Oil and Gas Investor

SPECIAL OGI REPORT

PERMIAN PLAYS

DECODING THE DELAWARE

How E&Ps are Unlocking the Future

IT'S COMPLICATED

Public E&Ps Find Financing a Mixed Bag

THE OGInterview

MOVING FROM THE MIDDLE

EIV Capital Expands Private Equity Investing with Non-Op, Transition Trends

SUMMER OF DISCONTENT

Warm Weather Weighs Down Natural Gas Prices

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MAY 2024

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ASSET DIVESTITURE	INITIAL PUBLIC OFFERING	ABL REVOLVER & TERM LOAN	FOLLOW ON OFFERING	HAS BEEN ACQUIRED BY
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UNDISCLOSED	$324 MILLION	$475 MILLION	UNDISCLOSED	$155 MILLION
UNDISCLOSED SELLER HAS SOLD NON-OPERATED WORKING INTERESTS TO IOG RESOURCES	Atlas Energy Solutions	PERFORMANCE PROPPANTS HAS AGREED TO BE ACQUIRED BY PROFRAC	KAM Energy LLC	CHEYENNE
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$1.3 BILLION	UNDISCLOSED	$55 MILLION	$126 MILLION	$307 MILLION
ENPC BUSINESS COMBINATION WITH SILVERROCK TO FORM GRANITE RIDGE	SPONTE RESOURCES	BRIDGER PHOTONICS HAS RECEIVED AN INVESTMENT FROM MADISON VALLEY PARTNERS NEXTfrontier CAPITAL CARICA	EnSight IV Energy Partners, LLC	MURCHISON OIL & GAS, LLC
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$63+ Billion
Energy Investment Banking Transaction Volume Since 2009

~$300 Million
Average Transaction Size

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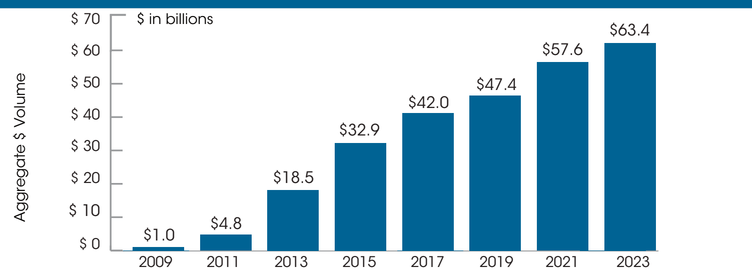
ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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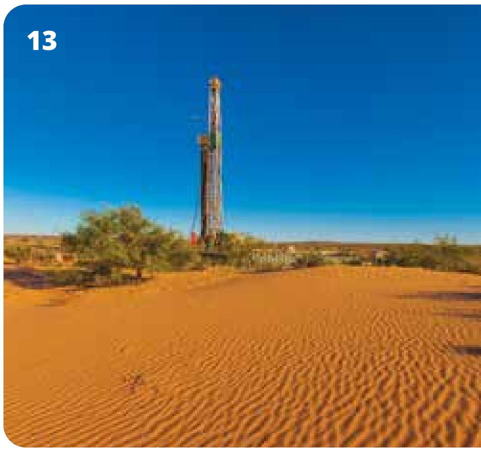

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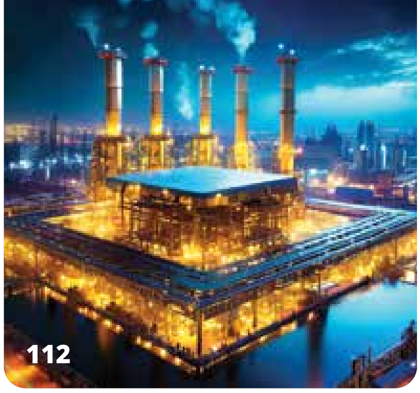
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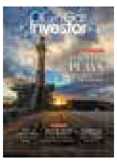
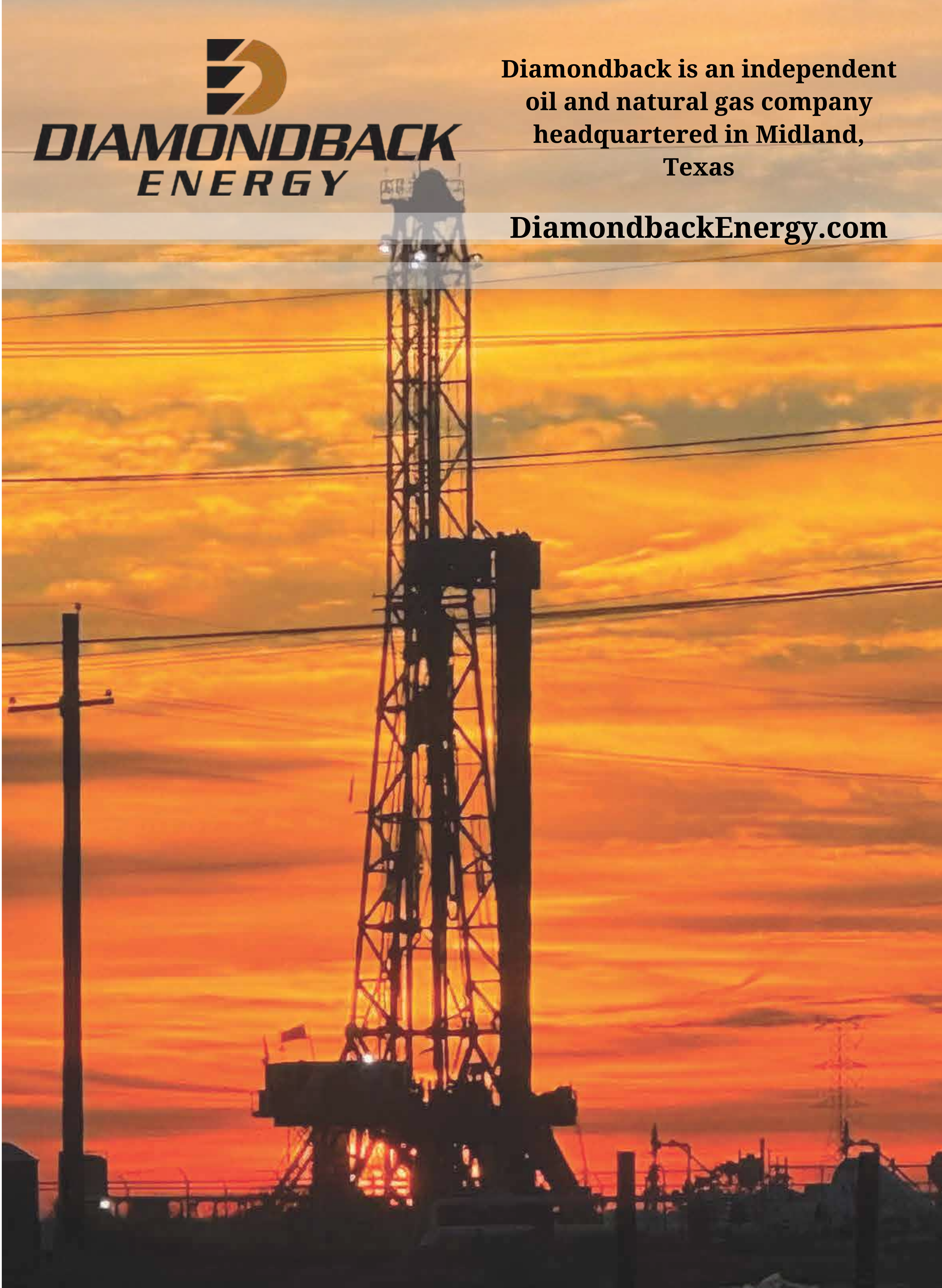


ABOUT THE COVER:
A rack full of casing sits ready for a new Delaware Basin oil and gas well. Photo by Jim Blecha.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DiamondbackEnergy.com

US Oil and Gas Lessons in Resilience

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A close examination of the U.S. oil and gas industry during the last decade is a veritable master class in resilience.

Got money problems? Tighten your belt.

What used to work is no longer getting the job done? Innovate around the problem.

Reputation taking a hit? Take control of the narrative.

Global backlash? Make yourself indispensable.

The industry and its participants may thrive on difficulty, as is the way of the rebel wildcatter. Despite the above challenges and others, where there is a mighty will, it appears there is some way.

The Permian Basin—counted out more times that I can quickly recount—continues to lead Texas to set new production records. Indeed, even as the pandemic dampened global morale to a level not seen in recent history, the industry pulled itself up by its bootstraps. The numbers bear this out.

The Texas Railroad Commission (RRC) reported in early April that the state's oil and gas production—led by the Permian—reached new records in 2023. For oil, volume reached 1.92 billion barrels, more than 3% above the previous record; natural gas production last year topped 12.01 Tcf, an increase of more than 13% above the prior peak.

Circling back to the industry's pandemic performance, all five top years for both commodities represent the period pre-pandemic, during the pandemic and throughout the recovery.

Fast-forward to the first quarter of this year, and production numbers around the country are down slightly. The Federal Reserve of Dallas' quarterly survey of some 200 industry executives reported the decrease. And while volume showed some slippage, costs increased at a slightly faster pace for those in both the oilfield services (OFS) and E&P spaces. OFS firms said input costs are rising. For E&Ps, lease operating expenses are increasing.

There's no cause for alarm, though. Historically, E&Ps expend the bulk of their operations capital during the first half of the year, putting the tools, people and equipment in place to boost production during the second half.

Expectations for both oil and gas indicate that the industry's leadership is planning for slow and steady increases.

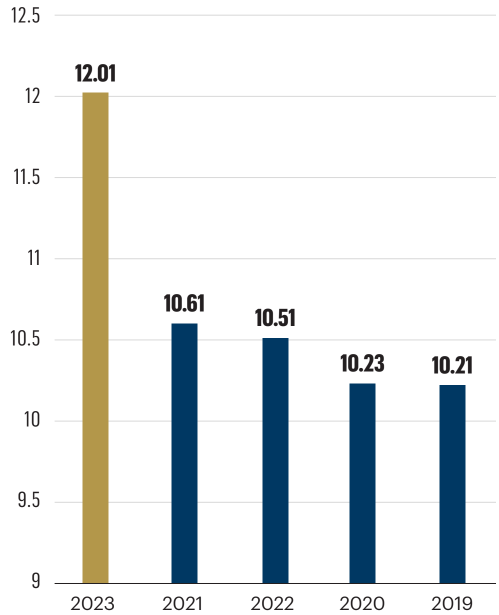
Perhaps the most telling element in the index is the rebound in corporate outlook. While it is gaining strength, uncertainty is also on the increase, suggesting a cautious optimism that has become the industry attitude baseline.

And it is with that stoic sense of optimism that we look forward to joining you all in Fort Worth, Texas, this month for our SUPER DUG conference, May 15-17. This is the nation's largest shale gathering of industry professionals for learning and networking.

In the meantime, we're continuing our Permian Basin deep dive in this edition of *Oil and Gas Investor* with an exploration of the Delaware Basin. The play is catching up to its Midland Basin neighbor, both in value and consolidation. We also dig into the Permian associated gas that's going to Mexico for processing, and the general state of the natural gas business.

We hope you enjoy the magazine and continue to watch this space. OGI

Top Five Natural Gas* Production Years in Texas (Tcf)



*INCLUDES GAS WELL AND CASINGHEAD GAS
SOURCE: TEXAS RAILROAD COMMISSION

DEON DAUGHERTY
EDITOR-IN-CHIEF


EnCap is proud to celebrate
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Want CO_2 Gone Now? Well, You Can't Always Get What You Want

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This all-or-nothing mindset is getting old. We see it in Congress with cavalier calls to shut down the government over policy disputes, and we see it in some corners of energy policy with an approach that opposition to carbon capture technologies is the best way to reduce carbon emissions (no, it doesn't work that way).

To some extent, I get it. In my present role, writers often ask me about deadlines for their stories. My visceral response: I want it all, and I want it now. It's an elegant blend of '70s classic rock anthem with post-Pandemic residual self-absorption.

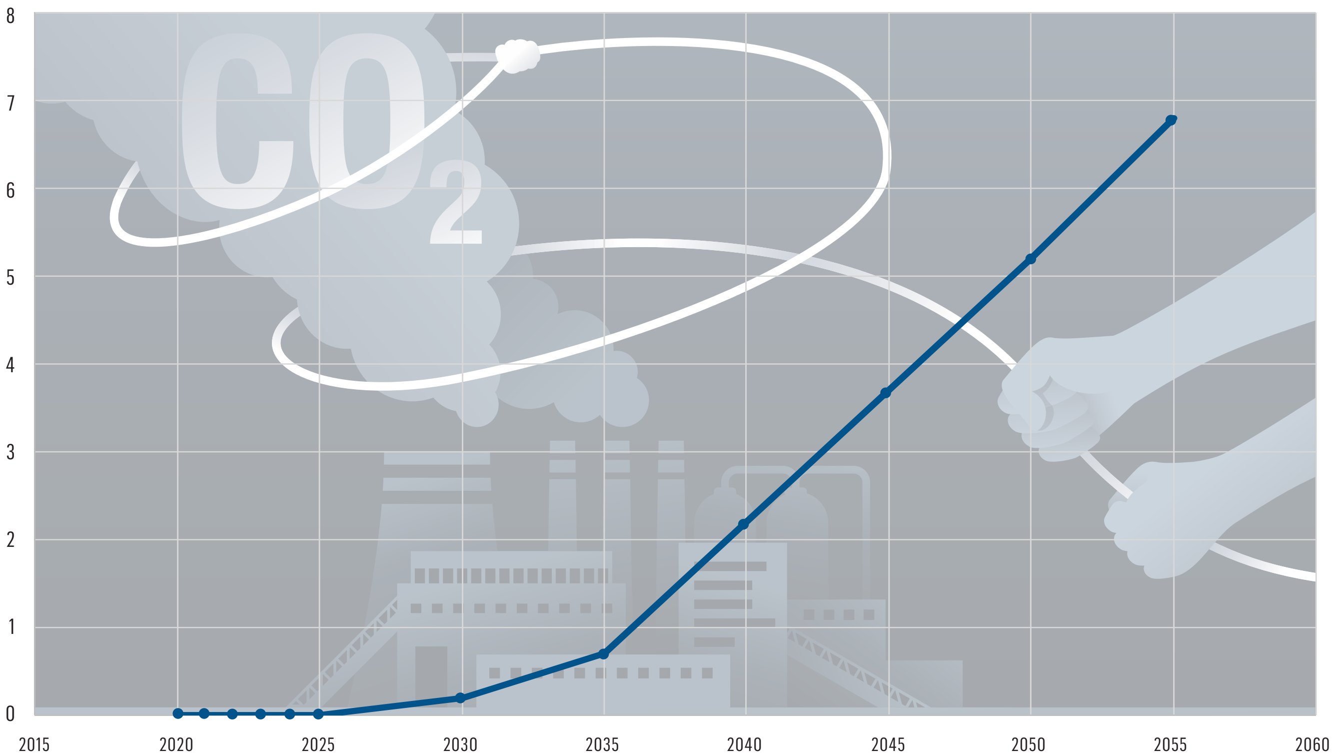
But the want-it-all-want-it-now policy from CCUS detractors is ignorant and unrealistic (as opposed to my want-it-all-want-it-now policy that is not ignorant though entirely unrealistic). Fact is, no, you can't always get what you want ('70s rock anthem), but if you try sometime, you'll find you get what you need.

What's needed is a reduction in the greenhouse gases (GHG) that rise into the atmosphere and alter the climate beyond what would be expected, given the natural history of the earth. This happens when fossil fuels combust to generate energy. If those gases are captured, then we have the benefit of affordable, accessible energy without placing the planet in peril. That's the goal (want it all), and it's looking like it can be achieved.

The United Nations COP28 framework sets the ceiling at a 1.5 C increase in the global temperature by 2100. How are we doing? In the Resources for the Future's (RFF) Global Energy Outlook 2024, released in April, the research institution examines numerous climate scenarios put forth by entities

The Carbon Capture Trend

The Shell Sky 2050 ambitious climate scenario estimate of gigatons of CO_2 per year



The Shell Sky 2050 projection of CO_2 captured from now until 2055 reflects confidence that the combination of direct air capture, CCUS and growing use of hydrogen will play a meaningful role in managing GHG emissions in the future.

SOURCE: SHELL

ranging from Exxon Mobil to the Energy Information Administration to OPEC to Equinor to Shell.

"To achieve international climate goals and limit warming to 1.5 C or 2 C by 2100, a true energy transition is needed," RFF says. "But does achieving such goals require phasing out fossil fuels entirely? The scenarios we analyze in this report suggest that the answer is no."

Fossil fuel use declines but is projected to remain substantial through mid-century and beyond, researchers have found. This is the case even under scenarios that limit warming to 1.5 C.

And that's a good thing. Solar and wind are excellent renewable sources of energy, but are not advantageous everywhere, such as Poland, which has been plagued with a decades-long uptick in heavy storms (can't always get what you want). Fossil fuels, on the other hand, are abundant, high in energy efficiency and used for transportation and industry everywhere, every day (you'll find you get what you need).

Transitioning away from fossil fuels is a complicated process, not a bumper sticker. The value of CCUS lies in easing the transition and accelerating carbon emission reduction. It just can't be done immediately.

But it can be done. Achieving the goal requires increased use of CCUS infrastructure around the world. In 2022 about 42 million metric tons (MMmt) of CO_2 were captured globally. That may not seem like much–it's only 0.1% of annual global emissions–but it was three times as much as captured in 2010.

By 2050, that figure could reach as high as 20% of worldwide emissions, as estimated in some ambitious climate scenarios. The RFF authors contend that a dramatic growth rate at that level is technically achievable (want it all) but faces considerable headwinds (can't always get what you want).

Direct air capture, for example, pulls CO_2 out of ambient air (want it all) and sequesters it (want it now). It can then be used, as Occidental Petroleum does in the Permian Basin, for EOR. That drives opponents batty because they say the fossil fuel produced eliminates the climate benefits of permanent sequestration (can't always get what you want).

"On the other hand, it is at least technically possible for the volumes of CO_2 stored using EOR to meet or exceed the emissions embodied in the oil produced; in other words, EOR could theoretically be used to produce 'carbon neutral' or even 'carbon negative' oil," the RFF authors say.

The energy transition is aptly named. Had Madison Avenue gone with energy turn-on-a-dime, the palpable disappointment might be understandable. This is going to take a while.

