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Billy Quinn

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Mike Bock

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Thanks to the continued support from our trusted clients, Jefferies completed 2024 with #1 market share in Upstream M&A.

We are committed to finding the best solutions and results for our clients, and we look forward to hearing from you.

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Energy — November 2024
Diamondback Energy
Undisclosed
Trade of Permian Basin assets with **TRP Energy**
Sole Financial Advisor

Energy — November 2024
Franklin Mountain Energy
$2,500,000,000
Sale to **Coterra Energy**
Sole Financial Advisor

Energy — November 2024
Ovintiv
$2,000,000,000
Sale of Uinta Basin assets to **FourPoint Resources LLC**
Lead Financial Advisor

Energy — October 2024 / April 2024
EQT
$1,250,000,000
Sale of Non-Op Assets to **Equinor USA**
$1,100,000,000
Sale of 40% interest in PA gas assets to **Equinor USA Onshore**
Sole Financial Advisor
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Energy — August 2024
Caerus Operating LLC
$1,800,000,000
Sale to subsidiaries of **Quantum Capital Group**
Lead Financial Advisor

Energy — July 2024
Grayson Mill Energy
$5,000,000,000
Sale of Williston Basin business to **Devon Energy**
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Energy — July 2024
Point Energy Partners
$1,100,000,000
Sale of Delaware Basin assets to **Vital Energy** and **Northern Oil and Gas**
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Energy — June 2024
XCL Resources
$2,550,000,000
Sale of Uinta Basin assets to **SM Energy Company**
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Energy — June 2024
eni
$1,000,000,000
Sale of Alaskan assets to **Hilcorp**
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Energy — May 2024
Crescent Energy
$2,100,000,000
Acquisition of **SilverBow Resources**
Lead Financial Advisor

Energy — February 2024
Diamondback Energy
$26,000,000,000
A Merger with Endeavor **Energy Resources, L.P.**
Lead Financial Advisor

Energy — February 2024
California Resources Corporation
$2,100,000,000
Acquisition of **Aera Energy, LLC**
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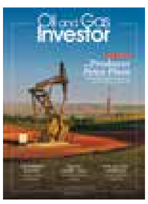
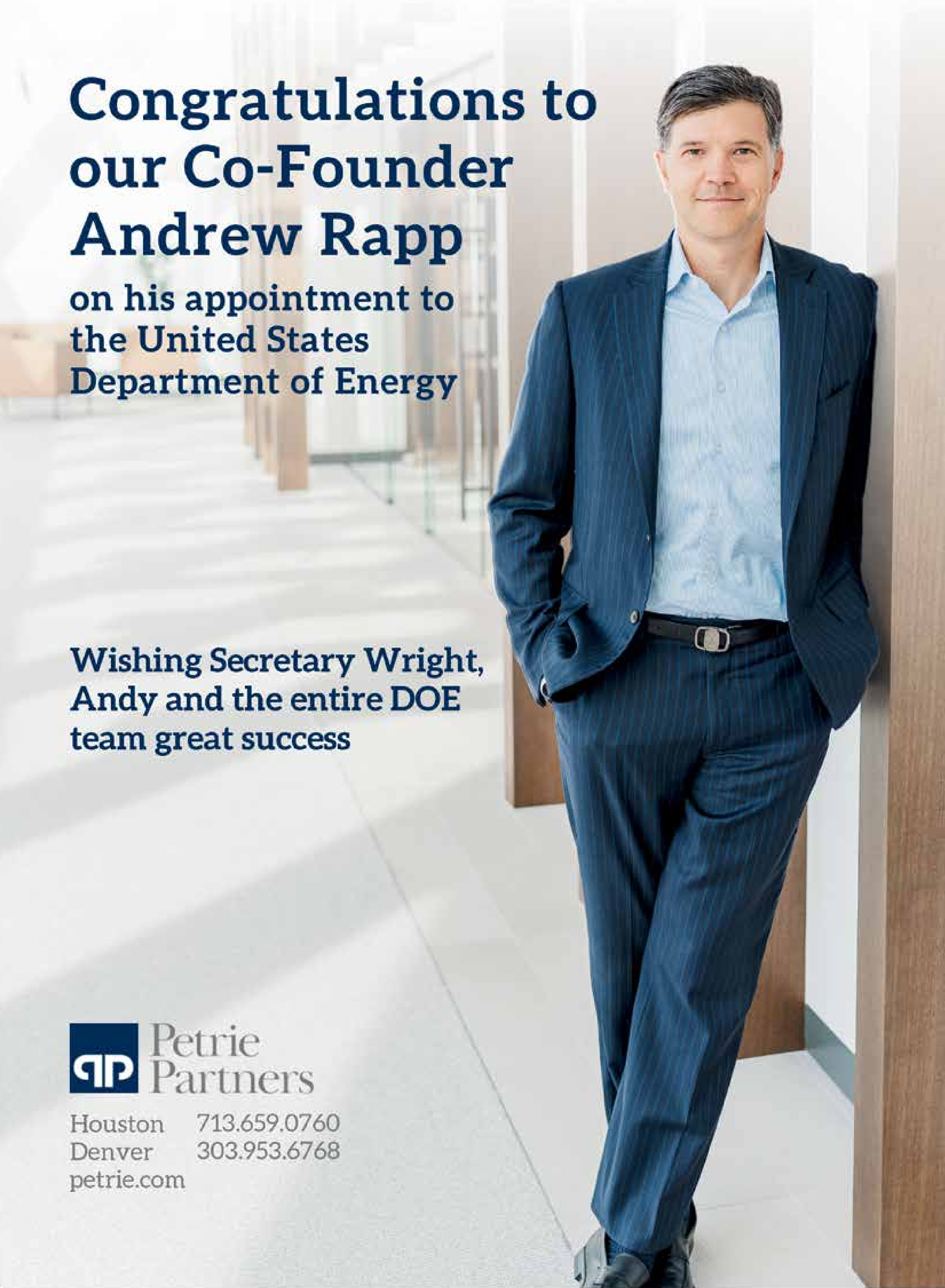


ABOUT THE COVER:
Devon Energy recently agreed to acquire Grayson Mill Energy in the Williston Basin. Devon shared legacy Williston photos.


Congratulations to our Co-Founder Andrew Rapp
on his appointment to the United States Department of Energy
Wishing Secretary Wright, Andy and the entire DOE team great success
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The Shape of Things to Come

A&D will continue to rework the industry landscape, and Donald Trump's second stint in the While House is sure to create a new normal.

DEON DAUGHERTY
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We spent much of January talking with executives and investors, corporate leadership and private equity veterans about the dealmaking ahead. This month kicks off with the 2025 NAPE Summit in Houston, where enterprising folks looking for a deal convene and get to the work at hand.

While the Permian Basin remains arguably the hottest shale play, plans are in the works to buy and sell assets well outside of West Texas and southeastern New Mexico. The Uinta Basin of eastern Utah, South Texas' Eagle Ford Shale, the Montney Formation in western Canada and the Williston Basin in the Dakotas and Montana are each gaining traction in dealmaking discussions.

One of the coolest parts of this gig is the access we have to some of the best minds in the business. In this edition, Hart Energy Editorial Director Jordan Blum talks with the legendary Roe Patterson about his latest venture in private equity, Marauder Capital. And I had the pleasure of gathering intelligence from Mike Bock, one of the founders of Petrie Partners; getting a peek into what's happening at Pearl Energy Investments with founder Billy Quinn; and what's next for the young E&P builders at the helm of Permian-focused Avant Natural Resources, Jacob Nagy and Skyler Gary.

In each of these conversations, there are plenty of positive prognostications, but there is also acknowledgement of uncertainty in the mix. The impact of Donald Trump's second presidency is rife with questions across the domestic and international spectrum and, in particular, the energy industry.

Whether he will wipe out strides made toward limiting emissions or push producers toward a growth-for-the-sake-of-growth strategy that puts prices in the tank is almost anyone's guess. For an industry ingrained with a deep streak of independence, there may be a response to some policies that gives the new president more hassle than he expects.

In the meantime, you again have the opportunity to nominate a young up-and-comer for *Oil and Gas Investor's* 2025 Forty Under 40 in Energy Awards. Scan the QR code on Page 19 to place a notable young colleague–or yourself–in consideration for this honor.

On the topic of notable colleagues, join us for the 2025 Influential Women in Energy Networking Luncheon and Awards program on Feb. 27 in Houston. *OGI* is proud to honor an incredible group of accomplished women who are driving the energy industry forward.

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And don't wait to register for Hart Energy's DUG Gas Conference & Expo on March 19-20 in Shreveport, La. We've assembled a lineup of top-notch speakers who will address key issues affecting the Haynesville Shale and other natural gas plays. They will touch on geopolitical challenges, emissions control, regulatory changes, investment trends and technological innovations.

There's never a boring time to cover this industry, and we're eager to see what's next. OGI

All the best,

DEON DAUGHERTY
EDITOR-IN-CHIEF

E&Ps Pivot From The Pricey Permian

Lower-cost plays like the Williston, Eagle Ford, Montney and Uinta are attracting producers in pursuit of M&A deals.

CHRIS MATHEWS
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After a whirlwind run of eye-popping M&A transactions last year, 2025 could be a year of resetting for the upstream sector.

Unlike in 2024, few obvious combinations in U.S. shale basins stand out to analysts. The best acreage in the mighty Permian Basin is mostly accounted for, locked up in the portfolios of some of the world's largest oil producers.

The growth engines for other key Lower 48 plays—the Williston, the Eagle Ford, the Denver-Julesburg (D-J)—have sputtered and transitioned into long plateaus.

More emerging plays, like Utah's Uinta Basin and the Ohio Utica oil window, are showing upside, but they are dwarfed by the Permian.

E&Ps seeking a longer runway in U.S. shale in 2025 will need to get creative, said Andrew Dittmar, director at Enverus Intelligence Research.

"I think it's going to be a tough market for buyers in '25 in terms of finding assets," Dittmar told *Oil and Gas Investor*, "whether you're looking in the Permian or elsewhere."

Priced Out of Paradise

Every E&P wishes it had more Permian Basin drilling locations.

Permian wells have some of the lowest breakeven costs of any U.S. shale play. Layers and layers of stacked pay give producers many shots on goal to co-develop multiple benches. Permian-heavy E&P names boast higher market values and trading multiples in the public markets.

Producers big and small clamor for a bigger slice of the Permian, the nation's only real driver of oil output growth, but asking prices for Permian assets are sky high. That's leading some cost-conscious producers to turn away from the basin and look elsewhere for new value.

SM Energy, Ovintiv and Devon Energy illustrated this trend in the back half of 2024.

Each of those E&Ps were rumored to be on the hunt for new Permian acquisitions—part of a broader M&A wave sweeping across the sector. Ultimately, each company decided to spurn high Permian prices in favor of more compelling returns in other basins.

Instead of doubling down on the Midland Basin, SM Energy set its sights on the Uinta Basin. SM teamed up with non-operated partner Northern Oil and Gas (NOG) to acquire leading Uinta producer XCL Resources for $2.6 billion.

SM acquired an 80% undivided interest in XCL's assets for $2.1 billion, while NOG picked up the remaining 20% non-op stake.

Building on the Uinta M&A momentum, Ovintiv decided to sell its Uinta assets for $2 billion to FourPoint Resources, a privately held E&P.

Instead of buying Double Eagle IV in the Permian, Ovintiv decided to enlarge its presence in Canada's Montney Shale through a US$2.38 billion (CA$3.33 billion) deal with Paramount Resources.

Despite their expansions in the Permian, both companies opted to take a breather from the Permian's high prices and look outside the basin for value, said Matthew Bernstein, vice president and manager of upstream solutions for Rystad Energy.

Devon Energy was also rumored to be scouring the Permian for deals when it announced a $5 billion acquisition of Grayson Mill Energy in the Williston Basin.

The Grayson Mill deal added 500 gross undrilled Williston locations, and around 300 candidates for potential refrac projects. Around 80% of the new locations were in the Bakken Shale, the remaining 20% in the deeper Three Forks benches.

"I think it's going to be a tough market for buyers in '25 in terms of finding assets, whether you're looking in the Permian or elsewhere."

ANDREW DITTMAR, director, Enverus Intelligence Research

Devon Energy's High Hawk 4-9H well in Dunn County, N.D.

DEVON ENERGY

Precision Drilling rig 96 on the Dakota-3 Bear Den 24-13H2 near the Nathan Hale 4-25H producer; McKenzie County, N.D.

DEVON ENERGY

"As those Permian assets get a bit more expensive, a bit riskier and harder to come by, you do see more companies being willing to look at other basins," Dittmar said.

"The unfortunate part is there's not a whole lot to find in those, either," he said. "It's not like there's a plethora of assets to go buy in the Eagle Ford or the Williston."

Enverus forecasts that 2025's M&A environment will include smaller deals and deals further up the cost curve, or looking at less economic, lower-tier rock, Dittmar said.

Williston Runway

The Williston Basin of North Dakota and eastern Montana lacks the growth profile of the Permian. Production from the mature Williston Basin actually shows signs of plateauing and declining, Williston wildcatter Harold Hamm told *OGI* late last year.

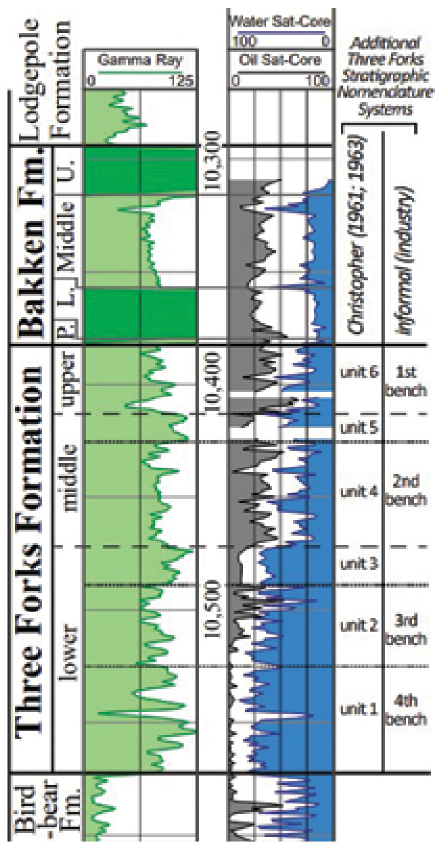
Williston operators are focusing on drilling more efficiently and lowering their costs instead of growing output at a breakneck pace. Producers are optimizing development of the Williston's secondary benches, the Three Forks zones, which underly the shallower Bakken Shale.

Historically, the Middle Bakken has been the Williston Basin's top drilling target. Williston operators like Hamm's Continental Resources began landing laterals in the upper Three Forks as geologic understanding of the play grew over time.

But new research suggests major undeveloped upside remains in deeper parts of the Three Forks bench.

Operators had only landed 40 laterals in the middle (second) and lower (third) Three Forks benches through August 2023, according to studies published by the North

Bakken-Three Forks Stratigraphy



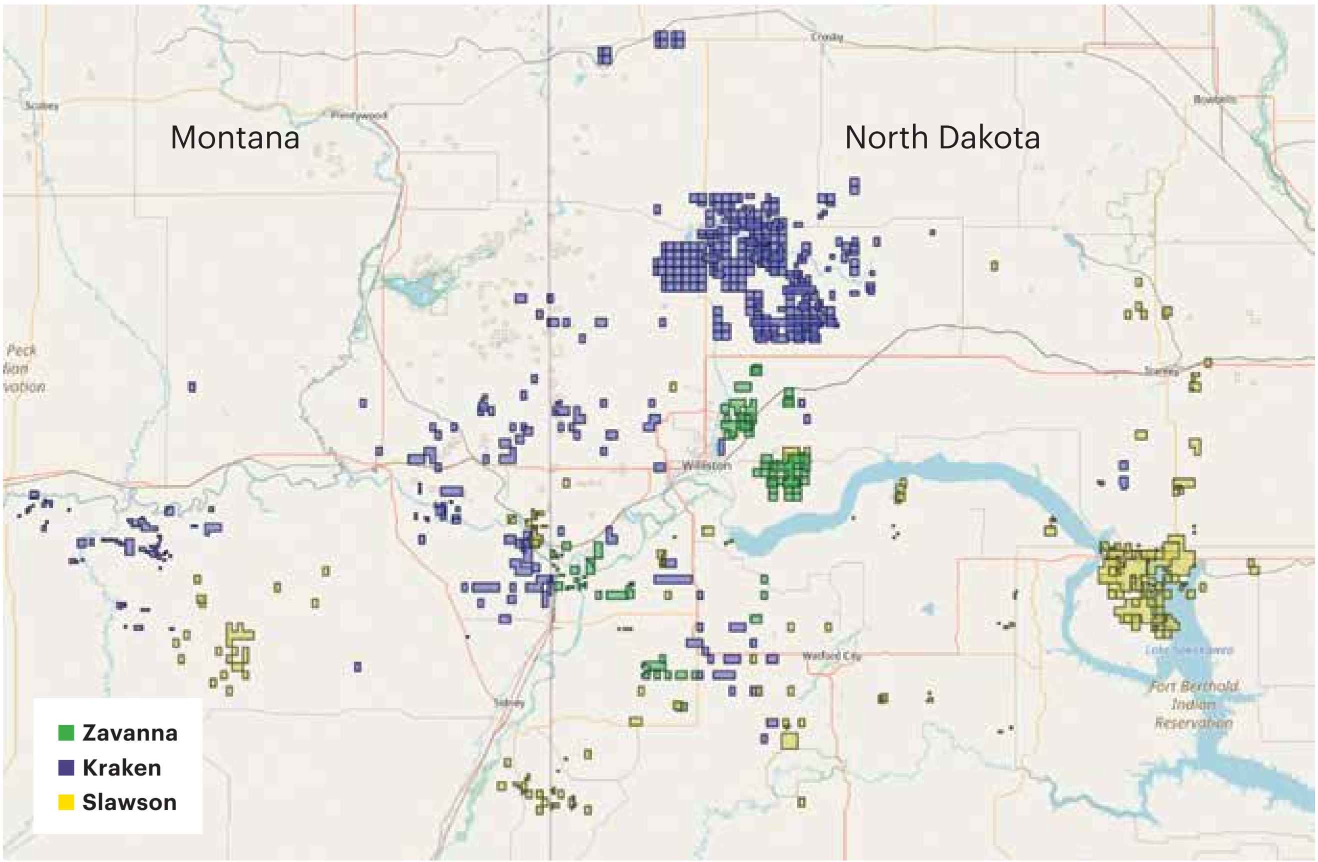
SOURCE: NORTH DAKOTA DEPARTMENT OF MINERAL RESOURCES

The major stratigraphic formations of the core Williston Basin; PICTURED: Gamma-ray wireline log example of the Bakken-Three Forks section with core-plug oil and water saturation data from Enerplus Resource's Hognose 152-94-18B-19H-TF.

Foreground: FBIR 13-24H well; Background: Patterson-UTI Drilling #336 on the George Evans 11-2H well in Mountrail County, N.D.

DEVON ENERGY

Williston Basin Standout M&A Targets



SOURCE: REXTAG

Dakota Department of Mineral Resources.

That represents only around 2% of total drilling activity in the entire Williston Basin, authors Timothy Nesheim and Edward Starns reported.

But data collected from 25 drilling spacing units (DSUs) shows that co-development of the middle Three Forks bench "exhibited a clear volumetric addition of oil" compared to DSUs without middle Three Forks wells.

Not counting existing wells, another 604 middle Three Forks horizontals could still be drilled within the core of the Williston Basin, according to the study. Ultimate EURs for the new projects could range between 165 MMbbl and 410 MMbbl of oil.

Williston operators are also combining land positions to drill longer laterals underground.

Devon plans to sustain production from the acquired Grayson Mill asset at around 100,000 boe/d this year through a mix of 2- and 3-mile laterals, as well as "tactical refracs" to supplement the base output, Devon COO Clay Gaspar said during the company's third-quarter earnings call.

"The Williston Basin has been a tremendous provider of energy for a long time," said William Westler, Rockies business unit vice president for Devon, in a statement to *OGI*. "We are excited and confident that the Grayson Mill acquisition allows us to continue to expand our production and operating scale with additional highly economic drilling inventory in the Williston for years to come."

After closing a $4 billion acquisition of fellow Williston operator Enerplus, Chord Energy planned to drill more 3-mile wells and aimed to begin drilling 4-mile Bakken laterals.

Formentera Energy Partners, founded by partner Bryan Sheffield, is watching nearby operators drill 3- and 4-mile laterals from its position in Divide County, N.D., Sheffield said at Hart Energy's Energy Capital Conference in October.

"Particularly in the Williston," Dittmar said, "being able to go from a 2-mile to a 3-mile lateral knocks about $5 off your breakeven."

Despite the runway to be had in the Williston, there aren't many obvious places to go after it. The acquisitions of Grayson Mill and Enerplus plucked two large Williston positions from the drawing board.

The $17.1 billion merger of ConocoPhillips and Marathon Oil also consolidated huge swathes of Williston Basin acreage.

Williston producers of notable scale that could be potential sellers include Kraken Resources, Slawson Exploration and Zavanna LLC.

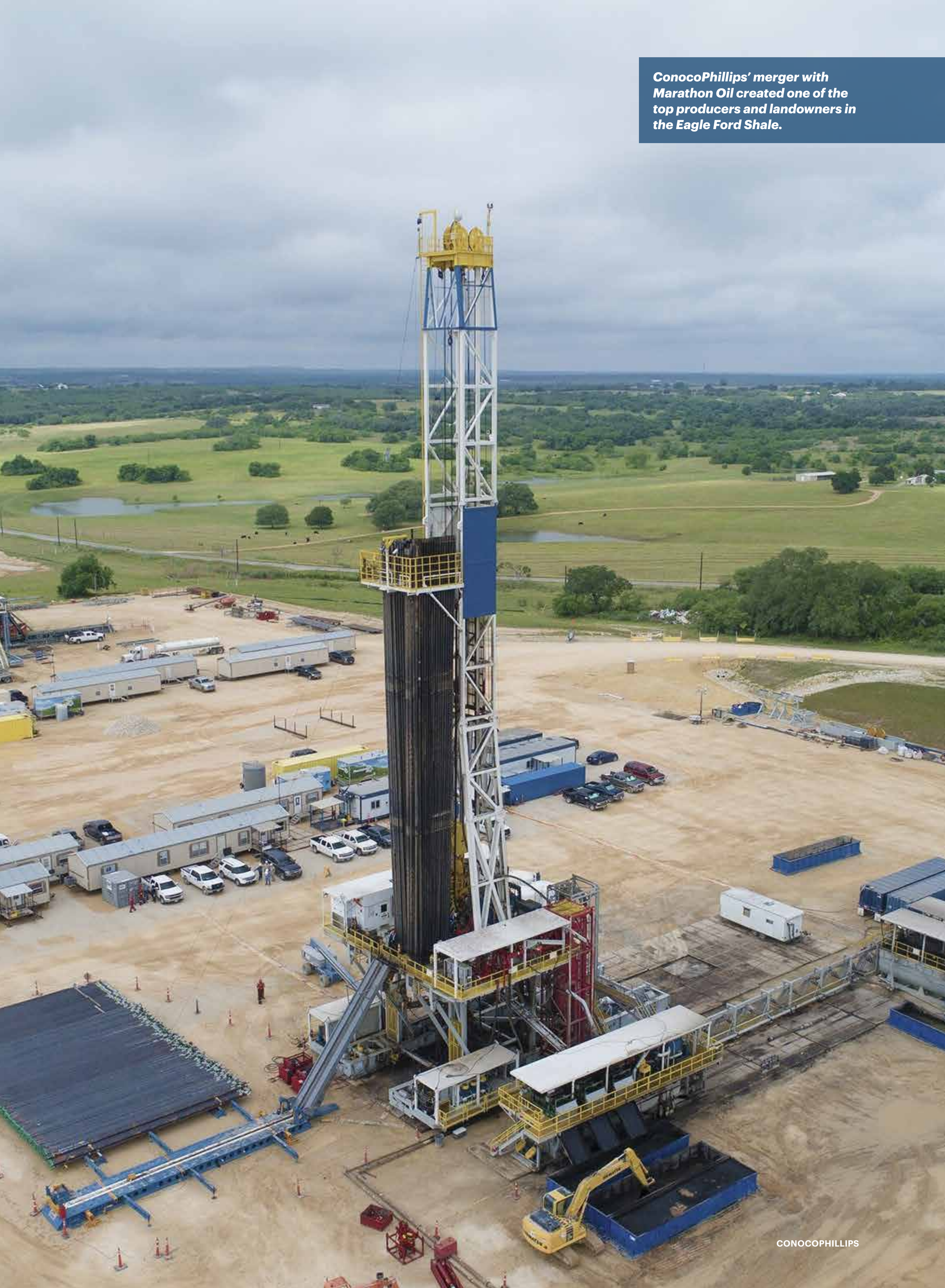
Private equity firm Carnelian Energy Capital invested in Zavanna last fall. The company has around 150 drilling locations across the Bakken and Three Forks.

Eagle Ford Flies

As another mature shale basin, the Eagle Ford has a similar outlook to the Williston.

The Eagle Ford's days of expanding production are largely in the rear view. Operators are looking to sustain output through a mix of new wells and refrac projects.

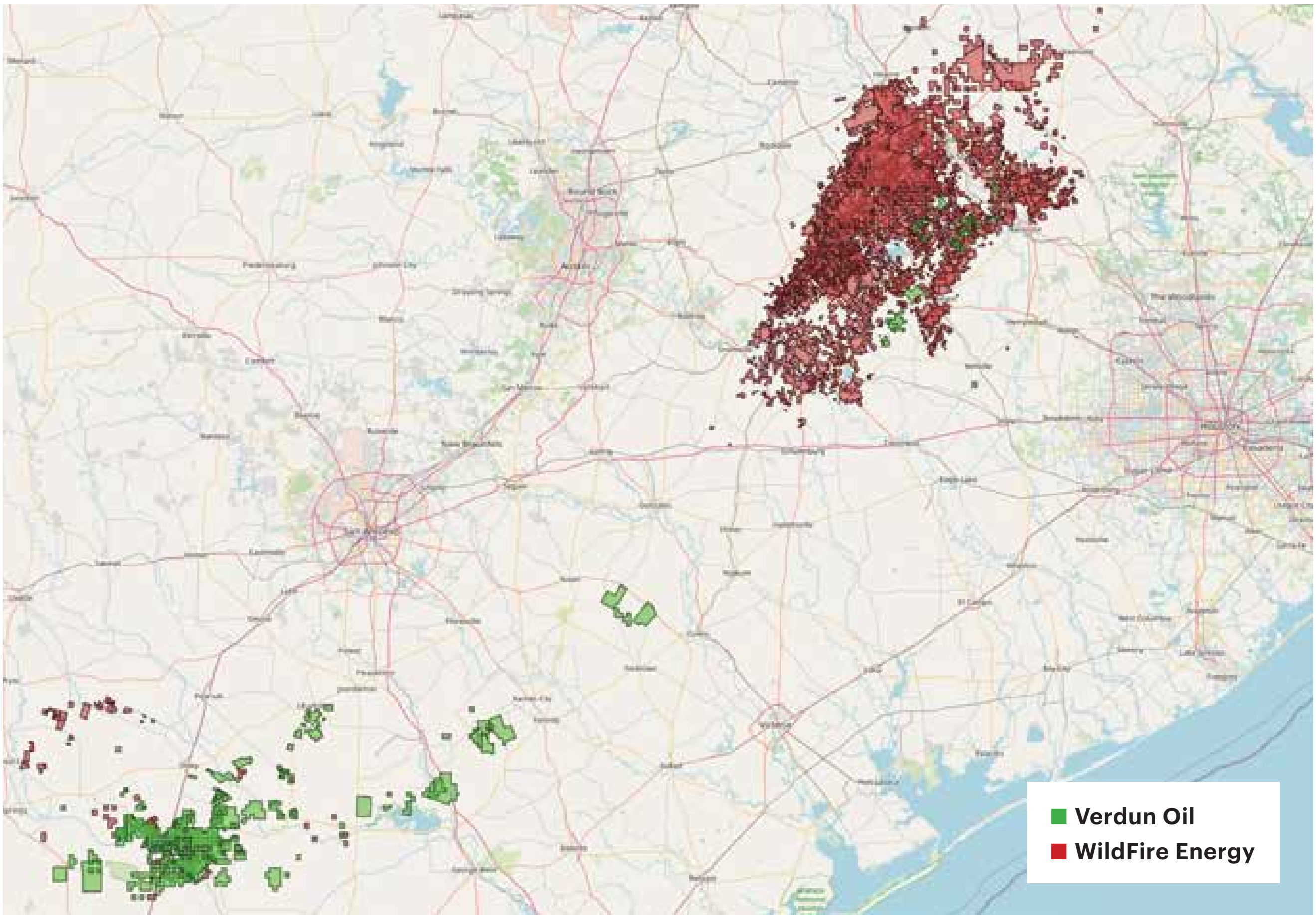
One of the earlier shale plays targeted with horizontal development, the Eagle Ford has thousands of older wells ripe for recompletion projects.



ConocoPhillips' merger with Marathon Oil created one of the top producers and landowners in the Eagle Ford Shale.

CONOCOPHILLIPS

Eagle Ford Standout M&A Targets



SOURCE: REXTAG

A growing list of Eagle Ford operators are leaning into refracs, re-entries, recompletions or other re-do jobs to breathe new life into legacy wells with declining production.

Eagle Ford producers touting refrac projects include ConocoPhillips, Devon, BPX Energy, Crescent Energy, Baytex Energy and Verdun Oil, among others.

Refracs are a hot topic today. For Verdun Oil, backed by private equity firm EnCap Investments, they're old news.

Verdun started developing a refrac strategy around 2018, when the company completed what it says was the first full linear isolation refrac job performed in the Eagle Ford trend.

A cemented linear refrac involves installing a new liner inside the wells' existing casing, which covers all the previous fracs. Then, the well is fracked as if it were a new project.

The other main type of refrac—bullhead refracs—do not direct frac fluid and are less costly alternatives to a full linear isolation refrac project.

Not every well makes sense for a refrac. The wells Verdun has singled out for refracs generally have lateral lengths of around 6,000 ft and were completed prior to 2016.

M&A Horizon

Like the Williston, the Eagle Ford holds fewer obvious combinations through potential M&A.

The merger between ConocoPhillips and Marathon Oil brought together two of the largest Eagle Ford producers.

The Marathon deal added around 1,000 Eagle Ford locations to ConocoPhillips' portfolio. The companies have touted an even longer Eagle Ford runway, including potential refracs in the play.

Crescent Energy has been an active consolidator in the southern and central Eagle Ford. In its largest deal last year, Crescent closed a $2.1 billion acquisition of SilverBow Resources.

Crescent added assets through a $905 million acquisition of private E&P Ridgemar Energy in late 2024, complementing a smattering of other smaller transactions in the play.

Magnolia Oil & Gas has been a buyer in the more northern Austin Chalk play. The company added acreage in the storied Giddings Field through smaller M&A deals last year.

But the potential for large-scale M&A in the Eagle Ford this year is still relatively limited.

Standout targets remaining in the basin include Verdun Oil and WildFire Energy. WildFire has been another active buyer in the Austin Chalk, near Magnolia's position.

Lewis Energy Group, a private operator in the Eagle Ford's gas window, has been a seller recently. Last September, TotalEnergies announced acquiring a 45% stake in dry gas assets operated by Lewis.

Kimmeridge Texas Gas (KTG), a gas producer backed by investment firm Kimmeridge, also aims to grow through M&A in the Eagle Ford.

KTG had hoped to acquire SilverBow, one of its nearby neighbors. But those efforts were rejected—in a high-profile back-and-forth between Kimmeridge and SilverBow—when SilverBow agreed to the deal with Crescent. OGI

The ConocoPhillips-Marathon merger also consolidated huge swathes of land and assets in the Bakken.

