operating parameters of TotalEnergies renewable projects. TotalEnergies said the acquisition will contribute to its profitability target of 12% return on average capital employed; and
- **Predictive Layer**, a machine learning and artificial intelligence solutions provider, which focuses on energy price forecasting on both physical and derivatives markets, as well as other tailor-made forecast modeling of demand, supply, production or non-commodity trading.

TotalEnergies will also take a controlled interested (56%) in **Time2plug** "to facilitate and accelerate" the deployment of EV charging points in France for its small B2B customers. Time2plug's marketplace can offer customers instant quotes and tap into a certified in-house installer network.

TotalEnergies said it has also signed commercial contracts with 10 other startups that took part in the acceleration program to continue to benefit from their innovations.

• Investment company **Blackstone** closed its acquisition of electrical supplier **Power Grid Components (PGC)** from **Shorehill Capital**, Blackstone said in December.

PGC, founded in 2017 by CEO Rick McClure and Shorehill Capital, is currently a supplier of high voltage disconnect switchgear, porcelain, glass insulators instrument transformers for revenue metering and protective relaying to electric utilities and original equipment manufacturers, the release added.

McClure and the other senior leaders will remain with PGC in their current positions following the transaction.

"The acquisition of Power Grid Components fits squarely within one of our favorite investment themes–the U.S. electrical grid, joining our other recent grid-related investments, including **Champlain Hudson Power Express**, equipment manufacturers such as **Sabre** and grid software companies such as **Energy Exemplar**," said David Foley, global head of Blackstone.

RENEWABLES

Maryland-based **Standard Solar** acquired the 9.9-megawatt Bluebonnet behind-the-meter solar project from **EDF Renewables North America**, marking its entry to the Texas renewable market.

Located in McGregor, Texas, southwest of Waco, the Bluebonnet project is expected to be completed in second-quarter 2024. During construction, the EDF Renewables Distribution-Scale Power team will continue to serve as engineering, procurement and construction contractor, according to the news release.

The greenfield project will feature bifacial modules on single-axis trackers, providing about 25,000 megawatt-hours of clean energy annually.

"This marks the fourth collaboration between Standard Solar and EDF Renewables in the past two to three years, including projects such as Lawsbrook, Knox and Lehigh University," Eric Partyka, director of business development for Standard Solar, said in the release.

Standard said the project will power part of an industrial process load for industrial gases company **Messer Americas** in Texas. The facility will mark the first time a direct connect solar energy system has mostly powered an air separation unit, according to Chris Ebeling, executive vice president of sales and marketing, for Messer's U.S. bulk operations.

With the acquisition, Standard now operates in 23 states.

• Paris-based TotalEnergies has invested £20 million (US$25.38 million) to acquire a minority stake in U.K. renewables company **Xlinks First.**

Xlinks is developing a renewable project in Morocco, combining solar and wind to supply green electricity to the U.K. through the installation of high-voltage direct current subsea cables and a large battery storage, the release stated.

Upon completion, the project plans to deliver enough renewable, "reliable and affordable" electricity to power over 7 million British homes.

Xlinks CEO Simon Morrish said he welcomed Europe's largest energy company to be a part of the company's long-distance power exchange. "TotalEnergies' investment goes far beyond capital, providing a rare combination of expertise in areas that meet the unique challenges we face," he said.

• **Komatsu America**, a wholly owned U.S. subsidiary of **Komatsu**, a developer and supplier of services and equipment for the construction, mining, forklift and forestry industries, announced plans to acquire battery manufacturer **American Battery Solutions (ABS)**.

ABS will operate as its own stand-alone business within Komatsu and will continue its current and prospective customer commercial vehicle programs.

ABS develops and manufactures heavy duty and industrial battery packs using lithium-ion batteries for commercial vehicles, transit buses and on- and off-road vehicles. Komatsu plans to develop battery-operated vehicles using ABS technology, as well as other projects contributing to the electrification of its products.

The acquisition brings Komatsu closer to electrifying construction and mining equipment and to a 50% reduction of its products' CO_2 emissions by 2030, compared to 2010 levels. OGI

Bankers: Get Serious About M&A or 'Disappear'

Returns to investors are becoming a pillar of the E&P business model while consolidation is increasingly a focus.

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Bankers and money managers are trying to be as clear as possible with clients: returns rule and consolidation is inevitable.

If one of the main points of a panel at Hart Energy's Executive Oil Conference could be consolidated into one word it would be—consolidation.

"We've been pounding the table, not just as bankers but just as folks looking across the sector saying, 'Look, all your clients are ultimately going to consolidate,'" said Austin Harbour, managing director of energy and power at Piper Sandler.

Harbour said oil and gas companies are returning to a business model mindset. M&A's benefit is scale, which opens the door to "cheaper and more efficient forms of capital."

Fellow panelist Sonu Johl, managing director and co-head of E&P investment banking at Raymond James, said there is a "recognition that these companies are going to be inquisitive [about consolidation] because you have to be doing acquisitions or you're going to disappear."

The momentum is building toward greater consolidation, even as oil and gas companies are locked into a strategy of fiscal discipline and capital returns to investors that has some investors migrating back to the space.

Investors are continuing to demand regular payouts, given the cyclical nature of the hydrocarbon business, which can see prices move in strange ways, often without warning. For every run on oil caused by a geopolitical event like the Russian invasion of Ukraine, there's a corresponding calamity like the COVID-19 pandemic that literally drove prices into negative territory.

"The reason why they're forcing the dividend is there are just so many variables out there," Johl said. "Investors are still cautious about how they are going to get that total return, and right now they're saying they want it all in yield.… Eventually, investors are going to get comfortable with the space again and they'll say, 'OK, I'll take part of my return in growth and part of my return in yield.' We're not quite there yet."

Harbour said investors are looking at relative trade, and energy is no longer a big enough piece of the S&P 500 for investors to build portfolios around; hence, the emphasis on returns.

Austin Harbour

Sonu Johl

Ann Rhoads

Michael Bodino

Ann Rhoads, managing director at Gulf Capital Bank, said distributions have even made their way into bank deals with small E&Ps.

"Five years ago, you probably wouldn't have seen that many deals that allowed for distributions and now you're seeing them allow for distributions provided that leverage is less than one time, and that they have at least 25% of the availability underneath their borrowing base," she said.

Michael Bodino, managing director of energy investment banking at Texas Capital, said even private equity firms are seeing demand for distributions.

"They've all got the mindset now of return to capital," he said. "It's important to the private equity folks to return capital to the LPs even in advance of raising new funds."

Dividends are important, but Hess Corp., which Chevron announced in October it would acquire, stands out as a company that made itself attractive by mastering the business fundamentals.

"Hess, from a valuation standpoint, traded at one of the best multiples out of any of the companies in the E&P space," Johl said. "A lot of that had to do with the fact that they had the best organic growth story. You have this yield that investors only want—yield or only want stock—yet Hess is the best-valued stock out there."

Harbour said other companies will likely feel the need to grow.

"If we're going to get to 13, 14, 15 MMbbl/d, which a lot of people think we will, we're going to have to add more people, we're going to have to add more equipment, we're going to have to add more infrastructure," he said. "At some point, the market is going to have to open up and enable companies to grow." OGI

Private Equity's Pursuit of the Right Stuff

Money may be much tighter than during the boom, but 'if it's the right opportunity, if it's the right team, if it's the right deal, there is capital that is available,' say private equity executives.

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Compared to 15 years ago, when investors were throwing money at companies working in shale plays, the current criteria for winning financial backing is much higher.

But plenty of money is there for "really good teams," speakers said at Hart Energy's Executive Oil Conference and Exhibition in November.

From the mid-1990s to early 2000s, "you raised money a little bit from private equity, but there was a lot of friends and family money," Billy Quinn, managing partner at Pearl Energy Investments, said.

Then, interest in the oil patch ballooned.

"By the time we got to 2014, 2015, you had every New York investment firm in the business and a lot of new entrants to energy private equity," he said, adding that number of firms is now about half. "On the dollar side, more than half of the money has gone away, but there's plenty of capital available for really, really good teams with good ideas. It's just the bar. I would say the bar is much higher."

Patrick McWilliams, partner at NGP, agreed.

"Everything kind of got smaller and a little bit tighter, and so where we find ourselves today is this concept of capital scarcity. I think there's capital scarcity in certain situations," he said, but "if it's the right opportunity, if it's the right team, if it's the right deal, there is capital that is available."

Quinn said he's seen management teams that didn't deserve to get backing receive it, but then returns went down and capital left the business.

"I think now we feel like we're in a healthy state, that really good teams who will be difference-makers in the business are getting backing, and we see that time and time again," he said.

McWilliams said some teams are led by entrepreneurs "convicted in their ideas" who want to create something, while others are "kind of running away from something. I don't like my current situation, maybe I can go raise capital."

But, he said, the latter are fewer in a world with less capital available.

At the same time, the Permian is competitive and an amazing resource that "keeps trying to figure out ways to regenerate itself," he said. "We've figured out a lot of different ways to put capital to work if it's upstream operated through non-op, through minerals royalties, we've built water businesses gathering and processing. So the Permian has a lot of different ways to play it."

The way some deals in the past were put together didn't always make sense, Quinn said.

Hart Energy

Patrick McWilliams, partner, NGP; Billy Quinn, managing partner, Pearl Energy Investments; and Nissa Darbonne, executive editor-at-large, Hart Energy at the Executive Oil Conference.

"We don't see deals now where people are buying assets, or buying acreage where we look at it, and it makes no sense. And we've seen that in past markets—2011, 2012 up through 2014—you'd see people pay dollar prices for assets and you couldn't justify them," he said. "You try to put the math together, and it didn't make sense."

But today, most of the time, he said, "you can understand why the person who bought them, why they paid the price."

McWilliams said that while investment firms compete against each other, there might not be as much competition as one would think.

"Everybody's a little stylistically different. The fundamental ways with which we underwrite deals, how we look at risk and our cultures are all different," he said. "How do you look at the world? How do you see risk? How do you see return? Why do you do what you do every day, and how do you interact with people? There's pretty material differentiation along the way. So, I don't see it as a lot of competition directly, and I actually see there's going to be opportunities to partner" because those partnerships can deliver a competitive advantage.

McWilliams isn't worried about the future of the oil and gas industry.

"I'm absolutely not worried about oil and gas having a terminal value. I mean, we look at where demand is right now, somewhere between 101 MMbbl/d and 102 MMbbl/d, and it's growing. We know that this is a hydrocarbon-based economy, and that making good solid investments in this space for a long time makes a lot of sense. So, I'm not worried about that over the next 30 years." OGI

Paisie: Prices to Depend on Whether OPEC+ Keeps Cuts in Place

JOHN PAISIE
STRATAS ADVISORS

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The price of Brent crude oil dropped below $80/bbl during the first part of December despite OPEC+ announcing additional supply cuts at its meeting on Nov. 30.

At the meeting, OPEC+ agreed to reduce its oil production by another 700,000 bbl/d. Those cuts will come from Iraq, UAE, Kuwait, Kazakhstan, Algeria and Oman. Additionally, Saudi Arabia agreed to extend its voluntary cut of 1 MMbbl/d and Russia agreed to reduce its exports of refined products by 200,000 bbl/d in addition to its current reduction of 300,000 bbl/d. The additional production cuts were to start at the beginning of the year.

The announced production cuts, however, did not have much of an immediate impact on the oil market for several reasons. First, the market was already expecting additional cuts of the magnitude that were finally agreed to at the meeting. Second, the postponement of the meeting from Nov. 26 to Nov. 30 because of pushback from the African producers supported the perception that the level of cooperation between the OPEC+ members is waning. Third, and most importantly, the cuts were announced as voluntary, which suggests that the full extent of the cuts will not take place.

Geopolitical worries decrease

The diminishing concerns about geopolitics also reduced the impact of the production cuts. While the possibility of the Israeli-Hamas conflict expanding remains, the risk premium has evaporated because the flow of oil has not been disrupted. Likewise, while there have been some indications that the U.S. and allies are considering ways to strengthen the sanctions on the shipment of Russian oil exports, there is currently little concern that the flow of oil will be affected in any material way.

Another geopolitical situation that could affect the oil market is the dispute between Guyana and Venezuela the Esequibo region. While still developing, the dispute is currently not expected to lead to a military conflict.

With oil prices decreasing after the announced production cuts, the current market sentiment appears to be that OPEC+ has lost, at least temporarily, control of oil prices.

- The robust growth in non-OPEC+ crude supply (around 2.5 million bbl/d) including the growth in U.S. production during the last two years has put further pressure on OPEC+;
- While oil demand has continued to increase during the last two years (and outstripped supply since the middle of 2023), there is a concern that demand growth will slow in 2024 because of weakness in the global economy and because of the increasing role of alternative fuels and electric vehicles; and
- Because of the concerns pertaining to supply and demand, oil traders have significantly reduced their net long positions since late September and their net long positions have fallen back to the levels of early July, prior to Saudi Arabia announcing its voluntary cut of 1 MMbbl/d.

It is our view that OPEC+ still has the ability to influence oil prices—especially in establishing a floor under oil prices—simply because OPEC+ represents around 48% of total crude oil supply. The addition of Brazil to the OPEC+ alliance (which was indicated at the Nov. 30 OPEC+ meeting) will increase the share of OPEC+ to more than 50%. Additionally, OPEC+ is the only source of spare production capacity.

Supply deficits possible

We also think the production cuts will ultimately provide support for oil prices. Prior to the announcement of the additional cuts, we were forecasting that oil demand would outstrip oil supply by around 600,000 bbl/d during the first and second quarters of 2024. As such, any additional cuts by OPEC+ will result in further supply deficits.

We are expecting that non-OPEC supply will increase in 2024, but only by 1 MMbbl/d, with U.S. supply growing by 330,000 bbl/d after increasing by a projected 930,000 bbl/d in 2023. The increase in U.S. supply has occurred even though the U.S. rig count decreased by around 20% from the previous year because of increased focus on the Permian Basin, efficiency gains and greater fracking intensity (longer laterals and increased proppant loading) coupled with a major drawdown in DUC wells, which has enabled the completion count to reach pre-COVID levels. These strategies, however, will have diminishing returns in terms of increasing supply—especially with the inventory of DUCS being depleted.

Regardless, members of OPEC+ will need to keep the latest round of production cuts in place, at least, through the end of the second quarter to establish the fundamentals favorable for higher oil prices and, most importantly, to convince the oil market of OPEC+'s ability to maintain cohesiveness among members. Additionally, OPEC+ must be willing to implement additional production cuts if demand growth is less robust than expected. OGI

Kissler: Higher Temps, Lower Energy Prices

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The Farmers' Almanac—or a team of meteorologists—may have a good picture of where energy prices are headed in the near term, even with OPEC+'s recent round of production cuts and the ongoing geopolitical unrest.

Natural gas prices in particular have been hit hard by the mild temperatures both the U.S. and Europe experienced during fourth-quarter 2023. As a result, heating degree demand has been very sparse, and the U.S. even had natural gas storage builds going into December.

Most traders will watch the week of Jan. 10 as a measure of NG storage-to-price relationships—but the fact that both regions are looking at mild winter forecasts isn't very positive for prices. Unless we see gas storage draw down to under a 5% premium to the five-year average or lower, a major move in winter prices is unlikely.

LNG will be the big demand pull, and with the current global expansion that is underway in the LNG space, the back month futures should continue to hold a nice premium to front-month prices, which is justified. While near-term prices will most likely stay subdued, any abnormal demand catalyst of late cold winter or extreme heat in the summer months could easily ignite a buying frenzy, as Russian supplies cannot be relied upon.

Energy vulnerability still an issue

However, even with the forecast for milder temperatures this winter, it's still risky for regions that are trying to wean themselves off gas and other fossil fuels. If there's a major weather event—and how often is there a winter in New England without a huge snowstorm?—these regions may face brownouts right when residents need heating the most.

As technology evolves, we will see somewhat of a transition to green energy, but this transition is going to take much longer than most people think. Countries or regions that try to force this transition likely will face costly energy vulnerability in the meantime. And this vulnerability could be potentially dangerous in cases of extreme heat or extreme cold if people don't have cooling or heating because of power outages.

Lower demand for oil could impact prices, despite production cuts

Seasonal global demand for gasoline and diesel has been slowing and will continue to do so until demand for heating oil in mid-January takes up some of the slack. Meanwhile, economic numbers in Asia and Europe weakened through the fourth quarter, with the U.S. also beginning to show lower numbers.

China's struggles to jumpstart its economy after the pandemic have hit energy demand particularly hard. Due to its manufacturing-focused economy, China has been a major consumer of oil and commodities. Of course, as China's economy has slowed, its energy consumption has slowed with it, so China's ability to increase economic growth has major implications for the energy industry. Meanwhile, economic activity in other regions, such as Europe, has declined as central banks raised rates to fight inflation. The simple math is that global oil demand is lower now, and prices are finding an equilibrium with a $70 handle.

Although the OPEC+ group agreed to another "voluntary" production cut of 900,000 bbl/d, it has had a minimal positive effect on prices. The major reason for the small impact is the word "voluntary," as OPEC+ members (especially from Africa) have opposed additional production cuts. Consequently, many traders believe most of the new quotas will be overrun with additional production. If you add in the fact that U.S. oil production also hit a new record in fourth-quarter 2023 of nearly 13.24 MMbbl/d, it really more than offsets OPEC's efforts.

However, all this isn't to say that energy prices moving higher is off the table. Both the Russia/Ukraine and Israel/Hamas wars remain intact and the unrest in the Middle East will continue. Any further escalation could turn prices higher very quickly. The U.S. is also forecasted to lower interest rates mid-year, which also could be a lingering positive for crude.

And so, although the forecast is for lower energy demand (and prices) at the moment, the tide can change very quickly. OGI

Varnado: Navigating the Royalties Landscape

LAUREN VARNADO (TOP) AND JESSICA PHARIS

Lauren Varnado is the managing partner of the Houston office of Michelman & Robinson, a national law firm based in Los Angeles. Jessica Pharis is an associate at M&R and member of the firm's energy practice group.

Litigation related to unconventional oil and gas plays steadily increased during the shale revolution. The subject of significant disputes in recent years: the calculation and payment of oil and gas royalties to interest owners.

To be sure, economic, political and societal pressures have expanded potential liabilities across the energy industry. Consequently, it has become more important than ever for producers to understand the current royalty litigation landscape.

While it is not uncommon for newer form leases—and manuscript leases in the Eagle Ford—to require "add backs" of embedded post-production costs or expressly provide for royalties on extracted refined NGL, many active oil and gas leases do not address these topics, which has led to significant litigation and questions about oil and gas royalty class certifiability.

'Add backs' of embedded costs

Of late, one of the most common claims brought by royalty owners complaining of alleged improper payments center on "add backs." By way of these claims, royalty owners demand that producers pay royalties based on the sales price they receive plus any embedded costs that were a component of the sales price.

"Add back" claims raise serious concerns for E&P companies in a global energy market where oil or gas may be sold at prices determined under a complex formula which utilizes European and/or Asian published indexes and includes various adjustments for downstream Asian and European transportation charges. Royalty owners with oil and gas leases that do not allow for deductions of post-production costs may argue that the cost components for Asian and European transportation are hidden post-production deductions that E&P companies must add back to sales prices prior to calculating royalties.

Last year, the Texas Supreme Court directly addressed the "add back" issue in Devon Energy v. Sheppard. In that case, the Sheppard oil and gas lease contained a "bespoke" royalty provision that required the lessee to add back costs that were a component of the sales price. On that basis, the court ruled that post-production costs identified in the contractual formula that determined the sales price had to be added to the price prior to calculating Sheppard's royalties.

Of note, the Sheppard decision has limited application to other royalty cases, as it was based on one-of-a-kind "add back" language in the Sheppard lease that would not apply to standard royalty provisions. At least in Texas, producers can breathe a sigh of relief that "add back" claims under leases with standard royalty provisions are unlikely to succeed.

NGL royalty calculations under gas royalty clauses

Another trigger for litigation these days is the calculation of royalties on NGL. Unlike dry gas, "wet" gas requires significant processing and fractionation to separate and refine NGL products from the gas stream. These post-production activities take place downstream from the wellhead at processing plants and fractionation facilities. After NGL are extracted from the gas stream, the residue gas and NGL products are separately marketed and sold, generating two distinct revenue streams.

Traditional oil and gas leases provide for the payment of royalties on oil and gas but are silent as to NGL. Courts have interpreted the term "natural gas" to include its component parts—read, NGL, which means producers must pay royalties in a manner that compensate royalty owners for both gas and NGL. But the question of how to calculate and pay royalties on NGL is the subject of hotly contested litigation in jurisdictions with substantial wet gas production. That a lease may be silent in terms of NGL does not end the inquiry, but only raises additional questions about the basis and location for valuation.

This can be rather consequential. Class actions can turn relatively small disputes over NGL royalty payments into multimillion-dollar statewide lawsuits over a producer's royalty practices. On the plus side for producers, oil and gas leases that only provide for royalties on "gas" but do not provide a separate royalty for NGL are arguably ambiguous and cannot be certified as a class action under the Federal Rules, as was the case in SWN Production Co. v. Kellam.

No doubt about it, a greater variance in oil and gas lease terms, higher volume of leases and more complicated allocations have created new challenges for producers in the administration of royalty payments. As such, it is critical for energy companies to implement strategies to defend royalty practices and mitigate the risk of class certification. OGI

Deckelbaum: US Shale Landscape Taking on New Shape

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Last year was monumental for shale producers in terms of news flow. Thematically, public investors continued to focus on free cash generation and returns of capital to shareholders while considering the future of inventory depth. Public companies touted benefits of longer lateral designs as average lateral lengths observed across shale plays increased 3% in the Permian, 8% in the Eagle Ford and 1% in the Bakken.

Coincidentally, for the first time in several years, oil productivity per-foot on average actually increased by 3% across all U.S. shale plays. This follows a relatively dramatic drop in per-foot productivity from 2021 to 2022. With most companies continuing to communicate relative maintenance programs, the market responded with relative surprise to U.S. shale oil growth, which trended up 9% year-over-year as of the third quarter while the rig count on average declined roughly 5% on average YTD and 20% since the beginning of the year.

MARKET WATCHERS

At the end of the day, this dynamic is roughly half-explained by the growth witnessed in the private market as operators likely look to monetize to publics, while also benefitting from improved well performance, cycle times and enhanced well designs. Indeed, shale operators have improved operating efficiency while facing the narrative of limited inventory life.

Most public investors have scrutinized shale oil inventory depth and questioned the long-term sustainability of high return of capital profiles while weighing the risk of acquisitions. On the other hand, we have witnessed majors such as Chevron and Exxon Mobil taking four public names off the board—Pioneer Natural Resources, Denbury, PDC Energy, and Hess Corp.—albeit using all-equity takeout mechanisms with scant premiums.

Indeed, the romance of large takeout premiums from majors is likely a relic of the past, but at the same time, the volatility around U.S. oil production growth should continue to decrease over time. Private-to-public consolidation has typically resulted in rig rationalization to augment near-term free cash. Considering that private operators contributed to roughly 5% of the 9% oil shale growth, the setup for U.S. oil production in 2024 will be heavily influenced by a marked shift in private operator market share that dropped from 60% at the beginning of 2023 to 52%, following a 32% decline in private rigs through mid-December versus 8% for public companies.

After averaging roughly 59% of the rig count since late 2020, the decline in private operator activity should have a noted impact on continued shale oil growth, particularly as publics continue to consolidate names like CrownQuest Operating, Forge Energy, Advance Energy and others, all meaningful players in the private Permian arena.

The path forward for U.S. shale in the public arena will inevitably now take the form of smaller bolt-on deals to replace inventory as limited opportunities in the private space remain for scale, with all eyes on the fates of names like Endeavor Energy. As the era of public-for-private consolidation theoretically comes to a near-term end, public names will now dictate the path of U.S. oil growth once again with an increased focus on development efficiencies, high-grading and inventory management.

As the world digests surprisingly robust U.S. oil production once again, along with several other global macro factors, it is fair to argue that one relatively bearish variable—private company shale growth—was significantly diminished heading into 2024.

Oil prices receded from north of $93/bbl at the end of September to about $72/bbl by mid-December, providing an interesting starting point for how U.S. public operators choose to behave that will be more heavily influenced by the majors' activities.

Ultimately, the 2023 wave of consolidation should prove to have ongoing impact on domestic industry capital restraint, a critical goal of the investing public since late 2018. At the same time, the productivity gains experienced in 2023 provide a compelling backdrop for domestic shale and the conversion of lower tier inventory to higher tiers that will only be further informed by proclamations from larger players such as Exxon look to dramatically increase recoveries in the Permian as their footprint has grown through acquisition. The 2024 U.S. oil shale chapter should indeed prove to be a page-turner. OGI

THE OG INTERVIEW

Time for TRANSITION

Rich Dealy steps into the Pioneer Natural Resources CEO role as the Permian Basin pure-play integrates operations with Exxon Mobil in a $60 billion merger.

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Pioneer Natural Resources veteran executive Rich Dealy took over from retiring Scott Sheffield as CEO on Jan. 1, and while he said he will diligently implement the plan leadership has put in place for the new year, Dealy has a side gig—leading the transition team for one of the biggest industry mergers in recent history.

The subject of rampant speculation for months before its announcement in October, Exxon Mobil's purchase of Pioneer seemed to be the spark needed to ignite a wild period of consolidation as 2023 drew to a close. But Dealy's focus remained steady on what's ahead for his company, shareholders and employees. The deal is expected to close this summer, even as federal regulators dig into this transaction and others both inside and outside the oil and gas industry.

"I don't anticipate any issues whatsoever," Dealy told Hart Energy in an exclusive interview at Pioneer's campus in Irving, Texas, in early December. "I think it'll be widely voted in favor of the transaction, then we will just get the regulatory approvals done and move forward."

Dealy's work at Pioneer has spanned more than 30 years. Armed with a degree in finance and accounting from Eastern New Mexico University in 1989, Dealy had job offers in Dallas and Houston. But he'd fallen for the Southwest, and accepting a position with KPMG in Midland, Texas, felt right.

It must have been fate.

His second client at KPMG was Parker & Parsley, where Sheffield was at the helm and, in 1997, would merge the firm with Mesa Inc. to create the nation's third-largest independent with Pioneer.

"After a couple of years, the CFO at the time said, 'Well, why don't you come work here where you'll work a lot less hours?' Which was probably the biggest lie I was ever told because I worked a lot more hours than I ever did in public accounting," Dealy said with a laugh. "But it has been a blessing for me for 31-plus years."

THE OGI INTERVIEW

Watch the video interview here:

Q&A

Deon Daugherty: Taking on the CEO role at Pioneer months ahead of Exxon closing its acquisition must make the day-to-day of leading Pioneer a bit different. What's next for you?

Rich Dealy: I'm not really focused on what's next for me. I'm focused on what's happening here at Pioneer and making sure that we execute our program until it closes. And then, working with Exxon so that when closing does occur, the transition is seamless, with the integrated teams working well together, and the combined company continues to execute at a high level.

DD: What goes into leading a transition of this size?

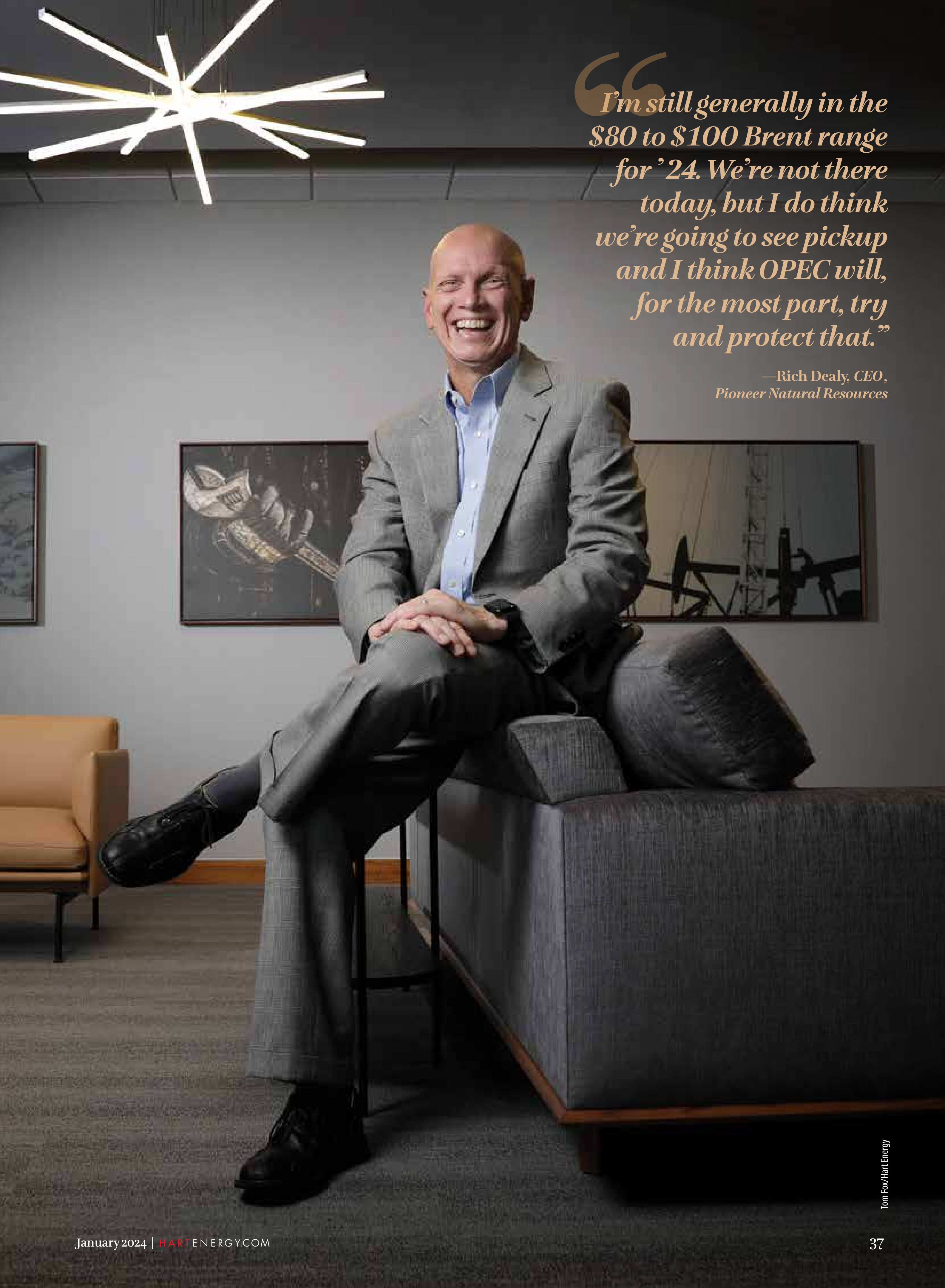
RD: It's really just putting the right teams together throughout the organization and making sure that they're positioned to share information in a way that allows people to figure out what's the best way to execute the business plan in the future.

Exxon is a $400-plus billion entity; we're a $60 billion entity. They have assets around the world. We have assets in the Permian Basin. They recognize that we do some things better than they do; we recognize they do some things better than us. How do we take the best of both worlds and integrate these two teams to execute in the best way? This opportunity is one of the reasons why it was such a compelling transaction and why it should provide significant long-term benefits.

From an investor's standpoint, it's a chance for our investors to essentially own 12% of a large, diversified oil and gas company, which is one of the best energy companies globally, with great assets and opportunities for employees around the world.

They're also going to be able to reduce emissions faster than we were on the path to accomplish. They've committed to net-zero emissions by 2030 on their existing Permian assets and plan to accelerate our reductions from 2050 to 2035.

From an employee perspective, Exxon has



"I'm still generally in the $80 to $100 Brent range for '24. We're not there today, but I do think we're going to see pickup and I think OPEC will, for the most part, try and protect that."

—Rich Dealy, *CEO, Pioneer Natural Resources*

Tom Fox/Hart Energy

global operations. So, anybody who aspires to do a lot of different challenging things around the world, they're going to have tremendous opportunities at Exxon. We think that's a huge benefit for our employees. Our goal with the transition is to seamlessly combine the operations and continue to execute at a very high level, while providing development and growth opportunities to our employees.

DD: What happens at Pioneer between now and closing on the Exxon merger?

RD: Our focus is going to be on executing our program. At this point, we run as two independent companies. At Pioneer, we are continuing to focus on 2024 exactly as we laid out to shareholders in our long-term plan. We're planning on growing oil production between 3% and 5%, with total production growing a bit more. We are working to do that as efficiently and economically as we can. At the same time, we are going to continue to work constructively with the FTC [Federal Trade Commission] in its review of the transaction and we continue to expect the deal to be completed in the first half of 2024, subject to the fulfillment of the closing conditions. Prior to closing, we can start integration planning such that we are ready to combine the two teams and companies as seamlessly as possible once closing is completed.

> ***"The beauty of what we do in the U.S. is that we [produce] the lowest emission barrels in the world."***
>
> **—Rich Dealy,** ***CEO, Pioneer Natural Resources***

DD: What are Pioneer shareholders saying about the merger?

RD: I think the shareholders understand it and the response has been tremendously positive. It was a transaction that people know makes sense.

Our shareholders will own roughly 12% of Exxon Mobil. Shareholders recognize that the combination of our acreage and people along with Exxon's technology and people is a positive. They also recognize the benefits and long-term strategic value of being part of a large, diversified global energy company as the world transitions. I don't anticipate any issues whatsoever. I expect shareholders to vote in favor of the transaction, such that when we get the regulatory approvals that are needed, we will be in a position to close and move forward.

DD: The industry's investment thesis has come a long way since 2017, and growing shareholder returns is a leadership dictate of most public producers. How much is enough—is there a minimum return formula that shareholders are willing to accept?

RD: I don't think there is a defined formula or threshold. You've seen our industry return capital to shareholders in different ways: via base dividends, variable dividends, special dividends and share repurchases—all of which are different forms of returning capital to shareholders, which is the primary request from shareholders.

There wasn't a one-size-fits-all and companies have responded in different ways. I'd say some of it was predicated on a company's depth of inventory, with companies wanting to add inventory choosing share repurchases. They are easier to turn off than dividends.

DD: That's part of why using a variable dividend seemed so clever.

RD: It was, but unfortunately, we didn't get any differentiation in terms of how our stock traded because of it.

It was different and shareholders understood it. We received many accolades, but it didn't bring the big "dividend" funds in because it was still going to be variable.

Overall, in 2022, it looks like those companies that bought back shares outperformed those that had variable dividend policies.

DD: How do you see diversification within the energy space going forward? It seems the general emphasis on cleaner fuels has opened it up to mean more than simply being an active operator in multiple basins.

RD: It's going to come down to economics, ultimately. Can we generate a rate of return that makes sense for shareholders and investors in alternative energies?

We have seen significant drilling and completion efficiency improvements, combined with productivity enhancements, which have helped oil and gas returns and the overall economics associated with drilling new wells. We need to see that same trend continue in solar, wind, hydrogen, nuclear, carbon capture, etc. Also, longer term, we need to figure out how to get more comfortable with safety aspects of nuclear as I think it is one of key opportunities for sustainable energy.

All energy sources have to be looked at, and we have to figure out how to develop them safely and reliably. Probably the biggest thing out there that could be a potential game changer is battery technology. If we were able to provide long-term battery storage, more of the renewable projects like solar and wind would provide better reliability 24/7, 365 days a year.

Those are the things that we need to continue to develop—not

Tom Fox/Hart Energy

only for the U.S., but for China, India, Africa and Southeast Asia (each with 1.4 billion people and growing demand for energy) as they are starving for reliable energy that can help improve their quality of life. How do we get energy to them in a way that is low-cost and reliable?

The beauty of what we do in the U.S. is that we [produce] the lowest emission barrels in the world. So, why wouldn't you want us to produce more of that to export to others?

DD: Both Exxon and Pioneer have done some work with extracting lithium and other minerals from produced water. How might this sort of research, or even development of these resources, figure into the U.S. energy industry?

RD: For Pioneer, it really comes down to the quantity of rare earth minerals (not just lithium) in the water that we produce. It's one of the potential benefits of combining with Exxon. They're working on their own technology in Arkansas to extract lithium from brine. The combined companies will benefit from that work and we will see over time if we can economically extract minerals from produced water in West Texas.

Time will tell, but I think we need to progress up the learning curve on all those things. Hopefully, one day we can figure out how to use this produced water rather than disposing [of] it. How do we desalinate it and convert it to water that we can use for irrigation, crops and livestock? And then, how do you extract needed minerals rather than relying on importing them from countries that we may not always be best friends with?

I think it makes the U.S. more self-sufficient and allows us and our allies to be less reliant on other countries that we may not always have common goals or the best relationships with.

DD: What do you expect from oil prices in 2024?

RD: As we get to '24, we see Brent oil prices averaging $80 or above. I think the inflationary pressures and the increase in interest rates around the world has stymied investment and is impacting demand. As you know, China's demand hasn't been what people anticipated, but India's demand had been strong. There's probably been more supply barrels on the market than people originally anticipated in 2023, with U.S. shale growth and growth from other countries being higher than anticipated. Despite this backdrop, I'm still generally in the over-$80 Brent price range for 2024. We're not there today, but I do think we're going to see a pickup. The forecasted global demand growth in 2024 will soak up the incremental supply we have today and we should see a more balanced market or the need for incremental supply over the course of 2024.

Having said that, there are many unknown factors in the world, whether it's Israel or Ukraine issues, interest rates, or something else that impacts the market, so oil prices are hard to predict.

I think the lack of global investment is still an issue that is out there and that we're not finding and developing much new supply in the world. There is not a lot of money going into exploring for new supply. I think at some point we are going to be in short supply again, which is going to cause inflationary pressures on oil.

DD: Let's talk about shale's runway. There's been lots of prognosticating about its lifespan and what's left. How do you view its future?

RD: Well, I think human ingenuity is a wonderful thing, and you've seen the benefits of that even in 2023, with U.S. production being quite a bit higher than people anticipated, while running fewer drilling rigs, which highlights the industry's continued efficiency gains.

If you look at the EIA production numbers, production at the end of last year was 12.4 million barrels a day versus today we're at 13.2 million barrels per day, so call it 800,000 barrels a day of incremental oil production. I think coming into the year, most people thought that the U.S. would grow around 400,000 to 500,000 barrels a day. We achieved significantly more growth than expected, such that I wouldn't want to undersell the capabilities of U.S. producers and shale production.

For future growth, I will focus on the Permian, which is what we know best. We see the Permian Basin growing to about 7 million barrels a day by 2030, an increase from the 5.6 million barrels per day when we exited 2022. The basin is currently producing about 6 million barrels a day today. Even when production hits 7 million barrels per day by the end of this decade, we expect that it'll be flat at that level for a significant number of years after that, given the depth of inventory in the Permian Basin.

Those projections also don't take into account any new incremental recoveries through enhanced oil recovery, downspacing or technology changes. We are only getting 8%-10% of the oil out of the ground, so there still is a vast resource in the basin to be recovered. As a result, I tend to think shale still has significant running room, particularly in the Permian. OGI

> ***"We're planning on growing oil production between 3% and 5%, with total production growing a bit more."***
>
> **—Rich Dealy, *CEO, Pioneer Natural Resources***

▸ **CONSOLIDATION** STRATEGY

Bryan Sheffield: Asset Sellers Need Bid/Ask Therapy

Advisers must sharpen their pencils at the negotiation table, E&P operator Bryan Sheffield said—because "all you're going to do is upset your seller by promising a market that isn't there. No one's going to pay you."

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The sparse capital available to the oil and gas sector is resulting in empty bid rooms, says Bryan Sheffield, who's built another portfolio after selling his Permian Basin-focused Parsley Energy in 2021 for $7.6 billion, including debt.

Some E&Ps might be poring over the maps, logs and production data, but "they don't have any money lined up," Sheffield told attendees at a Westwood Salient conference in Houston in November. "They're trying to raise money on the fly."

Bryan Sheffield

Sheffield's new E&P, Formentera Partners, has built a portfolio in the Bakken Shale, and Anadarko and Permian basins, as well as the Eagle Ford Shale and the conventional Gulf Coast via three funds to date. The company's focus is on harvesting production from pre-existing wells.

Sheffield is trying to be upfront when making deals, however.

In a look at a property in West Texas, Sheffield warned a seller, "You're not going to like my deal. It's going to be PV-18 on PDP."

Sheffield's small business development team worked it for six weeks anyway. They came away empty-handed. "So, we wasted our time. And I said, 'No more. Call every bank for teasers. The sellers need religion. They need therapy. They need to find out through a process where the bid/ask spread is.'"

Sellers will come back with "No, we can't do the deal. Can you move higher?" to which Sheffield replies, "No." So the seller asks, "Can you go up like 5%."

Again, the answer is "no."

Sheffield's bids don't change because, "I know that no one with real money is in the data rooms."

Some asset marketers are coming around, though, he said. "I think the banks have smartened up a little bit. Over time there have been more failed processes than you could ever imagine."