But if you try sometimes, well, you just might find, you get what you need. OGJ

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Wil Van Loh
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ConocoPhillips

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President and CEO
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Aaron Chang
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Franklin Mountain Energy

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CEO
FireBird Energy II

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John Raines
Vice President, Delaware Basin Business Unit
Devon Energy

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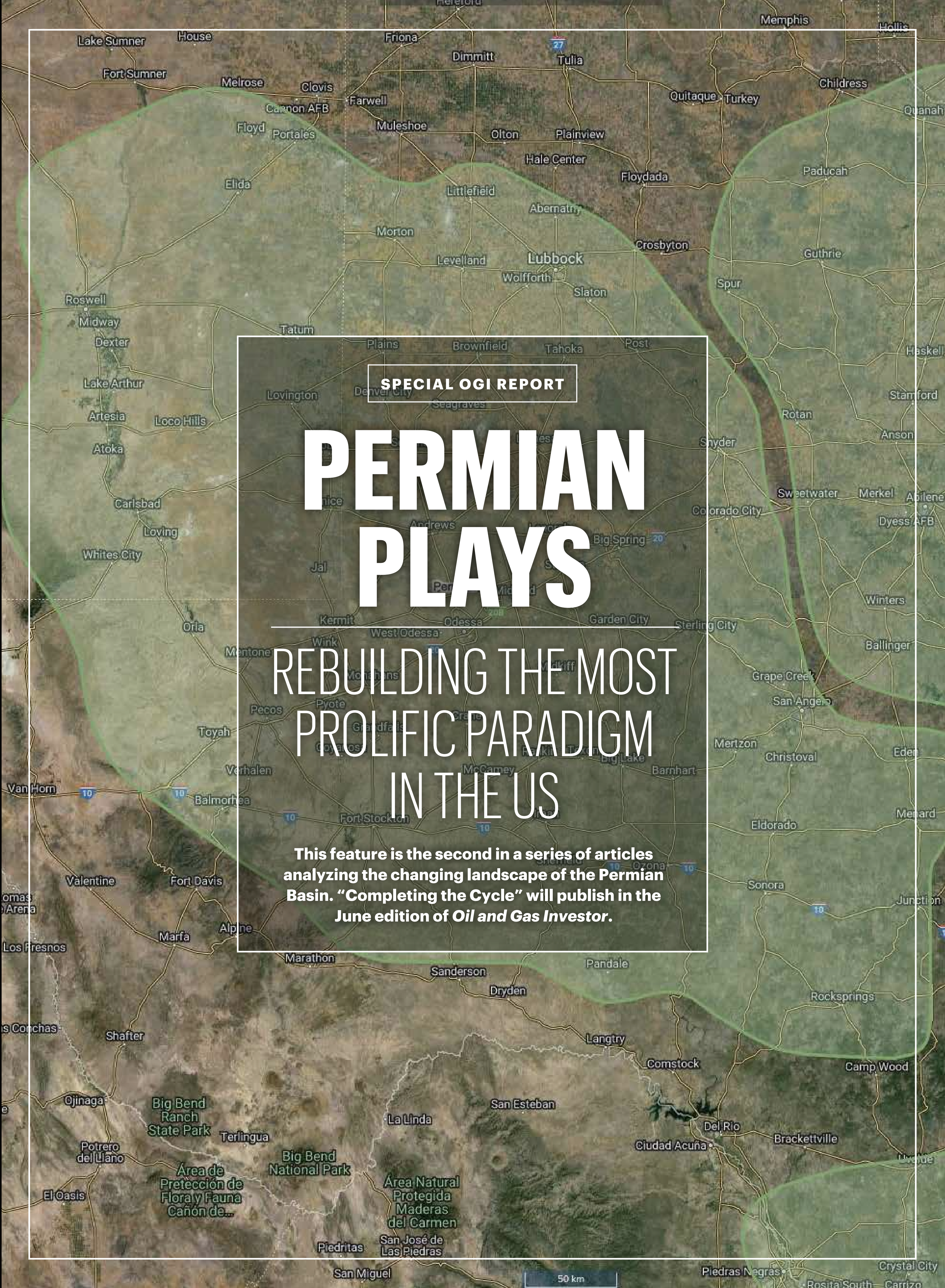
SPECIAL OGI REPORT

PERMIAN PLAYS

REBUILDING THE MOST PROLIFIC PARADIGM IN THE US

This feature is the second in a series of articles analyzing the changing landscape of the Permian Basin. "Completing the Cycle" will publish in the June edition of *Oil and Gas Investor*.



DECODING THE DELAWARE:

HOW E&PS ARE UNLOCKING THE FUTURE

The basin is deeper, gassier, more geologically complex and more remote than the Midland Basin to the east. But the Delaware is too sweet a prize to pass up for many of the nation's top oil and gas producers.

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Oil wells easily outnumber people in Loving County, Texas.

Loving (population: 43) is the least populous county in the nation, according to the U.S. Census Bureau.

But it's the epicenter of drilling activity on the Texas side of the Delaware Basin—a portion of the Permian from where operators expect to see decades of future crude oil production growth. The Delaware, extending from West Texas into southeastern New Mexico, is less developed than its eastern Permian cousin, the Midland Basin.

"We tend to think with today's activity and technology, if Midland's got 15 to 20 years left, the Delaware is probably in the 20- to 25-year range," said Jason McIntyre, Halliburton's Permian area vice president. "However we're very long on Permian Basin production."

Major operators are scrambling to buy the best acreage in the Midland, which has seen over $100 billion in corporate M&A and asset acquisitions over the past 12 months. That's because the Midland has some of the most productive and lowest-cost rock to drill in the country.

The Delaware Basin is a different beast.

The drilling targets in the Delaware are deeper. Pressures are higher. The potential for H_2S sour gas is much higher than in the Midland.

Power and water infrastructure constraints also present unique challenges to drill in one of the least-developed and sparsely populated places in the country.

To make matters more complicated, the core of the Delaware oil play extends into New Mexico, where operators face a more stringent regulatory regime than south of the border in the Lone Star State.

But the Delaware's prize—bountiful oil output potential and decades of future upside—is too sweet to pass up for many of the nation's top producers, including Exxon Mobil, Chevron, ConocoPhillips, EOG Resources, Occidental Petroleum, Devon Energy, Coterra Energy and Apache.

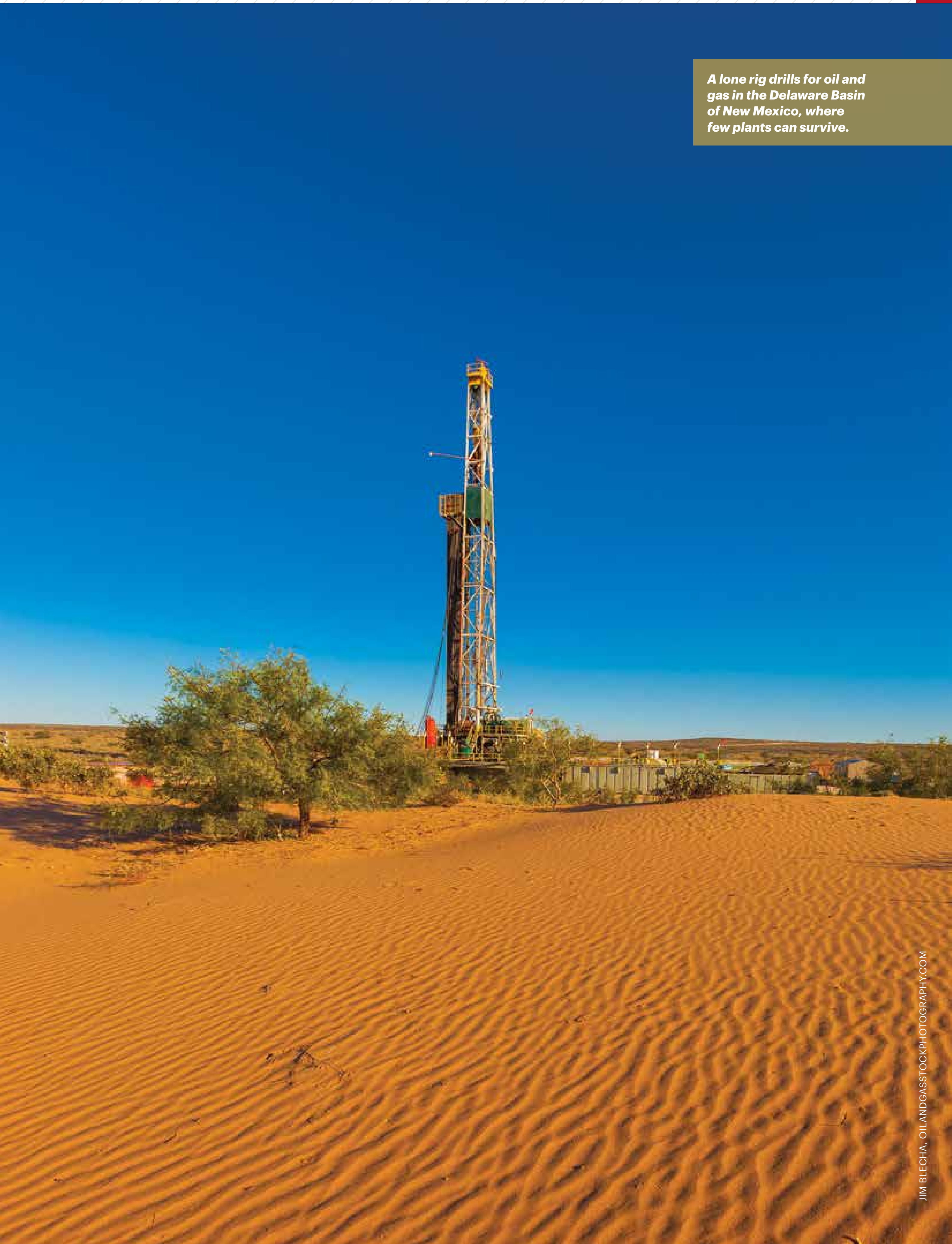
"A lot of operators that operate in both basins, they tend to see maybe more prolific production in the Delaware," McIntyre said, "but it comes at a higher development cost."

Exploring new horizons

Harold Hamm made himself a billionaire wildcatting in the Bakken and in the Midcontinent, but in recent years, the Delaware's potential has become too much for him to resist.

"We think there is a significant amount of opportunity for a company like Continental to grow in the Permian Basin. We see that through existing inventory. We see that through exploration, and we see that through efficiencies on the operating and technical sides."

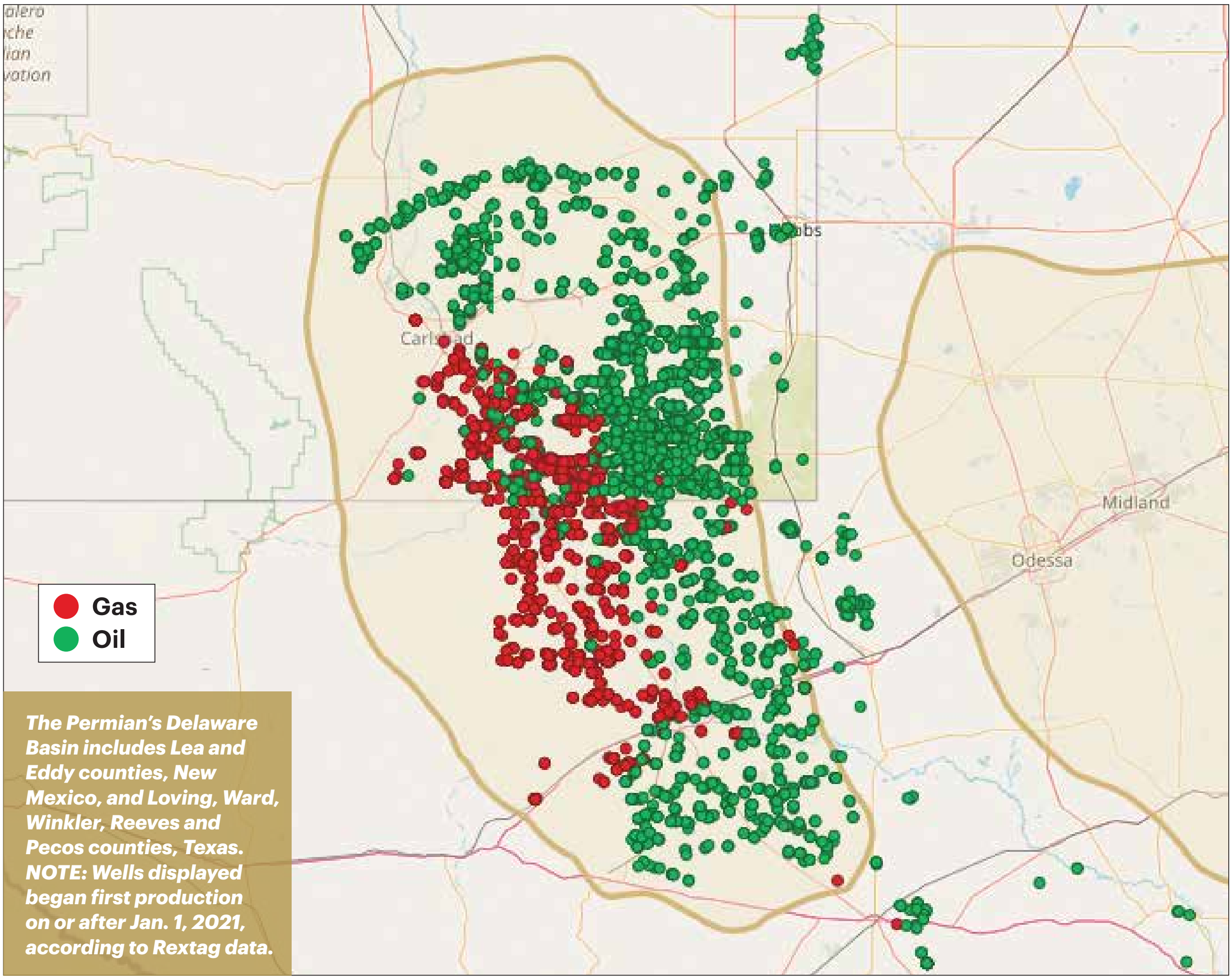
DOUG LAWLER, CEO, Continental Resources



A lone rig drills for oil and gas in the Delaware Basin of New Mexico, where few plants can survive.

JIM BLECHA, OILANDGASSTOCKPHOTOGRAPHY.COM

The Delaware Basin



The Permian's Delaware Basin includes Lea and Eddy counties, New Mexico, and Loving, Ward, Winkler, Reeves and Pecos counties, Texas. NOTE: Wells displayed began first production on or after Jan. 1, 2021, according to Rextag data.

SOURCE: REXTAG

He surprised industry insiders in late 2021, when his Oklahoma City-based company, Continental Resources, made an entrance into the Permian with a $3.25 billion acquisition of Pioneer Natural Resources' Delaware assets.

Horizontal development throughout the Permian already was a well-oiled machine; Continental was late to the game.

And the company's new asset was toward the southern part of the Delaware–Texas' Reeves, Ward, Winkler and Pecos counties–outside of what's largely considered the play's core oil window.

It wasn't long after Hamm's debut in the Permian that Doug Lawler, former president and CEO of Chesapeake Energy, joined Continental as COO in early 2022.

The Pioneer acquisition added around 92,000 net Delaware acres; oil volumes averaged approximately 35,000 bbl/d (50,000 boe/d).

The initial Pioneer deal delivered Continental "a relatively low amount of production" and undrilled inventory, Lawler told *Oil and Gas Investor* (OGI).

But the potential for future exploration also attracted Continental to Pioneer's Delaware asset.

"The timing was really based on when an opportunity became available for us to pursue some of that exploration without having to pay an extremely high premium because of a lot of associated current production," said Lawler, who took over as Continental's CEO at the start of 2023.

Texas Railroad Commission (RRC) records show Continental has mostly targeted the popular Wolfcamp and Bone Spring intervals with new wells drilled since taking over the Delaware asset.

But the wildcatting producer is also delineating locations to drill the deeper Woodford interval in Winkler and Pecos counties.

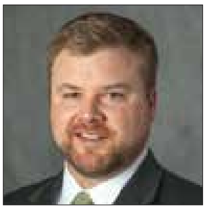
Continental has submitted production data on three Delaware Woodford wells drilled at depths ranging between 13,000 ft and nearly 16,000 ft.

The two Winkler wells (8,621-ft lateral; 9,714-ft lateral) have produced a combined 248,747 bbl since coming online in March 2023, per the RRC's most recent figures.

A Magnolia State Unit well (9,760-ft lateral) in Pecos County has produced 144,590 bbl since coming online in April 2023.

Apache Corp.'s operations in the Alpine High play in the southern Delaware Basin.

APACHE



"Infrastructure is still probably one of my biggest themes and one of the things I'm focused on the most. A lot of folks think gas and oil. I'm increasingly focused on water and power."

JOHN RAINES, Delaware Basin vice president, Devon Energy

Continental's Delaware oil production reached nearly 13.43 MMbbl (36,788 bbl/d) for full-year 2023.

Continental, which went private in a $4.3 billion buyout by the Hamm family in 2022, also has quietly added leases on the Midland side of the basin for future exploration. RRC records show Continental became operator on dozens of new leases in Midland and Ector counties, Texas, in November 2023.

"Our main focus is on the Delaware side, but we're looking also on the Midland side, as well," Lawler said.

The new Midland County leases, 87 in total, were transferred to Continental Resources by a subsidiary of Occidental Petroleum, RRC records show.

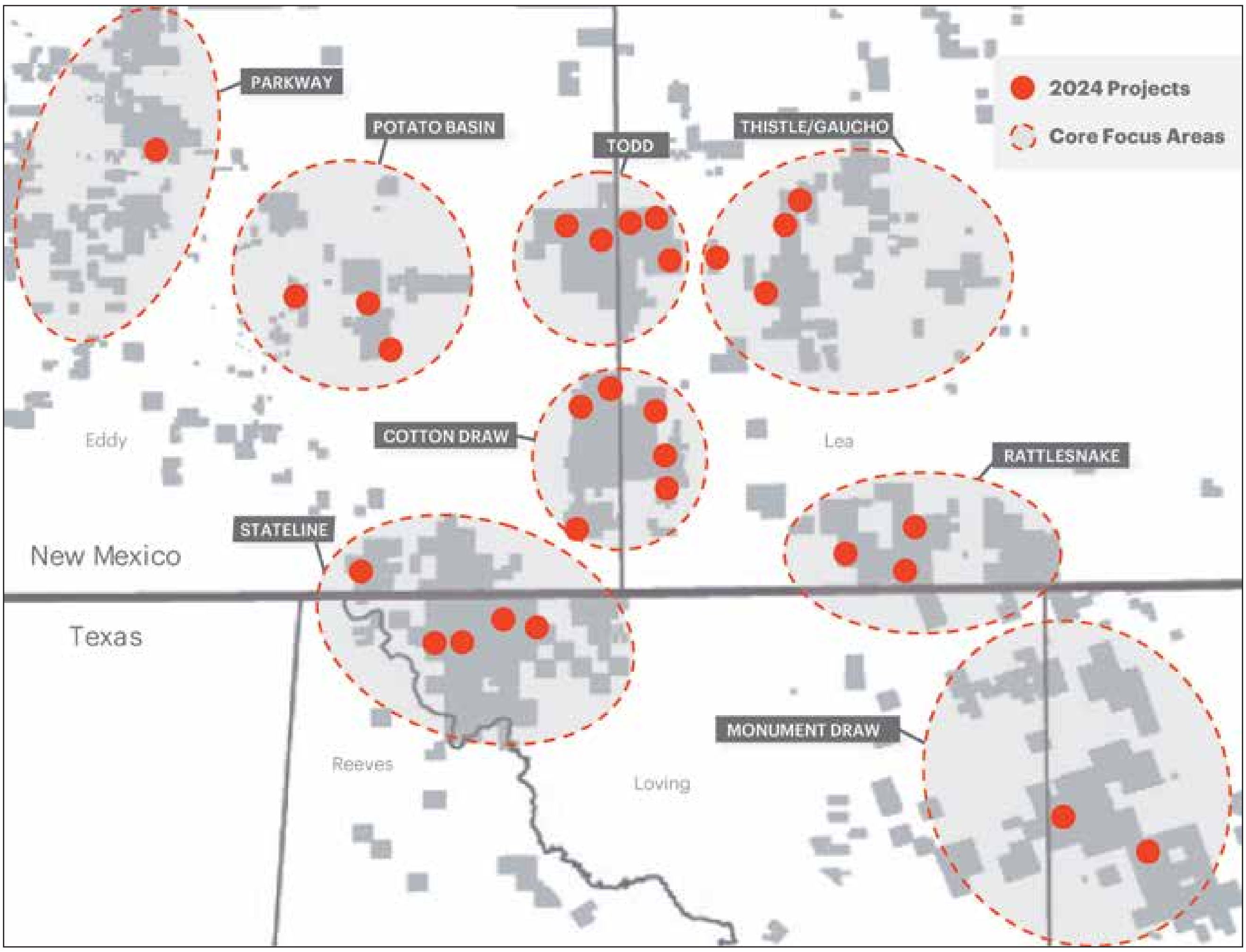
Continental also assumed operatorship of a handful of leases from Occidental in nearby Ector County, just to the west across the county line, in November. The Midland and Ector assets produced about 76,000 bbl of crude oil—an average of around 825 bbl/d—from November 2023 through January 2024, their first three months under Continental.