CONOCOPHILLIPS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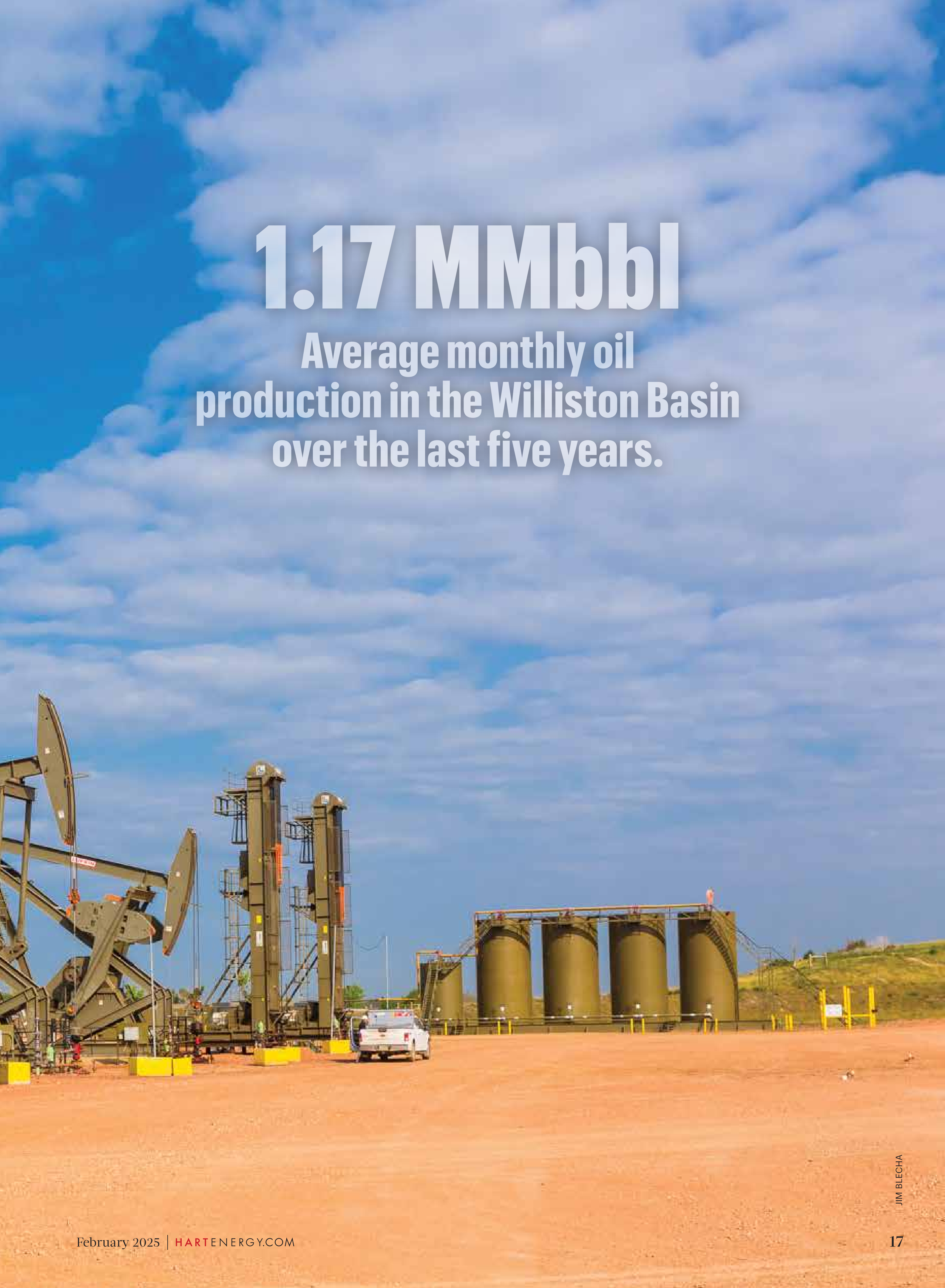


1.17 MMbbl

Average monthly oil production in the Williston Basin over the last five years.

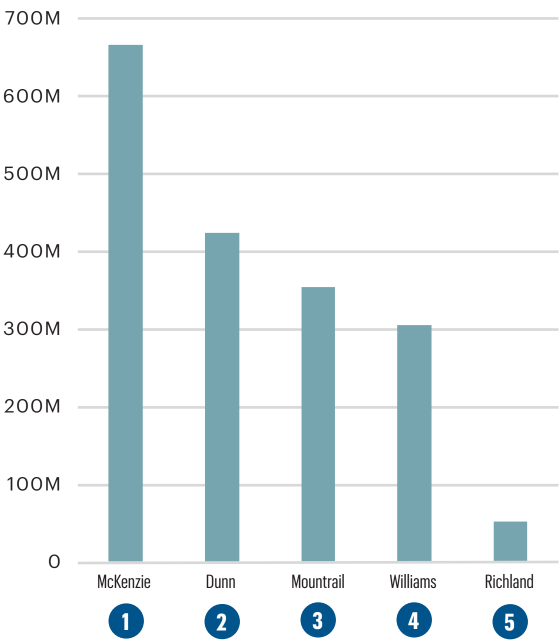
JIM BLECHA

BASIN FOCUS: WILLISTON BASIN

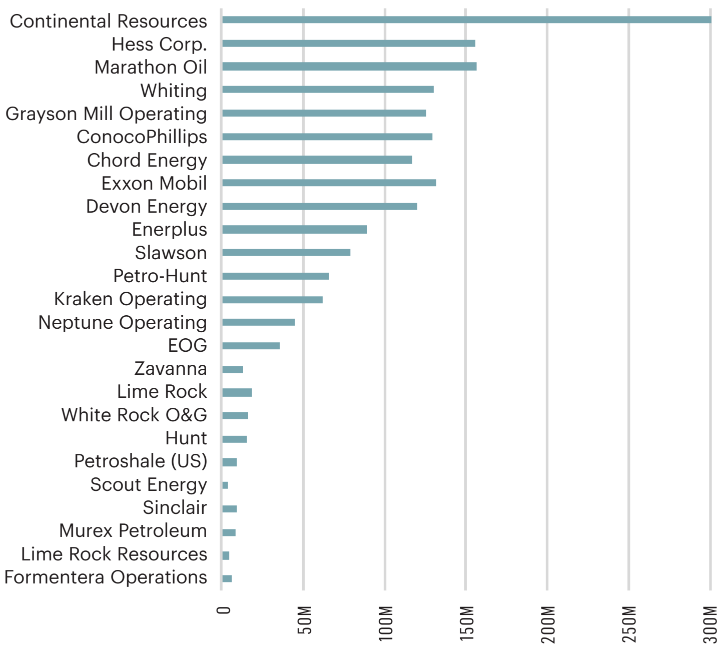
Oil production in the basin, focusing on the top five producing counties.

WILLISTON BASIN OIL PRODUCTION

Williston Basin Top Oil Producing Counties last five years



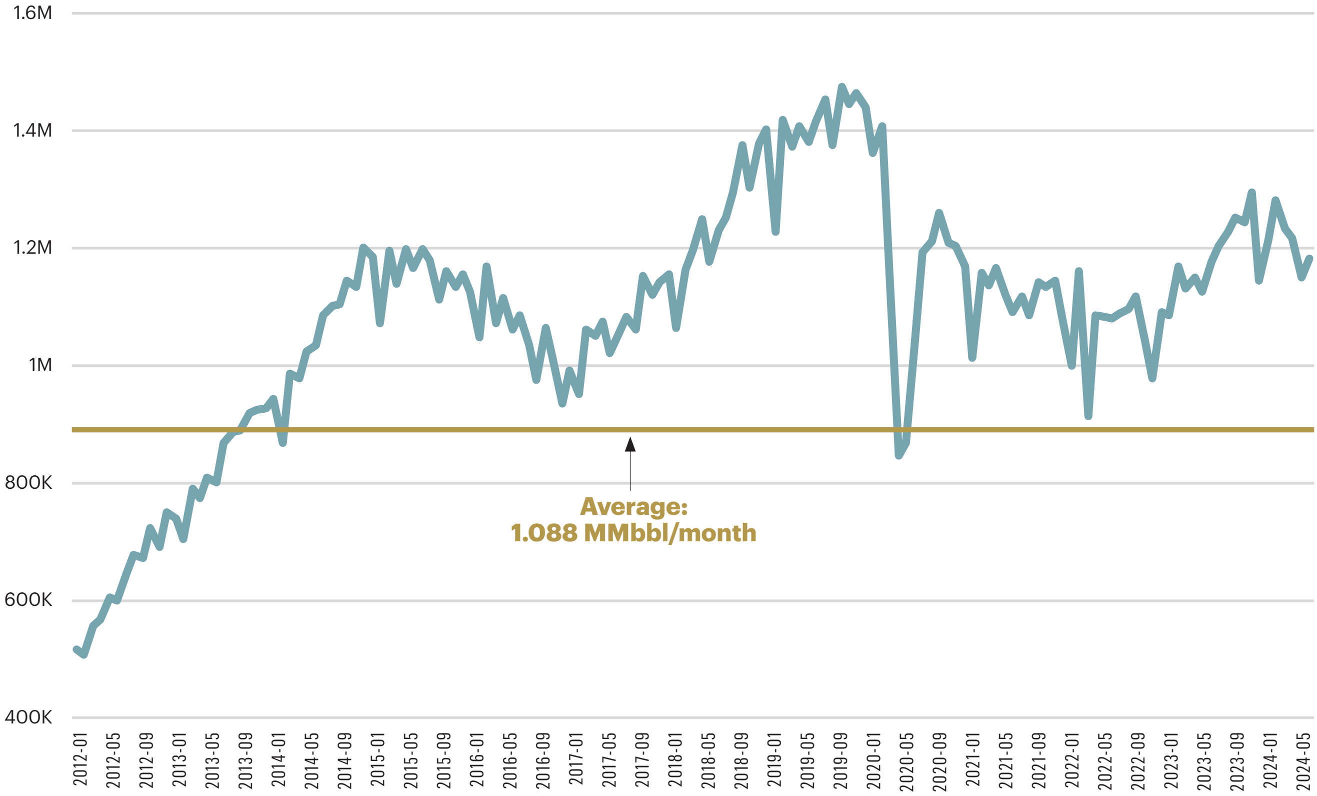
Williston Basin Top Oil Producers last five years



SOURCE FOR CHARTS AND MAPS: REXTAG

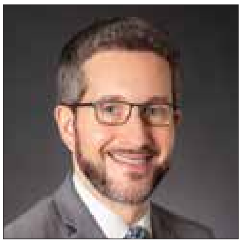
Williston Basin Oil Production

bbl/month



The Book of Patterson

Roe Patterson sees a bright future for oil and gas and his new PE firm, Marauder Capital, after lessons learned.



JORDAN BLUM
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An industry legend legacy, entrepreneur, oilfield services CEO and private equity firm founder, Roe Patterson has virtually seen it all in a half century of life in oil and gas.

The son of Glenn Patterson grew up with the Patterson Drilling Co., eventually branching out on his own at the turn of the century during the merger with UTI Energy that created Patterson-UTI Energy.

He joined Basic Energy Services in 2006 and rose to CEO as the company rapidly grew and acquired during the advent and early boom years of the shale revolution. He left at the end of 2019 amid financial struggles just before the pandemic.

In recent years, he's taken over ClearWell Dynamics and Ventana Midstream. He also co-founded Marauder Capital with his former Basic colleague, Adam Hurley, as a private equity firm focused primarily on OFS and conservative investments.

In 2018, he even wrote the book about his father and the cyclical ups and downs of the industry: "Crude Blessings: The Amazing Life Story of Glenn Patterson, American Oilman."

Roe Patterson spoke with Hart Energy's editorial director, Jordan Blum, about the current state of oilfield services, dealmaking, his businesses and what the future looks like in 2025 and under the new Trump administration.

Jordan Blum: Given the ongoing wave of upstream M&A, how do you see this impacting and creating issues for the services sector?

Roe Patterson: It's certainly had an impact on the service providers. Typically, as companies are getting ready to either buy or be sold, they love to shore up their cash positions, which usually means a slight reduction in capex or opex. They may trim a little going into a deal just to shore up their cash reserves. Then, it takes a little time as the acquiring company assimilates staff. That consolidation of two operating segments in fields where they overlap usually creates a little bit of slack in service intensity. It tends to go away over time, and then there's a big push to try to maximize the overall economics of whatever they've purchased.

But it does put a pause on things until the dust settles and until they figure it all out. Additionally, a lot of times we see these acquiring companies look at the portfolio as a whole, and they may divest some of the pieces that are not core to their strategy, and then we have to go through it again. We see those properties change hands again. There's kind of a secondary and tertiary impact whenever they sell off the non-core assets. So, it definitely does shrink the customer universe.

Typically, these companies are doing more with less and that falls directly on the shoulders of these service providers. In terms of the efficiency improvements, our services sector is largely responsible for new technologies and building in new efficiencies. It's almost like you're working your way out of a job in some respects. That is the overall impact to the drilling and completion side of the business.

JB: How does this impact you and Marauder?

RP: I focus more on the production side of the business, both with my personal investments and with Marauder Capital. The production side is sticky, it's less cyclically impacted and these

MARAUDER CAPITAL

services are necessary for every barrel of oil that's going to move in the U.S. or every MMcf of gas that's going to move. I liken it more to infrastructure than the overall kind of traditional oilfield service image that most of the market has for oilfield services. These businesses are more downstream and more production- and midstream-oriented for existing wells and existing production. You're not going to see an acquiring company go in and shut in wells. They don't do that. They want to keep and maintain the acquired assets production rate. It takes them awhile to digest that before they get their drilling plans put together and go exploit that new inventory of targets that they now have. Most of these big acquisitions have been primarily driven by inventory improvement within somebody's portfolio.

On the production side of the business though, we rarely see a lot of impact. We may not see new production coming on. The well count might stagnate for a little while, but it tends to bounce and come back to some norm after a period of time. And that's usually about six months, maybe a year at the longest.

JB: On the production side, I wanted to get your take on what you're most interested in, in terms of technologies and trends with artificial lift, production chemicals and anything else you want to highlight.

RP: Targets for us are both of the segments you mentioned. We love artificial lift, and we love production chemicals. We also look at a lot of water midstream, which has become a true midstream animal as we build more pipelines to take care of the wastewater capacity within each field. The hub-

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Saltwater disposal at a West Texas drill site. Water management has become a "true midstream animal," according to Roe Patterson, as the hub-and-spoke model of saltwater disposal is going away in favor of more efficient and cost-effective pipelines.

and-spoke model of going out and drilling saltwater disposal wells and then anchoring a truck fleet in a spoke around those hubs—that's going away. We're seeing much more efficiency and overall cost savings when we can tie all that in via pipe.

Another business we like a lot is in-basin power, where we're providing either temporary or permanent power within a field to run artificial lift and to run compression and to run product transfer. Natural gas-powered electrical infrastructure—I think that's a great segment.

We like contracted compression. That's a very sticky business. The contracts aren't always super long. They can be two years, three years. They're not 10-year contracts, but they're sticky. They rarely go away. It's all of those businesses across that whole production gambit. When you get past the flowback, I get really interested.

JB: Going back to M&A, I wanted to get your thoughts on how the upstream dealmaking is going to trickle down to services M&A, and how much consolidation is needed there? Obviously, there's been a lot of smaller deals, some bigger ones such as Patterson-UTI and NexTier Oilfield Solutions, but not a whole lot. How do you see it playing out?

RP: A lot of these segments in the production side or in drilling and completions are relatively fragmented. That's a function, I think, of the lack of capital that's been available to make the combinations work. There are not a lot of commercial lenders that are willing to provide capital to back those deals. Private equity in a lot of ways just got thumped pretty hard by taking the wrong strategy for roll-ups and LBOs (leveraged buyouts) and really played the game the wrong way. One, the multiples are depressed. Two, there's not a lot of capital. So, we want to come in and underwrite the deals at these lower multiples. We're not interested in businesses where we've got to go in and fix a capital stack, or we've got to go replace a management team, or we've got to go do a bunch of work to assets. If we can't check all three of those boxes—good team in place with reasonable cash flow, good assets and then a cap stack that's in decent shape—we would say, "No." Historically, private equity said, "Yes. Two out of three ain't bad." But two out of three is really bad. You need to have all three.

The difference for Marauder is Adam and I are both operators. There's pretty much not a segment within these production businesses that we haven't run. I've run drilling and frac companies, too. We've got a pretty broad operational track record, and so we're not reliant completely upon the team. We don't want to have to go in and do major surgery to the team. But we can give the team lots of ideas, give them lots of efficiency improvement opportunities. If you've underwritten it to the depressed multiple that you're buying it at, that's OK because you can still make your returns. There's way more room to the upside if the multiples do expand, and they should. We're already seeing capital migrate back into the businesses starting on the midstream infrastructure side, but it's trickling its way back into services.

If the industry remains relatively healthy and we don't see a big crash, then we'll see commercial lenders come back, we'll see more private equity come back, and we'll see more infrastructure funds and energy transition funds try to find their way in. They'll nibble around the outside edges, calling it infrastructure or calling it midstream or calling it energy transition, when really, it's just traditional oilfield service for most of us who have been in the game for 30-plus years. That's OK, because we want them to come back with a truckload of cash, but we want to be invested before they get here. That's kind of the crux in the thesis behind Marauder: underwrite it today and, if the multiple doesn't move, then fine. But we think there's some moonshot scenarios where the multiples will move, and we'll be in a really good spot.

People like to see capital returned. They've been in OFS before when no capital was returned, and it's been a downer for a long time. It makes M&A hard to do. If you've got any debt, or if you've got more debt than your peer, or maybe your peer is trading a halfturn more than you, these combinations are tough. Stock-for-stock transactions are difficult to do even in the best of times. They're harder to do when there's a shortage of capital and depressed multiples. So, I think M&A is coming for the service side, but it's trickling down more slowly from what's happening on the operator side. Until we see the public interest in the equities and the commercial lenders support the whole effort, I think

Roe Patterson on the History of the Shale Boom, the Pandemic and the Current Upswing from His OFS Perspective:

JB: I wanted to go into a bit of a history lesson. Going back to your Basic and Patterson days, what's your take on the evolution of the services industry and the highs and lows? Your Basic experience essentially covers the beginning of the shale boom to the pandemic. Before that, you grew up in Patterson with your father having co-founded it, and then you literally wrote the book on him.

RP: Starting with Patterson, when the drilling contractors in the early 1990s became public, there was a lot of fragmentation in that drilling onshore, contract drilling market. Patterson and Nabors [Industries] and UTI were probably the bigger three, and H&P (Helmerich & Payne) to some extent, even though they did a lot of organic growth. But those were the powerhouse companies that were out there doing a mass consolidation effort. I learned a ton during that period working with my dad and with [co-founder] Cloyce Talbott on how to integrate companies, how to buy, how to treat acquired employees when they came on board, the ethics, the dos and don'ts of M&A. I learned a lot there about how to transact with all-cash deals, all-stock deals, and then how to integrate and be a successful integrator.

When UTI and Patterson were coming together, that's when I said to my dad, "Hey, I want to go out on my own and cut my own path and do my own thing. It might be pretty hard to be a Patterson here after the merger." They were really a merger of equals, almost had the exact same rig counts. The board was going to change configuration massively, even though Cloyce and dad were going to run the company. So, I spent the

SHUTTERSTOCK

While frac and drilling technologies continue to improve, Roe Patterson believes they have reached the "climax of efficiency improvement." This, he says, means there will be more drilling targets at so-called "Tier B and C" wells, leading to more production work, more intervention, and more maintenance—music to his ears.

it'll be onesie, twosies for a while.

There are other dynamics that are green shoots. We have a lot of family offices that are enjoying yieldcos and investing in these spaces, and that's a group of buyers that weren't here, say, five years ago. There's definitely still a capital void, and I think that's filling, but it's slow. There's plenty of capital for these larger M&A deals on the E&P side. But It's taking longer to get it to the service side.

JB: You mentioned if things stay pretty healthy, price-wise. How do you see pricing and other industry trends playing out in 2025 as we're entering a new year and a new Trump administration?

RP: "Drill, baby, drill" doesn't scare me because we are already drilling, baby, drilling. It's not like there's a bunch of stuff to go do. They could open up some federal lands, but those projects take years to plan and put in place. I don't think the commodity prices justify a lot of big, aggressive growth on federal land today. There may be some activity in the deepwater auctions if Trump opens those up, but I don't think that's a needle mover. The thing he can do in the short term that would bolster the industry would be to free up the exports, specifically LNG. We have so much natural gas and the ability to provide it to a lot of the world that doesn't have access to natural gas.

I guess you also asked about 2025. I think we're stuck until China really starts to improve their demand numbers. We're probably range-bound on crude in the $65 to $75/bbl WTI kind of corridor. Maybe it pops a little higher than that. I think there's more upside potential than downside. There's

next five years building and flipping some oilfield service companies, and I learned a lot more at that point. I learned a whole lot about leverage, a lot about personal guarantees and how not to get in debt, and then how to get your ass out of debt when you get covered in it. I did some really good things, and I made a lot of mistakes, but it was a super learning curve for me running my own businesses.

I sold out of everything that I had in late 2005, and I had a little bit to show for it, but not much. But I had a lot of learning, a lot of scars and some pretty good wins and pelts on the wall. I probably didn't realize at that time how much I had learned

BASIC ENERGY SERVICES

Ranger Energy Services acquired Basic Energy Services assets in 2021 following Basic's bankruptcy.

still a lot of demand out there, and we understate demand globally and overstate supply, especially non-OPEC and non-U.S. supply. If the prices aren't good, that's not going to come to fruition. So, betting that that supply hits in a depressed crude market is a bad bet.

The gas equation is different. There's a lot of demand for natural gas in places that don't have access to it today, or don't have appropriate access. Europe, Japan, South Korea and India all need more natural gas. Those are the traditional places for LNG export, but there's a lot of African demand that's growing. LNG has a lot of green shoots to the upside, and I think gas prices this year probably have way more upside potential than crude does.

JB: I wanted to circle back from the services standpoint. You said the companies are almost working their way out of the job. I wanted you to maybe elaborate on just how the industry is becoming a victim of its own success in a way with the efficiencies.

RP: Let's talk about that in a couple of different views. The efficiency improvements have created the industry's current condition where we can drill a lot more with less, right? Our frac technologies, our drilling technologies, our directional technologies all continue to improve, but we're reaching what I would say is a climax of efficiency improvement. In other words, we're not going to drill these wells in a day.

We're kind of maxing out on technological advancement because we're starting to see the limitations of all of the drill pipe, the frac equipment, etc. So, we're just not going to continue to see the quantum leaps in technological advancement. We've done a lot in a 10-year window. Heck, we've done a lot in a five-year window. But I don't see big jumps coming that are going to cut well costs by half. We made those improvements, and they're probably pretty sticky for a while.

The target inventory that we're drilling today is not the best target inventory. We've drilled the best, Now, we're going backwards. If you want to grade them—Tier A prospects, Tier B, Tier C—we're definitely drilling a lot more Bs and Cs than we ever have. The wildcatting and the ability to go find more Tier A inventory is very limited. We're now going back to figure out how we can do more with the Bs and Cs. Or, can we reenter the As and use some new refrac technology? I like that because that usually spells more maintenance, more production work, more intervention, which is where I focus, anyway. That's music to my ears. I think there's going to be more of these tertiary recovery programs, such as water floods and CO_2 floods, that are very creative but very service intensive, that are going to be maximized.

JB: Can you go through the Marauder origin story a little bit? It's just a little over a year old. I wanted to get your take on how it came and how you developed the focus on more of the production services side.

RP: Adam and I worked together when we were both at Basic. I was there 14 years and left in 2019; dodged the pandemic. Adam wasn't as lucky. But we kept seeing this big arbitrage of the multiples that are at OFS versus what's in infrastructure or what's in energy transition, etc. How do you take advantage of that was always our question. He saw some of the things I did with Ventana Midstream and ClearWell Dynamics where I used my money combined with some partners that I know well and put together capital to go make the kinds of purchases that we have targeted within Marauder. It was late 2023, and we finally decided on a fund that is run by two ex-operators and looks at things through our lens. You've got to have those three things: people, assets, capital. Then, how can we underwrite it at a depressed multiple and grow the business.

It's a lot easier to go in and be a buyer of credibility when you've got a standing pool of capital behind you. Without a standing pool, it's hard to get their attention sometimes because they see you as they see a lot of potential buyers. You're a joker broker. You want to sign an LOI (letter of intent), but then you still have to go raise your capital, which may or may not happen. That's why we created Marauder. It's a small fund, relatively speaking. It's a $100 million fund. We are on our second raise right now. We really have stayed away from institutional money. We've stayed away from monies that are pooled together, be that maybe an endowment at a university or a pension fund that has a very heavy ESG mandate and a lot of reporting requirements.

We've been dealing mainly with family offices, high net-

until Ken Huseman, who was running Basic and was about to IPO Basic, came to me. One thing led to another. I came in helping with corporate development there in 2006 right after their IPO. We were right on the cusp of the shale boom.

There was a similar mindset at Basic to roll up the well-servicing and production services segments. The treadmill was how big you could get. At that time, the market was very concerned with growth, and not as concerned with capital returns. Three times debt-to-EBITDA was not a bad place to be. It was very comfortable for most companies. Public debt in the form of bonds was readily available. That's where a lot of that capital came from to do that growth, both in the IPO proceeds and the bonds. And so, we did it. We fed the beast. The market wanted to see growth and scale and critical mass. So, we played that game. We did 60 or 70 transactions in a very short seven-to-eight-year window after 2005. I can remember buying multiple companies per month and rolling them in and doing integrations, and it was definitely drinking from a fire hose. But, again, I learned a ton and used a lot of what I learned at Patterson and on my own to be a buyer of choice, to be the kind of assimilator and integrator of these companies that buyers liked.

And we were pretty damn good at it, but we were on the razor's edge when it came to that debt exposure. When I took over the company in 2013, we had about $1 billion of liabilities. We were still in that three times threshold of debt-to-EBITDA, but we were heavily levered. And that's not a problem until it is. What happened in late 2014 was the Saudis decided to fight over market share, crashed the crude prices on Thanksgiving Day. The curve ball was massive because our first set of bonds, which was about $400 million, was callable in the spring of 2015. When we went to market on that, the worst possible scenario happened. We had great EBITDA in 2014. We had great growth. We had a sizable

SHUTTERSTOCK

Until recently, producers wanted to own the water infrastructure, often relying on the hub-and-spoke trucking model for saltwater disposal. "It's flipped now," according to Roe Patterson. The producers are more interested in investing in the hydrocarbon infrastructure and the drill bit, which works out well for Patterson's Ventana Midstream and its growing water management infrastructure.

worth individuals who understand the business. They see the opportunity, they understand the need, they just don't know how to play it. So, we become that vehicle to play it. Multifamily offices, guys that just need doers and operators like us to be able to go play the game. That's really what Marauder is based on.

JB: Having a relatively smaller fund, I think you're seeing more interest in capital partnerships, joint acquisitions. Is that a rising industry trend overall?

RP: Yes. With all of our contacts within the capital space, we've stumbled on some pretty good opportunities to team up with people to come in either in front of or behind someone and help maximize the value in a deal. There's a lot of co-investing opportunities for our LPs. People have to be creative on how to assimilate this capital. The need is there, the desire and the want for consolidation in the service space is there. It's just a function of how do you back it, and how do you underwrite it, and where's the capital come from? Getting creative and finding good partnerships is definitely part of the answer, in my opinion. It's part of the recipe.

We don't want to be the operator. That's certainly not the mandate of Marauder that we go in and take over the day-to-day. But we can absolutely be very good coaches to operators. Sometimes it's because they're fighting the fight every day and that stuff is just not glaring to them. It's a forest-for-the-trees kinds of things. We can come in with that 50,000-ft view approach and say, "Hey, have you thought about

amount of cash, but we had a lot of debt and we were unable to replace it, so we couldn't get a new bond.

The debt markets were closed, and it was the first time in Basic's history that had ever happened. There was no debt, no capacity, no buyers. Now you're in this distressed debt world where your bonds start to trade down. We went from record revenue, record EBITDA to record-low EBITDA in 2015, 2016, and that was just a massive tailspin. The bondholders start to change their configuration pretty quickly. You go from pretty constructive bondholders when your bonds are trading around par to some very non-traditional, distressed debt guys who are really doing a takeout and takeover kind of strategy when the bonds start trading below 50 cents.

Then the elbows get super sharp. When you talk about high highs and low lows, the high high was 2014 when things were just as good as they could get. And 2015 and 2016 were just a wrecking ball. We played this game of trying to preserve any value at all for the old equity holders, and then we were trying to just save jobs at the end of the process and keep a company afloat and get it recapitalized. If you do make it to the other side, now it's the entire process of a new board, a new set of shareholders, a completely different dynamic of strategies that they want to go do.

Frankly, that usually is, at least it was in my case, really a subset of bad ideas. They're just wanting to do big roll-ups of the sector and not understanding all the dynamics of making that happen, how hard it is to do integration. It looks good on paper, and on a spreadsheet, I'm sure it looks wonderful. The reality of making it all happen is really tough to do. I spent the next two years trying to convince my stakeholders, who were these large bondholders and now equity holders, and my board the right path that I thought Basic needed to be on. Probably by the middle of that second year, I knew I wasn't going to teach these guys anything. They weren't listening. They had their adjusting this, closing this facility, selling off a segment that underperforms, and what the impacts would be to your cash flow and EBITDA?"

A lot of times they say, "Yeah, I know exactly what you're talking about. I don't have the money, and I haven't been given permission from my old sponsors because they don't want me to do anything. They just want me to sit here in place and not screw anything up until they can get out." We see a lot of stranded companies that are just stuck. Some of these companies we look at are within portfolio funds that were a 10-year fund, but they're a 14-year investment. That's a perfect target for Marauder because we can come in and be a fresh owner with fresh ideas and fresh capital, and we can take the handcuffs off these management teams and allow them to go do some more strategic thinking. I also think partnering up with good capital providers and teaming up, as you mentioned, is a path forward that is a potentially powerful one.

JB: Ventana and ClearWell are separate from Marauder. Can you talk to me about their strategies?

RP: Ventana was all Haynesville water-gathering assets that were based around the old hub-and-spoke trucking model where you strategically put saltwater disposal wells within a market and then built trucking fleets around them. What we've done is replaced a large portion of the trucking capacity with pipelines. Two years ago, the customers loved to own the water infrastructure, and they weren't very keen on the service company owning it. It's flipped now. They're more keen on owning their hydrocarbon infrastructure and spending their money at the drill bit and at the frac. That's been a shift that fell right in our lap.

We do like owning the transmission and the pipelines themselves. But, if a customer wants to pipe to us and own that infrastructure, that's fine. The shift Ventana has made is going to more sticky pipeline infrastructure to all of our saltwater disposal well facilities. We've added a lot of pipe. We're adding more pipe today. We're drilling additional wells. We've just completed two this year. We have a permit for the third. We want to keep growing the pipeline infrastructure to the saltwater disposal facilities and get that water off trucks, which is more expensive and dangerous.

ClearWell was the workover rigs that were in Pioneer Energy Services. Patterson-UTI bought those assets in the middle part of 2023. They did not want the wireline and the workover pieces. They wanted the drilling piece. We bought those workover rigs and the wireline business. We subsequently sold the wireline business to Caliber [Completion Services], and we kept the workover business. We went in and spent capital where they weren't spending it. We shut down locations that we thought were not profitable. We brought a super amount of efficiency to all of their field-level systems.

We created a plug-and-abandonment, well-decommissioning fleet that they didn't have before. No major surgery; just a little knob turning and creating business segments that make more sense, and closing segments that don't. We focused back on the traditional workover business and doing what they do best, and then creating a well-site decommissioning business that fit that portfolio of assets. It's the youngest fleet in the industry. We really don't run any rigs older than 2008. We have a lot of sophisticated equipment on location. All of our rigs are high-spec. The rigs are taller, our derricks are a little taller. When we built the well-site decommissioning P&A fleet, we did the same thing. We use a lot of automation. We have a much more sophisticated system for everything. That has allowed us to lock up work with the majors. We haven't been on a huge growth trajectory. We're running about double the rigs than we were when we bought the company in January 2022. Sometimes, growth for growth's sake or scale on a multi-basin platform doesn't really bring any added benefit. You end up creating lots of silos of G&A and more fixed costs, but you don't necessarily see it impact your bottom line. There was never an IPO strategy or anything like that. Let's grow it, let's do it within our own cash flow, and that's worked really, really well.

JB: Are ClearWell and, more broadly, Marauder focused on specific basins? Or are you pretty basin agnostic?

RP: Basin agnostic for the most part. Obviously, the Permian still has a lot of really positive attributes because it's still the largest oil field in the world, but it's a very tough place to operate. It's very competitive and the margins

own initiatives, and it was going to be better for them to find a CEO who wanted to do what they wanted to do.

I guess I could sit here and say, "I told you so," because they wrecked the thing and put it right in the damn ditch, but that'd be a waste of breath. So, the rest is history, right? They got hit, they went and did a deal, spent a lot of cash, got a lot of high debt to go do a big combination. They bought C&J [Well Services in March 2020]. And then COVID came along. You get caught flatfooted when bull prices trade negative and all kinds of crazy things happen. The business didn't make it. I left before all of that. I think my path was the right one, but I have the benefit of 20/20 hindsight.