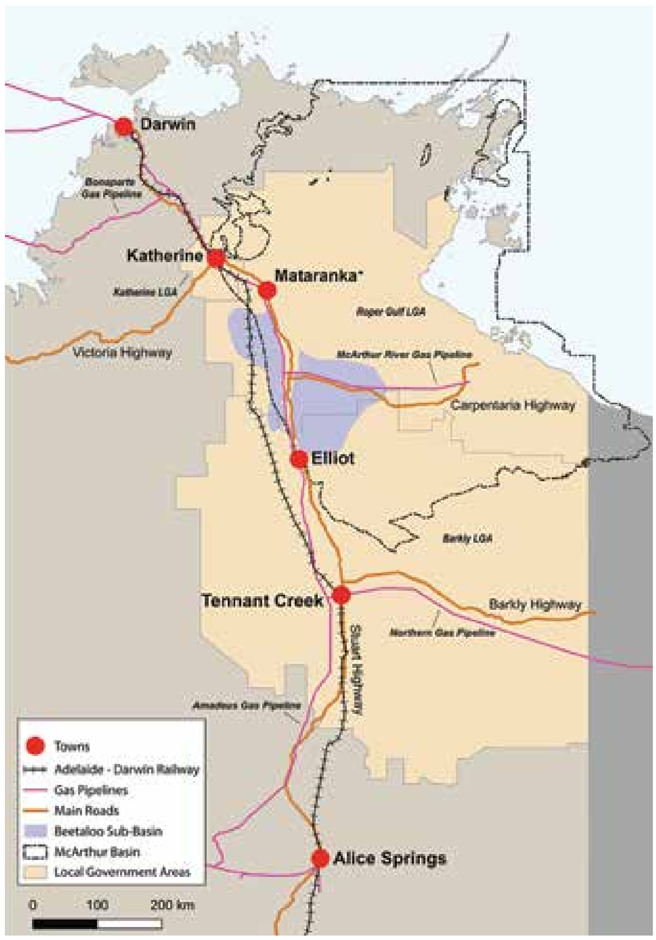
A couple of brokers remain adamant in their views of properties' current market values. "But they're going to [come around] eventually. All you're going to do is upset your seller by promising a market that isn't there. No one's going to pay you."

'It's OK to lose'

Sheffield lost a deal to a public operator willing to pay PV-12 and he either had a different plan for the property or didn't

Parsley assets acquired from Jagged Peak, photographed March 4, 2020. Bryan Sheffield sold his Permian Basin-focused Parsley Energy in 2021 for $7.6 billion, including debt.

The Oilfield Photographer, Inc.



Source: Australia's Department of Industry, Science, Energy and Resources

Beetaloo Sub-basin, Australia's Northern Territory.

"know where the market was."

In the Formentera model, the business model is built to lose bids if necessary, he said.

"It's OK to lose. I hated to lose at Parsley, but I'm fine to lose here [at Formentera] because there's no reason to overpay."

To date, Formentera has amassed 480,000 net acres, 40,000 boe/d and 1,500 wells plus an additional 832 PUDs that Sheffield said "I got for free" and are HBP by active wells. It's currently holding back on developing those. "We're warehousing them. We're going to be patient because we have the flexibility."

Its first fund, raised in 2021, is a 15-year fund. Fund II, raised in 2022, is built for 10 years plus three one-year options.

"We underwrite each asset as if we're going to be the last owner." The nature of the property is that "in three years, you've made your money back."

The largest dividend is in the first year; the second largest, the second year; and so on. "Now at the end of 10 to 15 years, I do believe times will change and local operators will likely roll assets up."

And "what do we care if selling at PV-25 in year 12? We've already made two times our money and now we're selling at PV-25."

The firm also has a Formentera Permian Fund that has producing assets in the central Midland Basin. It was raised in 2022.

The Houston forum's host, Westwood Salient, is among investors in Formentera's Fund I and Fund II. Greg Reid, president of real assets, noted there are "not many bidders for energy assets today.

"There's limited competition. The prices are low; the valuations are low. That's exactly what we want as investors."

'Need this energy now'

Sheffield said when he restarted after selling Parsley, "everyone thought that was crazy." The common view, he was told, was, "How long do you think this [oil business] is going to last? We're going to plug all these wells."

“There’s limited competition. The prices are low; the valuations are low. That’s exactly what we want as investors.”

—**Bryan Sheffield,** ***managing partner, Formentera Partners***

The way Sheffield sees it is, “we’re not going to plug the wells but maximize the potential of these wells. These wells across every basin have a lot of life left—between 30 and 40 years.

“So, even if we stop drilling, we still have this huge life of cash flow around the United States.”

The group thinking out there is that “fossil fuels are doomed and are going to be done by 2030. Tesla and other alternative energies are going to run us off the map,” he said.

But everything else Sheffield sees points to a long future for hydrocarbons.

Underserved populations are doubling, such as in Africa and India, for example. “They need this energy now—affordable energy,” he said.

The money well runs dry

The landscape for capital has changed dramatically from when Sheffield took Parsley public in 2014. One banker “always said, ‘Hey, if you want to start over, come to us.’ So I started over, went back to them and [others] and all of them said, ‘We love that you called, but we have no money for energy.’”

Skipping the broker and raising money directly from investors is more challenging today, too. One of them, “the energy guy of [a university endowment] said, ‘No, we’ve moved away from energy investing,’” Sheffield said.

“Think about it: He should be worried about his own job. He’s the energy guy.”

Sheffield is finding some pension fund uptake, though, and money is flowing from family offices. Formentera’s Fund II was oversubscribed with $828.5 million in commitments.

The target had been $600 million. Investors also include a couple of asset managers, insurance companies and many registered investment advisers. Eaton Partners, a unit of Stifel Financial Corp., served as placement agent.

“The family offices—they like the contrarian view and [oil and gas are] still contrarian, even at $75 oil and $3 gas. You’re like, ‘Wait, it’s not contrarian anymore.’

“But it is because of the lack of capital in the system.”

What’s wrong with the property Formentera’s picking up? Simply, “they’re fossil-fuel assets,” he said. “So, I’m back in this space and I started Formentera because there are so many opportunities.”

The disappearing banker

Sheffield presented a slide in the Westwood Salient program showing Parsley’s bankers during its seven-year run and their status today. A logo-laden column of 37 has evaporated into a few names.

Credit Suisse no longer exists, for example. Several others have visited Formentera but that’s as far as it’s gone.

Others, including Goldman Sachs and JPMorgan, which earned the largest fee among underwriters of Parsley’s security offerings, “have not been through my office one time. There’s nothing for them to talk about.”

Many others are still in oil and gas but only banking with their existing clients. “They’re not building a book. They’re not building relationships.”

Those with an asset-marketing unit want Formentera as an A&D client, “but we’re not going to call them and sell an asset through [them] because they don’t bank us and support our business.”

An attendee said of the disappearing-banker reference, “You should put this in your Christmas cards.”

Sheffield laughed and added, “I just get frustrated seeing these banks say, ‘Yes, we do lend to fossil fuels’ when the truth is they don’t. They’re limited to their existing clients.”

There are at least 30 commercial lenders remaining in oil and gas, according to the Haynes Boone price-deck survey results in November.

Sheffield said it used to be that a start-up backed by longtime, top-shelf private-equity firms would automatically get a commercial lender. Today, “the banks aren’t there.”

“They don’t care who you are, [suggesting,] ‘We’ve got to know that you’ve made money through small increments.’ And that’s the same thing they’re all saying.”

Then that might not be enough, either. Sheffield has a proven track record but, with a longtime Texas lender to oil and gas, “we were on the one-yard line to sign a lending deal,” he said.

“They pulled out.”

As for capital from PE firms that had invested 100% of former funds in start-up E&Ps, they may still be in the business, but a growing share of funds are migrating to alternative energies.

“You can see how the whole space is changing—the money is changing.”

He saw it as an opportunity. When investment bankers, asset marketers and commercial lenders weren’t calling him back, or did but said, “We can’t do fossil fuels,” Sheffield’s take was “We knew we were onto something.

“We knew we were doing something right because no one else wanted to be in this industry.”

Downspacing will resume

Production degradation due to downspacing “is kind of a bad word right now in the industry,” he said. But it works “and I do believe downspacing will be considered again when we have higher quality prices.”

A well on 660-ft spacing produces an expected EUR. Landing two wells, each on 330-ft spacing produces an average of 75% each of the 660-footer’s expected EUR—or 150% combined. Simply, “you need a higher commodity price to get similar returns,” he said.

He predicted that moving laterals closer together will reappear in quarterly conversations and news releases again, “but if I said ‘downspacing’ to a bunch of public investors right now, they would just start throwing food at me.”

“They do not want that.” They want up-spacing instead. “And, obviously, consolidation.”

He also expects investors will begin to support the E&P growth model again, departing from a harvest mode—underway since 2018—that demands free cash flow be paid in dividends rather than reinvested.

“The growth model will come back,” he said, but “I think we’ll be a little more disciplined than what we did the last time around.”

(from left) Parsley Energy senior operations manager Mark Timmons, drilling superintendent Joey Sims and company man Fernando Castillo visit in the early hours on the Ratliff 28 pad site in Upton County south of Midland, Texas, Monday, Feb. 22, 2016. Bryan Sheffield sold his Permian Basin-focused Parsley Energy in 2021 for $7.6 billion, including debt.

> ***"We knew we were doing something right because no one else wanted to be in this industry."***
>
> —**Bryan Sheffield,** ***managing partner, Formentera Partners***

The next inventory

Northeastern public money managers in New York and Boston see operators "ripping through inventory." Sheffield expects that in five to seven years, all the Tier 1 inventory will be gone. "They're going to move to Tier 2."

The next frontier? International. "There are shales around the world," he said. "They're all sitting there. It all depends on which country you want to do business with.

"Argentina has a great play [in the Vaca Muerta], but they're known for nationalization."

In his newest venture in Australia, Daly Waters Energy and Daly Waters Royalty, Sheffield has a large foothold in a tight-gas play in the Beetaloo Basin in Australia's Northern Territory. (Daly Waters is a town in the basin.)

Sheffield made the deal to sell Parsley in October 2020, closing it in January 2021. Then he turned to the Beetaloo. "The geology and the logs are just like in the Marcellus and Haynesville," he said.

He is also invested via Australia-listed operator Tamboran Resources. Helmerich & Payne was enlisted to invest and to bring a modern-tech Flex3 rig to the play.

"So, the service companies are buying into the play," he said. "We need more."

Also, APA Group, a leading energy infrastructure company in Australia, is evaluating a potential investment in a midstream deal.

The areal extent is one-sixth that of the Marcellus and the same as the Midland Basin. A half-dozen horizontals were landed by others in the past, but with 4.5-inch casing, Sheffield said.

"That's not what we do in the United States. We're running 5.5-inch casing. We saw an opportunity to apply a modernized well design and frac to this play."

Also, well completions had been with gel, which was tried uneconomically on gas shale in the past century until wildcatter George Mitchell tried a slickwater job in the Barnett Shale in the late 1990s. Making the wells horizontals launched the shale revolution.

Tamboran expected to complete Shenandoah South 1H, its newest horizontal, in December, using 5.5-inch casing and slickwater.

"You can't get a high enough pressure through 4.5-inch casing," Sheffield said. "You need higher pressure to break up the rock."

"That's what has delayed the play. The right services and the right recipe will get the job done." OGI

▸ **PRIVATE** EQUITY

Private Equity Exits Hit Five-year High

Some $30 billion worth of private deal-making in 2023 sets up slower pace ahead.

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Occidental Petroleum's $12 billion purchase of the private equity-backed CrownRock made 2023 the busiest year for private equity exits in at least five years, according to Enverus Intelligence Research.

The purchase of CrownRock, backed by private equity firm Lime Rock Partners, put the year's private equity exits at about $30 billion. Exits totaled $24.4 billion in 2021 and $23.3 billion in 2022—years considered to be high by people watching the industry.

"The private equity overhang might be over," said EnergyNet CEO and President Chris Atherton.

"It's been a very busy year. They've done a great job monetizing assets in their market. Tip of the hat to all the private equity guys," Josh Martin, a managing director at Pickering Energy Partners, told Hart Energy. "Five or six years ago, they said, 'Look, eventually the independents are going to have to come to us for inventory,' and that's what's been happening."

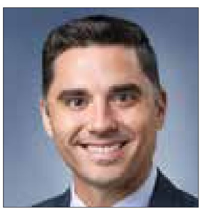
The private equity selloff is so large, experts tracking it believe exits will slow dramatically next year for lack of assets to sell.

"There's just not the opportunity set to go after because of the volume of deals we've seen over the last three years," said Andrew Dittmar, senior vice president of Enverus Intelligence Research. "What you're going to see, I think, is a pretty rapid roll-up of the remaining smaller core Permian positions, but most of those are going to have less than 100 net remaining locations and are going to be smaller size deals than what we saw in the last few years."

Atherton also said he expects 2024 to have far fewer exits by private equity.

"They're reloading right now, but it's not like there's another wave [of exits] coming," he said. "The queue of companies isn't as plentiful."

EnCap Investments' exit in 2023 stood out. By early October, it had monetized more of its E&P assets in 2023 than it had in the past five years combined.



Brooks Despot

Brooks Despot, a director at EnCap, said the exits that totaled more than $8.4 billion were a simple matter of timing.

"It felt like it was a really compelling time to monetize the assets that we monetized because there was momentum in the market.… The reason why we sold more assets in the last 12 months than we had in the last five years combined is largely because the market wasn't there," Despot said, explaining that the market improved dramatically in sellers' favor in 2023. Many E&Ps, particularly in the Permian Basin, have been on the hunt for quality inventory to shore up runway for future years.

"The stars aligned with everything. You had an economy that's been roaring, you had commodity prices that are, if you look at in the context of the last five years, are [in] a very constructive place," he said. "And by the way, if you look at the assets we sold, they're largely oil.… There was a flurry of public buyers in the market over the last 12 months."

Despot said the environment has changed since 2013-2020, when 10 to 50 wells would be drilled on an asset and then sold.

"Today, you really have to move that asset profile much further down the development timeline to fully delineate it," he said.

Likewise, NGP Energy Capital Management partner Patrick McWilliams said the private equity firm sold assets because of the favorable market, with strong balance sheets enabling E&Ps to buy.

Patrick McWilliams

"Our preferred consideration is cash, as compared to taking back equity," he said. "Companies are in strong positions, making big quarterly cash distributions and focused on that profitability. They need to buy an asset that is self-financing."

He said his firm was well-positioned to meet this demand.

"Our portfolio had gotten to the more mature threshold where a number of the companies that we sold … were large-scale companies that had nice remaining inventory, but also had a large amount of production and free cash flow that can fund that development on a forward basis," he said.

McWilliams said NGP's strategy since 2020 has been more focused on developing rather than acquiring assets.

NGP declined to release annual numbers, but it was the backer of sizeable Permian Basin operators that were acquired this year, including Hibernia Energy III LLC and Tap Rock Resources. Both were bought by Civitas Resources in deals valued at a combined $4.7 billion. OGI

▸ **EXECUTIVE** OIL CONFERENCE

Paying the Permian Premium

Top-tier Permian inventory scarce, 'extremely expensive.'

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Consolidation is sweeping the Permian Basin as operators scour West Texas and eastern New Mexico for top tier acreage.

But most of that elevated inventory already resides in the clutches of a relatively small batch of E&Ps.

Upstream investors are prioritizing shareholder returns over all other metrics. Commodity prices during 2022 and their relative stability in 2023 enabled E&Ps to reward investors with unprecedented cash share buybacks and dividends.

But inklings of lower oil and gas prices, and a declining inventory of quality drilling locations are beginning to rattle the free cash flow-driven shareholder return frameworks that have propped up some operators.

Upstream operating cash flow has generally been declining over the past few quarters, said Ryan Duman, director of U.S. upstream research for Wood Mackenzie, during Hart Energy's Executive Oil Conference in November. At the same time, inflation in services costs is driving capex up.

"What you've seen with these trends is there's been more pressure and less free cash flow for operators to deliver on those very valuable shareholder distributions," Duman said.

During the second quarter, companies actually had to start tapping their balance sheets to deliver on shareholder return promises for the first time since the COVID-19 downturn.

Recent lifts in commodity prices helped boost free cash flow generation in the third quarter, according to WoodMac.

But as E&Ps drill through their top acreage and move into deeper and less economic Tier 2 and Tier 3 benches, long-term free cash flow generation will start to become a bigger problem, Duman said.

Those fears have driven a wave of deals aimed at deepening quality drilling runway in the Permian Basin.

"One of the ways companies can stabilize these trends, if not improve them, is through M&A and refreshing some of that Tier 1 inventory," Duman said. "We're certainly seeing that through deals."

The Permian premium

Companies might have a desire to get deeper in the Permian right now, but they're going to need to pay a pretty penny to do so.

Consolidation in the Permian Basin isn't a new story by any means. What is relatively new is how consolidated the core-of-the-

> ***"Consolidation in the Permian is going to be extremely challenging, if not just extremely expensive, for companies looking to acquire any sort of significant number of locations going forward."***

—**Ryan Duman,** ***director of U.S. upstream research, Wood Mackenzie***

core Permian inventory is right now, Duman said.

Approximately 80% of the remaining Tier 1 drilling locations in the entire Permian Basin—throughout all benches of the Midland and Delaware basins—are held by a small number of companies with a market cap of more than $30 billion.

"This is going to be extremely challenging, if not just extremely expensive, for companies looking to acquire any sort of significant number of locations going forward," Duman said.

WoodMac generally defines a Tier 1 location as a well that can generate at least a 30% return at a $50/bbl WTI price.

To acquire anywhere between 500 Tier 1 and 1,000 Tier 1 drilling locations in the Permian, expect a price tag of between $3 billion and $10 billion, Duman said.

Over time, there will be fewer and fewer deals that companies, outside of the Exxons or Chevrons of the world, will be able to make.

"We're going to see more and more Permian Tier 1 inventory decline and just not be available," Duman said. "So, what are these companies going to do?"

One of the options is making Tier 2 locations generate returns like Tier 1 locations. That's happening in the Bakken, where modern completion techniques are being applied to legacy wells to boost productivity.

To achieve Tier 1 results from Tier 2 quality inventory, operators would need to see a roughly 30% decrease in total drilling and completion costs.

"With most companies comfortably having about a decade at least worth of inventory, this doesn't have to be imminent that companies target this either," he said. "Do you think over the next five years we could reduce costs by about 30%? I think that's certainly plausible."

And companies are even considering shale patches outside of the Lower 48. WoodMac has started getting questions about E&Ps moving into the Montney Shale in Alberta, or the Vaca Muerta Formation in Argentina.

Permian Buyers, Sellers Find 'Goldilocks' Zone

M&A in the basin took off in 2023 because deal prices were not too low, not too high.

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M&A was dominated by blockbuster deals in 2023 as the oil and gas market seemingly hit the perfect spot for both sides of the table.

Going forward, the driving force for companies in a re-established oil and gas industry will be creating a position for the future, said Tim Perry, vice chairman of Global Energy Group at RBC Capital Markets.

"We've gotten in this situation where (crude prices per barrel are) $80, $75, $65, $70 long-term strip," Perry said at Hart Energy's Executive Oil Conference in Midland, Texas, in November. "It's an area where both buyers and sellers feel very comfortable transacting. It's almost like Goldilocks—it's not too low, it's not too high."

In the second quarter, M&A deals tripled in value to $24 billion from the prior quarter, according to an August analysis by Enverus.

Civitas Resources made two deals worth $4.7 billion as it advanced its position in the Midland and Delaware basins. The trend continued into the next quarter, headlined by Exxon Mobil's $60 billion acquisition of Pioneer Natural Resources' assets in the Midland Basin—followed quickly by Chevron's agreement to merge with Hess in a $53 billion deal.

The surge in the marketplace followed trends that were building for more than a decade, but that began to come to a head following the COVID-19 pandemic in 2020, said Greg Chitty, managing director of Jefferies, who also spoke at the conference.

"One interesting thing to talk about today is, we've seen a massive transition from I would say the period in 2020, [in] which everyone thought oil was going away," Chitty said.

The oil and gas market has been bottled up for more than a decade, as trends globally pushed investments toward alternative energy sources. Some investment firms also divested from oil and gas holdings. Russia's invasion of Ukraine and the difficulty faced by some alternative energy companies reached a critical point last year.

"We are very bullish on supply and demand simply because now we're entering year 15 in underinvestment" in oil and gas, Chitty said. "I mean, that is a staggering thought when you think about it."

While the industry sees more companies willing to finance, the investor base has changed, Perry said. The sector is still short of dollars flowing in while E&Ps remain undervalued in the S&P 500. Energy stocks account for less than 5% of the market-valued weighted S&P 500.

"A lot of the market is made up of generalists, and a lot of generalists really don't understand this industry," he said. "And as a result, it's been harder and harder for this industry, unfortunately, to really get investor dollars to come into it."

In the past, Wall Street firms would pick a company and "park" investments in it for 10 years, Perry said. Today, investment firms have more of a renter's attitude toward their investments—they want to be able to get in and out of their holdings, focusing instead on trading liquidity.

Large-cap advantage

An investor's mindset works to the advantage of large-cap companies, Perry said.

"What's really happened over the last three years is, we've shifted from an industry that was focused on growth and adding rigs [into] an industry that's a much slower growth, growing flat to 5%, but really focused on return in capital and free cash flow," he said.

Larger companies are incentivized to continue buying assets to keep pace with production—particularly as their equity values eclipse their smaller peers on Wall Street.

"A lot of the market is made up of generalists, and a lot of generalists really don't understand this industry."

—**Tim Perry**, *vice chairman of Global Energy Group, RBC Capital Markets*

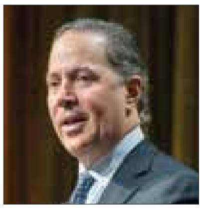
"If you are a very large company, you want Tier 1 inventory. You also want to be able to show a near-term accretion," Perry said. "Well, when you trade a turn to turn and a half higher, 20% to 25% higher on your multiples, it's much, much easier for a large-cap company to buy a medium or smaller company."

And large companies are primarily focusing on the leading growth sector of the U.S. gas and oil market—the Permian Basin—for their supply.

"The Permian has the most inventory and, frankly, it's the easiest way to generate a near-term barrel," Chitty said. "So, that makes it nice. When you get in situations where you're going to have just-in-time problems, you need a valve to quickly solve that problem."

Chitty said other basins in the U.S. lack the advantages of the Permian. While the Haynesville Shale has shown growth, it's a gassy play that, to some extent, has its fate tied to future LNG projects. Similarly, the Appalachia Basin faces its own headaches, including political opposition and an inability to permit new pipelines, even to neighboring states.

"We see that continuing because we don't see any of their basins providing growth," Chitty said. "And it's difficult unless there's a real strategic push in a particular basin and a particular asset, versus the Permian, where it's an easy button that's widely accepted by Wall Street, especially for the public."

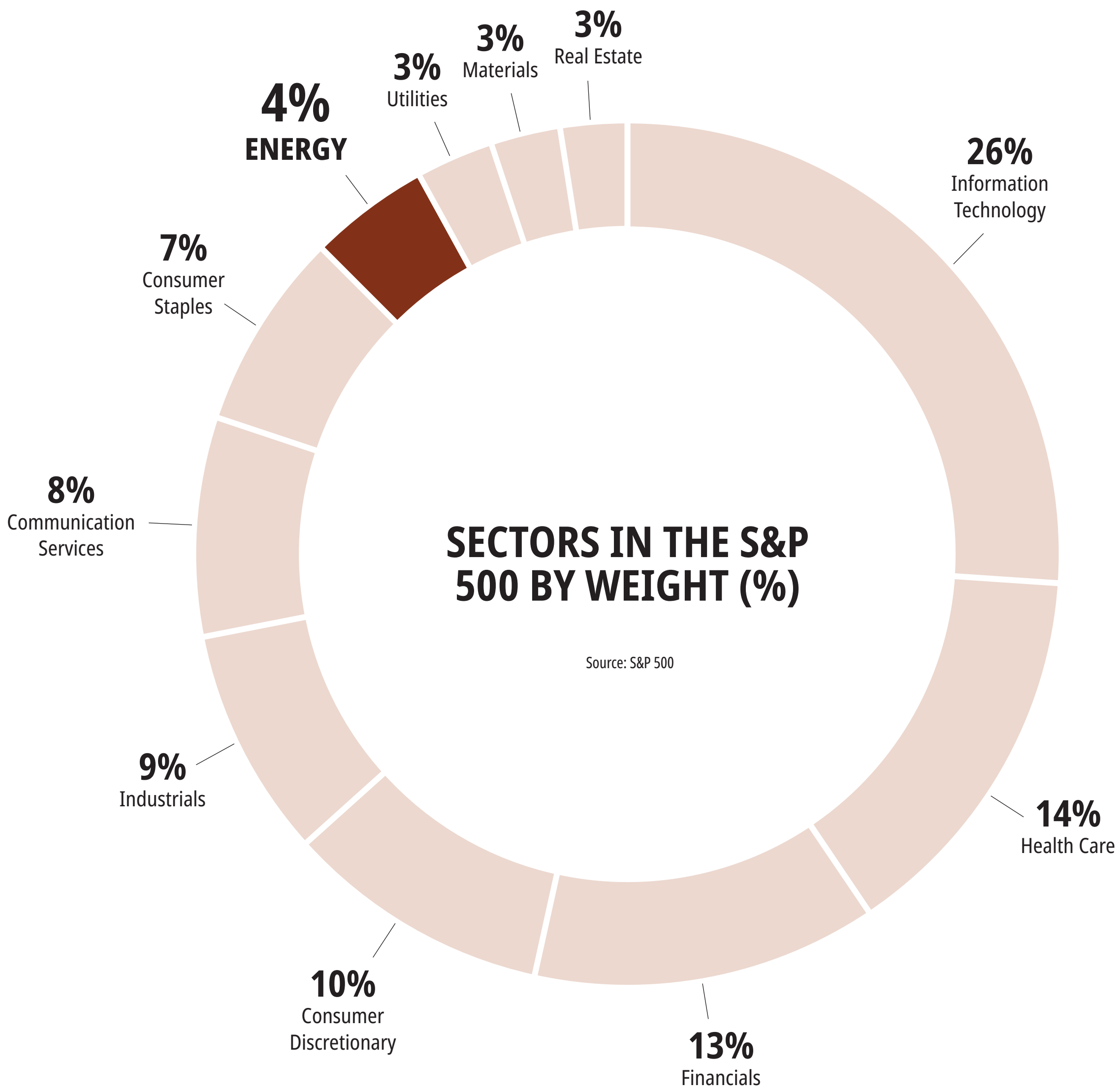


"The Permian has the most inventory and, frankly, it's the easiest way to generate a near-term barrel… When you get in situations where you're going to have just-in-time problems, you need a valve to quickly solve that problem."

—**Greg Chitty**, ***managing director, Jefferies***

Both analysts pointed out that while the investment market has changed, larger companies have started to go after future deals with the more traditional purpose of setting their company up for the long term, rather than responding to immediate market needs.

"When you look at Chevron and Hess, that was more a classic deal, where they saw some value out past what the public would say is a slam dunk," Chitty said. OGI



The Toby Rice Plan: 'Unleash US LNG'

The CEO of EQT Corp. wants to educate the public and avoid an inevitable energy 'train wreck.'

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Toby Rice, CEO of EQT Corp., with Nissa Darbonne, Hart Energy's executive editor-at-large, at the DUG Appalachia Conference.

Around the world, the measurements of a successful energy transition are ticking backward: global emissions are skyrocketing, energy security is shrinking and more people are living in energy poverty.

Toby Rice, CEO of EQT Corp., said he has a simple, proven and effective solution.

"Our energy transition plan is to transition the world from coal to gas, and transition gas to a zero-carbon energy solution and unleash U.S. LNG," Rice said at Hart Energy's DUG Appalachia Conference in Pittsburgh in November.

"LNG is the vehicle that will allow us to transition the world from coal to gas."

Carbon capture and hydrogen will be the vehicles that allow the transformation from natural gas to net-zero carbon solutions, he added.

"We believe we can do this without sacrificing energy security, keeping energy affordable and reliable, and the end result will be a pretty significant impact on the emissions front as well."

But obstacles are blocking the way forward.

Rice said that last year was the first in the last three decades in which fewer pipelines were built in the U.S.

Gas demand increased 56% since 2010, Rice said. But pipeline capacity hasn't kept pace, ticking up 25% while storage infrastructure has grown about 10%.

The U.S. has met demand through excess midstream capacity that was built during previous generations.

"Well, that can only last for so long and, unfortunately, we're now at a point where our pipeline capacity is maxed out," he said. "This means we're going to be in a very volatile period."

Geopolitical events, cyber-threats and capacity concerns are clear and present dangers to the industry's ability to meet demand, he said. The industry no longer has the necessary flexibility to manage a potential crisis.

'Train wreck' coming

A catastrophic event on the horizon wouldn't occur because natural gas lacks reliability, Rice said. Rather, policymakers have not focused on

> ***"The lack of energy education in this country is one of our biggest challenges. It's also one of our biggest opportunities because when people learn more about our industry, they're going realize everything we do is heavily scrutinized and [is] the best way to produce energy."***
>
> —**Toby Rice,** ***CEO, EQT Corp.***

the dependability of the power grid. The nation has been here before. Many energy policies to address the grid were the results of 1970s freezes in the Northeast that made it necessary to close hospitals and schools that were "literally freezing," he said.

"The lack of energy education in this country is one of our biggest challenges," Rice said. "It's also one of our biggest opportunities because when people learn more about our industry, they're going realize everything we do is heavily scrutinized and [is] the best way to produce energy."

The story is simple, he said. The push against fossil fuels has been easy because no one in the U.S. has seen the impact of blocking pipelines and shutting down reliable coal facilities. But the impact is coming; it is also preventable, he said.

"When this train wreck hits it, I think that people are going to wake up and they're going to get back to reality and we're going to get back to work doing practical things," Rice said.

But there will also be finger-pointing at the industry, and now is the time to let people know this is a "very dangerous game" that can be prevented.

"We have the resources, the ability and the drive to be a real solution provider here and address any problems," he said. "You'd think after Europe, people would really wake up," Rice said, referring to gas shipments being cut by Russia following its invasion of Ukraine.

The shale revolution has allowed the U.S. to evolve from coal to natural gas. Doubling down on natural gas is a proven and cost-effective way to lower emissions, Rice said.

Instead, leadership in states like Michigan are betting on 100% renewable power by 2040.

Such states could get lucky, or "They'll find out really quickly that it's, it's a really bad plan," he said.

People are blocking development in the U.S. and paying more to import power. Plans like the one in Michigan perpetuate the problem.

"It doesn't make sense," Rice said. "It's just a sign of the root cause of this whole thing. Political force has overridden market forces." OGI

▸ **DUG** APPALACHIA

'Forgotten Child' Ohio Sees Oil Output Soar

More than $100 billion in investments have poured into the state's oil and gas sector in the past decade.

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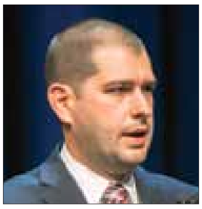
Buoyed by a decade of investment in the oil and gas industry, Ohio's production is up and expectations are high that even better numbers are around the corner.

Even though Ohio has sometimes been "the forgotten child" in the region, the state has plenty to offer, including the "holy trinity of hydrocarbons," Rob Brundrett, president of the Ohio Oil & Gas Association, said during an update on the state of the Utica Shale at Hart Energy's recent DUG Appalachia Conference. "We've got oil, natural gas, natural gas liquids and crude oil. So, we have them all right here in the Utica and the state of Ohio."



Rob Brundrett

Those resources have drawn in more than $100 billion in investments over the past decade, with the lion's share going to the upstream sector, he said.

"Most of this is private money. It's not government subsidies. We're very fortunate to have a strong, thriving industry," Brundrett said. "If you look at the producer side, about $70 billion of that is coming straight from the producers in the state of Ohio, and that money is going into eastern Ohio. And I can't again overstate the importance of that kind of infrastructure and that kind of investment in really one of the poorest regions in our state."

The state itself embraced its role as an energy producer during that time. With no corporate income tax, the climate is favorable for businesses, he said, and the regulatory environment is straightforward.

More than 4,000 permits have been issued for lateral shale wells, and more than 3,000 horizontal shale wells are producing, he said.

"We've got a really good regulatory environment that's allowed oil and gas to sort of thrive on the edge of this play," he said.

Brundrett said the industry-friendly environment is one of the big draws Ohio offers.

"Just last year, the state of Ohio declared natural gas a green energy. It's more of a declaratory statement than anything, but I think it doubles down on where the state's elected officials are when it comes to the production and use of natural gas," he said.

And Ohio has a fully integrated oil and gas industry with production, processing and refining in the state, he said.

Second sibling

In 2012, he said, the industry was excited about the possibilities and potential across the Utica Shale, which stretches from New York state in the north to northeastern Kentucky and Tennessee in the south, according to the U.S. Energy Information Administration (EIA).

Ohio's seemed to have potential even as neighboring states—and the Marcellus Shale—got most of the attention.

"Ohio is on the edge, so it's kind of like the younger sibling of the other two. And so maybe the projections weren't as great for Ohio as what

A natural gas well pad in Jefferson County in eastern Ohio is nestled among corn fields in the rural countryside. Ohio promises a favorable business and regulatory environment for natural gas production, according to Rob Brundrett, president of the Ohio Oil & Gas Association.

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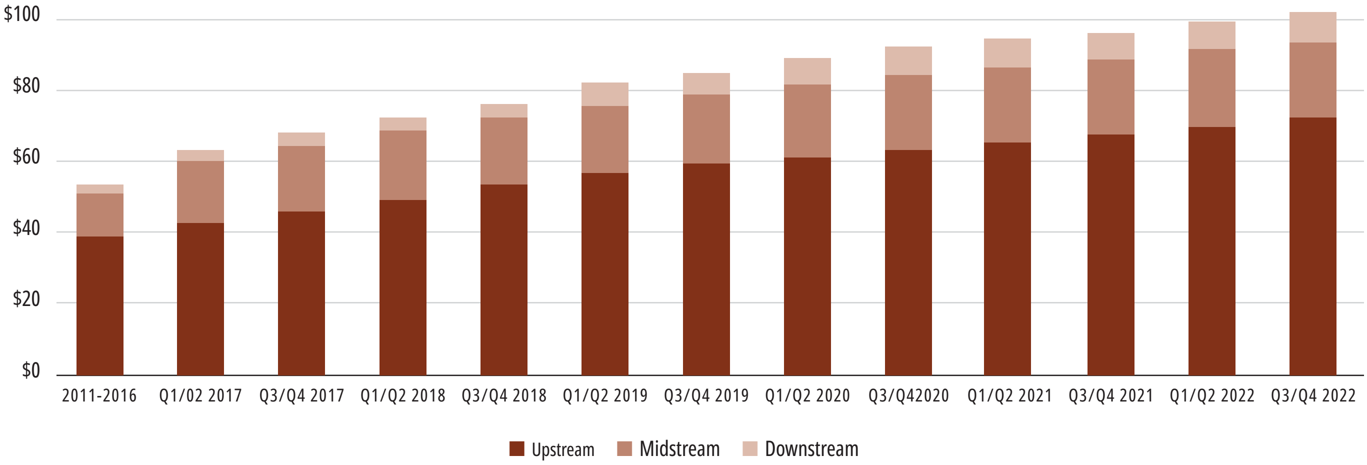
Cumulative shale investment in Ohio over time

($ billions, 2011-2022)



Source: Ohio Oil & Gas Association

they were for West Virginia and Pennsylvania," Brundrett said.

But 10 years later, he said, investments in the state are paying off.

"We've always had a strong gas play and we've continued to have a strong gas play," he said.

But the play's oil production is also picking up. Between first-quarter 2022 and second-quarter 2023, oil output increased by 51%, he said.

Overall Ohio, oil production is also up. In second-quarter 2023, the state produced a total of 6.9 MMbbl of oil. That compares with second-quarter 2022 production of 4.9 MMbbl—a 40% increase, according to the Ohio Department of Natural Resources.

Brundrett believes Ohio's contribution to the energy mix will continue to grow as the industry continues to improve its understanding of the source rocks and better parse data.

"I think we've all learned a ton over the last decade on how best to drill and how best to finish these wells to get the … maximum for your investment. And I think it's starting to finally really pay off in the state of Ohio, especially with natural gas liquids," he said. "We've found a way to kind of crack that code and really maybe extract the maximum benefits that we can from the ground in Ohio, which is really, really exciting. And we're probably going to see, obviously, a lot more investment in Ohio based on these results." OGI

▸ HALL OF FAME

Hart Energy's 50th Anniversary

Our reception was a place for the energy industry's elite to meet, greet and eat.

All Photos Hart Energy

1

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1) Attendees pack the A.D. Players at the George Theater at the reception. 2) A fireside chat was moderated by Agent of Change in Energy honoree Dan Pickering of Pickering Energy Partners, left, and featured Hall of Fame honoree Harold Hamm of Continental Resources; Hall of Fame honoree Tom Petrie, formerly of Petrie Partners; and Agent of Change in Energy honoree Chris Wright of Liberty Energy. 3) Cupcakes sporting the 50th anniversary logo. 4) Petrie is interviewed on camera by Jordan Soto. 5) Hall of Fame honoree Cindy Yeilding, formerly of BP. 6) Britney Geidel of Comerica and Sasha Gumprecht, consultant.

7) Hall of Fame honoree Ronnie Irani. 8) Hall of Fame honoree Floyd Wilson sits beneath a huge banner displaying Hall of Fame and Agent of Change in Energy honorees, and a timeline covering energy events of the last 50 years. 9) Hall of Fame honoree Mohamed Soliman and Syed Farouq-Ali of the University of Houston. 10) Agent of Change honoree Lyndal Cissell of SLB with guests. 11) Hamm with guest Jennie Idlett. 12) Sweta Sethna of Energy Transfer and Minoo Sethna of Rail Consulting. 13) Lily Wang of Crowe and Mohamad Al-kawafha of LaPorte CPAs & Business Advisors. 14) Chantal Hagen of ComboCurve.

HARTENERGY

Shale 2024

A SUPPLEMENT TO Oil and Gas Investor

QUALITY OVER QUANTITY

As US Shale Consolidates, Fewer Players with Bigger Balance Sheets to Dominate the Field

VALUE ADDING

Shale Producers Temper Ambition with Consolidation

MONTNEY MOMENTUM

Canada's Top Shale Plays Plan to Boost Production

CRITICAL MASS

Shale Players Weigh Opportunities in Lithium Mining

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Shale 2024

TABLE of CONTENTS

Buckle Up for Shale

Corporate strategy, geopolitics and emerging technologies are reshaping U.S. energy.

One thing you can be sure of is that the oil and gas industry is now, and probably forever will be, steeped in uncertainty.

Our editorial team has drawn on our experiences of covering the industry's top stories for you in 2023 to assess how those events—billions of dollars' worth of consolidation, private equity exits, advances in artificial intelligence, the energy industry's transition and, of course, the calamity of wars—will shape the energy business during the coming 12 months.

The world continues to grapple with the supply and demand mechanics of its reluctant dependence on fossil fuels. And the industry continues to seek ways to maintain its social license in the midst of transformation.

The corporate landscape of U.S. shale has changed and it will continue to do so. Corporate sweeps during the last six months have upended legacy independent producers: Exxon Mobil wrapped a highly acquisitive year with its deal for Pioneer Natural Resources; Chevron took out Hess Corp.; and Occidental Petroleum bought privately held CrownRock to make 2023 the busiest for private equity in years.

These megadeals have primed the sector for a new A&D round in 2024 as buyers will no doubt shed some of the assets accrued to perfect their portfolios.

Haynesville assets in Chevron's pro forma holdings from the PDC Energy closing are likely to be unloaded, along with the Bakken assets included in the Hess deal. Selling off non-core assets will shore up the balance sheet for additional shareholder returns or building up precious assets in Chevron's growing Guyana business.

A variety of analysts, including Ernst & Young, Siemens, Precision Reports and others forecast millions of dollars in annual investment to advance artificial intelligence (AI) applications in the industry, both in terms of efficiency and emissions.

Some companies have been to reluctant to embrace the technology as anything more than a consultant, a kind of advanced spreadsheet or highly gifted librarian—not quite ready to put it in control of sensitive or critical tasks.

Still, AI advocates say it could be more important to the world—especially in the energy sector—than all recent technology combined.

As 2024 unfolds and money is spent, the AI implications will come into clearer view.