Legacy vertical wells drilled on most active leases have targeted the Dora Roberts Field.

Occidental recently disclosed selling "certain non-core proved and unproved properties in the Permian Basin for $202 million" in its latest annual report. Occidental recorded a net gain of $142 million from the divestment.

Continental declined to discuss details of the lease transfers in Midland and Ector counties, but said it continues to look at Permian M&A.

Devon Energy's Core Delaware Development Areas



SOURCE: DEVON ENERGY

Floor hand Fredrick Laiche (left) helps Lance Ayzinne stack pipe on Cactus Rig 148 ("Rocket Rig") as the crew trips pipe on a saltwater disposal well for Cimarex Energy Company in Culberson County, Texas. The Elwood 29 Fed SWD #1 site is in the western part of the Delaware Basin.

TOM FOX

"While we prefer not to comment on any specific transaction in detail, you can expect Continental to continue to be active with additional bolt-ons and new acquisition opportunities in the basin," a Continental spokesperson told *OGI*.

With the wave of consolidation underway across the Midland Basin, experts anticipate M&A will take place in the Delaware.

But there aren't as many potential combinations left after a record year of upstream transactions. Among private Permian producers, Mewbourne Oil and Continental stand out with the most attractive portfolios of undrilled inventory, said Rystad Senior Analyst Matt Bernstein.

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

But in an environment dominated by large-scale consolidation, Continental appears to be focused on growth and exploration–not necessarily selling assets.

Continental plans to invest around $1 billion per year over the next four to five years across the Delaware and Midland basins, Lawler said.

The company aims to double its current daily production, around 70,000 boe/d, by 2028.

"We think there is a significant amount of opportunity for a company like Continental to grow in the Permian Basin," Lawler said. "We see that through existing inventory. We see that through exploration, and we see that through efficiencies on the operating and technical sides."

Riding the line

Before the $5.75 billion combination with WPX Energy in early 2021, Devon Energy's Delaware footprint was mostly concentrated on the New Mexico side of the basin.

That presented challenges to growing in the Permian, Devon's Delaware Basin Vice President John Raines told *OGI*.

"Your primarily development going forward pre-merger for Devon is on federal acreage," Raines said.

Heading into 2020, about 40% of Devon's Delaware leasehold resided on federal lands in New Mexico, per regulatory filings.

When Democrats retook the White House, many operators questioned how the federal regulatory landscape for oil and gas leasing and permitting might change.

"You want some optionality," Raines said.

WPX Energy had options: A big portion of WPX's Delaware assets were located on the Texas side of the basin.

The combination with WPX yielded a combined 400,000 net Delaware acres, with 35% of the leasehold on federal land.

Raines now oversees Devon's most important asset: Roughly 60% of the company's planned capital investment will flow into the Delaware in 2024.

But despite a more favorable regulatory regime in Texas, operators still like drilling for oil in New Mexico.

The core-of-the-core of the basin's oil fairway extends considerably into New Mexico, unbound by the borders on the surface.

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Devon still plans to concentrate 70% of its Delaware budget in New Mexico this year, the company said during its fourth-quarter earnings call with analysts.

But operating in the New Mexico Delaware requires some flexibility: For example, the U.S. Bureau of Land Management recently withdrew seven parcels covering over 3,000 acres from an upcoming lease sale in southeastern New Mexico.

Devon had 17 rigs operating in the Delaware at the start of the year, targeting the basin's most popular Bone Spring and Wolfcamp intervals.

Devon COO Clay Gaspar highlighted some recent gushers being drilled in southeastern New Mexico during the company's earnings call:

The eight-well Clawhammer pad on federal leasehold in the Stateline development area produced 3,900 boe/d in the fourth quarter, the highest productivity per lateral foot of any of Devon's wells that quarter.

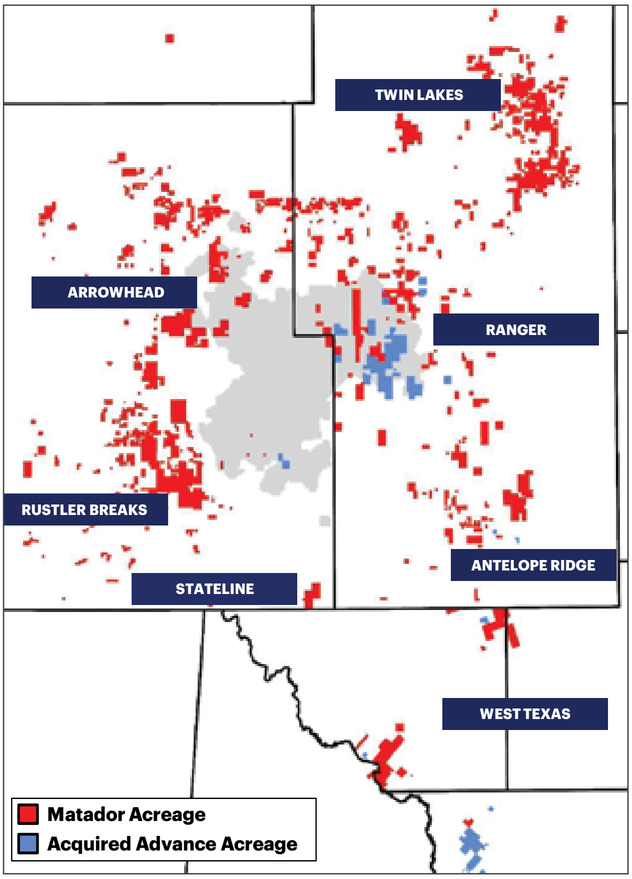
The Clawhammer project featured two-mile laterals targeting multiple intervals in the Wolfcamp A formation.

Devon also brought online 11 three-mile laterals in the Cotton Draw area across the Avalon, Bone Spring and Wolfcamp intervals during the quarter.

Raines said Devon typically thinks about developing its Delaware projects in "flow units" by different sections, or intervals, in the stratigraphic column.

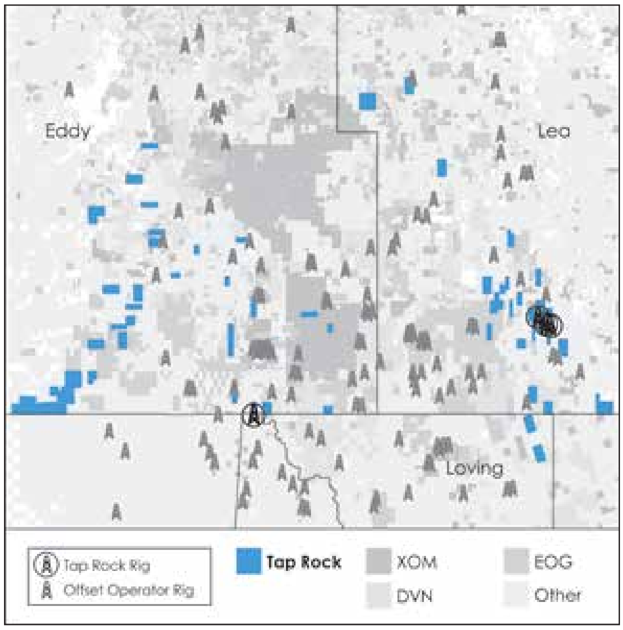
These flow units are broken down by their own

Matador and Advance Energy Partners



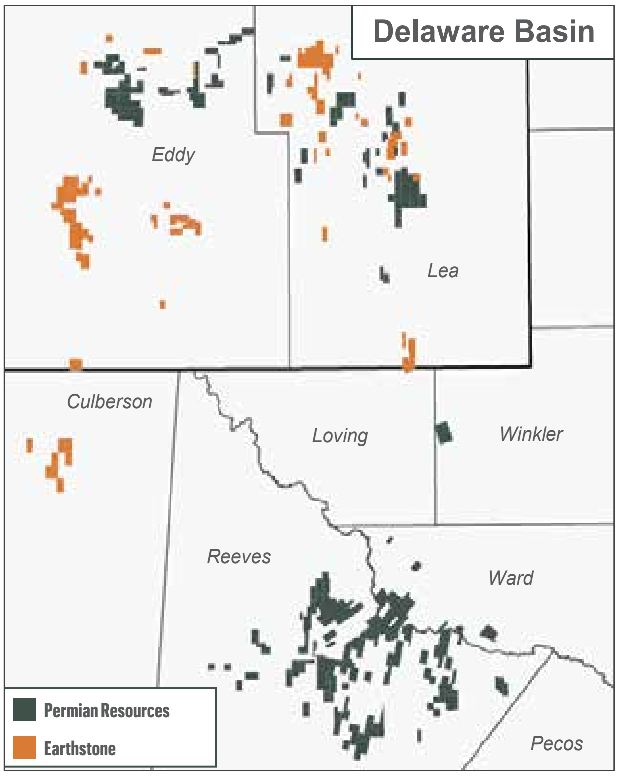
SOURCE: MATADOR

Civitas Resources and Tap Rock



SOURCE: CIVITAS RESOURCES

Permian Resources and Earthstone



SOURCE: PERMIAN RESOURCES

pressure regimes, spacing needs and completion designs, allowing Devon to simultaneously develop multiple stacked pay zones at once—a concept the industry commonly refers to as cube development.

An Upper Bone Springs flow unit would generally include the Avalon and the first and second Bone Spring formations.

Drilling deeper, a Lower Bone Springs flow unit in some cases might include the second Bone Spring Sand, the third Bone Spring Lime and the third Bone Spring Sand. In the Wolfcamp formation, an Upper Wolfcamp flow unit might contain that third Bone Spring Sand—depending on the area—the Wolfcamp XY and, generally, the Wolfcamp A.

Devon also thinks about a deeper Wolfcamp flow unit containing the Wolfcamp B's various landing zones and the Wolfcamp C.

It's not an exact science. The subsurface nomenclature tends to change from operator to operator, Raines said. What you'll find underground really depends on where you end up drilling.

"The zones we include in the Upper Wolfcamp flow unit in, say, a Rattlesnake versus a Cotton Draw verses a Potato Basin—those can look very different in terms of how you land and space your wells," Raines said, "because of those geologic inflows, outflows and changes from area to area."

Devon has over 10 years of resource opportunity remaining in the Delaware Basin, but the company also is keeping an eye on opportunities for future exploration.

Deeper formations like the Woodford or Barnett haven't yet become major targets in the company's Permian drilling plans.

"It's deeper, it's more expensive," Raines said. "Even though we think the resource is there, it may not be as competitive for us currently."

Running room

U.S. upstream M&A activity approached $200 billion in 2023, but the bulk of the dealmaking centered on the Permian Basin, most of that in the Midland. Some of the Permian's oldest and largest producers were snapped up by larger operators in a matter of months.

The most prominent example of onshore consolidation is Exxon Mobil's roughly $65 billion acquisition of Pioneer, a legacy Permian pure-play.

Diamondback Energy is scooping up Endeavor Energy Resources for $26 billion, the largest buyout of a private U.S. upstream company in the industry's history, per Enverus Intelligence Research data.

Occidental is wading further into debt to acquire private Midland producer CrownRock and selling off non-core assets to deleverage. Occidental plans to monetize between $4.5 billion and $6 billion in non-core domestic assets within 18 months of closing the CrownRock deal. That's part of the reason Occidental sold the legacy Permian assets in Midland and Ector counties to Continental late last year.

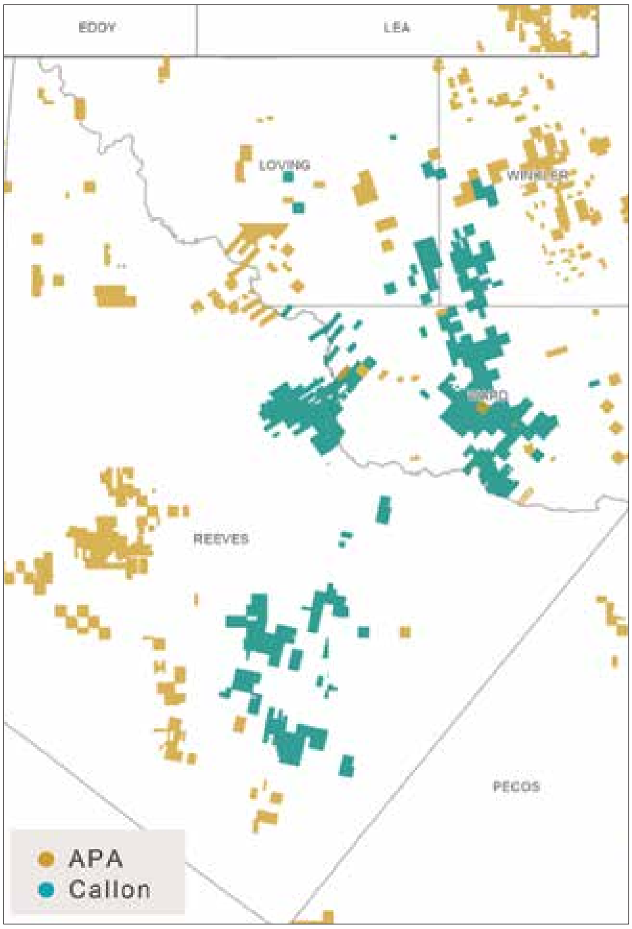
But the drumbeat of consolidation is slower in the Delaware Basin, at least for now.

Compared to the Midland, parts of the Delaware are still much more fragmented with privately held producers. But

"More recently, the performance of some of the Callon wells has significantly improved, which has demonstrated that their acreage has a lot more potential than may have been previously perceived. We're excited to apply our unconventional technical expertise and our proprietary workflows to drive further significant improvement on those properties."

SARA REILLY, vice president, U.S. assets, Apache Corp.

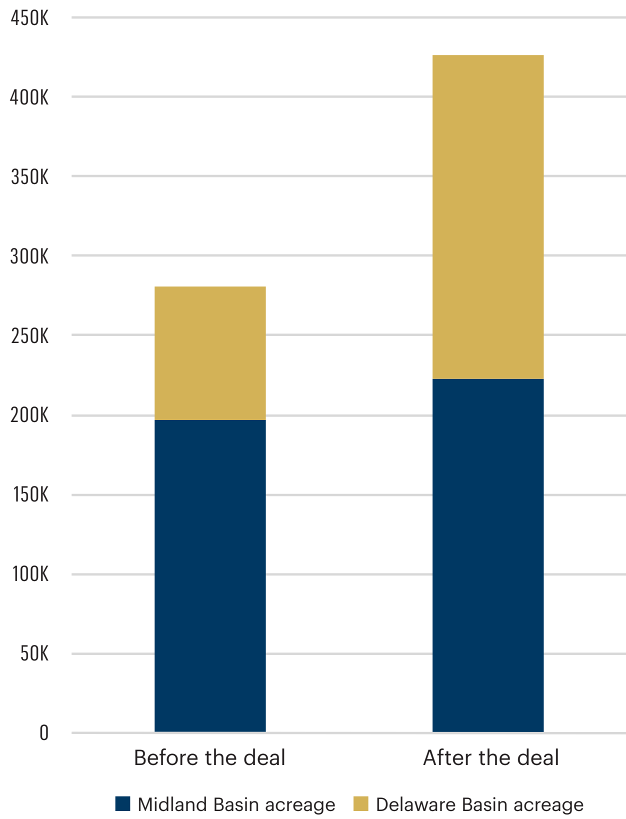
APA and Callon Petroleum



SOURCE: APA CORP.

APA-Callon Deal's Impact

APA Corp.'s $4.5 billion acquisition of Callon Petroleum increased its net acreage in the Permian Basin by 52%, but in the Delaware Basin alone, the total soared by 142%.



SOURCE: APA CORP.

core parts of the Delaware have attracted M&A from mid-sized public producers in the past year and change.

Matador Resources closed a $1.6 billion acquisition of EnCap-backed Advance Energy Partners in early 2023. Matador's largest acquisition in company history, the deal included about 18,500 net acres in Lea County, N.M., and in Ward County, Texas.

Formerly a Colorado pure-play, Civitas Resources made its foray into the Permian last year by picking up NGP-backed privates Hibernia Energy and Tap Rock Resources for $4.7 billion in cash and stock.

The Tap Rock acquisition included around 30,000 net acres and average production of 59,000 boe/d (52% oil) across Lea and Eddy counties, N.M., and Loving County, Texas.

Permian Resources' $4.5 billion takeover of Earthstone Energy gave the company additional scale in New Mexico, though a smaller entry into the Midland Basin.

In June, Vital Energy—formerly Laredo Petroleum—inked a $540 million deal to enter the Delaware by acquiring Forge Energy from EnCap. Non-operated partner Northern Oil & Gas covered 30% of the purchase price. Vital followed with additional Delaware dealmaking.

Large-cap players are starting to deepen their roots in the Delaware, too.

APA Corp., parent company of Apache, closed a $4.5 billion acquisition of Callon Petroleum on April 1. Before the Callon deal, Apache's Permian position was heavily weighted on the Midland side of the basin, where the company held 197,000 net acres. Apache had about 84,000 net Delaware acres before the Callon deal.

Callon brought to Apache about 119,000 net Delaware acres across Ward, Reeves, Winkler and Loving counties, according to RRC data. Callon also had a smaller 26,000-acre footprint in the northern Midland Basin, including Andrews, Borden, Dawson, Howard, Midland and Martin counties.

"It's an oil asset, and we like that [Callon] balances our portfolio across the basin," said Sara Reilly, vice president of U.S. assets at Apache. "We're excited to be able to add to our portfolio both in the Midland Basin and, in particular, in the Delaware Basin."

Apache has spent considerable time and resources testing well spacing and D&C designs to boost Delaware Basin well productivity.

Reilly said Apache is applying its skills learned from drilling in the southern Midland Basin to improve resource recovery in the Delaware. Under the updated workflow, Apache is widening the space between wells per section and using larger fracs. It's led to a notable uplift in overall productivity compared to the company's designs about five years ago.