BASIC ENERGY SERVICES

Basic Energy Services also entered into asset purchase agreements with each of Axis Energy Services Holdings LLC and Select Energy Services Inc. for the sale of its remaining assets.

are skinny. Sometimes, you look at a certain business and you say, "Why is their Permian division the poorest performing?" It's because of the makeup of the business. Within ClearWell, we're agnostic, but we stick to what we're best at. We haven't shown up in the Permian in a big way. We nibble around the edges of the Permian now. There's a lot of well-servicing capacity there and a lot of providers, and it's tough to keep employees in the Permian. They jump around, they job hop.

So, we like these markets where we're one of maybe four or five service providers rather than one of 20 or 30. We still have a Williston footprint. We created a Barnett footprint and an eastern Permian footprint. And then we've doubled down on all of our efforts in the Gulf Coast, the Eagle Ford, the Woodbine, southern Louisiana and deep South Texas where we have economies of scale and we have roots that we can maximize. That's been our model. It's worked well. Don't step out just for stepping out.

Now, Marauder is basin agnostic. We look at a lot of Permian stuff. We look at things all over the Lower 48, but we're more interested in the business itself. How profitable is it? How profitable could it be if the right levers were pulled? Again, if it's major surgery, it's probably not for us. It just takes too long within a fund life to make those things happen. OGI

This interview was edited for clarity and length.

CLEARWELL DYNAMICS

ClearWell Dynamics workers replacing pipe as part of production maintenance at an Eagle Ford well.

JB: That's 2020 in more ways than one.

RP: Yeah. I didn't have a peer that wasn't in my position. Not one single peer that I had in 2014 made it. Every single one of them went through restructuring. Everybody got whacked. Everybody went through Chapter 11 or some sort of restructuring, and so everybody was caught flatfooted.

The lesson now is that you rarely see leverage ratios on services go more than about two times. They're probably more in the one and 1.5 range, which I still think is high, by the way. That's how much my mindset has changed in 10, 11 years. I like one times or less on debt-to-EBITDA. I'm a firm believer in the cyclicality of our industry and how fast things can shut off. Whether it be the Saudis' plan for market share or COVID-19, you don't want to get caught in a big crash—even if it's a short one—with a bunch of debt because it'll probably cost you your company. The lenders don't want to be there either, right? That's why there's no capital. In 2015, 2016, you saw Wells Fargo and Bank of America and Credit Suisse write off some massive oil and gas lending that they had done. Everyone took a thumping together. You can't blame those commercial lenders for being very hesitant to get back in a robust way. The appetite for debt has dramatically changed across the sector. The appetite to conserve cash, make distributions, be a capital returner rather than a capital consumer, it is magnified so many times because of what everyone learned during 2015 and during COVID.

We're a healthy industry today. I guess you're never completely healthy when you're dealing with commodity-based businesses, but we're probably as healthy as we ever have been, both on the E&P side and the service side. There's a lot of resiliency in the businesses today. It's funny, but history tends to repeat itself in our business. If we ever look up again and guys are getting three times levered, or they're starting to build a Ferrari dealership in Midland, Texas, we all need to run for the hills. It's going to get ugly. OGI

'HEARTBREAK SHALE' RAISES WILDCATTERS' HOPES AGAIN

Formentera Partners is counting on bigger completions and longer laterals to crack the Pearsall code in South Texas.

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Rumor had it more than a decade ago that the Pearsall Shale's oil and condensate window underlying Eagle Ford in south-central Texas was a new play.

Today, "the trial's still out," Bryan Sheffield, managing partner of Formentera Partners, told Hart Energy.

But, he added, "We're going to drill."

Wildcatters IPed liquids from Pearsall horizontals in the early 2010s but the EURs proved uneconomic.

Sheffield's premise today is based on that operators were using the best frac recipes of the time—and laterals were a mile or less.

For example, he said, one of those trials was a Marathon Oil well, Whitley-Dubose #1H, in Frio County in 2014. "This is in the middle of our block."

Lateral length was 5,736 ft and proppant per lateral foot was 475 lb in a 20-stage frac, according to the completion report filed with the Railroad Commission of Texas (RRC). Frac fluid was 16 bbl/ft.

In 10 years, the well, which is now owned by Formentera's partner, Britanco, made 97,429 bbl of oil and 348 MMcf through October.

In that time, shale producers' frac recipes have advanced to 2,000 lb/ft and more. Sheffield's thinking is more proppant and pressure-pumping intensity should make more liquids.

"If we go to 2,000 and 3,000 pounds per foot, you know that well is going to IP north of 400 bbl/d."

And there is another point he considers promising, he said: "You have EOG [Resources] leasing everywhere."

Joe Jaggers

Formentera had two Pearsall laterals underway in mid-January near the Whitley-Dubose in southeastern Frio with explorer Joe Jaggers' Britanco in a 35,000-Pearsall-acre deal signed in June.

Jaggers founded Permian-focused Jagged Peak Energy, which Sheffield's Parsley Energy bought in 2020 before selling Parsley to Pioneer Natural Resources a year later. Prior to Jagged, Jaggers was CEO of Ute Energy until its 2012 sale; president of Bill Barrett Corp. until 2010; and president of Barrett Resources until its sale to Williams Cos. in 2001.

The Pearsall could be a great play for small independents like Formentera, Sheffield said.

"I don't know if it's big enough for guys like EOG. Maybe EOG has leased up enough acreage [with Pearsall rights] where it does move the needle."

Formentera was drilling the Hurrikain Cat I-STX #S731H in mid-January and planned the Darlene 1-STX #N731HP next.

Each is from one pad, with one traveling southeast; the other, northwest. They are about 20 miles northeast of an EOG Pearsall wildcat.

"We are in the volatile oil window and our payzone is right around 10,000 to 11,000 feet," Sheffield said. "We are a little shallower and updip and less mature than EOG's position, which is contiguous to our block on the south."

Deposited in the early Cretaceous, the Pearsall sits under and north of the Eagle Ford (Late Cretaceous) trend as the ancient shoreline was receding, forming the Gulf of Mexico.

"We think our position points to more oil," Sheffield said. "EOG is deeper, around 12,000 feet on payzone, so probably a little more condensate.

"But I think their area is going to be just as good."

EOG's Burns Ranch #1H

Into early 2014, there was a slew of Pearsall news articles, Sheffield noted. "And then nothing. Nothing!"

That's until this past July when Hart Energy reported: "EOG Resources Wildcatting Pearsall in Western Eagle Ford Stepout.'"

EOG moved a Nabors Industries rig some 30 miles west of its next-nearest South Texas drilling—which is for Eagle Ford—to southern Frio, spudding Burns Ranch #1H in late June to land in Pearsall.

"We think our position points to more oil. EOG is deeper, around 12,000 feet on payzone, so probably a little more condensate. But I think their area is going to be just as good."

BRYAN SHEFFIELD, managing partner, Formentera Partners

SHUTTERSTOCK

"The trial's out" on whether the Pearsall Shale's oil and condensate window underlying Eagle Ford in south-central Texas is a new play, according to Formentera Partners managing partner Bryan Sheffield, but "we're going to drill."

The well is about 6 miles east of Dilley, Texas, and has a permitted depth of up to 12,000 ft.

The completion report and production had not been released by mid-January by the RRC.

Evan Kochelek, Formentera senior geologist, told Hart Energy, though, "We were told [by sources] the well has good pressure, between 3 and 4 MMcf/d and 400 bbl/d with low water."

EOG's Moonlight #22H

The Burns Ranch wildcat follows a 2-mile Pearsall test EOG made in northwestern McMullen County, Texas, in 2023 in its 30-Eagle Ford-well Moonlight development.

The Pearsall test, Moonlight #22H, IP'ed 1,115 bbl and 7.3 MMcf from a 10,627-ft lateral.

Gravity was more than 50° API

"So, definitely condensate," Kochelek said. "Rumor is that only part of the well is producing, not the entire 10,000-ft lateral."

EOG did not include proppant load in its completion report to the RRC.

Through October, the well produced 44,738 bbl and 750 MMcf in 19 months online.

It's "a bit too gassy, but great liquids," Sheffield said. "I think [the Pearsall] is going to be highly economic when we bring down capex."

Indio Tanks (Pearsall) Field

Frio County hasn't made much historically in comparison with its neighbors. Except for Eagle Ford wells along its southern end, holes in the county consist of legacy verticals and short Austin Chalk laterals.

Eagle Ford production represented nearly all of Frio's 383,000 bbl of oil and 30,000 bbl of condensate in August. As for the Pearsall in Frio, Indio Tanks (Pearsall) Field made 600 bbl of condensate, no oil.

In La Salle County, the field's August production was 351 bbl of condensate, no oil.

Across South Texas, the field made 2,000 bbl of condensate, plus 14 bbl of oil.

In Indio Tanks' 17-year history, its output totaled 699,038 bbl of oil and 654,156 bbl of condensate through this past October. Gas was some 30 Bcf.

Early 2010s

The horizontal Pearsall play was lit in mid-2012 when Coterra Energy predecessor Cabot Oil & Gas signed Osaka Gas up to invest $250 million for a 35% stake in exploring the shale.

TPH & Co. reported the deal was the equivalent of $14,000 an acre. "This mark of value caught industry by surprise, given limited well control," TPH analysts wrote.

The focus was on the intersection of Atascosa, McMullen, Frio and La Salle counties.

Soon, four wells were online with 30-day rates averaging 630 boe/d, 56% oil.

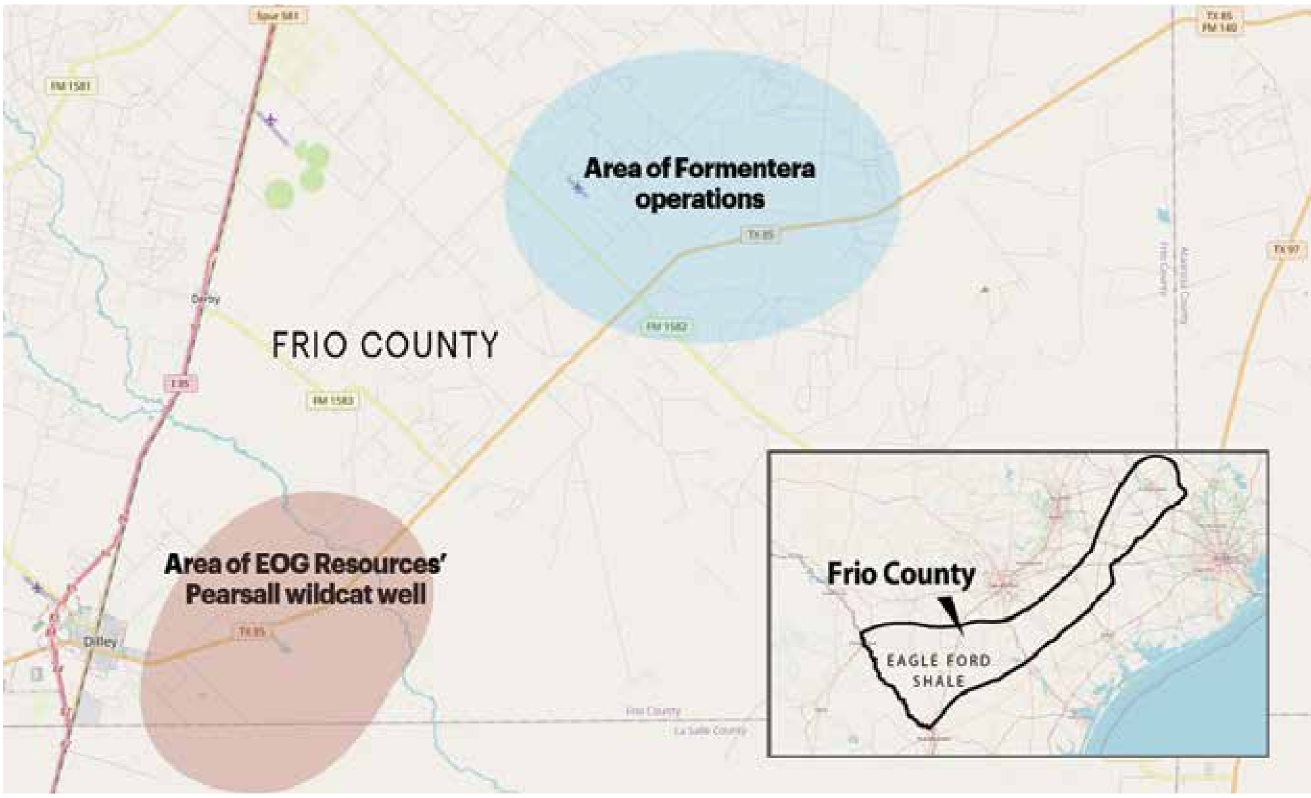
"Assuming a 550 MMboe EUR and $9.5 million well cost, these assets appear to be slightly less competitive than Cabot's Eagle Ford position," the analysts wrote.

In Frio, Cabot's RH Pickens A #103H tested 559 bbl from a 5,489-ft lateral. It made 49,213 bbl its first 10 months online and a total of 89,391 bbl before it was shut-in in 2022 by its new owner, Crescent Energy, according to RRC data.

Also in Frio, Cabot's Chilipitin #101H tested 670 bbl from a 4,387-ft lateral. It made 34,905 until 2020, when it was shut-in. It is also owned by Crescent Energy now.

In Atascosa County, Cabot tested its Hindes-Live Oak Unit #101H for 534 bbl from a 5,958-ft lateral. It made 32,346 bbl through January 2023 and has been offline since, according to the RRC. Crescent Energy now owns this well, too.

EOG and Formentera Partners' Pearsall Wildcat Play Areas



SOURCE: HART ENERGY VIA RAILROAD COMMISSION OF TEXAS DATA, REXTAG

EOG Resources' Pearsall wildcat well is in south-central Frio County near Dilley, Texas, while Formentera is testing the Pearsall updip in southeastern Frio.

Cabot quickly shelved its Pearsall program. In 2014, Osaka took a one-time impairment deeming Pearsall "economically unfeasible."

The Japanese gas utility's general manager said at the time, "We learned investment risks through the Pearsall experience. We want to target projects and fields with good production track records in our next acquisition."

In 2019, it turned to the Haynesville Shale instead, buying Sabine Oil & Gas, which has grown into a Top 10 Haynesville producer.

'Heartbreak Shale'

The vertical Pearsall discovery was in the early 1960s west of Frio in the Maverick Basin. Elsewhere, "the Pearsall was known as a heartbreak shale," Richard Mason, retired technical editor for Hart Energy, wrote in 2012.

The horizontal Indio Tanks opener was TXCO Resources' Glass Ranch B #177 that came on in November 2007 and made 194 MMcf with no liquids before being shut-in 11 months later, according to the RRC.

TXCO made four more Pearsall wells before filing for Chapter 11 bankruptcy: FOGMT #2SP for 1.9 Bcf and 210 bbl of condensate through September; Myers #2683H for 267 MMcf and 188 bbl of condensate; Myers #1683D for no MMcf or liquids; and O'Meara-Webb 687 Unit #1H for 446 MMcf and 553 bbl of condensate.

The property came to be owned by Newfield Exploration (now part of Ovintiv) in 2010 when TXCO was dissolved.

Crescent Energy is now the owner of FOGMT #2SP. El Toro Resources owns the O'Meara-Webb well, which was still producing gas in October and had last produced condensate in 2015.

Other Early Pearsall Wells

Two other early Frio wells in Pearsall are still online. Blackbrush Oil & Gas' Pals Ranch #12H tested 568 bbl from a 3,815-ft lateral. It made 26,946 bbl through September.

Separately, Pals Ranch #11H tested 706 bbl from a 2,670-ft lateral. It made 14,164 bbl through September.

In 2013 in La Salle, Carrizo Oil & Gas' Crawford Ranch B #12H was completed with 14 stages and IPed 105 bbl of condensate and 1.7 MMcf. Carrizo reported at the time that it planned "to monitor the performance of the well before deciding whether to drill additional Pearsall tests."

Carrizo didn't make any more Pearsall wells, according to the RRC. Eventually, the Crawford well made 39,992 bbl condensate and 819 MMcf from its 1,700-ft lateral. It continued to produce in October. The well is now owned by Texas American Resources.

In Atascosa County, Marathon's McCarty A Unit #1H IPed 440 bbl. The well produced 33,245 bbl through May 2021 and was shut-in upon SilverBow Resources' acquisition of the property. The lateral was 5,668 ft. The well is now owned by Crescent Energy, which acquired SilverBow in July.

Another Pearsall attempt in Atascosa was EOG's Alonzo Peeler A #1H, which tested 368 bbl from the 3,510-ft lateral. The well produced 4,359 bbl until shut-in in 2018.

Far northeast in Gonzales County, Penn Virginia Oil & Gas put Cannonade Ranch South #50H in Pearsall for 140 bbl from a 4,210-ft lateral. It made 4,481 bbl before put offline in September 2014. OGI

As Lateral Lengths Grow, Vaca Muerta's Output Sets Record

Chevron and Shell have backed a new crude pipeline project that aims to boost takeaway capacity—and exports—of the Argentine shale play's oil.

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Argentina's Vaca Muerta Shale is producing record oil volumes, trending toward a 1 MMbbl/d output by the end of the decade.

But takeaway constraints have always been barriers to growing crude output from the vast shale field in Argentina's remote Neuquén Basin.

"Argentina has lacked evacuation capacity to develop that resource in the Vaca Muerta," Adrian Lara, Wood Mackenzie's principal analyst for Latin America, told *Oil and Gas Investor (OGI)*. "That's not the only reason, but it's been a main restriction."

The new Vaca Muerta Sur crude pipeline project aims to alleviate some of the constraints. The midstream project has not only gained interest from local Argentine producers seeking to boost output, but also from supermajors Chevron and Shell.

Both own operated and non-operated interests in the Vaca Muerta Formation. Shell operates the Cruz de Lorena, Sierras Blancas, Coirón Amargo Sur Oeste (Shell interest 90% each), and Bajada de Añelo (Shell interest 50%) areas, according to investor filings.

Chevron operates a 100% interest in the east area of the El Trapial Field for unconventional development and 100% in the El Trapial's conventional waterflood field.

Chevron holds a 50% non-operated interest in the Loma Campana and Narambuena concessions. There were 41 horizontal wells drilled in Loma Campana during 2023, per company filings.

Experts say the US$3 billion Vaca Muerta Sur pipeline is one of Argentina's most significant infrastructure projects. It's expected to be developed under an ambitious new incentive regime to spur large capital investments within the nation.

Vaca Muerta Sur, which received unanimous shareholder approval to move forward in mid-December, is designed to transport up to 550,000 bbl/d from the Loma Campana field in Vaca Muerta to an export point on the Atlantic coast.

The crude pipeline can also be expanded to move 700,000 bbl/d "if necessary," state-owned producer YPF told investors last month.

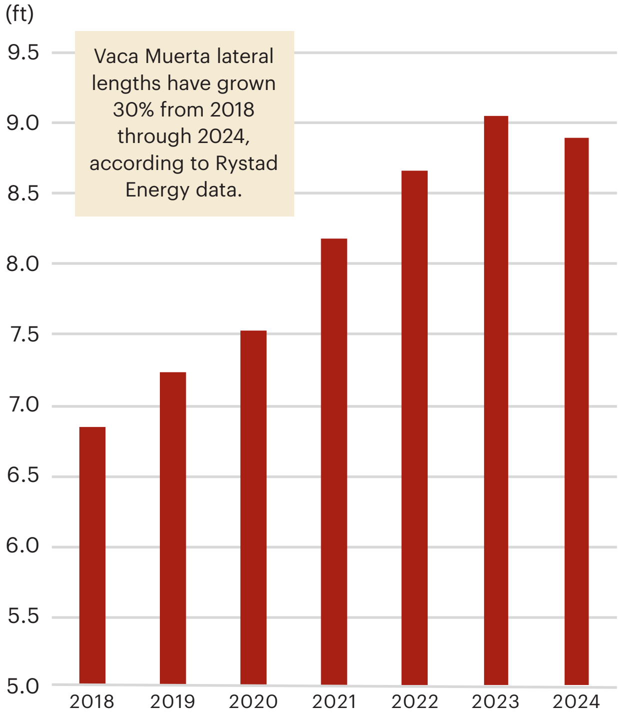
The pipeline will be developed by midstream company VMOS SA. Vaca Muerta Sur's initial shareholders included YPF, Vista Energy Argentina, Pampa Energía and Pan American Sur.

Later in December, Chevron Argentina, Shell Argentina and Pluspetrol exercised their options to join as shareholders in the project.

Exxon Mobil agreed to sell its Vaca Muerta assets to Pluspetrol in November.

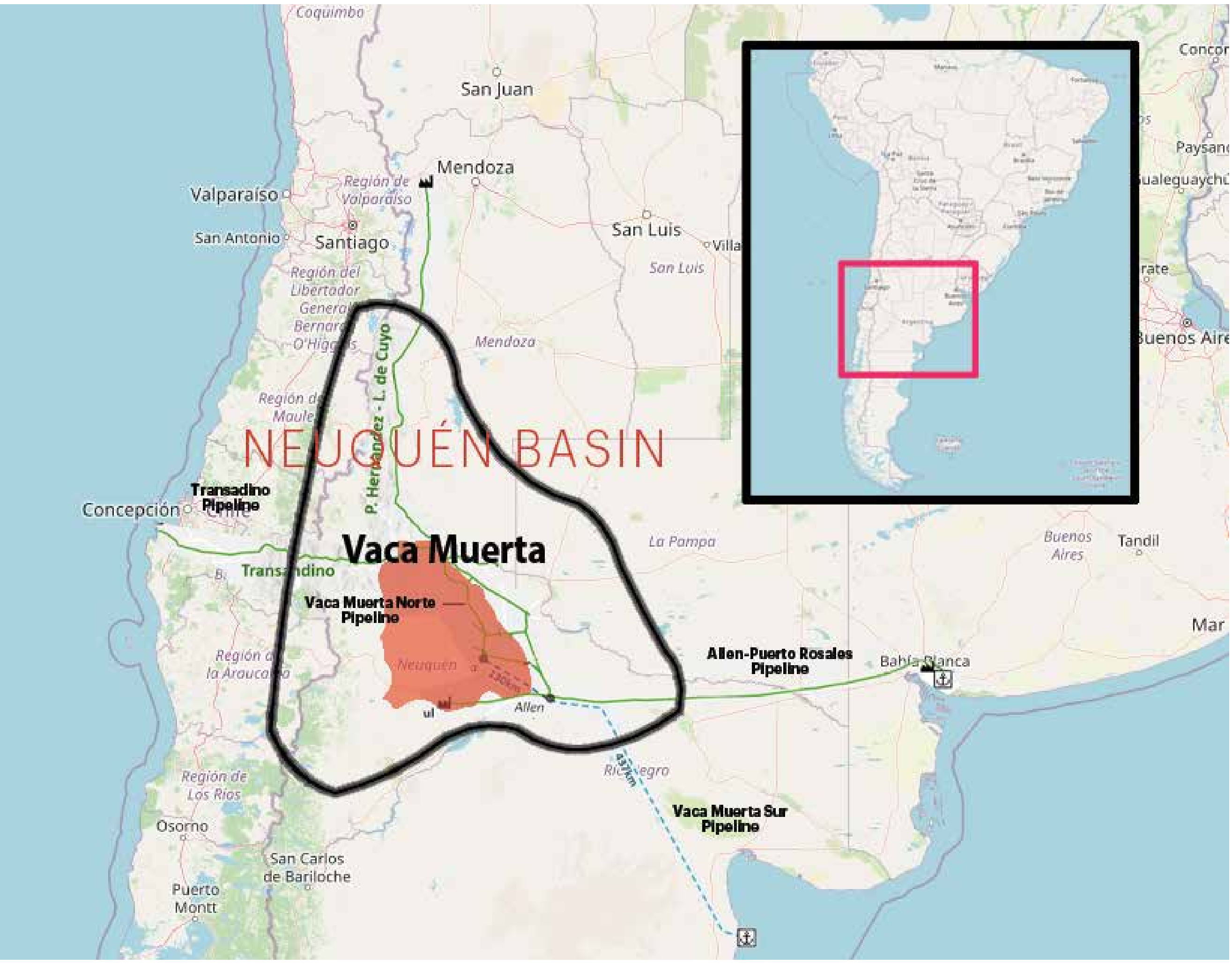
The first phase of the Vaca Muerta Sur project is already under construction. The first tranche will carry 500,000 bbl/d from Vaca Muerta around 80 miles east to a pumping station in Allen, Río Negro.

Lateral Lengths for Vaca Muerta Horizontals



SOURCE: RYSTAD ENERGY SHALEWELLCUBE

Vaca Muerta Shale and Pipeline Projects



SOURCE: RYSTAD ENERGY, REXTAG

Vaca Muerta Sur's first phase is under construction and will carry crude from the Loma Campana field to a pumping station in Allen, Río Negro province. The second phase will carry crude from Allen to an Atlantic coast export point at Punta Colorada, Río Negro.

VMOS will develop the second tranche of Vaca Muerta Sur, which will carry crude around 273 miles from Allen to an export terminal in Punta Colorada, Río Negro, on the Atlantic Coast.

YPF, the top Vaca Muerta producer, has secured 120,000 bbl/d of transport capacity on Vaca Muerta Sur, according to company filings.

Vista Energy, the second-largest producer behind YPF, secured 50,000 bbl/d of takeaway capacity.

Vaca Muerta Ramps Up

A record 400,000 bbl/d was produced in the Vaca Muerta during third-quarter 2024, a 35% increase year over year, according to a Rystad Energy analysis.

Producers brought online an average of 40 Vaca Muerta horizontals per month in the quarter, up from 34 in the second quarter and 33 in the first, according to Rystad.

"A record 46 new wells were brought online in September [2024] alone, of which 39 were in the oil zone and the remainder in the gas zone, underscoring the continued operational efficiency and momentum of Argentina's flagship shale play," Rystad analysts said in a December report.

Vaca Muerta operators have also drilled longer and longer laterals in the play over time.

1 MMbbl/d
expected oil production by the end of the decade

Lateral lengths for Vaca Muerta horizontals averaged approximately 8,900 ft in 2024, a 30% increase from 2018's average of around 6,800 ft, according to Rystad.

Chevron has drilled some of the longest Vaca Muerta wells. The company has reported laterals extending up to 14,700 ft (2.78 miles).

Vaca Muerta producers are also testing the stacked pay potential of the shale play. YPF is the current leader testing multi-bench pad development on its Vaca Muerta asset, Rystad Vice President of Upstream Research Radhika Bansal told *OGI*.

Producers have mainly targeted Vaca Muerta's Lower and Middle benches due to their high effective porosities, high total organic content and low water saturations, according to Enverus Intelligence Research.

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Unconventional oil extraction operations in Añelo, Neuquén province, in Argentina's Vaca Muerta shale field.

Barriers to Growth

The involvement of the supermajors bodes well for Vaca Muerta Sur's momentum, experts say, but the pipeline's construction still faces hurdles, including financing. Producers with stakes in the pipeline have agreed to cover 30% of the project's roughly $3 billion price tag.

The remaining 70% is supposed to come from a syndicate of international banks, Bansal said.

"We actually think this is going to be a crucial thing this year for Argentina—seeing [financing] occurring," Lara said.

Regulatory and political instability have been barriers for international capital to be deployed within Argentina. The Incentive Regime for Large Investments (Régimen de Incentivo para Grandes Inversiones or RIGI) aims to address those concerns.

The RIGI ensures certain tax breaks and other benefits for large-scale investments that spur economic development and employment within Argentina. RIGI projects may also freely import and export goods without prohibitions or restrictions.

550 Mbbl/d
capacity of Vaca Muerta Sur pipeline

To be covered under RIGI, projects require a total minimum investment of US$2 billion, with at least $400 million deployed in the first two years of development.

Qualifying export projects will enjoy stability in taxes, customs, foreign exchange matters and dispute resolution mechanisms for 30 years after startup.

VMOS aims to complete construction on the Vaca Muerta Sur extension during fourth-quarter 2026 and commence commercial operations by summer 2027.

But depending on the fundraising process and the RIGI regulatory structure, that could be an ambitious timeline for Vaca Muerta Sur, Lara said.

"The commitment is there; the investment is going to come," he said, "but when are you going to have it built?" OGI


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PEARLS OF WISDOM

Billy Quinn, founder and managing director of Pearl Energy Investments, leads a team that thrives amid the oil and gas investment cycles.

DEON DAUGHERTY
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William J. "Billy" Quinn's Pearl Energy Investments is the driving force of some of the nation's most successful energy investments during the last 20 years in terms of simple net return on investments. As founder and managing director of the firm, Quinn has led a baker's dozen of colleagues, including industry veterans and next-gen rock stars, to assemble investments in energy when it wasn't just not cool—general interest was frozen over.

While larger funds backed out of energy or went belly up, Quinn and his team hunkered down to emerge not only capable of surviving the one-two punch at demand from COVID and the ESG movement, but to thrive. The firm closed its Fund III in 2023 with $720 million—the largest in its history—and in September 2024 began work on Fund IV, steeped in great expectations. In this exclusive interview with Oil and Gas Investor, *Quinn explains what's kept his optimism alive during the industry's troughs and his excitement about the new peaks he envisions ahead.*

▸ CLOSER LOOK

PEARL INVESTMENT'S PORTFOLIO COMPANIES

- **Allied Energy**
- Apogee Petroleum
- Avad Energy Partners
- **Camino Natural Resources**
- Colgate Energy
- **Covee Energy**
- **Eagle Mountain Energy Partners**
- **Infinity Natural Resources**
- Oilfield Water Logistics
- **Permian Resources**
- **Powderhorn Energy Partners**
- **Ridgemar Energy**
- **Slant Energy**
- **Spring Valley Acquisition Corp.**
- **Spur Petroleum**
- **Streamline Innovations**
- **Swordfish Energy**
- **Voyager Midstream**

Companies in bold are current investments

Q&A

Deon Daugherty: It seems it's been more challenging for private equity during the last few years. There is something like 80% less private equity money in the space now than there was just five or 10 years ago. Given that, was it difficult to close Fund III? Did it take longer?

Billy Quinn: In a word, yes. During the fourth quarter of 2021, there probably couldn't have been a worst time in the last 15, 20 years—as long as I can remember—to actually raise a fund. Things were just starting to turn back over post-COVID, but people still weren't having full in-person meetings. The fundraising environment was difficult. Then, from that perspective, the venture world was on fire, so all the LPs had venture funds that were coming out and they were having to re-up. Whether you were general buyout or oil and gas, whatever you were competing with, there were astronomical venture returns that, as we know now, were not sustainable. But that didn't matter, and so there was that competition.

In September of 2021, Harvard [University] came out and said, "We are divesting from all oil and gas, not making new commitments, not making new investments, and we're going to sell everything off over the course of the next couple of years." And, so, when Harvard came out and made that claim, the entire oil and gas investing world, if they had capital to invest, was almost a big chunk of it, and almost 70% of it was put on pause.

In the oil and gas private equity world, between 2021 and today, we've had a ton of exits, but those didn't really kick in until mid-to late '22. There were a lot of investors who in late '21 and through '22 that said, "We committed to all these funds, 2014 through 2020, and nobody's returned us any money."

Even if they liked energy, they were full, they were at their allocations and they didn't have any money to put in it. So, for an oil and gas fund, 2021-2022 was as hard as it's ever been.

DD: You still had some success with the closing of Fund III's raise of $720 million. And then, in September 2024, you launched a fourth fund, suggesting some optimism. What was your thinking about that launch?

BQ: The simple answer on fundraising is, it's never just one thing, right? It's always a handful of things. I will say the combination of a revisiting of the longevity of oil and gas in this world, and whether you're saying it's an ESG push or that what you need to make power demands work what you need from security of energy resources … Ukraine gets invaded by Russia … all of these little things on a macro level [lead] people to revisit [the industry] and say, "Well, wait a minute,

PEARL ENERGY INVESTMENTS, OIL AND GAS INVESTOR

if we put oil and gas investing on pause, was that the right decision?"

Now I would say there are three camps there. There's a camp that has gone public with a hard line like Harvard, saying they're not doing fossil fuel investing—they're not changing their minds. They made that decision three years or three and a half years ago. And if they change their mind, it's going to be like turning an aircraft carrier around, it's going to take 10 years for them to reverse that.

There was a big middle camp of people who said, "Oh, let's just pause. We don't know, but let's not make any bold statements." A lot of that group has come back and said, "OK, we need to be smart investors. We need to really think about what our fiduciary obligations are and who they're to and should we revisit investing in oil and gas?"

And then, because of some of the macro variables, there's been a large universe of people revisiting and being more open to investing in oil and gas.

DD: And exits in recent years have proven to be quite profitable for investors.

BQ: The private equity returns, meaning cash back whether it's us or Carnelian [Energy Capital], EnCap [Investments] or Quantum [Capital Group]—you name it—there have been exit markets for our companies that have been really good the past two years. A lot of cash has been sent back to LPs that injects more liquidity into our system. So now, [answering] the people who said, "Oh, I'm overallocated. I haven't seen any money in the last eight years." But in the last two years, they got a ton of it back. With that component, there's more money in the system.