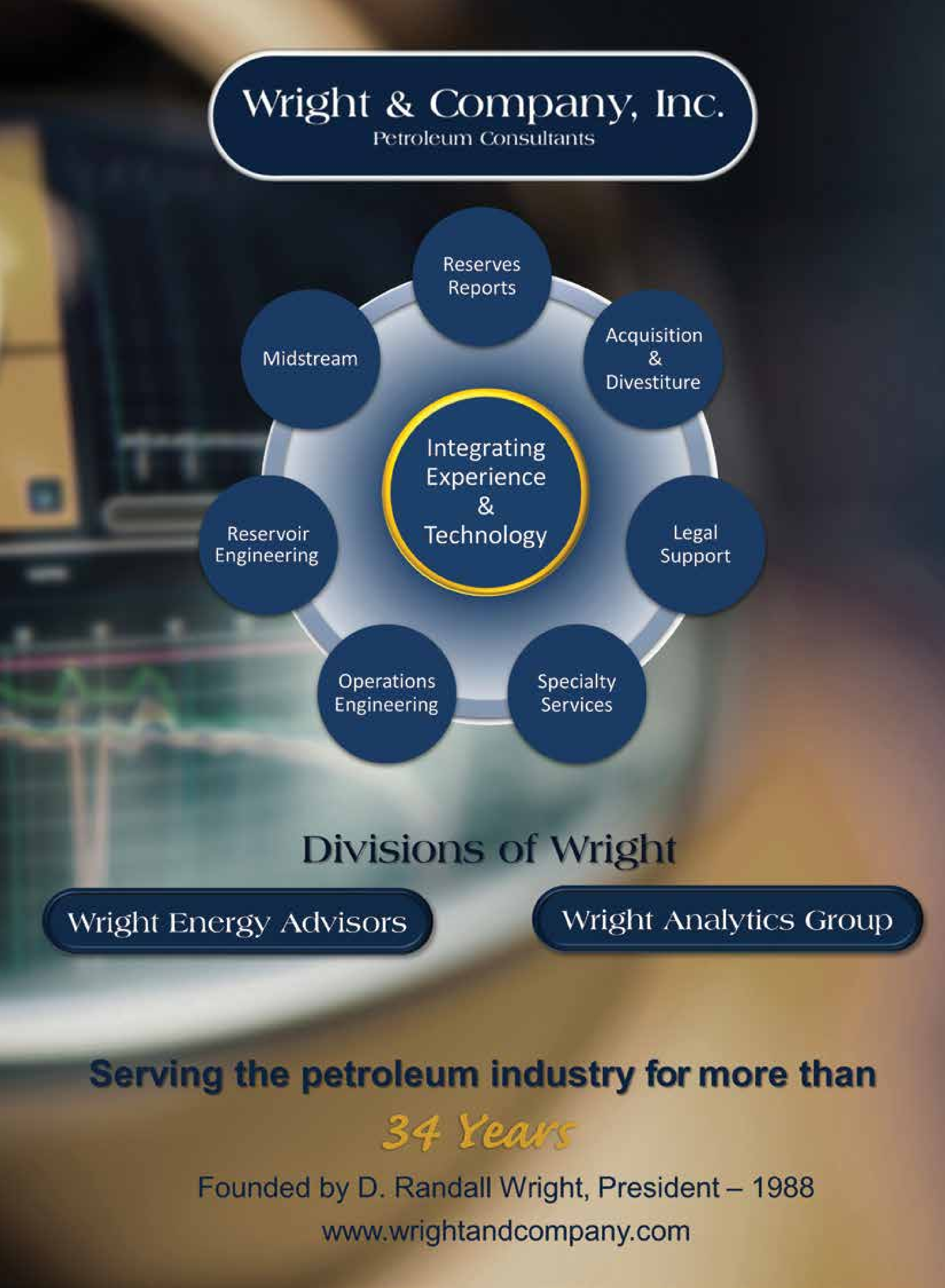
But as the promise of the new and novel takes shape and rebuilds the industry, the oil and gas business remains vulnerable to geopolitical upheaval.

Russia's invasion of Ukraine has shaken world markets and made U.S. deployment of its LNG resources an imperative, but how it plays out remains a big question.

Most companies consider energy security as a measure in most of their decisions, strategic or otherwise. In the U.S. and in allied European nations, energy security is prominent in the speeches of serious politicians and other thought leaders.

Nevertheless, some may still say that the more things change, the more they stay the same. Fitch Ratings expects the industry's sector performance in the year ahead to look much like it did in 2023, with perhaps some strength in mid-cycle levels. OPEC-plus curtailments and slowing U.S. crude production will keep oil prices broadly stable, according to Fitch.

But that's if all goes to plan. Other analysts predict U.S. shale growth inching well above the 5% many companies anticipate; OPEC has proven itself to be unpredictable at times; and war is hell. ■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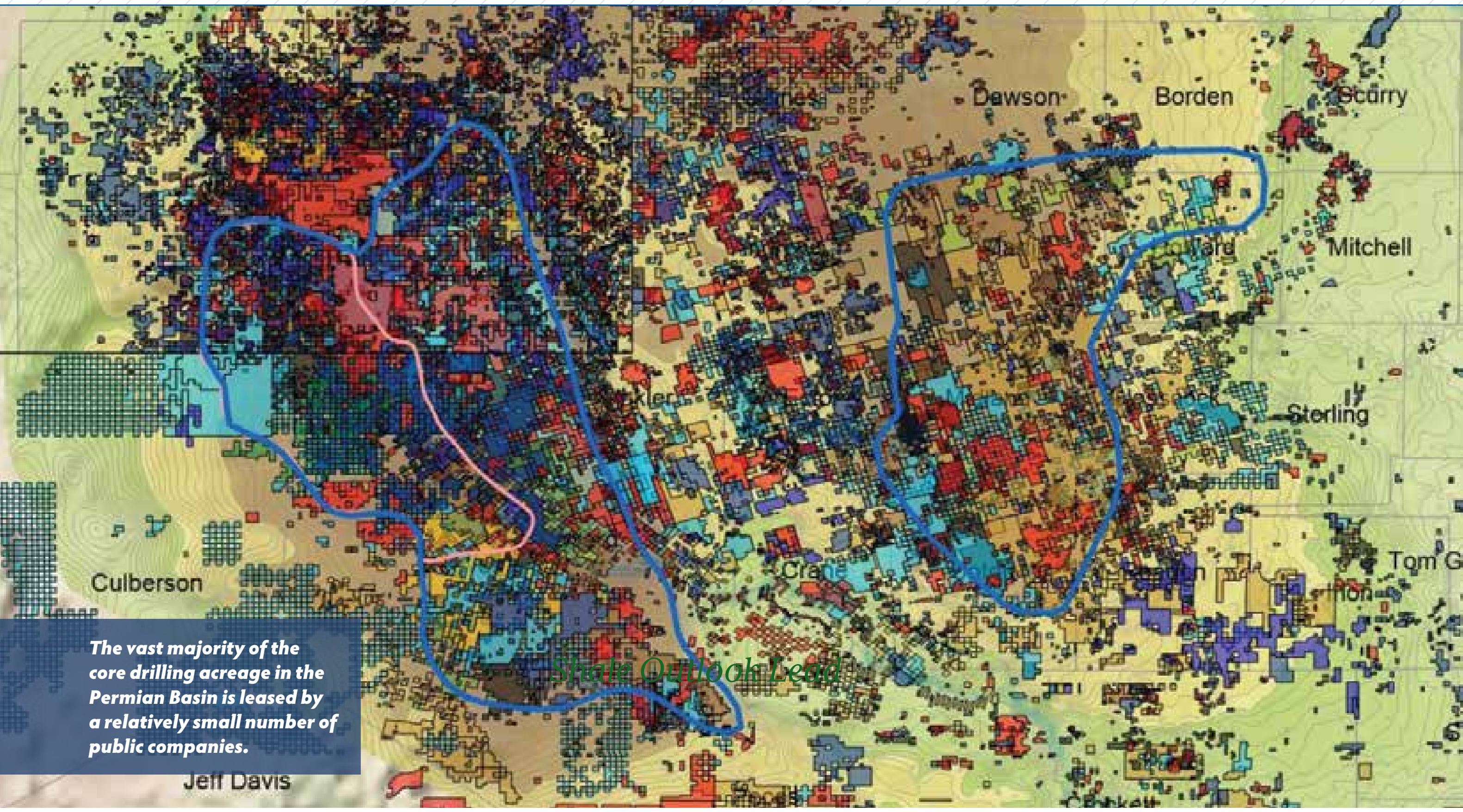


The vast majority of the core drilling acreage in the Permian Basin is leased by a relatively small number of public companies.

Source: Bernstein, Enverus

M&A Bonanza Can't Stop, Won't Stop

Permian Basin well productivity has trended down. Top-tier drilling locations are scarce. Capital is at a premium. E&Ps need low-cost inventory and scale, and they're willing to pay big bucks to get them.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Civitas Resources was fresh off of a merger deal with three Colorado E&Ps when questions started to pop up about its drilling runway.

The deal among Denver-Julesburg (D-J) Basin producers Bonanza Creek Energy, Extraction Oil & Gas and Crestone Peak had yielded Civitas, the largest pure-play Colorado producer. Chris Doyle had recently been brought in as president and CEO after an executive search.

Civitas had a strong position in the D-J Basin, Doyle told Hart Energy in an exclusive interview. These were high-quality assets with low breakeven costs that could generate strong volumes of free cash flow.

"It was a very successful business model for the first six, nine months of Civitas," Doyle said.

"What we were really trying to do is: How do we take that business model that's focused on shareholder returns, little growth, maximizing free cash flow, and how do we extend the duration of that business model?"

The company needed to find more inventory depth—ideally the same kind of high-quality, low-cost inventory already competing for capital in its D-J Basin drilling plans. But that was going to be a tall task to actually locate and buy in the D-J Basin.

At that point, the D-J was already significantly consolidated, Doyle said. The basin's core was essentially

"I do think there is a recognition from industry that high-quality inventory and access to resource is more precious today than it was a year ago, or certainly a couple years ago."

CHRIS DOYLE, president and CEO, Civitas Resources

already leased up by the likes of Chevron, Occidental, PDC Energy and Civitas itself.

And the basin consolidated even more when Chevron bought PDC for $6.3 billion last year.

"That really limited the opportunities for Civitas to continue to grow and extend our business model within the D-J," Doyle said.

If Civitas couldn't find the high-quality inventory it desired in Colorado, it needed to look somewhere else. So the Colorado pure play turned its attention south to Texas and New Mexico.

Doyle said Civitas knew it needed to enter a new basin—the Permian Basin, America's top oil-producing region—with scale. Instead of dipping its toe into the pool, Civitas cannonballed its way into the Permian with nearly $7 billion in M&A in 2023.

The first pair of deals, announced in June, included Delaware Basin assets from NGP-backed private operators Hibernia Energy III and Tap Rock Resources. Civitas agreed to pay $4.7 billion in a cash-and-stock transaction.

In October, Civitas entered the Midland Basin with a $2.1 billion acquisition of Vencer Energy. Vencer is backed by international energy trader Vitol.

Scale matters in the oil and gas business, Doyle said. Being bigger helps you negotiate more favorable services contracts to lower drilling and completion costs. You can be more efficient with your rigs and frac crews on a larger, more contiguous position. All of those help you lower the breakeven cost of your drilling inventory.

But scale also helps your balance sheet and trading liquidity. Larger companies generally trade at higher multiples than smaller players. And a strong, investment-grade balance sheet can help you access lower costs on bank debt—an important point with elevated interest rates.

Civitas has seen some of the benefits of scale: the company's stock price was up around 20% year over year when the market closed on Dec. 7.

"I do think there is a recognition from industry that high-quality inventory and access to resource is more precious today than it was a year ago, or certainly a couple years ago," Doyle said.

Top 50 U.S. shale public companies
(Average first-half 2023)

Rank	Operator	Boe/d
1	Exxon Mobil	1,167,969
2	Chesapeake Energy	1,130,230
3	EOG Resources	1,103,901
4	EQT Corp.	990,448
5	Occidental Petroleum	977,228
6	ConocoPhillips	970,496
7	Southwestern Energy	926,887
8	Chevron	903,877
9	Devon Energy	809,620
10	Pioneer Natural Resources	801,198
11	Coterra Energy	799,473
12	Antero Resources	540,976
13	Diamondback Energy	491,636
14	Marathon Oil	439,170
15	Permian Resources	391,236
16	Ovintinv	355,588
17	Range Resources	352,079
18	Comstock Resources	343,248
19	BP	301,417
20	CNX Resources	263,056
21	Chord Energy	225,408
22	Crescent Energy	220,905
23	Gulfport Energy	218,957
24	APA Corp.	207,481
25	Civitas Resources	202,492
26	National Fuel Gas	195,655
27	SM Energy	194,141
28	Repsol	187,581
29	Matador Resources	165,966
30	Hess Corp.	154,760
31	Diversified Energy	141,445
32	Vital Energy	141,405
33	Callon Petroleum	126,277
34	California Resources	103,722
35	Exco Resources	103,218
36	Magnolia Oil & Gas	86,205
37	Enerplus	78,822
38	TotalEnergies	70,666
39	Silverbow Resources	70,321
40	Kinder Morgan	69,803
41	Baytex Energy	57,400
42	Amplify Energy	55,508
43	HighPeak Energy	55,304
44	Tellurian	39,685
45	Murphy Oil	32,052
46	Berry Petroleum	28,529
47	Riley Exploration	26,305
48	Ring Energy	23,195
49	Dominion Energy	22,568
50	Equinor	19,264

Source: Enverus

Some well productivity has declined in the Permian Basin, even as average lateral lengths have increased.

Shutterstock

Anatomy of a bonanza

E&Ps have spent years and billions of dollars innovating and trying to organically boost shale productivity. But a new realization is settling across the shale patch: If you want the highest quality drilling inventory, you'll probably have to buy it from someone else.

In our 2023 Shale Outlook, we highlighted efforts by Pioneer Natural Resources—one of the Permian Basin's largest and most adept players—to overcome well productivity declines and a rising gas-to-oil ratio on its Midland Basin position.

These concerns weren't exclusive to Pioneer. Exxon Mobil, Chevron and several other of the basin's top operators were dropping their outlooks for Permian oil and gas volumes because of declining well production, services cost inflation and other headwinds.

E&Ps expressed optimism despite the challenges. Both Chevron and Exxon continued touting plans to push their respective Permian outputs up to at least 1 MMboe/d in the coming years.

Pioneer said it would go back to the drawing board and reshuffle its 2023 drilling portfolio to target wells

Top 10 U.S. shale producers
(By oil production, average first-half 2023)

Rank	Operator	Gross bbl/d
1	EOG Resources	626,454
2	ConocoPhillips	590,931
3	Occidental Petroleum	567,771
4	Pioneer Natural Resources	503,072
5	Exxon Mobil	500,093
6	Chevron	458,355
7	Devon Energy	453,315
8	Diamondback Energy	328,028
9	Marathon Oil	247,982
10	Permian Resources	204,667

Source: Enverus

Top 10 U.S. shale producers
(By gas production, average first-half 2023)

Rank	Operator	Gross bbl/d
1	Chesapeake Energy	6,672,115
2	EQT Corp.	5,888,008
3	Southwestern Energy	5,419,569
4	Exxon Mobil	4,007,100
5	Coterra Energy	3,929,764
6	Antero Resources	3,162,310
7	EOG Resources	2,864,588
8	Chevron	2,673,046
9	Occidental Petroleum	2,456,643
10	ConocoPhillips	2,277,330

that could potentially generate higher returns.

The industry believed it would be able to develop itself out of declining shale productivity, leaning on engineering innovation like the kind that ushered in a historic fracking boom more than a decade ago.

And beyond making development more efficient, there was still plenty of runway for the industry to continue drilling like it had been. In 2022, energy analytics firm Enverus Intelligence Research estimated there were 125,000 remaining undeveloped locations across North America that could break even below a $40/bbl WTI price.

A lot can change in a year.

Drilling and completion costs continued to rise. New well productivity in the Permian appears to have peaked and is declining moderately, and the basin's gas-to-oil ratio continues to climb. The circumstances are even less rosy in more mature shale plays like the Bakken and the Eagle Ford.

Shale wells, by and large, aren't getting all that much better: Average well productivity across U.S. shale appears to have peaked in 2021, according to data analyzed in reports by Bernstein, Enverus and Novi Labs.

The roughly 7,300 horizontal wells that came online during 2021 produced an average of 106,800 bbl/d of oil in their first six months of production, Novi Labs found. Meanwhile, the 3,000 horizontal wells that began production this year—and have been producing for at least six months—averaged 97,700 bbl/d, a decline of 4.2% each year.

Moreover, productivity declined despite average lateral lengths increasing from 9,200 ft in 2021 to 9,800 ft in 2023.

The conundrum is even more pronounced in Lea County, N.M., the heart of the Permian's Delaware Basin and the only Permian county that produced more than 1 MMbbl/d in August 2023.

Well productivity in Lea County dropped by 16% over two years, despite a small increase in average lateral lengths.

Headwinds like rising drilling costs and declining productivity caused Enverus to recently reduce its previous estimates from 125,000 to around 75,000 remaining Tier 1 drilling locations, at a sub-$45/bbl WTI price, across North America.

At current activity levels, it represents just about six years of remaining top-tier drilling inventory across the continent.

And that top-tier inventory isn't easy to find. The vast majority of the remaining Tier 1 drilling locations throughout all benches of the Midland and Delaware basins—approximately 80%—are held by a small number of public companies with a market cap of more than $30 billion, according to Wood Mackenzie research.

U.S. rig count by top 50 operators
(Average first-half 2023)

Rank	Operator	US Rigs Running
1	EOG Resources	27
2	Occidental Petroleum	26
3	ConocoPhillips	25
4	Devon Energy	21
5	Pioneer Natural Resources	20
6	Exxon Mobil	19
7	Chevron	18
8	Diamondback Energy	15
9	Marathon Oil	11
10	Permian Resources	11
11	BP	11
12	Chesapeake Energy	10
13	Coterra Energy	10
14	Ovintiv	8
15	Southwestern Energy	7
16	Matador Resources	7
17	Comstock Resources	6
18	APA Corp.	6
19	SM Energy	6
20	EQT Corp.	5
21	Chord Energy	4
22	Hess Corp.	4
23	Callon Petroleum	4
24	Antero Resources	3
25	CNX Resources	3
26	Gulfport Energy	3
27	Vital Energy	3
28	Enerplus	3
29	Range Resources	2
30	Crescent Energy	2
31	National Fuel Gas	2
32	Repsol	2
33	Exco Resources	2
34	Magnolia Oil & Gas	2
35	Silverbow Resources	2
36	Baytex Energy	2
37	HighPeak Energy	2
38	Ring Energy	2
39	Dominion Energy	2
40	Civitas Resources	1
41	Kinder Morgan	1
42	Tellurian	1
43	Riley Exploration	1
44	Diversified Energy	0
45	California Resources	0
46	TotalEnergies	0
47	Amplify Energy	0
48	Murphy Oil	0
49	Berry Petroleum	0
50	Equinor	0

Source: Enverus

Untapped potential

Civitas isn't alone in its U.S. shale aspirations. E&Ps big and small are spending billions to acquire undeveloped drilling inventory capable of generating returns even if oil prices slump below $40/bbl.

In a transaction that might have been considered unthinkable a year or so ago, Exxon inked an agreement to acquire Pioneer Natural Resources in an eye-popping $60 billion deal, excluding the assumption of Pioneer's net debt.

The megadeal adds Pioneer's more than 850,000 net acres in the core of the Midland Basin to Exxon's existing 570,000 net Permian acres. At closing, Exxon's Permian production will more than double to 1.3 Mboe/d, based on 2023 volumes; Permian output will grow to 2 Mboe/d by 2027, up from Exxon's previous goal of 1 Mboe/d the company laid out before inking the Pioneer deal.

In another large-scale Permian deal, Occidental Petroleum agreed to scoop up private E&P CrownRock for $12 billion.

CrownRock holds one of the most coveted acreage positions among private Permian E&Ps. Occidental's acquisition includes 94,000 net acres of stacked pay assets and a runway of 1,700 undeveloped drilling locations across the core of the Midland Basin.

Smaller players are also spending billions to add Permian runway: Permian Resources added runway in the Delaware and Midland basins through its $4.5 billion acquisition of Earthstone Energy.

Ovintiv acquired three EnCap Investments-backed portfolio companies for $4.275 billion to bolster its footprint in the Midland Basin. EnCap also sold Delaware Basin E&P Advance Energy Partners to Matador Resources for $1.6 billion last year.

Vital Energy's desire to boost the oil weighting of its portfolio fueled nearly $2 billion in Permian M&A in 2022.

But public E&Ps are also looking for quality drilling runway outside of the Permian.

Chevron's acquisition of Hess Corp. delivers the California supermajor some incremental onshore production from Hess's large footprint in the Bakken Shale.

But Chevron's $60 billion megadeal was mostly about getting into the action offshore Guyana, the world's latest and most prolific oil discovery.

Those massive deals tighten an already tight market for quality M&A.

"Exxon and Chevron effectively took two of the best assets that were available for purchase off the board," said Fernando Valle, senior oil and gas equity analyst at Bloomberg Intelligence.

"There isn't another Pioneer out there," he said. "There isn't another Guyana out there for sale."

A new era?

The U.S. shale patch looks a lot different today than it did when horizontal drilling and fracking advances first

"There's certainly a tacit understanding moving forward for the next 10, 20, 30 years that the industry has a lifetime, both geological- and demand-wise. And it's really about being in the driver's seat to be a competitive force in the long term."

MATTHEW BERNSTEIN, senior shale analyst, Rystad Energy

unlocked tight oil and gas.

Droves of privately held independents were among the early pioneers in unconventional resource plays like the Eagle Ford, the Bakken and, more recently, the Permian.

As these basins matured over time, it's become more difficult for the small players to compete with the scale and engineering prowess of the majors and super-independents.

As a result, there are fewer small independents out there. The most successful private players with attractive assets have been acquired and integrated into larger E&Ps.

Many of the less fortunate wildcatters restructured or liquidated their assets through bankruptcy during periods of low commodity prices like the 2014 global oil glut, the Saudi Arabia-Russia price war and the COVID-19 pandemic.

Emerging from the pandemic, the survivors of the great shale reckoning have worked to attract capital back into the sector by spending within their means and pushing oodles of cash back to shareholders.

Matthew Bernstein, senior shale analyst at Rystad Energy, colloquially refers to this period of capital discipline by the shale industry as "Shale 3.0"—a period in contrast to the early innovations of the fracking industry and the drill-at-any-cost boom the sector saw in the years that followed.

Bernstein said U.S. shale could be entering a fourth era defined by the largest players absorbing even larger swathes of tight oil inventory into their portfolios.

Experts expect the deluge of shale M&A to continue in 2024. With fewer attractive private E&Ps left to buy, Bernstein thinks the market could see more mergers between public players in the future.

"There's certainly a tacit understanding moving forward for the next 10, 20, 30 years that the industry has a lifetime, both geological- and demand-wise," Bernstein said. "And it's really about being in the driver's seat to be a competitive force in the long term." ■

Drilling rigs operating in west Texas.

Shutterstock

Scarcity Fuels Record Year for M&A in Permian

The big have grown bigger and the Tier 1 acreage even pricier in the U.S.' hottest oil basin.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Inventory scarcity is fueling a historic wave of consolidation across the Permian Basin as U.S. shale enters a new phase of maturation.

Activity across the Permian Basin, America's hottest oil play, took a major hit during the COVID-19 pandemic. Operators slashed rigs and frac crews, and shut in production; the industry worked through a wave of restructurings as oil prices collapsed.

But today, the Permian is back. E&Ps have ramped up their drilling cadence over the past three years—working hard to spend within their means and return as much cash back to shareholders as possible.

The strategic importance of the Permian Basin cannot be understated: The Permian was expected to account for more than 5.98 MMbbl/d of crude oil production in December—or roughly 62% of total Lower 48 oil output, according to the Energy Information Administration.

The Permian's prolific resource output continues to attract investment from among the world's largest oil and gas companies, like supermajors Exxon Mobil and Chevron.

Top Permian public producers
(Average first-half 2023)

Rank	Operator	Boe/d	Bbl/d	Mcf/d	Well Count	US Rigs (Nov 19)
1	Exxon Mobil	1,167,969	500,093	4,007,100	17,103	19
2	EOG Resources	1,103,901	626,454	2,864,588	9,285	27
3	Occidental Petroleum	977,228	567,771	2,456,643	16,051	26
4	ConocoPhillips	970,496	590,931	2,277,330	8,066	25
5	Devon Energy	809,620	453,315	2,137,760	6,023	21
6	Pioneer Natural Resources	801,198	503,072	1,788,724	6,555	20
7	Diamondback Energy	491,636	328,028	981,631	4,863	15
8	Permian Resources	391,236	204,667	1,119,399	2,356	11
9	Ovintinv	355,588	197,923	945,960	3,843	8
10	APA Corp.	207,481	82,715	748,551	6,749	6

Source: Enverus

Source: Hart Energy

And with the Permian anticipated to drive U.S. oil production growth for the foreseeable future, E&Ps are spending big bucks to give themselves a bigger piece of the pie.

The problem is, there isn't that much more of the Permian pie to go around.

Hunting for inventory

The highest quality acreage inventory in the Permian with the lowest drilling costs—often referred to as core or Tier 1 inventory—is scarce.

About 80% of the remaining Tier 1 drilling locations throughout the entire basin, including all benches of the Midland and Delaware basins, are held by a small number of companies with a market cap of over $30 billion, according to data from Wood Mackenzie.

That inventory scarcity is driving up prices for acreage and production in the Permian. Acquiring between 500 and 1,000 Tier 1 drilling locations in the Permian could fetch a price tag anywhere between $3 billion and $10 billion.

With acquisition targets dwindling and investors demanding greater scale and inventory runway, E&Ps are pumping historic amounts of cash into Permian Basin deals.

Total transaction value in Permian assets eclipsed $100 billion during 2023, said Wood Mac. The previous record was $65 billion in 2019.

The $60 billion megamerger between Exxon Mobil and Pioneer Natural Resources, announced in October, will reshape the future of the Permian Basin.

Exxon expects its Permian production to grow to approximately 1.3 MMboe/d after closing the Pioneer deal, positioning it atop the Permian producer leaderboard.

By 2027, Exxon aims to boost its total Permian output to 2 MMboe/d—up from its previous goal of 1 MMboe/d before acquiring Pioneer.

Roughly 45% of Exxon's global upstream volumes will come from U.S. production after closing the Pioneer acquisition.

Occidental Petroleum is also digging deeper into the Permian: The company inked a $12 billion deal to acquire CrownRock, one of the most attractive remaining private E&Ps in the basin.

The acquisition of CrownRock, a joint venture between CrownQuest Operating and private equity firm Lime Rock Partners, includes more than 94,000 net acres of 1,700 undeveloped drilling locations in the core of the Midland Basin.

"This most recent deal will create the sixth soon-to-be 1 MMboe/d U.S. [Lower 48] producer, with others including Chevron, EOG, Exxon Mobil, EQT and ConocoPhillips," said Robert Clarke, vice president of upstream research at Wood Mac.

"And in the Permian specifically, Oxy will become a top three producer behind the majors, pumping more oil and gas pro-forma than Pioneer did at the time of its sale announcement," he said.

The Permian has also seen a deluge of smaller transactions as public E&Ps work to shore up their balance sheets and inventory portfolios.

Civitas Resources allocated nearly $7 billion to jump into the Permian with scale during 2023. The company entered both the Midland and Delaware basins with a pair of deals with private E&Ps NGP-backed Tap Rock Resources and Hibernia Energy III.

Citivas followed with a $2.1 billion acquisition of Vitol-backed Midland Basin E&P Vencer Energy in October.

"Given what has happened with commodity prices—we've seen a significant run-up last year and now some softness as the market's digesting global macro issues—it underscores again the importance of having high-quality, low-breakeven inventory," Chris Doyle, president and CEO of Civitas, told Hart Energy.

In a rarer public-public transaction, Permian Resources spent $4.5 billion to acquire Earthstone Energy, adding core Delaware inventory and production in the Midland.

Ovintiv spent $4.275 billion acquiring three private Midland E&Ps backed by EnCap Investments.

"If you're a company with a more limited scale in the basin, there's less both long-term opportunity and current valuation upside that comes as a result of that," said Matthew Bernstein, senior shale analyst at Rystad Energy.

Companies unable to afford premium Tier 1 inventory are moving out into fringier areas of the Permian or targeting less developed zones deeper underground. But these Tier 2 or Tier 3 opportunities require more money to drill and exploit than core Tier 1 locations.

"We have a way to get more oil out of the ground," said Fernando Valle, senior oil and gas equity analyst at Bloomberg Intelligence. "It's a matter of whether it's worthwhile and how that cost can come down over the next five to 10 years."

62%
Permian's share of Lower 48 oil production

$100B+
Permian transaction value in 2023

Buying bonanza

E&Ps in the Permian still need inventory, so experts think the trend of consolidation will continue in 2024. But the number of attractive and somewhat affordable acquisition targets is shrinking as options are plucked off the market.

Endeavor Energy Partners holds a coveted position in the core of the Midland Basin. A Fitch Ratings report from November disclosed that the privately held E&P is producing 331,000 boe/d, up 25% from 2022 levels.

But Endeavor wouldn't be cheap to acquire: Analysts suggest that its current market valuation could be in the neighborhood of $30 billion. That's a whopping asking price that few oil companies, outside of the majors, could afford to pay.

There's also Tyler, Texas-based E&P Mewbourne Oil, one of the Permian's top private producers and among the most active drillers in the Delaware.

In an exclusive interview with Hart Energy last summer, Mewbourne President and CEO Ken Waits insisted that the company wasn't for sale.

"[Endeavor's and Mewbourne's] strategies may be a bit more different in terms of willingness and timing of wanting to sell," Bernstein said.

Fort Worth-based Double Eagle has been one of the largest independent purchasers of oil and gas leasehold interests in the Permian.

Double Eagle IV, formed in 2022, is growing a position mainly in the Midland Basin but has also scooped up interests on the Delaware side.

There are several other private equity-backed E&Ps developing footprints in the Permian, but many of the most attractive options were bought up last year. The runway for public-private deals might be shorter in 2024 than it was in 2023.

"As opposed to X private equity firm bundled together three operating companies and sold them for $1 billion to X midsize E&P, I think it's going to be a bit more of those public names to watch, for sure," Bernstein said.

The gas glut

E&Ps buy Permian acreage to drill for crude oil volumes, but Permian wells are producing more natural gas over time as the oily basin develops and matures.

Associated gas volumes—the natural gas output associated with drilling new oil wells—continue to rise across the Permian.

Permian associated gas output was expected to hit a record 24.85 Bcf/d during December, according to the EIA's most recent forecast.

Energy intelligence firm East Daley Analytics reported that natural gas flow out of the Permian Basin hit record volumes during November 2023.

Companies are pouring a lot of money into getting more associated gas and NGL out of the Permian and into demand centers.

East Daley found that 60% of the midstream capex budgets across the Lower 48 are being spent in the Permian Basin; 49% of that total is being spent on Permian NGL takeaway capacity, excluding gathering and processing investment. ■

Hart Energy

The World Calls Out for US LNG. Is Haynesville the Answer?

Booming production and proximity to Gulf Coast export terminals weigh in the play's favor.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Nations around the globe are increasingly demanding secure supply of U.S. LNG. Gulf Coast LNG developers are tapping Haynesville gas to answer the call.

The sprawling Haynesville Shale, which stretches from northwestern Louisiana into eastern Texas, has boomed into a hub of U.S. natural gas production since the play was pioneered by Chesapeake Energy and Petrohawk Energy in 2008.

Natural gas volumes from the Haynesville were expected to average 16.43 Bcf/d during December 2023, according to the U.S. Energy Information Administration (EIA). Only Appalachia (35.76 Bcf/d) and the Permian Basin (24.86 Bcf/d) are more prodigious than the Haynesville in shale gas output.

The Haynesville is home to several of the nation's top public gas producers, including Chesapeake Energy, Southwestern Energy and Comstock Resources. Privately held E&Ps Aethon Energy and Rockcliff Energy II are also producing significant gas volumes from Louisiana and East Texas.

The past few years have been extremely volatile for the natural gas sector.

After Russia's invasion of Ukraine, Henry Hub natural gas

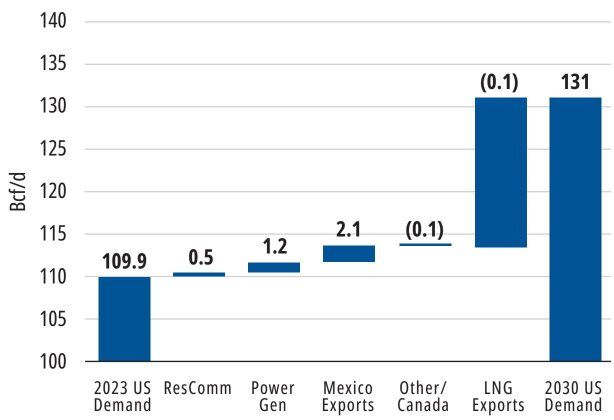
Top Gulf Coast public producers
(Average 1H 2023)

Rank	Operator	Boe/d	Bbl/d	Mcf/d	Well Count	US Rigs (Nov 19)
1	Marathon Oil	439,170	247,982	1,147,085	4,382	11
2	Comstock Resources	343,248	146	2,058,594	1,509	6
3	BP	301,417	61,934	1,436,881	1,636	11
4	Crescent Energy	220,905	98,303	735,549	8,602	2
5	Diversified Energy	141,445	5,905	813,183	6,772	0
6	Exco Resources	103,218	16,864	518,120	977	2
7	Magnolia Oil & Gas	86,205	39,174	282,169	1,403	2
8	Silverbow Resources	70,321	13,791	339,174	793	2
9	Baytex Energy	57,400	45,469	71,580	1,002	2
10	Tellurian	39,685	-	238,108	39	1

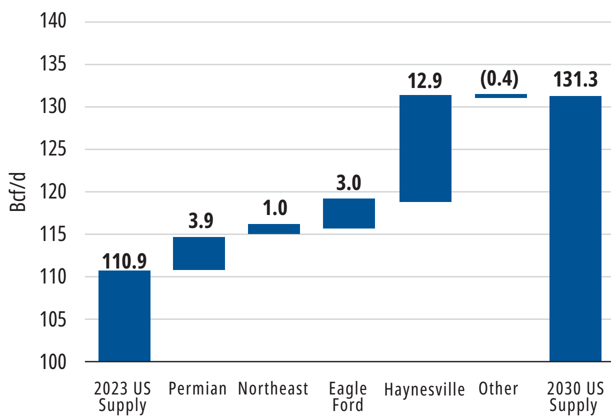
Source: Enverus

Source: Hart Energy

East Daley U.S. demand forecast



East Daley U.S. supply forecast



Source: East Daley Analytics

prices rose above $9/MMBtu in August 2022—their highest levels since the 2008 Great Recession, per EIA figures.

Producers chased the high prices and raked in big profits. Once again, high prices proved to be the cure for high prices.

Instead of the structural market shortages seen during 2022, today the market is glutted with natural gas.

Henry Hub spot prices are expected to average around $2.80/MMBtu this winter, the EIA reported in its latest Short-Term Energy Outlook. That's down over 60 cents from the November forecast.

"The downward revision reflects both a warmer-than-average start to the winter, which has reduced demand for space heating in the residential and commercial sectors, and high natural gas production," the EIA said.

U.S. natural gas inventories will end the winter 22% above the five-year average at over 2 Tcf in storage.

The liquefaction gravy train

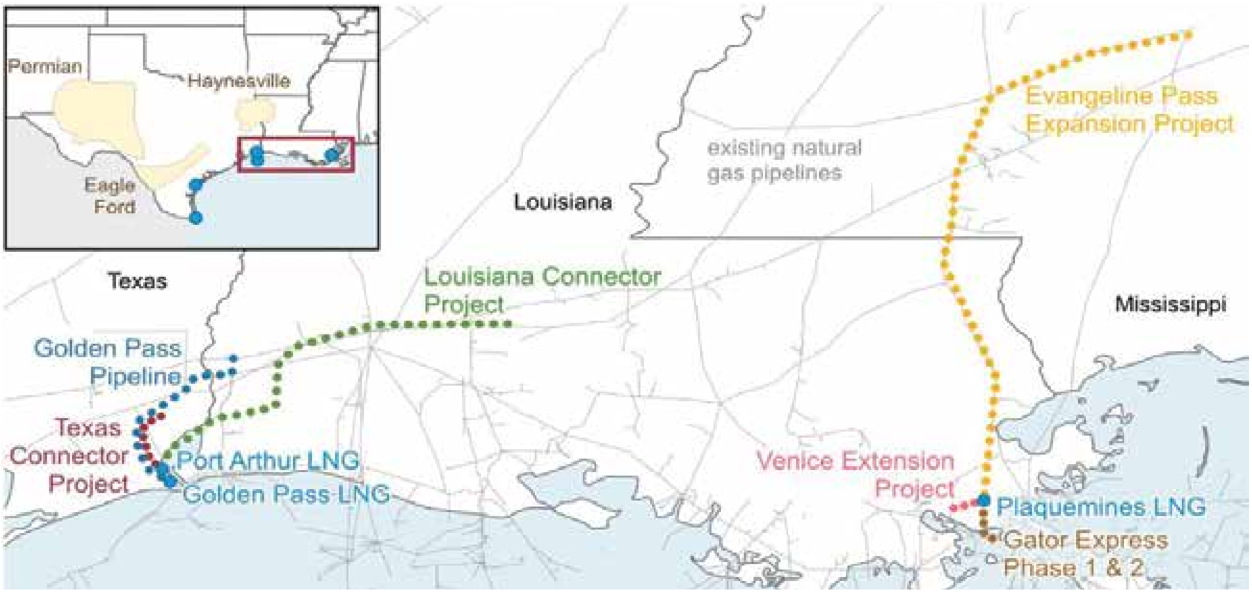
Instead of raking in big profits, gas E&Ps have had to hedge production and lick their wounds amid the collapse in prices.

But all eyes have fixated on the proverbial light at the end of the tunnel: Hockey stick-like demand growth from U.S. LNG export facilities in the coming years.

Gas demand for U.S. LNG exports is expected to grow by 17.4 Bcf/d between 2023 and 2030, said Justin Carlson, co-founder and chief commercial officer at East Daley Analytics; LNG will make up more than one-fifth of total U.S. gas demand by that time—far outweighing projected gas demand growth for residential consumption, power generation or pipeline exports to Mexico.

It's a huge amount of demand growth in a relatively short

Pipelines to Golden Pass LNG, Port Arthur L.NG, and Plaquemines LNG as of December 2023



Source: EIA

About 13.5 Bcf/d of gas pipeline capacity to feed Gulf Coast LNG projects is currently under construction.

amount of time. For context, the EIA said U.S. LNG exports averaged 11.81 Bcf/d during 2023.

And questions linger about whether U.S. gas supply, hampered in some regions by regulatory red tape, can meet the growing demand.

"What's sustainable and where is all this gas going to come from?" asked Alan Smith, co-founder, president and CEO of Haynesville-focused E&P Rockcliff Energy, at Hart Energy's America's Natural Gas Conference in September.

Due to the basin's close proximity to several Gulf Coast projects under construction, the Haynesville's shale gas will be tapped by the LNG industry in a big way.

Of the roughly 20 Bcf/d of total U.S. gas demand growth through 2030, approximately 13 Bcf/d is expected to come from Haynesville output, says East Daley.

The Haynesville's nearness to LNG export facilities is its saving grace, because a lot of the most cost-competitive gas production is located in other parts of the U.S. The Haynesville is a deep play. Equipment to drill wells has to be able to withstand extremely high temperatures. These factors all translate into higher drilling costs.

The cheapest gas production, by and large, is coming out of Appalachia plays like the Marcellus Shale.

But getting greater volumes of Appalachia gas across state borders to the Gulf Coast is easier said than done. The Mountain Valley Pipeline recently required an act of Congress to move forward.

Associated gas output from Permian Basin oil wells is also cheaper than Haynesville gas. But the Permian, historically a play for crude oil, is dealing with gas takeaway constraints of its own.

The good news for the industry is that more than 20 Bcf/d of new pipeline capacity to feed LNG export projects is under construction, partly completed or approved, according to the EIA. Around 13.5 Bcf/d is currently under construction.

Five new LNG export terminals—Plaquemines LNG, Golden Pass LNG, Port Arthur LNG, Corpus Christi LNG Stage III and Rio Grande LNG—have one or more pipelines under development.

Gas M&A outlook

The U.S. shale patch has seen a lot of activity for oil-weighted M&A. The Permian Basin has been the epicenter of upstream deal activity; recent megadeals include Exxon Mobil's $60 billion acquisition of Pioneer Natural Resources and Occidental Petroleum's $12 billion acquisition of private E&P CrownRock.

Extreme natural gas price volatility has chilled the market for gas-weighted transactions. But experts anticipate a narrowing of the spread between buyer and seller as demand, and prices, increase in the coming years.

In a rare gas deal last summer, a consortium led by family office investment groups took ownership of Wyoming gas producer PureWest Energy in a $1.84 billion cash deal.

Rumors are also swirling that Chesapeake could merge with Southwestern to create a premier public natural gas E&P. Both companies already have large positions in the Haynesville and in the Marcellus.

Combined, Chesapeake and Southwestern would have a production of around 8 Bcfe/d—positioning the combined firm ahead of EQT, the nation's current largest gas producer, analysts say. ■

Vaca Muerta Offers Argentina Game Changing Options

Argentina's Vaca Muerta Shale is the most prospective outside the U.S., and represents an opportunity to convert the South American country into a major exporter of oil, piped-gas and LNG.

PIETRO DONATELLO PITTS | INTERNATIONAL MANAGING EDITOR

Argentina's famed Vaca Muerta ("dead cow") Shale is arguably the most prospective play outside the U.S., representing a game-changing opportunity to convert the country into a major exporter of oil, piped-gas and LNG to South America and world markets.

In recent years, production gains in Argentina have been impressive, driven primarily by higher production from the Vaca Muerta in Argentina's Neuquén Basin. Further gains hold the potential to drastically change the country's energy matrix and help it achieve energy self-sufficiency. That's if Argentina can overcome the numerous above-ground headwinds linked to economics, finance and infrastructure, all tied to political uncertainties.