"More recently, the performance of some of the Callon wells has significantly improved, which has demonstrated that their acreage has a lot more potential than may have been previously perceived," Reilly said.

"We're excited to apply our unconventional technical expertise and our proprietary workflows to drive further significant improvement on those properties."

Gary Clark, Apache's vice president of investor relations, said the Callon acquisition also helps APA better stand out as a Permian-weighted stock.

"Permian acreage, cash flows and production get more highly valued than just about any place in

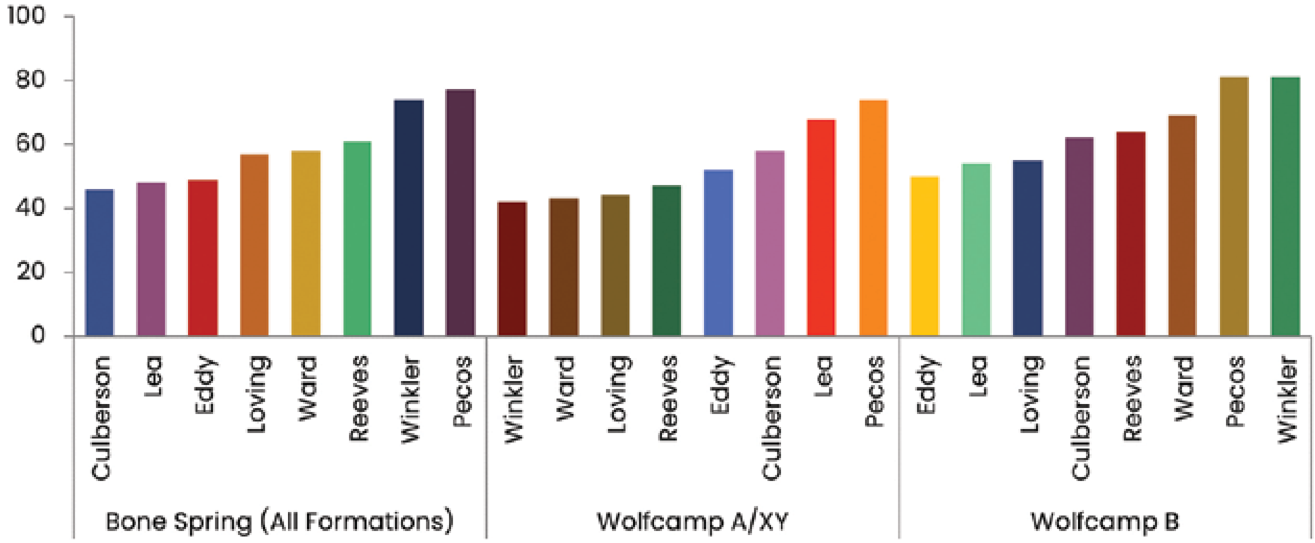
Replicating Success

SOURCE: APA CORP.

◀ *APA Corp. has worked to improve its D&C designs and well spacing in the Midland Basin to boost productivity. Apache plans to replicate its successes in the Delaware Basin.*

Delaware Breakeven Costs

2-Year WTI Breakeven ($/bbl)



SOURCE: NOVI LABS
BREAKEVENS ARE THE FLAT WTI PRICE NEEDED TO GENERATE A 2-YEAR PAYOUT PERIOD, ASSUMING $2/MCF HENRY HUB AND $20/BBL NGL PRICES. THE H2S-RICH PORTION OF WINKLER AND WARD COUNTIES WAS EXCLUDED.

Breakeven costs can vary widely across the Delaware Basin's most popular intervals, the Bone Spring and Wolfcamp formations.

the world," Clark said. "We think there's a pretty good opportunity for multiple expansions as well."

It's a similar story to what Callon itself saw play out last year as the company exited South Texas to become a Permian pure-play.

Callon announced plans to acquire Permian-based Percussion Petroleum Operating II and sell its Eagle Ford Shale assets to Ridgemar Energy Operating after markets closed May 3, 2023. From that point to Jan. 4, 2024—the day APA Corp. announced plans to acquire Callon—Callon's stock price grew by nearly 13%.

Powering the future

Operators are positioning the Delaware Basin as a key driver of U.S. crude production for decades, and the future of domestic crude volumes are depending on it.

Chevron plans to tap its Delaware acreage in Texas and New Mexico for drilling locations at least through 2040, the company told investors.

But these plans will matter little if infrastructure bottlenecks—natural gas takeaway and processing, water logistics and electricity capacity, for starters—continue to plague the basin, said Raines of Devon Energy.

"Infrastructure is still probably one of my biggest themes and one of the things I'm focused on the most," he said. "A lot of folks think gas and oil. I'm increasingly focused on water and power."

The Midland Basin produces a lot of water, but the Delaware produces "significantly more," Raines said. Being intentional about building out water transport is critical for Devon in the Delaware.

Power shortages are becoming an issue for grid managers across the U.S., but power availability is another top concern in the Delaware—one of the most sparsely populated regions in the Lower 48.

It's not just electric vehicles; fracking is going electric, too. Oil and gas operators are increasingly finding ways to reduce diesel consumption by turning to natural gas for electric power to reduce emissions associated with drilling.

"Just generally for the basin, you're seeing demand for power dramatically outpace the ability of utilities to supply that power," Raines said.

Devon is in good shape with its power needs right now, but operators have concerns about growing power demand outstripping supply as the basin scales up.

Diamondback Energy recently inked a non-binding agreement to explore deploying small-scale nuclear reactors around its Permian footprint to power its drilling needs for decades.

To manage its own power needs, Devon is evaluating a multi-year process to develop an interconnected microgrid across its Delaware development areas. Devon would set up centralized power generation in each development area using large-scale natural gas turbines—powered by an abundant supply of gas stranded in the basin. The company has some of its own power lines in those areas to manage power distribution.

"It's something we're diving into," Raines said. "We're in the process of making that transition now."

And with so much stranded gas in-basin and growing power demand, Devon could become well-positioned to sell power to other operators or demand centers in the area.

Raines admits there's a laundry list of regulatory concerns about becoming a pseudo-utility provider, tangoing with the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) in New Mexico.

"It's a little daunting because it's new," he said. "I didn't anticipate being in the power business a few years ago." OGI

+185%

From its low in February 2021 to its peak in August 2023, Delaware Basin oil and gas production soared.

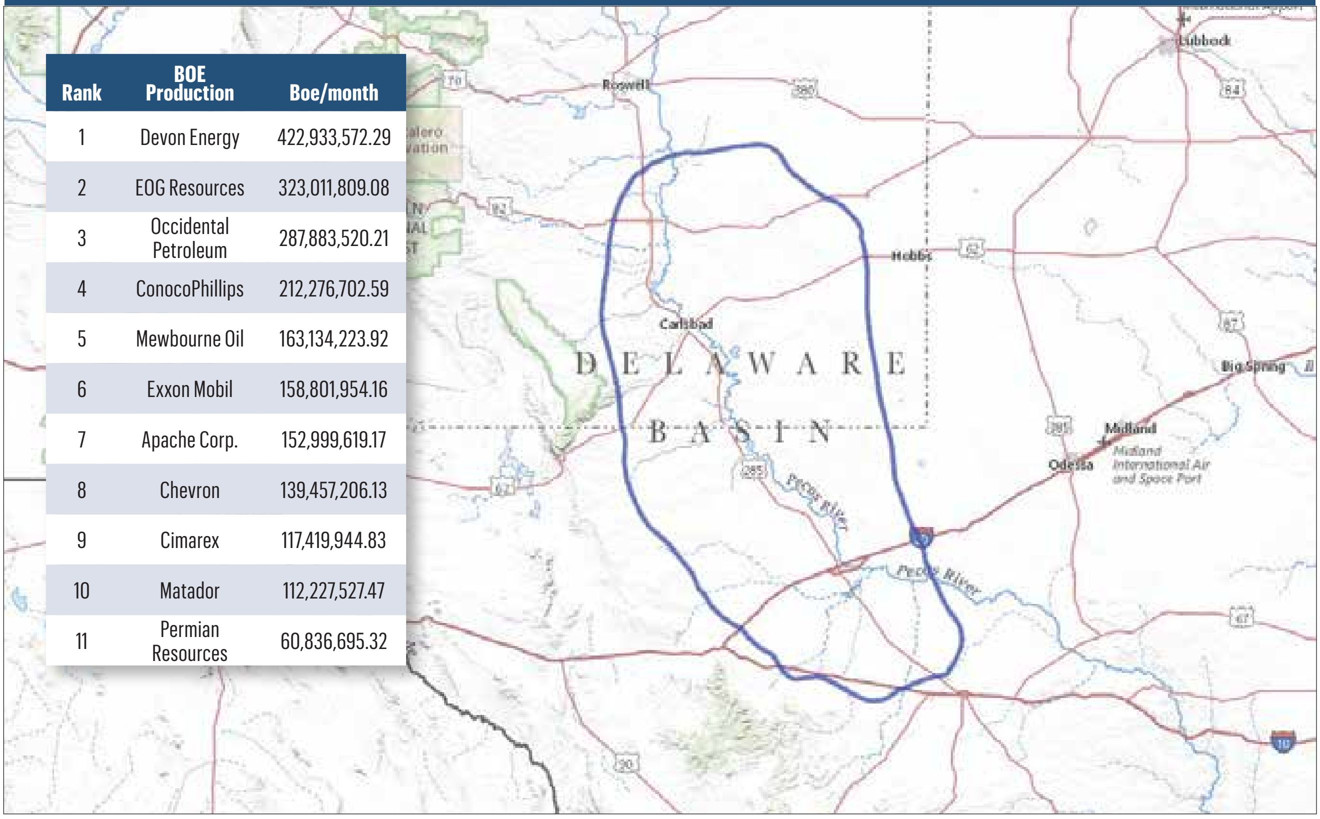
APACHE

BASIN FOCUS: DELAWARE BASIN

Led by Devon Energy and EOG Resources, the basin's operators have presided over a remarkable comeback in oil and gas production.

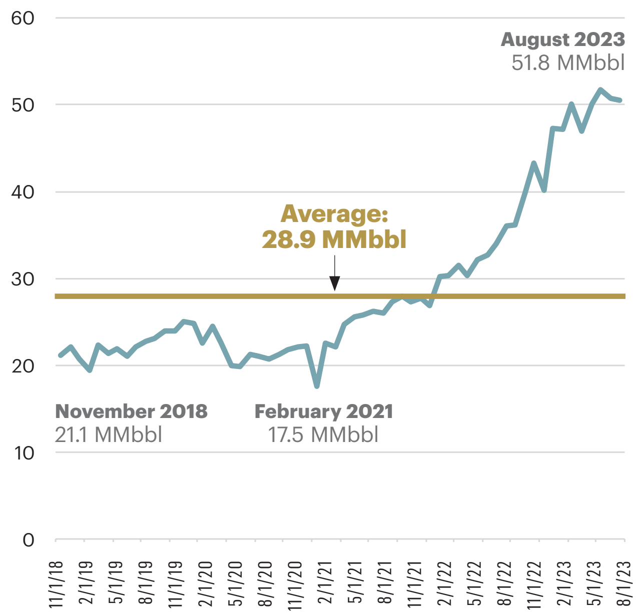
Delaware Basin's Top Operators

Rank	BOE Production	Boe/month
1	Devon Energy	422,933,572.29
2	EOG Resources	323,011,809.08
3	Occidental Petroleum	287,883,520.21
4	ConocoPhillips	212,276,702.59
5	Mewbourne Oil	163,134,223.92
6	Exxon Mobil	158,801,954.16
7	Apache Corp.	152,999,619.17
8	Chevron	139,457,206.13
9	Cimarex	117,419,944.83
10	Matador	112,227,527.47
11	Permian Resources	60,836,695.32



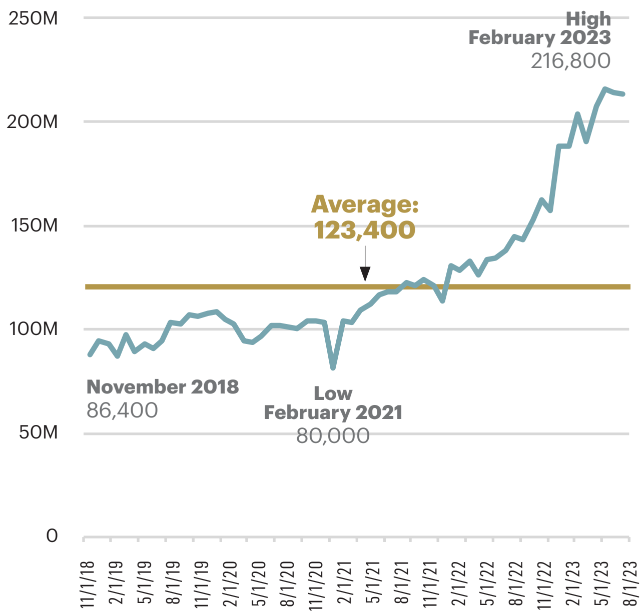
Delaware Basin Oil Production

(bbl/month)



Delaware Basin Gas Production

Mcf/month



SOURCE FOR CHARTS AND MAPS: REXTAG.COM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L.L.C.
www.petrohunt.com

PERMITS

Weld County, Colo., in the Denver-Julesberg Basin, was home to the most well permits in the last month.

Permitted Wells by County

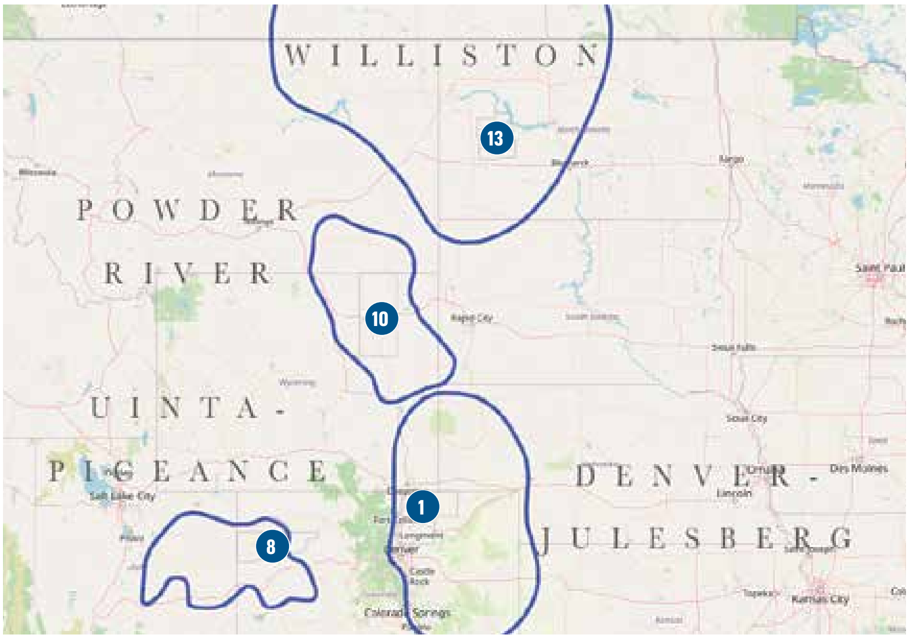
Rank	County	Well Count
1	Weld, Colo.	48
2	Loving, Texas	42
3	Reeves, Texas	38
4	Midland, Texas	30
5	Martin, Texas	27
6	Karnes, Texas	25
7	Glasscock, Texas	18
8	Rio Blanco, Colo.	16
9	Howard, Texas	15
10	Campbell, Wyo.	13
11	Culberson, Texas	13
12	La Salle, Texas	12
13	Dunn, N.D.	10

Permitted Wells by Operator

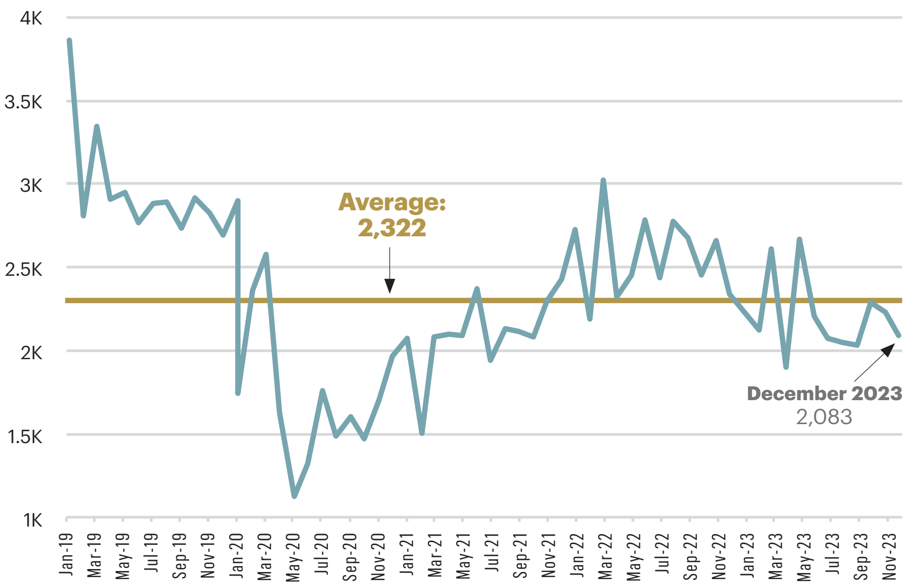
Operator	Well Count
Pioneer Natural Resources	26
EOG Resources	25
Chevron	24
BPX Operating	20
CrownQuest	20
Terra	18
Occidental Petroleum	17
Anshutz Exploration	17

Permitted Wells by State

State	Well Count
Texas	379
Colorado	82
North Dakota	39
Oklahoma	28
Wyoming	18
Louisiana	13



U.S. Permits Issued Monthly



Moving from the Middle

Midstream-focused EIV Capital has added non-operated assets and transition projects to its portfolio as a sign of the times.

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EIV Capital co-founder and managing partner, Patricia "Patti" Melcher, came to oil and gas private equity via investment banking in Houston. But the road to EIV's formation in 2009 was a winding one. Her first foray into the field came in 1986, when oil traded for $9/bbl and she was working for Simmons & Company.

"I got a really good education quickly into which companies survived and which ones didn't," she told *Oil and Gas Investor* (OGI). "I just really love being in the energy industry. It is always something different, and it's never boring."

She went to work in private equity in 1989 with SCF Partners founder L.E. Simmons, investing capital, watching investments grow and engaging with management teams–work that she loved, but took a temporary backseat to caring for her two children, one of whom had special needs. While working "part-time" for around 50 hours a week, she founded The Joy School in Houston, a K-8 school that assists students with learning differences in their journey to traditional classroom settings.

Through her part-time consulting work, Melcher developed a rapport with Anthony "Tony" Annunziato, and together, they founded EIV Capital in 2009.

"It was a good time to get back into energy private equity," Melcher said. "We started with $50 million as our first fund and then used that track record to then go raise institutional capital for Fund II. Tony basically backed me as a management team as he had backed others in the energy companies. And so here we are. We have grown quite a bit. We started investing $2 [million] to $12 million [into] each fund, and we always needed more capital. Now we typically invest $50 [million] to $150 million of equity per investment, with the ability to go higher."