[For] a lot like the public markets, it's become clear that they don't just want to invest in oil and gas just to have an allocation. They want to generate differentiated rates of return. And if they're going to invest in oil and gas, in energy privates, the returns need to be there.

Our returns have been best in class. We stack our returns against, not only on an absolute basis, but against everybody else. And they look very different from the rest of the market. Carnelian looks very good, and we look very good. And then candidly, amongst the big funds, the best performers are EnCap and Quantum, and you saw in recent months that both of those firms came out with big fund raises.

DD: Apart from returns, are there other things at play? Has the ESG movement lost all of its momentum? Do they realize the energy transition is going to take longer than expected or that oil and gas will never really go away?

BQ: I say yes and yes to the last two questions. They realize oil and gas isn't going away anytime soon. What's the decision point here? "Who's our fiduciary obligation to, and how do we generate returns for fiduciary?" There's that component of it. And so, they're revisiting the ESG component.

It's not that these institutions are saying, "Oh, that was silly, let's blow off the environmental aspect of this, and we're just going to dismiss it." It's more of them acknowledging that, "Wait a minute, ESG is environmental, social and governance. If you … take action on the E, … does it have a negative impact on the S? Are we doing more good than bad, or more bad than good?"

There's not a crystal-clear answer. For example, if we do things to hurt the oil and gas business and it makes hydrocarbons more expensive, are there people on this planet that are a lot worse off because the cost of energy just went up?' And the answer is yes, there are, especially people in the developing world.

DD: So, you've got to strike a balance?

BQ: I think there's a balance now where people are at least thinking through that there's a negative in that because you have carbon emissions, but what are the consequence of not having carbon emissions and what do we get for that in exchange quality of life?

I ask the question on the energy transition: What does that mean? What are we transitioning to? If you're going to transition anything else you do in life, if you're transitioning from one thing to another, you're at point A and you're going to go to point B. But nobody knows what point B is.

Nobody can explain it, nobody can quantify it. What are we transitioning to? I think that realization is becoming more and more profound every day where people just say, "We don't know." And that just changes the attitude behind investing in oil and gas. It may not say you have to do it or love it, but I think it takes the edge off of ESG. It's not going away.

But it brings in questions, enough to where people have to sit back and say, "Are we doing the right thing? And what should we be doing?" Then that takes some of the pressure off of for some of these institutions from going "no" on fossil fuel.

Most of these institutions that go toward no on fossil fuel investing, it's not the investment staff that is sitting back saying, "We shouldn't be investing in oil and gas." I have yet to meet somebody who works on the investment team at any of these institutions saying, "We don't want to invest in oil and gas."

They want to generate returns. What happens is at the board level of these organizations where they're not necessarily thinking financial returns, they're the ones making that decision,

DD: How much are you hoping to raise with Fund IV and then, where are you going to deploy the capital? What's your plan for it?

BQ: We look for great management teams who have an expertise, which usually means deal flow and technical knowledge in a particular basin, whether it's in the Midland Basin or the Delaware Basin or in the Appalachian Basin. There's a real niche focus.

We look for great teams, and they really lead us to the opportunities. We are not macro in how we look at the fund and say, "We want 80% of the dollars in oil and 20% in gas, or vice versa." We look for good risk-reward investment opportunities. That's what our focus is and finding teams that lead us to those.

DD: Following the consolidation trend of the last 18 months or so, it seems like there are significantly fewer private equity-backed players. Do you expect a flurry of new ones to enter the market?

BQ: No. Since we were formed in 2015, we've always said—and always done it this way—that we manage a concentrated book. We have in any one fund, plus or minus seven or eight investments, and most of the money's probably going to be in three or four of the companies at any one time. Maybe there are 10 portfolio companies in our entire portfolio. Maybe that peaks at 12, but then it dips back down.

We like to have a concentrated portfolio, and I think with most, like us and Carnelian, that's what you see with the smaller funds. We like that approach and we're going to continue with that.

Historically, what you saw with the management team proliferation that came, you had the compounding effect where you had the large-cap private equity funds—EnCap, NGP [Energy Capital], Quantum and you could even throw them in with Riverstones (Riverstone Holdings), the Apollos (Apollo Global Management) and the Warburgs (Warburg Pincus)—you had the generalist funds. Well, a lot of those firms would have 25 teams in a fund, not seven or eight.

> *"The second you think it's easy, you're done because there's somebody who's going to out hustle you. But because it's just never easy, it's always a lot of work and you've got to grind. But if you keep doing those things, they usually work out. But it's not easy to do."*
>
> **BILLY QUINN,** founder and managing director, Pearl Energy Investments

Today, I think you've got two things going on, and in part this is when you look at gross dollars. We've talked about the market being better today than it was three years ago, but there aren't near the number of dollars today as there were 10 years ago for oil and gas private equity. It's a combination of a lot of the bigger players no longer exist ... They're not in the oil and gas investment business anymore from a deploying new capital and raising new funds [perspective].

And then, the EnCaps and Quantums, the NGPs of the world have basically said, "Hey, it's harder for us to raise larger dollars." And their fund sizes are not what they were the last go 'round. They've shrunk from fund-size perspective. They look and say, "Well, wait a minute, we don't want to back 25 teams. That doesn't get us where we want to be, return-wise."

So, they're running more concentrated portfolios. If you take half the firms that were around 10 years ago and they don't exist, and then the large ones that still exist that are surviving, they're going from 25 teams to eight or 10 in their portfolio, you just don't have as many teams running around.

There's been a dramatic contraction, and I don't know scientifically what the number is, but we always try to estimate, and it feels like today there's probably somewhere between 30% to 40% of the number of teams active out there than there were 10 years ago.

DD: How does this impact the exit strategies? Does it mean you intend to hold on for a long time? Pearl still has some ownership in Permian Resources, and Infinity Resources has filed for an IPO.

BQ: The simple answer for us is, there's no one formula. There's no one recipe for how we exit. When we make investments and when we manage our portfolio companies, we make the assumption that we're going to own these companies for forever, even though we know we're not.

What are the cash-on-cash rates of return of holding these businesses forever? That's where we start as far as we build them out. One of the things we love about our size, not being a mega cap fund, is that it allows us to think through exits in a way where maybe it's breaking up a company and selling it in five or six different asset packages. Maybe it's selling it as one company, maybe it's reverse merging it into another public company or selling

"We look for great teams, and they really lead us to the opportunities. We are not macro in how we look at the fund and say, 'We want 80% of the dollars in oil and 20% in gas, or vice versa.' We look for good risk-reward investment opportunities. And so that's what our focus is and finding teams that lead us to those."

BILLY QUINN, founder and managing director, Pearl Energy Investments

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it to a public company for stock. Maybe it's taking it public on our own. What we look at is, you can never predict where the market's going to be when you're ready to have an exit.

What we try to do is build in as much flexibility as possible, and this way we can manage and pivot as needed to generate the best rate of return possible on our investment.

DD: Let's talk about your rate of return on investment, which is significant at 250% across all three of your previous funds. How do you do that?

BQ: I always say we're patient. We're just patient capital and we're opportunistic in how we go about investing in the business. And what that means is we don't programmatically invest. We don't think, "Oh, we have to invest $200 million this year."

We are evaluating opportunities constantly. We're looking at investments and deploying capital with some of our teams; with others, we're talking about exits, but we're still remaining opportunistic across the board. And what that means is there are periods of time where we'll go 12, 18, 24 months, and we won't deploy a whole lot of capital.

We're active. We're the proverbial duck floating around the pond.… (Y)ou're expending a lot of energy, you're looking at a lot of things, but you just don't get a lot done because you're patient.

You can go two years without doing anything, and then one year you deploy $500 million. It's about being nimble and opportunistic. I've been doing this almost 30 years now, and I think it leads to generating better investment outcomes.

DD: Billy, as you've noted, there are a lot of shops that no longer invest in the energy business or those that tried have gone away. Was it hard to stick with energy during the COVID and post-COVID period? Did you ever contemplate going into aviation, healthcare or taking another avenue?

BQ: No, but that's a good question. I never thought about it. But there's that moment in time when, if one of my kids said they want to go into this, what would I tell them? Is this really the best decision for them?

For me, there was never the thought of pivoting away. In fact, I tend to be contrarian in how I think about investing and deploying capital. When the entire world was basically talking about writing this business off, my answer was, "Wait a minute. We've got good fundamentals from a price perspective, capex projects, the market's disciplined and all this money's going the other way. That should lead to better value opportunities."

I was actually thinking more the opposite, that selfishly, if we have capital and that dynamic's going on … it's never easy investing capital, but that should make our lives a little bit easier in generating returns we want to generate.

DD: Because there's less competition for those assets?

BQ: Exactly. We're in business with teams that lead us to opportunities. We don't look around and say, "We need to be in the powder." We just don't think that way.

More than anything, we look at the market and ask, "What's going on fundamentally that we think is positive from an opportunity set?" I think that the starting point is, we think there's been real capital discipline, both with the publics and the privates, which leads to a constructive price environment. People are disciplined on capex. The rates of return on most capex projects look pretty attractive.

There are some nice development opportunities out there when you're buying assets. But I think where this all kickstarts is the consolidation that has gone on in the business over the past couple of years. Whenever you see these large consolidation waves happen … you see very material exits.

DD: We've already started to see some of that, right?

BQ: Apache [has done] a big deal. They buy Callon [Petroleum], and then on the backside of that, they sell out of the Central Basin Platform. Exxon [Mobil] buys Pioneer [Natural Resources] and they start selling. Exxon has been a very active seller over the past year. You look at all these companies that are consolidating, and what happens is on the backside they wake up and they say, "You know what? When we were at the size of our company of X, we had the bottom 10% on the drawing board to sell. For whatever reason, we weren't selling. Now we just bought another company and we're 50% larger. You know what that bottom 10%, let's get rid of it. Let's get it out the door. Now's the time to do it."

For us, where we think the opportunity is, it's the combination of what we're seeing and what we expect to see with some real good asset turnover velocity. Assets on the market and then a very disciplined and balanced capital markets. There's still not a lot of money in our business. It's very disciplined capital, which means if assets at the market, people are disciplined, we should be able to make some attractive long-term investments. And I think that's where we see the opportunity. The opportunity is in that macro overlay.

There's nuance in business strategy across every basin. If you said, "Hey, I want to go start a business in the Central Basin Platform," we'd say you can make some good chunky acquisitions there, and there's a lot of good conventional stuff you can buy, and there's some asset turnover.

If you said, "Hey, I wanted to go start in the Delaware Basin," I'd scratch my head and ask how you're going to start. Are you going to start looking at $50 [million] and $100 million deals? And if the answer is yes, well, how are you going to compete with the offset operators who are big public companies who can drill and operate way more cost effectively than a private company can? How do you pay them in an environment where some of those publics in the shale basins, they're looking to add inventory, not get rid of that type of inventory? So, how do you build a business there? And our opinion in certain places is, you have to be prepared to play really small ball.

DD: How small?

BQ: We're talking about building a $400 million business or a $500 million business, but it starts with doing $300,000 and $500,000 deals that maybe build up to $5 [million] and $10 million deals. And you wake up after two years and you've done $50 [million] or $100 million worth of deals, but your biggest deal was $10 [million] or $12 million.

DD: So, that is quite different.

BQ: In some basins, that's the way you have to go.

DD: Another thing that seems to differentiate Pearl from other private equity firms is that you do invest so much of principal capital in these funds.

BQ: Yes, we as the GP (general partner), I think relative to other funds, we invest a lot more as a percentage of the fund. We like to act and think like investors, not money managers. We have belief and conviction of what we're capable of doing from a return perspective and think that that's better than doing anything else with your money.

Remember, we invest with our portfolio companies. We have governance and controls, and so we're involved in all the decisions and how things get done, and we work closely in partnership with the management teams. It's what we do every day. I feel so much better having a lot of my money in our funds where we know everything that's going on in the businesses, and we're partnered with great management teams and we work together. You spend your entire livelihood driving the outcome of that investment.

Whereas, if you have something in public stock, how much influence can you have? You don't have any influence and you have limited knowledge; it's only what's publicly disclosed. It's just a very different investment opportunity when you're talking about what we do day-to-day. We just have conviction in that and how we do things and think that's the best use of our own personal capital.

DD: Your passion for this business really comes through. What drew you into investing in oil and gas? Why are you still so excited about it?

BQ: I was lucky. I've been doing this almost 30 years. I got in very early and became one of the managing partners of Natural Gas Partners (NGP) at a really young age and was just fortunate enough that before going back to business school, I was in investment banking for a few years.

I knew I wanted to be in the investment business. I grew up in the Dallas area but didn't have any oil and gas experience. All the stuff I did in investment banking was anything but oil and gas. And then I got the opportunity to go work in Richard Rainwater's office. And back then, really, there were only three or four investment professionals in his office in Fort Worth. I was one of them and so was Ken Hersh. I worked closely with Ken on a lot of things for Richard, and those were the early days of NGP. And I almost laugh when I talk about it. We were a couple of $35 million funds, so we were tiny.

But I was fortunate enough in the mid-'90s to be in that office and be around really smart people, and ended up co-managing NGP from '97-'98 through until I left there in early 2014.

DD: Why did you want to open your own shop?

BQ: I was basically co-running the firm with Ken and David Colt, and we got big, and I tell this when I have conversations with LPs and everyone else: a multibillion-dollar private equity fund is too big to generate the returns that we expect to generate.

I think it's really, really hard deploying that amount of capital. And we'd reached the size of NGP, where we are going out and raising for plus-or-minus billion dollars at a clip, and it's really hard to invest. And the simple answer is. when you become a multibillion-dollar fund complex, you don't choose to go back to being a billion-dollar fund or an $800 million fund. The only time that happens is when the market forces you to do that.

And so, as much as I loved all the people at NGP, my partners there from A to Z, it was a fantastic place … we were not going back to where we were from '95 to 2007. We had already made the decision to go big. That wasn't going to change, and I just didn't want to do that anymore.

> *"You can go two years without doing anything, and then one year you deploy $500 million. It's about being nimble and opportunistic."*
>
> **BILLY QUINN,** founder and managing director, Pearl Energy Investments

DD: So now, going forward, what's exciting to you now or what's keeping you up at night?

BQ: What's exciting is our team at Pearl. We have an awesome team that has evolved incredibly over the last 10 years. Now we have 13 going to 14 or 15 employees. We've maintained a nice small size, everybody knows each other–the investment team, the real investment deal team, and our general chief operating officer, office manager, CFO–everybody's been there since day one.

DD: So now the question: what's keeping you up at night?

BQ: I have to laugh because in our world, I feel like your head is always on a swivel. You're like, OK, where's the next thing to go wrong? Are we going to have an issue at a portfolio company? Whether that's drilling a well and operations, or is there an HR issue at a company? You have enough companies, you have enough employees at these companies, you get HR issues from time to time. Are we going to be able to find some great investments over the next year?

We think we will. We have confidence [that] we will, but you never know. And so you're just constantly looking and it's never easy. It's never easy.

The second you think it's easy, you're done because there's somebody who's going to outhustle you. But because it's just never easy, it's always a lot of work and you've got to grind. But if you keep doing those things, they usually work out. But it's not easy to do.

DD: If it was easy everyone would do it, right? What else is out there that we should be talking about when we think about private equity in the energy space this year?

BQ: I think it's more of a next five-year question. You've seen the push on the energy transition side and we now are really starting to learn and know what, and some people had opinions and maybe knew beforehand the limitations of that, but there's still a lot of money out there chasing those deals. And it'll be interesting to see how the investing side of that happens.

We don't think the returns are there; we don't think they're good enough. We think there's a lot more risk in those businesses. And it'll be interesting to see how all of that plays out in the next four to five years. There's a lot of capital chasing not too many opportunities. When all it started, I thought it could be one of the greatest destructions of capital that we've seen in our lifetime. OGI


AETHON
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GENERATES
EXCEPTIONAL
RESULTS
Aethon Energy is a leading North American owner-operator private equity firm looking for exceptional individuals to join our team.
aethonenergy.com

The Private Equity Puzzle:

Rebuilding the Portfolios

In the Haynesville, Delaware and Utica, Post Oak is supporting companies determined to make a profitable footprint.

DARREN BARBEE
SENIOR MANAGING EDITOR, DIGITAL
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Each of the past three World Jigsaw Puzzle Champion winners assembled 500-piece Ravensburger scenes–tigers prowling jungles, blue-chaired outdoor cafes, pastel housing–in less than 40 minutes.

As impressive as that is, jigsawing a shale unit map of the Haynesville Shale would clearly be next level. For one, the Haynesville covers about 5.76 million square acres–each a potential piece. And Louisiana state activity maps show shale units in red, preproduction in green triangles. The overall effect is of a Christmassy Lite-Brite project gone too far.

Still, it's *what's not there* that could matter. The puzzle for private equity's startups in all shales is to find the spots that don't yet shine. And, regardless of the play, it won't be easy after rampant M&A ransacked the Lower 48's PE portfolio companies, along with some large publics.

Beginning early last year, Post Oak Energy Capital began supporting a number of companies with equity commitments. The companies are working to assemble positions in some of those same lucrative (and expensive) plays as private equity firms begin to rebuild after the running of the M&A bulls.

During the latter part of 2024, *Oil and Gas Investor* caught up with three of the new companies: the Haynesville Shale's Quantent Energy Partners; Delaware Basin-focused Ichthys Energy Partners; and the Utica Shale's Tiburon Oil & Gas Partners.

Building a profitable footprint in any of those plays will be no easy task. Quantent, Ichthys and Tiburon are banking on a network of connections, a feel for their respective plays and a willingness to lock down every profitable piece of acreage still available. All while facing off in the oil and gas version of Squid Game: A&D.

In the Haynesville, most of the best and biggest blocks of acreage are locked down by major producers waiting to cash in on increased LNG exports. Operators range from privately held Aethon Energy to public E&P Expand Energy, the country's largest natural gas producer. Expand holds 650,000 net acres in the play and averaged 2,452 MMcfe/d in the third quarter.

But Quantent has already locked down one acquisition and sees more opportunities ahead.

In the Utica, the liquids-rich areas have been swarmed by new entrants chasing EOG Resources and jockeying with top producers Encino Energy, Ascent Resources and Infinity Natural Resources. Finding a viable large contiguous positon will be increasingly difficult there.

Scott Hudson, president and CEO of Tiburon, sees a lot more grassroots leasing that can be done in what he calls "pockets" or "donut holes" in which an operator can pick up three-or five-well units.

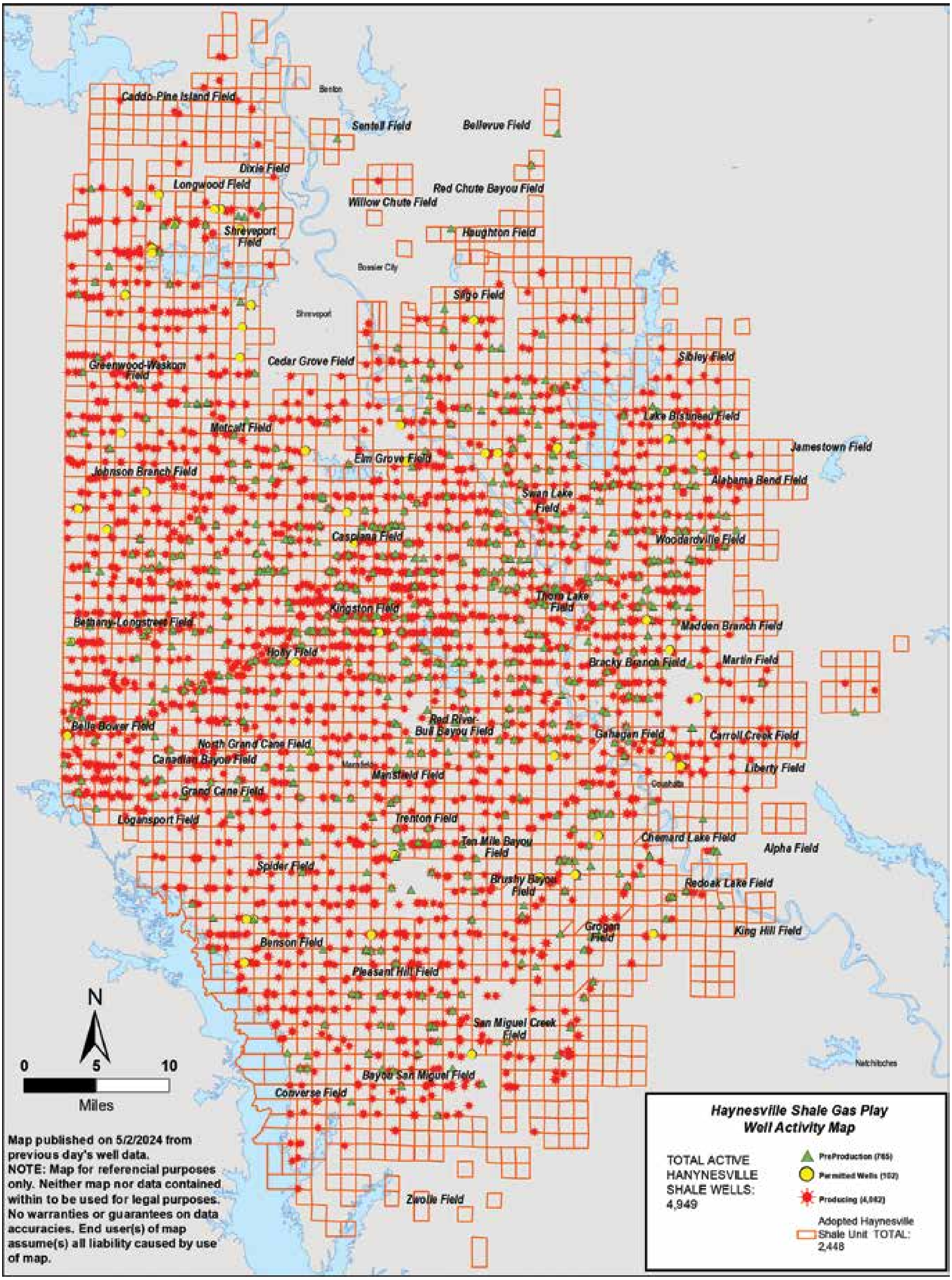
"Those definitely do exist," he said. "I mean, you're not going to go up into the Utica and pick up 10,000 acres in the windows that we're talking about today, but there are definitely opportunities out there."

Pieces of the Permian

Then there's the picked-over Permian, which lacks any convenient edges or an inviting lid depicting the sweep of counties stretching from arid Texas to arid New Mexico. With its horizontal wells jutting every which way, the Permian is vast and competitive. And, again, large independent E&Ps and majors hoard the best pieces.

The consolidation in the basin, including large-scale deals by Occidental Petroleum, Diamondback Energy and Exxon Mobil, creates a space for Ichthys "to come in and hopefully do some cleanup work on the smaller side, building those assets that way," Ichthys CEO Michael Poynter said.

Haynesville Well Activity Map



SOURCE: LOUISIANA DEPARTMENT OF ENERGY AND NATURAL RESOURCES

The Louisiana state activity map of the Haynesville is so dense that even a jigsaw puzzle master would struggle to find the individual pieces—but that won't stop companies from trying.

Private equity has to source new, younger teams that "have the skill sets and capabilities … with some support from us from the capital side. And whatever we can do to try to match assets with teams, we do as well."

FROST COCHRAN, managing director and founding partner, Post Oak Energy Capital

"We really feel like, with our operational background and track record, plus with our ability to be creative on deal structures, there's a lot of opportunities still left in the Haynesville to get into those parts of play."

KEVIN DELAY, CEO, Quantent Energy Partners

The other benefit of all the Permian M&A is that, as larger companies get even larger, "their appetite and focus on the much smaller interests that take time and some dirty work to piece together into something more valuable is maybe just less meaningful and doesn't move the needle as much for them."

Post Oak's teams are largely made up of new blood, unlike the tried and true portfolio companies EnCap Investments and Quantum Capital Group that are re-upping with more funding. (NGP Energy Capital has said it's unlikely to fund more than a couple of new teams.)

Frost Cochran, managing director and founding partner of Post Oak, told Hart Energy in October that Ichthys, based in Dallas, is a group of "young guys who are just getting started with their first company, but they're focusing in the area that they know best, which is the Permian and specifically more, the northern Delaware."

The company's leadership was spun off of Permian Resources.

Cochran said private equity has to source new, younger teams that "have the skill sets and capabilities … with some support from us from the capital side. And whatever we can do to try to match assets with teams, we do as well."

Some of the Post Oak teams had made initial acquisitions and held acreage out of the gate when the private equity firm committed equity to their ventures. Other teams were still looking.

What unites Post Oak's teams is a shared entrepreneurial drive and that special trait common in startups: confidence in their strategies, experience and expertise.

Haynesville 9,000

Quantent CEO Kevin DeLay views the Haynesville's opportunity set, essentially, as a math equation.

The Haynesville comprises 9,000 sq miles—an area larger than the nation of Israel. And within that expanse are a lot of tracts that aren't getting the attention, or capex, they need.

"They're underdeveloped either due to lack of capitalization or operational expertise to develop those positions," DeLay said. "We really feel like, with our operational background and track record, plus with our ability to be creative on deal structures, there's a lot of opportunities still left in the Haynesville to get into those parts of play."

DeLay is well-versed on the Haynesville.

DeLay served in engineering and management roles at Devon Energy, including operations and portfolio management. He also served as general manager at McClendon Energy Partners and led engineering efforts for several new ventures at Chesapeake Energy founder Aubrey McClendon's American Energy Partners.

"Aubrey loved the play," DeLay said. "He was always very excited about it. I will admit he was excited when I came to him in 2014 saying I thought the play had bigger potential."

DeLay had observed a set of about 12 wells that had used larger completions—more sand and fluid.

"And one-for-one, every one of those wells outperformed their direct offsets and gave me a feeling that the Haynesville had a step change of performance in front of it with new completion techniques," he said.

Before co-founding Quantent, DeLay served and directed upstream development projects as COO at Nadel and Gussman New Ventures, which was backed by Post Oak. He largely worked in the Haynesville, drilling out more than 40 wells, often at 20% lower costs than an offset operator.

In 2023, the Haynesville was still top of mind.

DeLay's thesis: a lot of potential remains in the play.

In September, Post Oak announced the closing of an equity commitment to Quantent and its initial acquisition of 7,000 net acres in North Louisiana.

Quantent captured an asset in the play "offsetting an existing asset we had in the Haynesville," Cochran said. The management team "was the execution team with that prior asset we worked with. So, it's really a second iteration with that team on a similar asset."

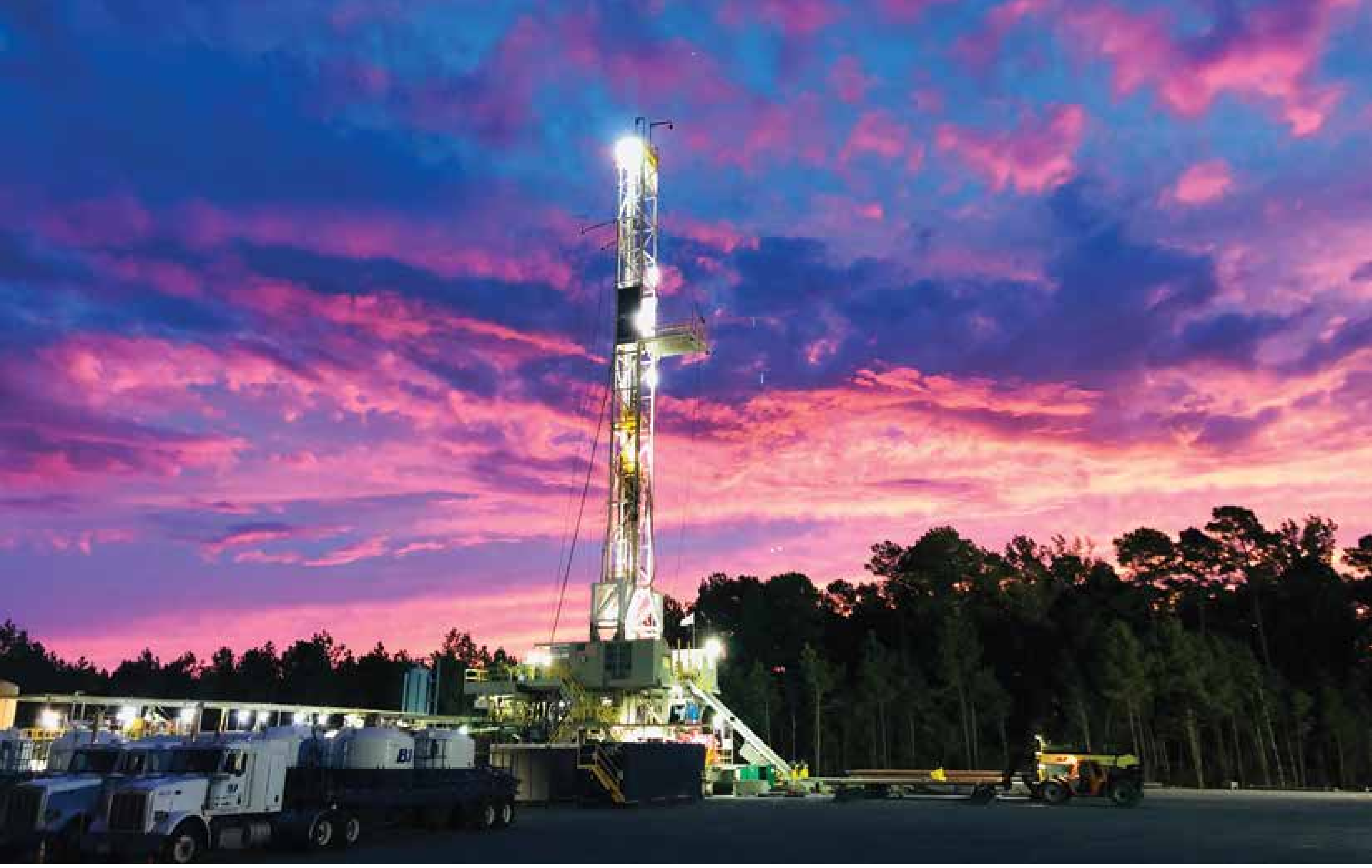
The company's strategy is to find untapped inventory and maximize its operational expertise. Following its September acquisition, DeLay said Quantent had a solid PDP base.

Ultimately, however, the company is looking for places to put the drill bit into the ground while searching for more upside locations through acquisitions.

"Obviously, if the deal has PDP involved and it works into our economics and we will go after it. But I would say, right now, we are focused on trying to find undeveloped locations," DeLay said.

And the company is in the play for the long haul.

"Strategically, anything we buy, we're going to be willing to fully develop and produce. That has to be the strategy at this point in the cycle of our industry."



POST OAK CAPITAL PARTNERS

Despite a dizzying amount of activity in the Haynesville, Quantent CEO Kevin DeLay there's "a lot of opportunities still left" to gain traction in the play.

And that plays to the strengths of Quantent's team.

DeLay said an important lesson McClendon taught him was the value of expertise.

"Your people are the most important part of your company. [You can] have the best rock in the world, but if you don't have people to execute it, then you're not going to be a top performer," he said. "I think we bring in some of, what I consider, the best experts in the field to come drill these wells with us and complete them."

Tiburon Set for 2Q Utica Drilling

Scott Hudson worked in nine shale basins during his career at Carrizo Oil & Gas before the company was sold to Callon Petroleum.

About two years ago, Hudson started to think back on one play in particular: the Utica.

While digging into the Utica at Carrizo, there'd been no modern day frac techniques brought to bear, he said. Right-sizing well spacing hadn't been implemented. Around 2013, Hudson was also working without the benefits of fully built out midstream infrastructure, which was a challenge and expense for the company at the time.

Hudson's conclusion: All the lessons that had been applied to the Delaware and Midland basins and the Eagle Ford Shale ought to be brought to the Utica.

"I kind of felt like, 'Hey, there was a big opportunity.'" And Tiburon was born.

Considering the various basins, his expertise and his team's expertise, the Utica seemed ripe for the picking. And so, Tiburon was built from a team forged at Carrizo, largely with experience in the Appalachian Basin.

In mid-October, Tiburon, backed by an investment from Post Oak, closed on an initial acquisition of leasehold in the liquids-rich portion of the Utica.

Hudson said Tiburon had been working for a year on grassroots leasing. The acquisition, with some other funding, allowed the startup to coalesce a sizeable acreage position with enough running room to get started.

"We're really excited about how many acres that we have out there," he said. "We have the ability to drill about 30 wells. So, it's a sizable footprint that we've been able to put together."