Whether newly elected President Javier Milei, an economist with two masters on the topic, can change any of that remains to be seen.

Developments related to the Vaca Muerta have been massive. Without production contributions from the formation, Argentina's oil production would be about half of what it is and gas production would be about one-third of what it is, Argentina's Neuquén Province Energy Minister Alejandro Rodrigo Monteiro told Hart Energy in late November.

Monteiro said that without development of the Vaca Muerta, Argentina would have paid over $20 billion to import hydrocarbons and energy in 2023.

"In other words, the country would have serious energy supply problems, in addition to problems related to reserves in Argentina's Central Bank," Monteiro said. "So, the Vaca Muerta's development can be seen through all the energy that we stop importing, and also in the volume of energy that we can export and the dollars that this generates for the country."

Production from the Vaca Muerta could surpass 1 MMbbl/d by 2030 under a moderate growth scenario compared to around 323,000 bbl/d foreseeable in 2023, according to extrapolated production data through July from the government of the Neuquén Province. Through July, the Vaca Muerta contributed around 51% of Argentina's total oil production profile and around

"The country would have serious energy supply problems, in addition to problems related to reserves in Argentina's Central Bank. So, the Vaca Muerta's development can be seen through all the energy that we stop importing, and also in the volume of energy that we can export and the dollars that this generates for the country."

RODRIGO MONTEIRO, energy minister, Argentina's Neuquén Province

Technically recoverable shale resources

Country	Gas (Tcf)	% of Totals	Oil (Bbbls)	% of Totals
Argentina	802	41%	27	37%
Bolivia	36	2%	1	1%
Brazil	245	12%	5	7%
Chile	48	2%	2	3%
Colombia	55	3%	7	9%
Mexico	545	28%	13	18%
Paraguay	75	4%	4	5%
Uruguay	2	0%	1	1%
Venezuela	167	8%	13	18%
TOTALS	1,975	100%	73	100%

Source: EIA/U.S. Geological Survey (USGS), June 2013 study, which excluded Guyana.

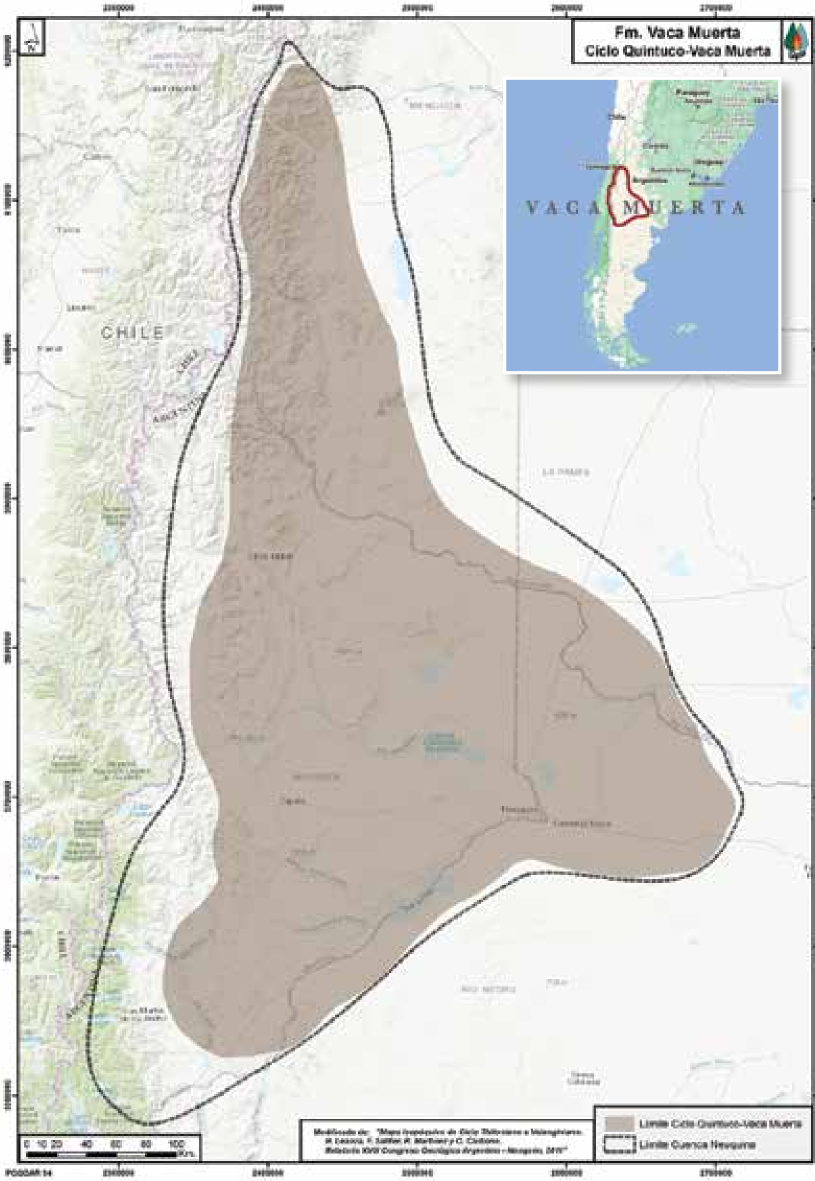
65% of its total gas production, according to provincial data.

The forecasted rise in Vaca Muerta production is only possible if takeaway capacity and rig availability don't limit growth, said Alexandre Ramos-Peon, Rystad Energy's vice president of shale research, in a May 2023 report. If production rises, it could lift Vaca Muerta's profile and position the formation as a leading source of shale production, comparable to the Bakken or Eagle Ford developments.

Reaching a threshold of 1 MMbbl/d would pull Argentina out of its more than a decade-long production slump, reducing its reliance on imports to become a key regional and global oil market player, he said.

"In this scenario, we assume new wells that start production from now onwards have the same performance per foot as the average completed and put-on-production (POP) in 2021-2022; oil production from gas wells is negligible; capital re-investment is assured until 2030; linear growth in POP activity in 2023 and onwards," Ramos-Peon said. "For the operators, we assumed that they adopt two-mile laterals gradually within the next three years. Finally, we considered no downturns in the oil industry, global pandemics, significant macroeconomic changes or political unrest in Argentina until 2030."

Argenitina's Vaca Muerta Shale



Source: Argentine Geological Association

Changing Southern Cone dynamics

The U.S. Energy Information Administration (EIA) estimates Argentina had around 13.6 Tcf of proved gas reserves at the end of 2020, enough to last 10.1 years. Argentina also had around 2.5 Bbbl of proved oil reserves, enough to last 11.3 years.

The relatively short-lived oil and gas reserves are already a lingering energy security threat, and Argentina continues to rely heavily on imported LNG during its winter months to fulfill domestic demand. Argentine officials are hyper-focused on developing the Vaca Muerta, especially after Russia's invasion of Ukraine in early 2022 as both Europe and Asia seek secure sources of LNG to offset energy declines from Russia.

The dynamics of trading gas in South America, especially among the Southern Cone countries—Argentina, Bolivia and Brazil—is undergoing a dramatic change. Bolivia's production is declining while production is ramping up in Argentina's Vaca Muerta formation, offshore Brazil in the pre-salt formation and in the Equatorial margin, Rystad Energy analyst Gabriela Sanches and senior analyst Vinicius Romano wrote in late November in a gas report focused on South America.

"Brazil, Argentina and Bolivia are currently interconnected by a network of gas pipelines which help manage supply and demand balances between the three countries. Argentina and Brazil's promising new gas resources could see a rejigging of this relationship in the coming years," Sanches and Romano wrote. "However, the success of these plans depends on construction of

Technically recoverable shale resources by basin and formation

Basin	Formation	Gas (Tcf)	Oil (Bbbls)
Neuquén	Los Molles	275	4
	Vaca Muerta	308	16
	Total	583	20
San Jorge	Aguada Bandera	51	0
	Pozo D-129	35	1
	Total	86	1
Austral-Magallanes	L. Inoceramus-Magnas Verdes	129	7
Parana	Ponta Grossa	3	0
TOTALS		**802**	**27**

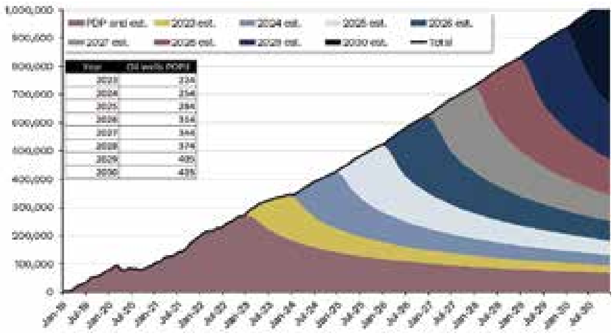
Source: EIA/U.S. Geological Survey (USGS), June 2013 study, which excluded Guyana.

Argentina oil and gas production
(Neuquén Basin)

	2013 A	2021 A	2022 A	2023 E
Oil (bbl/d)	107,130	202,764	277,380	322,858
Gas (MMcf/d)	1,753	2,548	2,967	3,010

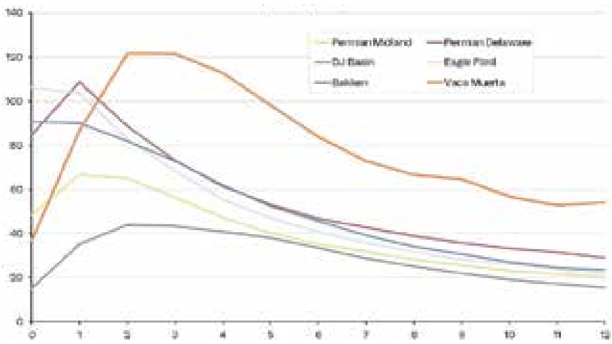
Source: Government of Neuquén Province
Note 1: Figures for 2023 are from a straight extrapolation from data through July.

Vaca Muerta production growth scenario
(Bbl/d)



Source: Rystad Energy's Shale Solution, May 2023

Performance of Vaca Muerta vs. US shale*
(Bbl/d per 1,000 ft lateral)



Source: Rystad Energy's Shale Solution, May 2023 *Only horizontal wells put on production in 2021-2022

critical gas transportation infrastructure in the years ahead, which could either see the region flooded with gas or choked by bottlenecks."

In Argentina, gas is shipped on three different routes from the Neuquén to the Buenos Aires region where key demand centers are situated. In addition to gas pipelines already in place, the country recently inaugurated the first stage of the Nestor Kirchner pipeline.

"By 2025, gas imports from Bolivia are expected to cease as part of the Argentine government's plan to increase domestic gas production and become self-sufficient in gas supply, while also exploring export opportunities," Sanches and Romano said.

Argentina's state-owned YPF SA and its Malaysian counterpart Petronas continue to eye an LNG plant on Argentina's Atlantic Coast that would source Vaca Muerta gas and have a combined capacity of 25 million tonnes per annum (mtpa).

Monterio said he couldn't envision a greenfield LNG project before 2030 but said an intermediate-stage floating LNG project had potential to see cargoes as early as 2026 or 2027.

Argentina ranks No. 2 in the world in technically recoverable shale gas resources, according to the most recent study published by the EIA about 10 years ago. Argentina has technically recoverable shale gas resources of 802 Tcf, positioning the country only behind China, which has an estimated 1,115 Tcf. Argentina ranks fourth worldwide in shale oil resources, according to the EIA.

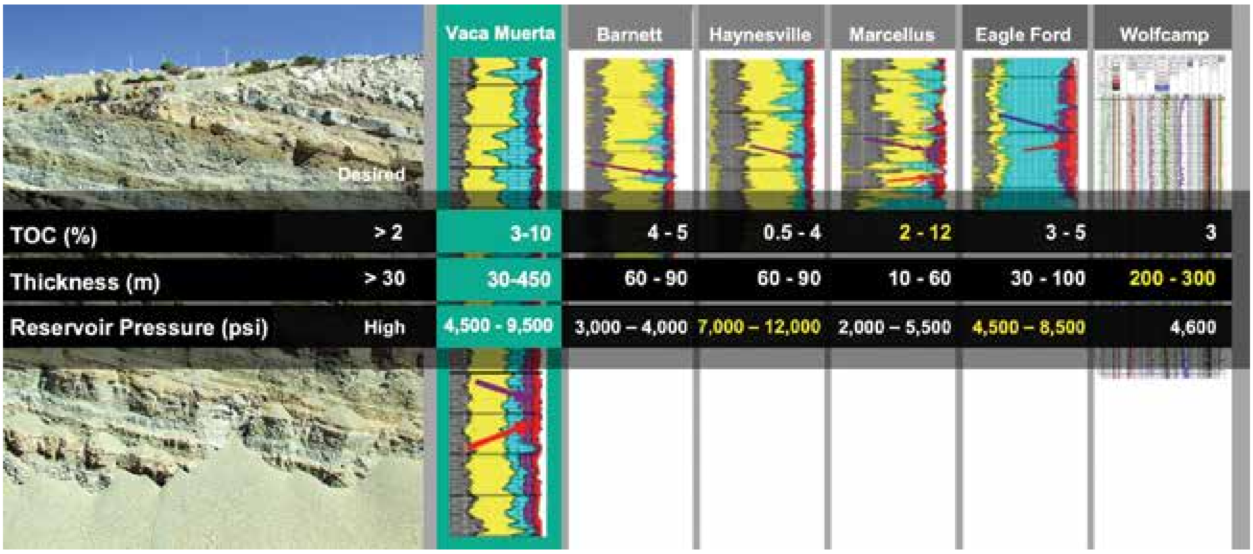
The Vaca Muerta, in Argentina's Neuquén Basin, holds technically recoverable shale gas resources of 308 Tcf. Of that total, 194 Tcf is dry gas, 91 Tcf is wet gas and 23 Tcf is associated gas, according to the EIA. These volumes put the Vaca Muerta on par with the Permian Basin, according to shale basin data published by Rystad.

Argentina is believed to have 27 Bbbls of technically recoverable shale oil resources. Approximately 60%, or 16.2 Bbbl, are located in the Vaca Muerta—2.6 Bbbl of condensate and 13.6 Bbbl of volatile/black oil, according to the EIA. But Argentina is primarily concentrating its Vaca Muerta efforts to supply piped-gas exports and eventually LNG, even as oil exports continue on the uptick.

The Vaca Muerta—which crosses four Argentine provinces: Neuquén, Río Negro, La Pampa and Mendoza—is the main drilling formation targeted by companies. The formation holds 53% of the Neuquén Basin's gas resources and 38% of Argentina's gas resources.

The other major formation in Neuquén is the Los Molles, which is on the radar of companies and investors alike, but not a primary drilling focus. Neuquén has good production potential in the marine-deposited Los Molles and the Vaca Muerta shales.

Vaca Muerta statistics



	Desired	Vaca Muerta	Barnett	Haynesville	Marcellus	Eagle Ford	Wolfcamp
TOC (%)	> 2	3-10	4 - 5	0.5 - 4	2 - 12	3 - 5	3
Thickness (m)	> 30	30-450	60 - 90	60 - 90	10 - 60	30 - 100	200 - 300
Reservoir Pressure (psi)	High	4,500 - 9,500	3,000 – 4,000	7,000 – 12,000	2,000 – 5,500	4,500 – 8,500	4,600

Source: Argentine Geologic Association

"The success of these plans depends on construction of critical gas transportation infrastructure in the years ahead, which could either see the region flooded with gas or choked by bottlenecks."

GABRIELA SANCHES AND VINICIUS ROMANO, Rystad Energy

Argentina has four main sedimentary basins. The other three include:

- Golfo San Jorge, which contains mostly non-marine lacustrine shale source rocks of Jurassic to Cretaceous age;
- Austral Basin, also known as the Magallanes Basin in Chile, which contains marine-deposited black shale in the Lower Cretaceous, considered a major source rock in the basin; and
- Paraná, although more extensive in Brazil and Paraguay, a small area with Devonian black shale potential is located in Argentina.

Vaca Muerta: Geology 101

The Vaca Muerta formation in the Neuquén Basin was found when American Charles Edwin Weaver (1880-1958), doctor in geology and paleontology, noticed the cropping throughout the Vaca Muerta mountain range. The Vaca Muerta is comprised of sedimentites, called bituminous marls due to their high content of organic matter, according to the government of the Neuquén Province.

Under current plans, the Vaca Muerta is now an important part of Argentina's economic development.

The Neuquén Basin is located in west-central Argentina and contains Late Triassic to Early Cenozoic strata deposited in a back-arc tectonic setting, according to the EIA. The basin is bordered on the west by the Andes Mountain range, on the east by the Colorado Basin and on the southeast by the North Patagonian Massif. The sedimentary sequence exceeds 22,000 ft in thickness, comprising carbonate, evaporite, and marine siliclastic rocks. Compared with the thrusted western part of the basin, the central Neuquén is deep and structurally less deformed.

The two primary shale formations in the Neuquén Basin are the Vaca Muerta and Los Molles.

Vaca Muerta: The Late Jurassic to Early Cretaceous (Tithonian-Berriasian) shale is considered the primary source rocks for conventional oil production in the basin. The formation is comprised of finely-stratified black and dark grey shale, as well as lithographic lime-mudstone totaling 200 ft-1,700 ft thick. Organic-rich marine shale was deposited in a reduced oxygen environment and contains Type II kerogen. While the Vaca Muerta is somewhat thinner than Los Molles, its shale is of a higher total organic carbon and is more widespread across the basin.

Los Molles: The Middle Jurassic (Toarcian-Aalenian) shale is considered an important source rock for conventional oil and gas deposits. On average, the prospective shale in the formation is found at depths between 8,000 ft and 14,500 ft, with maximum depth surpassing 16,000 ft in the center of the basin. ■

Production from Canada's Montney and Duvernay Gains Momentum

The dust has settled on acquisitions, and the leading players have publicized five-year plans that demonstrate a commitment to increasing production from Canada's premier shale plays.

JUDY MURRAY | CONTRIBUTING EDITOR

Natural Resources Canada describes the Montney and Duvernay shales as primarily natural gas and NGL plays, with relatively small oil production. The Montney, in British Columbia and Alberta, and the Duvernay, in Alberta, are the two prominent geological formations comprising the Western Canadian Sedimentary Basin.

The Montney Shale's natural gas resources are estimated to be among the largest in the world, and production numbers continue to rise. From 2010 to 2022, natural gas production in the Montney grew to 8.06 Bcf/d from approximately 0.82 Bcf/d. Over that same period, production from the Duvernay grew to approximately 0.58 Bcf/d.

As of 2022, natural gas from the Montney and Duvernay regions represented 50% of Canada's total natural gas production. Natural Resources Canada says that, according to all scenarios in the Canada Energy Regulator's latest "Canada's Energy Future 2023" report, the area is expected to contribute more than 60% of domestic gas production by 2030.

Favorable financials

Mark Sadeghian

Mark Sadeghian, senior director for North American energy at Fitch Ratings, said that although natural gas production is an important factor in assessing the outlook for Canada's shale developments, condensate is the key to the economics in the core of the play because of its value as a diluent used to blend Western Canadian Select, one of North America's largest heavy crude oil streams.

"There is a symbiosis between local condensate production and oil sands bitumen production," he said.

Locally produced diluent economics are attractive because they compete with higher priced imports from the U.S., Sadeghian said, noting that higher oil sands production potentially increases demand for condensate from the Duvernay and Montney. "We don't anticipate dramatic production growth anytime soon, but there is certainly room to grow with recent pipeline expansions, including the pending TMX [Trans Mountain Expansion] pipeline," he said.

Rextag

Regional natural gas pricing, which historically has been under stress due to system constraints, may also be set to improve.

"We think there will be some system improvements and some tightening balances coming from LNG—both south of the border and in Canada," he explained. "When Canada LNG comes onstream, that will be supplied through regional Canadian gas, and that should help balances. Also, there is a fair amount of new LNG export capacity coming up on the Gulf Coast, which could tighten up balances regionally through interconnects."

"As always," he said, "weather is still a dominant factor when it comes to gas pricing, so we will want to see what

Crescent Point Energy added a second rig to its production operations in the Kaybob Duvernay Shale in 2023.

Crescent Point Energy

Historical and projected natural gas production from the Montney and Duvernay shales

	Production	2010	2022*	2030 (CER CM**)	2030 (CER CNZ***)
Montney	Natural Gas	0.82 Bcf/d	8.06 Bcf/d	10.66 Bcf/d	10.70 Bcf/d
Duvernay	Natural Gas	0.00001 Bcf/d	0.58 Bcf/d	0.60 Bcf/d	0.61 Bcf/d
Canada Total	**Natural Gas**	**14.58 Bcf/d**	**17.29 Bcf/d**	**17.69 Bcf/d**	**17.67 Bcf/d**

Source: Canada Energy Regulator

*Estimated 2022 data **Canada Energy Regulator's Canada's Energy Future 2023 Report's Current Measures Scenario. ***Canada Energy Regulator's Canada's Energy Future 2023 Report's Canada Net-Zero Scenario.

things look like on the ground when we get there."

Developing the Duvernay

While financial analysts take a wait-and-see approach, forward-looking producers are laying plans for expansion. Calgary-based Crescent Point Energy, Canada's seventh-largest E&P company and the largest acreage holder in the Kaybob Duvernay Shale, is optimistic about the region's potential. Over the last few years, the company has transformed its portfolio and added to its positions in these reservoirs to enable consistent production growth from its Alberta Montney and Kaybob Duvernay shale acreage.

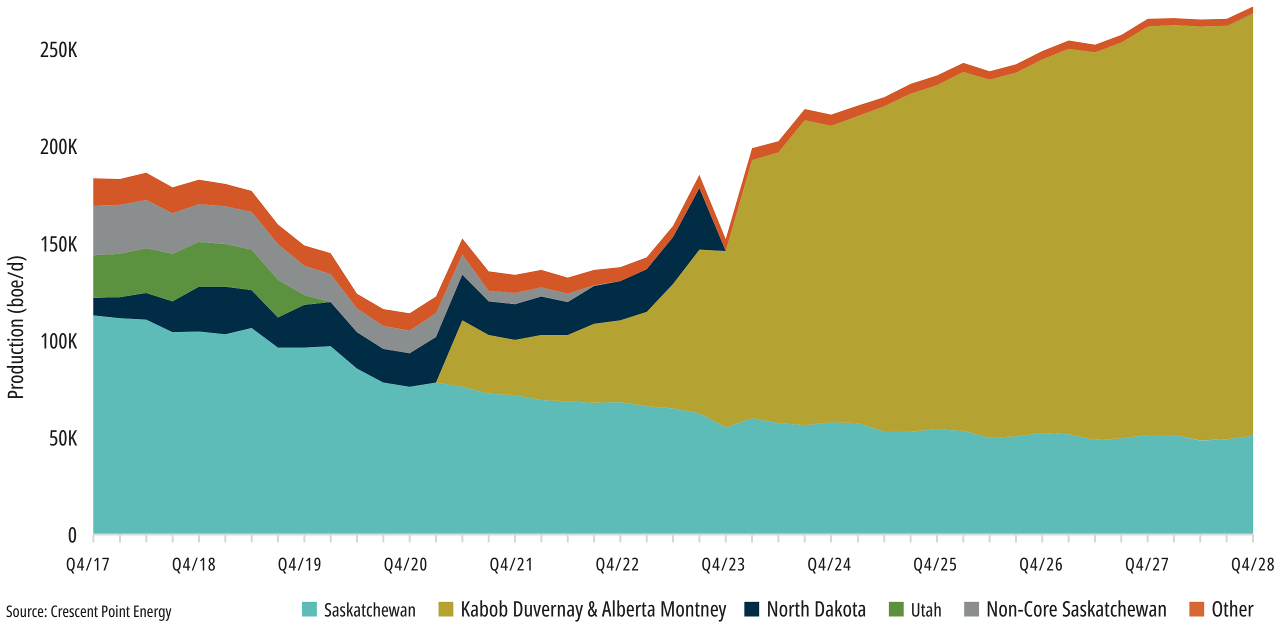
Crescent Point Energy COO Ryan Gritzfeldt said the characteristics of these plays give the company top-tier economics, and the quick payback periods of less than a year at current pricing make the economics exceptionally strong.

Ryan Gritzfeldt

The company has assessed the Duvernay and Alberta Montney and found them both attractive. "The Montney offers multiple benches that contribute to significant resource in place, and because the Duvernay is over-pressured, it yields significant initial production rates and enables considerable reserves recovery," Gritzfeldt told Hart Energy.

"What attracted us to this region is the liquids weighting,"

Historic and expected production



Crescent Point Energy has consistently added production from its Montney and Duvernay assets and expects continued growth through 2028.

he explained. "We wanted to target the condensate- and liquids-rich window of the Kaybob Duvernay and the volatile oil window in the Alberta Montney."

When his company acquired its first Kaybob Duvernay acreage in 2021, the asset was producing only 30,000 boe/d.

"We knew when we studied the reservoir, we could enhance results and lower costs," he said. "When we did that, we started adding to our position in the play in late 2022 and early 2023 and now have 500 premium drilling locations in the Kaybob Duvernay." The company's 2024 production forecast from the Duvernay is 50,000 boe/d.

Crescent Point also targeted the volatile oil window of the Alberta Montney for acquisitions, entering the play in spring 2023. Production was about 38,000 boe/d, Gritzfeldt said, "but we knew the quality of those assets was outstanding."

With that acreage and recently acquired assets of Hammerhead Resources, the company is now the dominant player in the Alberta Montney volatile oil window with 350,000 net acres (close to 550 net sections), giving it 1,400 premium drilling locations at conservative spacing. Total production from the company's Montney wells is expected to hit 95,000 boe/d in 2024.

"We refer to the Montney and Duvernay as 'short-cycle' assets—assets that have high initial production, quick payouts, and very strong rates of return, but come with some decline," he said. Crescent Point has combined these with its "long-cycle" assets in Saskatchewan, which are waterflood and polymer-flood assets that have low decline and high netback, and generate long-term free cash flow.

"Over the past three years or so, we have pivoted the portfolio of the company," he said. "Now, with the premium short-cycle shale assets combined with long-cycle assets, we have a balanced, resilient portfolio that can deliver sustainability and growth for years to come with more than 20 years of premium drilling inventory."

Gritzfeldt said these two sets of shale assets will attract about 80% of corporate capital in 2024 and will constitute approximately 70% of 2024 corporate production.

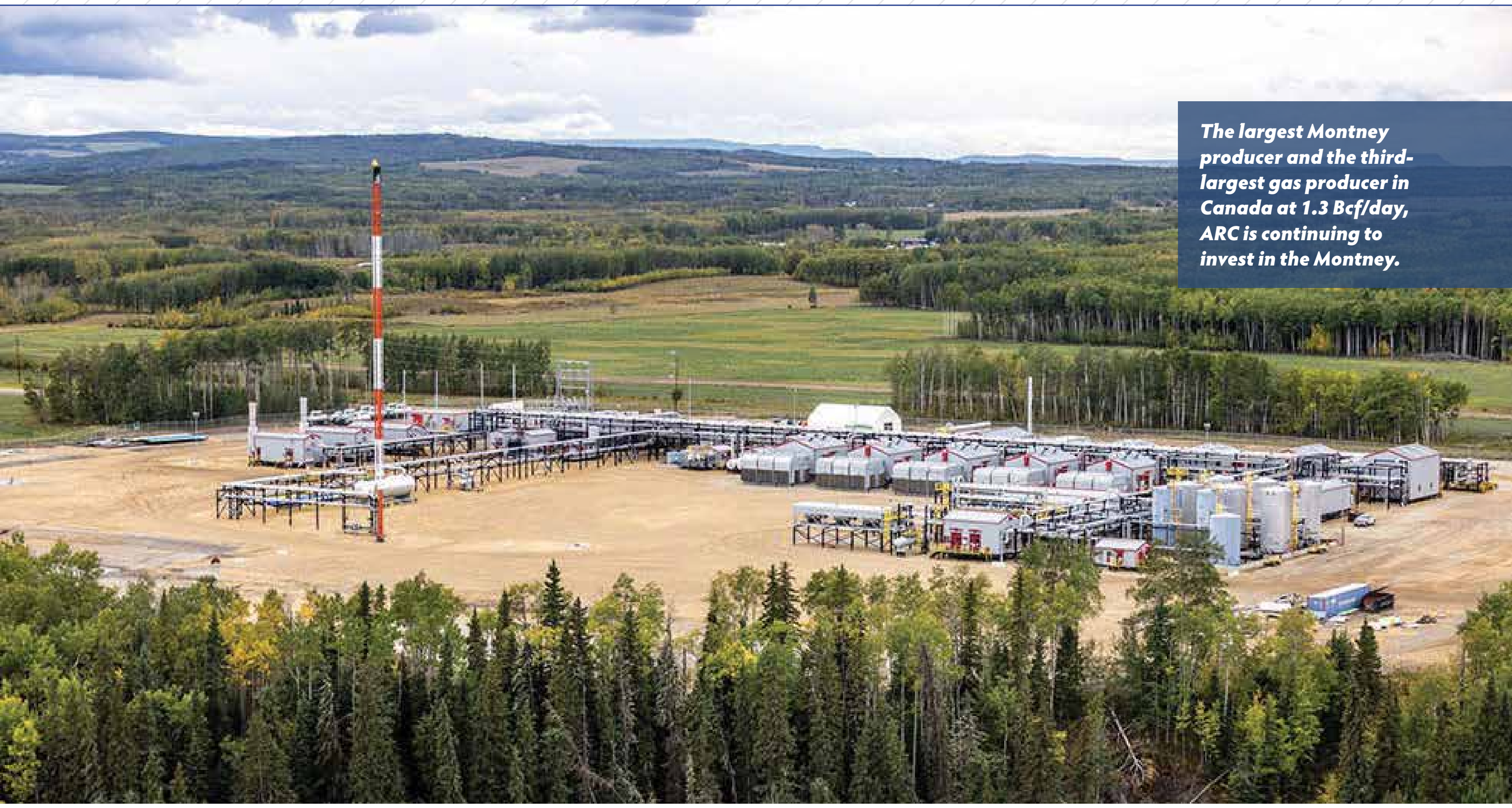
"So, 140,000 boe/d of our 204,000 boe/d in 2024 will be from the Duvernay and Montney," he said. "This grows about 50% to almost 210,000 boe/d, about 80% of corporate production by 2028, according to the company's five-year plan."

Maximizing the Montney

While Crescent Point is combining assets in the two plays in its portfolio, 100% of the production from ARC Resources comes from its Montney acreage. The largest Montney producer and the third-largest gas producer in Canada at 1.3 Bcf/d, ARC is continuing to invest in the Montney and is convinced that it holds the key for consistently increasing production.

In a June 2023 presentation to investors, President and CEO Terry Anderson described the company's position in simple terms. "We are a pure-play Montney producer for a reason.

"The Montney is one of the most profitable and one of the largest resource plays in North America. We know the Montney better than anyone ... and that is a strategic advantage."



The largest Montney producer and the third-largest gas producer in Canada at 1.3 Bcf/day, ARC is continuing to invest in the Montney.

ARC Resources

"We know the Montney better than anyone ... and that is a strategic advantage."

TERRY ANDERSON, CEO, ARC Resources

A decade ago, ARC leadership transitioned away from what Anderson called “old conventional assets” to “the new world-class Montney resource play.” ARC drilled the first Montney horizontal well in 2005 and, with it, kicked off its Montney boom. The company began acquiring large swaths in sweet spots, rounding out its position with the Kakwa acquisition, the final piece of the puzzle, two years ago. Now, ARC holds more than 1 million acres of high-quality Montney resource.

Anderson pointed out that, in 2014, ARC produced 110,000 boe/d from 5,700 well bores (60% gas and 40% liquids) and that today, the company produces 350,000 boe/d from 1,700 well bores with the same 60:40 split. Now, he said, the company is poised to pursue new business opportunities like LNG and deliver even greater value to shareholders.

The company’s five-year plan is a disciplined program that balances capital allocation in phased development with a three-year cadence between development projects. For example, Attachie Phase 1, the leading development opportunity within the company’s portfolio, will be fully onstream in 2025, followed by Phase 2 in 2028. According to Anderson, free cash flow per share is expected to triple from about $1.60 in 2024 to $4.80 in 2028.

“Our asset portfolio has the potential to easily grow to 500,000 boe/d and remain flat for decades,” he said. “We are very fortunate to be in a position to not have to worry about inventory duration or asset quality.”

ARC also is working to link to end-markets at the lowest possible cost through a diversified transportation portfolio with natural gas connectivity to Malin, Ore., in the northwest U.S., Chicago in the Midwest, Dawn in southern Ontario, and Henry Hub on the Gulf Coast. An agreement with Cheniere Energy, signed in November 2023, commits ARC to supplying 140,000 MMBtu/d of natural gas to Texas for a term of 15 years with commercial operations of the first train of the Sabine Pass Stage 5 Expansion Project, anticipated in 2029. This will allow ARC to export gas to Europe. Plans are in place for 25% of production to move eventually into international markets.

This is significant, Anderson said, because the world needs more Canadian natural gas to address energy security, affordability and reliability, and to help lower global emissions.

“We need to do more as a country,” he said. “This is an important part of our business.” ■

More M&A for E&Ps

Industry experts expect E&Ps to stick with tried and true capital discipline with lighter hedging and more credit financing.

PATRICK MCGEE | SENIOR EDITOR, FINANCE

Two sides of the same coin are expected in E&P finance in 2024—ambition balanced with responsibility. Ambition is expected in the form of more consolidation, and responsibility is expected in continued capital discipline with companies staving off temptations to drill more.

Possible changes on the horizon such as tweaks to hedging and more reliance on credit are seen as slight adjustments to a financing model that's been working for E&Ps.

"I am extremely bullish [on] publicly listed energy companies," BlackRock's head of public energy equities, Will Su, said at a recent energy finance conference at Rice University. "If you look at the S&P 500, the energy sector produces more than 10% of its net income, and its current weighting is less than 5%."

He said E&Ps' strategy to provide growth in the form of capital return to investors has clearly worked.

"When you value a company, it's not just growth in revenues, because you can always go out and buy another company. It's always about appreciation, it's always about growth in the per share value to the shareholder," he said. "I think that's why these companies are really in the sweet spot here."

'Win the day'

Nitin Kumar, an energy analyst at Mizuho, told Hart Energy that E&Ps' protectiveness of their strong balance sheets was shown in Exxon Mobil's and Chevron's decisions to make major acquisitions as all-stock transactions in late 2023.

Nitin Kumar

"They don't want to spend a bunch of cash, increase their balance sheet and then have to worry about downside," he said.

Josh Martin, a managing director at Pickering Energy Partners, told Hart Energy that E&Ps' financial game plan for 2024 should largely be what it was for 2023 because

FIVE FINANCE ISSUES TO WATCH IN 2024

While consolidation has everyone's attention, analysts, attorneys and investment bankers will also have their eye on five other issues in 2024.

1 After three very active years in lucrative private equity E&P exits, private equity monetization of E&P assets is expected to slow in 2024.

"There's just not the opportunity set to go after because of the volume of deals we've seen over the last three years," said Andrew Dittmar, senior vice president at Enverus Intelligence Research. "What you're going to see, I think, is a pretty rapid roll-up of the remaining smaller core Permian positions, but most of those are going to have less than 100 net remaining locations and are going to be smaller-size deals that what we saw in the last few years."

EnergyNet CEO and President Chris Atherton also said he expects far fewer exits by private equity.

"They're reloading right now, but it's not like there's another wave [of exits] coming.... The queue of companies isn't as plentiful," he said. "The private equity overhang might be over."

2 Behind closed doors, attorneys will hustle to take advantage of a 1940s federal law that is expected to exempt oil and gas funds from coming Security and Exchange Commission regulations and transparency requirements for private equity and hedge funds.

Haynes Boone partner Vicki Odette

"(E&Ps) don't want to spend a bunch of cash, increase their balance sheet and then have to worry about downside."

NITIN KUMAR, energy analyst, Mizuho


Josh Martin

it worked. He expressed doubts about CEOs' assurances in recent earnings calls that they are not looking at consolidation deals.

"I just don't think a company can say, 'We're not going to do something' because things change," Martin said. "There are obviously fewer companies than there were 12 months ago or 24 months ago—but there's still some things to be done."

Experts dove into great detail about consolidation at the Rice conference, suggesting they believe more acquisitions are coming.

Jonathan Cox, global co-head of energy investment banking at J.P. Morgan, said while higher commodity prices tend to suppress M&A activity, higher interest rates and inflation make M&A easier because there's more pressure on costs.

Alexander Burpee, senior managing director at Guggenheim Partners, said E&Ps need to compare their project level IRR to their cost of capital when evaluating deals.

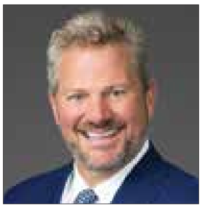
"If the project level IRR is greater than your cost of capital, then you can do that deal," he said. "The lower your cost of capital, the greater your ability to beat out the competition in some of these competitive processes. We have seen a lot of processes recently that have had worse competition, and those with advantaged cost of capital can win the day."

ConocoPhillips vice president and treasurer Konnie Haynes-Welsh said reducing costs is still one of the main drivers of consolidation.

"Some of the reason consolidation is necessary is to get the G&A out, take the best ideas and really make sure that those are being consolidated," she said.

Give credit where banking is through

Holt Foster, co-Leader of Sidley Austin's Global Energy Practice Team, told Hart Energy more consolidations could significantly increase financing activity in the oil and gas sector. If this occurred, he said it would further impact an already rapidly changing banking landscape in the oil and gas sector. Many banks have left the space, and many of the remaining regional banks have reached their desired oil and gas lending allocations. That, Foster said, coupled with a potential real estate crash, has many banks even less inclined to issue more debt. That capital void could be enough to lure some of the larger banks back to the E&P space.


Holt Foster

"Recently, I've seen some large global banks such as J.P. Morgan start dipping their toe back in the oil and gas financing space, but you're also seeing increased activity in the space from alternative credit sources such as credit funds and family offices," Foster said.


Michael Bodino

At Hart Energy's Executive Oil Conference in November, Michael Bodino, managing director of energy investment banking at Texas Capital, told attendees that smaller banks

said her law firm is seeing some uptick in oil and gas investment interest, partly because of the protections offered in the 1940 Investment Company Act.

3 Energy stocks did well in 2023, and some expect more energy IPOs in 2024.

"Coming on the heels of five energy IPOs so far in 2023, the pipeline of energy and energy-transition IPOs is building at the healthiest rate we've seen in a few years," said Ryan Maierson, a partner at Latham & Watkins, a law firm active in IPO work. "Potential IPO candidates run the gamut from traditional upstream to oilfield service companies to renewable energy and distributed energy providers."

Sonu Johl, managing director and co-head of E&P Investment Banking at Raymond James, said that after a few years of skepticism around small- and mid-cap energy IPOs, attitudes are starting to change.

"IPOs are back," he said. "There's a lot of institutional demand looking to play in upstream energy."

4 With small- and mid-cap E&Ps facing sizable maturity walls for their high-yield bond debt, investment bankers expect these companies to seek high-yield refinancing in late 2024.

Jay Salitza, managing director of oil and gas investment banking at KeyBanc Capital Markets, said $3.8 billion in high yield bond debt held by small- and mid-cap E&Ps is don't want to be part of large syndicates, so credit is showing up to fill the capital need.

"Things are changing. What we see in the market is this rapid expansion of the private credit markets," he said. "Private credit has really come in and created solutions for a lot of these companies."

Bodino said $250 million senior note offerings were once commonplace, but now banks require a $500 million minimum for such offerings. Many banks are too small for this—and private credit is stepping in to make up for it, he said.

Nimesh Bhakta, head of investments for the Americas for the Swiss energy trader Vitol, said Vitol recently moved into the private credit space to meet some of the capital need.

"We are stepping into that space, especially in this higher-rate environment," he told Hart Energy. "The risk-adjusted return profile is simply too attractive to ignore."

Drill, barely, drill

The U.S. Energy Information Agency predicts Brent crude oil prices will rise to an average of $93/bbl in 2024, but there is just barely interest in new drilling.

Virendra Chauhan

In a recent survey by the law firm Haynes Boone, 7% of reserve base loan lenders expressed great interest in new drilling.

Virendra Chauhan, head of upstream at the British energy research company, Energy Aspects, said inflation and E&Ps' focus on maximizing recovery rates has E&Ps drilling slower. Martin said only increases in strip pricing would get E&Ps to drill significantly more.

Hedge, a smidge less

An analysis from Capital One Securities shows that E&Ps will ease up on hedging in 2024, but just slightly. Chauhan said this is a sign of the strong shape E&P balance sheets are in; there's less need for caution. PPHB Managing Director Jim Wicklund told Hart Energy that hedging is easing because of expected increases in commodity prices.

Jim Wicklund

"No one wants to hedge out all of next year at $72 [a barrel] and then have the consensus prediction actually come true and all the prices be higher," he said.

Kumar said lighter hedging shows how the industry—and investors—have changed.

"If you employ too much hedging, you're only going to lock in cash flows. You're taking the upside away from investors, which is not where investors' minds are today," Kumar said.

Go with the free cash flow

With some small changes in credit and hedging, experts are nearly all of the opinion that E&Ps will stay away from heavy capex spending to keep their hefty free cash flows supportive of capital return to investors.