EIV Capital partner and CEO of EIV Resources, Claire Harvey, strode a more traditional path toward oil and gas investing. Her grandfather was a landman for Southland Royalties; her father was a four-time private equity-backed wildcatter, making Harvey a third-generation oil and gas investor.

"This was a family business. I'm an only child, and so I remember very vividly in 1987, my dad drilling his first prospect on his own, called Vermilion 117, and I was asleep on the

"We do not believe that oil and gas is going away today, which is why we invest in it. We also don't believe it's going away tomorrow. I'm not sure we believe it will ever go away in its entirety. There will always be a need for it, but we believe in the transition as well."

CLAIRE HARVEY, CEO, EIV Resource; partner, EIV Capital

Welders with J Irwin Co. work under an umbrella to connect 12-inch pipe to a new 30,000 barrel tank on Brazos Midstream's Bison Crude Station near Pecos, Texas. The tank was expected to be utilized in April.

TOM FOX

“There’s still a number of institutional [limited partnerships] who will not touch oil and gas—or maybe they won’t touch upstream, but they’ll do midstream. The capital discipline has been one of the best things for the industry I’ve ever seen, and that is all driven by investors.”

PATRICIA MELCHER, co-founder and managing partner, EIV Capital

two seat cushions in his office,” she told *OGI*. “My parents looked at me and my mother started crying and she said, ‘Today’s a good day.’ It was probably 1 o’clock in the morning, and our lives had changed.

“That is what really drew me to the business—not just following in anyone’s footsteps—I really liked the energy of the oil and gas business.”

Harvey joined EIV Capital in 2022 to lead the upstream, non-operated interest investment business as chief of EIV Resources. An industry and investment veteran even then, she had previously founded Gryphon Oil and Gas, a Blackstone-backed firm focused on non-operated oil and gas interests in the Permian Basin.

Together, the two women lead energy private equity investing throughout the energy value chain with focuses on midstream infrastructure and non-operated assets. Melcher and Harvey talked with *OGI* this spring about the opportunities ahead for private oil and gas endeavors as well as their financial backers.

13
EIV portfolio companies

2009
year founded

$702 million
raised in Fund IV

Starting in the middle

Prior to 2021, EIV had no exposure to the upstream space but post-Covid, things began looking a bit differently, Harvey said.

“The upstream investment landscape finally looked a lot more from a risk adjusted returns basis, a lot more like what EIV had historically done from an investment perspective, less risk, you can protect principal for your investors a lot better, and we do that by buying things,” Harvey said. “So we can buy cash flowing assets for lower multiples than we used to, so our payback periods are lower and we can hedge the commodity price exposure.”

The first has grown significantly. From early investments between $2 million to $12 million, EIV’s typical backing today is between $50 million to $150 million in equity.

“It’s all for growth,” Melcher said. “We like to find a management team and back their business plan. Ten years ago, most of these teams were focused on developing greenfield midstream infrastructure projects. Today, we are more likely to acquire existing, cash-flowing assets, which our management teams can then focus on growing further.”

EIV was also an early mover in the renewables space, but the projects generally had a midstream element.

“Our first renewable deal was a landfill gas-to-energy project in 2010. It looked just like a midstream project with a gas processing plan, a pipeline, some engines and long-term contracts—but the methane came from a landfill instead of an oil and gas well,” she said. “We’ve done a good job in investing in both traditional and transition.”

EIV’s earliest investments were in the midstream space, where principals’ investment had some built-in protection through long-term contracts or offtake agreements, Harvey said. Similarly, the firm looks for ways to protect upstream investors in cash-flowing assets, often through hedging.

“It plays a big role, and the only way you can hedge is if you actually have forecasted volumes and in the form of wells that are already drilled that you can actually hedge,” Harvey said. “If the volumes didn’t show up [from new wells] and oil prices go up, then you might owe your hedge counterparty money that you’re not receiving from the wells themselves. Really what we invest in here at EIV is a lot more production heavy, so it’s wells that already exist.”

Melcher said the firm buys non-operated working interests, and then hedges much of the commodity exposure for the next few years to protect principal “and make it look a lot more like a midstream investment.”

In a midstream deal, EIV would look for a contract that has minimum volumes or minimum cash flows, and then use our management teams’ commercial expertise to go find new volumes, use their operational expertise to optimize, or say if it’s a gas processing plant, to better reduce its emissions.

A midstream investment would be supported by contracts. But given the current commodities market, a clearly defined hedging strategy can replace those contract structures, she said.

But we would do it, typically we’d have contracts. And so given the market and clear strategy using hedges, replaces those contract structures

In 2022, EIV Capital underwrote Harvey’s ARM Resource Partners using the hedging strategy to protect its downside risk, and the portfolio company performed well, Melcher said.

“We deployed a lot of capital pretty quickly, and so then we worked with Claire and we were able to convince her to bring her team inside EIV,” she said, which created a new investment platform called EIV Resources, which Harvey leads.

“That has allowed the collaboration with Claire and her team, which is very technical and that brings a broader array of expertise into EIV, which we are very excited about,” Melcher said. “Her team is focused on the

SHUTTERSTOCK

upstream investing, but her team helps us evaluate the rock under our midstream investments or to think about share insights from how they look at things with our team and vice versa."

The competition

New private equity firms are emerging to fill a financing void within the traditional midstream and upstream spaces created by the emergence of anti-fossil fuel investor movement, which now appears to be on the wane.

"Right after Covid, it felt like no one was ever going to invest in oil and gas again; the pendulum is starting to swing the other way," Harvey said. "I think institutional investors have looked at how well the publics have performed in terms of return on capital employed in terms of distributions, and so that's making people want to come back. They see that there are good returns possible."

Also, the public is acknowledging that the transition will take a lot longer than envisioned a couple of years ago, Melcher said.

"There's still a number of institutional [limited partnerships] who will not touch oil and gas—or maybe they won't touch upstream, but they'll do midstream," Melcher said. "The capital discipline has been one of the best things for the industry I've ever seen, and that is all driven by investors."

Today there are opportunities to investor and financiers who want to engage, she said.

"It's just such a different environment when you don't have that capital just sitting around waiting to invest. It's created so much opportunity in the space, and it's repriced risk a lot," Melcher said. "And so risks that we used to take, we used to take for a lot lower return risk profile that we take today. We have to take less risk for the same return or we take the higher risk stuff and get much higher returns."

Some investors may feel like they've missed out by sitting on the sidelines.

"People are actually taking phone calls," she said, adding that it's a sign of renewed interest.

Still, it will be a "gradual evolution back to traditional energy investing, but I don't think it'll be near as much as it was five years ago."

But even that point isn't a negative one because capital needs have changed, too.

As unconventional drilling took hold of the industry, new infrastructure, pipelines, processing and terminals were needed—and those were pricey midstream endeavors. Today, the space is dominated more by expansion than new projects. Similarly, the well costs and input expenses for hydraulic fracturing have come down as technology allowed producers to innovate their way to capital discipline.

Harvey summed up the industry forecast: "We do not believe that oil and gas is going away today, which is why we invest in it. We also don't believe it's going away tomorrow. I'm not sure we believe it will ever go away in its entirety. There will always be a need for it, but we believe in the transition as well." OGI

It's Complicated: E&Ps Find Some Financial Tailwinds, But It's Not All Smooth Sailing

Relatively stable WTI prices in the $80s/bbl provide some breathing room as companies allocate cash for operations, and pragmatism is seeping into the energy transition movement.

MARK DRUSKOFF
CONTRIBUTING EDITOR

If you're a glass half-full person—and most scions of the proud wildcatter tradition certainly subscribe to that philosophy—financing options for top performing oil and gas producers appear full of opportunity with a capital "O," even if it means getting a little creative.

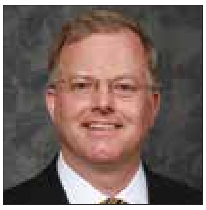
Natural gas prices remain low, even by the standards of that market, restraining both gas- and oil-weighted producers. U.S. domestic politics also create uncertainty. And capital just isn't available in the quantities it used to be.

Energy's current share of the S&P 500 is well below historical levels. Or put another way, the combined market cap of the 23 constituent energy companies of the S&P 500 ($1.78 trillion) *almost* equals Amazon's market cap.

Cautious capital

With discipline being the watchword, upstream operators looking to tap the capital markets need to be circumspect, and even a little bit creative.

It is ironic, given the general financial health of the sector, said Jeff Nichols, partner and co-chair of Haynes and Boone's energy practice group.



Jeff Nichols

"The industry is as bankable as it's ever been," he said.

Most top producers have "very lean balance sheets from a historical standpoint," said Michael Bodino, managing director of investment banking at Texas Capital Bank, pointing to the financial discipline companies are showing. And, for oil-weighted companies, current pricing levels definitely help.

"There's a robust level of cash flow out there these companies are generating," he said.

Cash flow from operations is the single greatest capital source, according to the Haynes and Boone's biannual Borrowing Base Redeterminations Survey.

Meanwhile, traditional capital sources, such as bank debt, have seen their role diminished through a combination of factors.

Lenders are assigning "significantly lower" advance rates for non-producing wells and proved undeveloped (PUD) wells for reserve-based lending (RBL), said Jackson O'Maley, partner in Vinson & Elkins capital markets and M&A practices.

Jackson O'Maley

Additionally, upstream firms find the uncertainty around borrowing base redeterminations disquieting.

Prices may be stable now, but companies haven't forgotten that in volatile times, borrowing bases can be cut dramatically. "You don't want to rely solely on the borrowing base for your liquidity," O'Maley said.

Furthermore, many foreign banks withdrew from the RBL space, pushing upstream companies to look elsewhere for capital, added Haynes and Boone's Nichols.

Bodino acknowledged the structural shifts in the marketplace, such as lower advance rates. The upshot is that E&P companies have moved away from using bank debt as a permanent source of capital in favor of other options, and it now forms a smaller piece of the overall debt stack.

But winds of change might be coming.

Although foreign banks withdrew from the market to reduce their exposure to energy over sustainability concerns, other lenders want back in. Owing to financial industry consolidation, many bank portfolios are now

A natural gas oil well pad in Harrison County in eastern Ohio in autumn.

SHUTTERSTOCK

"There's less rhetoric about ESG today than there was two years ago."

MICHAEL BODINO, managing director of investment banking, Texas Capital

underweight to energy.

"We're seeing a lot more interest from the bank community broadly to get new credits in their portfolios," Bodino said.

Pensions and insurance companies chasing yield have also been eyeing the upstream sector more closely, Nichols said.

Debt options

But don't count reserve-based loans out just yet. Though their status is diminished, said Bodino, they "play nicely in the same sandbox" with other instruments, such as leveraged loans, and have a complementary role in providing working capital.

The leveraged loan market has seen quite a bit of activity, Bodino noted. Such loans are "a better fit with companies that may have some complexity, or need an extra layer of diligence done" to get investors comfortable with an asset, he said

In September 2023, Texas Capital served as administrative agent for a $1.2 billion senior secured term loan credit agreement for HighPeak Energy. The proceeds were used to repay two outstanding senior note issuances and its outstanding borrowings on its reserve-based credit facility, according to a company press release. As a result, HighPeak was also able to enter into a $100 million super senior revolving credit facility.

The HighPeak leveraged loan had an "unbelievable level of interest," Bodino said.

A few months later, Texas Capital also served as administrative agent for Mach Natural Resources on an $825 million term-loan credit agreement to fund the acquisition of EnCap Investments-backed Paloma Partners IV, said Bodino. On top of that very large facility, Mach also entered into an RBL, he said.

Leveraged loans are not the only market segment experiencing a surge.

The high-yield debt market has "come back pretty robustly in the last 12 months," said O'Maley. Companies are taking advantage of the current stability in prices to "opportunistically" use high-yield debt to term out debt and create liquidity under their RBLs.

They also will be motivated to act ahead of the U.S. presidential election to avoid additional uncertainty, O'Maley said.

When traditional bank loans, leveraged loans or high-yield offerings don't meet corporate needs, however, E&P companies must explore more exotic alternatives.

Securitizations begin to shine

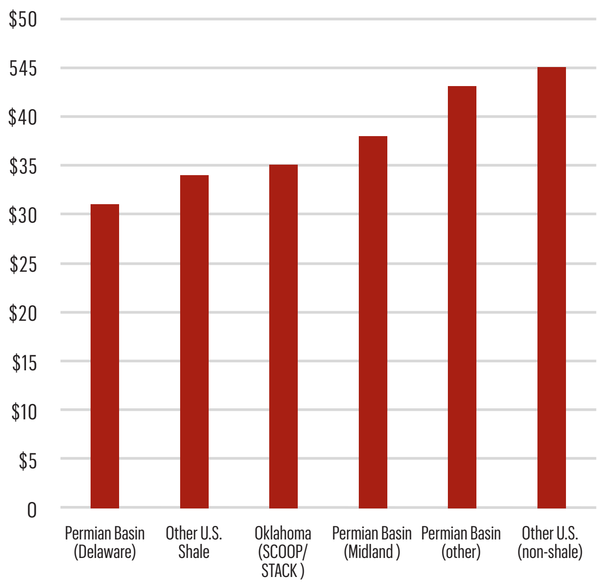
With the pullback in the RBL space, companies seeking options discovered the fit of a PDP asset-backed securitization (ABS). Since 2019, dozens of ABS deals have

Covering Costs and Turning a Profit

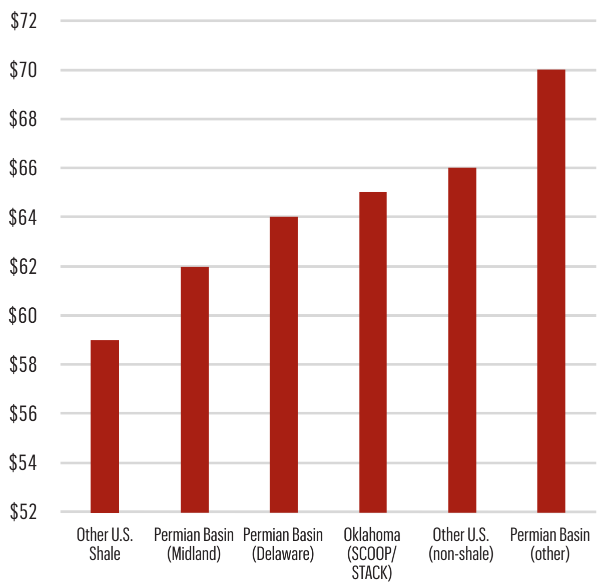
In March, when WTI prices were in the upper $70s/bbl, the Dallas Fed released its latest energy survey asking respondents to share the WTI price they need to cover operating expenses in the top two areas in which they are active. The average price was $39/bbl, up slightly from $37/bbl the prior year, but well below current WTI levels. The Delaware Basin had the lowest overall of breakeven cost of $31/bbl.

More interesting, however, is the gulf between large and small firms. Large firms (producing more than 10,000 bbl/d as of fourth-quarter 2023) require just $26/bbl to cover operating expenses for existing wells. In contrast, smaller firms (producing less than 10,000 bbl/d) require a price nearly 70% higher at $44/bbl.

Breakeven Price of WTI in Selected Basins



Breakeven Price to Profitably Drill a New Well



SOURCE: FEDERAL RESERVE BANK OF DALLAS

been completed in the upstream space, said Haynes and Boone's Nichols, whose team has advised on a number of such transactions.

Private companies have been the primary beneficiary of ABS deals, but public companies have made use of them, too.

For example, Diversified Energy, an onshore producer focused on the Appalachia Basin but with positions in the central regions of the U.S., has undertaken multiple securitizations. Until last year, Diversified had been publicly listed only on the London Stock Exchange. In December, the company began trading on the New York Stock Exchange under the ticker symbol "DEC."

In 2022 alone, Diversified completed four securitizations totaling $1.1 billion, including a $460 million ABS with Oaktree Capital Management for co-owned assets in Oklahoma, the company said in a news release. Diversified planned to use the funding to repay borrowings under a sustainability linked loan. The note had a fixed coupon of 7.50% owing to the BBB+ investment-grade rating assigned by Fitch Ratings.

With ABS deals, assets are dropped down into a special purpose vehicle and production is protected with hedging out five to seven years, Nichols said. That hedging enables ABS deals to secure a better rating from the ratings agencies, resulting in a lower interest rate.

Thanks to that hedging, the advance rate can be as high as 80% to 90%, said Nichols. In contrast, the current advance rate for RBLs is more in the 40% to 50% range, he said. Of course, the cost of hedging an ABS so many years out is not insubstantial.

On Diversified's ABS deal with Oaktree, Haynes and Boone advised the trading affiliate of an undisclosed financial institution as a secured commodity hedge provider.

Securitizations definitely have some advantages, said Texas Capital's Bodino. The upstream company retains its interest in the wells and continues to operate them, and once the ABS fully amortizes, the ownership of the wells reverts back to the company.

But investors in ABS want to avoid concentration risk and want "a lot" of well diversification, he said. No single well can account for more than 1% to 2% of production. He noted that one securitization involving Raisa Energy included over 9,000 wells.

Bodino observed that most of the companies that have completed ABS deals are "very gassy" and there haven't been as many oil-weighted producers. Some of that bias can be attributable to different operational characteristics of natural gas wells, which experience fewer mechanical issues and produce more steadily. But another significant factor is the different pricing dynamics of natural gas, he said.

Equity in the wings

While yield is spurring investors to re-evaluate energy debt financings, driving a rise in deal flow, equity offerings have remained relatively muted. The activity that has occurred is the result of the wave of M&A that has taken place over the last five years, said O'Maley.

Many private equity-backed companies were acquired by publics and took equity as part of the consideration. In the last year, the bulk of equity issuances have been secondary offerings by investors looking to monetize that stock, he said.

Recent examples include Permian Resources offering 48.5 million shares in March, sold not by the company but by multiple private equity firms whose portfolio companies had been acquired. Sellers included EnCap Investments, NGP

Energy Capital Management, Pearl Energy Investments and Riverstone Investment Group. It was preceded by a similar offering last December of 39.4 million shares by NGP Energy Capital Management, Riverstone and EnCap. Vinson & Elkins advised on both offerings.

Meanwhile, primary common stock offerings have been scarce, but they could make a return.

The recent consolidation trend among producers is producing the newly scaled-up companies that will inevitably look to shed assets for cash–and cash only, Bodino said. Private equity-backed portfolio companies will be ready and willing to pony up, and any public company looking to compete with those buyers will also require cash. That need could lead to an increase in equity offerings, he said.

Additionally, there could be some upstream companies taking to the equity market with an IPO during the next 12 months.

In 2023, multiple companies managed to get out the door, including TXO Energy and Mach Resources, while others, such as BKV Corp., had put their public plans on hold. Nevertheless, there are more companies biding their time and looking to test the market, Bodino said.