But, in November 2022, EOG Resources announced what it called the "Utica Combo" play in Ohio, including the acquisition of about 395,000 net acres in Ohio's volatile oil window and black oil windows. EOG's publicly disclosed successes in the play quickly overshadowed the play's gassy reputation. A&D efforts began to focus on liquids. In October, Infinity Natural Resources filed paperwork to launch an IPO.

"It's definitely gotten a lot more competitive in the last 12 months since EOG announced their presence in the basin, whereas when we started, there were [few] people looking in the basin," Hudson said. "Now, there's a ton of competition."

Hudson said the company has built a solid position

"[Large companies'] appetite and focus on the much smaller interests that take time and some dirty work to piece together into something more valuable is maybe just less meaningful and doesn't move the needle as much for them."

MICHAEL POYNTER, Ichthys Energy Partners

"It's definitely gotten a lot more competitive in the last 12 months since EOG announced their presence in the basin, whereas when we started, there were [few] people looking in the basin. Now, there's a ton of competition."

SCOTT HUDSON, president and CEO, Tiburon Oil & Gas Partners

while actively grabbing additional units where "we can find additional sticks to drill," Hudson said.

The company has no set parameters on its eventual size. It will likely be a 10-person shop in the near term. For now, the plan is to scout out good opportunities and acquire while setting up rigs, drilling and turning wells to production. The company plans to start production in the second quarter.

For now, the team is enthusiastic as it begins to apply advanced completions to the Utica.

"We're excited to work with Post Oak. They've been incredibly supportive," he said. "And we're ready to get that rig up in the air."

But that's been the team's path since their Carrizo days.

"We had this lease and drill strategy where we wanted to go in and we wanted to take our expertise that we've had for the last decade, decade and a half, and we wanted to go in and get this opportunity to get this acreage that we had put together and develop … not drill one or two wells," he said. "We wanted to drill the whole well set, and so they believed in that methodology."

Hudson said he's been in the industry about a quarter of the century–on the young side for oil and gas veterans.

"But yeah, we're still hungry," he said. "What my team loves to do is lease and drill, lease and drill. That's what we did at Carrizo together. That's what we want to do now. And so, we're just really excited about it."

Permian Itch

Ichthys' approach to building a position in the Permian Basin–specifically the northern Delaware– is to do it any way it can. So far, the company hasn't made an acquisition. But the company has multiple strategies, including picking up smaller assets that are not meaningful enough for the larger E&Ps to spend time on.

Poynter said the initial pitch to Post Oak was focused on the networking, relations and experience his team, with roots in Permian Resources and Colgate Energy, had in Midland, Texas, and in the basin.

The more nuts-and-bolts strategy of the company is to create an operated E&P with a focus on a land-first ground game, building up from smaller acquisitions into one or two drillable units at a time.

"I think that strategy really resonated with the Post Oak team. It's reflected in a lot of my past experience of teams that I've been on from the private equity company building side where we have done things from sort of the ground up," he said. "I think, given our backgrounds and the companies, the successful companies that we've been at, [we] really fit with that strategy."

However, Poynter said the company's business development pipeline could range from grassroots leasing to acquiring smaller non-operated interests "where we see a strategic angle to trade with other parties or participate in forced pooling, for instance, to maybe the third being farm-in opportunities and strategic partnerships with others in that way."

Another avenue is the post-consolidation rationalization acquirers are likely to engage in. Poynter said the company may look at larger packages or marketed processes.

Ichthys CFO Will Weidig said the consolidation-driven asset rationalization deals can be divided into two buckets.

"There's what I would call the macro bucket and a micro bucket. And the macro would be what Michael mentioned around large marketed assets, where an investment bank is sending out teasers and it's a $500 million plus [to] $2 billion type of transaction," he said. "And then there's the micro-scale deal, which is kind of what Michael mentioned secondarily, which is the smaller transaction, the DSU that was originally on the drill schedule that now isn't and therefore creates some kind of optionality for us.

"I think we'll be more focused on the latter. And that's not to say we'll be fully cut off from the macro bucket, but I think it'll be more opportunistic to see us engage in something like that."

Poynter added that the company would participate in large deals if a "real strategic edge" emerges "as opposed to us just outbidding other parties."

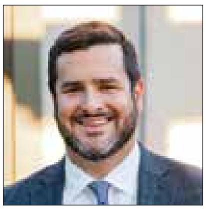
Poynter said he recognizes the Permian is a highly competitive market, but "that's a big part of why we want to be there."

"We go back to the strategy and the partnership with Post Oak and how that fits and think that this is the right time … on the consolidation side to be pursuing a strategy like this. I think we also have the right backgrounds from our prior experiences with both private and public companies in the Permian. We're both intimately familiar with the Permian Basin, but then also our networks within Midland and the Permian, as well."

Weidig said the company's willingness to be nimble

SHUTTERSTOCK

Building a new position in the incredibly competitive Permian Basin can seem daunting, but young and nimble companies like Icthys are banking on their experience and entrepreneurial spirit to make a space for themselves.



"Hey, this is the right time with the right people, and we think, the right strategy to go and execute."

WILL WEIDIG, CFO, Ichthys Energy Partners

and creative to get deals done is key, "whether that's from a structuring perspective, a partnership perspective or just being willing to do a series of smaller transactions versus maybe one splashy larger deal."

"I think all of those will accrue to our benefit as we go out and execute the strategy," Weidig said.

In the next three to five years, Poynter sees Ichthys focused on building units from the ground up and maintaining an ongoing series of operated drilling units that are staggered so that, by the time the first wells are generating cash flow, new wells are being drilled or coming online.

"I think my vision a few years from now would be that we've made this strategy repeatable enough to have multiple projects going" with varying "maturation points" and cycles of "developing, partnering, potentially even buying and selling various pieces all simultaneously by that point and continuing to build the business organically.…"

Ichthys started with what Poynter called a "sort of entrepreneurial itch."

"For me it was just kind of time," Poynter said. "We had accomplished what we set out to accomplish with the Colgate investment and then had seen Permian Resources stabilized and headed in the right direction."

Weidig said he has the same entrepreneurial streak.

"For me, it was identifying timing, a partner to work with and a partner from the private equity perspective, just that really rounded out the picture and made it make sense and look really compelling," he said. "We really found that, in terms of what we think is a really attractive market opportunity right now."

All of that added up to, "Hey, this is the right time with the right people," he said, "and, we think, the right strategy to go and execute." OGI

CORPORATE STRATEGY

The Aggregators

Avant Natural Resources buys small, sells big and is loving every minute of it.

DEON DAUGHERTY
EDITOR-IN-CHIEF
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In less than five years, private E&P Avant Natural Resources has built two businesses in the Permian Basin, sold them off and is ready to do it again. Co-founders and co-CEOs Jacob Nagy and Skyler Gary spoke exclusively with Oil and Gas Investor *about their winning formula.*

Q&A

Deon Daugherty: Your deal selling to Coterra Energy should close any minute now, so what's next?

Jacob Nagy: We are back at it again, just consolidating acreage in the Delaware Basin. We built a pretty big team and a big platform, a big acquisition-driven enterprise, and it doesn't really slow down for much. We're raising additional money and we're closing on our first set of deals over the next few weeks.

DD: Avant is more than just an E&P, too. You're involved in minerals, and you're involved in infrastructure projects. Are you looking at these acquisitions from an E&P perspective or from minerals and infrastructure?

JN: Our bread-and-butter business at this stage of our company's evolution is working interests, buying leaseable drilling wells. We started off as a minerals and royalty aggregator, and we thought we did a pretty good job with that. We sold our first package to Brigham [Exploration] in 2022 for $132 million and that was a good proof-of-concept exercise. And so, we continue to aggregate minerals and royalties and sell them when we think the market [is ready], when it makes sense to sell, and otherwise continue to aggregate. We'll always have a minerals and royalty presence.

And then, infrastructure is something more recent that dovetails pretty nicely with how our upstream operations work. There's often a lot of overlap there. But we built out a water recycling system as part of our operational footprint in the Delaware Basin, and we were actually in the process of selling that right before Coterra came and started talking to us. Coterra decided they wanted that, too, so that went with the sale.

DD: The Brigham deal was specifically Midland assets, but in the time that's elapsed, have you decided you're more interested in playing in the Delaware now?

JN: We sneakily do both. I think our Midland Basin royalty footprint was always more prominently featured, but we were always dabbling in the Delaware. Our Delaware working interests and operating footprint are more prominent, but we are exploring and actively looking at stuff in the Midland Basin as well.

So, we're really Permian focused. I think we're staying away from the conventional areas as well as some of the more exploratory extensional plays, but the Midland and Delaware basins for us, especially in this new venture, will be fair game. And, it's two areas that we'll be heavily focused on for working interest in minerals and royalties.

DD: How much can you tell us about this new venture?

JN: We're calling it Avant II, and we're raising capital currently. We're structured differently than most other private companies in the Permian. You have the legacy, family owned-companies, and then you have a significant chunk of private equity-backed teams. We're a little bit different. We're privately funded, so we went directly to investors and cobbled together an investor base of about eight core individuals or groups for institutions and did it the old-fashioned way, I guess, and provided a little bit more flexibility on our mandate and ability to put capital to work, which is helpful in the Permian because things just tend to move superfast.

That's been a crucial part of our strategy

"We feel like we're really hitting stride on the aggregation game and also operationally, so we're going to keep going. It's too much fun. We feel like we're doing a good job with it, and our investors are incredibly supportive."

JACOB NAGY, CO-FOUNDER AND CO-CEO, AVANT NATURAL RESOURCES

"We like to make sure that we're paying close attention to everything that's happening and try to anticipate changes perhaps a bit early, earlier than the industry."

SKYLER GARY, CO-FOUNDER AND CO-CEO, AVANT NATURAL RESOURCES

in terms of capital. We're at probably about half a billion [dollars] to deploy here in the near-term with a lot more behind it if we find the right opportunity set.

DD: It's almost as if Avant is a private equity firm unto itself.
JN: Correct.

DD: How did it come about?
JN: The genesis of it really was that when we first started the company, there were a lot of challenges across the industry. This was 2018, 2019, and we frankly weren't sure exactly how we wanted to capitalize the business. [We] were afraid of getting stuck in a path or with a single sponsor that might not be dynamic enough to evolve with the shifting landscape.

The way we counteracted that was to raise a smaller amount of money and then do it privately with a handful of investors. That gave us the autonomy to pivot if we needed to or shift direction or if it made sense. With the success we had early on with the royalty strategy, we were able to build upon that and expand our investor base.

Skyler Gary: I do think, too, the switch from our royalty strategy, which was quite successful, to running an operating business was by virtue of that flexibility we had at that point. We always wanted to work towards being in the position we're in now. And that's one of the most exciting pieces of getting a deal done with Coterra. We have a great investor group and we're really well-positioned to keep doing what we do best, which is putting acres together and drilling good wells.

DD: I wanted to follow up on your investors. Family offices have been very engaged of late. Are they part of your core, or what is the composition of your investor group?
JN: We kind of have the full spectrum of capital sources. I guess we don't have any endowments, but institutional sources, family office, multifamily offices–it's a diverse group.

DD: We've been writing about large private equity fund closings and while it's still not easy, bigger funds have had some success. At least, it's certainly better than it was a few years ago. Is that the case that you're finding, especially in the Permian, where there's a lot that has been bought up?

JN: I think the landscape, while it's gotten easier, is still challenging. It's still an asset class that [has] a differentiated level of scrutiny on the allocation side. But in terms of our track record and experience and fundraising, I think we have a good track record of execution, both putting capital to work and returning it back to investors. That makes life a lot easier. We've done a good job of getting into positions and executing on strategies quickly and then also recognizing when there are windows to exit.

We've done that twice now, with the second time being the Coterra trade. And I think our investors really appreciate the mindfulness and the wherewithal we have around market conditions and ability to exit.

DD: Avant formally started in 2019, so that's two raises and two exits in a period of less than five years, much of which included COVID. How did you manage to pull that off when a lot of folks really struggled during the COVID years?
SG: We've been able to put together a really effective group. It's a pretty young firm and we have a strong culture of hungry young folks who just push really hard. At the end of the day, it is very difficult to aggregate and, at some point, you have to just get a lot of shots on goal and keep pushing. There'll be slow months and then there'll be great months. But we feel like we've never been better at this at any point in our history than we are right now.

JN: I think we do a good job at identifying either soft points in the market that might be within a basin in a certain geographical area, or just soft times in the market from a cyclical nature. And we've really tried to push as much capital out the door to execute when we see those types of opportunities. The obvious one with our royalty strategy was during COVID and no one else was buying; that gave us a leg up, being well-capitalized during that stretch, with folks that trusted our judgment on putting that money to work.

Most recently, with our New Mexico strategy, we were just seeing the world a little bit differently than folks had in the past in terms of the area in which we were deploying our capital. We believed in the rock, in the well results.

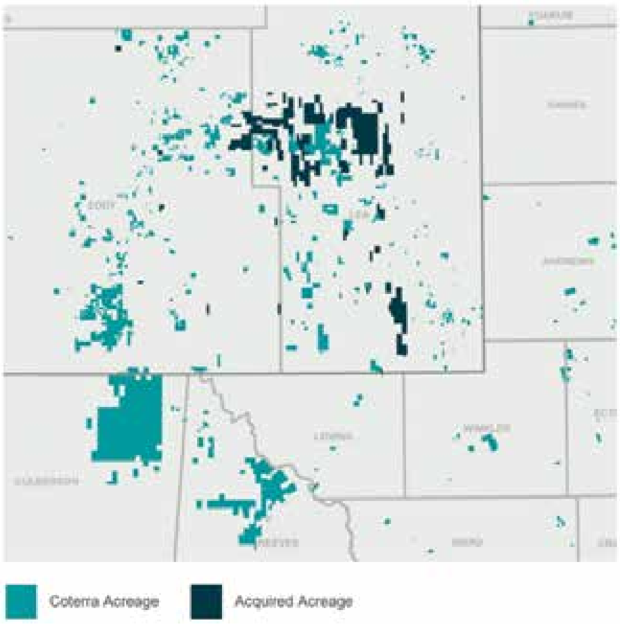
I think the bigger companies weren't paying enough attention just because they had a lot to chew on in other parts of the basin. And all the corporate M&A, the consolidation going on, kind of left them distracted from the day-to-day ground game. We saw an opportunity to execute and we did. It's really just a multitude of factors. There's not one secret ingredient. And as Skylar mentioned, I think it's the hard work that everyone puts in across the whole team.

DD: We've been through 18 months, two years of consolidation. Conventional wisdom says that's going to create A&D opportunities as these companies sell off non-core assets. Is that an opportunity set specifically for you to continue to focus on the Permian?

SG: I think that'll be one piece of the puzzle that we look for in terms of putting capital to work. The reality is there are a lot of other teams that are banking their strategy on being competitive from A&D processes that are marketed broadly.

While we've been successful in a couple circumstances there, to us that's not a strategy that we really want to build our company around. We're going to stick heavily to our roots, which is the ground game consolidation. And what we tend to find and what we found in this last one was, there's always opportunity. If you look diligently and look hard, it might not be as obvious and it might not look as traditional in terms of this giant block of acreage in the core of the basin, but at the same time, one drilling unit, you can put $100 million, $200 million to work through the drill bit and that's a lot of capital, especially given our size.

Coterra Acreage



SOURCE: COTERRA

Coterra is coring up its Delaware Basin position with acquisitions from Avant Natural Resources and Franklin Mountain Energy.

We don't need 20,000 acres—that's a giant block to be successful. It only needs to start with one and then we'll start looking at the second, third and so on and so forth.

DD: The assets you'd amassed in New Mexico were included in the Coterra deal, right?

JN: We love working and operating on the Texas side. Frankly, we had kind of a three-pronged strategy in terms of areas we wanted to deploy capital in the Delaware. This spot in New Mexico just was an area in which we felt like we could deploy the quickest and most effectively. But we still like a couple other spots on the Texas side and intend to revisit those as part of our next strategy.

DD: You'll remain Permian-focused?

JN: Yes, absolutely. It's been good to us and we enjoy working in that region. We know a lot of the folks and it's a great universe of operators and counterparties and competitors and peers, and we look forward to hopefully working in that basin for many, many years.

DD: Let's pop back over to something that Skyler was talking about earlier—switching from a minerals and royalties focus to where you are today. That's sort of counter to the industry trend in which it appears that minerals and royalties has really heated up in the last year or so.

SG: We were trying to be intentional about how we grew this platform and how we built our track record. Jacob and I were quite young when we started this company. At the time, we felt like minerals and royalties in the Midland Basin were maybe a bit undervalued relative to other opportunities we're looking at. And it seemed like the right time for us to push towards that strategy. And we were quite effective putting together a really nice position there.

We felt similarly when we were kind of wrapping that up that there was an interesting opportunity to push into the Delaware Basin on the operated side. There was some regulatory uncertainty, given politics at the time. So, we were just trying to be opportunistic and make the right business decision. I think a lot of our peers and perhaps even some of our investors expected us to do a bigger royalty-focused fund to follow up on the success we had, but we felt like it made a lot of sense to pivot into what we viewed as maybe a better opportunity to buy effective on the ground by working interest in the Delaware.

We like to make sure that we're paying close attention to everything that's happening and try to anticipate changes perhaps a bit early, earlier than the industry. And so, at the time it made a ton of sense and I think our perspective at that point has been validated since then. We were effective again, putting land together to go operate.

I think also one of the most exciting pieces about that pivot was that we started a very small operating company at a time when I think the perception was that it was turning into a game that was largely dominated by very large operators. We wanted to make sure that we could prove to our investors that we could be an effective low-cost operator, and we were very successful drilling wells right out of the gate. We had some really fantastic well results and that allowed us to accelerate the growth of that business. An interesting part of the pivot was making sure that we could be effective and maintain the level of excellence we expected from our group drilling wells, not just buying acreage. And the team did an incredible job. So, a big part of the story, I think, was the operational success that we had, and we wanted to go prove that we could do that. I think we've proven that now.

DD: Your focus will continue to be acquiring working assets as opposed to non-op deals?

JN: That's right. We'll be focused on putting together an operated position in the Permian. Sometimes that's by acquiring a bunch of non-operated [assets] and doing some trades or getting creative with deal structures to get your way into some of these units. But our intent is certainly to stay on the operated side.

DD: How long will it take to put together a new set of assets for Avant?

JN: We started this last iteration, it really got going at the beginning of 2023, and we had a five-year plan to put together about 4,000 acres. We got to 17,000 within two years.

Look, there's no question that it continues to get more competitive out there. We feel like we have a good team, our track record is really strong on aggregation, so we're hopeful we'll have a rig up in pretty short order

DD: By the end of the year?

JN: That'd be the hope. New Mexico certainly gets a little tricky with the regulatory and pooling and permitting timelines, but I wouldn't be surprised if we had a breakup by the end of the year on the new assets.

DD: What is your end game? Will you keep doing this process of buying assets, fixing them up and then selling? Or are you planning to become the next mega independent?

JN: I think I'll steal one of Skyler's lines so he can think of something else to say, but I think we've never been better at what we're doing than right now, so it'd be almost a crime to stop. Our team's really effective at this stage. We've built in a lot of really good structures and protocols and tactics, and everyone's learned a lot. We've made some mistakes, no doubt, but we've learned a lot from those. And so, we feel like we're really hitting stride on the aggregation game and also operationally, so we're going to keep going. It's too much fun. We feel like we're doing a good job with it, and our investors are incredibly supportive. So, I think we're certainly laser-focused on this next iteration. Haven't given too much thought about what comes after that, but as Skylar mentioned, we're all pretty young and want to be in this business for our careers.

SG: The only thing I would really add is that Jacob and I just love the oil and gas business. We have a team that loves the oil and gas business. We're all pretty close over here and when we hang out with each other, we're having beers talking about oil and gas deals. It's been really fun. So, plenty of horsepower and ambition on the team. I think everybody's really enjoying it right now. I also think we've been really well served, being kind of agnostic about what our end goal was as long as it was a success for our investors.

We're not married to the idea of empire building, but if we think getting bigger is important for us to deliver the types of returns our investors expect, we can do that. If we see an opportunity to put a big win up on the board that's a really short timeframe like what we did in this round, then we'll decide that perhaps that's the right strategy and that's what we'll do. At the end of the day, if we do right by the capital partners that have supported us to this point, we know we'll be able to just do another company. We're always just going to focus on what the market dictates and make sure that we're delivering the best result for our capital group.

Petrie Partners Offers the Private Equity Perspective

Applying veteran wisdom to the oil and gas finance landscape, trends for 2025 begin to emerge.

DEON DAUGHERTY
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Mike Bock, co-founder of Petrie Partners, shares his perspective on how deals will be made in oil and gas this year in an exclusive interview with Oil and Gas Investor.

Deon Daugherty: What do you expect to emerge as the top trends for energy finance in the short-term and then across 2025?

Mike Bock: There have been a lot of changes in the macro, or at least, there are going to be changes in the macro, with a change in administration. [President Donald Trump] has the ambition to get things rolling as soon as possible. Chris Wright (nominated as energy secretary) is someone we know in Denver and expect to do great things dealing with policy. But those things take a while.

The trends are still challenging on the equity side. We saw a decline in private equity on offers for new or smaller private companies. At the same time, we saw a narrowing window for public companies as well to tap equity capital … to position for better free cash flow and economies of scale and better efficiency.

I think it is still challenging in the public market around equity capital. There is a little more optimism about realizations and a few things around the margins are helpful, but for straight equity [deals], there are still some challenges.

BKV [Corp.]'s IPO, if you look at that deal, they had a lot to offer investors. For example, their carbon sequestration business opened up their offering to investors that were outside the pure upstream space.

We've seen some financing innovations to slice and dice access to financing—it's a very capital-intensive business—over the years and that may continue. In drilling JVs, we had a client that was looking at equity and the next option was to scale down to a non-op piece of assets and raise some cash, then raise some equity and continue to operate a smaller piece that will be replenished by a sell-down with a partner to front costs of the drilling. It's a shrink-to-be-better approach, and that's capital that's available.

There are two distinct ways of having a drilling JV. One is, a strategic player takes a non-op interest in the assets and they'll maybe carry you on some portion of drilling, paying a third for quarter or 100% for a three-quarter interest. Operators benefit from that structure because they are paying off interest. That's perpetual—they can keep that investor forever.

Then there is a finite structure—not forever, it's just a return—they'll pay 80% for 70% and when they achieve their return, it reduces their interest in the asset; or they pay 100% for 90%, then achieve greater invested rate or return on investment, and then they'll revert to a quarter on assets or something like that.

We've seen both types of deals, and that will probably continue.

The other trend we've seen is a switch in the private equity space. Because of the pullback in private equity, some funds didn't continue or failed. We've seen some successes with EnCap [Investments] and Quantum [Capital Group], and some were excellent like Carnelian [Energy Capital] and Post Oak [Energy Capital], but a big segment of the private equity space didn't survive.

Private equity funds still exist, but some are managing down investments that are long in tooth and maybe are not in the greatest market to liquidate. We're seeing continuation vehicles activity. If you look at the capital for that side of that business, it's kind of industry agnostic, but there is a lot of demand for secondary funds that deploy capital in this way.

We're working on one now with some of the folks who are interested. Two years ago, [the market] was a half-billion [dollar market]. Then six months ago, it was $1 billion, then it'll be $2 billion, so there's a lot of demand from LPs for those secondary funds to invest in opportunities.

PETRIE PARTNERS

"Assets are moving down the food chain and I think for those assets to land in the right homes, there has to be more equity formation among smaller private companies and innovation to make those tired old assets work better."

MIKE BOCK, co-founder, Petrie Partners

Energy has become a focus because of stranded portfolio companies. That trend will continue.

Some portfolios got healthier and there is still a decent demand that will break loose some of those opportunities. Some equity that is restructuring some stranded portfolio companies in the private equity space across 2025, too.

DD: What is the status of energy companies' access to capital this year? Will public markets be more receptive, especially to upstream and infrastructure financing?
MB: I think in upstream, it's still going to be a struggle. It's gotten to a point where energy is a small enough piece of the market picture as a part of the S&P 500 that generalist portfolio managers don't spend a lot of time there. They'll pick a few stocks here and there, and I don't see it getting a lot better this year.

On the infrastructure end, it's a different story. Given the risks and rewards of that business, there are a lot of funds out there. Investors like infrastructure, the lower return but also lower risk. Like in the secondaries space, it's a lot of capital and rolls on to demand; energy is a good candidate for infrastructure investing.

Venture Global coming to the [IPO] market—that's a huge infrastructure play—and I think it looks better for infrastructure financing.

As we ramp up and consider all means of export at our disposal, there's a lot of opportunities for infrastructure that laps over to the energy transition space with carbon sequestration, carbon capture. I think that's an area where there's projects and capital available.

DD: Which particular basins or regions are most interesting to investors in oil and gas?
MB: Many are basin agnostic. But I think from an overall perspective, the Permian continues to be a focus for investors. This consolidation wave has been pretty Permian-focused. Diamondback [Energy] built a large business just making acquisitions in the Permian, and I think that's still the case [going forward]. We're also seeing development in the Uinta, a lot of transactions activity. So, there's going to be a point where people have to look outside of the Permian, but we're not there yet.

DD: What are the challenges this year for companies that require outside finance, whether through public or private investment?
MB: I'm really interested in seeing what we've got with a more relaxed regulatory environment, greater access to property and potentially more incentive to develop offshore in the U.S.

I'm interested in seeing how that coincides with the trend of last five years of public companies saying they won't not grow for growth's sake. If everyone goes all-in on drilling, that will significantly lower prices and it doesn't square with promises to shareholders to be really disciplined. I think there is the ambition to do one thing, but I think the market will be the decider, and capital formation is a part of that.

If prices drop, free cash flow diminishes, and the drilling pace diminishes. But I'm interested to see play out with the promises made around capital discipline.

DD: How do you expect available capital to differ this year compared to 2024?
MB: Another trend—not a new one, but it's building momentum—we've seen some ambition to acquire PDP assets and then refinance using asset-backed securities given the interest rate arbitrage. We've seen PDP not fetch as much as they have historically with discounts in the mid- to high teens, whereas in the past, it was low double digits to low teens.

DD: Where is capital needed the most?
MB: There are big projects and there are a lot of incentives to develop them; I think it's needed the most in the upstream because that's where it's lacking. You'll see more consolidation for better economies of scale, but I think broadly, the next wave is through divestiture.

Not all of these assets belong together, and [companies] will be looking to divest. We've seen major companies with big mergers so we should see that happen in reverse….. Assets are moving down the food chain and I think for those assets to land in the right homes, there has to be more equity formation among smaller private companies and innovation to make those tired old assets work better. I think that's where it's needed the most; that's where it's less available, too.

DD: Do you expect to see new small E&Ps come together?
MB: I hope so. There are a lot of good management teams that have had several successes and they'll be capital partners.

It's not over for energy investing, given the lack of supply of capital, and you can drive really good bargains, so I think some hope there they'll partly fund another generation of private companies that build assets from acquisition and exploit that and fund a market for the production ultimately. That's how we're hoping it plays out. OGI

To Be Continued

Continuation funds help solve private equity's exit challenge.

MARK DRUSKOFF
CONTRIBUTING EDITOR

Huge sums of private capital have been invested onshore since the beginning of the shale boom. Since 2015, $327 billion has been invested in 1,844 deals across all segments of the U.S. oil and gas sector, according to analyst reports. Nearly two-thirds of that total was deployed from 2015 to 2019.

While the volume of activity has been strong, the data point on timing is the most telling. Typical private equity funds have a 10-year lifetime, with the possibility of a couple one-year extensions. That means the clock is running out on vast swaths of investments.

Limited partners who provided the capital for those deals fully expect private equity general partners to get their money back—and then some. The torrid pace of deal activity in recent years has certainly helped, but plenty of assets still remain out there.

So, what is private equity to do?

Arrows in the Quiver

There has been a generalized shift in the way private equity firms have structured exits for their portfolio companies, Robert Seber, partner in Vinson & Elkins' private equity practice, told *Oil and Gas Investor (OGI)*. Whereas M&A and IPOs were the predominant paths to exit in the past, a third option has rapidly emerged: continuation funds.

In their simplest concept, continuation funds are specialized funds created by private equity firms to extend the deadline for when a portfolio company needs to exit. They go by many names. They are also known as continuation vehicles, CVs in industry parlance, or, for those who favor arcane terms, general partner-led secondaries.

Whatever name they go by, continuation funds are clearly gaining momentum.

Seber said that continuation vehicles have eclipsed IPOs as a preferred exit strategy.

"Continuation funds have definitely become a very accepted form of exit for private equity funds," he said.

It was not always the case.

Stellar Case Study

One of the first continuation funds to really grab attention in the oil and gas sector was a 2018 Lime Rock vehicle, Seber said.

"Everybody in the industry was looking at it and asking, 'How can we do this?'"

Lime Rock Partners IV AF Acquisition Fund closed in June 2018 at $1.9 billion. The lead outside investor was HarbourVest, but Lime Rock employees constituted the single largest investor in the fund. All limited partners had the option to reinvest in the acquisition fund or receive full or partial liquidity, the company said.

The CV acquired all the remaining assets from the 2006 vintage Lime Rock Partners IV. The majority of the asset value of that fund was a controlling interest in Midland-based CrownRock. The company had been formed in 2007 and, by 2018, had 90,000 operated acres in the core of the Midland Basin with 40,000 boe/d of production, the firm said.

In 2021, Lime Rock closed a separate $203 million continuation fund to acquire assets connected to CrownRock Minerals from Lime Rock Partners VI, a 2013 vintage fund. Goldman Sachs was a major investor in the continuation fund.

The continuation fund strategy paid off handsomely in August when CrownRock completed its sale to Occidental for $12.4 billion—17 years after the initial investment. In the intervening years, the company had increased its production to 170,000 boe/d.

Lime Rock grossed 79 times its $96.5 million investment in CrownRock, making it one of the highest returning investments, not just in the natural resources space, but across any private equity segment. CF Private Equity, formerly known as Commonfund Capital, was one of the limited partners investing alongside HarbourVest Partners in the 2018 continuation fund, according to the company.

Investor Perspective

A major driver of continuation fund decisions is the strategy of its limited partners, John Grand, partner in private equity and M&A at Vinson & Elkins, told *OGI*. LPs exert pressure on private equity firms to return their capital, he said.

Existing LPs already invested in a portfolio company have a separate and distinct point of view compared to LPs seeking to invest through a continuation fund, Seber said. Existing LPs have "not been too fond" of CVs and have started to "tighten the screws" on procedures surrounding continuation deals.

Part of the reason stems from the concern by existing LPs that assets put into a continuation fund are sold at discount to attract new investors, Seber said. The percentage of existing LPs that rollover to the continuation fund is "relatively low," he noted.

To address these concerns, the Institutional Limited Partners Association has put out guidelines on continuation funds, said Seber. Limited partners have begun negotiating terms related to potential future continuation vehicles at the fund formation stage, such as requirements to explain the rationale for a possible CV or ensuring processes are being undertaken to maximize value, he said.

On the flip side of the coin, however, limited partners in the continuation funds themselves see the vehicles as attractive opportunities. Although private equity fundraising has generally been down, continuation fund formation has been "booming," Seber said.

Relative to other sectors, investor interest in oil and gas continuation funds has been somewhat delayed, he said. He attributed that delay to ESG, which has generally dampened the appetite for such investments. As the ESG movement has slowed down, Seber said there's greater interest from investors in the oil and gas sector, enabling continuation funds.

Most of the interest has been in the upstream space, likely because the opportunities are larger, he said.

Multiple Considerations

While Lime Rock appears to be an outstanding example of what continuation funds can achieve, the vehicles present a multifaceted set of issues to overcome.

CVs fall into two distinct types, said Vinson & Elkins' Grand. The first bucket includes portfolio assets where private equity sees "real upside" but the fund is reaching the end of its life. The continuation fund provides more runway to reach full potential valuation.

The second bucket includes assets located in basins that have fallen out of favor and require more time to become attractive to investors again, Grand said.

Deal activity, driven by public companies, has been heavily weighted toward the Tier 1 acreage in the Permian, he noted. The thinking is that it will take many years for that acreage to be built out, but when that happens, publics will turn to Tier 2 opportunities. A CV can give a portfolio company the time and space to see that investment thesis to its conclusion.

Quantum Capital was seeking a $1.6 billion continuation fund to buy out its stake in Appalachian-focused HG Energy at an enterprise value of $1.9 billion, according to a March 2024 report. Elliott Investment Management reportedly committed more than $500 million to the CV and was joined by private equity firm Andros Capital Partners, the company said.

In 2023, Andros Capital closed Andros Energy Capital II at a $750 million hard cap. The new fund would target $100 million to $500 million middle-market transactions and would maintain a "completely flexible and opportunistic investment mandate."