"The energy industry struggled to deliver returns to shareholders in the decade between 2010 and 2020. That record has been corrected, but operators will be keen to keep the momentum up in order to keep long-only type investors," Chauhan said. "Producers that are confident in their long-term inventory will continue to de-lever their balance sheets, which should allow them to ratchet up the proportion of free cash flow that they can return directly to shareholders."

Martin said, "The most important message we keep hearing here is just keep focusing on shareholder returns, and the market will come to us eventually." ■

FIVE FINANCE ISSUES TO WATCH IN 2024 (CONTINUED)

set to mature in 2024, and that will skyrocket in the two years after that; $7 billion of this debt is set to mature in 2025 and $16 billion is set to mature in 2026.

"I think the senior bond market is going to be very active in 2024 for E&P companies," Salitza said, adding that they will be helped by healthy balance sheets and further incentivized to seek refinancing if the Federal Reserve Bank cuts interest rates.

5 A blue state legislature might shake things up with a Fossil Fuel Divestment Act in California that would mandate that state pension funds withdraw from oil and gas funds. The bill may have a hearing in July and, unsurprisingly, it is unpopular in the E&P community.

Dan Romito, a partner at Pickering Energy Partners focusing on ESG strategy and implementation, said an abrupt withdrawal from oil and gas isn't feasible with such a high demand for fossil fuels.

"Ironically, California imports about 55% of its crude oil from Russia, Ecuador, Saudi Arabia and Iraq," Romito said. "If emissions were really that important to the state, they would reduce that degree of foreign reliance and tone down the virtue signaling. Divestment only means that a stakeholder loses their seat at the table, weakening future decarbonization efforts over the long term." ■

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OPPORTUNE

Super-EOR Performance

Shale Ingenuity and Titan Oil Recovery's chemical EOR methods, while different, provide a sustainable way to produce more oil in mature basins.

JAXON CAINES | TECHNOLOGY REPORTER

The reservoir wells of the shale revolution that once gushed like geysers are beginning to run dry.

"Since [the shale revolution], there's been about 100,000 horizontal shale wells drilled and put in production, [increasing] our production by about 6 million barrels a day," Robert Downey, CEO of Shale Ingenuity, told Hart Energy. "But today, about a third of those wells are now producing less than 10 barrels a day because they come on like gangbusters and then they have a really steep decline. Pretty much all the wells were drilled prior to 2015 are [almost] depleted."

Robert Downey

According to a Texas Bureau of Economic Geology study, the estimated typical oil recovery is about 6% of the oil in place, or as Downey explains, "You drill this horizontal well, spend $7 million on it and produce for 10 years. And by the time the well is pretty much producing nothing, you've recovered a whopping 6% of the oil."

The Williston and Permian basins and the Eagle Ford Shale hold a combined 3.1 trillion barrels of oil. A 6% recovery at full development leaves 2.9 trillion barrels of oil in place, which is 77 times the proved reserves of the United States. Getting that remaining 94% of oil is the challenge for oil and gas companies today.

SuperEOR is Shale Ingenuity's solution to the shale wells running dry. The SuperEOR process is similar to huff and puff injection, as it involves injecting a solvent into the reservoir, which expands into a gas and drives the oil out of the rock. However, the solvent has a specific composition, making this process more sustainable than other EOR methods. That's because the solvent is able to be recovered from the rock and reused multiple times.

"It's much different than if you just injected natural gas or CO_2 [into the well], because with natural gas or CO_2, you have to get the bottom of pressure up to 3,000 or 4,000 psi to get those gases to go into solution. Our solvent goes into solution at 700 psi," Downey said. "Once you inject it, it forces all this oil through the pores. It expands to a gas and it flows up the wellbore and you recover it on the surface, condense it back into a liquid state, store it on location and then reinject it."

"We've got blending set up in the U.S., Canada, U.K., Holland, Dubai and Singapore. So, we can service the entire world already from our mark."

MIKE CARROLL, vice president of technology, Titan Oil Recovery

When using SuperEOR for a core test, over 90% of the oil was able to be recovered out of the core, said Downey. The recovery process is also quick and efficient, as only five to 10 days of solvent injection can lead to between 10 and 20 days of flowback.

"If you were injecting gas, you'd be injecting for one month to two months and then flowing back for three or four months, but our cycles are fast and the recovery is much greater. So, instead of getting maybe 10% to 40% more oil, we can get 300% to 500% more oil," Downey said.

Another sustainable EOR solution is actually an OOR, or Organic Oil Recovery, solution.

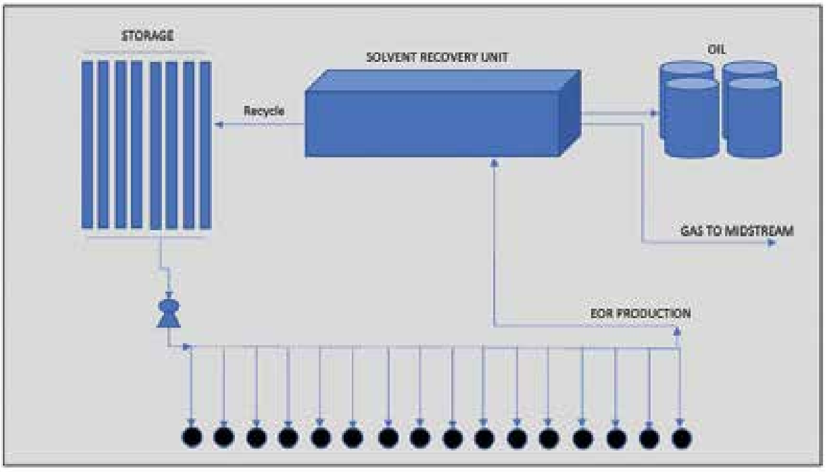
California-based Titan Oil Recovery uses a specialized EOR process that takes advantage of indigenous microbes that have adapted to the environment over millions of years in order to extract oil from mature reservoirs.

Titan activates the biology and ecology of oil reservoirs by working with specific species of microbes that can physically deform oil, turning them into micro oil droplets. This allows the trapped oil in reservoirs to escape and be recovered. The technology has a low carbon footprint and can also reduce hydrogen sulfide production in oil fields.

Kenneth Gerbino

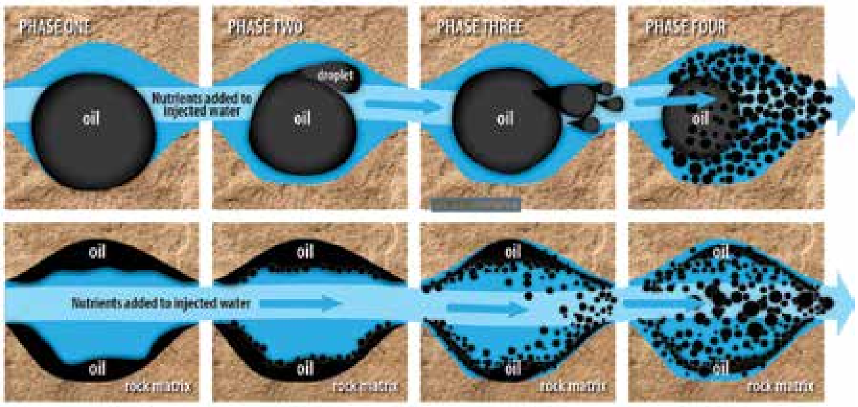
"We do an analysis in our lab and find out which species down [in the reservoir] we can work with," Kenneth Gerbino,

SuperEOR project process schematic



Source: Shale Ingenuity

The SuperEOR package includes solvent storage bullets, solvent recovery unit, triplex pump, controls and SCADA.



Source: Titan Oil Recovery

Titan Oil Recovery's Organic Oil Recovery breaks down oil in order to release it from pores in the reservoir.

CEO of Titan Oil Recovery told Hart Energy. "There are certain species that eat our food and we can change their living habits. Instead of wanting to be next to the water and the rock in the oil reservoir, the sandstone or the carbonates, they now want to be next to oil."

The "food" Gerbino refers to is a complex formula of organic and biodegradable nutrients that is tailor-made for every field. The food causes the targeted microbes to multiply and induces the targeted microbes to become oleophilic (affinity for oils) and attach themselves to oil droplets.

The microbes also become hydrophobic (not wanting to be near water); they move away from the water and rock interface where they have always been and surround the oil, Gerbino said. They then physically deform the oil, creating micro oil droplets.

"They don't eat the oil," Gerbino said. "They just surround it and they break it down. And now, for the first time, you have these micro oil droplets in a reservoir that can now escape from the tight spaces down there."

The Titan process works both onshore and offshore and is able to provide a high return on investment, because the initial investment is next to nothing, the company said. A peer-reviewed SPE paper by Husky Energy in Canada found that the cost of the recovery process was $6 per incremental barrel. Recent results in projects in both the Middle East and North Sea have returned over 1,000% ROI to customers, the company said.

"What's real important with our technology is that there's zero capex … we're not putting in and installing equipment or building things. We have the potential to move quicker than any other technology in the market to market," said Mike Carroll, vice president of technology for Titan Oil Recovery. "We've got blending set up in the U.S., Canada, U.K., Holland, Dubai and Singapore. So, we can service the entire world already from our mark."

Titan Oil Recovery has been in 63 oil fields on five continents with 350 well applications, including 275 injection well applications, and has delivered an average increase in production of over 90%, the company said. The SuperEOR process has been used in the Bakken Shale and the Utica Shale, as well as in other NDA-protected projects, and has recovered at least 20% more oil than traditional methods of EOR, the company said. The industry has been slow to embrace these less expensive EOR methods, tending to rely more on traditional drilling and completion methods.

"Everyone does the same thing. You drill, you frack, you produce, you drill, you frack, you produce. And that's pretty much the entire focus.... Our industry has kind of gotten away from enhanced oil recovery.... EOR only accounts for about 1.5% of all production worldwide," Downey said. "We've kind of gotten fat, dumb and happy as an industry drilling these shale wells and haven't needed to do EOR. But as we're starting to drill out our acreage and our wells are getting pretty mature and depleted, we're going to have to start thinking about EOR."

Currently, Shale Ingenuity works to install and operate projects for clients or license out their SuperEOR patent for a cost. Titan Oil Recovery, who has already worked with four of the top companies in oil and gas and has a partnership with Hunting Plc, looks to find a service company to buy them out.

Despite the industry being slow to adopt these new methods of EOR, both CEOs believe a watershed moment is soon to arrive in the oil and gas industry. ■

Reuse, Recycle, Recover Revenue

Effectively managing produced water can mitigate environmental challenges and even result in revenue streams.

JAXON CAINES | TECHNOLOGY REPORTER

Water's role as the largest byproduct of oil and gas production has become increasingly problematic.

"If you can't handle the produced water or if you can't manage it and it gets out of hand, then it will impact your operations as it will impact energy production," Devesh Mittal, vice president and general manager at Aquatech Energy Services, told Hart Energy. "So, while it is a byproduct, it can be a sort of hindrance if you're not able to manage it."

Produced water comes out of the well along with crude oil when a reservoir is being produced. It can contain both soluble and non-soluble oil and organics, suspended solids, dissolved solids and other chemicals used in the production process. Operators are required by law to manage that waste.

Traditionally, produced water has been injected into underground disposal wells. However, the capacity of these injection wells is limited and the increased use of disposal wells has, in some instances, been linked to seismic activity such as earthquakes. This has led to stricter regulations on the use and development of disposal wells.

Mitigating the impact

That's where companies like Aquatech come in.

"We are working to reduce the impact of the increasing volumes of produced water. We'll recover and purify that and then treat that recovered water to make it suitable for a variety of applications, tailored to a customer's specific needs," Mittal said.

Aquatech's go-to solution is reuse and recycling. For produced water to be reused, the chemicals and organics from the formation must be removed. For water with a high level of total dissolved solids (TDS), Aquatech employs clarifiers and evaporators to use at or near the wellpad. In Oman, Aquatech has one of the largest evaporator systems for produced water, Mittal said, treating about 300,000 bbl/d.

"In certain instances, depending on the TDS of the produced water, it can be recovered using membrane systems such as our Osmotically Assisted Reverse Osmosis (OARO)," Mittal said.

Reverse osmosis is a popular method for water purification in the industry due to its low energy consumption. During the process, seawater or brackish water is forced through a semipermeable membrane, leaving salt and other contaminants on the pressurized side of the membrane while pure water is allowed to pass through.

"The quantity of produced water is increasing and so we have to work to find innovative ways to supplement our current ways of dealing with produced water to provide long-term sustainability."

DEVESH MITTAL, vice president and general manager, Aquatech Energy Services

Aquatech uses a variety of membrane-based solutions, most notably its Advanced Recovery Reverse Osmosis (ARRO) process. ARRO uses modular configuration and automation technology to reduce operator intervention and achieve water recovery rates of over 95%, which is 20% better than traditional reverse osmosis solutions, according to Aquatech.

In addition to ARRO, Aquatech's High Efficiency Reverse Osmosis (HERO) system places reverse osmosis membranes in a high pH environment, causing them to remain in a "continuous cleaning mode." This prevents contaminants from collecting in the pores of a filtration membrane and restricting water flow.

Once rid of the various contaminants in the water, the produced water is available for reuse in applications such as EOR or even irrigation of crops if the water is pure enough.

Adding lithium extraction

Aquatech is also stepping into water reuse in lithium production.

Most produced water has only a small concentration of lithium, but since the amount of produced water from traditional oil and gas operations is significant, a reasonable amount of lithium can be gathered from

Aquatech Energy Services

HERO's "continuous cleaning mode" prevents contaminants from collecting in the pores of the filtration membrane.

Aquatech Energy Services

ARRO is able to achieve water recovery rates 20% better than traditional reverse osmosis solutions, Aquatech says.

the process. Lithium, used in batteries, opens up a completely new pathway for Aquatech customers to generate revenue from water.

"Finding ways to extract lithium out of produced water is a way to reduce the cost of managing this water," said Mittal. "Right now, it's a waste, but if you can convert it into a critical mineral source and you can recover revenue out of it, then it might offset some of the overall water management costs."

The company has succeeded in the oil and gas industry for more than 40 years because of its ability to scale treatment solutions, Mittal said. Now it's working on scalability for lithium production.

"The quantity of produced water is increasing, so we have to work to find innovative ways to supplement our current ways of dealing with produced water to provide long-term sustainability," Mittal said. "That's where we are putting our minds and money." ■

Lithium Rush

Traditional oil and wastewater players join chemical manufacturers and North American lithium pure-play companies to lift production of the critical material.

VELDA ADDISON | SENIOR EDITOR, ENERGY TRANSITION

Traditional oil and gas players looking to tap into another potential revenue stream as the world goes greener are turning to lithium in the U.S., relying on drilling and other expertise to enter new markets.

The lightweight metal is a key ingredient for rechargeable batteries used to power items such as laptops, cell phones and—most notable for the energy transition—energy storage and electric vehicles (EVs).

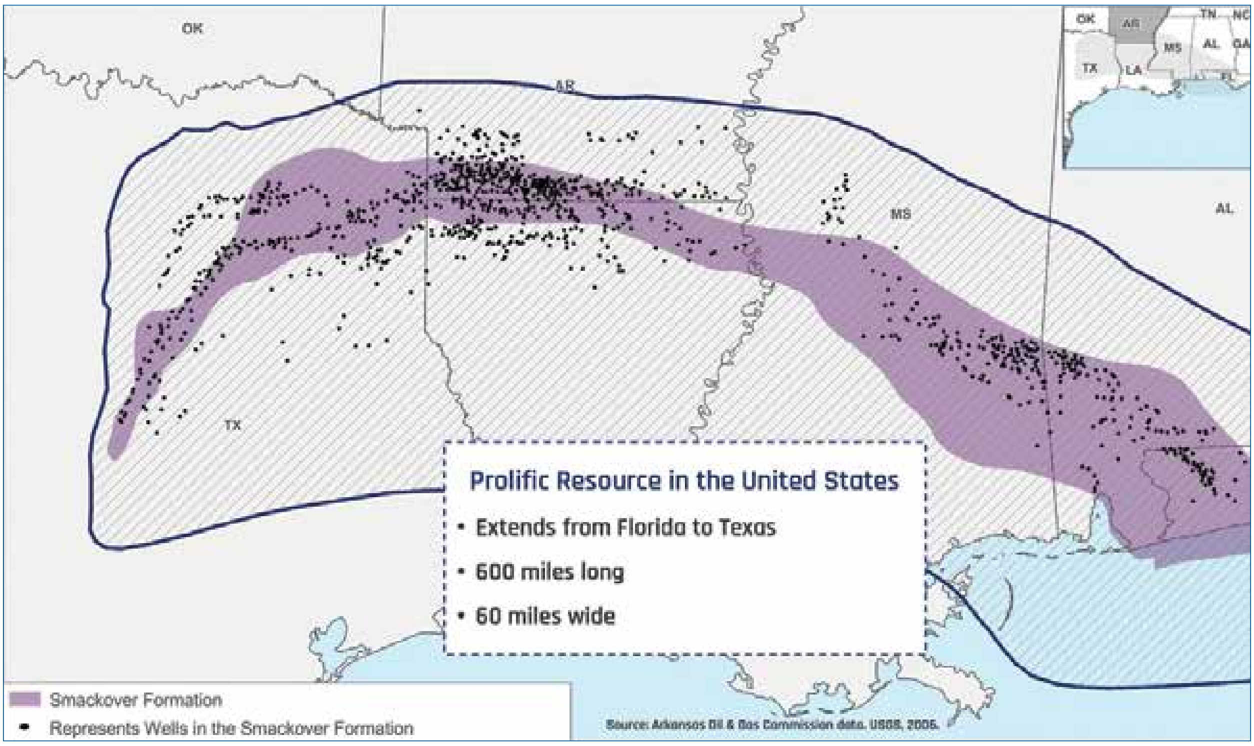
Given President Joe Biden's goal of having 50% of all new vehicle sales be electric by 2030, a power sector free of carbon pollution by 2035 and other emissions reductions objectives, U.S. demand for lithium batteries is expected to increase by nearly six times by 2030, according to an industry report from Li-Bridge, a public-private partnership coordinated by the Argonne National Laboratory. In the U.S. alone, the market for lithium battery cells is forecast to hit $55 billion per year by 2030.

Exxon Mobil has jumped into this market in the Smackover region of Arkansas.

"We're excited about the opportunity and really excited to deploy our skills and capabilities in this new area," Patrick Howarth, lithium global business manager for Exxon Mobil Low Carbon Solutions, told Hart Energy. "We think we've got a pretty unique set of capabilities across this value chain."

Lithium resources, including in the Smackover Formation that spans from Texas to Florida, could be ripe for development.

The U.S. has identified an estimated 12 million tons of lithium resources in the nation from continental, geothermal and oilfield brines as well as claystone and igneous rock, according to the U.S. Geological Survey. The nation is home to only one lithium mine, but efforts are underway to boost domestic supplies of critical materials and manufacturing capacity.



Source: Standard Lithium

Aerial view of solar power and battery storage units in the desert.

Shutterstock

“We see DLE as being very advantageous from an environmental footprint perspective.”

PATRICK HOWARTH, lithium global business manager, Exxon Mobil Low Carbon Solutions

The Smackover Formation in Arkansas was known for its oil production, but the bromine-rich region has attracted companies to brine due to its high concentration of lithium. Brines from wells in southwestern Arkansas’ Columbia County contain as much as 445 parts per million lithium, according to Arkansas’ Office of the State Geologist.

Growing interest

Exxon Mobil entered the region to begin drilling in 2023, joining Albemarle, the world’s largest lithium producer, and Canada-based Standard Lithium, which has two projects in southern Arkansas near the Louisiana state line.

The supermajor plans to lean on its conventional oil and gas expertise, drilling about 10,000 ft underground to access lithium-rich saltwater. It will then use a process called direct lithium extraction (DLE)—also used by Standard and Albemarle—to separate lithium from the saltwater, which will be reinjected to the reservoir. The extracted lithium will be converted onsite into battery-grade material, the company said.

The method produces fewer emissions and requires less land than the traditional method of extracting lithium via hard rock mining. It also doesn’t require as much land as lithium brine extraction in evaporation ponds, where brine sits for several months or years as the sun evaporates most of the liquid content, ultimately leaving behind lithium and other metals. The brine, with its higher concentration of lithium, is then pumped to a facility for processing.

“The world has two different sources of lithium today. It’s either hard rock or from brine. Most of the brine is shallow brine within Latin America, and they use evaporation as the main mechanism to concentrate up the lithium and remove impurities,” Howarth said.

“Within Arkansas, we don’t feel that there’s an

"I think there is a world of endless possibilities" in extracting battery materials from brine.

REAGAN MARBLE, partner, Jackson Walker

opportunity for evaporation there. And frankly, we see DLE as being very advantageous from an environmental footprint perspective," he added. "So, significant benefits from a land use or water use perspective but then also substantially lower carbon intensity versus hard rock mining."

Exxon Mobil aims to begin lithium production in 2027. Standard Lithium is targeting first production of battery-quality lithium carbonate in 2026 at its Phase 1A Project at LANXESS Corp.'s South Plant near El Dorado, Ark.

The year 2023 saw increased activity in the lithium brine space. Companies such as Standard Lithium, for example, unveiled positive feasibility studies and strong project economics—an after-tax NPV of $550 million and IRR of 24%, assuming an 8% discount and long-term price of $30,000/ton for battery-quality lithium carbonate for its Phase 1A project in Arkansas.

While Arkansas may be considered an emerging epicenter for potential lithium brine development and Nevada is the hotbed of lithium brine activity in the U.S., Texas is also in play. Standard Lithium reported in October 2023 that it delivered the highest-ever North American lithium brine grade at 806 mg/L in East Texas.

Oil and gas companies along with water midstream companies are showing interest in pursuing lithium in northeast Texas, according to Reagan Marble, a partner with the Jackson Walker law firm.

Legal uncertainty lingers

Newcomers looking to get in on the action should consider a few things beforehand. Topping that list is who owns the lithium, Marble said.

"Unfortunately, in Texas, we don't have a clear answer to who owns lithium. We do know that brine is a part of the surface estate and, more particularly, the groundwater in the state is owned by the surface owner," Marble said. A legal case touches on the issue but the case mainly focuses on extracting salt—defined as a mineral in Texas—for commercial use. It has left some companies interested in entering lithium extraction in Texas wondering whether to pursue leases from surface owners or mineral owners.

"There are a lot of issues that pop up on your due diligence checklist as you're trying to figure out which one to go after," Marble said. "And to be candid, I don't think we are going to see quite the land grab that Texas could be experiencing at the moment until we have a legislative solution to who owns the lithium.... [The issue] came too late during our extended legislative sessions to really address it, and I don't think it's going to be addressed until 2025."

In Arkansas, such issues are resolved because the state has a well-established brine production industry that has been around since the 1950s. Lithium extraction is regulated under Arkansas's Brine Production Act and the state's Brine Production Regulatory Program.

With case law unclear in Texas, Marble advises oil and gas operators with active leases not to just go out and start exploring for lithium on those leases.

"There's not a ton of case law [in Texas] on how you look at the ordinary and natural meaning of the term mineral. And quite frankly, until there is a legislative solution, there surely won't be a legal solution in court interpreting whether lithium is in the ordinary natural meaning of the word mineral or falls under the surface destruction test," Marble said. "We just don't know."

However, he added companies could avoid the ownership issue by pursuing what is known as fee owners, or those who own both the surface and the minerals.

Still, lithium development in Texas "will surely be stunted until we solve this issue," he said.

Extracting lithium from produced water that comes from the wellbore during oil and gas production is another area that could attract interest from operators looking to find value in oil and gas waste. Areas that come to mind for Marble include parts of the Haynesville Shale in the East Texas area.

"I think the fight eventually will be if that produced water starts to be processed through direct lithium extraction, whether that was a right that an operator has under an oil and gas lease," Marble said. "I find it hard to believe that when the legislature put together the oil and gas waste statute and included produced water, that they meant to give companies the windfall of lithium one day."

Legal issues aside, the future appears promising for lithium extraction from brine. While lithium is "kind of the lowest hanging fruit" for electricity and battery storage, brine could help source other emerging battery technologies.

Marble compared brine to natural gas. Oil producers at times viewed natural gas as a waste product until Henry Hub natural gas spot prices shot up to $6/Mcf.

"You may see that in some of these brine production leases one day, maybe where they are going after

Lithium-ion batteries are produced for EVs.

Shutterstock

lithium, then someone cracks the sodium ion technology wide open and all of a sudden people are buying salt from the brine," Marble said. "I think there is a world of endless possibilities."

Another route

In the Marcellus Shale, Eureka Resources has been receiving wastewater from natural gas companies, extracting minerals from it and generating clean water, Eureka Resources Chief Commercial Officer and CFO Chris Frantz told Hart Energy. The company was formed in 2008 with a business model of grabbing the sodium chloride and treating the rest of the wastewater.

According to Eureka's website, the company's products include pure water, salt, calcium chloride, oil and methanol. Processes used include an exclusive mechanical vapor recompression distiller evaporation technology, which is used to separate particles from the water, resulting in distilled water. Vacuum crystallization, a method that evaporates water from minerals, is used to extract minerals from purified brine. It's the same technology used by salt producers, the company said.

Eureka's focus has turned to lithium in recent years. Working with technology partners and academics, Frantz said the company learned a lot about its brine and the DLE process.

"We also learned that that's [DLE] not the right solution for us because it's a slow process. What we want to do is we want to scale up to high volumes and get lots of lithium quickly," he said.

The DLE process is difficult when working with complicated brine containing many different types of metals, such as in the Marcellus. While the DLE approach plucks out lithium and leaves everything else, Eureka takes the opposite approach and uses methods similar to those it has carried out for years to remove metals from wastewater, Frantz explained. The most prevalent salt is removed, followed by the next and the next until lithium is the end product.

"It took us two and a half years to figure that out," he said.

Working with partner SEP Salt & Evaporation Plants at a pilot plant in Europe, Eureka celebrated a milestone in 2023: the successful extraction of 97% pure lithium carbonate from oil and natural gas brine from production activities. The recovery rate was up to 90%, the company announced in July 2023.

"We made actual lithium carbonate that meets a technical grade specification at the moment suitable for battery manufacturers," Frantz said.

Currently, the company is raising funds to expand its existing facilities in Pennsylvania to add lithium to its list of products from wastewater.

"Based on our current volumes, we're projecting about 500 metric tons per year of lithium carbonate," he said. "We're also simultaneously working with a partner in the oil and gas space for a brand-new facility in another part of the state that would be about 10 times the size of what we currently have."

A third-party investor is already working on locations in other basins where the technology can be used, Frantz added. ■

Turn Down Service: Autonomous Devices' Detection Evolves

Autonomous inflow control devices have evolved from a simple on-off switch to reservoir management tools.

JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

When the goal is to get as much oil or gas out of the ground as possible, controlling the flow of hydrocarbons—and other fluids—is critical. Knowing which fluid is which is part of the challenge.

Inflow control devices (ICDs) are typically installed as part of a completion. Advances from the mid-to-late 2000s made it possible for the device to autonomously shut off the flow when an interval was producing unwanted water or gas to maximize oil production.

"The original AICDs (autonomous inflow control devices) were just kind of on-off tools" that restricted production from an unwanted water or gas producing zone or were used to balance production across the horizontal well, John O'Hara, Halliburton's global business development manager for advanced completions, told Hart Energy.

When water was produced, the AICDs restricted total production or shut off the individual zone. Much like how intelligent completions went from intervention avoidance or to open, or shut off, AICDs have advanced from their original designs, he said.

"They've become more reservoir management tools than just on-off or intervention avoidance technologies," he said. "Now AICDs have more capability in allowing wanted oil production while restricting only unwanted fluids."

AICD technology was originally developed by Equinor—then known as Statoil—and used widely across the Norwegian Continental Shelf (NCS) with well-documented use in the Troll Field.

Detecting viscosity changes

Halliburton is working to develop advanced AICDs that apply to a wider range of wells, he said.

Halliburton's viscosity-based AICD technology detects viscosity changes to differentiate oil from water and gas. Still, that's not effective when oil and gas or water have the same or similar viscosity, he said.

A newer autonomous inflow control device technology detects different densities in the well fluids and restricts the flow of undesired fluids, he said.

"We have those reservoirs where the oil is very similar to water (density). We can still shut off that water and maximize that oil production," he said.

While detecting viscosity is fairly straightforward, O'Hara said the biggest hurdle in developing a density-based AICD came down to orienting it in the well to account for gravity. In essence, he said, Halliburton developed a mechanical centrifugal switch.

"It creates artificial gravity that then identifies the difference in buoyancy forces," he said. "By doing that, it allows us to close off a valve, basically, or shut off flow when it's water and have it reopened if it becomes oil again."

Part of what Halliburton worked out is how to create the centrifugal force for the artificial gravity in a small tool that could be packaged, sent downhole and then operate reliably over the life of the well, O'Hara said. There were, he added, some unique engineering challenges around the mechanical switch, which Haliburton calls the "fluid selector."

"It allows us to prevent a water-producing interval from dominating the overall production in the well," O'Hara said. "One of the big advantages of that is we leave water in place rather than handling water at the surface."

In early testing, he said, an unexpected outcome of the new density-based AICD is that it performed equally well in producing gas while still restricting water versus traditional oil producing wells.

That'll help meet a gap in the market, he said, because one of the limitations of existing AICD technology across all vendors has been a device that shuts off water in gas wells.

Halliburton's density-based tool, slated for field testing with a large Middle East operator in the first quarter, is intended for mature fields with high water cuts or unwanted gas. Following the Middle East trial, additional

> *"Now AICDs have more capability in allowing wanted oil production while restricting only unwanted fluids."*
>
> **JOHN O'HARA,** global business development manager for advanced completions, Halliburton

deployments are planned on the NCS as well as in South America and Asia-Pacific, he said.

Uptick in use

AICD deployment is simple, whether it's viscosity-based or density-based, he said. The AICD integrates with perforated pipe or screens as part of the completion.

"We don't have any control lines from the surface, we don't have anything we need to connect to actuate the balance. Again, they're autonomous," he said.

Typically, one density-based AICD would be placed per screen joint.

"It allows you to truly compartmentalize over long horizontals," making it possible to shut off where the water zone happens to be while still allowing for maximum production in the other producing oil intervals, O'Hara said.

In multi-phase flow, the AICD responds to a defined water cut, but it still allows a small amount of flow to proceed, he said.

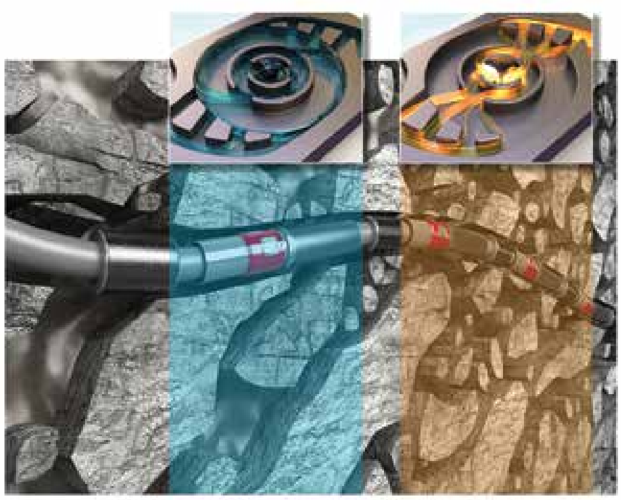
Halliburton's current density-based AICD is a 3.5-inch tool; a 5.5-inch tool is planned. Together, those tools will be able to serve lower flow rate, mature fields like those in the Middle East, along with higher flow rate NCS applications, he said.

The service company has also been working to merge the viscosity-based and density-based AICDs with gravel pack and intelligent completions technologies, O'Hara said.

While AICDs can be retrofitted, he said they are most typically installed as part of the original completion design.

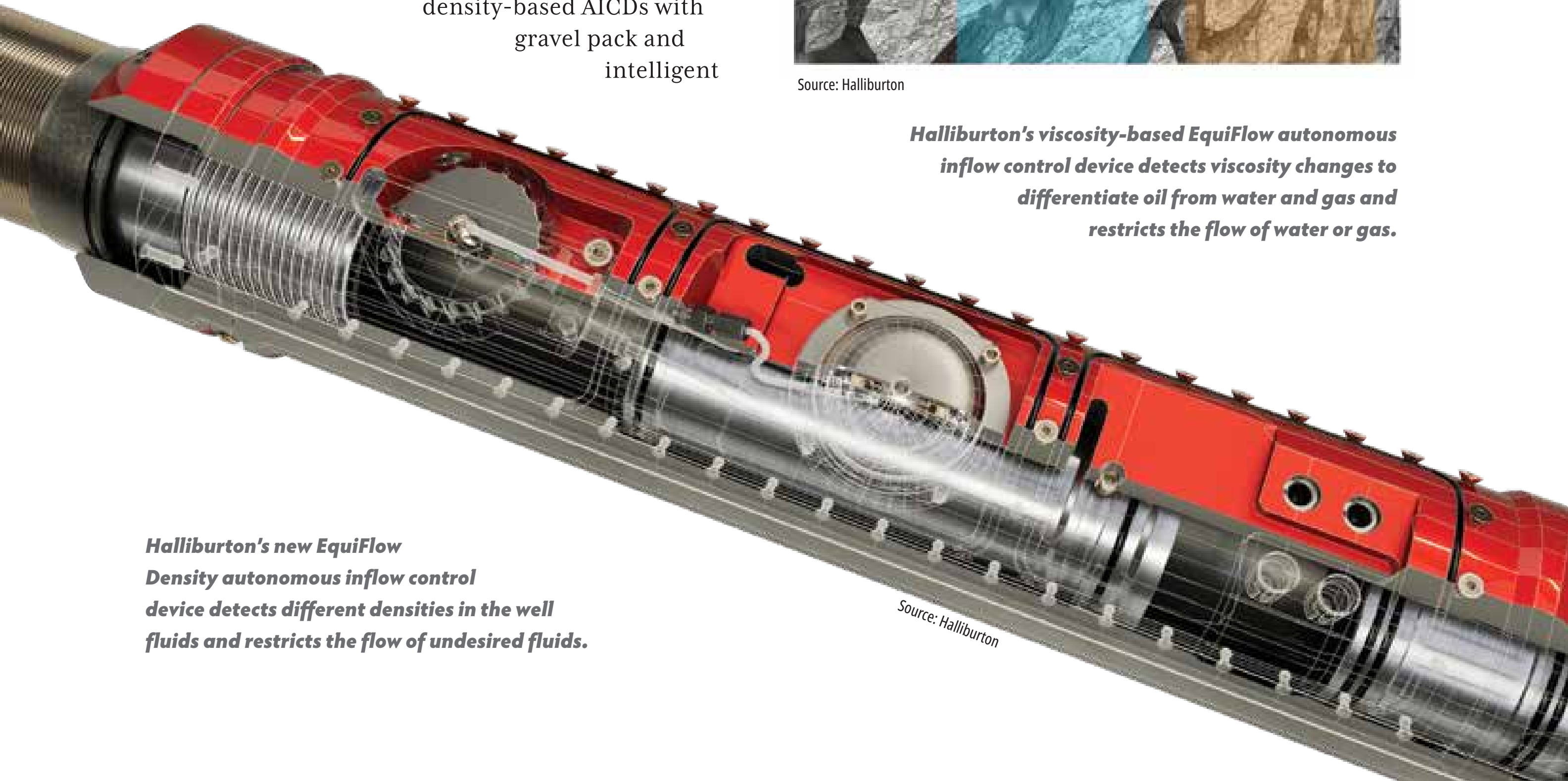
O'Hara said he has seen an uptick in industry use of AICDs.

"Your overall recovery rate is very important, so what we see is, with that need to squeeze every drop out of existing reservoirs or existing fields, technologies like AICDs become critical because as that field ages, it does produce more water," he said. "We're being challenged to squeeze more oil out of rock. This is very much an enabling technology that still has a cost advantage in that it doesn't have complex infrastructure tied to it." ■



Source: Halliburton

Halliburton's viscosity-based EquiFlow autonomous inflow control device detects viscosity changes to differentiate oil from water and gas and restricts the flow of water or gas.



Source: Halliburton

Halliburton's new EquiFlow Density autonomous inflow control device detects different densities in the well fluids and restricts the flow of undesired fluids.

Sibal: Pockets of Growth Balance Fears of Slowdown

SUNIL SIBAL | MANAGING DIRECTOR, SEAPORT GLOBAL

U.S. midstream and energy infrastructure sector entered 2024 on a very interesting note. It was with a mixed fundamental outlook as U.S. and global economies prepare for the potential of a slowdown which could temper energy demand.

Hydrocarbon demand could also experience a loss in market share in overall energy demand growth as renewable fuels gain more traction. This view is offset by a solid oil price backdrop, which should continue to support drilling activity, healthy midstream industry state and some pockets of growth.

The pockets of midstream growth include:

Gas processing in the Permian Basin. The top six public processors that Seaport Global estimates account for close to two-thirds of the total processing capacity in the basin have announced plans to increase capacity by more than 12% in 2024 and about 5% in 2025. Additional project announcements may further push the 2025 number.

This growth is supported by growing crude production in the basin as well as growing Gas to Oil Ratio (GOR) as wells in the basin age. The U.S. Energy Information Administration (EIA) estimates that GOR for production in the Permian has risen by more than 25% over the last five years, matching the crude production growth in the basin and essentially compounding the need for gas processing capacity to support growing crude production.

Gas takeaway capacity in the Permian has been bottlenecked. The fourth-quarter expansion of the Permian Highway (PHP) and Whistler gas pipelines adds a combined 1.05 bcf/d of egress capacity. Additionally, the expected completion of the 2.5 bcf/d Matterhorn pipeline in third-quarter 2024 is expected to provide capacity to move the residue gas from the processing plants to the end-markets.

Similarly, NGL takeaway pipelines from the region are expected to see capacity increases of more than 1.5 MMbbl/d over the next couple of years. This should support good utilization of these processing facilities by providing downstream connectivity to products coming out of the new processing plants.

LNG liquefaction capacity—a continuing growth story. U.S. LNG nameplate capacity reached about 90 mtpa at year-end 2022 following start-up of Venture Global's Calcasieu Pass facility. Average gas flows to LNG plants in 2023 totaled about 13 bcf/d versus 11.8 bcf/d in 2022 and 10.7 bcf/d the previous year, recording a second consecutive year of 10% growth.

Looking forward, we expect U.S. LNG exports to enjoy significant growth based on the facilities already under construction. We estimate total liquefaction capacity of about 75 mtpa currently under construction in the U.S. This includes about 45 mtpa through three projects which can be viewed as in the advance stages of construction and expected to see majority of capacity available by year-end 2025:

- Exxon Mobil's Golden Pass: 16 mtpa;
- Cheniere Energy's Corpus Christi Phase 3: 10 mtpa; and
- Venture Global's Plaquemines facility: 20 mtpa.

We could thus see a U.S. LNG liquefaction capacity expansion of close to 50% through these three projects, providing a major boost to U.S. natural gas demand.

Russia's invasion of Ukraine in 2022, and the subsequent explosion of the Nord Stream gas pipeline that alone had the capacity to provide piped gas from Russia to Europe to the tune of about 75 mtpa of LNG equivalent, has increased the call on U.S. LNG. This provided an impetus to new projects supported by European customers which, in turn, has supported another 28 mtpa of U.S. LNG liquefaction capacity that took FID in 2023. Those projects are:

- Sempra's Port Arthur Phase 1: 11 mtpa; and
- NextDecade's Rio Grande Phase 1: 17 mtpa

These projects would boost capacity in the 2027-2028 time frame. Additional projects under advance consideration include Sempra's Cameron Phase 2, Tellurian's Driftwood, GlenFarne's Texas and Magnolia LNG, among others and could further add to the visibility of growth pipelines.

Regulatory clarity could drive gas infrastructure. The Fiscal Responsibility Act of 2023 included a timely and unified federal review of energy infrastructure projects. This review includes completion within one year of an environmental assessment report and two years for environmental impact statements when needed for projects.

The act had special provisions for the long-delayed Mountain Valley Pipeline (MVP), providing a pathway for its completion that is now expected in the first quarter. The Williams Cos. is looking at gas infrastructure downstream of its Transco compressor station in Virginia, where MVP terminates. This regulatory certainty, coupled with recent cost escalation and setbacks in offshore wind development, could prompt more infrastructure projects in the region. ■

▸ TECHNOLOGY

At the Centro of it All

Weatherford's well construction platform utilizes five pillars to cut costs and increase efficiencies.

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Weatherford is tackling the complexity of oilfield collaboration with its digital Centro platform.

"We want to make sure that people are working together in a collaborative way, not in silos," Denise Livingston, product manager of digital solutions for Weatherford, said. "If I'm working in real time and if I bring everybody together to look at the same data and the same type of information, then I can improve the agility of making my decision."

The Centro platform is a vendor-agnostic digital environment integrating drilling and geoscience information with real-time engineering, data-driven machine learning models and real-time, KPI performance analytics, Reisha Bouska, global product manager at Weatherford, told Hart Energy.

The efficiency gained by using the collaborative effect of Centro can increase operational speed and safety, both onshore and offshore. The platform has been used in projects in Mexico and Colombia and proven its time-saving capabilities, said Marian Patranescu-Metea, Weatherford's software services lead for Europe and the Caspian Sea.