Prospective new public E&P companies should weigh their options and choose their opening carefully, given the vagaries and complexities awaiting them, the experts said. OGI

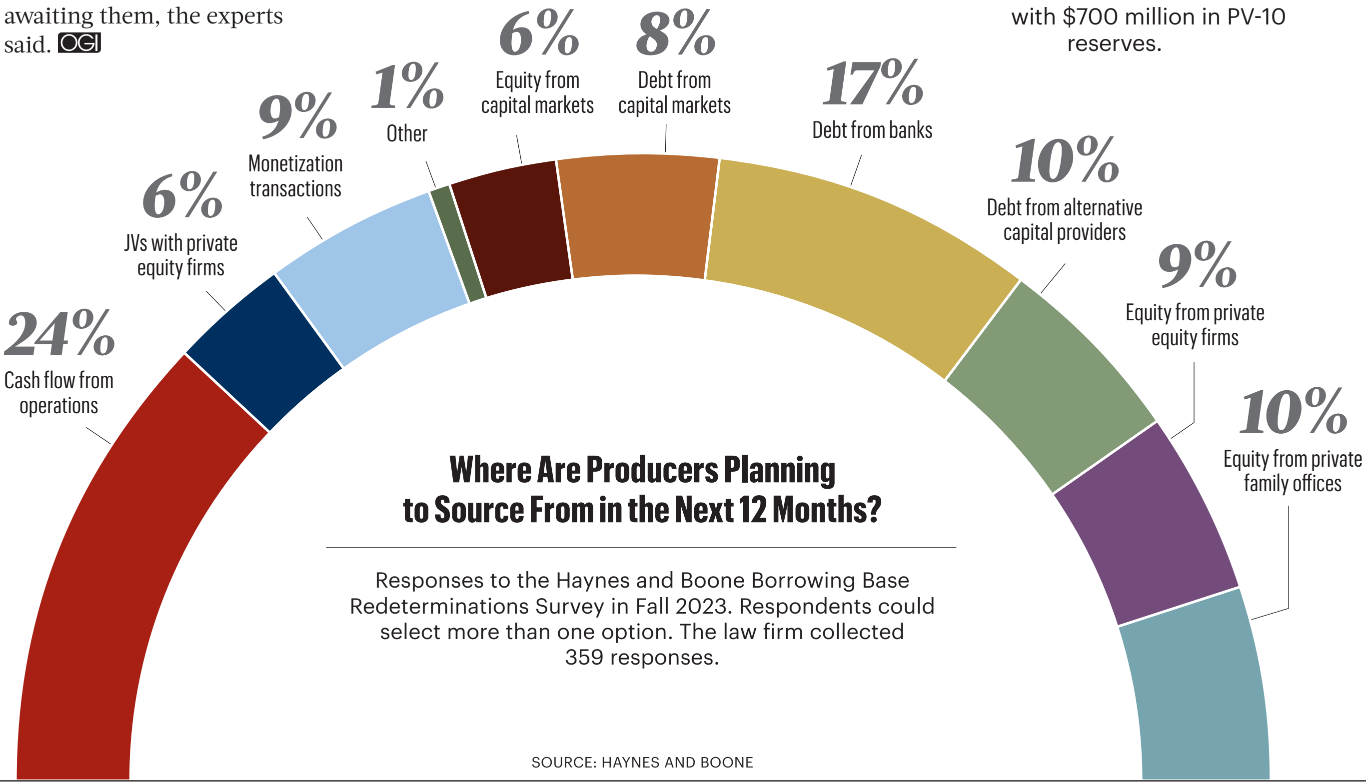
Case Study: Crescent Energy

Crescent Energy tapped the capital markets in the last 18 months to term out debt and pay down its revolving credit facility. In March, the Eagle Ford- and Uinta Basin-focused operator announced the pricing of $700 million private placement of 7.65% senior notes due 2032 to purchase the company's outstanding 7.250% senior notes due 2026. Vinson & Elkins served as issuer's counsel for the transaction.

Crescent Energy was formed in late 2021 through the combination of Independence Energy and Contango Oil & Gas. The company is affiliated with KKR, which owns approximately 15% of its common stock, and is helmed by David Rockecharlie, who also serves as head of KKR's energy real assets business.

Crescent also tapped the high-yield market to repay amounts outstanding under its revolving credit facility. In total, Crescent raised $1 billion over the course of 2023 via four private placements of 9.250% senior notes due 2028, including two upsized offerings.

The sale of the unsecured notes, free cash flow and a modest $146 million equity raise were used to "effectively" pay for a pair of transactions Crescent undertook in the Eagle Ford for a total of $850 million, according to Fitch Ratings. The total included a $600 million acquisition of assets from Mesquite Energy, formerly known as Sanchez Energy. That deal included 75,000 acres in Dimmit and Webb counties with $700 million in PV-10 reserves.



Where Are Producers Planning to Source From in the Next 12 Months?

Responses to the Haynes and Boone Borrowing Base Redeterminations Survey in Fall 2023. Respondents could select more than one option. The law firm collected 359 responses.

SOURCE: HAYNES AND BOONE

Sustainability's Sustainability

The concept of ESG is being redefined, said Jeff Nichols at Haynes and Boone. One telling data point—natural gas has been gaining acceptance as an energy transition fuel.

Compared to a couple years ago, there is a "renewed interest" in the energy space, Jackson O'Maley at Vinson & Elkins said. There are even signs of pushback to ESG-driven investment strategies to divest oil and gas, he said.

"There's less rhetoric about ESG today than there was two years ago," Texas Capital's Michael Bodino said. He gives much of the credit to the upstream companies themselves for adopting ESG practices and curbing their Scope I and Scope II emissions.

The reason is simple—to be competitive in the fight to secure capital you have to address ESG. Bodino likened this shift to the Sarbanes-Oxley era in the early 2000s, where ESG has now become "a box everyone is going to ask about and need to check," he said.

Permian Gas Finds Another Way to Asia

A crop of Mexican LNG facilities in development will connect U.S. producers to high-demand markets while avoiding the Panama Canal.

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Permian Basin natural gas will soon take on a protagonist role south of the U.S. border where numerous liquefaction facilities planned on Mexico's northwest Pacific Coast will process significant volumes for re-export to premium LNG consuming markets in Asia.

Mexico's push for LNG exporting glory hinges on completion of liquefaction plants and crucial pipelines from the Permian, buildouts that are expected to happen concurrently as the next wave of U.S. liquefaction capacity prepares to comes online toward the end of this decade.

If all goes according to plan, Mexico will soon be a net exporter of LNG, no longer relying on costly LNG imports.

Initial Permian feedgas volumes could reach gas-hungry Asian markets as early as summer 2025, according to San Diego-based Sempra, whose affiliate Sempra Infrastructure is nearing completion of its Energía Costa Azul (ECA LNG) Phase 1 project north of Ensenada in Baja California, Mexico.

Mexico is betting big on LNG exports, especially from its Pacific Coast. If five projects proposed by Sempra Infrastructure, Mexico Pacific, and LNG Alliance Pte Ltd Singapore move forward, they will assist Mexico in bringing to market 59 million tonnes per annum (mtpa) of liquefaction capacity or around 7.8 Bcf/d, according to data compiled by *Oil and Gas Investor* (OGI).

Such a figure will convert Mexico into the third-largest LNG exporter in the Americas, trailing only the U.S. and Canada, according to a Rystad Energy analysis of current, approved and proposed projects.

Mexico is also contemplating export facility developments off the country's Atlantic Coast. However, these developments will be better positioned to serve European destinations.

"Projects on the West Coast of Mexico have the advantage of avoiding the Panama Canal when exporting cargoes, which is becoming an increasingly important advantage," Josephine Mills, Enverus Intelligence Research senior associate, told *OGI*. "However, projects on the west Coast don't have the ease of access to Haynesville, Appalachia and Eagle Ford gas that Gulf Coast projects have."

"Projects on the West Coast of Mexico have the advantage of avoiding the Panama Canal when exporting cargoes."

JOSEPHINE MILLS, senior associate, Enverus Intelligence Research

The Biden administration's LNG pause on new export authorizations, announced in January, impacts both Mexican and U.S. LNG projects.

"Any project exporting U.S. gas needs non-free trade agreement (non-FTA) and FTA licenses from the Department of Energy (DOE). Therefore, Mexican LNG projects exporting U.S. gas are subject to the Biden pause as well," Mills said.

Biden's policy gives the DOE time to review applications for permits to export LNG to non-FTA countries as well as update its economic and environmental analysis to determine the public interest value of the applications.

"The advantage to Mexico is that it is closer to Asia, so you save on transportation costs, not on construction," Benjamin Nolan, Stifel managing director, told *OGI*.

Russia's invasion of Ukraine in 2022 led to a drastic decline in Russian energy exports to the European Union and the UK and prompted a major energy crunch. The U.S., which just started exporting LNG in 2016, was able to provide LNG to many countries, including the UK, France and Spain.

European and Asian countries continue to explore ways to guarantee their energy security. North America–the U.S., Canada and

Proposed LNG Facilities

SOURCE: REXTAG

Mexico—is shaping up to be a dominant LNG exporting region despite continued competition from Qatar and Australia.

"The U.S. and Qatar will provide around 50% of total LNG production by 2029, a rapid increase from their 40% combined share in 2023. This looming supply concentration raises Asian LNG buyers' political and operational risks, especially given the exposure of U.S. and Qatari LNG production to potential shipping chokepoints: the Panama Canal and the Strait of Hormuz," Ruaraidh Montgomery, Welligence Energy Analytics global head of research, told *OGI*.

"Asian LNG buyers are therefore currently actively evaluating supporting western Mexican LNG export projects. These projects can offer quicker and cheaper LNG shipping routes into Asia, while avoiding the potential shipping bottleneck of the Panama Canal," Montgomery said.

The U.S. and Mexico are already major trading partners. On July 1, 2020, they entered into the United States-Mexico-Canada Agreement (USMCA), which replaced the North America Free Trade Agreement (NAFTA), and in 2022, the trade of U.S. goods and services with Mexico totaled an estimated $855.1 billion, according to the Office of U.S. Trade Representative.

And Mexico—a major manufacturing hub and member of OPEC+—is no stranger to piped gas from the Permian, which it has long imported to fulfill domestic demand.

Permian producers exported an average 5.8 Bcf/d of piped gas to Mexico in the week ended April 3, according to the Energy Information Administration (EIA). And this demand isn't expected to retreat anytime soon, according to Mexico's Federal Electricity Commission (CFE).

"Mexico is poised to commence initial LNG exports in 2024."

SERGIO CHAPA, analyst, Poten & Partners

As such, Mexico is on the very cusp of finding a dual use for its Permian imports.

"Mexico is poised to commence initial LNG exports in 2024," Sergio Chapa, Poten & Partners' LNG analyst, told *OGI*, referring to possible cargoes to flow this year from New Fortress Energy's first fast LNG installation, FLNG 1, in Altamira, Mexico. The project, also referred to as Altamira LNG, is a partnership with CFE to liquefy Permian gas supplied by the Sur de Texas-Tuxpan pipeline and will help create a new FLNG hub off the East Coast of Mexico.

Permian gas to Asia

Mexico's reliance on U.S. shale will be crucial as the Latin American country seeks export opportunities. There is benefit to Permian producers that want to fulfill rising demand for LNG not only in Asia, but worldwide.

The Permian Basin covers 86,000 miles and 52 counties across West Texas and southeastern New Mexico. Permian dry shale gas production averaged 17 Bcf/d in February, according to the EIA. Many analysts say it will continue to rise to meet demand from LNG developments on Mexico's West Coast as well as others along the U.S. Gulf Coast. However, the biggest challenge relates to the build-out of takeaway capacity from the basin, Stifel's Nolan said, adding that "the availability of the gas is not a problem."

"That said, you do have a single source of gas, so as is the case with projects like that (versus something in Louisiana, for instance, where there are multiple pipelines), should something happen to interrupt gas inflows, there is no workaround," Nolan said.

"[Enverus] forecasts the Permian to grow [about] 7.2 Bcf/d by 2030. However, [about] 5 Bcf/d of additional pipeline capacity is needed to achieve this growth," Mills said. "Of note, the proposed Saguaro [Connector] Pipeline from the Permian to the Mexican border would add 2.8 Bcf/d of capacity. The pipeline would be met by the proposed Sierra Madre Pipeline in Mexico. However, these projects are waiting for the Saguaro LNG I facility to reach FID."

"We see Mexican demand growing, providing an outlet for Permian growth. We forecast pipeline flows into Mexico from the Permian will increase ~2.5 Bcf/d by 2030," East Daley Analytics told *OGI*. "Even with that growth outlook, we believe there will be sufficient capacity once Saguaro Connector is built in early 2029. With our current North American LNG outlook (DOE pause in effect), U.S. producers will be able to keep up with production with growth out of the Permian, Haynesville, Northeast and Eagle Ford."

Mexico's main problem, some analysts say, relates to its overreliance on Permian gas due to its inability to boost domestic production.

Mexico had gas reserves of 6.3 Tcf in 2020, enough to last around 5.9 years, and oil reserves of 6.1 MMbbl, enough to last around 8.7 years, according to BP's Statistical Review of World Energy. Those figures and scenarios haven't changed much since then. That's because state-owned Petróleos Mexicanos (Pemex), Mexico's main producer, continues to struggle to boost reserves and production under the financial weight of a $106 billion debt load, at the end of 2023, as well as ongoing financial obligations to the government.

Sempra: ECA LNG Phase 1 sailing in 2025

Mexico's first LNG cargoes to reach Asia with Permian feedgas will likely come from Sempra Infrastructure's ECA

Mexico-based LNG Projects with non-FTA Authority from DOE

			Volume (Bcf/d)				
Project	**Company**	**State (City)**	**Authorized**	**Under Construction**	**Operating**	**IOD**	**Construction Status**
Energia Costa Azul (ECA)	Sempra Infrastructure	Ensenada	2.18	0.44	0	2025	Phase 1 under construction; Phase 2 FID pending
Saguaro Energia LNG	Mexico Pacific Limited	Sonora (Puerto Libertad)	1.7	0	0	N/A	Pending FID
Amigo LNG (Epcilon LNG)	LNG Alliance	Sonora (Guaymas)	1.08	0	0	N/A	Pending FID
Vista Pacifico LNG	Sempra Infrastructure	Sinaloa (Topolobampo)	0.55	0	0	N/A	Pending FID
TOTALS			**5.51**	**0.44**			

SOURCE: US DEPARTMENT OF ENERGY

Mexico-based LNG Projects to Tap Perman Gas

	Project	Company	State (City)	LNG Feed Gas	Trains	MTPA	Bcf/d	Commerical Operations Date
1	Energia Costa Azul (ECA)	Sempra Infrastructure	Baja California (Ensenada)					
	ECA Phase 1			Permian gas	T1	3.3	0.4	Summer 2025
	ECA Phase 2			Permian gas	T2 + T3	12.0	1.6	In development phase
	Total ECA					**15.3**	**2.0**	
2	Saguaro Energia LNG	Mexico Pacific Limited	Sonora (Puerto Libertad)					
	Saguaro I			Permian gas	T1 + T2 + T3	15.0	2.0	2027
	Saguaro II			Permian gas	T4 + T5 + T6	15.0	2.0	In development phase
	Total Saguaro Energia					**30.0**	**4.0**	
3	Amigo LNG (Epcilon LNG)	LNG Alliance	Sonora (Guaymas)					
	Amigo LNG 1			Permian gas	T1	4.2	0.6	Second quarter of 2026
	Amigo LNG 2			Permian gas	T2	3.6	0.5	In development phase
	Total Amigo LNG					**7.8**	**1.0**	
4	Vista Pacifico LNG	Sempra Infrastructure	Sinaloa (Topolobampo)					
	Vista Pacifico 1			Permian gas	T1	3.0	0.4	In development phase
5	Salina Cruz LNG	Sempra Infrastructure / CFE	Oaxaca (Salina Cruz)	Permian and/or Mexican gas				
	Salina Cruz 1				T1	3.0	0.4	In development phase
TOTALS						**59.1**	**7.8**	

SOURCE: COMPANY WEBSITE DATA; U.S. DEPARTMENT OF ENERGY

LNG Phase 1 in Baja California. The strategic location of ECA LNG Phase 1 on Mexico's West Coast is geographically positioned to connect Asia, Pacific Basin and international LNG markets.

Sempra Infrastructure and its Mexican subsidiary, Infraestructura Energética Nova (IEnova), continue to move forward with ECA LNG Phase 1. Structural steel work is 90% complete, Sempra Infrastructure told *OGI* in an emailed statement.

"Western Mexico also benefits from existing LNG infrastructure in Sempra's ECA terminal. The terminal originally started up as an LNG import facility in 2008 and is currently being converted into an LNG export plant," Welligence's Montgomery said.

ECA LNG Phase 1 is on the site of Sempra Infrastructure's existing ECA Regas facility, which still has long-term regasification contracts for 100% of its capacity through 2028. Sempra Infrastructure doesn't expect construction or operations at ECA LNG Phase 1 to interrupt operations at its ECA Regas facility, and continues to target the summer of 2025 for the start of commercial operations.

ECA LNG Phase 1 will consist of one-train with a capacity of 3.25 mtpa and an initial offtake capacity of 2.5 mtpa. Sempra Infrastructure has an 83.4% working interest and France's TotalEnergies has an 16.6% working interest.

Gas will be delivered to ECA LNG Phase 1 with the completion of the GRO pipeline expansion, which will have a capacity of 0.5 Bcf/d, according to Sempra Infrastructure. The GRO is on schedule to reach its targeted commercial operation date in the second half of 2024.

Sempra Infrastructure also has plans for ECA LNG Phase 2, which will consist of two trains and one LNG storage tank. ECA LNG Phase 2 will have 12 mtpa of export capacity and also source Permian feedgas. Sempra Infrastructure has already signed a heads of agreement with Houston-based ConocoPhillips as well as memorandums of understanding with TotalEnergies and Japan's Mitsui.

However, Sempra Infrastructure expects construction of ECA LNG Phase 2 to conflict with the operations at the ECA Regas facility. Any development decision would depend on the long-term financial benefits of continuing with its regasification services and existing contracts, Sempra said in a U.S. Securities and Exchange Commission (SEC) filing earlier this year.

Mexico Pacific: Saguaro Energía LNG I begins in 2027

Mexico Pacific's Saguaro Energía LNG I and II projects are located in Puerto Libertad in Sonora, Mexico. Both facilities will offer Permian producers a relief valve for associated gas and connect the U.S.' cheapest gas to Asia, the world's largest demand center, says Mexico Pacific.

The location of the facilities will offer a 55% shorter shipping route, which translates into savings of $1/MMbtu or more and a 60% lower carbon emissions profile compared to Gulf Coast peers, according to Mexico Pacific.

"The Permian Basin is the largest and lowest-cost gas basin in the world with over 600 Tcf of remaining gas reserves. Production is forecast to grow from [about] 17 Bcf/d today to nearly 25 Bcf/d over the next 10 years–we would need nearly seven similarly sized LNG projects to absorb this excess gas," Mexico Pacific told *OGI* in an emailed statement.

Saguaro Energía I will include three trains with a processing capacity of 5 mtpa each (combined capacity of 15 mtpa). A final investment decision (FID) for each of the first three trains is imminent.

"We're sold out across all three trains, fully permitted to commence construction on both the pipeline and terminal and are receiving strong support from capital markets, so we're progressing strongly toward our initial T1 & T2 FID and expect to take a subsequent T3 FID a mere three to six months later," Mexico Pacific said.

Saguaro Energía I has the backing of Shell, Exxon Mobil and ConocoPhillips with key additional end-user customers secured, including Chinese firms Guangzhou Gas and Zhejiang Energy.