Another consideration is whether a private equity sponsor is looking to exit a single asset or an entire portfolio, Seber said. Finding a buyer for a portfolio of assets may be more challenging. In this instance, continuation fund represents the best option.

Continuation funds are formed with either a single asset- or multi-asset focus. In the first half of 2024, 64% of all continuation funds had a single-asset focus, according to a report by Jefferies.

In December, Warburg Pincus announced a $2.2 billion multi-asset continuation fund with backing from HarbourVest Partners, France-based Ardian and Canada Pension Plan Investment Board (CPPIB). CPPIB has been an active investor in the oil and gas space, and HarbourVest was lead investor in Lime Rock's successful continuation vehicle.

Private equity firms are not being forced into continuation funds but actually elect them, Seber noted. Continuation funds enable PE firms to retain assets under management, he said, which is important in a fee-driven business. OGI

▸ A GROWING TREND

Continuation funds have been growing in number and scale across the private equity sector globally. Private equity breaks down into two types of investments: primary and secondary.

Primary investments involve direct investment in a portfolio company by a general partner (GP), the private equity firm, using capital provided by limited partners (LPs) through the purchase of equity or credit. Secondary deals, however, involve the reselling of that primary investment by either the GP or LP.

The private equity secondary market has been steadily growing. Since 2018, global secondary volume has risen from $74 billion across all sectors to a projected $140 billion for 2024, according to Jefferies.

Relative to the primary, however, the secondaries market is not large. Bain Capital notes that secondaries pale in comparison to the full scale of the private equity market, which it estimates to hold $20 trillion in assets under management globally.

Historically, LPs have tapped the secondary market to sell off stakes held in various funds. Such transactions are called LP-led secondaries. What has changed is that GPs are increasingly utilizing the secondaries market to create liquidity for their investors, which are known as GP-led secondaries.

GP-led secondaries grew 56% year-over-year between the first half of 2023 and the first half of 2024, the Jefferies report showed. Such deals represented 41% of all secondary deal volume in the first half of 2024. Continuation funds make up the primary strategy utilized in GP-led secondaries, reaching 90% of all such deals in the first half of 2024. Continuation funds now constitute 14% of global private equity sponsor-backed exit volume.

▸ INVESTORS RESPOND

The Institutional Limited Partners Association has nearly 600 members representing more than $2 trillion of private equity assets under management. The association's guidelines related to continuation funds point out the flexibility provided by the structure to private equity firms, but also that continuation funds "are conflicted by nature, with the GP sitting on both sides of the transaction." Additionally, continuation vehicles require LPs to make investment decisions about individual assets rather than PE funds or managers, sometimes under short timeframes.

The guidelines suggest that general principles regarding continuation funds are that they should maximize value for existing LPs. Limited partners rolling over into the continuation fund should be no worse off than if a transaction had occurred. LPs should have no less than 30 calendar days or 20 business days to make a rollover or sell decision.

Additionally, the private equity firm should present a rationale for a continuation fund transaction and should have already explored alternative options for the asset being considered.

A competitive process should be undertaken to ensure a fair price was obtained and the process should include a third-party validation. An experienced adviser should be selected by the private equity firm. The limited partners should review the adviser selection and have access to the adviser throughout the process.

▸ NON-UPSTREAM CVS

Within the upstream space, Lime Rock and Quantum Capital have both raised sizable continuation funds. But the trend extends to other segments, including midstream and oilfield services.

In January 2023, ArcLight Capital Partners announced the close of ArcLight 3C SPV with $407 million in capital commitments. The fund acquired a 25.1% interest in Third Coast from ArcLight's Fund V. Third Coast is a U.S. Gulf Coast and Gulf of Mexico midstream infrastructure asset focused on serving eastern deepwater and shallow water Gulf of Mexico producers.

In September 2023, GEC announced completion of a $215 million single asset continuation fund focused on its portfolio company Estis Compression Solutions. The company is a high-pressure gas lift company acquired by GEC in 2019. Kline Hill Partners was the lead on the continuation fund.

In September, Amberjack Capital Partners formed a $200 million multi-asset continuation vehicle for eight assets from two legacy funds. BlackRock, Banner Ridge, LSV Advisors and Goldman Sachs were co-lead investors in the continuation fund.

Kissler: Can U.S. Produce Enough Oil for the '3-3-3' Plan?

Producing an extra 3 MMbbl/d is easier said than done.

DENNIS KISSLER
BOK FINANCIAL SECURITIES

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

President Donald Trump's pick for Treasury secretary, Scott Bessent, has proposed a three-pronged economic plan that involves increasing economic growth to 3%, cutting the budget deficit to 3% of gross domestic product (GDP) and increasing U.S. energy production by 3 MMbbl/d.

The last point sounds like good news for the U.S. oil industry; however, before anyone celebrates, there are overarching questions to consider: Can oil production be increased by that level and what are the challenges of doing so?

Running Out of 'Good Rocks?'

Many Americans have an antiquated view of oil and gas: They think that these commodities are not only abundant now but also that they will always be reliable, easy to tap into and inexpensive. However, we in the energy industry know that this is not the case.

Yes, the U.S. is the biggest oil producer in the world today, churning out about 13 MMbbl/d, but that doesn't mean that the supply is limitless or, moreover, that it would be advantageous for oil producers to increase production by the level proposed. After all, there's a lot of risk in the energy business and a lot of capital that must be spent to increase production, while at the same time the inflow of outside money that we saw five to eight years ago is no longer there.

For instance, many people don't realize the amount of depletion (life of a productive well)—particularly in the Permian Basin, which accounts for approximately 40% of U.S. oil production. To put it simply, we're running out of good rock formations—the "low-hanging fruit" of hitting long lateral wells.

As oil producers move west toward New Mexico, they're still hitting some of these longer lakes, but their depletion rates are much sharper than what we've seen in the past. For these reasons, some in the oil industry believe that most of the major production out of the Permian has already been achieved. Wells are no longer going to come online and produce for 30 or 40 years economically like they did in the past. In my opinion, if the Permian is not at peak production now, it's very close to it. When that happens, oil production levels can only go down from there.

Restrictions and Price Points

As a result, oil producers likely will have to start looking at other places to drill in the future, such as in the Gulf of Mexico and Alaska, especially if the U.S. is to produce an additional 3 MMbbl/d. When that happens, there will be an entirely different price point to produce crude, and that's another factor that many people in the U.S. don't realize.

Moreover, before leaving office in January, former President Joe Biden banned future oil and natural gas leasing in the entire U.S. East Coast, the eastern Gulf of Mexico, the Pacific off the coasts of Washington, Oregon and California, and additional portions of the Northern Bering Sea in Alaska—a total of more than 625 million acres.

Those restrictions likely can't be reversed immediately. Furthermore, from what I understand, some of the areas that are already leased in the Gulf may have some protected drilling areas that can be tapped. Nevertheless, these restrictions altogether stand in the face of a "drill, drill, drill" mentality and may hinder increasing production by the level proposed in the 3-3-3 plan.

In sum, it's not as easy as the new presidential administration simply reversing the decisions made by the past administration.

Where Will the Money Come From?

Finally, there's access to capital to consider. On one hand, many believe that there will be less regulation of the energy and financial services industries under the Trump administration, which should free up some capital for energy lending. On the other hand, that doesn't erase the fact that access to capital has become more expensive and more competitive in recent years. The number of financial institutions involved in energy market lending has shrunk significantly since the pandemic.

Meanwhile, oil companies have had to contend with greater expenses from both inflation and high interest rates. Although inflation has come down significantly from its peak, material costs are still high. (They're just not rising as quickly as they were before.)

The Fed has lowered interest rates somewhat, but rate-cut expectations for this year have come down. Oil companies will continue to face these higher expenses amid a tighter lending landscape than they were accustomed to pre-pandemic.

In sum, the U.S. can "drill, drill, drill" all it wants, but you can't Trump the rocks—or capital constraints. Achieving a production rate of an additional 3 MMbbl/d is not impossible, but it may be easier said than done. OGI


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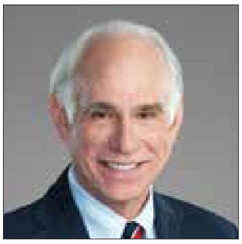
Hirs: Investing for 2025—Growth by Acquisition

Fundamentals will push against increased production and a buyers' market will rule.



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U.S. oil and gas investing in 2025 will be a mixed bag. Fundamentals including the political winds argue against drilling more wells, while these same fundamentals argue for a buyers' market for assets.

The negative fundamentals start with the WTI forward strip in backwardation with futures trading below $70/bbl. Next, more than 50% of respondents in the latest Dallas Fed Energy Survey will not make investments at less than $70/bbl. Third, the new year has started with the U.S. oil rig count down year-over-year despite the historically strong oil price. And the data point to rising breakevens for oil, especially in the Permian Basin, which is gassier by the day.

The last two years have not been kind to gas producers, with the Henry Hub averages and electricity price averages below $3/Mcf. Demand growth is expected but will not happen quickly. LNG export facilities under construction will help, but most are still years away from commissioning.

Data centers are driving new demand for onsite or behind-the-meter gas power plants, but in this instance, gas marketers will be more likely than producers to profit initially because the ability of U.S. gas producers to get to market is restricted by limited pipeline capacity exacerbated by very tight federal regulations.

U.S. oil and gas producers will face higher costs in 2025 from mass deportations, new tariffs and wastewater disposal even if recent Biden administration rules are reversed. Abandonment liabilities will continue to increase.

Political Headwinds

For the next four years, climate-driven federal political headwinds will lessen, but the energy transition is underway in electricity markets. It is hard to compete against suppliers that have virtually no operating costs. Solar farms will continue to expand while battery farms that use the simple model of buying low and selling high in the restructured electricity markets will continue to displace legacy generation assets.

For 2025, the global oil market is biased to scenarios that will bring lower oil prices back to the U.S. On the supply side, a ceasefire in the Russia-Ukraine war will bring pressure on the allies to relax oil market sanctions against Russia. Within OPEC, Saudi Arabia's shut-in capacity may be brought to market for one of two reasons: to punish OPEC members who have been cheating on quotas or as part of a geopolitical deal with the U.S.

On the demand side, China appears to have reached and passed the point of peak oil demand. While the U.S. has enacted 100% tariffs on China's electric vehicles, that tariff has zero impact on China's transition to EVs or the impact on the global oil market. China's slower economic growth is also a factor.

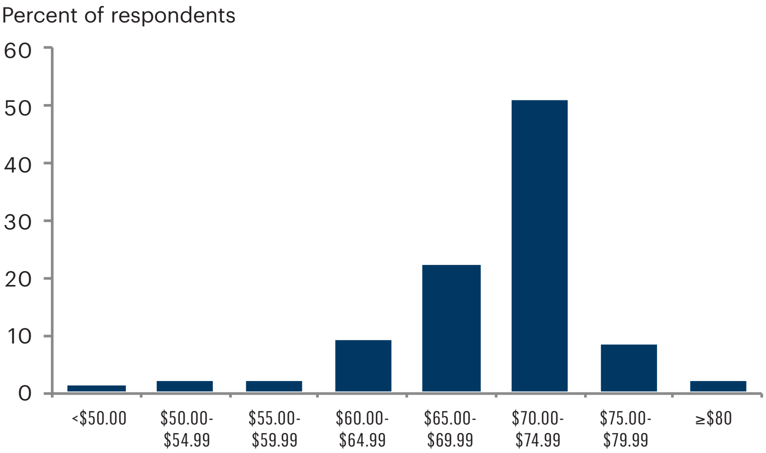
Market Opportunities

While oil and gas stock prices have rallied recently, they have not exceeded that of many market indexes. The buyers of public stocks are not investors *per se* but technical portfolio managers who are focused on the risk-return characteristics of all stocks and financial instruments.

When one stock deviates from market averages for risk and return, the portfolio manager will buy or sell depending on the arbitrage that is available. Consequently, oil and gas stock prices have been lifted more by the broader stock market expansion than they have by the industry's investment fundamentals.

The prospect of lower oil prices, stable natural gas prices and continued lower interest rates argue in favor of lower valuations for oil and gas assets, both public and private, for 2025. Public markets will continue to see non-cash acquisitions, with some public companies exiting by going private. The year 2025 will be a year for buyers—growth by acquisition will dominate growth by the drill bit. OGI

What West Texas Intermediate Crude Oil Price is Your Firm Using for Capital Planning in 2025?



NOTES: EXECUTIVES FROM 129 OIL AND GAS FIRMS ANSWERED THIS QUESTION DURING THE SURVEY COLLECTION PERIOD, DEC. 11–19, 2024. THE AVERAGE RESPONSE WAS $68 PER BARREL.
SOURCE: FEDERAL RESERVE BANK OF DALLAS.

Will Civitas Sell in the D-J, Buy in the Permian?

A sale of its legacy Colorado position could bring in $4 billion; analysts say Double Eagle IV could be a target.

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Civitas Resources could potentially exit its Colorado position and acquire more Permian Basin assets, according to analysts and media reports.

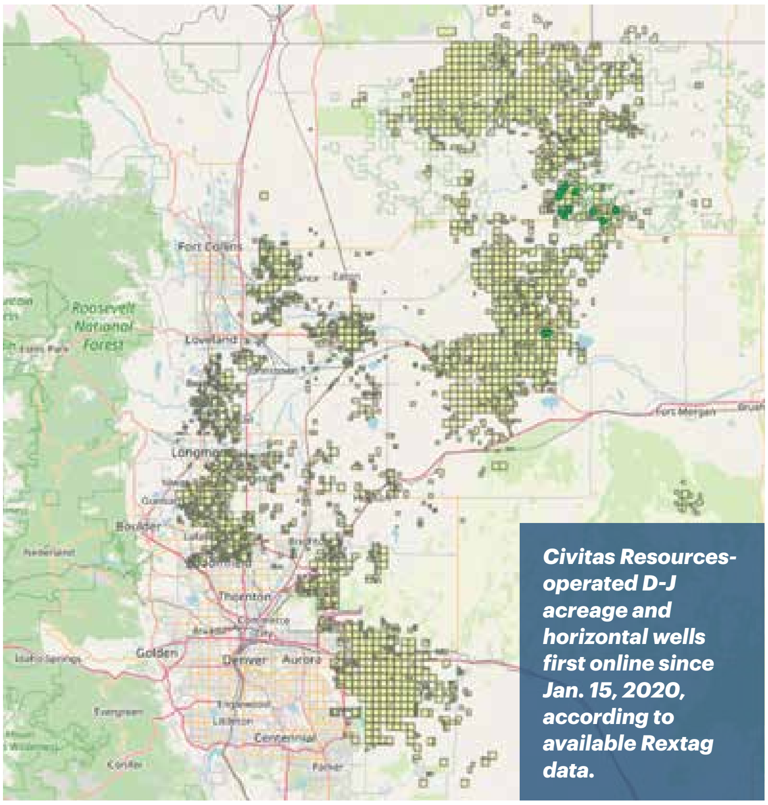
Civitas is reportedly exploring a sale of its legacy assets in Colorado's Denver-Julesburg (D-J) Basin. The Denver-based E&P has retained a financial adviser to assess buyer interest in the assets.

Civitas Resources did not immediately respond to a Hart Energy request for comment.

Civitas is reportedly open to selling all or only portions of its D-J Basin portfolio. Production from Civitas' D-J Basin assets averaged around 160,000 boe/d (70,674 bbl/d oil) during third-quarter 2024.

Civitas' Colorado assets could potentially fetch about $4 billion. Analysts at TD Cowen said the $4 billion headline price tag would screen as a proved developed producing (PDP)-only transaction, with little if any value placed on undeveloped drilling locations.

Civitas Operations in the D-J Basin



Civitas Resources-operated D-J acreage and horizontal wells first online since Jan. 15, 2020, according to available Rextag data.

NOTE: ACREAGE MAY DISPLAY NON-OP INTERESTS.
SOURCE: REXTAG

Given regulatory concerns within Colorado and the relatively short inventory life of Civitas' D-J assets, a PDP-only deal "makes sense in our view," TD Cowen analyst Gabe Daoud Jr. wrote in a Jan. 15 report.

Taking the proceeds from a D-J Basin exit, Civitas could try to acquire Double Eagle IV–one of the most coveted private E&Ps remaining in the Permian's Midland Basin.

Acquiring Double Eagle IV would make sense for Civitas, given their overlapping acreage in the Midland Basin, Daoud said.

But buying Double Eagle would come with risks, including a high asking price and only around 424 drilling locations, according to TD Cowen estimates.

Analysts had previously questioned whether Ovintiv, which has been more Permian-focused lately, might make a run at acquiring Double Eagle.

But Ovintiv ultimately turned its attention north to its legacy roots in Canada, acquiring Montney Shale assets from Paramount Resources for US$2.38 billion (CA$3.33 billion) in cash.

Ovintiv is also selling its Uinta Basin assets in Utah to privately held FourPoint Resources. The transaction is expected to close in the first quarter.

Rocky Mountain High

Civitas was created in 2021 through a combination of three Colorado pure-play producers: Bonanza Creek Energy, Extraction Oil & Gas and Crestone Peak.

But the need for additional inventory outside of Colorado drove Civitas to spend nearly $7 billion on Permian Basin M&A in 2023.

Civitas acquired private equity-backed producers Hibernia Energy III in the Midland Basin for $2.2 billion and Tap Rock Resources in the Delaware Basin for $2.5 billion.

In October 2023, Civitas followed on with a $2 billion acquisition of Vencer Energy, a Midland Basin E&P backed by international commodities trading house Vitol.

Since entering the Permian, Civitas has focused on optimizing costs and drilling efficiently in the D-J Basin.

Civitas is drilling some of the longest laterals in the D-J, including several 4-mile wells that began production last summer, CFO Treasurer Marianella Foschi reported at the 2024 EnerCom Denver conference. OGI

Amplify Adds D-J, Powder River Assets

The combination with companies in Juniper Capital's portfolio will bolster its Rockies presence by 287,000 acres.

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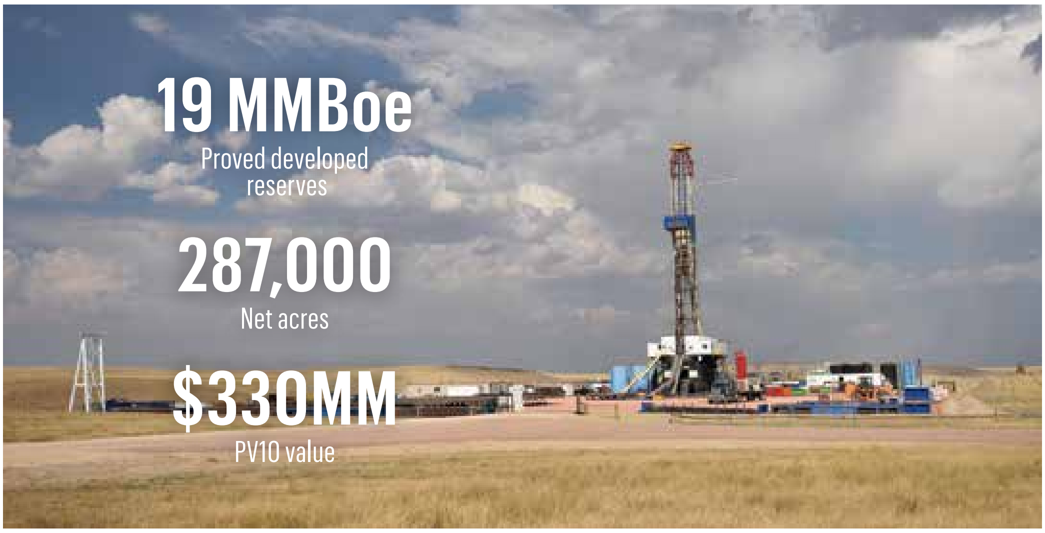

SHUTTERSTOCK

Exploration drilling rig in the Powder River basin. Amplify Energy has identified target formations near properties held by large operators which include the Codell Formation in the D-J and the Parkman, Turner, Niobrara and Mowry in the Powder River.

Amplify Energy will combine with certain privately-held Juniper Capital portfolio companies, adding complementary oil-weighted producing assets and leasehold interests in the Denver-Julesburg (D-J) and Powder River basins to its portfolio, the company said in mid-January.

As part of the agreement, Houston-based Amplify will issue approximately 26.7 million shares of its stock to Juniper at 1 cent per share and assume approximately $133 million in debt. Juniper shareholders will own 39% of the combined company and Amplify shareholders will retain 61%.

The deal increases Amplify's scale in the Rockies, adding approximately 19 MMBoe of proved developed resources with a PV10 value of $330 million. It includes 287,000 net acres in the D-J and Powder River, with over 115,000 net acres operated and held-by-production.

Average daily production of the assets in third-quarter 2024 was 7,900 net boe (81% oil, 90% liquids).

"This transaction adds a new oil-rich area with significant current production and substantial upside to the company's asset base," said Amplify President and CEO Martyn Willsher in the press release. "Juniper's assets in the Rockies complement Amplify's ongoing development of our Beta Field and our strong cash flow from our legacy onshore assets."

Amplify has identified target formations near properties held by large operators such as EOG Resources, Devon Energy and Occidental Petroleum, which include the Codell Formation in the D-J and the Parkman, Turner, Niobrara and Mowry in the Powder River.

"The combination of our Rockies assets with Amplify's existing operations creates a differentiated public company with strong cash flow and deep inventory," said Edward Geiser, Juniper's managing partner. "The combined company will have the flexibility to grow organically within its existing asset base and to pursue strategic consolidation in highly economic areas where few other large companies are currently focused."

As part of the transaction agreements, two of Amplify's board members will be replaced by Geiser and Josh Schmidt, Juniper's partner and COO.

Houlihan Lokey Capital served as Amplify's financial adviser for this transaction and Kirkland & Ellis served as Amplify's legal advisers. Wells Fargo served as Juniper's financial adviser and Gibson, Dunn & Crutcher served as Juniper's legal advisers.

A Polar LNG Express

The next major natural gas export project has a location advantage with Asian markets.

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North American natural gas producers spent most of 2024 hanging on for better times and higher prices.

Relief finally came in the last weeks of the year, when two major LNG export facilities on the Gulf Coast, Plaquemines and Corpus Christi Stage III, began production.

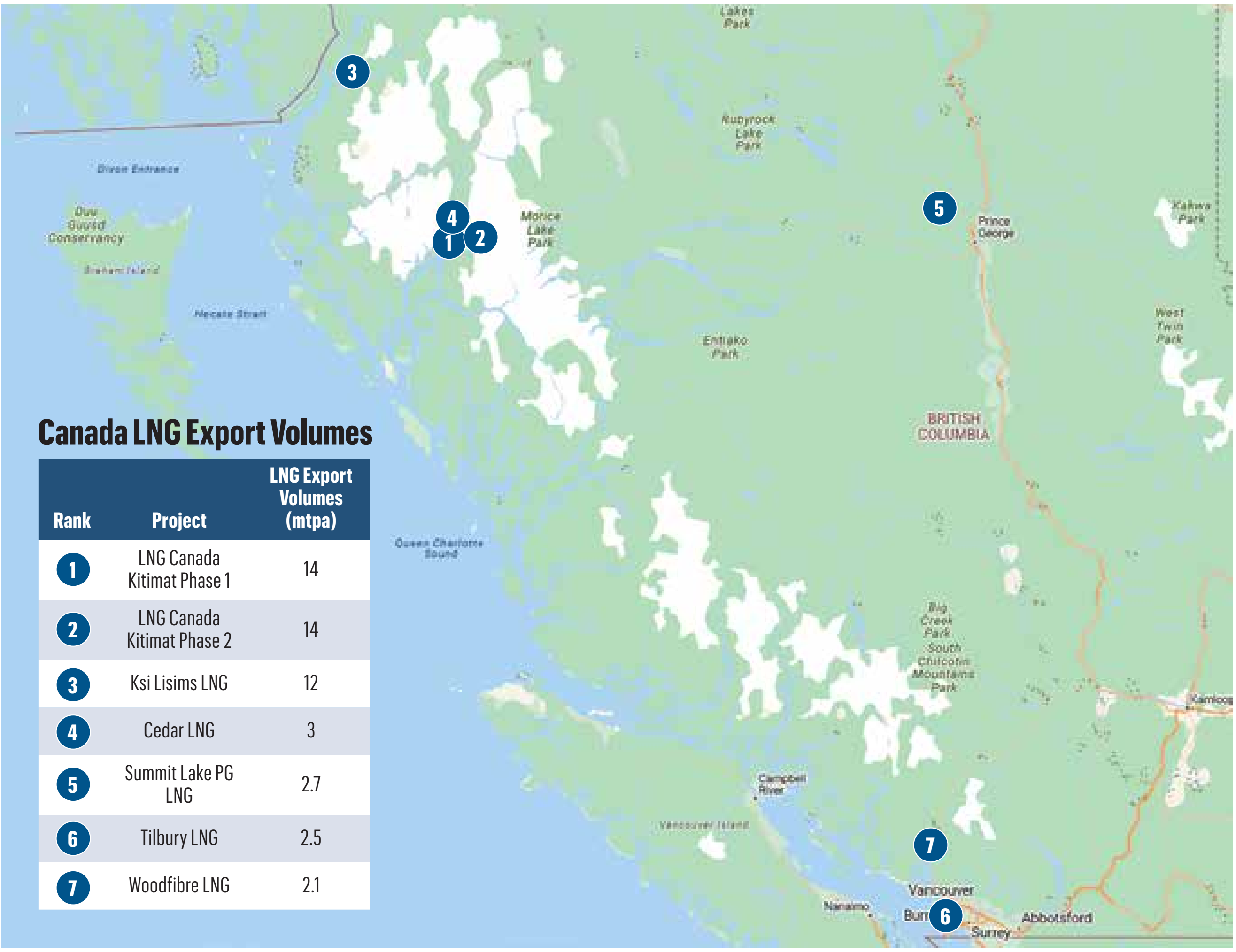
Plenty of LNG projects are still in the chute, but the next major project expected to come online is much farther north and west of the primary U.S. production zone–and will offer a considerably different alternative for potential international customers.

LNG Canada is expected to come online sometime in the middle of 2025. The facility, located on Canada's West Coast in Kitimat, British Columbia, is an international joint venture that will produce 14 million metric tonnes a year (mtpa) after its first construction age is complete.

The facility's opening will change the natural gas market dynamics in North America, at least for LNG. Cheap Canadian gas will have a major pull toward the country's West Coast as opposed to pipelines heading into the U.S. and a faster, easier trip to theoretically growing markets in Southeast Asia.

Same Story, Different Accent

The factors pushing for the development of a Canadian LNG export sector mirror the issues that led to an aggressive push for more export capacity in the U.S. The price differential between the countries, however,



Canada LNG Export Volumes

Rank	Project	LNG Export Volumes (mtpa)
1	LNG Canada Kitimat Phase 1	14
2	LNG Canada Kitimat Phase 2	14
3	Ksi Lisims LNG	12
4	Cedar LNG	3
5	Summit Lake PG LNG	2.7
6	Tilbury LNG	2.5
7	Woodfibre LNG	2.1

SOURCE: NATURAL RESOURCES CANADA, REXTAG, S&P GLOBAL COMMODITY INSIGHTS

LNG Canada, in Kitimat, British Columbia, will be Canada's first large-scale LNG export facility once complete, aiming for first exports by 2025. The majority of the other projects target beginning operations between 2027 and 2030.

TC Energy built the 416-mile Coastal GasLink pipeline to supply LNG Canada. The pipeline entered commercial service at the end of 2024.

LNG CANADA

shows U.S. dominance.

For the last two years, the U.S. natural gas market has been in the doldrums, thanks to overproduction, weak demand and record levels in storage. This is due, in part, to a couple of warm winters. Benchmark Henry Hub prices fell below $2/MMBtu for much of the spring in 2024, causing producers to cut production and delay the completion of some wells.

One reason for the overproduction? Producers in some basins were building their infrastructure in preparation for the opening of several LNG projects along the Gulf Coast.

The story has been repeated north of the border.

In September, Alberta Energy Co. (AECO) prices reached CA$0.05 (US$0.035) per MMBtu, a two-year low, Reuters reported. Thanks to warm weather and low continental demand, Canadian gas storage was practically full, and producers had cut production by about 750 MMcf/d, analysts at RBN said.

However, cold weather and anticipation of the oncoming LNG draw led many producers to bump up natural gas production again as the year closed. RBN analysts estimated Western Canada set a new production record on Dec. 25 of 19.38 Bcf. The AECO price midway through January had shown a corresponding improvement, up to CA$1.90/MMBtu, or US$1.32/MMBtu.

Canada's push to ready its natural gas market for the opening of its own LNG export terminal has, as a temporary side effect, benefitted U.S. natural gas customers, said Ian Heming, a natural gas analyst with East Daley Analytics.

"Especially with LNG Canada and other LNG projects coming up on that Pacific Coast, we've seen that producers in Canada are starting to position themselves for that—to make sure they've got that production already ready to go to answer the demand," Heming said.

"As a result, right now it's benefitting the U.S. in those lower AECO prices. So, any time we can bring anything in from Canada, that's the first lever we're trying to pull because those prices are so beneficial to us."

A study by Wood Mackenzie showed that in the first week of January, the U.S. imported an average of 9 Bcf/d of Canadian natural gas, up from 5.6 Bcf/d during the same time in 2024, Natural Gas Intelligence reported.

The prices may be a boon for U.S. customers, but Canadian producers are anxious for its new LNG facility to start up and bring long-awaited relief to the sector, the Canadian business journal Financial Post reported in November.

"We think the outlook for natural gas in Western Canada is probably the best since 2005," said Randy Ollenberger, an analyst at BMO Capital Markets, at a luncheon of oilfield service contractors in Calgary. "Because gas has really sucked since then, and we think it's going to be much better over the next couple of years here."

Northern Opening

Producers are excited because the new facility opens up a new LNG pathway to a growing market.

LNG Canada is an international joint venture led by Shell. The other partners in the business are a lineup of potential southeast Asia customers.

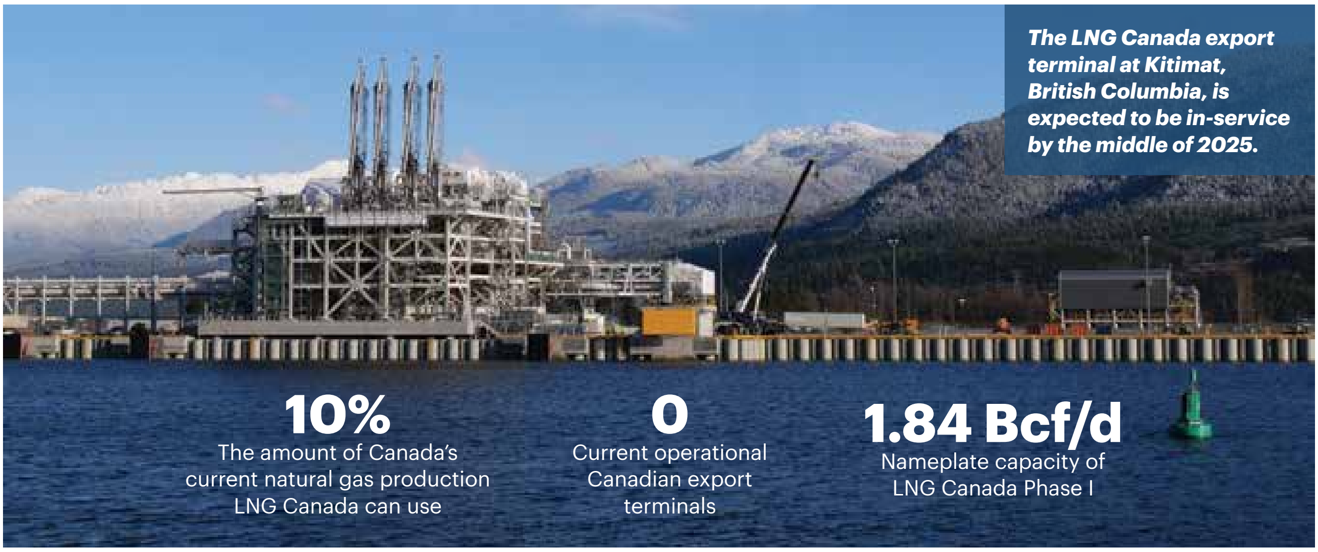
Shell owns 40% of the JV. Petronas, Malaysia's national oil and gas company, has a 25% stake. PetroChina owns 15%, Mitsubishi has 15% and Korea Gas Corp. owns 5%.

Wood Mackenzie forecast in December that Asian LNG demand would grow from 270 mtpa in 2024 to 510 mtpa in 2050. LNG is essential for a region trying to develop economically while attempting to wean itself off of coal, the analytical firm reported.

"Nations like Bangladesh, Vietnam, the Philippines, Indonesia and Malaysia will not be able to realize their plans to transition to gas-fired power if LNG prices are high and coal use, which hit record levels in both 2022 and 2023, will keep growing," the study said.