"In Mexico, we aggregated data from six different providers and created an end-to-end solution for the customer, which led them to achieve 32% production enhancement and a 60% time reduction," he said.

This project, which Patranescu-Metea said reduced costs by 40%—saving $1.8 million—integrated data from five different external vendors.

In Colombia, Weatherford's client had an issue with a lost hole, meaning it wasn't able to drill the wellbore to its absolute maximum depth. The client was also dealing with a tight drilling window and excessive vibrations downhole, said Patranescu-Metea. With Centro's well optimization capabilities, the client was able to reach total depth on the well and achieve a 33% reduction in time with no incidents.

Five pillars

Centro's well optimization is built on its five pillars: aggregation, monitoring, engineering, prediction and benchmarking.

"We start aggregating the information from multiple rigs," Livingston said. "We aggregate that information and we send it to our cloud, or whatever is the deployment of choice."

When shared to the cloud, users are able to use 2D and 3D visualizations to monitor the data from the rig and make observations. Then they can make informed decisions about drilling strategies and equipment adjustments, and diagnose problems.

"Using Centro engineer's planning capabilities, [operators] can generate a tentative well program design, considering rig configuration, piping and rig piping instrumentation," Bouska said. "[Operators] can also look at the well path by inputting [their] trajectory plan, and look at the well geometry based on whole sizes and casing designs and can also plan for various drilling fluids and different work strings."

After highlighting areas of improvement and using different engineering modules, operators can further validate changes to well designs with respect to mechanics, hydraulics and geomechanics. Combining the real-time data with dynamic models and calculations allows for early detection of operational performance needs. Predictive algorithms and Centro's machine learning capabilities are then combined with physics-based algorithms to provide other insights for well optimization.

After the prediction phase of operations has been completed, benchmarking is then done to update information and strategies for well optimization. This will allow operators to leverage decades of industry expertise by seamlessly integrating multidisciplinary fields.

"The platform has communication channels, alarms in place, document management tools that allow the user to make quick decisions," said Patranescu-Matea. "It also has the ability to be accessed from remote locations with only your mobile device or the tablet. So you are not dependent on a computer or laptop and you can monitor the activity when you are traveling."

Centro also provides a "wide variety of tools for the people that are inside of the platform working and monitoring the activity," said Patranescu-Metea, with various ways of intra-platform communication, allowing each user to share with their team members and store any vital information within a safe place on the platform. The platform also has various alarms and document management tools in place that have the ability to be accessed remotely from a mobile device as well.

"We want to bring up both productivity and efficiency, but not just efficiency for one particular drilling operation," Livingston said. "Of course, efficiencies reduce costs, but at the same way, I want to be able to be safer. We understand that one KPI for one particular operation may change, but the overall goal is for us to work together in a safer environment and when we bring everybody together, we achieve that collective efficiency." OGI

Oxy: Parts of DAC Ready to Scale

A major challenge is whether the process can be cost-competitive.

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The industry has been capturing carbon for decades, but most of that has been the easier-to-capture pre-combustion carbon.

Direct air capture (DAC) is taking on "the harder stuff," or the post-combustion carbon, Rohan Dighe, North American analyst at Wood Mackenzie, told Hart Energy.

"There's lots of different capture technologies for that. The more accepted industry standard right now is using amines as a solvent, but there's new proposed solvents," he said. "There's new absorbents, there's membranes, there's other technologies that are being proposed and are at different levels of technology readiness and commercial adaptability."

The technology to capture the carbon is only part of the puzzle. Storage is a major factor that includes scale, technical risk and proximity to carbon emitters, Peter Findlay, Wood Mackenzie's director of CCUS economics globally, told Hart Energy.

He said a challenge of storage is ensuring there's enough scale to deal with two to four decades of emissions.

"You can decrease your technical risk by really understanding the geology and where the plume is going," he said.

To date, storage has mostly been successful in small-scale operations, with the notable exception of the Sleipner project offshore Norway, he added.

And once emitters believe a project can handle the scale of emissions reliably, there's still the transport issue, he said.

"You want enough emitters that can be convinced that the whole CCS (carbon capture and sequestration) business model is favorable for them, so they can actually make money on this with a reasonable amount of risk," he said.

Right now, Findlay said, everyone is trying to understand how to make CCS and storage projects feasible without opening up for unforeseen future risks.

"To some extent, there's some similarities there in the early days of shale production in that the risks seemed manageable, but people were determining the level and order of magnitude of risks as they level," he said.

At some point, there is the potential that carbon may be stored in shale plays, he said, although it's most likely it will be stored in depleted oil and gas wells.

"In the U.S., we see some areas where there's contingent or close to storage, not usually in the shale, but in depleted oil and gas wells that are near the shale," he said.

More CCS projects needed

Carbon capture projects are critical to meet net-zero emissions goals by 2050. According to Wood Mackenzie, 7 billion tonnes per annum (btpa) of CO_2 capacity is required to meet those goals, but the world is only on track to meet a base case scenario of 2 btpa by 2050, which would result in global warming of 2.5 C, well above the goal of limiting the temperature increase to 1.5 C.

In October, Wood Mackenzie said globally planned CCUS capacity was at 1.4 btpa of CO_2 across capture, transport and storage projects. The U.S. leads in planned activity with 33% of all projects.

In 2020, Occidental Petroleum's venture capital arm, Oxy Low Carbon Ventures, joined with Rusheen Capital Management to form 1PointFive. The new company licensed Carbon Engineering's DAC technology to build a DAC plant in the Permian Basin. Since then, Occidental's DAC focus has thrust that technology into headlines.

"Oxy is going all in on DAC as a way of offsetting the carbon from its upstream portfolio," Dighe said. "I think the big issue—or the big hurdle—for DAC is cost and making sure that it's cost-competitive, especially compared to other point source emission abatement."

While there has been some pressure not to use DAC merely to justify continuing oil and gas emissions, he said the main issue is that DAC is "just fundamentally expensive" compared to other carbon capture methods.

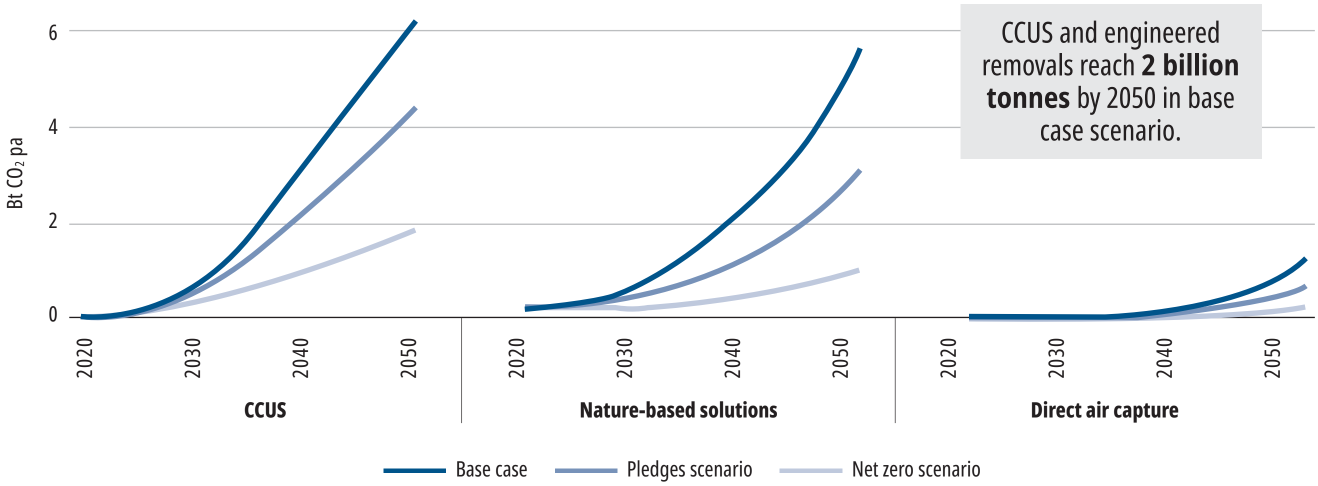
Richard Jackson, Occidental's president for operations, U.S. onshore resources and carbon management, said during the company's third-quarter earnings call that DAC is both a necessary and valuable technology.

"Near term, we believe our DAC technology can provide carbon dioxide removal credits for CDRs (carbon dioxide removal) at a lower cost and a larger scale than other product solutions," he said.

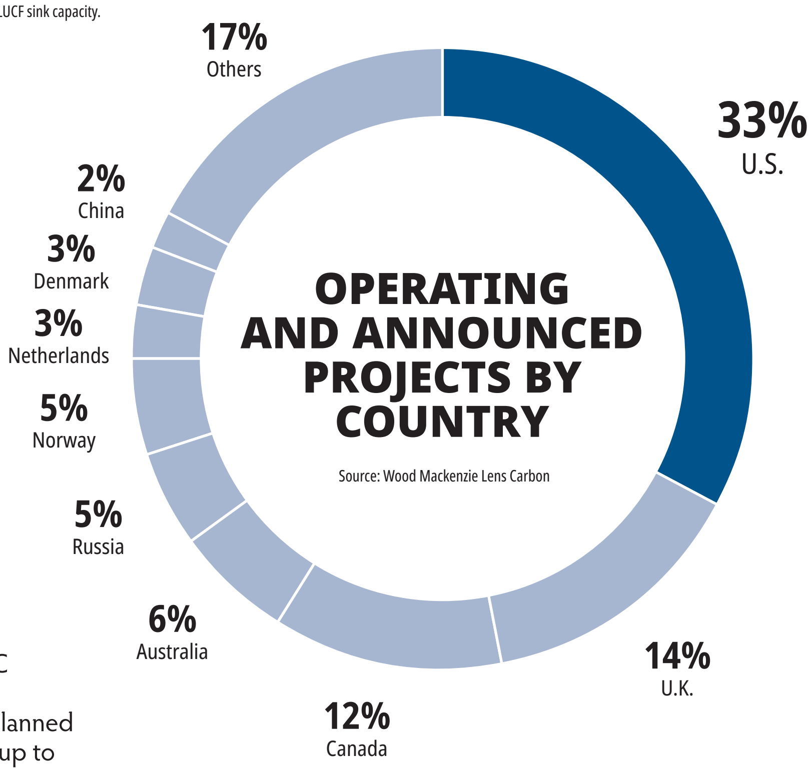
DAC technology

1PointFive's planned DAC facilities will use Carbon Engineering's carbon removal technology. The first step uses fans to pull large volumes of air into an air contractor, which is a large structure modeled on industrial cooling towers. Once the fan pulls air into the contractor,

Carbon capture and removals - by scenario



Source: Wood Mackenzie
Note: CCUS includes BECCS. Nature-based solutions forecast in the graphic is additional to existing LULUCF sink capacity.



it passes over a surface with a potassium hydroxide solution flowing over it. The potassium hydroxide solution chemically binds with the CO_2 molecules, trapping them in the liquid as a carbonate salt.

The carbonate salt is concentrated, purified and compressed so it can be delivered in gas form for storage or use. This process separates the salt out of the solution, forms the salt into small pellets and heats the pellets to release the CO_2 in pure gas form.

In August, Occidental announced plans to purchase Carbon Engineering for $1.1 billion.

"Carbon Engineering created a unique and innovative large-scale carbon removal process that has a strong fit to our OxyChem capabilities. This process uses equipment and materials that are ready to deploy at scale," Jackson said.

Stratos underway

1PointFive broke ground in April 2023 on its first DAC facility, known as Stratos, in Ector County, Texas, and construction is more than 30% complete. Start-up is planned for mid-2025, and that facility is expected to capture up to 500,000 metric tonnes of CO_2 per year.

Mike Avery, president and general manager of 1PointFive, said during the earnings call that Stratos's net capacity is 65% to 70% sold out through 2030. He said a growing pipeline behind that of earlier stage negotiations takes Stratos up to about 85% net capacity sold out to 2030.

"I think there's also growing recognition that direct air capture is not sitting out in the future. It's a technology that's ready to go now at commercial scales and that it's actually more affordable than people think when placed next to some of the other alternatives out there," he said.

Occidental said Carbon Engineering is adapting Stratos's FEED study for a DAC plant to be built at King Ranch in Kleberg County. The U.S. Department of Energy's Office of Clean Energy Demonstrations in August announced the Kleberg County facility would receive a grant of as much as $600 million as part of the South Texas DAC Hub.

"The acquisition of Carbon Engineering comes at a time where the need to accelerate DAC innovation is critical," Jackson said, adding Occidental will work to rapidly integrate Carbon Engineering's innovations into the DAC plants.

Jackson said the next phase of the company's DAC strategy will focus on accelerating cost reduction and expanding partnerships.

He said some improvements to air contactor design might reduce the number of air contactors required per facility. Air contactor fan motors that consume less power are under development.

1PointFive has said it envisions deploying over 100 DAC facilities worldwide by 2035 under current compliance and market scenarios, but during the quarterly earnings call, Jackson said market demand and the ability to reduce costs will influence the pace at which the company develops future DAC facilities.

"If the CDR market develops slower than expected, we will have the flexibility to refocus our efforts on R&D, with the goal of bringing costs down faster," he said. "If the CDR market develops in line with the medium or high cases we've laid out, then we intend to continue executing on our cost-down plan and to be positioned to secure development partners for this." OGJ

▸ TECHNOLOGY

Virtual Looking Glass: Collaborating with Digital Twins

Integrating digitized rock information with lab data is helping inform decisions in completions, EOR, carbon capture and storage, geothermal and other areas.

PAUL WISEMAN
CONTRIBUTING EDITOR

The digital looking glass continues to show improvement as a tool to oil and gas companies simultaneously performing field operations while fine-tuning ops with virtual twins.

Core Lab and Halliburton have combined their distinct methods of core sample evaluations to speed the process and give producers deeper insight into production decisions.

Core analysis testing is among the oldest assessment tools used in reservoir characterization and decision making. In recent years, Core Lab has used computed tomography (CT) scans to digitize that data for analysis and archiving—collecting massive data sets from onshore and offshore oil and gas fields around the world.

At that same time, Halliburton combined pore scale digital imaging and fluid dynamics to address industry challenges such as predicting IP and EOR methods. However, laboratory analyses of physical core samples are also required—a process that can take several months. In the past, a combined physical and digital program required transporting a physical core sample from one laboratory to another.

Chris Tevis

Chris Tevis, vice president for wireline and perforating for Halliburton, said while the digital version alone could help with "log calibration interpretation and to accelerate the use of data in static or dynamic reservoir models," it still requires physical lab analysis for the highest accuracy. By the time lab tests come in several months later, "those results will create questions about the original log interpretation. So, the earlier that a customer can get a quick look at data, the more it improves their base log interpretation and reliability."

Tevis said combining pore scale imaging with numerical modeling can reduce the turnaround on experiments to a few days or weeks depending on the complexity of the rock.

Joe Ramoin, Core Lab's general manager for petroleum services, said the company uses digital imaging for varied purposes.

"We're looking at overall core quality, basic lithology, potential fractures or heterogeneity—things that may impact core analysis," he said.

Combining the two workflows made sense, Ramoin said, because "it streamlines processing. There's no need to trade samples. You get both solutions in a more efficient manner."

To enhance the two companies' collaboration, Core Labs and Halliburton are opening a joint space in Houston where samples can flow through both laboratories seamlessly.

The need for speed

The watershed moment for this collaboration evolved from increased client activity due to carbon capture and storage (CCS) projects in the U.S., where there's a tight window for permitting and technical review of data. Halliburton and Core Lab both understood that operators need trusted digital special core analysis data to obtain timely CCS permits.

"We decided we could partner well with Core Lab and combine our respective datasets to complement each other," Tevis said.

Peering into pore throat

Micro CT and scanning electron microscopy systems collect data in a manner similar to medical CT scans, Tevis said. In the field, the difference is that systems use special lenses that examine rock pores up to one-10th the diameter of a human hair. This detail allows operators to study the flow of hydrocarbons, water and CO_2 for CCS.

But most often, he said, "It's about resolving the pores and the tiny doors, or spaces connecting the pores, known as pore throats." From there the view is extrapolated. "The key is to move up from pore scale to log scale to basin scale," for more complete analysis.

Indestructible digital twin

Tevis and Ramoin saw the benefits of using digital twins in rock and fluid flow assessments. Software allows for unlimited digital testing of strategies for a long list of procedures including drilling and completions, fracturing, production and EOR options—all without harming or altering any actual rock samples.

Ramoin said he sees tremendous potential for reducing risk, especially in EOR. "Sometimes, clients want to conduct feasibility studies with

Cutting-edge recirculation relative permeability rig at Core Lab enables an in-depth analysis of rock-fluid and fluid-fluid interactions under reservoir conditions.

Core Lab

"Sometimes, clients want to conduct feasibility studies with different surfactants or different EOR mechanisms. The ability to simulate multiple scenarios quickly helps with decision making."

—**Joe Ramoin,** *general manager for petroleum services, Core Lab*

different surfactants or different EOR mechanisms," he said. "The ability to simulate multiple scenarios quickly helps with decision making."

In a lab environment, testing those options could take months rather than a few days or weeks.

Ramoin observed that only in the field will the true results be known, but digital testing can narrow the choices to the methods with the greatest chance for success.

IPs can also benefit from the process, Tevis said—as Halliburton saw in North Dakota's Williston Basin.

One client's mature field production had become limited. After imaging the rock and examining the porosity and connectivity, the producer asked Halliburton to run simulations for relative permeability, capillary pressure and other properties.

Tevis said the test revealed "different layers of rock demanded different recovery techniques, so they used primary recovery fluids in one section and secondary recovery methods in another. With that, they were able to significantly improve production."

For the future

While the collaboration is in its early stages, both parties are excited about its possibilities. To borrow a line from "Casablanca," the partnership could be "the beginning of a beautiful friendship."

Ramoin said the future offers opportunities "for continued development by pulling measurements and modeling data together." He foresees unique workflows designed to reduce risk by combining the digital and physical solutions, along with both companies' extensive knowledge. The ultimate goal is to assess clients' needs, "leading to better decisions and better wells."

Tevis said, "As we see success in this partnership, I see it expanding to wherever our customers need us. Right now we're focused on North America, but we see these markets and the opportunity going global quite easily."

Those markets would include all types of oil and gas activity, along with CCS, geothermal and other energy and transition-related drilling and production. OGI

Tech Bytes

BP Taking on Copilot

BP is rolling out the generative artificial intelligence (AI) tool Copilot for Microsoft 365 across a substantial part of its workforce in early 2024.

The operator said in November it would be one of the first companies globally to act as a launch partner for Copilot, billed as an intelligent AI assistant. The cloud-based service integrates with the Microsoft 365 ecosystem and uses AI and natural language processing to automate a variety of daily tasks, such as writing emails and managing inboxes.

BP expects the use of Copilot to help employees boost productivity and upskill, enhance business performance and support innovation. Additionally, BP may offer insights that may help shape the future functionality of the product.

In a press release, Leigh-Ann Russell, BP's executive vice president of innovation and engineering, said the Copilot collaboration is a significant step in the company's digital transformation.

"Leveraging the latest developments in AI-powered workplace solutions offers the opportunity for BP to transform how work gets done. Our ambition is to empower our people to spend more time on innovation and the problem-solving that will help make the energy transition a success," she said.

In 2020, BP and Microsoft announced a strategic partnership for the operator's digital transformation.

Weatherford, Honeywell Sign Emissions MOU

Weatherford International said in November it had signed a memorandum of understanding (MOU) with Honeywell to deliver a combined CygNet SCADA and Honeywell Emissions Management suite for emissions management and decarbonization.

The MOU leverages Weatherford's CygNet SCADA platform, which allows operators to process data and information in real-time to support daily operations and strategic decision making, and Honeywell's Emission Management suite, an outcome-based offering that helps customers measure, monitor, report and reduce emissions. The integrated system will facilitate immediate access to essential data, empower decision-makers to act swiftly to mitigate risks and enhance operational efficiency to achieve decarbonization targets.

Halliburton, Sekal Automating Well Construction

Halliburton and Sekal AS announced in November a joint venture to provide well construction automation solutions as part of a longer-term strategy to deliver fully automated drilling operations. Under the agreement, Halliburton and Sekal are collaborating on technologies and services that incorporate Halliburton's digitally integrated well construction solutions and the Sekal DrillTronics automation platform.

CGG Launches OaaS for HPC, AI Solutions

CGG in November launched a new Outcome-as-a-Service (OaaS) offering designed to deliver customized, capability-focused high-performance computing (HPC) and AI solutions for scientific and engineering domains, including generative AI and life sciences. The company said the OaaS offers a guaranteed cost-effective approach for users wanting to transition their HPC and AI workloads to a production-based model aligned with business objectives.

EOR Technology Earns Certification

Locus Bio-Energy announced in November its AssurEOR STIM biosurfactant technology has been certified to reduce carbon intensity and boost production.

SGS issued the ISO-14064 certification for AssurEOR STIM. The technology has been deployed on hundreds of wells to address declining oil and gas extraction, the company said.

CGG and LightOn Collaborate to Evaluate AI

Global technology company CGG and AI company LightOn announced a new contract between companies to leverage CGG's industrial high-performance computing solutions.

The partnership will enable LightOn to evaluate and test large language models to support the industrial deployment of AI. The agreement will allow LightOn to use CGG's high-performance computing and AI center to benchmark its large language models to identify solutions.

Baker Hughes Launches New RTP Solution

Baker Hughes

PythonPipe by Baker Hughes.

Baker Hughes announced in November the launch of its reinforced thermoplastic pipe (RTP) known as PythonPipe.

The PythonPipe offers up to 60% reduction in installation time and achieves up to 75% reduction in carbon emissions throughout its lifecycle, according to Baker Hughes. The solution also offers up to 80% reduction in maintenance costs and trims crew requirements by 60%, according to the company.

EV Downhole Launches AIVA SaaS Platform

Downhole visual analytics specialists EV launched the AIVA cloud-based platform in October. The software-as-service (SaaS) solution reveals key information about condition, status and performance of assets and infrastructure. The cloud-based AIVA platform allows users to store, visualize and interact with a variety of logs and data types. It integrates, manages and safeguards data, instantly accessible from anywhere with internet access.

AIVA's log data visualization tool provides synchronized 2D and 3D data displays with real-time data statistics that reveal trends. Its video and visual analytics provide a clearer perspective with video imaging and video playback. Users can see a continuous, depth-based image for the complete circumference of the wellbore.

DIALing Up Dual Completion Gas Lift

Silverwell Technology announced

Kongsberg Digital will install four brand new K-Sim Offshore simulators at the North Cape Simulator Center in northern Norway.

Kongsberg Digital

in November a successful dual completion gas lift deployment using its digital intelligent artificial lift (DIAL) production optimization system for a major oil company.

DIAL overcomes production and operations constraints of traditional gas lift practices in dual-completion wells by enabling production from both strings in the well, the company said. The system, in use globally, integrates in-well monitoring and control of gas lift well performance with surface analytics and automation to continually optimize gas-lifted fields, remotely and without intervention.

"Gas lifting both strings enables operators to achieve increased production from their dual string wells, while saving them the capex of having to drill additional wells," Steve Faux, Silverwell's operations manager, said in a press release. "DIAL enables the recovery of by-passed reserves. It also allows easy adjustment of the gas lift parameters as reservoir conditions evolve over time, such as increased water cut or lower well productivity."

OFFSHORE TECH & NEWS

Shearwater, Petrobras Team Up on Seismic Tech

Shearwater said in November it had entered into a multi-year collaborative technology agreement with Petrobras aimed at reshaping seismic exploration and field developments.

Central to the endeavor is Shearwater's marine vibrator, which the company said promises significant gains in operational efficiency, seismic data quality and reduced sound emissions when compared to traditional methods. This commitment will include the industrialization of Shearwater's marine vibratory source technology and associated services for Brazilian offshore basins.

Strohm's TCP Earns Deepwater OK from DNV

Strohm

Strohm's thermoplastic composite pipe.

Strohm's 6-inch EGF-PE pipe earned a Statement of Qualified Technology from DNV for use as a flowline or jumper in deep waters, Strohm said in November.

Starting in 2018, nearly 40 tests were carried out on Strohm's thermoplastic composite pipe (TCP) subsea flowlines. According to Strohm, this is the first time DNV has granted an accreditation of this kind.

MODEC Signs MOU for Drone Inspections

MODEC signed a memorandum of understanding with Terra Drone Corp. for the technical development of inspection drones for FPSOs, MODEC said in November.

Regular maintenance and inspections are needed to ensure the integrity of FPSOs, but manual inspections at heights and in confined spaces pose significant occupational safety and health concerns.

Terra Drone's Terra UT Drone conducts inspections using ultrasonic testing capabilities for non-destructive testing. The labor-saving technology enhances safety and efficiency in inspection operations, MODEC said.

Kongsberg Selected by Equinor for Offshore Simulator Installation

Equinor picked Kongsberg Digital to deliver simulation solutions for safety and emergency training in Norway, Kongsberg said in November.

Kongsberg will deploy four of their K-Sim Offshore simulators to the North Cape Simulator Center in Norway. These will be integrated with KONGSBERG's K-Pos dynamic positioning systems and Aptomar, NORBIT's pioneering Oil Spill Detection system. The configuration enables offshore procedure training for personnel, as well as environmental conservation drills, oil spill detection and recovery simulations and "all-encompassing" safety and crisis management drills for Equinor's specialized personnel.

The investment will enable the training of professionals from Johan Castberg, Norne, Åsgård A and Njord N offshore installations, as well as the Melkøya onshore plant. OGI

Renewed Urge to Merge

Get ready for more consolidation in the renewable sector, Lazard's George Bilicic says.

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Even though traditional oil players Exxon Mobil and Chevron are inking multibillion-dollar deals to expand their fossil fuel portfolios, it doesn't mean the energy transition is stalling, according to investment banking firm Lazard.

"I think there's been a bit of confusion around those two transactions and some discussions around some other traditional energy companies about whether there's some pivot away from the energy transition," said George Bilicic, vice chairman of investment banking for Lazard. "Look at how companies like that are allocating capital, and there's still firm commitment to the energy transition."

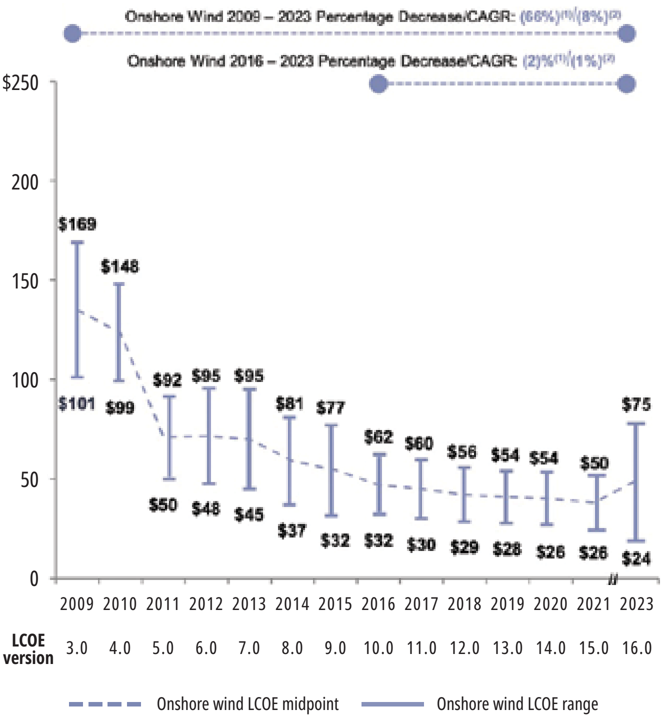
Capital will continue to flow into both lower carbon areas as well as traditional oil and gas business, he said in November during the Reuters Energy Transition North America conference in Houston. Exxon Mobil and Chevron, two of the world's biggest oil producers, are still driving innovation and investing in areas such as biofuels, carbon capture, geothermal and hydrogen.

Energy players and industry watchers maintain that oil and gas will still be needed, especially as developing countries raise living standards by transitioning from coal to natural gas and oil, while other parts of the world turn to renewables and lower-carbon energy to reduce global emissions.

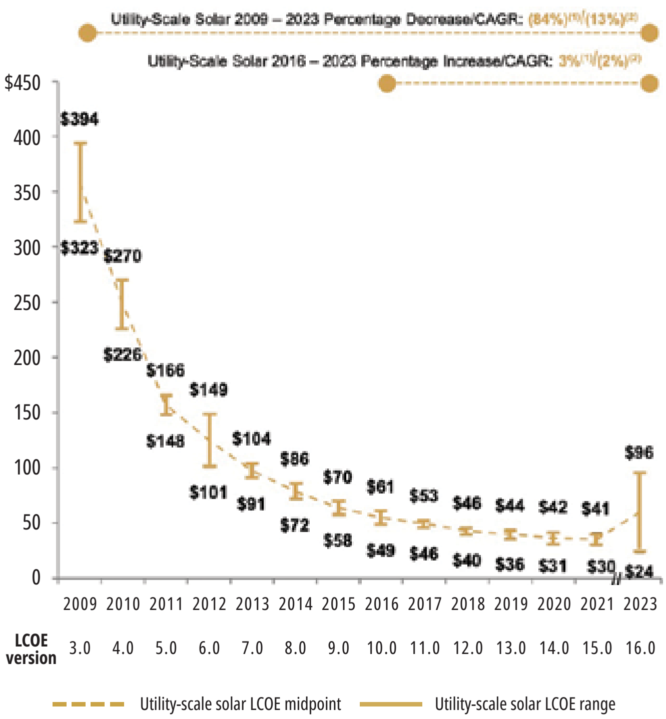
Chevron's $53 billion move to acquire Hess Corp. and Exxon Mobil's nearly $60 billion acquisition of Permian Basin pure play Pioneer Natural Resources left many wondering which oil deal would unfold next. But there could also be more M&A on the horizon in the energy transition space.

"We think there's going to be some horizontal mergers," Bilicic said, adding it could mean a company good at development merges with one good at operations. The firm believes there will be more consolidation among companies looking to become public and gain more access to capital.

Unsubsidized onshore wind LCOE
($/MWH)



Unsubsidized solar PV LCOE
($/MWH)



Source: Lazard
(1) Represents the average percentage decrease/increase of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

More consolidation?

Large strategics, equity firms and infrastructure funds are interested in acquiring companies in the broad renewable energy transition area, Bilicic added, though some of the larger strategics may have in place capital constraints and limitations on what they are willing to do.

"Enbridge bought a renewable natural gas company recently. RWE bought the Con Ed[ison's clean energy] business. Shell bought Savion," he said. "Just think about the transactions that have taken place over the last five to seven years, and we think you'll see the same thing over the next block of time."

Deal activity in the renewables sector was robust in 2022 when the value of renewable M&A deals jumped to about $12 billion in the fourth quarter, according to data from BTU Analytics.

Though deal value is down to about $1.8 billion in third-quarter 2023 compared to about $3 billion a year earlier—attributed to rising interest rates increasing the cost of capital—deal volume and associated renewable capacity are starting to pick up, data show.

"The number of pending and completed M&A deals for the quarter reached 32. This marks a small gain from the 29 deals identified in the prior period, though it remains far below peak levels," BTU said in a third-quarter 2023 report on renewable M&A activity. "The amount of acquired renewable assets—consisting of development-stage projects and operating facilities—has also advanced, reaching 30 GWs in the quarter. As with deal value, this also remains far below peak levels, meaning the sector may be operating far below full capacity."

$1.8B

Renewable deal value in third-quarter 2023

$3B

Renewable deal value in third-quarter 2022

Cost of capital

The cost of capital is higher because long-term rates are higher, Bilicic said, noting everything—including labor and steel—is more expensive. Cost of capital is the return needed to justify budgeting capital for a project.

Offshore wind is among the areas that were hit hard in the U.S.

"What we see is there is a kind of resetting of expectations on costs across everything that we do. And I think that's flowing through the system," he said.

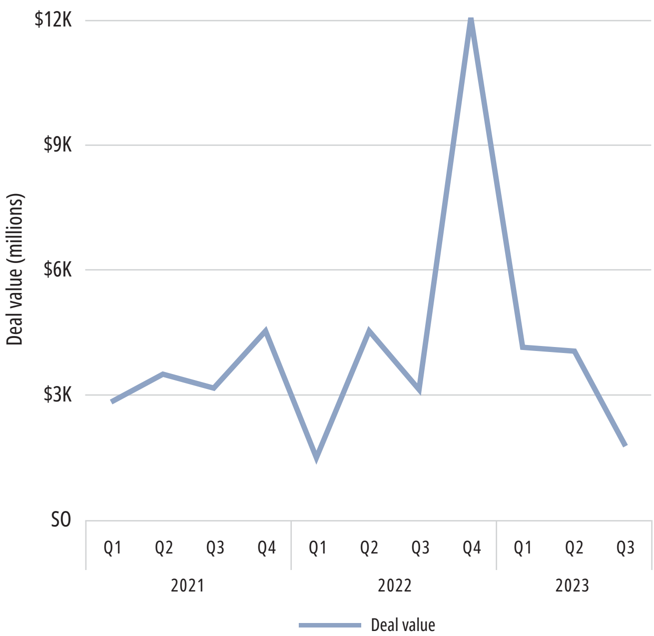
A levelized cost of energy (LCOE) analysis published by Lazard in April 2023 showed that despite inflation and supply chain challenges, the low end of costs for onshore wind and utility-scale solar declined.

"The reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies," Lazard said in its report.

Companies with scale that can manage the supply chain or have strong engineering, procurement and construction partners that can help manage the supply chain are advantaged, Bilicic said.

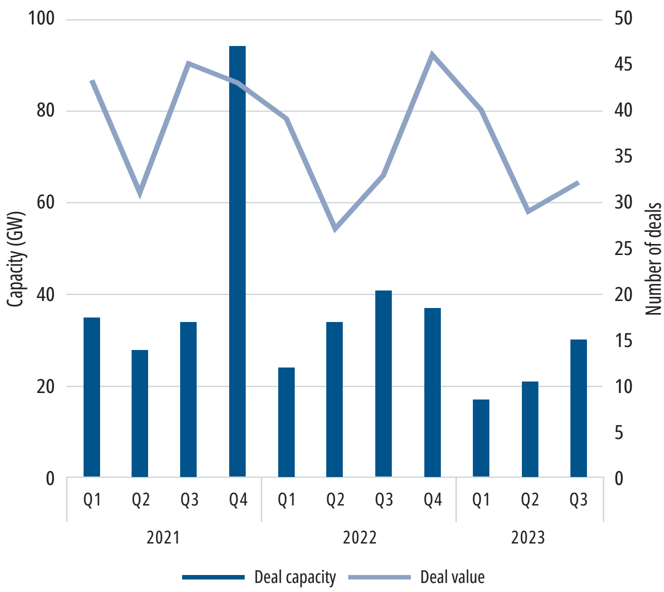
"We think this is an industry—not because we're in the business of helping companies consolidate—but we think the industry across all elements of energy, whether it's Exxon or Chevron or utilities or renewables company ... we're going to see a lot of consolidation because of the opportunities to control costs, to access the lowest cost of capital and manage supply chain." OGI

Disclosed M&A deal values in U.S. renewable sector

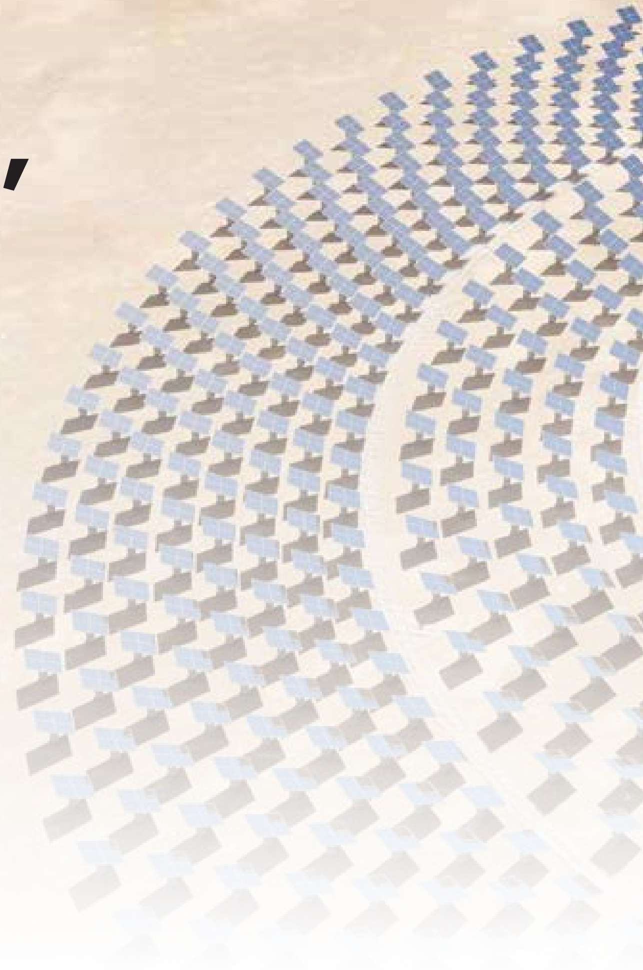


Source: BTU Analytics - a FactSet Company (Data Updated October 18, 2023)
Note: Deals consist of pending and completed M&A transactions that have been publicly announced, or are tracked by BTU Analytics, and that pertain to publicly announced. or are tracked by BTU Analvtics. and that pertain renewable assets (solar, wind, battery storage) or entities (developers, owners, operators) located in the U.S. Deal values may include assumed liabilities and maybe subject to closing adjustments. Pending deals may be subject to approvals. Private equity and venture capital deals excluded.

Announced M&A deal volume, capacity in U.S. renewable sector



Source: BTU Analytics - a FactSet Company (Data Updated October 18, 2023)
Note: Deal volume and renewable capacity from pending and completed M&A transactions that have been publicly announced, or are tracked by BTU Analytics, and pertain to renewable assets (solar, wind, battery storage) or entities (developers, owners, operators) located in the U.S. Renewable capacity is prorated when share of acquisition is specified; includes development-stage and operational projects; and consists of utility-scale and distribution-level solar, wind, and battery storage facilities. Pending deals may be subject to approvals. Assets identified as having a DC rating have been converted to AC rating. Capacity of battery storage projects sized only in MW are estimates. Private equity and venture capital deals excluded.



'Killer Combination' for Energy Storage

With an assist from AI, Heliogen's hybrid solar-thermal projects offer a dispatchable energy solution.

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As a child, did you ever use a magnifying glass to focus the sun's light and burn a hole or melt something?

Concentrated solar power (CSP) is essentially the same concept, said Christie Obiaya, CEO of California-headquartered Heliogen. Instead of a magnifying glass, mirrors called heliostats are used to reflect and concentrate sunlight onto receivers that absorb the sun's heat. That heat can then be used as is or to produce electricity with a steam turbine generator, paired with an electrolyzer, to produce hydrogen or a thermal desalination unit.

Heat created by concentrated solar power systems can also be stored for later use, providing a solution when the sun sets or on cloudy days.

The technology has been around for decades and used in Africa, Asia, the Middle East and South America, though not so much in the U.S.

Heliogen aims to change that by incorporating its artificial intelligence (AI) technology, automation and other core intellectual property into a hybrid system that combines a solar field of mirrors with solar photovoltaic (PV) and thermal energy storage to tackle the long-duration energy storage dilemma.

The hybrid concept is not new, Obiaya said, noting CSP plus PV and energy storage is used, for example, by the Dubai Electricity and Water Authority. (Heliogen is not part of that project.)

Depending on the project's location and solar source, the hybrid projects can be a "killer combination" of advanced technologies that offer a dispatchable energy solution.

"You can take advantage of the low-cost solar PV because solar PV over the last couple of decades has really ridden down the cost curve," Obiaya told Hart Energy. "But as the sun goes down, daytime solar PV does not have a role to play and so that's where the CSP for thermal energy storage kicks in.

"During the daytime, that CSP—the solar field of mirrors—can be collecting and essentially charging up the thermal energy storage to be dispatched at night."