Last year, Mexico Pacific said Saguaro Energía I would involve a $15 billion investment and start up by year-end 2027. Quantum Capital Group is the controlling owner and lead sponsor of Mexico Pacific.

The anchor project, Saguaro Energía I, will source gas from Waha to be shipped along a 253-km pipeline on the U.S. side of the border and then connect with an 802-km pipeline on the Mexican side of the border. Both segments have capacity to handle 2.8 Bcf/d of gas.

"We consciously designed the Sierra Madre Pipeline to avoid environmentally sensitive areas, indigenous areas and population centers, which is a first in Mexico, perhaps all of North America," Mexico Pacific said. "The pipeline will be buried, which also reduces fears of attacks or vandalism. Indeed, the northern regions of Chihuahua and Sonora have a great deal of pipeline infrastructure that continue to operate without issues."

Welligence's Montgomery said sabotage to the gas pipeline would be "extremely odd," but reiterated that pipeline attacks do happen in Mexico. "But it's the small fuel pipelines that are targeted in order to steal the fuel," he said.

"We don't believe the [Mexican] elections will change anything. It's unlikely any of the two candidates would say no to any project that [Mexico's President] Andrés Manuel López Obrador (AMLO) has already approved," Montgomery said.

Mexico Pacific has already started development planning for its expansion project, Saguaro Energía II, also comprising three trains and representing an incremental 15 mtpa of capacity.

Three other Mexico LNG projects to watch

Three other Mexico LNG projects–LNG Alliance's Amigo LNG (Epcilon LNG); Sempra Infrastructure's Vista Pacifico LNG; and Salina Cruz LNG, developed by Sempra Infrastructure and CFE–are on the radar.

Amigo LNG, located in Guaymas in Sonora, Mexico, continues to move forward. The project will consist of two trains with combined capacity of 7.8 mtpa. First cargos could still flow in 2027, LNG Alliance CEO Muthu Chezhian told *OGI*. Vista Pacifico LNG, located in Topolobampo in Sinaloa, Mexico, is envisioned to have a combined capacity of between 2-3 mtpa, according to Sempra Infrastructure, while Salina Cruz LNG located in Salina Cruz in Oaxaca, Mexico, is envisioned to have a combined capacity of around 3 mtpa, according to Sempra Infrastructure and CFE. OGI


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IN MEMORIAM

Herbert Hunt, Wildcatter

The industry leader was instrumental in dual-lateral development, opening the North Sea to oil and gas development and discovering Libya's Sarir Field.

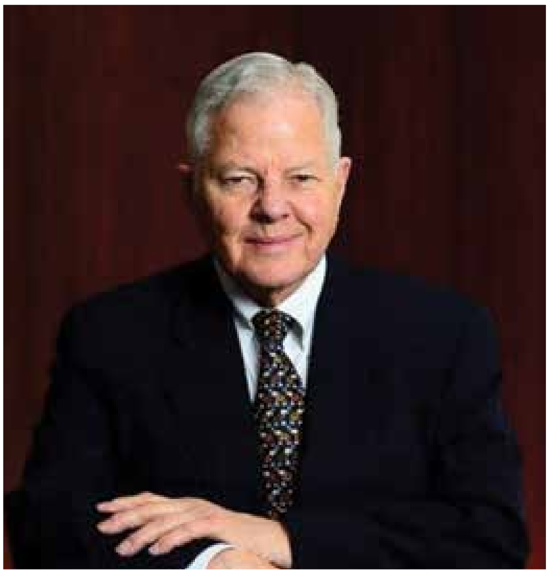
HART ENERGY STAFF

William Herbert Hunt, founder of Top 10 U.S. privately held petroleum producer Petro-Hunt, died on April 9. He was 95.

A son of East Texas oil wildcatter H.L. Hunt, he grew his Dallas-based Petro-Hunt to operations globally and across the U.S., including in the Permian, Williston and Powder River basins and in the Eagle Ford Shale.

Hunt and his family were inducted into Hart Energy's Hall of Fame in December.

Domestically and globally, Petro-Hunt was instrumental in some of the largest oil discoveries in the world. In 1961, Hunt and brother Nelson Bunker Hunt discovered the Sarir Field in Libya, one of the largest oil fields onshore Africa.



Later, the family had a role in Placid Oil's discovery in the 1970s on Block L 10/11, which opened the North Sea.

In extraction innovation, Petro-Hunt drilled and completed the first medium-radius double-lateral well in South Texas in the 1990s, taking the concept to North Dakota.

In addition to oil and gas production, Petro-Hunt has operations and interests in gas processing, oil refining and real estate.

A geologist, Hunt earned his bachelor's degree from Washington and Lee University in 1951 and was a member of in the American Association of Petroleum Geologists throughout his career, receiving the organization's Pioneer Award.

He took on numerous leadership roles in industry organizations, including a seat on the API board, president of the American Association of Drilling Contractors (now known as the International Association of Drilling Contractors) and chairman of the National Ocean Industries Association.

He was president of the Dallas Wildcat Committee in 1965-1966 and president of the Dallas Petroleum Club in 1970.

Hunt was the last surviving original inductee of the All-American Wildcatters, which was founded in 1969, and lived by the group's creed, "My word is my bond."

He was an advisory board member for the Maguire Energy Institute at Southern Methodist University (SMU) and was on the board of SMU's Institute for the Study of Earth and Man.

In his community, Hunt was on the executive board of the Boy Scouts of America's Circle Ten Council, where he was president from 1984 to 1986; the Presbyterian Hospital Building Corp. from 1985 to 1990; and many years on the board of Wadley Blood Bank (now part of Carter Blood Care).

A long-time member of Highland Park Presbyterian Church, he was a deacon and elder and taught Sunday School for many years.

He is survived by his wife of 72 years, Nancy Jane (née Broaddus), children Doug (Margaret), Barbara Hunt Crow, Libby Allred (Al), Bruce (Leeanne) and David (Libby); grandchildren Taylor Hunt (Elizabeth), Casey Hunt (Morgan), Nathan Crow (Itzel), Marshall Hunt (Brittany), Hunt Allred (Brittny), Austin Hunt (Chelsea), Davin Hunt (Anne Lindsey), Megan Carter (Joel), Margaret Crow Casselbrant (Magnus), Nancy Collins (William), Carter Hunt (Michelle), Daniel Crow, Bailey Hunt (Jordan), Dallas Hunt, Elizabeth Hunt and Sharon Hunt; and 35 great-grandchildren.

He is also survived by sister-in-law Caroline Lewis Hunt, as well as half-siblings Ray Lee Hunt (Nancy Ann), June Hunt, Helen Lakelly Hunt (Harville Hendrix) and Swanee Grace Hunt.

He was preceded in death by his parents, sisters Caroline Rose Hunt and Margaret Hunt Hill, and brothers Hassie, Nelson Bunker and Lamar Hunt. OGI

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ACQUISITIONS & DIVESTITURES

Mesa Royalties III Reloads in Haynesville

After Mesa II sold its portfolio to Franco-Nevada late last year, Mesa III is jumping back into Louisiana and East Texas.

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NGP-backed Mesa Royalties III's early April acquisition of mineral and royalty interests in the Haynesville Shale reflects its continued efforts to grow a portfolio of interests in the Haynesville and mid-Bossier targets in north Louisiana and East Texas.

The transaction with an undisclosed private seller includes approximately 6,200 net royalty acres across the core of the play, the company said in a release.

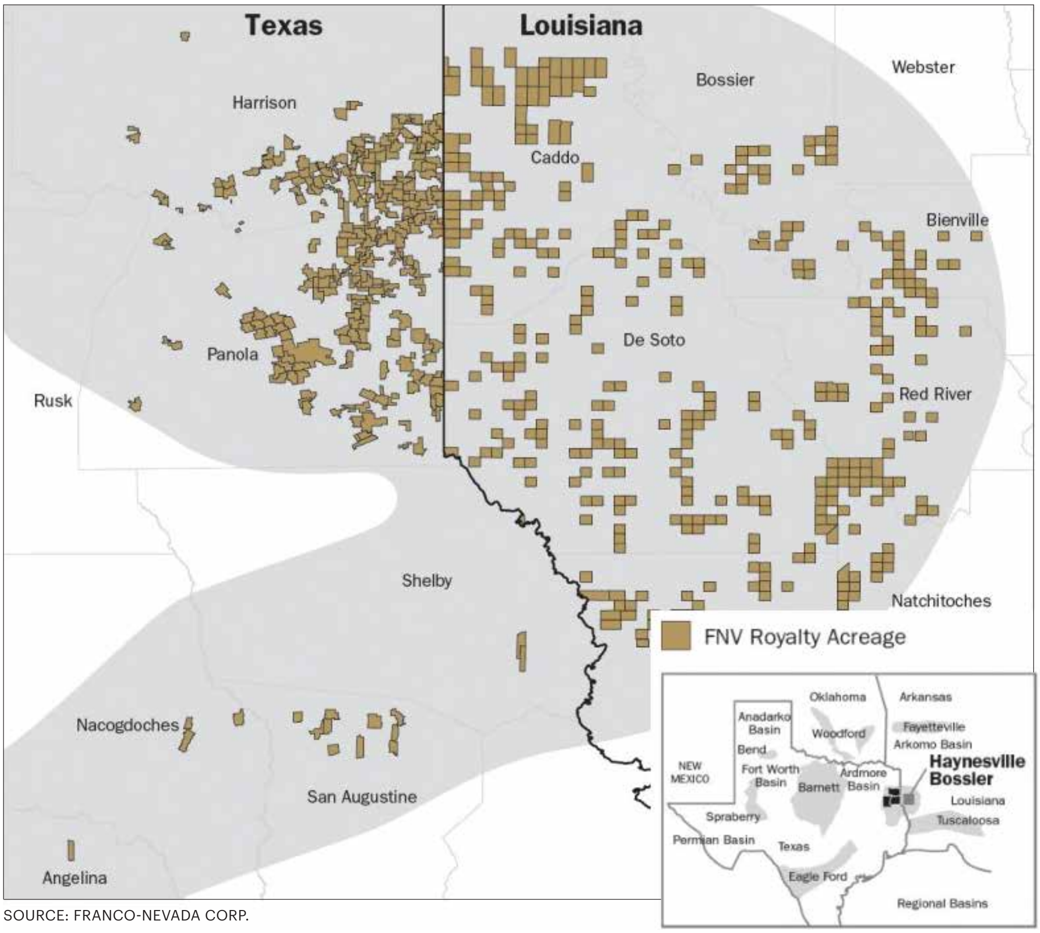
The deal added two net producing wells (253 gross wells) operated by notable Haynesville players including Chesapeake Energy, Southwestern Energy and Aethon Energy.

Mesa III financed the Haynesville acquisition using equity commitments from private equity backer NGP Energy Capital Management.

"We have ample capital available with our recent commitment upsize from NGP and are poised to continue acquiring in both the Haynesville Shale play as well as in the Permian Basin where our current buying efforts are focused," said Mesa III President and CEO Darin Zanovich in the release.

Following the latest acquisition, Mesa will own more than 11,000 net royalty acres in the

Franco-Nevada Haynesville Portfolio



SOURCE: FRANCO-NEVADA CORP.

Franco-Nevada Corp. acquired Mesa II's Haynesville portfolio for $125 million last year, adding interests on the Louisiana side of the shale play. FNV previously purchased Mesa I's East Texas portfolio.

"We have ample capital available with our recent commitment upsize from NGP and are poised to continue acquiring in both the Haynesville Shale play as well as in the Permian Basin where our current buying efforts are focused,"

DARIN ZANOVICH, president and CEO, Mesa III

Haynesville play, where the company plans to continue to aggregate and scale its position, Zanovich said.

Weil, Gotshal & Manges LLP served as legal counsel for Mesa III's Haynesville acquisition.

Haynesville hunt, Permian prowl

Zanovich also led Mesa Minerals Partners II, a previous iteration of the minerals and royalties acquisition vehicle, backed with $150 million in equity commitments from NGP.

Mesa II was active in 2023: The company sold some of its Haynesville natural gas mineral and royalty assets to WhiteHawk Energy in a $20 million deal announced in August.

Mesa II closed out the year by selling the remainder of its Haynesville assets to gold- and commodity-focused royalty company Franco-Nevada Corp. The $125 million deal had an effective date of Jan. 1, 2024.

The Franco-Nevada deal included around 1,400 net acres of Haynesville Shale royalties on the Louisiana side of the border; Franco-Nevada's existing Haynesville footprint was concentrated in East Texas.

The deal delivered Franco-Nevada additional exposure to Haynesville natural gas with operators including Chesapeake, Southwestern and Comstock Resources, the company said in first-quarter earnings.

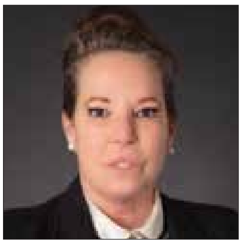
Mesa II's predecessor, a Quantum Energy Partners portfolio company, also completed a deal with Franco-Nevada in late 2020. Mesa Minerals Partners' royalty portfolio in East Texas, assembled in partnership with upstream operator Rockcliff Energy II, sold to Franco-Nevada for $135 million.

Late last year, Rockcliff Energy II sold to Tokyo Gas and partner Castleton Commodities in a $2.7 billion deal.

Mesa Minerals Partners III was formed in 2022 with $250 million in NGP equity commitments. Outside of the Haynesville, Mesa III is actively hunting for mineral and royalty acquisition opportunities on both the Delaware and Midland sides of the Permian Basin. OGI

Chevron's Hot Asset in the Haynesville

The supermajor may cut loose its lightly developed 72,000-net-acre property in Panola County, Texas.



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Appetites have been whetted by 72,000 net, mostly contiguous, undeveloped Haynesville acres that sit in the center of the shale play.

Chevron owns them and is putting them on the market, according to sources at Hart Energy's DUG GAS+ Conference and Expo in Shreveport, La.

"That is a position that all Haynesville operators are interested in," Mike Winsor, CEO and COO of Paloma Natural Gas, said in an on-stage interview.

"[And] mainly because it's undeveloped: You don't have parent-child [well] concerns."

Chevron had five horizontal Haynesville wells online in 2023 on the property, which is in Panola County just across the Texas border from De Soto Parish in Louisiana, south of Shreveport, according to Texas Railroad Commission (RRC) files.

In December, only four of those wells were online with production reaching 159 MMcf, gross, or an average 1.28 MMcf/d per well.

The company reported in a March Securities and Exchange Commission filing that it is "evaluating strategic opportunities for these assets." Chevron did not respond to a request for comment from Hart Energy.

The company added in the filing that it cut spending in East Texas in 2023. According to the RRC, Chevron's latest request for a new-drill horizontal permit in Panola County was submitted in June 2023.

The neighbors

Meanwhile, Chevron's neighbors in the field, Carthage-Haynesville, produced more than 42 Bcf in December, including 18.5 Bcf by Rockcliff Energy II, which was bought at year-end by TG Natural Resources (TGNR).

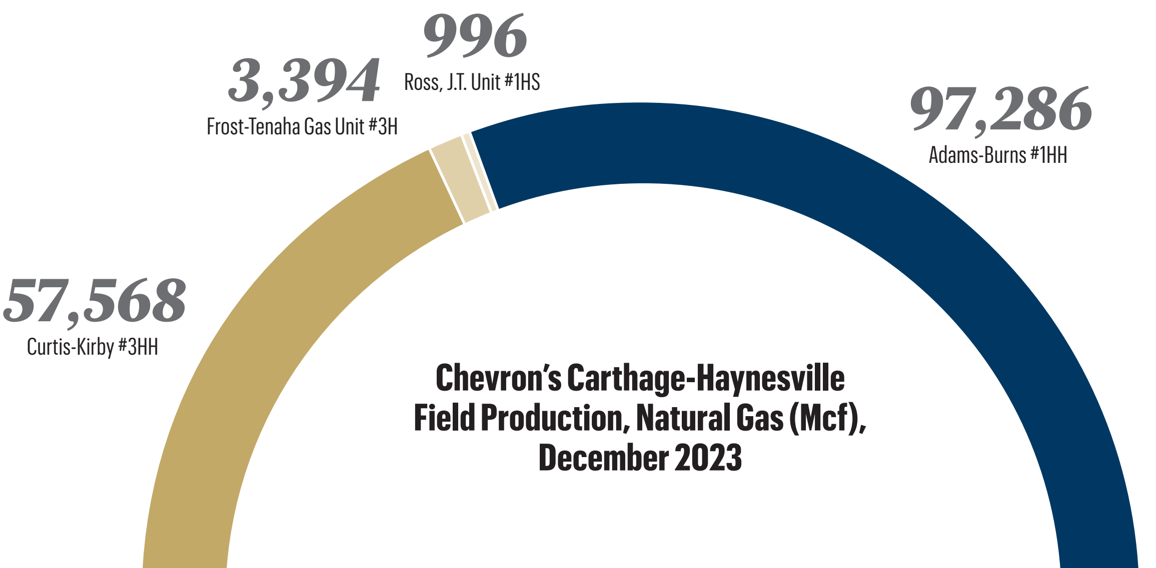
TGNR itself produced 1.6 Bcf from Carthage-Haynesville in December.

Craig Jarchow, TGNR's CEO, said onstage at the conference that he was aware that the property may be sold. But, he added, "we're very busy with the [Rockcliff] acquisition, onboarding those assets, making sure that the transition goes smoothly."

TGNR will still likely look at the property, he said. "We really have our hands full, but generally we look at everything just as a matter of discipline. Right now, we're pretty busy."

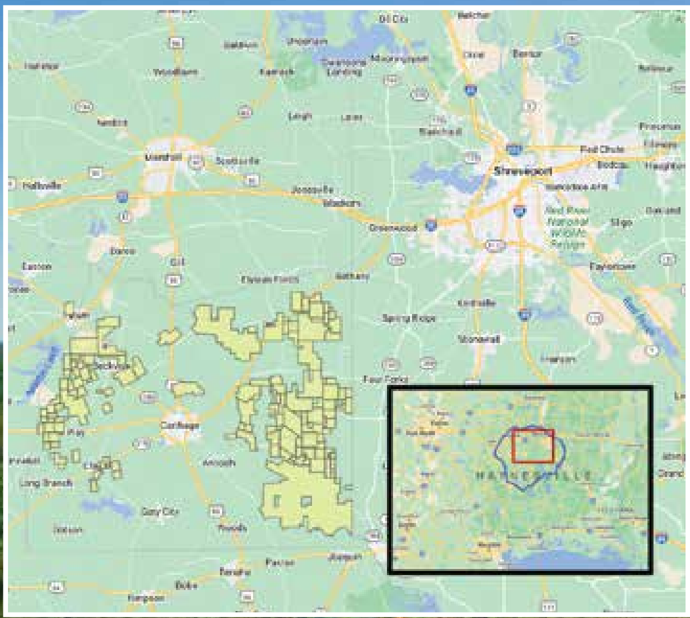
Another neighbor, Sabine Oil & Gas, produced 9 Bcf in December from Carthage-Haynesville. Carl Isaac, Sabine's president and CEO, didn't comment on the property while speaking at the conference.