While the pricing levels are still to be determined, LNG Canada's British Columbia location does give it a distinct time advantage over current U.S. facilities.

As a rule of thumb, it will take an LNG carrier eight to nine days to ship from Canada's Prince Rupert LNG terminal



The LNG Canada export terminal at Kitimat, British Columbia, is expected to be in-service by the middle of 2025.

LNG CANADA

to Tokyo, said Racim Gribaa, president of Global LNG Consulting, at the annual Canada Gas Exhibition and Conference in Vancouver in May 2024. It takes ships departing from the U.S. Gulf Coast twice the time to reach the same destination.

On the Asian side of the Pacific, some potential customers already have an LNG infrastructure, while others are building. Japan is largely credited with turning LNG into a viable energy source. China, meanwhile, announced in mid-2024 that LNG infrastructure will account for 47% of its midstream projects through 2028, GlobalData reported.

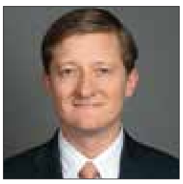
Northward Progress

Canada has endured some stumbles during its foray into the LNG market. The JV partners announced the project in 2012, but construction didn't start until 2018.

Energy firms have had difficulty with LNG projects on Canada's West Coast before, with several major projects canceled, stopped in court or abandoned because of ongoing environmental disputes, S&P Global's Santiago Canel Soria said in a November analysis.

Besides opposition from environmental groups, Canadian producers also face difficulties in working on tribal lands and the added costs of delivering the natural gas from central Canada to the far west of British Columbia.

Canadian LNG export projects are among the globe's most expensive because of the high cost of the pipelines required. Another barrier is the remote location, which is difficult to build in and does not have access to a large labor pool, Soria wrote.



Jason Klein

LNG Canada has walked a tightrope with development and working with the First Nations Haisla people, who own the territory where construction is ongoing. The JV developed a community charter with the Haisla and other First Nations people in the area.

The company has also bought five tug boats (three electric) that will be operated as a business by people from the tribal lands.

Jason Klein, LNG Canada CEO, said in a company publication that the firm has emphasized transparency and communication with its neighbors. Recently, the facility began flaring as part of its startup operations and has kept in touch with tribal leaders throughout the process.

"We want everyone to know what we're doing, why we're doing it, and when," Klein said.

Next in the Chute

Once LNG Canada goes online, its capacity will be equal to about 10% of Canada's natural gas output, said Phil Hodge of Pine Cliff Energy in an interview with Michael Campbell, a Canadian financial analyst.

The project will dwarf all others slated in Canada through the end of the decade, but several other LNG projects are expected to add to the 10% by the end of the decade.

Woodfibre, with a 2.1 Bcf/d capacity, and Cedar FLNG, with 3 Bcf/d, are expected to come online in 2027. Woodfibre is located close to the U.S./Canada border while Cedar is in the same bay as LNG Canada.

Another major LNG plant, Ksi Lisims LNG, has an expected capacity of 12 Bcf/d of natural gas but is not expected to come online until the end of 2030.

LNG Canada potentially has a Phase II expansion, but the JV is still deciding whether to go forward.

Government Grace

The Canadian project has another difference than counterparts in the U.S.—straight up government support, at least for the time being.

In 2024, several U.S. LNG projects had to wait for permits while the Department of Energy studied the need for more LNG export projects, as ordered by the Biden administration.

In Canada, while environmental and political opponents fought the project early, some leaders in the Canadian government are acknowledging the economic promise and potential environmental benefits.

Without natural gas, the potential LNG customers will be burning coal, said David Eby, the British Columbia premier. Eby said he saw the trade as reducing emissions overall, in an interview with Canadian publication EnergyNow.

"We've made some pretty clear commitments around driving down emissions in the province, and we're at a table with them about how we can try to achieve both of our goals," Eby said, referring to LNG Canada's investors. "From their perspective, ensuring that reliable, low-carbon energy, and from our perspective, all the emissions not showing up on BC's books as the main producer." OGI

Segrist: Russia, Ukraine and American LNG

The last gas pipeline connecting Russia to Western Europe has shut down, but don't expect a follow-on effect for U.S. LNG demand.

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The oddly late cut-off of Russia's last natural gas pipeline link to Western Europe is another extraordinary moment in a war that's about to enter its third year.

But any effects on the U.S. LNG market will be more mundane, said one analyst. Energy industry leaders had been well aware before 5 a.m., Jan. 1, when Gazprom, Russia's national energy company, stopped the flow on its Urengoy-Pomary-Uzhgorod pipeline.

It marked the end of a historical partnership going back to the Cold War.

Pipelines and Cold War History

On June 1, 1968, Austria became the Soviet Union's first natural gas customer on the other side of the Iron Curtain, signing an agreement to hook up to the Russian supply.

Deals between political enemies became a normal part of the cold war, said Evgeniia Kirillova, Lead Energy Market Analyst for Data at Energy Exemplar, in an email to *Oil and Gas Investor*. The deals sounded normal, considering the nations involved had nuclear weapons pointed at each other.

"European nations began to commit to long-term agreements, often spanning decades, while securing funding to develop the necessary infrastructure," Kirillova said. "In response, the Soviet Union launched an ambitious pipeline construction program, using the latest technology and sourcing equipment from European suppliers."

At the time, the USSR had plenty of experience building international networks. Austria connected the Soviets' 390-mile Brotherhood Pipeline, which brought Russian gas to then-communist Czechoslovakia. As Austria already had a gas hub about a mile away from the Czechoslovak border, the connection did make sense, at least geographically, Kirillova said.

Germany eventually got into the deal with a long-term "Gas-for-Pipes" agreement.

"This landmark deal became the largest in the history of Soviet-German and Soviet-European economic cooperation and set the stage for decades of partnership," Kirillova said.

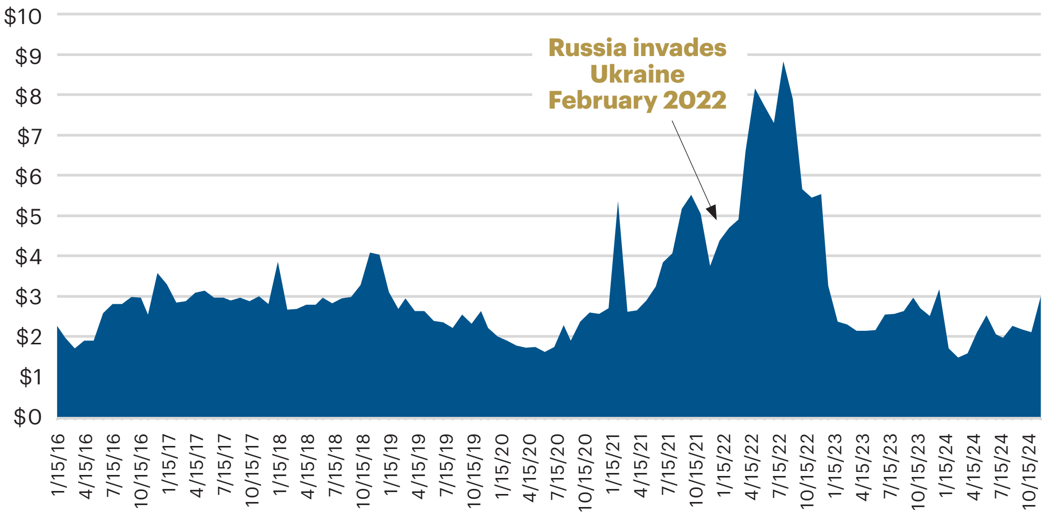
At the time, problems elsewhere in the world strengthened the relationship. The 1973 OPEC oil crisis showed Europeans the dangers of overdependence on a non-diverse supply. Socialists in the USSR had a chance to earn hard currency.

"Europe's growing energy needs made affordable Soviet gas a key pillar in maintaining its industrial competitiveness," she said.

Eventually, the leaders of the solidifying European Union began to take the steady supply of Soviet, and later Russian, gas for granted.

"The assumption had been that Europe

Henry Hub Natural Gas Spot Price Since LNG Exports Began



SOURCE: ENERGY INFORMATION ADMINISTRATION

A sign marks the location of a Russian crude pipeline, the "Druzhba," in Ukraine. The last Russian gas pipeline delivering natural gas to Western Europe shut down on Dec. 31.

SHUTTERSTOCK

and Russia were locked into a mutually beneficial, secure relationship since Europe needed gas and Russia had no infrastructure to sell that gas anywhere else," wrote foreign policy analysts Samantha Gross and Constanze Stelzenmüller in a study for the Brookings Institution. "That belief turned out to be wrong."

Fleeing Russia

The ongoing dependency between Europe and Russia was evident in January's pipeline cutoff. Ukrainians and Russians have been trying to militarily kill each other for almost three years, and no one had thought about cutting off one of Russia's primary sources of income?

While Europeans overwhelmingly condemned Russia for the invasion, they also pleaded with Ukraine not to shut down the Urengoy-Pomary-Uzhgorod.

In 2019, before the war, the two countries signed a five-year transit agreement. Europe, by then, was heavily dependent on Russian gas simply to keep from freezing in the winter. Ukraine, in turn heavily dependent on Europe to supply military aid, honored the contract until its expiration at the end of 2024.

Europe used that time to shift its energy supplies. Germany went so far as to reopen coal plants (at the same time it was shuttering nuclear plants). By 2023, Russia made up only 15% of EU gas imports, and the continent heavily increased its LNG supply from Qatar, North Africa and the U.S.

Prior to the Ukrainian invasion, Russia had eight pipeline routes for shipping natural gas to Europe, Kirillova said. The Nord Stream famously blew up in September 2022.

The others have shut down in far less dramatic circumstances. For example, the Yamal-Europe pipeline closed in April 2022 after Gazprom said it would accept payments in rubles only.

Overall, the EU has a non-binding goal of stopping all Russian gas transports by 2027.

As of the beginning of 2025, only one Russian pipeline still delivered gas to the west—the Turk Stream, which serves countries such as Hungary, Bulgaria, Romania and Greece. Since the invasion, Russia has increased the flow on the line by 23%.

The rest of the continent has increased imports from Norway's blooming gas fields and LNG.

The Ukrainian-U.S. Bump

Check any multi-year chart tracking the U.S. natural gas price and it's apparent when Russia decided to invade.

The Henry Hub spot price was at $3.76/MMBtu in December 2021. By August 2022, as Europe scrambled to secure supply for the oncoming winter, the price hit $8.81/MMBtu. It was the highest the price had been since July 2008. The highest since the U.S. began exporting LNG in 2016.

Since rapidly falling off in the following months, Henry Hub gas prices haven't recovered to even half of that level.

While U.S. gas prices spent fourth-quarter 2024 rallying up to $4/MMBtu, the increase was due to cold weather, a rising demand for power generation and a rising global market for LNG.

Kirillova said the U.S. should not expect a jump in gas prices or LNG exports similar to the market in 2022. Three years is a long time for countries to rethink and change up their energy supply situation. The eventual closing of Russia's last gas line to Western Europe has been baked into the cake.

"There is likely little impact to the U.S. LNG market in the short term, given most liquefaction and regasification capacity is fully booked," she said. "Most of the potential issues with supply disruptions were accounted for years back, which created price shocks and ultimately resulted in strategic shifts away from Russian gas."

Russia managed to surprise the world with its invasion, but the old Soviet Union's network has been replaced by a much more nimble system. OGI

ESA

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- Derating, Power, and Effective Service Factor
- Efficiency and Line Frequency
- Load and Speed
- Percent Load and Full Load Amps
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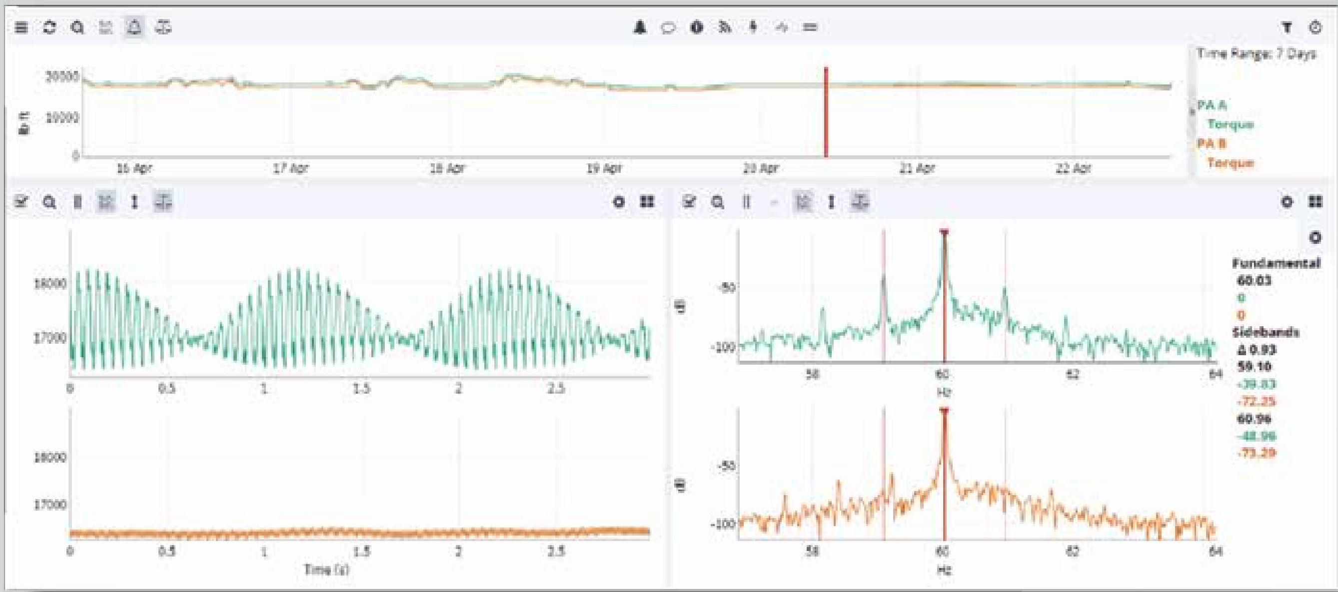

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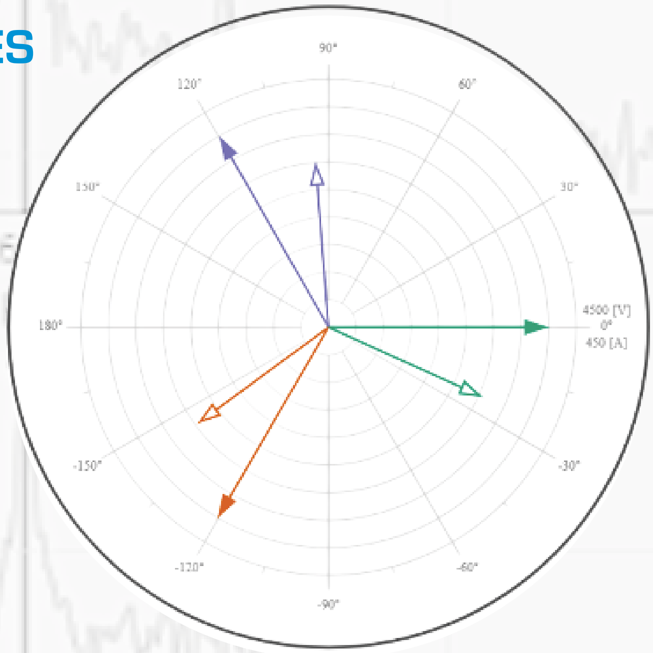

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Dell: Why DOE's LNG Forecast Will Be Wrong

The department's premise that increased LNG exports will raise domestic natural gas prices ignores a market full of surprises.

BEN DELL
KIMMERIDGE

Ben Dell is managing partner at private equity firm Kimmeridge.

The Department of Energy's (DOE) latest study predicts domestic natural gas prices will materially rise if the U.S. increases the export of LNG.

Yet, predicting such pricing has invariably been a fool's errand. It is a commodity market that always surprises. With over 60% of demand driven by weather, and upstream drilling technology consistently changing the economics of supply, the only thing we can confidently say is that almost all long-term forecasts are going to be wrong and should be balanced with broader factors at play when making policy decisions on energy.

For those who need more evidence, look no further than our own government agencies (Energy Information Administration and DOE), who in 2007 incorrectly forecast the U.S. would be in need of imported LNG.

Of course, we didn't—less than two years later, there were multiple LNG export projects pending regulatory review before the DOE and Federal Energy Regulatory Commission. In 2012, these same agencies forecast that when exports reached 12 Bcf/d, gas prices would rise to $6.37/Mcf.

Reflect on this for a moment: the most informed federal agency studying U.S. energy previously forecast a need to import natural gas (prior to the shale revolution), and then when the nation became an exporter of LNG in 2016, it forecast that the exports we have today would double gas prices. The reality is, gas prices did not in fact double. They didn't even come close.

It is against this backdrop that we should take the DOE's latest "study" with a pinch of salt. Irrespective of this analysis having become a political football, as evidenced by former Secretary of Energy Jennifer Granholm's grossly sensationalized summation of the report, it is clear that the likelihood of the forecasts being right is also very low. The authors themselves make this clear, stating that "[g]iven the global scope and timeframe examined in this study, there should be recognition of the inherent uncertainty in conclusions."

That might be the only thing we're certain they got right. Take a step back and look at historical data. Since 2000, natural gas prices have averaged $4.34/Mcf, with a low of $1.49/Mcf and a high of $13.42/Mcf. The mid-January Henry Hub price of $3.54/Mcf and the forward price in 2027 of $4/Mcf are not unusual.

Among a basket of goods, natural gas is one of the few commodities that has not inflated. Since 2016—the start of U.S. LNG exports—prices have remained broadly flat. In short, prices have seen little to no inflation because supply (up 50 Bcf/d or 100% since 2000) has easily met demand, with new technology consistently unlocking lower-cost shale resources.

So, what to make of Granholm's forecasts that "unfettered exports of LNG would increase wholesale domestic natural gas prices by over 30%"? From today, a 2% inflation in price—which is the Fed's target—would be 64% higher in 2050. So, even the DOE's own worst case is deflationary relative to target wage growth. Moreover, the forward strip in 2028 is already at this level, and while this 30% rise would in fact be equivalent to $4.42/Mcf in 2050, this is merely 7 cents/Mcf above the 24-year average (2000-present) of $4.35/Mcf.

As for the fear of another 40 Bcf/d of LNG exports (the "unfettered" case) by 2050, based on historical performance, this too could be met by domestic growth, but realistically is never going to be required. This all seems to suggest that even if the DOE were correct, then any increase in price would be moderate, below core inflation and net positive for the consumer.

But what about emissions or the impacted communities that the report frets over? Overwhelmingly, Louisiana and Texas Gulf communities support LNG. The developments bring good, high paying jobs, while LNG project sponsors are financing massive community investments such as the rebuilding of a local hospital. In this regard, DOE's study does not explicitly find U.S. LNG exports inconsistent with the public interest, which is the legal standard under the Natural Gas Act.

Opportunities to have such a materially positive impact on U.S. economic growth, jobs, investment and global emissions, as well as on some of the lowest-income communities of the U.S., should not be passed up. While the U.S. procrastinates on its future LNG strategy, globally, the share of non-U.S. LNG contracts signed in 2024 with producers from the Middle East and elsewhere has outpaced contracts signed with U.S. producers.

As far as setting U.S. energy policy, we should expand U.S. LNG exports based on the many tangible, verifiable outcomes that definitely are in the public's best interest. OGI

Crescent Midstream Charts CCS Course with $1B Project

CEO Jerry Ashcroft discusses the carbon capture and storage landscape and how the company is evolving.

VELDA ADDISON
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Crescent Midstream is known in the oil and gas world for its offshore and onshore pipelines in the Gulf of Mexico and Louisiana, transporting nearly 200 MMbbl of crude oil annually across its 1,200-mile-plus pipeline network.

However, the independent energy company backed by the Carlyle Group private equity firm has sights set on growing in the carbon capture and storage (CCS) market, targeting the power market in the Gulf Coast area.

The Houston-headquartered company was selected by Entergy to develop and build an integrated CCS project at one of its gas-fired plants in Louisiana. The $1 billion-plus project, which includes a CO_2 facility at Entergy's 994-megawatt Lake Charles Power Station and a 30-mile pipeline, is expected to be fully operational by 2029 and capture up to 3 million tonnes of CO_2 per year. Crescent is collaborating with Samsung E&A and Honeywell on the project.

By leveraging existing infrastructure where feasible along with pipeline and transportation expertise, midstream oil and gas companies like Crescent are taking on crucial roles in developing CCS projects to help drive down global greenhouse gas emissions.

Analysts say the market is expected to grow this year in the U.S., where the Inflation Reduction Act (IRA) bumped up the 45Q federal tax credit from $50 to $85 per metric ton of captured CO_2 stored. If the permitting and regulatory approval processes go smoothly, CCS projects could prove beneficial for hard-to-abate sectors like power, that is expected to experience a boon in demand driven by data centers, the reshoring of manufacturing and the continued electrification drive.

More CCS activity is also anticipated due to new Environmental Protection Agency rules that require existing and new gas-fired plants to reduce emissions, including the use of CCS systems.

Crescent Midstream CEO Jerry Ashcroft spoke with Velda Addison, senior editor of energy transition, about the changing CCS landscape, carbon-neutral blue electrons and activity in the Gulf Coast region as Big Tech and others seek lower-carbon energy.

Velda Addison: The Gulf Coast appears to be an active spot for CCS projects. What do you think makes this region attractive for CCS development?

Jerry Ashcroft: The main thing is geology. The Frio and Miocene Formations in the Gulf Coast have tremendous potential for storing large quantities of CO_2. The Frio and Miocene are large sand formations that are between 5,000 and 10,000 ft below the surface on the Gulf Coast and filled with saltwater. When CO_2 is injected (sequestered) it displaces the saltwater. Over time the CO_2 undergoes mineralization and converts to limestone. The Frio and Miocene formations consist of sand formations with high porosity interbedded with shales and clays. These interbedded shales and clays form natural barriers which help keep the injected CO_2 contained within the formations that it is pumped into. Thicker sections of these barriers such as the Amphistegina B and the Anahuac shales act as impermeable upper seals for CO_2 injection wells, acting as a "cap" that keeps the CO_2 in place.

We just have great geology. We have this natural container for CO_2 that is well below any potable water sources. Right now, carbon sequestration projects are primarily onshore; in the future, we believe offshore sequestration will play a much larger role.

The other advantage is that we have abundant, low-cost electricity in the United States in the Gulf Coast. We are in close proximity to multiple natural gas supply hubs. So, when you look at it from that standpoint, this is the ideal area for these projects because we struggle from a social economic standpoint in Mississippi, in Louisiana, parts of Texas, and that's where these data centers are going. You're talking about thousands of construction-related jobs and hundreds of permanent jobs in economically challenged areas.

VA: Can you tell me more about the project that Crescent is working on with Entergy? What's on tap for 2025 as far as targeted milestones?

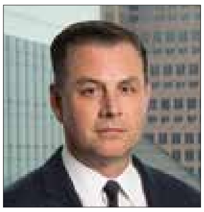
JA: We first went through a feasibility study with Entergy. Entergy owns and operates Lake Charles Power Station. It is a combined cycle gas turbine location. So, it's basically two jet engines laid on their sides that burn

A rendering of the Crescent Midstream-led carbon capture and storage project at Entergy's Lake Charles Power Station in Louisiana. The project will capture and store up to 3 million tonnes of CO_2 per year.

SOURCE: CRESCENT MIDSTREAM

natural gas and create electricity. Right now, their emissions come from what we see as flue stacks.… We're going to pull all of those [CO_2] emissions out of our flue stacks and wash them through a Honeywell technology. It washes that CO_2 out. Then, we're able to take that CO_2 gas and compress it into a liquid. It's about 1,200 pounds of pressure to do that.… We'll then ship it on a pipeline as a liquid to a sequestration or storage site that we talked about earlier and inject it 10,000 ft below the Earth's surface.

Doing this allows you to receive $85 from the U.S. government for every ton you store, and we'll be storing about 3 million tons a year at this facility. The electrons from the power plant are sold into the market and are carbon neutral. So, that's our project. We are now doing detailed engineering and that will take most of 2025. We'll also be working on commercial agreements. At the same time, we are actively bidding on three more Entergy power plants. You're probably looking at 10 to 15 more, whether it's Entergy or other power generators looking to meet aggressive emissions goals. They're basically in the Gulf Coast. You'll see a sprinkling in Texas, a sprinkling in Louisiana, some in Mississippi and we're even bidding on projects in Arkansas.



"I personally believe the carrot is working. It's just taking us all a lot longer to figure out how to become efficient enough."

JERRY ASHCROFT,
CEO, Crescent Midstream

VA: Do you anticipate the projects being economic without the $85 tax credit?

JA: It would be very challenged without the $85 the IRA provides. Right now, we need $85 to make these projects work. Would there be a conversation without them? I don't know the margins Meta and Google are getting on AI. That's hard for me to understand. What is the elasticity of what they're willing to pay for carbon neutral electrons? That becomes the question. But from our current vantage point, we absolutely need the $85.

VA: If you could tweak anything in the IRA, what would it be?

JA: I think the thing that I would probably tweak in the IRA regulations would be related to receiving cash flows on a timely basis. The IRA regulations have a mechanism for direct payment; however, those payments aren't on a timely basis. It's like when you and I file our taxes. You have to do a whole year of work, then file your taxes and then someone reviews it and hopefully sends you a check. That typically takes 18 months from when the year started. If you think about these projects and their $85 credits, you must go through a whole year of operation with no cash flow, and then possibly another six months or longer after that has ended to receive the revenue stream. So, during that first 18 months or two years, I wish there was a mechanism for the government to help you obtain cash flow more quickly.

VA: The environmental benefits of CCS are quite obvious, but what about the economic value of CCS? How do you all make money, and how do you see that changing in the future?

JA: When you're looking at private equity returns, you're trying to achieve mid-teen returns. It's challenginig for these projects to provide returns at that level, especially the first project. What we hope to do is basically create a portfolio of these projects. We feel like the first one will be expensive because of the learning curve. But once we figure out the learning curve, once we're able to buy more in mass versus

ENTERGY

"I'm just buying this one pump for this project," the returns will improve. It's just like when you run a fleet of vehicles. If you can buy 10 vehicles, you get different pricing than if you buy one vehicle. So, we see that now there's this line of sight for multiple power plants and even though our first project doesn't have normal returns, that a portfolio of projects would.

VA: What are your thoughts on a carbon tax to help promote adoption of CCS nationwide and the likelihood of that happening?

JA: I just feel as though it's kind of against our culture in the U.S. It's a whole Boston Tea Party mentality. I'm not sure we've changed that much. I personally believe the carrot is working. It's just taking us all a lot longer to figure out how to become efficient enough at those levels. When they changed [the tax credit] from $50 to $85; at $50, it was only the ethanol and ammonia projects that worked; at $85, people are looking at cement plants, people are looking at pulp mills, paper mills and power plants. So, we're on the verge. I just believe that's a better method from a capitalism standpoint.… We react a little bit better to the carrot versus the stick.

VA: What about products that utilize CO_2? Do you see a future in carbon utilization for products?

JA: I absolutely see that. Where we are today, sequestration is the answer. If you think about what we're doing, all of the technologies we're using have been around for 50, 60, 70 years. Amine units to take CO_2 out of the air are nothing new and that's what we're using. And putting molecules in the ground to stay like we do with natural gas caverns along with our ability to do upstream work and well work, we're not coming out with anything new. To me, that's the field that we're going to play on. I like where you're going, and what people are starting to talk about. We're studying in the lab how you can make graphite out of CO_2 or we can make these building products more rigid with CO_2. It's just not to the scale. If you've got 3 million tons pouring off of a power plant, we have to do what we know. But I do believe in the future. Once you have this source and it's a pure source, people will tap into that source and use it for X, Y or Z.

VA: How you see Crescent Midstream evolving over the next four years or so?

JA: We currently move about 25% of the Gulf of Mexico's oil on our systems. Carlyle came to us and challenged us with becoming carbon neutral. In 2023, we became carbon neutral and then we said, we want to become carbon negative. So, we looked at these CCS projects and we found a way to do that. I see where we have created a really wonderful journey that I hope others copy. We're using our base foundation in fossil fuels and our generation of cash flow from fossil fuels to then invest into carbon neutrality and now going carbon negative.

As a business, we're probably one of the smaller players that you're watching evolve. In four years, I see where CCS will be a larger portion of our business than moving crude oil in the Gulf of Mexico. There's no cash flow from it now. In four years, I hope to be cash flowing, and I hope that it's greater than 50% of my cash flow by then. OGI

This interview was edited for clarity and length.

Bioenergy

Montana Renewables Closes $1.44B DOE Loan for Facility Expansion

SHUTTERSTOCK

A technician refuels a private jet with sustainable aviation fuel at an airport.

Calumet subsidiary Montana Renewables closed a $1.44 billion guaranteed loan facility from the U.S. Department of Energy's Loan Programs Office (LPO) to help finance expansion of the company's renewable fuels facility in Great Falls, Mont.

Montana Renewables is expected to produce about half of North America's sustainable aviation fuel (SAF) and about 12% of the SAF produced globally when the expansion project reaches full capacity, the LPO said.

Called MaxSAF, the expansion project will lift annual production capacity to about 300 million gal of SAF and 330 million gal of combined SAF and renewable diesel, Calumet said.

That's up from about 140 million gal/year of biofuels, mostly renewable diesel, produced today.

"This is essentially the largest agricultural investment in Montana history and will double our purchases of seed oils and tallow from approximately 1.5 billion pounds per year today to 3 billion pounds per year post expansion," said Montana Renewables CEO Bruce Fleming. "This is possible through the strong support and partnership of DOE and follows over two years of detailed due diligence."

The initial tranche of about $782 million was expected in January with the balance of proceeds funded through the planned construction period, according to a news release. The project is scheduled to begin coming online in 2026.

Carbon Management

California Resources Advances California's First CCS Project

California Resources Corp. (CRC) approved its carbon capture and storage project at the Elk Hills cyrogenic gas plant, marking a first for the state.

The approval by CRC and its carbon management business, Carbon TerraVault, followed receipt of required Class VI well permits for underground CO_2 injection and storage from the U.S. Environmental Protection Agency.

CRC will invest between $14 million and $18 million to capture CO_2, the company said in a news release. The internal rate of return for the project is expected to be at the high end of its previously disclosed range of 10% to 30%.

CRC and partner Brookfield are targeting first injection in late 2025. Plans are to store up to 100,000 metric tons (mt) of CO_2 per annum from the plant in Kern County into the 26R Reservoir. The reservoir, which is one of two depleted oil and natural gas reservoirs that make up the CTV I storage site, has an estimated capacity of up to 38 million mt of CO_2.

The project is expected to lower Scope 1 and Scope 2 emissions from the Elk Hills Power Plant by up to 7%, according to CRC.

The JV anticipates generating EBITDA of $50 to $60 per mt in sequestration fees paid by CRC, the company said. It also anticipates the project will qualify for $85/mt in 45Q tax credits.

Energy Storage

MVP Produces Lithium at DLE Plant in Montney

SHUTTERSTOCK

Canada-based lithium extractor Midas Vantage Projects (MVP) Lithium produced battery-grade lithium from brine at its direct lithium extraction (DLE) pilot plant in the Montney Formation, the company said.

MVP said it produced 99.9% pure battery-grade lithium hydroxide.

"These results demonstrate that the pilot is operating optimally and as expected," said MVP Lithium CEO Max Iyer. "This milestone not only validates our technological capabilities but also positions MVP Lithium to play a pivotal role in meeting the rapidly growing global demand for lithium."

DLE involves extracting lithium, a key component in electric vehicle batteries and other energy storage systems, directly from brine using technologies and processes such as adsorption, resin or membranes. The method is considered better for the environment than hard rock mining. It also requires less land and processing time when compared to solar evaporation brine extraction that utilize evaporation ponds.

Ormat Starts Operations at New Jersey Energy Storage Facility

Reno, Nev.-based Ormat Technologies commenced commercial operations for its Montague energy storage facility in New Jersey, according to a press release.

The project has a capacity of 20 megawatt (MW)/20 megawatt-hours (MWh) bringing Ormat's total capacity in Pennsylvania, New Jersey and Maryland (PJM) to 120 MW/120 MWh, the release stated.

Ormat currently operates 290 MW/658 MWh of energy storage projects.

The company has several other projects in development to achieve its goal of 950 MW/2.5 gigawatt-hours of energy storage capacity by 2028, CEO Doron Blachar said.

"The addition of the Montague project brings valuable ancillary services to the PJM market, enhancing the reliability of the grid while also supporting the transition to a cleaner energy future. We are proud to support the PJM market with our premium renewable power generation and energy storage solutions," Blachar said.