Something old, something new

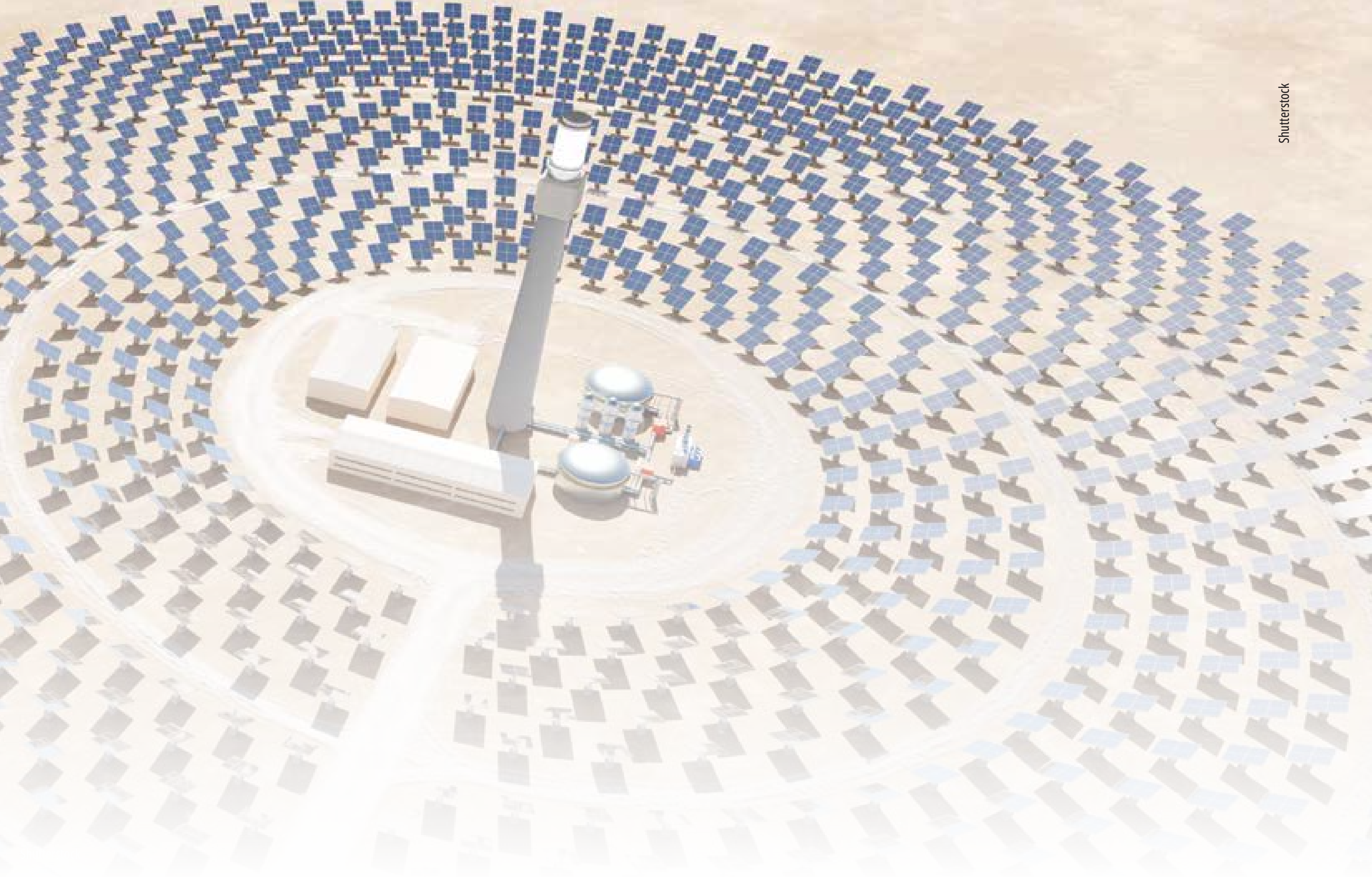
The concept of combining the solar energy and storage technologies with AI and automation is something Obiaya hopes will catch on in the U.S., where electrical grids are strained amid rising demand and prices due to higher natural gas prices.

"The lowest cost incremental storage solution is thermal energy storage when you're looking at long duration."

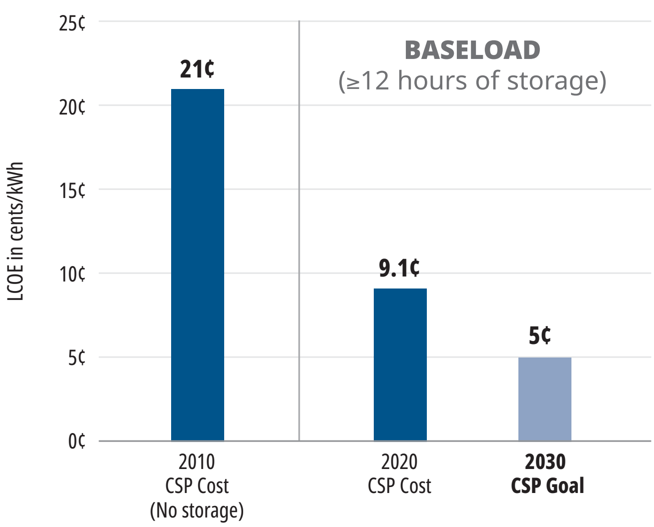
—**Christie Obiaya**, *CEO, Heliogen*

Renewable energy companies have ramped up solar PV output, but the intermittency challenge remains. Temporary gas generators have been used at some plant sites to avoid blackouts, Obiaya said.

Plus, today's short-duration energy storage technology is only able to discharge power for up to 10 hours or so, and the batteries can be



CSP goals



Source: U.S. Department of Energy

Heliogen

Heliogen's facility in Lancaster, Calif. The company's CEO says hybrid solar-thermal projects and an assist from tech can create a "killer combination" that offers offer a dispatchable energy solution.

cost-prohibitive for large utility-scale solar farms. While long-duration storage provides more flexibility in balancing the grid, technologies are still evolving.

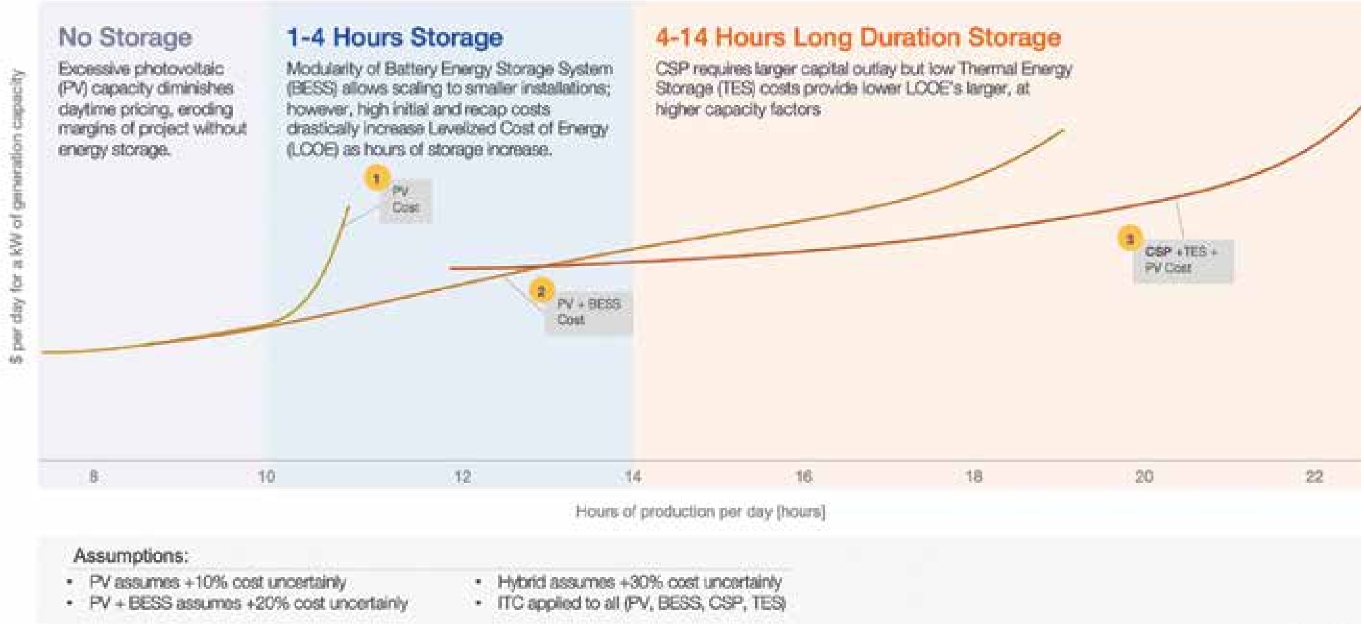
Heliogen has designed a hybrid power offering that combines CSP and PV with thermal energy storage, providing an alternative to traditional lithium-ion battery storage that typically provides a couple of hours of storage.

"If you're looking for a long-duration energy storage, [using batteries] becomes very quickly cost prohibitive because they've not driven down the cost curve yet," Obiaya said. "The lowest cost incremental storage solution is thermal energy storage when you're looking at long duration."

The company, which is fleshing out detailed engineering for its hybrid projects, is focused on long-duration storage where baseload power is needed. CSP systems are championed for their flexibility. However, a history of high construction and installation costs as well as performance has slowed adoption in the U.S. Competition from low-cost natural gas to power grids is also a barrier.

CSP's saving grace appears to be its thermal energy storage capability and improving technology, which has led to efficiency gains.

CP provides higher profits compared to PV or lithium-ion



Source: Heliogen

According to the U.S. Department of Energy's Solar Energy Technologies Office, in the past decade, "the cost of electricity produced by CSP has dropped more than 50% thanks to more efficient systems and the wider use of thermal energy storage, which allows solar energy to be dispatchable around the clock and increase the time each day that a solar power plant can generate energy." The department has set a goal for CSP to reach $0.05 per kilowatt-hour for baseload plants with at least 12 hours of thermal energy storage.

Improving technology

At an energy transition conference in Houston, Obiaya said Heliogen is improving solar-thermal by using advanced computing to eliminate spillage—in this context, a misalignment in which mirrors aren't placed correctly on the tower.

Suboptimal point accuracy is why some previous projects underperformed, she said.

"Achieving the 500th of a degree tracking accuracy to optimize energy collection is extremely challenging for a mechanical system operated outdoors for decades in an uncontrolled environment and subject to wind and temperature fluctuations," Obiaya said.

The cost-saving hybrid approach can be customized to any load profile and can share infrastructure, grid connections and support structures, she added.

"These hybrid plants are actually attracting a ton of interest from governments, commercial entities and investors worldwide, and they're already proven in operation," she said.

However, siting will play a role in whether the targeted CSP cost is hit in the U.S., since projects are dependent on the strength of the solar resource.

"Other projects across the world have successfully competed and won in the five and a half- to 8-cent range. So, it seems like it should be achievable," Obiaya told Hart Energy. "What we're doing is enhancing that further. Our focus is really toward that target of $0.05 per kilowatt hour. But we talk with customers all the time that say, hey, 'If you can get 8 and a half cents per kilowatt-hour of delivered energy inclusive of long duration energy storage, then that would be a success.'"

Though CSP has a larger capital outlay compared to PV with battery storage, Obiaya said the hybrid combining CSP, solar PV and thermal energy storage has a competitive all-in delivered cost of energy.

'Strong' cash position

Heliogen has financial backing from Bill Gates, NantCapital, Prime Movers Lab and Idealab Holdings among others, and plans to take advantage of tax credit incentives offered in the Inflation Reduction Act.

However, the company's average global market capitalization dipped below the 30 consecutive days at $15 million minimum set by the New York Stock Exchange (NYSE) in November, forcing its delisting.

Obiaya addressed the NYSE delisting on the company's third-quarter 2023 post-earnings call, saying the move has had no impact on the company's plans. Projects include the fully integrated Gen3 CSP commercial demonstration Project Capella with Woodside Energy in California, where it marked in October deployment of the first commercial-scale centrifugal particle receiver for on-sun testing and completion of the design verification of the prototype particle receiver.

The company is also building a small-scale commercial steam plant in the Permian Basin, and plans to use its hybrid power offering for green hydrogen production in Arizona.

Heliogen reported third-quarter revenue of $2.3 million with 7 megawatts and three projects in its backlog—representing $73 million in contracted revenue. CFO Sagar Kurada said the company ended third-quarter 2023 with $91.6 million in liquidity.

"At the end of the day, our cash position remains strong," Obiaya said. "We have the funding needed to execute through our near-term plans, including through the end of 2024, and we are looking forward to demonstrating the successful execution of the strategy that we outlined."

Heliogen began trading in mid-November on the OTCQX Best Market under the ticker symbol "HLGN." OGI

Transition in Focus

ENERGY STORAGE

Dominion Energy

The Dry Bridge Battery Energy Storage System is located in Chesterfield County, Va.

Dominion Brings Battery Energy Storage System Online in Virginia

Virginia-based Dominion Energy brought its largest battery energy storage system online, the company said, capable of storing enough electricity to power 5,000 homes for up to four hours.

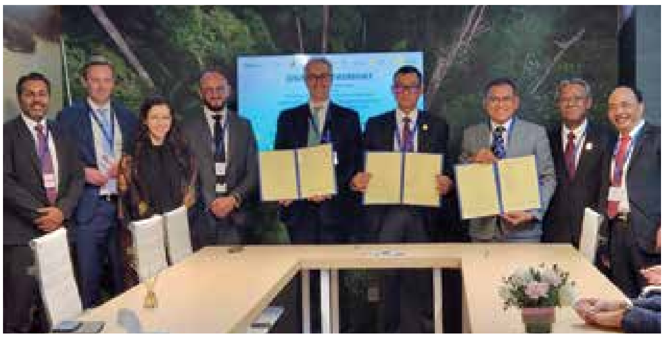
The Dry Bridge Battery Energy Storage System (BESS), which can store up to 20 megawatts (MW) of electricity, is located in Chesterfield County, Va.

"Batteries play an increasingly critical role in electric reliability as the company builds the largest offshore wind project in the U.S. and continues expanding the second-largest solar fleet in the nation," Dominion said. "Batteries can store energy from renewables during periods of low demand and then discharge it to the grid during periods of high demand when customers need it the most."

Dominion, developer of the 2.6-gigawatt (GW) Coastal Virginia Offshore Wind project, has focused on adding energy storage. Work is underway on a battery storage project at Dulles International Airport. When the 50-MW BESS comes online, it will be the company's largest battery storage system.

HYDROGEN

ACWA Signs Deal to Develop $1B Green Hydrogen Facility in Indonesia



ACWA

The agreement among ACWA, PLN and Pupuk Indonesia Holding Co. was signed during COP28 in Dubai.

Water desalination and power company ACWA Power plans to develop a $1 billion green hydrogen facility in Indonesia, making it the country's largest.

Partnering with PT Perusahaan Listrik Negara (PLN), Indonesia's state-owner electricity provider, and PT Pupuk Indonesia, a state-owned fertilizer and chemical producer, ACWA said the Garuda Hidrogen Hijau (GH2) Project will run on 600 MW of solar and wind power to produce 150,000 tonnes of green ammonia per year. Commercial operations are scheduled to begin in 2026, ACWA said in the release.

ACWA is part of the joint venture with NEOM and Air Products and Chemicals that is developing the $8.4 billion NEOM green hydrogen facility in Saudi Arabia. The facility, which will be the world's largest green hydrogen facility, will use up to 4 GW of solar and wind energy to produce 600 tonnes per day of hydrogen, in the form of green ammonia, by the end of 2026.

Sila, Worley Partner for EPCM Services for Battery Materials Plant

Battery materials company Sila partnered with Worley for engineering, procurement and construction (EPC) management services for a silicon anode materials plant being developed by Sila in Moses Lake, Wash., according to a news release.

Sila's silicon anode materials plant will have a battery material capacity of up to 150 GW hours annually by 2028, enough to power 1 million electric vehicles for five years, according to the news release. Production is expected to begin in 2025.

The silicon anode, called Titan Silicon, that will be manufactured at the plant is considered an alternative to traditional graphite anodes in lithium-ion batteries. The company claims it can increase battery energy density by 20%, which extends the range of batteries and speeds EV charge times.

SOLAR

Standard Solar Acquires Texas Solar Project from EDF Renewables

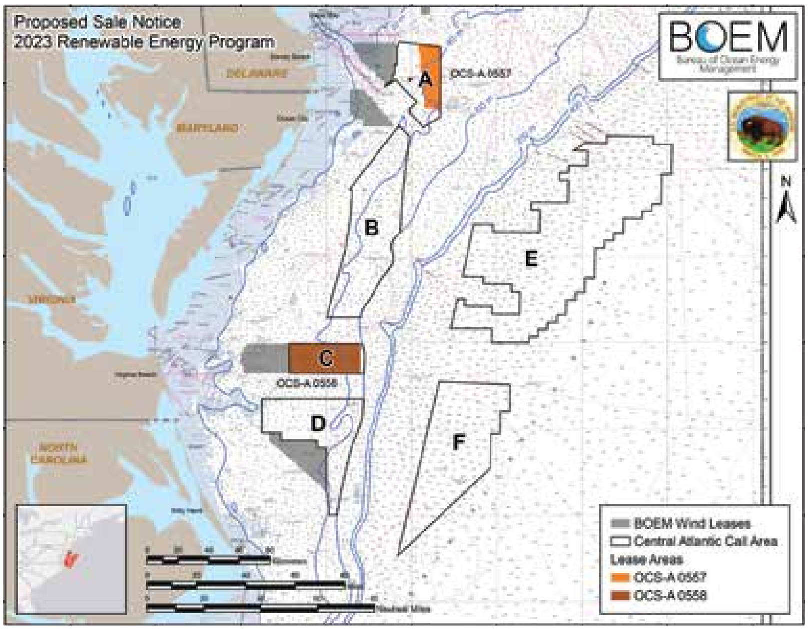
Maryland-based Standard Solar has acquired the 9.9-MW Bluebonnet behind-the-meter solar project from EDF Renewables North America, marking its entry to the Texas renewable market.

Located in McGregor, Texas, southwest of Waco, the Bluebonnet project is expected to be complete in second-quarter 2024. During construction, EDF Renewables' Distribution-Scale Power team will continue to serve as EPC contractor, according to the news release.

The greenfield project will feature bifacial modules on single-axis trackers, providing about 25,000 megawatt-hours (MWh) of clean energy annually.

Standard said the project will power part of an industrial process load for industrial gases company Messer Americas in Texas. The facility will mark the first time a direct connect solar energy system has mostly powered an air separation unit, according to the release.

With the acquisition, Standard now operates in 23 states.



Source: U.S. Bureau of Ocean Energy Management

Highlighted in orange and brown are the proposed wind lease sale areas in the Central Atlantic.

WIND

US Eyes Central Atlantic Wind Lease Sale

The Biden administration is proposing an offshore wind lease sale in the Central Atlantic, offering development rights across nearly 278,000 acres with the potential to power more than 2.2 million homes.

The proposal, which comes amid efforts to boost offshore wind capacity to 30 GW by 2030, includes one area covering 101,443 acres offshore Delaware and Maryland and a 176,505-acre area offshore Virginia, the U.S. Interior Department said in a news release. The proposal also comes as the offshore wind industry grapples with higher costs and supply chain constraints.

So far, the U.S. has held four offshore wind lease auctions during the current administration, including offshore New York, in the Pacific and in the Gulf of Mexico. The record-setting New York Bight lease sale brought in $4.4 billion in winning bids from six companies in February 2022. The nation's first offshore wind sale in the Pacific Ocean in December 2022 brought in more than $757 million in winning bids for five lease areas; however, the first-ever federal wind auction in the Gulf of Mexico ended with only one winning bid. The single high bid was for $5.6 million.

Additional areas offshore Maryland are also being considered for future leasing, the U.S. Bureau of Ocean Energy Management announced separately. Identified acreage will be analyzed further and considered as a wind energy area for possible inclusion in a wind lease sale as early as 2025, BOEM said.

TotalEnergies, Kazakhstan Sign Agreement to Develop $1.4B Wind Farm

TotalEnergies signed an investment agreement to develop a more than 1-GW wind farm with a 600 MWh battery storage system in Kazakhstan, the company said in a news release. The agreement represents an investment of about $1.4 billion.

Called Mirny, the wind farm in Kazakhstan's Zhambyl region would be the largest wind project for Kazakhstan, supplying more than 1 million people with electricity and avoiding the emission of 3.5 million tons of CO_2 annually, TotalEnergies said.

The investment agreement came about six months after TotalEnergies signed a 25-year power purchase agreement with the Financial Settlement Center of Renewable Energy, a public entity owned by the government of Kazakhstan, to supply power to the grid.

Mirny will be developed by TotalEnergies in partnership with the National Wealth Fund Samruk-Kazyna and Kazakhstan's national oil company KazMunayGas, which will each own a 20% stake in the project, TotalEnergies said.

RWE, Masdar Team Up to Develop Huge Offshore Wind Project

UAE's clean energy developer Masdar acquired a 49% stake in RWE's 3-GW Dogger Bank South (DBS) projects, which are expected to generate enough energy to power 3 million U.K. homes.

The companies agreed to work together and invest up to 11 billion pounds (US$13.9 billion) in the projects. The transaction is expected to close in first-quarter 2024, subject to customary approvals.

The Dogger Bank South offshore wind farms will be split across two sites in the North Sea—DBS East Array and DBS West Array—with each site having 1.5 GW of capacity. Construction could begin in 2025 with the first 800 MW of electricity online in 2029, the companies said in a news release. Plans are for the projects to be fully commissioned by the end of 2031.

RWE will have a 51% share and Masdar a 49% share in the project.

RENEWABLES

Clean Energy Developer EnergyRe Raises $1.2B to Expand Portfolio

U.S.-based EnergyRe, a clean energy project developer, raised $1.2 billion from European investors to help expand its portfolio of utility-scale transmission and renewable energy projects.

Glentra Capital, Novo Holdings and Denmark-based pension fund PKA were among the investors committing capital, according to a news release.

EnergyRe, which has headquarters in Houston and New York, is a partner in the public-private collaboration Clean Path NY, an $11 billion project targeting the development of 3.8 GW of new solar and wind power along with a 175-mile, underground 1.3-GW high-voltage direct current transmission line. The company is also a development partner on the 350-mile SOO Green HVDC Link transmission line that will connect the midwestern and eastern power markets.

EnergyRe's portfolio of projects includes solar, wind and storage, plus distributed generation, the company said in a news release.

Elia Group, a Belgium-based electricity transmission player, also agreed to acquire a 35.1% stake in EnergyRe Giga. Elia Group's WindGrid subsidiary will serve as the holding entity. Elia Group said it will deploy $400 million over three years into EnergyRe Giga projects. OGI

▸ MIDSTREAM

Exxon's Big Deal: Midstream's Permian Win, Lose or Draw?

In the wake of Exxon Mobil's $60 billion deal to buy Pioneer Natural Resources, pipeline companies await consolidation and potential production boosts.

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Exxon Mobil's acquisition of Pioneer Natural Resources will have repercussions for nearly every midstream company with a stake in the Permian Basin, but analysts disagree on who stands to win, lose and even the outcome for the storage and transport sector as a whole.

The question is how much Exxon will continue to increase production in the region, and whether the growth will be enough to outweigh possible consolidations of midstream services.

Exxon has been more aggressive than Pioneer in the Permian Basin, targeting 10% production growth over the year, which could indicate more volumes for midstream companies to handle in the future.

"The transaction has positive general implications for those midstream operators in the region, driven by a modest acceleration of development versus what each company was planning on their own," said Hinds Howard, a portfolio manager at CRBE Investment Management.

However, as Exxon moves to eliminate any redundancies, it's likely some producing facilities—and the pipelines supporting them—will no longer be needed.

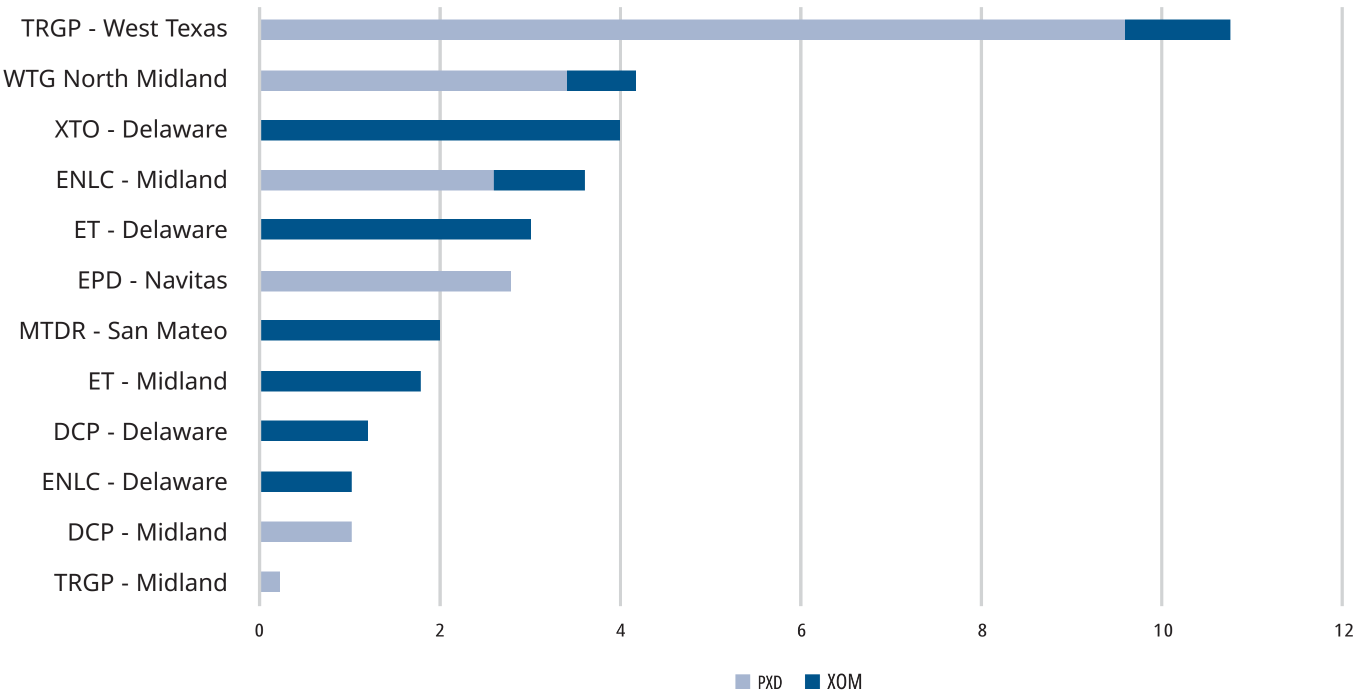
Two producers combining efforts indicate that the number of operating rigs in an area will fall, East Daley Analytics (EDA) noted in an analysis of the deal. "EDA's review of recent upstream deals finds buyers and sellers have dropped rigs by nearly 30 percent once companies combine," EDA analyst Ajay Bakshani said in a research note.

Pioneer owns 27.2% of Targa Resources's West Texas system and sends most of its Permian gas to the company.

Exxon primarily sends gas to both Targa and Energy Transfer, bringing to the table its gathering and processing system in the region, including a terminal in Wink, Texas, and operates the 650-mile Wink-to-Webster

XOM/PXD - Permian rigs by G&P system

Average rig count - September 2023



Source: East Daley Analytics

WhiteWater Midstream

The Whistler natural gas pipeline, seen under construction, transports natural gas from the Permian Basin. Its expansion, completed in September, increased its capacity to 2.5 Bcf/ from 2 Bcf/d.

"The transaction has positive general implications for those midstream operators in the region."

—**Hinds Howard,** ***portfolio manager, CBRE Investment Management***

pipeline, which it owns with six other companies.

According to EDA, Exxon and Pioneer had a combined 38 rigs in the Delaware and Midland basins in September. Targa serviced the most rigs in the time frame, averaging 11, according to EDA. West Texas Gas Midstream and EnLink Midstream were second at four rigs. Exxon also used its subsidiary XTO Energy to service four rigs in the Delaware.

The companies most vulnerable to consolidation are those with stakes where Pioneer's and Exxon's acreages overlap. Targa and Energy Transfer, companies that have benefitted the most from Exxon's rising production in the area, are also facing the most risk, Bakshani said.

However, EDA also acknowledged that a combined company would have less overhead and could use the extra money to develop areas that have otherwise been seen as too marginal to develop.

Wells Fargo analysts reported that the merger would be an overall "positive for midstream as (Exxon Mobil) intends to accelerate Permian production growth." Targa and Plains All American Pipeline, which operates a network of 5,500 pipeline miles in the region, would be the "main winners" while Energy Transfer and Enterprise Products Partners would also see more business.

11.4%

Exxon's pro forma projected CAGR for overall production by 2027

The positive overall outlook follows from Exxon's plans to grow its overall production from 1.3 MMboe/d in 2023 to 2 MMboe/d by 2027, an 11.4% CAGR—compared to about 5% CAGR that the companies had planned individually, according to Wells Fargo's "early read" of the deal.

Other midstream companies, which are expanding their networks in the Permian and terminals on the Gulf Coast, are expecting a greater amount of traffic from the deal, especially since behemoth Exxon has joint ventures with most of the industry's major players.

Kinder Morgan is expanding the Permian Highway Pipeline (PHP) system, which it jointly owns with Exxon Mobil and Kinetik Holdings. Kinder CEO Kim Dang said operations on the PHP are "nearly complete" during the company's third-quarter earnings call and should be in-service by December. Kinder Morgan will operate the pipeline, which increases its natural gas capacity by about 550 MMcf/d. OGI

▸ MIDSTREAM

For Enterprise, 'Right Time' to Focus on Permian NGL

Its $3.1 billion gas-related network expansion announcement coincides with MPLX's continued Midland Basin pipeline development.

Shutterstock

Enterprise Products also announced its Seminole pipeline will be converted from shipping crude to shipping NGLs in December.

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The decision by Enterprise Product Partners to bulk up its network with $3.1 billion in projects may not have been a direct reaction to the Exxon Mobil acquisition of Pioneer Natural Resources, but the transaction clearly reaffirmed the plan.

Executives considered steadily rising demand for NGL over the last few years, and announced the decision to greatly expand shipping capacity prior to announcing its third-quarter earnings.

"I guess what changed is the opportunities were there," said Randy Fowler, Enterprise Products co-CEO and CFO. "We thought ... it is the right time to go."

Besides the new projects, Enterprise Products also announced the December conversion of the Seminole pipeline from shipping crude to shipping NGL. The 1,281-mile Seminole pipeline, which has a capacity of 210,000 bbl/d of crude, transports materials from Hobbs, N.M., to Mont Belvieu, Texas.

"We took Seminole's crude service because we need NGL takeaway right now, until the Bahia pipeline gets in service," Fowler said. The Bahia is a 550-mile NGL pipeline that will take material from the Permian Basin to Enterprise's fractionation complex in Chambers County, Texas. It's expected to begin service in 2025.

210K
Seminole pipeline's bbl/d crude capacity

Besides the Bahia pipeline, the $3.1 billion in capital projects is dedicated to two natural gas processing plants, an NGL fractionator and an associated deisobutanizer at the Chambers County complex. All projects are expected to be online by 2025.

Enterprise was not alone in announcing an NGL network expansion. Marathon Petroleum's midstream company, MPLX, said that its Whistler pipeline expansion was completed at the end of the third quarter. The project raised the pipeline's capacity from 2 Bcf/d of natural gas to 2.5 Bcf/d of natural gas. The pipeline serves the Permian and terminates near Corpus Christi. For NGL, the company

"I guess what changed is the opportunities were there."

—-Randy Fowler, *co-CEO and CFO, Enterprise Products*

expects to have its expansion project for the BANGL pipeline, a joint venture between MPLX, WTG and Rattler, complete by the first half of 2025. The expanded pipeline will have a capacity of 200,000 bbl/d.

'Just scratching the surface'

Enterprise Products executives decided that an aggressive expansion was warranted, given the current state of the market, even if other midstream services were also expanding.

"I look at what somebody like (the) Exxon CEO [Darren Woods] said about getting more efficient and getting better recoveries, and I think we're just scratching the surface," said Jim Teague, co-CEO of Enterprise Products. Exxon Mobil recently acquired Pioneer in a $59.5 billion deal that focused on acreage in the Permian.

Enterprise made its estimates for what it would need by tracking Exxon Mobil's potential plans for the area.

Exxon's data is "very hard to set your watch to," said Tony Chovanec, Enterprise Products' vice president for fundamentals and supply appraisal, adding there are no indications that production will drop.

"I have to tell you when I look at what's going on relative to activity and profitability for the producer, I have to ask myself what's going to change this trajectory in 2024 or for that matter, what's going to change in 2025?" Chovanec said.

For third-quarter 2023, Enterprise Products reported a drop in total revenues from last year. Overall revenues came in at $12 billion for the quarter, as opposed to $15.5 billion from the same period of 2022. Teague said that, despite shipping record volumes on its system, earnings dropped with low commodity prices and record heat in August and September that hampered the company's operating capacities at several locations on its pipeline network. OGI

Carlson: Who Else Benefits from Exxon-Pioneer Deal?

JUSTIN CARLSON
EAST DALEY ANALYTICS

Justin Carlson is co-founder and chief commercial officer of East Daley Analytics in Colorado.

Exxon Mobil's (XOM) $60 billion all-stock deal for Pioneer Natural Resources (PXD) caps off a year of active dealmaking in the Permian oil patch. The acquisition is notable not only for its size—creating the largest producer in the Permian Basin—but also the direction Exxon plans to take the combined company.

New guidance indicates the supermajor intends to step on the gas once it completes the acquisition of Pioneer. In the company's third-quarter earnings update, XOM said it expects its Permian production in 2024 will more than double to 1.3 MMboe/d with the addition of Pioneer. XOM set a target to grow its combined Permian oil and gas production to 2 MMboe/d by year-end 2027, suggesting 10%+ annual growth from the XOM-PXD combo.

The guidance sets the supermajor apart from its peers in the Permian. Producers have mostly eased up on spending following recent mergers and acquisitions, resulting in less drilling activity. A recent review by East Daley Analytics found Permian operators involved in M&A, as either acquirers or buyout targets, dropped their combined rig counts by 30% in 2023. Exxon signaled the different direction after announcing the blockbuster merger earlier in October, telling investors the company had no plans to cut Pioneer's drilling program or headcount.

The company gave more details on its latest earnings. On the call, executives said Pioneer has the most Tier 1 inventory of any producer in the Midland sub-basin in West Texas. Yet XOM noted its own Midland wells have similar recovery as PXD's, despite drilling in less favorable acreage. Exxon credited its "cube" completion program for recovering more hydrocarbons. On Midland acreage of comparable resource quality, XOM said its cubes deliver about 20% higher recovery than PXD's wells.

XOM predicts synergies from the PXD acquisition to average about $2 billion per year over the next decade. However, the company expects most of the benefits (about 65%) will come from applying its superior completion program to PXD's premier acreage, rather than cuts to spending.

A question of infrastructure

Exxon's outlook for growth is great news for midstream companies in the Permian overall, and particularly in the Midland where Pioneer operates. But which assets are positioned to benefit from growing volumes, and what are the implications of growth for other operators in the Permian?

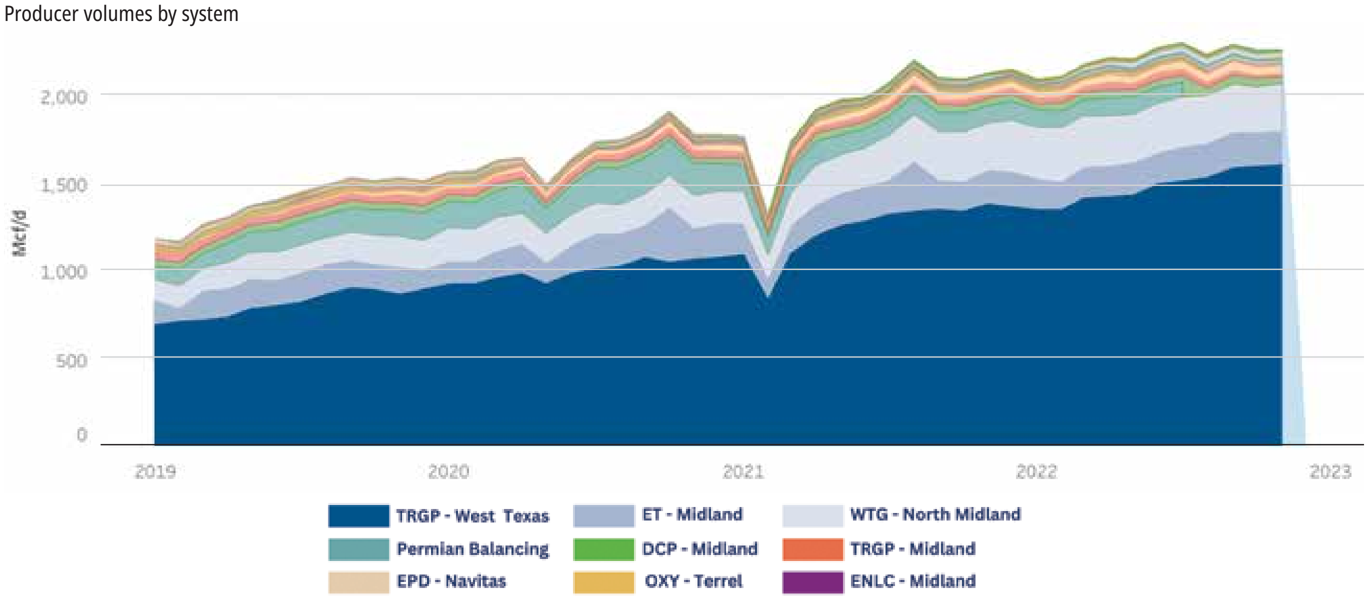
Pioneer sends most of its raw natural gas to Targa Resources (TRGP) for processing, and also owns 27.2% of the West Texas system with Targa. The WestTX system processes about 70% of the combined Midland volumes for XOM and PXD, according to East Daley's Energy Data Studio figures. West Texas Gas, Energy Transfer (ET), Enterprise Products Partners (EPD), DCP Midstream (DCP) and Pinnacle Midstream are other midstream companies that serve PXD and XOM in West Texas.

Energy Data Studio shows Exxon and Pioneer produced over 2.2 Bcf/d of raw natural gas in the Midland Basin at the end of 2022. We estimate

Exxon-Pioneer gas processing in Midland Basin
Peak system utilization through the next 12 months

Exxon/Pioneer - Midland gas volumes by G&P system

Producer volumes by system



combined volumes could grow another 1 Bcf/d by 2027, based on the latest company guidance.

The stumbling block to these plans could be infrastructure. East Daley forecasts most of the Midland gathering and processing systems used by XOM and PXD are already full or nearing capacity limits for natural gas processing. We estimate processing utilization on the top three G&P systems serving XOM/PXD to range from 87% to 119% over the next 12 months.

Several of the midstream systems serving the producers in the Midland already plan to expand. Targa, for example, is adding over 2 Bcf/d of gas processing capacity to its Midland and Delaware systems through 2025. But with Permian production continuing to grow, we expect capacity to remain tight.

The latest guidance from Exxon is a bullish point for midstream. By breaking from the Permian pack, the XOM/PXD combo could fuel another wave of midstream investments. OGJ

Analysis: Just Get Used to Volatility

East Daley forecasts instability over the mid-term as major change engulfs the industry.

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Expect change to be the unchanging trait of the energy industry over the next few years, said Justin Carlson, chief commercial officer of East Daley Analytics (EDA). And expect the changes to be erratic.

Carlson said the U.S. natural gas market faces dramatic changes from growing global demand for LNG, limited storage expansions, new infrastructure and capital discipline, not to mention the weather, during a webinar covering East Daley's annual report, "Dirty Little Secrets: Volatility Will Continue Until Morale Improves."

"What really matters today is weather," Carlson said. "If we keep on the pace we're at, December will break a decades-long record of where storage inventories are at this time of year."

Warm winters lead to customers using less gas to heat. After a year of record U.S. natural gas production and a mild fall season, the U.S. Energy Information Administration reported that natural gas storage in the U.S. was 3.719 Tcf on Dec. 1, 6.7% higher than the five-year average.

East Daley predicted the price of gas would resemble a yo-yo in action through 2027. In 2024, Carlson said, full storage levels would cause gas prices to fall to around $2.63/MMBtu in the spring, only to shoot back up close to $4/ MMBtu by December, thanks to heavy summer demand and a growing market for LNG.

LNG demand will continue to stress the U.S. supply system into the next decade. EDA expects demand for U.S. LNG will increase by 22 Bcf/d to a total of 132 Bcf/d by 2030. Supply is expected to increase to 131.8 Bcf/d. Tier 2 basins such as the Anadarko in Oklahoma and the Texas Panhandle and the Barnett in North Texas will play key roles in keeping up U.S. supply.

Midstream update

In the midstream market, Carlson said that competition was heating up among companies to collect the largest amount of NGL possible. Companies are using free cash flow of about $15 billion to build pipelines that will transport chemicals out of the Permian to the Gulf Coast, as NGL export demand is rising along with that of LNG.

"The rush to defend territory will create an overbuild that favors the large, integrated companies," he said.

Carlson said analysts expect the M&A market for midstream companies to pick up. With a lack of new major pipeline projects to spend on, many midstream companies have recently focused on financial discipline and have large amounts of free cash flow. The result is that some companies will look to expand through mergers.

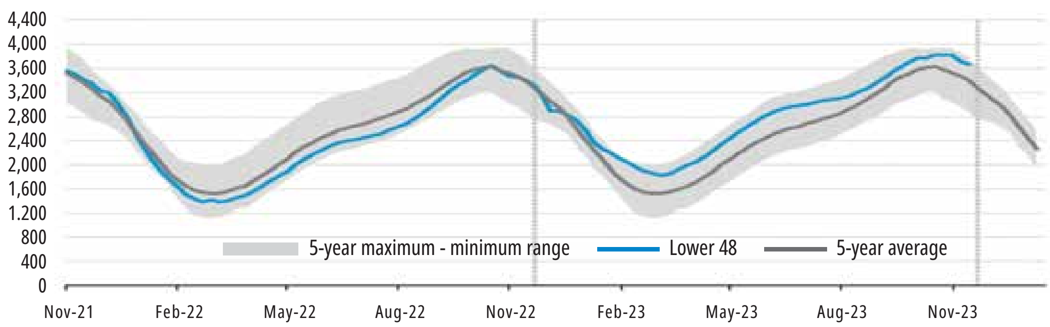
Other midstream companies may not be interested in immediately selling, but EDA analysts said it may be a strategically good time.

"I would say, on the buyer side, let's not get too greedy, and look for opportunities to share in some long-term growth," he said. "On the seller side, I'd also say, don't get too greedy.

"You may not realize the value that cooperation has in feeding, driving synergies to feed volumes through the full value chain and ultimately have even bigger growth." OGI

Working gas in underground storage compared with the 5-year maximum and minimum

Billion cubic feet



Source: U.S. Energy Information Administration

Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2018 through 2022. The dashed vertical lines indicate current and year-ago weekly periods.

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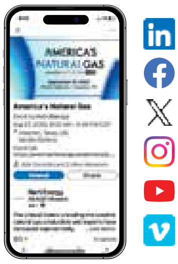

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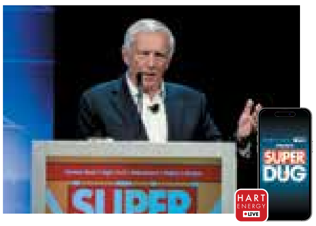

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Permian 2.0? Argentina Makes the Case for its Vaca Muerta Shale

Argentina's Neuquén Province Energy Minster Alejandro Rodrigo Monteiro discusses how the shale play is transforming Argentina into an energy exporter.

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Argentina's Neuquén Province Energy Minster Alejandro Rodrigo Monteiro is making a case for Argentina's Vaca Muerta Shale to be considered a super play—the Permian Basin.

The play has been transformational for Argentina's hydrocarbon sector and could drastically change energy trade in the Southern Cone region of South America as exports ramp up to Bolivia, Brazil and Chile. Additionally, a 25 million tonnes per annum (mtpa) liquefaction plant proposed by state-owned YPF SA and its Malaysian counterpart Petronas to be located on Argentina's Atlantic coast will open further markets for Vaca Muerta gas.

Monteiro spoke with Pietro D. Pitts, Hart Energy's international managing editor, about the Vaca Muerta's progress so far and its potential.

Pietro D. Pitts: Just how important is the Vaca Muerta for Argentina?

Alejandro Monteiro: If Argentina hadn't developed Vaca Muerta today, the country would have about half the oil production it has and one-third of the gas production it has. A little less than 60% of Argentina's gas production is unconventional while around 50% of its oil production is unconventional. In the case of gas, over 90% is consumed internally, and in the case of oil, it's close to 80%.

Without the development of Vaca Muerta—Argentina with all its macroeconomic problems and the lack of reserves at Argentina's Central Bank—the country would have imported hydrocarbons and energy worth over $20 billion in 2023. Or, said another way, considering the currency problem, the country would have had a hydrocarbon bill of $20 billion. And by not having currency, the country couldn't have acquired these hydrocarbons and energy. In other words, Argentina would've had serious energy supply problems, in addition to problems related to its Central Bank reserves.

Vaca Muerta has allowed Argentina to balance its energy trade. We continue to import some energy, especially LNG during the winter as well as Bolivian piped-gas, but with rising Vaca Muerta oil and gas exports, our energy trade is already in balance. We have almost completely eliminated the need to import energy. [This is important] if we consider that in 2011-2012, Argentina was importing about $12 billion in energy, mainly gas.

Source: Neuquén Province Energy Ministry

Argentina's Neuquén Province Energy Minster Alejandro Rodrigo Monteiro.

Source: Argentina government

Argentina should have a positive energy balance of about $4 billion in 2024 as production grows, primarily due to infrastructure projects moving forward that enable more exports. Internally, refineries are being supplied and, due to the improved gas infrastructure, we'll only have to import some LNG in the winter.

We plan to completely displace all Bolivian gas [imports]—as the [land-locked country] has warned that in 2024 it will not be able to continue sending gas to Argentina—and reverse the gas flows along the northern gas pipeline as Bolivian and northern Argentine basins are running out of gas production. Currently, the pipeline is set up for Argentina to import Bolivian gas, but the plan is for Argentina to be able to export its gas to Bolivia and on to Brazil. Basically, the gas pipelines come from Bolivia and go to the center

Top 15 Neuquén oil producers
January-October 2023

	Rank	bbl/d
YPF S.A.	1	189,957.1
Vista Energy Argentina SAU	2	42,409.1
Shell Argentina S.A.	3	28,326.5
Pan American Energy SL	4	18,890.6
Pluspetrol S.A.	5	8,600.4
Exxonmobil Exploration Argentina S.R.L.	6	7,570.6
Tecpetrol S.A.	7	7,552.3
Kilwer S.A.	8	6,679.4
Chevron Argentina S.R.L.	9	4,174.2
Total Austral S.A.	10	3,230.9
Oilstone Energia S.A.	11	2,509.0
Petrolera Aconcagua Energia S.A.	12	575.3
Capex S.A.	13	547.5
Patagonia Energy S.A.	14	458.7
Petroleos Sudamericanos S.A.	15	247.9
Others		119.1
Total		**321,849**

Top 15 Neuquén gas producers
January-October 2023

	Rank	MMcf/d
YPF S.A.	1	1,022
Tecpetrol S.A.	2	573
Total Austral S.A.	3	442
Pampa Energia S.A.	4	367
Pan American Energy SL	5	322
Pluspetrol S.A.	6	208
Vista Energy Argentina SAU	7	39
Oilstone Energia S.A.	8	32
Capex S.A.	9	28
Exxonmobil Exploration Argentina S.R.L.	10	24
Shell Argentina S.A.	11	15
Chevron Argentina S.R.L.	12	8
Kilwer S.A.	13	3
Petrolera Aconcagua Energia S.A.	14	2
Patagonia Energy S.A.	15	1
Others		0
Total		**3,084**

Source: Argentina government

of Argentina as well as gas pipelines that come from southern Argentina and go to the center of the country.

The national government [of outgoing President Alberto Fernández] put out a pipeline tender, but it wasn't awarded. So, it's pending to be awarded by the incoming government [of President Javier Milei]. If awarded soon, companies have [the] potential to finish work before next winter so Neuquén gas can supply a great part of northern Argentina.

Again, Vaca Muerta's development can be seen through all the energy that Argentina stops importing and also through the energy production export and the dollars this generates for the country.

PDP: There has been some interest from companies in Argentina's offshore region. Do you think that's a better strategy or is the Vaca Muerta their best option?

AM: Considering the learning curve that we've had with Vaca Muerta in these first 10 years of its development, the risk is very low. We have an enormous resource—308 Tcf or enough gas for around 200 years and around 27 billion barrels, enough oil for over 80 years—that has undergone enormous advances in terms of efficiency and productivity. So, today for an investor, the Vaca Muerta offers a low-risk, high-profit return.

There is also the first shale-related exploration in Santa Cruz in Palermo and the spudding of an offshore well by a consortium made up of Equinor, Shell and YPF, which will be the first exploratory well. But Argentina still doesn't have an alternative hydrocarbon project that can compete [with the Vaca Muerta].

It will take time to get another project to the state of maturity of Vaca Muerta. And as I look over the short- and medium-term hydrocarbons investment and development horizon in Argentina, it will be related to Vaca Muerta due to its low risk. In terms of profitability, due to the improvements in efficiency, the results are very good and comparable to the Permian. In some cases, they have even had better results than in the Permian, but not in terms of productivity.

PDP: What does Argentina need to do to really be called the Permian 2.0?

AM: It doesn't depend on geology. It depends on the decisions in terms of economic policy of the country and whether Argentina can get organized on the macroeconomic front. That's to say, Argentina opens itself to the world so that investors can bring in money, earn money and make profits and then invest again in Argentina or anywhere they want.

By 2030, we expect production in Neuquén to exceed 1 MMbbl/d. Today, we are producing 350,000 bbl/d. Our projections are based on a scenario in which Argentina doesn't achieve a complete opening of its economy. So, this is a moderate scenario. If Argentina, with the new government able to organize itself and generate confidence in investors, then that projection will be surpassed and we're going to have more growth problems than we have today, which would be good problems.

Only around 10% of the Vaca Muerta is under development, so if we advance with more projects, then the 1 MMbbl/d oil production forecast is going to be vastly surpassed. But in order for that to happen, the conditions need to be created so that international capital can invest in Argentina. Because … the capital, we have in the country, it isn't enough. So, beyond the capital we still need service companies, hydraulic fracturing companies, as well as technology and equipment, among other things.

We have to demonstrate that in addition to having a world-class resource, these are the needs that we have, and not only in terms of materials, equipment and technology since it's a permanent race against efficiency. You always have to manage to continue improving in terms of efficiency because the world is advancing in that sense. We can't just think oil will be $80/bbl and that LNG will be around $12/MMbtu. We have to have a project that is resilient, that supports low-price scenarios and that can continue to be produced and that can continue to make money.

PDP: Have you changed your mind since our last discussion regarding the Argentina LNG project proposed by YPF and Petronas and when it could realistically export its first LNG cargo?

AM: Work on a new law was sent to the Congress of the national government, which establishes certain regulations regarding fiscal security and security of supply related to a potential LNG project. With the change of government, there's uncertainty about what will happen to this law.

Under the current YPF leadership and with the agreement they have with Petronas, the conditions established in that law are appropriate to start the liquefaction project. If this law is approved, it's because the national authorities about to enter the government agree with those terms, which could see YPF and Petronas move forward with initial construction work. But, considering that equipment needed for the facility's construction isn't made in Argentina, I don't see a greenfield project before 2030.

However, the Argentina LNG project has an intermediate stage and, under the agreement, Petronas could bring in one of its liquefaction ships until they can construct the first modules of the facility. If this option is viable and feasible, we could perhaps have LNG as early as 2026 or 2027. But it also depends on how the law advances as well as new changes at YPF already announced by the incoming national government.

PDP: So, there is now a lot of uncertainty related to the incoming government and then YPF?

AM: Regarding LNG? Yes, because we have to see what the new government's vision will be regarding the intervention of the state in the economy. If the government gains the trust of investors, the law wouldn't be necessary. But, based on Argentina's track record, it will be difficult for investors to have trust without the law. So, it's important to have the law combined with a new vision from the national government that instills confidence in the private sector and towards investors, both private and foreign. Only then can this project advance.

PDP: The Néstor Kirchner pipeline aims to boost shipments of Vaca Muerta gas but bottlenecks still need to be resolved, right?

AM: The Kirchner pipeline has two stages. The first stage also has two stages. The gas pipeline was built and started operations in August 2023. In its intermediate stage, it has a transport capacity of 11 MMcm/d. [The] second stage of the first stage includes the construction of compressor plants at both ends of the gas pipeline. The compressors are under construction and, when installed, will allow the pipeline to boost its transport capacity to 22 MMcm/d.

Again, even with the conclusion of the first stage of the pipeline, there will still be a need to continue importing LNG during the winter months.

What's next is the bidding, awarding and construction of the second stage. The current national government started the bidding process with some financing from multilaterals from China. Today, everything is on standby as the incoming government doesn't want to continue doing public works with the public budget, but instead wants public works to be done with agreements from the private sector, via concessions with the private sector or the participation of public-private or contracts related to construction, operation and maintenance and fees.

Until the new government takes office and ultimately makes the decision regarding large infrastructure projects, things will be on standby.

PDP: How are Argentine gas exports to Chile since you restarted the gas flows?

AM: Today, Chile is our main gas export destination. In 2023, we practically exported gas to Chile the entire year, including the entire months of July and August, because we had surplus production with respect to the capacity of the gas pipelines that we have for internal supply. We had enough gas to continue supplying the internal market as well as Chile.

With work to revert the direction of the northern Argentine gas pipeline, we will have two pipelines that take Neuquén gas to northern Argentina that can be sold to northern Chile.

Chile is a very important market for Vaca Muerta gas. We have to continue adapting the infrastructure to reach the different gas export points. For Chile, it's beneficial to buy gas from Argentina because in comparative terms with LNG, it's cheaper and easier to ship to certain places in Chile. Remember, Chile imports LNG and uses trucks to ship some volumes to other close-by and distant internal locations. So, the cost of gas supply that comes from LNG, in relation to Argentine gas we can export via gas pipeline to different parts of Chile, is much costlier. We have been working well with the Chilean authorities regaining confidence in [an attempt to get them] to again view Argentina and Vaca Muerta as a reliable gas supply source.

PDP: Considering the gas trade history between Chile and Argentina, is the idea of Argentina exporting piped gas to Chile to be liquefied and exported as LNG to Asian markets being discussed?

AM: From the perception of the private sector there have been conversations. Gas producing companies in Argentina have raised the possibility of taking advantage of the Quintero regasification facility in Chile, which could be converted into a liquefaction plant, to export Argentina gas as LNG via Chile on the Pacific side of South America to target the Asian market.

It's a concrete possibility for the incoming national government, which has a more open vision with regard to international trade and Argentina's economy and its impacts globally. Obviously, it will require many agreements between Argentina, Chile, the off-takers and investments that need to be made.

The investment would be made in Chile, so there it would probably also have a much lower cost than what it could cost to build a new plant in Argentina. But the supply is still from Argentina, so there is the Argentine risk, which relates to breach of contract, which has happened [in the not-so-distant] past. If we can rebuild this trust, the Argentine risk would decrease and the entire project would be competitive.

Having said that, to supply a Chilean LNG export plant there would need to be a dedicated gas pipeline from Neuquén to Chile that would be much longer than Neuquén-Bahia Blanca pipelines that will eventually feed Argentina's proposed LNG plant. Importantly, any new pipeline from Neuquén to Chile would have to cross the southern Andes mountain range, which is no easy feat.

Also in Chile, where the Quintero facility is located, there are potential environmental risks related to earthquakes which don't exist on the Atlantic side. This would also create extra costs for any large-scale LNG plant in Chile. So, the idea of sending Argentine gas to Chile for export as LNG doesn't offer many advantages other than Chile's closeness to Asian markets.

But Argentina also has the opportunity to move forward a potential petrochemical project due to the characteristics of the Neuquén gas. Again, it's feasible to have liquefaction capacity on the Atlantic side [of southern South America] with an eye on European markets which will continue to demand LNG. Vaca Muerta gas and LNG can make it into markets that will have high demands related to carbon emissions and greenhouse gases, which is the case of Europe. While it's a challenge, it's also a plus so Argentine gas can enter European markets.

Argentina has plenty of gas when Europe lacks gas in the winter, so we also have that advantage. OGI

Pitts: Is Vaca Muerta Argentina's Permian?

Shutterstoc

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Can Argentina's Vaca Muerta Shale truly garner the title of "Permian 2.0?"

In terms of geology and game-changing potential: yes. In terms of eventual production volumes: no. That being said, it would be hard to believe that any government of the South American country wouldn't be happy with the game-changing aspect.

The Vaca Muerta ("dead cow") play is again attracting attention domestically and internationally for the expected economic and financial upside through rising oil and gas production, the potential for Argentine energy self-sufficiency and rising oil and gas exports that will boost revenues for government coffers and companies alike.

For Neuquén Province Energy Minister Alejandro Monteiro, development of the Vaca Muerta in its most basic analysis needs to be seen through two lenses.

"Vaca Muerta's development can be seen through all the energy that Argentina stops importing [and those associated costs] and also through the energy production [and] exports and the dollars this generates for the country," Monteiro told me in December.

Since the Vaca Muerta might not achieve the Permian's production volumes, the title of Permian 2.0 might not apply in theory in the eyes of Westerners or other onlookers. But at this point, even achieving a Permian 1.2 or Permian 1.5 label would be reason enough to celebrate.

The Vaca Muerta shares many geological similarities to U.S. shale plays, especially the Permian. Thus, opening the door for operators in the Vaca Muerta to leverage insights from those plays will expedite the development curve and reduce costs.

Operators in the Permian and the Vaca Muerta are similarly focused on oil. In the Permian, the price of oil is important to incentivize higher oil production, which includes a lot of associated gas. In Argentina, the focus on oil is similarly driven by the commodity's price but also other factors.

Government subsidies in Argentina have driven operators to pivot away from gas assets in the Vaca Muerta to oil developments. This issue is coupled with a lack of piped gas and LNG export capacity, consultancies from Rystad Energy and Enverus to PwC have said.

Piped gas from the Vaca Muerta, unlike piped gas from the Permian that only truly reaches one international destination directly, Mexico, is already reaching Chile and could potentially reach Bolivia and Brazil in the future.

But further development of the Vaca Muerta will be tied to politics. Argentina, which seems to always be confronting some sort of crisis or default scenario, is not for the faint of heart investor.

For investors already worried about all things Argentina from economics to finance, the recent presidential election of Javier Milei—an economist and libertarian who wants to abolish the Central Bank and dollarize the economy—certainty has potential to increase anxieties, if that hasn't happened already.

For what it's worth for those wondering where Milei stands, in recent months The New York Times dubbed him a "mini-Trump." In a video posted by Sky News, former President Donald Trump congratulated Milei on his election win in November and told him "the whole world was watching." Trump said he was very proud of Milei and his potential to "turn [the] country around and truly make Argentina great again."

Only time will tell if Milei will "make Argentina great again" and whether the comparison to a billionaire former U.S. president is the case or not.

For energy investors pondering Milei's talk about privatizing Argentina's state-owned YPF SA, the idea is interesting, especially as the country looks to attract much-needed foreign direct investment (FDI), technology and know-how that YPF lacks owing to financial constraints as a national producer.

At the end of the day, the Vaca Muerta is Argentina's anchor supply source in its quest for LNG exporting glory. For now Argentina's quest remains just that. Yeah, the Vaca Muerta can go head-to-head with the Permian in particular and other U.S. shale plays in general, but its continued commercialization will be hampered by above-ground issues that will dictate whether in the future we're able to talk about the Vaca Muerta on the scale of a Permian 1.2, a Permian 1.5 or a Permian whatever. OGI

Wicklund: US Gas Producers Need Price Stability

In an exclusive interview, PPHB Managing Director James "Jim" K. Wicklund talks U.S., Canadian and Mexican LNG projects and why the world may miss its net zero ambitions in 2050.

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Not one to mince words, James "Jim" K. Wicklund, managing director at Parks Paton Hoepfl & Brown (PPHB), gave his frank assessment of LNG projects from the U.S. and Canada to Trinidad and Argentina to Hart Energy's international managing editor, Pietro D. Pitts. Some projects, Wicklund said, are more about prestige than money. Others are more promising and profitable.

Pietro D. Pitts: What does it mean for U.S. producers to be able to sign on to long-term LNG contracts, especially in Europe or Asia?
Jim Wicklund: Surety of market. The biggest problem has always been the lack of stability in our industry. Several people said that if we just have a stable oil price or a stable gas price, it would be better than having a really high oil or gas price. And that's true. The long-term contracts represent the stability of the market that we've been aiming for. And if you're drilling a well in Haynesville and you're worried about, where do I put all this gas other than just dropping my domestic price, I'm now working on what will be normalizing arbitrage over time. The more LNG I export, the more I normalize, bring down the international price and bring up the domestic price. The more LNG we ship, the higher price U.S. producers get for their gas in addition to the surety of the markets.

PDP: How important is it now for U.S. gas producers to think about international markets for their gas, be it through Europe, Asia or Mexico?
JW: Right now, LNG is closer to 12% of U.S. production. I know we still export gas to Mexico and other places, but LNG exports are growing and 12% is a huge number when you're talking about such large things. I mean a 2% inflation rate going to an 8% inflation rate is huge. But if you look at the same relative moves over 12%, it's huge. So, it matters.

PDP: When we talk about the U.S. LNG producers, do you expect a lot of the deals that have been announced and that are planned to really come through by the end of the decade?
JW: I do. I don't see any impediments. The biggest impediment was going to be the financing of them. So far, they've been able to sign long-term contracts and get project financing.

PDP: We've seen three deals already this year.
JW: Exactly. The last one was $18 billion. So, we're getting financing. There was actually a school of thought that still exists that because of [President Joe] Biden's promise of LNG to Europe, along with [Canadian Prime Minister Justin] Trudeau's promise of LNG to Europe, even though Canada doesn't currently produce any LNG, was that you may have to use MARAD [Maritime Administration, U.S. Department of Transportation] financing to build some of these U.S. LNG facilities. Basically, getting the U.S government to guarantee the loan just to fulfill his promises to Europe. Now, so far, the financial markets have been such that we haven't had to do that, but in a changing interest rate environment. Who knows what's next?

PDP: And that couldn't be fulfilled via Mexico LNG exports that use U.S. gas?
JW: That's correct.

PDP: While the U.S. has emerged as a big-league LNG exporter, the country still relies on LNG imports from Trinidad and Tobago.
JW: When you think about where we're importing it into—Boston, the state of Massachusetts, won't let us lay a pipe, nor will New York. Either they get gas from that regas facility that's sitting within sight of downtown Boston or they have no power at all. The U.S. trade agreement was originally started to be nice to Trinidad and give them a market. So, there's favored nation status all over that situation. But, mainly without that, the Northeast would lose a huge source of LNG, natural gas availability through the Boston facility.

PDP: How do you view the build out of LNG export facilities on Canada's West Coast and then the competition potentially between the U.S. and Mexico for Asian markets in the future?
JW: An LNG Canada project is already well underway because it's been able to sign enough contracts to get project financing money. Who they sell their gas to, it's pretty much a foregone conclusion. I don't know offhand how much they're saving for the spot market, but

PPHB Managing Director James "Jim" K. Wicklund speaks at Hart Energy's A&D Strategies & Opportunities conference in Dallas.

Hart Energy

"There is no way we can get to net zero by 2050. Can we work toward that as a goal? We already are. Can we get there? No."

—**Jim Wicklund,** ***managing director, PPHB***

considering the banks aren't just throwing money around these days, it's probably not much. There are two LNG efforts trying to get underway that are looking at putting it in smaller containers and putting it on container ships as opposed to big LNG ships for use in remote locations in Asia. That hasn't gotten completely funded yet. And if you remember back seven years, there were four different LNG facilities planned for the West Coast of Canada, and none of them came about, in part, because the tribal nations couldn't come to an agreement. But in the projects that are going on now, the nations are actually partners. And so that's why you're seeing that start to develop.

PDP: In terms of developing an LNG project like Tellurian's Driftwood project, is it more important to have equity partners or off-takers or are both equally important?
JW: They're both important. Tellurian has a different business model in that they're trying to be vertically integrated by owning the natural gas production Haynesville properties, as well as the LNG facilities. And that is a different business model, and that spooks a lot of lenders. So far, it has spooked a lot of equity players, too. I think the financing and the banks have left him (former Tellurian Chairman Charif Souki) no choice but to try and raise equity, and he's having very little success doing it. At one point, I was as hopeful and optimistic as anyone else, and when they explained to you the logic of the vertical integration, it makes sense. But then you can explain a lot of things that make sense, in theory, but don't work in practice. And it has not been very well received at all [as] demonstrated by his inability to raise capital. So, that's going to continue to be a challenging model.

PDP: Would it make sense to spin off the upstream segment to move the project forward?
JW: I'm sure it's been raised.

PDP: When it comes to profits, and what you have to do

> ***"The biggest problem has always been the lack of stability in our industry."***
>
> —**Jim Wicklund,** ***managing director, PPHB***

as a company, that sometimes takes precedence over the environment, right?

JW: Yes. Investors often choose a higher return investment over an investment that has a low return but is more green.

PDP: So how do we get to net zero for 2050 around the world, if that's still kind of the sentiment that we still see?

JW: There is no way on God's green earth we can get to net zero by 2050 unless somebody identifies warp drive or whatever "Star Trek" did to move people around with the technology that is even leading edge today. There is no way we can get to net zero by 2050. Can we work toward that as a goal? We already are. Can we get there? No.

PDP: Venezuela's flaring just over 2 Bcf/d of gas into the environment. From a climate change perspective, shouldn't that be an issue for Washington to consider in terms of easing sanctions to try to allow perhaps Trinidad and Tobago to capture and use that gas?

JW: Yes, there are environmental funds out there on a global basis who will definitely loan money at ridiculously low prices to do environmentally beneficial things and that would be one. The problem, as you mentioned, is the dictatorship called Venezuela, and that has not been an actual magnet for capital lately. The answer, if you were almost any other country, would be: absolutely. You're back to politics and that's going to be a challenge.

PDP: How do you view Argentina and the idea of the country becoming a LNG exporter and then, how does the Vaca Muerta gas compete with gas sourced from the Permian? How do they compete on the LNG side of things?

JW: Well, they can't on price, and that's the problem. You've got a country with runaway inflation even today, so their [LNG] plant is going to cost a whole lot more than was the original plan. If the idea is to generate a positive return on invested capital, that's going to be a challenge. And yes, while the rocks are very similar to the Permian, the ease of getting gas out of the ground into a pipeline and to a Cheniere [Energy] plant in Corpus Christi [Texas] is a whole lot easier than getting it out of the ground through a pipe to the LNG facility in Argentina, considering the union issues, the political issues [that] make it more expensive for a feedstock. And they would operate at lower margins and significantly lower returns than competing projects in North or South America. Now, we have seen with things like the IRA [Inflation Reduction Act] in the U.S. that governments can fund, can subsidize losing projects for rationalized reasons all over the place. And the idea of the stature that it would give Argentina to be an LNG exporter and put them up on the board with the real players, I think the Argentine government would probably be willing to sacrifice margin to get that done, and the partners would not be happy. They wouldn't have a lot of choices and they'd have to make promises about the future.

PDP: How do you view Mexico developing its LNG projects anchored by U.S. Permian gas?

JW: I think it's going to be a challenge. I know that [TechnipFMC] has a contract to build a facility, and so the facility will get built. The politics of Mexico are always so capricious, it's difficult. The surety of supply to LNG facilities, when you know it can be nationalized at any point in time, means contracts don't really mean anything. The risk factor is significantly higher. And I'm sure that was expressed in the cost of the capital [related to Mexico Pacific's project].

But Mexico is struggling and trying desperately to generate more revenues from its energy reserves. Its oil production has been in decline for several years now, and they can't seem to arrest that. Pipelines from the U.S. through the center of Mexico and down to the bottom have been proposed for years and nothing's ever happened. Because the capital commitment to the LNG facilities, they're not going to have any choice but to actually make it work. The only issue I have is how much energy is needed in Mexico. So, instead of using it domestically, which would've been ideal, they're doing the LNG ship out for hard currency. So, they're caring more about the general fund than they are the overall economy. But it's politics.

PDP: There's politics in Mexico and then there are also Mexican cartels in the northern part of the country. Does that raise a flag for you as well in terms of security and projects securing financing?

JW: It has to. I mean, as long as we don't interdict their drug trade, people say, well, it won't matter. If there's an economic opportunity for them to hold something hostage and make money, we would be foolish to think they wouldn't do that. Is it a risk? Absolutely. I'm going to have billions of dollars of things flowing through pipelines to a location on the coast. And whether you see that as natural gas or dollars … I would think it's all being priced in.

PDP: Trinidad and Tobago's government is seeking to source Venezuelan gas to feed its Atlantic LNG export facility. How do you see that playing out considering the ongoing U.S. sanctions on Venezuela?

JW: Well, you saw the U.S. sanctions for Venezuela were bent dramatically for Chevron. And when you talk about energy security, whether it's the Willow project in Alaska or whether it's leasing restricted—but still leasing the Gulf of Mexico from a president who said he was going to end all of that—there is a level of practicality, especially lately on energy security. And I just don't see if we're willing to make a deal to let Chevron go back to producing, then again, I'm back to favored nation status, [and] would the U.S. be willing to help Trinidad or help Venezuela or Chevron develop gas reserves for Trinidad? We've seen all over the world [after Russia's invasion of Ukraine] that no one will buy Russian oil, and China and India are loving the heck out of this. I think it happens. It just gets a little twisted around from where we look at it today. OGI

Around the World

BRAZIL

Petrobras Eyes Capex of $102B Under New Strategic Plan

Brazil's state-owned Petrobras plans to invest $102 billion between 2024 and 2028 under its new strategic plan, up 31% compared to its 2023-2027 plan, aiming to achieve production of 3.2 MMboe/d by the end of the five-year period.

"Petrobras looks to continue boosting oil and gas production to generate value for its business, while creating value … with a focus on capital discipline," Petrobras' CEO Jean Paul Prates said in November during the company's webcast to present its strategic plans. "Controlling debt is one of our priorities," Prates said.

Higher capex is mostly related to new projects, including potential acquisitions and assets in the divestment process and investment portfolio, as well as cost inflation, which impacted the entire supply chain, Petrobras revealed in a press release and complimentary presentation related to the roll-out of its plan.

Of the capex, approximately $91 billion relates to projects under implementation, while $11 billion relates to projects under assessment, which are subject to additional financial feasibility studies before contracting and execution begin.

Petrobras is forecasting an average Brent price of $75/bbl during 2024-2028 and expects funding for its investment program will come from after tax cash generations as well as judicial deposits.

Petrobras' exploration and production (E&P) segment will absorb 72% of the total $102 billion in capex, followed by refining, transportation and marketing (16%), gas and low-carbon energies (9%) and corporate (3%).

MEXICO

Pemex Reports Higher Q3 Production, Lower GHG Emissions

Mexico's state-owned Petróleos Mexicanos (Pemex) reported an uptick in the amount of gas it used during third-quarter 2023, which averaged 92%, up 89.6% year-over-year (yoy), the company announced in October in its quarterly financial and operations press release.

However, the percentage in the most recent quarter is lower than the 94.2% reported in second-quarter 2023. Pemex continues to eye a goal of achieving 98% gas use by year-end 2024.

The Mexico City-based oil giant implemented its "Gas Use Strategy" in 2021 to boost the use of its gas, which could reduce the amount of gas released into the atmosphere by its upstream affiliate Pemex Exploration and Production (PEP).

Pemex's strategy relies on infrastructure development and rehabilitation activities that handle, transport and condition its gas as well as maintenance of its compression and booster equipment and the closure of producing wells that exhibit high gas-oil ratios, among other actions, the company said in the release.

Flared gas volumes averaged 393 MMcf/d in third-quarter 2023 compared to 491 MMcf/d yoy. The flared volumes related mainly to gas production "highly contaminated with nitrogen in the Northeast Marine Region, maintenance, and failures of compression equipment in the South Region, as well as rejections and releases from PTRI's Gas Processing Centers," Pemex said.

Pemex's gas strategy allowed the company to reduce its production of CO_2 equivalent (CO_2e) emissions as well as its emissions of sulfur oxides (SO).

The company's CO_2e emissions were 15.2 million tons (MMton) in third-quarter 2023, down 17.8% from 18.5 MMton yoy due to the implementation of infrastructure projects that manage and use associated gas in upstream processes as well as the continued operation of compressors in gas processing complexes.

The company's SO emissions were 280,700 tons in third-quarter 2023, down 17.1% yoy, due to lower fuel oil consumption in refining processes and a decline in sour gas flaring in the upstream processes.

SURINAME

Suriname Momentum Builds for APA Corporation

APA Corp. and its partner TotalEnergies continue to make progress in Suriname's promising offshore Block 58.

The companies plan to proceed with FEED work for a 200,000 bbl/d FPSO unit, they both announced in mid-September

"A considerable amount of planning, engineering and technical work is being directed toward this project, targeting final investment decision before the end of 2024," APA CEO and President John J. Christmann IV said in November during the company's third-quarter 2023 webcast, adding that first oil from the block was still expected to flow by 2028.

Regarding the first oil target, Christmann said "obviously there's incentive and motivation to try to accelerate that," and that he expected TotalEnergies to do everything possible to make that happen.

UNITED STATES

Looking to Right the Ship, Tellurian Plans to Raise $125MM in Financing

Tellurian Inc., which recently issued a "going concern" warning in its 10-Q filing, wants to spend about $125 million in 2024 on drilling and is attempting to raise financing to that end, according to board member Charif Souki.

"The purpose of the financing is to use our platform with the current production of around 200 MMcf/d to finance both the production for next year and reduce our

"We look forward to maintaining our accelerating progress in order to again deliver LNG to the market, well ahead of schedule."

—**Jack Fusco,** ***president and CEO, Cheniere***

corporate liability significantly and eliminate the need for [the] going concern … remarks that we had to put in our last 10-Q," Souki said in a November video posted on the company's website.

Souki, who said Tellurian had $60 million cash at the end of the quarter, did not disclose any details about how Tellurian plans to raise capital. And despite the company's own warnings about its financial security, Souki said that misinformation was being spread about the company, some of it fueled by "malicious intent."

The company has not filed any disclosures with the U.S. Securities and Exchange Commission (SEC) related to financing since the start of November. In its third-quarter report, the company said the company maintains an at-the-market equity offering program that allows the company to sell stock from time to time. As of Nov. 2, the company said it had "availability to raise aggregate gross sales proceeds of approximately $425.8 million under this at-the-market equity offering program."

Souki said Tellurian, which is also developing the Driftwood LNG export project in Louisiana, aims to boost its Haynesville Shale production to 350 MMcf/d, an increase of about 75%, by 2026.

Tellurian has 31,000 acres and 400 well locations, or about 30 years' worth of inventory at its current drilling pace. Souki also said the company's production team has delineated a new "mini trend" to add to production by "going higher on the risk profile to drill deeper and at higher pressures."

Sempra Eyes Cameron LNG Phase 2 FID in 2024

San Diego-based Sempra expects to announce a final investment decision (FID) for its Cameron LNG Phase 2 project in 2024, according to Justin Bird, the CEO of Sempra affiliate Sempra Infrastructure.

The FID would be subject to "definitive commercial arrangements, project financing and any needed regulatory extensions," Bird said during Sempra's third-quarter conference call with analysts.

"At Cameron Phase 2 we're working with Bechtel on value engineering … and are continuing to conduct that exercise and expect that work to go through the end of the year," Bird said. "The goal is to optimize the design and reduce the construction cost and project risk."

Cameron Phase 2 will add one liquefaction train with a production capacity of 6.75 million tonnes per annum (mtpa) or around 0.89 Bcf/d. Additionally, debottlenecking activities at the three-train 12 mtpa (1.58 Bcf/d) Cameron LNG Phase 1 export facility in Hackberry, La., will boost production capacity there by up to 1 mtpa, Sempra said in its third-quarter SEC 10-Q filing.

The Cameron LNG site can accommodate additional trains beyond the one proposed under the Cameron LNG Phase 2 project, which partners Sempra Infrastructure, TotalEnergies, Mitsui & Co. and Japan LNG Investment.

For the potential expansion, Cameron LNG had previously received major permits, free trade (FT) and non-free trade agreement (FTA) approvals, which included up to two additional liquefaction trains and up to two additional full containment LNG storage tanks.

"The non-FTA approval for the proposed Cameron LNG Phase 2 project includes, among other things, a May 2026 deadline to commence commercial exports, for which we expect to request an extension," Sempra said in the filing.

Cheniere's Corpus Christi Expansion to Send First LNG Cargo by 2024

Cheniere Energy expects the initial LNG cargo from its Corpus Christi Liquefaction Stage 3 (CCL Stage 3) brownfield expansion project will set sail by year-end 2024—ahead of schedule, president and CEO Jack Fusco said during a webcast with analysts.

"I'm optimistic we'll be commissioning on Train 1 with first LNG production by the end of 2024 and forecast all seven trains to achieve substantial completion by the end of 2026," Fusco said during Cheniere's November third-quarter earnings webcast.

During the webcast, the executive said he was confident in the ability of the Cheniere and Bechtel teams to continue with an accelerated schedule and the delivery of CCL Stage 3.

The CCL Stage 3, which will consist of seven "midscale" trains that will add more than 10 million tonnes per annum (mtpa) of production capacity. Fusco said progress on the third stage had reached the 44.1% mark.

"We look forward to maintaining our accelerating progress in order to again deliver LNG to the market, well ahead of schedule, increasing our operating capacity again starting in 2025," Fusco said. During the quarter, Cheniere produced its 3,000th LNG cargo since its start-up in 2016, thus "becoming the fastest LNG producer in history to achieve that milestone," he said.

Additionally, Cheniere is developing two midscale trains (Train 8 and Train 9) with an expected total production capacity of 3 mtpa adjacent to the CCL Stage 3 project. Cheniere has already filed an application with the Federal Energy Regulatory Commission for the two trains, Fusco said.

"We need to get going on construction of Train 8 and 9 at Corpus in 2026 as the first seven trains complete. And our goal is definitely well ahead of that to get going," Cheniere CFO Zach Davis added during the webcast. OGI

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2024				
Floating Wind Solutions	Feb. 5-7	Houston	Hilton Americas	floatingwindsolutions.com
NAPE Summit	Feb. 7-9	Houston	George R. Brown Conv. Ctr.	napeexpo.com
Louisiana Oil & Gas Association Annual Meeting	Feb. 26-27	Lake Charles, La.	Golden Nugget Casino	loga.la
5th American LNG Forum	Feb. 26-27	Houston	The Westin Galleria	americanlngforum.com
OTC Asia	Feb. 27-March 1	Kuala Lumpur, Malaysia	Kuala Lumpur Convention Center	2024.otcasia.org
Influential Women in Energy Luncheon	**March 8**	**Houston**	**Hilton Americas**	**hartenergy.com/events**
AOG Energy	March 13-15	Perth, Australia	Perth Convention & Exhibition Centre	aogexpo.com.au
CERAWeek by S&P Global	March 18-22	Houston	George R. Brown Conv. Ctr.	ceraweek.com
DUG Gas+	**March 27-28**	**Shreveport, La.**	**Shreveport Convention Center**	**hartenergy.com/events**
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 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 Stampeded 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	San Diego	TBD	cipa.org
New Energies Summit & Expo	**June 25-26**	**Las Vegas**	**TBD**	**hartenergy.com/events**
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
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.
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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.

Life in the Anthropocene Epoch

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Banksy, the street artist, infamously places "art" within museums, such as a Mona Lisa with an emoji smile inside the Louvre and a painting of a Tesco can of soup in the Museum of Modern Art, adding a wink: "Best before end."

Each is accompanied with an assimilated wall placard with explanation. The soup remained on display for six days.

Remaining in a British Museum antiquities exhibit for three days was a block of concrete containing a hieroglyphic of a speared buffalo. In the foreground is a caveman pushing a grocery cart.

Banksy's take on hunting in the Anthropocene Age.

British Museum @Instagram

The description he attached to it: "This finely preserved example of primitive art … is thought to depict early man venturing towards the out-of-town hunting grounds."

The 2005 work could represent the Anthropocene Epoch that a working group within the International Commission on Stratigraphy has been attempting to define.

If the group of geoscientists is successful, the Anthropocene will be declared as having begun in 1950 and the current Holocene Epoch (begun 11,700 years ago) to have ended.

In this new epoch, man is affecting the climate rather than merely being a byproduct of it. The Holocene's start was at the end of the most recent Ice Age, bringing nutrient-rich, arable land and hospitable oceans.

Another example could be evidence from the recent COP28 gathering, the circus in the desert, where an estimated 70,000 people gathered in Dubai to talk about man's carbon footprint.

Science-based findings would exclude news reports from it, such as the New York Times' opinion-presented-as-fact summary that fossil fuels "are dangerously heating the planet."

John Holdren, science adviser to President Barack Obama, told NPR this summer, "The hubris is in imagining that we are in control." Holdren believes the Anthropocene started earlier than 1950.

"The reality is that our power to transform the environment has far exceeded our understanding of the consequences and our capacity to change course."

The late H. Leighton Steward, geologist and chief of Louisiana Land & Exploration Co., was an advocate of more CO_2, co-founding PlantsNeedCO2.org in 2009 with Houston's Corbin Robertson, head of Quintana Minerals.

Steward published "Fire, Ice and Paradise" in 2009, writing, "This current climate and overall environment are as good as, if not better than, at any other time in Earth's history." His point was that a better understanding of Earth's natural history would point to "what we might be able to do or not do to try to preserve this paradise."

He told Hart Energy in 2009 that his findings on CO_2's role in geologic time are that "ice cores show that temperatures rise before CO_2 does, with CO_2 lagging by an average 800 years."

His point: The alleged "cause" in climate change did not result in an "effect." Yet, "some high-profile people are trying to stiff-arm scientists who believe this and they want no debate on it."

The growth in climate CO_2 has resulted, instead, in faster plant growth, creating sustenance for more people on Earth, he said. "If CO_2 levels nearly double, barley would grow faster by 41.5%. Rice growth goes up 34.3%. This is from 152 studies!"

Otherwise, "we can't feed [everyone] on the existing arable land without converting wildlife habitat to farm land."

According to NASA, atmospheric CO_2 is 412 parts per million, steadily rising from less than 320 ppm in 1960. Also, it has reported that assumptions as to the cause may be unfounded.

For example, rainforests are believed to be net absorbers of CO_2 but data are showing they are a net source.

"We're finding that plant respiration is outstripping their ability to absorb carbon dioxide," David Crisp, an atmospheric scientist who works in NASA's Jet Propulsion Laboratory, said in a 2019 article at Climate.NASA.gov.

Meanwhile, non-tropical vegetation is becoming a better absorber. "Things that didn't used to grow well at high latitudes are growing better and things that were growing well there before are growing longer," he said.

The absorption is so intense that farms in Central China are "erasing all but a thin strip of fossil fuel emissions along the coast."

Better data are expected from the European Space Agency's Copernicus CO_2 Mission satellite array that is scheduled to be launched in 2026.

Crisp concluded that data are inconclusive without the array. If investing in CO_2 to reverse climate change, "wouldn't you like to know that it worked?" OGI


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