Hydrogen

Advanced Ionics Raises $6.7MM, Names CEO

JERA, Lummus Venture Capital and the Argosy Foundation joined BP Ventures and Clean Energy Venture Group in backing electrolyzer startup Advanced Ionics, which said it raised an additional $6.7 million in funding.

The Wisconsin-based company said it will use the capital to accelerate development of its water-vapor electrolyzer technology and build out its manufacturing and research and development facility.

Advanced Ionics also announced the appointment of Ignacio Bincaz as its CEO. Bincaz previously served as the company's chief commercial officer. The company's founder, Chad Mason, will serve as CTO.

"We believe our technology has the potential to revolutionize this market at a time when new technology is most critical," Mason said, "and we're building a world-class company to make that a reality."

Advanced Ionics has developed a new class of electrolyzers that uses process or waste heat already present at industrial facilities. The water vapor electrolyzer, called Symbion, is made using materials and steel that are widely available. The electrolyzers can be scaled and use off-the-shelf components such as stainless steel and nickel instead of expensive catalysts such as platinum or iridium.

Solar

Swift Air Solar Project Powering Oxy's Stratos Secures Funding

Origis Energy has closed a $415 million funding package for the Swift Air Solar project, the company said in early January.

The funding package includes $290 million in construction and term debt arranged by Natixis Corporate & Investment Banking (CIB) and $125 million in tax equity from Advantage Capital, according to the release.

Located in Ector County, Texas, the project will provide solar power for Occidental Petroleum and subsidiary 1PointFive's Stratos direct air capture facility. The solar project is under construction and scheduled to go online in mid-2025.

"This is an exciting project, helping to power the world's first large-scale direct air capture plant. This directly aligns with our mission to supply decarbonization solutions," Origis Energy CEO Vikas Anand said.

Origis is the builder, owner and operator of Swift Air Solar.

Enbridge, EDF Renewables Bring Fox Squirrel 3 Solar Project Online

EDF RENEWABLES/BUSINESS WIRE

Fox Squirrel Solar in Central Ohio generates solar energy for Amazon.

All three phases of the 577-megawatt (MW) Amazon Solar Farm Ohio-Fox Squirrel Solar project are operational, according to developer EDF Renewables.

The renewable energy company, which owns the solar farm with partner Enbridge, said in early January that Fox Squirrel 3 reached full operational status in December. The 150-MW Fox Squirrel 1 went online in December 2023. It was followed by the 250-MW Fox Squirrel 2 in July 2024. All power generated at the solar farm will be delivered to Amazon, which has power purchase agreements in place, according to a news release.

Located in Madison County, Ohio, the solar farm has 1.4 million solar panels and nearly 160 inverters. It is considered one of the largest utility-scale solar developments east of the Mississippi River.

Wind

Equinor Secures $3B in Financing for New York's Empire Wind 1

Equinor has secured more than $3 billion in project financing for the 810-megawatt Empire Wind 1 project it is developing offshore New York, the company said.

The Norway-based company, which closed on the financing package at the end of 2024, said total capital investments for the project are about $5 billion. The amount includes fees for use of the South Brooklyn Marine Terminal and the effect of expected future tax credits.

The company said it plans to farm down its stake in the project to a partner to further augment value and lower exposure.

Equinor has already inked a 25-year purchase and sale agreement with the New York State Energy Research and Development Authority at a strike price of $155 per megawatt hour.

Construction of the offshore wind farm, which is expected to power about 500,000 New York homes, is underway. Empire Wind 1 is scheduled to begin commercial operations in 2027.

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Less Flaring, More Bitcoin

Startup 360 Energy joins with Halliburton Labs to fuel data centers with natural gas.

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Oil and gas operators often produce more associated gas than they can handle. The excess is often flared—an outcome benefitting no one.

360 Energy, a startup that recently joined forces with Halliburton Labs, believes it has a solution.

The company's answer is a Bitcoin mine. It's actually 12 Bitcoin mines, so far all in Texas, and the collaboration with Halliburton raises the possibility of many more in the future.

CEO Chris Alfano and CFO Sean Milmoe started 360 Energy, then known as 360 Mining, in 2021. They met at Southern Methodist University as freshmen and graduated in 2016. The duo's first idea was to own their own wells.

"We put our first Bitcoin mine on our wells in the Barnett and realized it provides a lot of value to the broader oil and gas industry," Alfano told Hart Energy. "So, we spun out a service company in 2023. We've been doing that now successfully for 18 months, deployed all over Texas, some big names, and excited to have Halliburton as an equity investor in our company now."

Quick explanation of Bitcoin: It's a digital currency that operates on a decentralized platform called a blockchain. Companies like 360 use sophisticated mathematical computing to add blocks to the chain, and the system pays them in Bitcoin. In mid-January, the value of one Bitcoin was about $96,500.

'So Many Facets'

360 Energy sets up at the pad sites.

"You co-locate a natural gas generator—or many, depending on how much gas is available—that converts the natural gas into electricity, and then co-locate a shipping container, which is your data center, right next to that generator," Alfano said. "There's a ton of retrofitting going on, electrical and airflow and cooling technologies and all the rest of it."

"It looked like a home run in Excel, but it was anything but what Excel would've suggested. There's so many facets to the operation."

CHRIS ALFANO, CEO, 360 Energy

The gas that might otherwise have been flared goes into the generator, which powers the computers, which do the math, which results in Bitcoin.

Simple, right? Not exactly. Milmoe and Alfano had backgrounds in finance, but quickly learned they'd need more than spreadsheets to succeed.

"It looked like a home run in Excel, but it was anything but what Excel would've suggested," Alfano said. "There's so many facets to the operation."

Among them: maintaining gas flow, volume and pressure to a generator operating around the clock; selecting generators and managing

360 ENERGY

360 Energy's centers are designed to withstand West Texas weather and elements—heat, cold, wind and dust.

360 ENERGY

By using the gas to power on-site operations, 360 Energy said it helps minimize flaring.

360 ENERGY

360 Energy uses standard shipping containers to create Bitcoin data mining centers on the pad sites of natural gas operations.

"We're seeing this cataclysmic shift in understanding and acceptance and adoption, largely fueled by [President Donald] Trump and the ETFs [exchange-traded fund] and Bitcoin and all the positive tailwinds that are happening there."

SEAN MILMOE, CFO, 360 Energy

different types of gases; ensuring electrical compatibility of the generator and data center; and, of course, keeping servers cool and dust-free in the middle of West Texas.

"It took us two-and-a-half years and many millions of R&D [dollars] in our infrastructure to reliably do this," Alfano said.

World of Possibilities

For the well operators, 360 Energy offers two main options.

"We can just buy the gas from you for a fixed dollar per Mcf price, and we're basically midstream, but we're not going to pay you a lot for that, we might pay you only 50 cents," Milmoe said. "Or you spend $2 million, we build it for you, we operate it for you, and then you are running your own gas through your own mine and you're making $12/Mcf."

There are also environmental benefits. In its marketing materials, 360 Energy says it's far more efficient than flaring, removing up to 99% of methane emissions and 28% of volatile organic compounds.

The equity investment from Halliburton Labs, a wholly owned subsidiary of Halliburton, came about through a friend who received one of the company's first investments a few years ago. The connection opens up a world of possibilities, given Halliburton's global presence.

"Abroad, the opportunity size is 50 times larger when you look at the amount of assets being flared in places like Argentina, the Middle East, things like that," Alfano said. "That's where Halliburton can really help us, with all their clients in these areas where there's infinite gas that's just being wasted."

The companies can take their cut in Bitcoin or dollars, Milmoe said, and some companies now want to hold cryptocurrency as part of their financial strategy.

"We're seeing this cataclysmic shift in understanding and acceptance and adoption, largely fueled by [President Donald] Trump and the ETFs [exchange-traded fund] and Bitcoin and all the positive tailwinds that are happening there," he said. "It's setting up for a really exciting 2025." OGI

Taking a Second Swing: The Mulligan Fund's Mission to Transform Lives

The Mulligan Fund is a Houston-based nonprofit with a clear and compelling mission: to provide financial and community support to individuals facing social and economic hardships, giving them a second chance at success. Guided by the belief that everyone deserves the chance to prosper over setbacks, The Mulligan Fund empowers recipients to take their "mulligan" and achieve their goals.

Turning Vision Into Action

At the heart of The Mulligan Fund's initiatives are scholarships for individuals pursuing educational or career advancement. These grants open doors for personal growth, professional opportunities, and financial stability. Their initiatives additionally help to directly fund projects that improve community safety and social determinates of health - promoting economic equity and community prosperity.

WE DON'T ALWAYS GET IT RIGHT THE FIRST TIME.

The Power of Community and Connection

A cornerstone of The Mulligan Fund's impact is its commitment to fostering community connections. Corporate sponsors, philanthropists, and supporters come together through events that inspire collaboration and amplify their collective potential to drive meaningful change.

One signature event is The Mulligan Fund Golf Tournament. This annual gathering combines friendly competition with a meaningful cause, creating a space for sponsors and supporters to network and exchange ideas while supporting the fund's mission.

Held at Memorial Park Golf Course in Houston this year, the tournament provides participants and spectators with a unique opportunity to enjoy the same course as the PGA pros.

Beyond the game, the event is a catalyst for life-changing outcomes, with all proceeds fueling the fund's mission to transform lives.

Maximizing Impact – Together

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Solving Two Problems at Once

Pioneer Energy's technology promises more throughput with fewer emissions.

RICHARD STUBBE
SENIOR EDITOR, TECHNOLOGY
rstubbe@hartenergy.com

Pioneer Energy knows the industry has plenty of room to improve efficiency.

The company, based in Lakewood, Colo., was recently selected for a series of U.S. Department of Energy grants for the rollout of technology capable of delivering efficiency gains in two ways: emissions reduction and increased crude yield at the well pad.

Pioneer plans to use the funds to help producers improve throughput of oil and gas, with the extra benefit of reducing one of the industry's more visible problems—flaring.

Flaring grabs headlines. The practice can be seen from space, unlike the invisible release of other greenhouse gas emissions, said Joseph Palaia, the company's vice president of business development. Cutting out the process improves a company's image and its bottom line.

With the Trump administration pledging to ease restrictions on emissions, Palaia expects less producer interest, and investment, in paying more to reduce emissions.

"But if it's emissions reduction that also pays," Palaia said, "then why wouldn't you want to do it?"

Pioneer's Emission Control Treater (ECT) technology improves crude production while also reducing emissions. The technology processes wellhead fluid, replacing traditional infrastructure such as phase separators. This closed system completely processes the crude, resulting in zero routine flaring with no need for atmospheric storage tanks. Pioneer says it can boost a well's crude yield by 5% to 10%.

Pioneer started in the early 2010s making gas processing systems to do something with flared gas, Palaia said. It builds equipment at a factory in Lakewood.

"We've seen a lot of the inefficiency and what we view as the opportunity to turn that waste and that inefficiency into additional product," he said. "We have developed a line of crude stabilization systems, essentially an entire surface facility on a skid. We can set this on an existing well pad or on a new site."

Operators can monitor and control production from a centralized dashboard, reducing the number of trips to a wellsite.

The ECT can replace multiple systems designed to separate oil and gas, Palaia said.

"You've got a lot of inefficiency in the process because every time you have another pressure drop, you have another low-pressure gas stream that you generate, which means then you need compression for that gas stream to get it up to a sales line pressure," he said. "And even after all of that, you still have crude molecules that are trapped in the gas, and gas molecules that are trapped in the crude."

PIONEER ENERGY

Pioneer Energy's Emission Control Treater technology reduces emissions and can boost a well's crude yield by 5% to 10%, executives say.

The extra throughput comes from improving the separation of those gas and oil molecules while limiting the potential for emissions.

"Any place you have a connection point—a flange, a valve—you've got the potential for fugitive emissions," he said. "We can replace all of that with refining technology that we've miniaturized and automated. We build in a factory environment, with a minimum amount of field labor required to install it and operate it. And it's 100% electric."

Where electricity is not available, Pioneer makes a version of the system that uses a gas-fired heater.

The projects are:

- ▶ $10 million to scale the ECT from pilot to a commercial scale of 2,500 bbl/d and deploy units with Bayswater Exploration & Production and Prairie Operating for six-month field trials in Colorado. Work has begun with expected field deployment in fourth-quarter 2025.
- ▶ $6 million to adapt the 2,500-bbl/d ECT for use in processing sour crude oil. In addition to demonstration of emissions reduction, the system is projected to sweeten the crude down to low-sulfur concentration of parts per million.
- ▶ $5 million to create mini-ECT systems as inexpensive, drop-in replacements for surface infrastructure at marginal wells. The technology will be demonstrated for 12 months on several sites operated by Diversified Energy in the Cotton Valley Formation.
- ▶ $6 million to convert flare gas to methanol in collaboration with Emvolon, which has the exclusive rights to the technology. The technology will be demonstrated for 12 months in the Eagle Ford Shale.

Paisie: Assessing an Uncertain Energy Future

A scenario depicting greater market volatility in an increasingly unstable world is appearing more likely.

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

Several years ago, Stratas Advisors developed three long-term energy scenarios covering the period through 2050:

- ▶ **Scenario 1:** Muddling Through One "Crisis" After Another
- ▶ **Scenario 2:** Shifting to a New Global Framework to Facilitate Energy Transition
- ▶ **Scenario 3:** Breaking Down into Multi-polarization with a Focus on Energy Security

The first scenario describes the world through the lens of reality and pragmatism in which policymakers need to strike the appropriate balance between basic societal and economic needs and more ideological objectives within the context of addressing short-term disruptions and crises. Since the development of the scenarios, the first scenario most closely resembles our reference scenario that is used as the basis for our forecasted supply, demand and prices.

The alternative scenarios, in simple terms, can be equated with a more optimistic view of the world (Scenario 2) and a more pessimistic view of the world (Scenario 3).

The macro-level inputs, along with the associated supply and demand fundamentals, lead to dramatically different scenarios with each scenario encompassing unique risks, challenges and opportunities.

Three Scenarios

The first scenario, "Muddling Through One 'Crisis' After Another," presents a future in which the energy transition is happening but progress ebbs and flows with the potential for shifts in policies. Within this scenario, oil prices remain relatively high until oil demand finally peaks later in the forecast period. This dynamic creates strategic ambiguity for decision-makers in the energy sector.

The second scenario, "Shifting to a New Global Framework to Facilitate Energy Transition," presents a future in which there is global buy-in and cooperation in pursuing carbon reduction and energy transition. Within this scenario, oil prices can move higher during the earlier part of the forecast period because of tighter supply/demand conditions resulting from reduced oil-related investment coupled with lagging availability of low-carbon alternatives.

The third scenario, "Breaking Down into Multi-Polarization with a Focus on Energy Security," presents a future that is a return to a global dynamic that is more akin to the 1960s and 1970s when there was less integration, more economic friction and more potential for conflict, including conflict between the major powers.

Within this scenario, oil prices bounce between an upper band and lower band of prices. The future described by this scenario can present the most significant challenges, given that there will be the need to manage the non-market risks more proactively and ensure appropriate level of strategic and operational flexibility to react to "shocks" and the resulting aftermath.

Multitude of Challenges

Based on the last couple of years—and recent events—the third scenario has the potential to be a more likely description of the future than the first scenario and certainly more likely than the second scenario. There are ongoing regional conflicts with the risk of becoming broader in nature, including geographically, as well as involving the major powers in direct conflict. There is also the threat of trade wars that will affect economic growth and market conditions.

While it is not a given that this pessimistic scenario best represents the future, it seems that an inflection point is close to being reached. Additionally, each region and major economy are facing not only short-term challenges, but also long-term challenges that are structural in nature and with the potential to have substantial consequences that only add to the uncertainty about the future. OGI

Long-Term Energy Scenarios

Factor	Reference Scenario	Upside Scenario	Downside Scenario
GDP Growth	Moderate	Strong	Weak
Technology Penetration	• EVs and technologies pertaining to batteries gain traction • Progress is hindered by constraints across the supply chains and policy uncertainties	• Aggressive penetration of renewables and EVs with respect to transportation sector • Meaningful progress within the stationary sectors	Moderate, but based on energy security, not carbon reduction
Geopolitical Stability	Regional conflicts	Focus on global cooperation and regional interdependencies	Trade wars, conflict ridden with growing risk of conflict between major powers
Policy	Limited global action: some countries act but the progress is not in a straight line	Widespread carbon-reduction focus with global coordination	Focus on domestic economies and energy security

SOURCE: STRATAS ADVISORS

Belcher: Trump's Stances Will Impact Energy Markets

Policies to move the needle in the Middle East, Europe and Asia are high risk with potentially high return.

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

President Donald Trump began shaking up the global order even before he was inaugurated with a slew of pronouncements that included threats of tariffs, reinstatements of trade sanctions and acquisitions of Greenland and the Panama Canal. It is clear that we are on the cusp of a new foreign policy that will have huge implications on global politics, impacting crude and natural gas markets.

The tariffs expected to be put in place by the Trump administration are likely to be designed to set the stage for future negotiations over trade agreements. They are, however, not without consequence to the oil and gas industry, which will pay more for products and equipment manufactured overseas if they are instituted. The energy services sector, which directly employs over 655,000 Americans and amounts to $271 billion in direct economic activity, will have to absorb the estimated $2 billion in additional costs associated with higher costs from tariffs.

At worst, new tariffs could result in a trade war that restricts the movement of global commerce, creates a worldwide recession and squeezes supply chains. At a minimum, it could increase interest rates and the overall cost of capital.

A return to sanctions by Trump on Venezuelan and Iranian oil would impact around 4.28 MMbbl/d of crude. This will undoubtedly significantly decrease output from these oil exporting nations, putting upward pressure on prices. While higher prices are welcome news for oil producers, economic troubles in Europe and Asia have been driving down demand, and higher crude prices would further exacerbate headwinds in those economies.

In the last few weeks of his administration, President Joe Biden, no longer fearing the impacts of higher energy prices, increased sanctions on two Russian oil companies, its LNG exporters and its "dark fleet" oil tankers. While lower prices and lower global demand have lessened the perceived impact of sanctions on Russian oil, the additional sanctions on Venezuela and Iran will further complicate the equation.

The sanctions imposed by Biden were meant to weaken Russia vis-à-vis Ukraine, its global ambitions and its complicated alliance with China. Evidence of the emergent Russia-China alliance can be seen in recent incidents in which Russian and Chinese vessels have dragged their anchors across subsea power and communications cables in the Baltic Sea and Taiwan Strait, an act of sabotage in an increasingly tense global environment.

Tariff Strategy

Early signs suggest how the Trump administration will address the situation in Europe. At the same time that Trump has been threatening to impose tariffs as a negotiating tactic over trading terms and calling on NATO countries to increase their financial contributions to the alliance, Europe's economy is fragile amid high energy prices and a consequent bleak outlook for competitiveness of Europe's manufacturing sector.

Following the Jan. 1 expiration of a natural gas supply contract between Russia's Gazprom and Ukraine's Naftogaz, almost all pipeline routes for Russian gas to Europe have been shut down. Meanwhile, Trump is expected to take all possible actions to maximize U.S. LNG exports to Europe (and elsewhere), with the LNG market a potentially significant area of cooperation between the U.S. and Europe that could help stave off a deterioration in transatlantic relations.

At the same time, the Trump administration is moving away from the Paris climate accords and other policies that commit to climate action and ESG, representing another area of contention with the EU and some European countries individually. Europe's Carbon Border Adjustment Mechanism, EU Methane Regulation and other climate-related rules that impact trade will likely be areas of negotiation with the Trump administration, as it seeks to reduce the impact of these initiatives on U.S. trade, including American LNG exports.

Additionally, 2025 could be a tumultuous year politically in Europe, as center-right and populist political parties seek to build upon recent victories in Italy and the Netherlands. Elections will occur in Germany, France and potentially the U.K., where unpopular left-of-center governments, facing a backlash from high energy prices and immigration, are likely to fall and be replaced by governments more politically aligned with Trump.

Trump is seeking to end the war in Ukraine through a peace agreement. The war has resulted in hundreds of thousands of casualties and has severely weakened Russia financially and

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For 2025 sponsorship information please email info@oilbunker.com militarily. Critics of a peace agreement argue that Russia will be emboldened by an agreement which would likely result in territorial gains. It could also allow Russian oil back into Western markets, which would help to strengthen its economy and influence in the West.

However, peace would also allow the U.S. and Europe to reprioritize their mutual goals of expanding manufacturing capabilities, better concentrating on containing Chinese expansionism and ensuring that the growth of a BRICS currency does not rival the dollar as the world's reserve currency.

Adding Greenland

Trump's global ambitions and related rhetoric is another area of consequential tension. Talk of territorial acquisitions in Greenland and Panama complicate relations with Latin America and further complicate dealing with Europe, especially Denmark and the rest of Scandinavia.

There is a long history of the U.S. seeking to purchase Greenland for resource development and for reasons of national security, and Russian and Chinese ambitions in the Arctic are a real geopolitical concern. Both nations have been acting aggressively by growing their presence in the Arctic archipelago of Svalbard, which is owned by Norway and has significant mineral resources.

As for Panama, Trump's talk of reacquiring the strategically important Panama Canal is part of an overall China strategy that includes a goal of countering China's presence in the Canal, which is vital to global energy trade, including crude oil.

Middle East Challenges

Nowhere is geopolitics more complicated and historically important to the oil industry than the Middle East. Israel's recent victories over Iranian proxies Hamas, Hezbollah and the Houthis have Iran on its back foot after years of being on the offense. Trump will make weakening Iran a priority of his Middle East policy, not only through the aforementioned oil sanctions but through diplomatic actions in the region.

A major priority includes building upon diplomatic successes in the first administration with the Abraham Accords—which normalized relations between Israel and United Arab Emirates, Bahrain, Sudan and Morocco—by mending relations with Saudi Arabia and the Gulf States. As part of this effort, the administration will be attempting to drive a wedge between these countries and Iran, Russia and China.

Energy dominance is a key goal for the new administration. Clearly, much of that goal is focused domestically on increasing production of oil and gas, maintaining the dominant U.S. position in refined products, chemicals and NGL, boosting LNG production and exports, meeting increased power demand, and upgrading and expanding our energy infrastructure (pipelines, transmission and distribution, and ports).

However, an equally important part of energy dominance is geopolitical. The new U.S. administration aims to accomplish this by growing the strength of the West, strengthening our relationship with Saudi Arabia and the Gulf States, restructuring our North American trade alliance with Canada and Mexico, isolating Iran and Venezuela, and countering Russia, China, and the BRICS movement. It is a complicated chess match that will no doubt be fun to watch. OGI

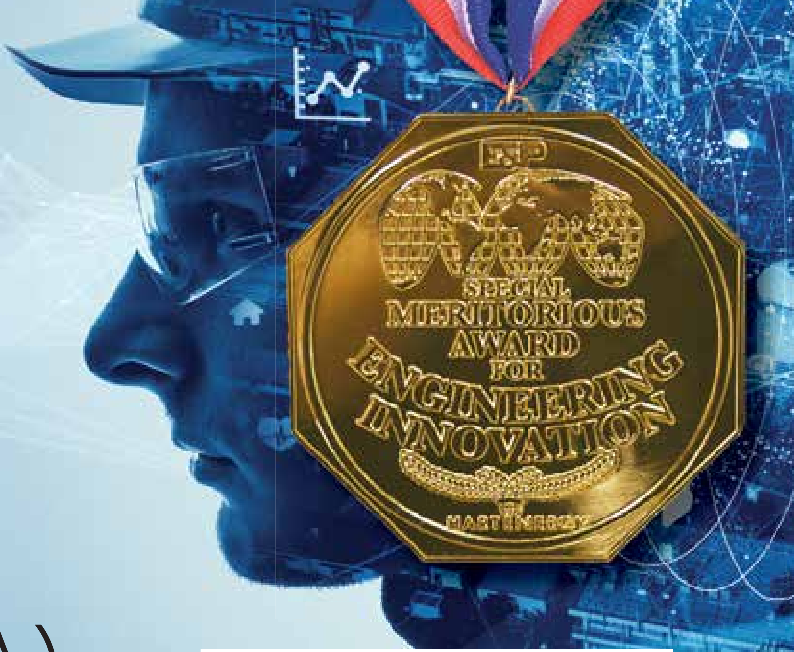
EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2025				
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
NAPE	Feb. 5-7	Houston	George R. Brown Conv. Ctr.	napeexpo.com
6th American LNG Forum	Feb. 10-11	Houston	Westin Galleria	americanlngforum.com
Oil & Gas Automation and Technology Week	Feb. 11-12	Houston	Hyatt Regency Intercontinental Airport Hotel	oilandgasautomationand technology.com
Influential Women in Energy Luncheon	**Feb. 27**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
SGA 2025 Spring Gas Conference	March 2-5	Charlotte, N.C.	Charlotte Convention Center	southerngas.org
SPE/IADC International Drilling Conference and Exhibition	March 4-6	Stavanger, Norway	Stavenger Forum	drillingconference.org
CERAWeek	March 10-14	Houston	Hilton Americas	ceraweek.com
DUG Gas Conference & Expo	**March 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**hartenergy.com/events**
SPE/ICoTA Well Intervention Conference & Exhibition	March 25-26	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
AI in Oil & Gas Conference	April 8-9	Houston	Hyatt Regency Houston West	aioilandgas. energyconferencenetwork.com
Energy Workforce & Technology Council Annual Meeting	April 9-10	Frisco, Texas	The Westin Dallas Stonebriar Golf Resort	energyworkforce.org
World Oilman's Mineral & Royalty Conference	April 14-15	Houston	Post Oak Hotel	mineralconference.com
SPE Improved Oil Recovery Conference	April 23-25	Tulsa, Okla.	River Spirit Casino and Resort	speior.org
Offshore Technology Conference	May 5-8	Houston	NRG Park	2025.otcnet.org
Canada Gas Exhibition & Conference	May 6-8	Vancouver, Canada	Vancouver Convention Center	canadagalng.com
SUPER DUG Conference & Expo	**May 14-15**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**hartenergy.com/events**
World Hydrogen 2025 Summit & Exhibition	May 20-22	Rotterdam, Netherlands	Rotterdam Ahoy	world-hydrogen-summit.com
SGA Energy Symposium	May 22	Houston	TBD	southerngas.org
URTeC	June 9-11	Houston	George R. Brown Conv. Ctr.	urtec.org/2025
IADC World Drilling Conference & Exhibition	June 10-11	Amsterdam	Beurs van Berlage	iadc.org
Global Energy Show Canada	June 10-12	Calgary, Canada	BMO Centre at Stampede Park	globalenergyshow.com
Reuters Data Driven Oil & Gas 2025	June 24-25	Houston	TBD	events.reutersevents.com
2025 Operations Conference	July 22-25	Austin, Texas	TBD	southerngas.org
IMAGE	Aug. 25-28	Houston	George R. Brown Conv. Ctr.	imageevent.org
Gastech Exhibition & Conference	Sept. 9-12	Milan, Italy	Fiera Milano	gastechevent.com
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.



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Entry is free, and winners will be featured in the May 2025 issue of *Oil and Gas Investor*. Additionally, the awards will be presented at SUPER DUG 2025, taking place from May 13-15 in Fort Worth, TX.

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- IOR/EOR/Remediation
- Machine Learning and AI
- Marine Construction & Decommissioning
- Nonfracturing Completions
- Onshore Rigs
- Subsea Systems
- Water Management

Deadline for submissions is March 31, 2025.

Contact: meainfo@hartenergy.com with any questions.

HARTENERGY

The Year of Natural Gas

New LNG export capacity and new gas-fired power demand have prices for 2025 gas and beyond much higher than the early 2024 outlook expected. And kicking the year off: a 17-day-and-counting freeze across the U.S.

NISSA DARBONNE
EXECUTIVE
EDITOR-AT-LARGE
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The LNG carrier* Isabella *was loading at Venture Global's Plaquemines terminal south of New Orleans in mid-January.

SHUTTERSTOCK

Demand is aligned for an upside year for U.S. natural gas producers in 2025 as LNG export capacity expansions underway for years add to the daily draw. And forecasts for some 50 gigawatts (GW) of additional U.S. dispatchable power generation for AI data centers have appeared in just the past six months.

Already in early January, the prompt-month contract was $3.98/MMBtu and the 12-month strip was $3.83/MMBtu.

A year earlier, the prompt-month price was $3.10/MMBtu and the strip was $3.02/MMBtu.

LNG Exports

LNG exports of some 13.5 Bcf/d in late December may grow to 16.1 Bcf/d in this quarter as Venture Global reaches full capacity at its newest plant–Plaquemines on the Mississippi River south of New Orleans.

The LNG operator's first shipment left the dock in late December on its *Venture Bayou* tanker, unloading at Wilhelmshaven, Germany, in early January, and was en route to Louisiana for a reload on Jan. 12.

Another of Venture Global's tankers, *Venture Gator*, was en route to Europe in early January. The LNG producer bought the two tankers in July from Astra Ltd.

Meanwhile, *Isabella* was loading. And *Flex Rainbow* was anchored at the Mississippi's mouth, waiting its turn to load.

Gazprom's contract to deliver gas to Ukraine expired at year-end. Three years after Russia's invasion of the country, Europe is nonplussed without Russia's gas. The LNG price delivered to The Netherlands (Dutch TTF) was about $14/MMBtu.

And Europe's outlook is positive. Futures contracts for LNG priced at the TTF are backwardated, declining to $11 into the winter of 2028-2029.

Venture Global's Plaquemines plant has FERC approval to 3.3 Bcf/d. It currently is operating at 2.63 Bcf/d, according to Venture Global.

Separately, Exxon Mobil's long-awaited Golden Pass LNG export plant on the Sabine River at the Texas-Louisiana border has FERC approval to 2.6 Bcf/d. It is expected to load a first tanker later this year.

And Cheniere Energy's expansion at Corpus Christi, Texas, began liquefaction in December. A first load is expected later this quarter. Full capacity from the seven-train expansion will be 1.3 Bcf/d, bringing the plant's total output to more than 3.3 Bcf/d.

Data Centers

Nuclear power generator Constellation Energy has put itself in front of answering new data-center electricity demand. First, it signed a deal with Microsoft Corp. to restart the Three Mile Island nuclear plant in 2028, which would put some 835 megawatt (MW) back onto the grid.

And in early January, Constellation signed a deal to buy gas-fired, privately held, Houston-based power generator Calpine Corp. for $29.1 billion, including debt assumption, for a combined generation capacity of more than 60 GW, becoming the largest U.S. power generator.

"It just seems like there's a new story every day about the demand growth," Joe Dominguez, Constellation president and CEO, told investors in a call about the deal in January.

"The fact of the matter is, demand for our products is expected to grow at levels we haven't seen in a lifetime. We can all raise questions about the ultimate magnitude of these increases. Do we believe all of it's real?

"It's hard to say, really. But let me offer a couple thoughts here. First, even if only half or one-third of this forecasted growth occurs, it's a very big deal."

Microsoft announced it will spend $80 billion on AI demand centers. "The demand is real," Dominguez said.

The combined assets will be Constellation's nuclear fleet and Calpine's natural gas, geothermal and co-generation plants—all producers of power 24/7.

Data centers use "eye-popping amounts of power," Maeghan Rouch, a Bain & Co. partner, reported this past fall. "Serving a 1 GW data center requires the capacity of about four natural gas plants or around half of a [two-reactor] large nuclear plant."

Microsoft's plans alone are expected to call for 5 GW—and all 24/7 power.

Analysts' projections are generally for an average of 50 GW call for additional power supply.

Adjacent to the Haynesville Shale play, two power producers announced new gas-fired fleet expansions in December.

Swepco plans to build a 450 MW plant in Harrison County, Texas, and convert a 1 GW plant from coal to gas nearby in Morris County. Both are in the Southwest Power Pool, outside Texas' ERCOT grid.

Just east of the Haynesville, Entergy announced three newbuild combined-cycle turbines with a combined capacity of 2.32 GW, with two of these in Richland Parish in North Louisiana.

The plants are to power Meta's $10 billion data center, its largest to date, in the parish.

Winter

As of Jan. 12, most of the U.S. had been below 32 degrees for seven days already in Winter Storm Blair. And the 10-day forecast expected 10 more days of this as Winter Storm Cora immediately followed Blair just as the Deep South had found a one-day reprieve in the 50s.

The first sub-freezing week's gas-draw data was to be released by the EIA on Jan. 16.

Winter gas draws had already brought the supply overage to par with a year ago—about 3.3 Tcf—but remained about 0.2 Tcf greater than the five-year average.

The gas draw due to Blair was anticipated to gain a ranking among the biggest. At No. 1 was a 2018 draw of 359 Bcf; No. 2, the 338 Bcf draw in 2021 that would have been larger had Texas had electricity that week; and No. 3, the 326 Bcf of a year ago. OGI

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