Comstock Resources is also a large operator in Carthage-Haynesville, producing 3.5 Bcf in December. However, it has not reported an interest in Chevron's



SOURCE: TEXAS RAILROAD COMMISSION

Chevron Acreage in Panola County



SOURCE: REXTAG

Chevron's 72,000-net-acre property in Panola County, Texas is lightly developed for the underlying Haynesville formation—and the supermajor may cut it loose.

HART ENERGY

Haynesville acreage. Instead, it has been investing in its greenfield play, the far western Haynesville north of Houston.

Private-equity-backed Silver Hill Energy Partners produced 2.4 Bcf from Carthage-Haynesville in December, according to the RRC. It recently added property in the Williston Basin.

Pipe deal

Another operator told *Oil and Gas Investor* in Shreveport, though, that the Chevron asset includes a long-term firm-volume contract with The Williams Cos. that Chevron signed in 2023.

In the deal, Williams will install gas-gathering on 26,000 acres Chevron dedicated, connecting it to Williams' Louisiana Energy Gateway (LEG) pipeline across the border.

That 1.8 Bcf/d long-haul pipe was to come online this year but was delayed to second-half 2025 in February. Another delay is expected as a result of a pipeline dispute with Energy Transfer that surfaced in March.

'Blank slate'

With the exception of Panola County, all of Chevron's E&P operations in Texas are in the Permian Basin, according to the RRC.

Its gross production from Panola was 1.1 Bcf in December, primarily from hundreds of legacy, shallower vertical wells it gained from the 2000 acquisition of Texaco and that Chevron drilled post-acquisition before the horizontal Haynesville play developed in 2008.

"We like to say there's not any Haynesville or Bossier acreage that we don't like. [But] it's just a matter of which ones we want to acquire."

MIKE WINSOR, CEO/COO, Paloma Natural Gas

Most of Chevron's production from Panola in December was from Carthage-Cotton Valley Field with 748 MMcf gross.

"It's not very often you can come into an acreage position that is consolidated. You can come in with a blank slate," Winsor said.

"And whatever your well spacing, whatever your design, there's a huge amount of running room there."

EnCap-backed Paloma will look at the package, he said. "We like to say there's not any Haynesville or Bossier acreage that we don't like. [But] it's just a matter of which ones we want to acquire."

As a private equity portfolio E&P, "we would look pretty closely at the ratio of [proved undeveloped reserves] value to PDP [proved developed producing]. We look to acquire property with a fair amount of running room," Winsor said.

Overall, "it's definitely a package that many people would be interested in," he said. OGI

Brett: Oil M&A Outlook is Strong, Even With Bifurcation in Valuations

CLAY BRETT
PARTNER, BAKER BOTTS

Clay Brett is a partner at Baker Botts and an authority on private energy investment.

An oil pump sits in a field in the Eagle Ford. While activity is ongoing in the major non-Texas basins, the Permian and the Eagle Ford offer a clear valuation premium independent of the mix of developed and undeveloped inventory.

SHUTTERSTOCK

Valuations across major basins are experiencing a divergent bifurcation as value rushes back toward high-quality undeveloped properties. Geographically, while activity is ongoing in the major non-Texas basins, the Permian and the Eagle Ford offer a clear valuation premium independent of the mix of developed and undeveloped inventory.

Across basins, in both public and private M&A, the market is very clearly placing a premium on undeveloped locations, and the anxiety of the publics with respect to their depth of inventory is palpable. As a result, companies and asset packages in the major basins with significant undeveloped upside enjoy a seller's market and would be expected to trade way north of PDP PV-10 value, with the excess value attributable to acreage.

In contrast, wellbore and low- to no-upside deals still trade at a deep discount rate, as buyers must cleave all their base case return from the declining production value. Facing a subscale buyer, prices will suffer from the buyer's diseconomy of scale and an internal equity return hurdle in excess of 20%, which manifests itself in the bidder's PDP discount rate. As a result, scaled PDP buyers with a low cost of capital balance sheet, utilizing a borrowing base or securitizations, continue to enjoy a significant advantage.

What some may call a bifurcation in value, others may simply call a PUD (proved undeveloped reserves) premium, although one struggles to find a consistent discount rate applied to PDP. These developments have created a number of interesting deal dynamics to note:

- The allocation of value across the properties under a production sharing agreement becomes a highly material transaction item, shifting from its typical role as a ninth inning schedule delivered by the buyer, and allocation of value can become disruptive to a transaction if the allocation suggests a seller may be able to obtain a more interesting valuation for its undeveloped properties elsewhere.
- Significant value allocation to PUDs also creates more complexity to the operation of tag-along and preferential rights, and the consummation of transactions inclusive of tag and preferential rights, leading

buyers deeper into diligence to identify these material issues earlier than usual, with more flexible financial resources and deal strategies to accommodate them.

- Acquisition financing has resurged to become a very popular way for credit funds to participate in the market, particularly in PDP-heavy transactions, as the entry point on PDP collateral has remained relatively cheap. Alternative financing is generally as freely available and competitive to E&P as it has been in recent cycles, as a preponderance of financing sources compete to deploy capital into the current interest rate environment.
- Market practices regarding bring-down title thresholds between acquisition financing players (PDP-based) and buyer-borrowers (PDP + PUD) are divergent, where the buyer-borrower will have a higher scope of defect in a PSA title defect mechanic (and thus more sensitive closing defect threshold) than the closing conditions to the acquisition financing, which will require verification of a threshold level of PDP value (85%-90%).
- Financing covenants lag behind M&A market practices in the covenants' lack of value attribution to undeveloped properties, suggesting that credit participants will be forced to become more aggressive and flexible to keep up in the marginal market for partial monetizations.
- Good title to undeveloped properties becomes a new source of risk to sellers and buyers as the land function has been de-emphasized at some E&Ps over the last decade in favor of an as-needed, when-needed focus on drill-site title opinions. Sellers must attend to their land values ahead of a sell-side process to present a clean picture of undeveloped leasehold.
- The technical methodology of reserve engineering firms to limit PUD attribution to immediate adjacencies to existing PDP wells does not reflect market valuation practices and may serve an obfuscating purpose in a deal context. The market is clearly laying down locations across the observable reservoir and the market is paying for these locations regardless of reserve classification, calling into question the role of third-party reserve reports as a bedrock valuation framework for both M&A and financings.
- Representation and warranty insurance continues to be a popular means of addressing post-transaction risk, but it is more difficult to satisfy due diligence requirements in a transaction with large undeveloped value attribution, as the scope of diligence to satisfy an insurer may be more extensive than prevailing industry practices.

We traverse 2024 with green shoots of global industrial activity, creating a tailwind for oil prices that should continue to drive M&A activity generally. A long-term WTI curve above major basin breakevens remains very strong for both acquisition and development activity. The structural logic behind the developed/undeveloped divergence does not show any sign of abating today, and many believe that only another sharp cyclical collapse or a sea-change in the near-term role of hydrocarbons would cause the market to recalibrate in a way that obviates this divergence. All signs point to market strength and sustained transaction trends of the nature discussed here.

FTC Waives Added Scrutiny to Sunoco-NuStar Deal

The acquisition survived the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act.

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Sunoco's pending $7.3 billion deal to acquire NuStar Energy pulled through as another deal to survive a U.S. Federal Trade Commission regulatory waiting period.

The companies announced the expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 on April 9, bringing the transaction one step closer to completion.

Chord and Enerplus' proposed merger also cleared the antitrust hurdle under the regulatory act, with that deal's waiting period expiring on April 5.

Recent waiting period expirations seem to be the exception, not the rule, amid growing FTC scrutiny of consolidation sweeping the industry. The FTC has delayed multiple other proposed mergers, including the $7.4 billion Chesapeake-Southwestern merger, Chevron and Hess Corp., and Exxon Mobil's acquisition of Pioneer Natural Resources.

The FTC updated its merger guidelines in December 2023, indicating that any potential deals with a combined market share greater than 30% will face greater scrutiny.

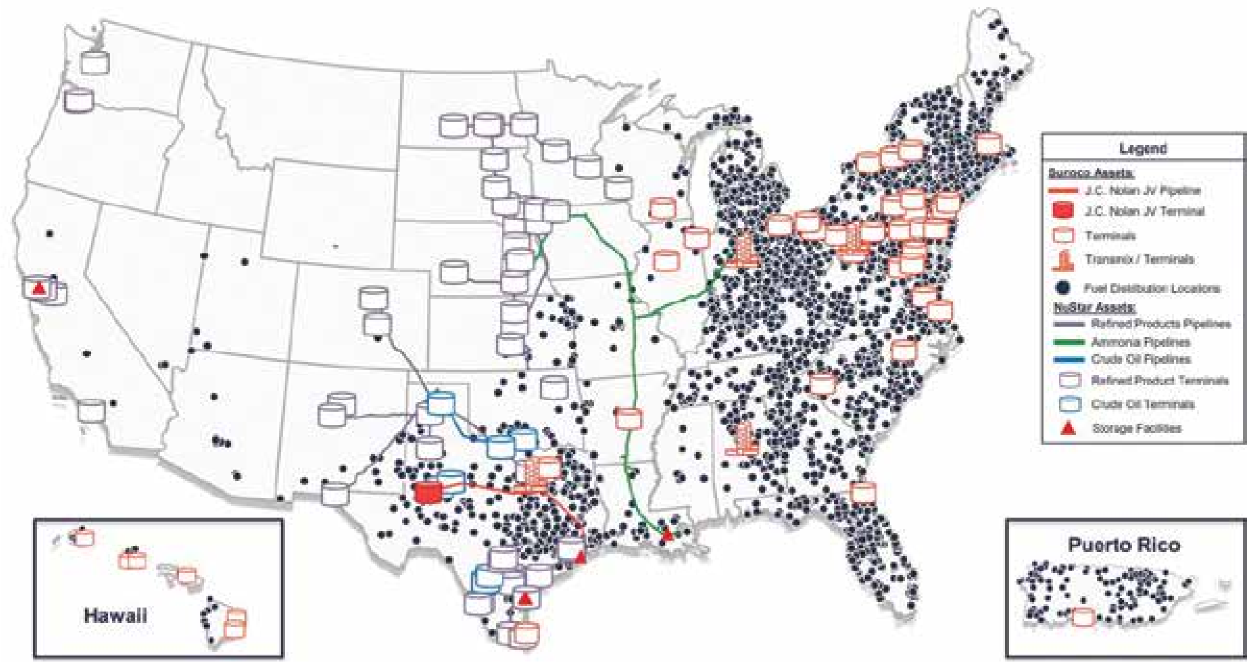
Sunoco's acquisition of NuStar adds the liquids terminal and pipeline operator's Permian Basin crude oil system to the Energy Transfer MLP's portfolio. But despite Energy Transfer's market cap being the third-largest among North American midstream players, Sunoco didn't seem to be worried earlier this year.

"If you take a look at the combined assets of our organization, they're very complementary in that there's very little geographic or market overlap that you may typically see in mergers that have historically been of interest to the commission," Scott Grischow, Sunoco treasurer and senior vice president of finance, had said in an analyst call.

A NuStar special meeting was scheduled for May 1 for unitholders to vote on the terms of the proposed acquisition. The companies said the transaction is expected to close shortly after unitholder approval.

Following the transaction's close, NuStar unitholders will receive Sunoco's distributions for first-quarter 2024. OGI

Sunoco and NuStar's Combined Assets



SOURCE: SUNOCO

With Industry Under a Microscope, Diversified Takes on Methane

Producer with emission reduction success wants to share how it's done.

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When it comes to taming the so-called super pollutant, methane, all eyes are on the oil and gas industry as regulators roll out new rules.

The U.S. Environmental Protection Agency (EPA) has set standards to lower emissions from high-emitting equipment and mandated monitoring of methane leaks from well sites and compressor stations. The federal regulator has also required companies, among other directives, to eliminate routine flaring of natural gas—primarily made of methane—produced by new oil wells. Plus, they must switch to zero-emitting technologies and ditch natural gas-powered pneumatic controllers, which are responsible for a substantial amount of the industry's methane emissions.

Publicly traded companies are also in the crosshairs of the U.S. Securities and Exchange Commission, which narrowly passed rules requiring disclosure of climate change related information in their filings. A federal appellate court, however, imposed a temporary stay on the rules pending a judicial review amid legal challenges.

The year is bringing change for oil and gas companies, including Alabama-based Diversified Energy, an active M&A player with tens of thousands of wells across parts of the U.S. Its production mix is about 97% natural gas and NGL.

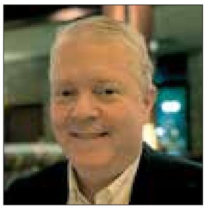
"There's so many things in flux. We just need to reevaluate what our next targets are," Paul Espenan, senior vice president of environmental health, safety and risk management for Diversified Energy, told Oil and Gas Investor*. "We're still focused on methane reduction. We have methane reduction projects that are moving forward, and so we're not stopping."*

Diversified reached its 2030 target to reduce methane intensity by 50%, compared to its 2020 baseline, ahead of schedule. The company reported in April a methane intensity of 0.8 metric tons of CO_2 equivalent (MT CO_2e) per MMcfe. Its absolute Scope 1 methane emissions dropped 39% to 420,000 MT CO_2e, compared to 686,000 MT CO_2e in 2022. The company said it conducted about 246,000 voluntary emission detection surveys with about a 98% no-leak rate on companywide surveyed assets.

Tools in its kit include leak detection and repair (LDAR) equipment such as optical gas imaging cameras and the Teledyne FLIR GT-44 handheld gas detector, Bridger Photonics aerials for methane detection for midstream assets, measurement technologies, predictive analytics and one of Espenan's favorites—

Diversified's suite of handheld emissions technologies include the Teledyne FLIR GT-44. Well tenders survey wells across the company's operating areas.

Diversified Energy says it reduced its methane intensity by 33% in 2023, compared to 2022, to 0.8 MT CO2e/MMcfe and exceeded 75% of its 5-year goal for pneumatics conversions.



"It isn't just about us getting better, it's about us helping others to get better."

PAUL ESPENAN, senior vice president of environmental health, safety and risk management, Diversified Energy

"At the end of the day, our goal is to keep those gas molecules in the pipe."

TERESA ODOM, senior vice president of sustainability, Diversified Energy

Xplorobot, which makes a 3D digital model of an inspected asset and provides measurements if emissions are detected.

Espenan and Teresa Odom, senior vice president of sustainability for Diversified, shared additional insight on the company's methane emissions efforts.

Velda Addison: Diversified Energy has a business model that differs from most other oil and gas companies, focusing on "acquiring existing long-life, low decline producing wells, and at times their associated midstream assets" to improve production, optimize operations, increase efficiencies and reduce emissions. What challenges, if any, does this model pose when it comes to mitigating methane emissions, especially from acquired assets?

Teresa Odom: I wouldn't see it as a challenge. Paul may feel differently, but we see it more from the perspective of, because of that business model, we're not out there drilling very capital-intensive brand new wells with larger emissions. What we're trying to do is focus on the wells that we already have and make those wells as efficient as possible from a production and an operations standpoint, but also from a responsible stewardship environmental performance standpoint. And to that end, that's exactly what the methane emissions activities that we're doing are.

Paul Espenan: We have the same challenges on methane reduction that everyone else does. Ours are certainly of a large scale.… We made a very bold decision a little over two years ago to make every single one of our well tenders and operators an LDAR technician and arm them with the tools they needed to do that. From a logistics standpoint, somebody travels to a location, finds a leak and then–under many models–ties a yellow piece of ribbon around that leak and then waits for somebody else to come and fix it. Our model says: You're going to show up at that location. You're going to look for leaks, and you're going to fix them right away before you leave. When we did that, we obtained a 98% tight rate. In other words, when that operator left that location in 2023, 98% of those locations were leak free. So that's a challenge for everyone. We're ahead of the pack in terms of what we like to say making leaks rare by land and air.

VA: Pneumatic devices in particular have been singled out for contributing significantly to emissions from oil and gas operations. What methods and technologies are the company using regarding pneumatic devices?

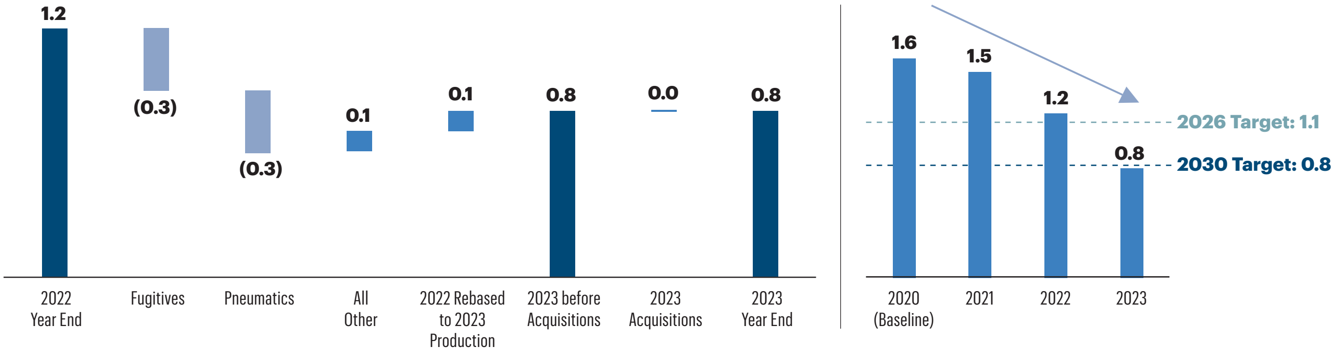
PA: Once upon a time, folks didn't really do what I would call a hard inventory of their pneumatics. They didn't make sure that they knew exactly what was out there, and not just what was out there but the make, the model, the function, the how far does the stroke in it travel? How often does it actuate? There's all these characteristics that you can get on your pneumatics. Only then, can you calculate your emissions and find out where the highest ones are. Then, target those for elimination.… It's extremely hard work to get all that data in there, get it cleaned, get it understood. Then and only then you can strategize on it.… We're working more this year

DIVERSIFIED ENERGY

Diversified says it made about $7 million in investments in 2023 to lower emissions, mainly in additional upstream and midstream fugitive emission leak detection and repair, natural gas-driven pneumatic replacements, and compression conversion and elimination.

Scope 1 Methane Intensity

(MT CO2e per MMcfe)



SOURCE: DIVERSIFIED ENERGY

on converting from using natural gas to compressed air. And, we're evaluating other technologies like nitrogen and chemical reactions to control those emissions, rerouting them or just eliminating them.

TO: Being able to understand that and then measure it is a whole lot different when it comes to your emissions profile than using default factors that the EPA is requiring us to use, which are outdated and overstated. So, it's significant for us to be able to fully understand and appreciate what our inventory is, what we have in our inventory before we start the process of conversion, elimination, whatever the next step may be.... Our well tenders are effectively the owners of those wells in a sense that they know what that well does now, should do, can do, needs to do better, and we empower them to make the decisions around those wells for repairs, for getting things done. I think that's a little bit of a different business model for us, too. Whereas, before, if it's a low-producing well, and these other developers are more interested in sort of a shinier penny, making that new well happen and not necessarily the old one, then the well tenders for those older wells are maybe not necessarily empowered. That's not where they want to spend the money. We're the opposite. We take those wells and we make them core in our portfolio, and then we empower those well tenders.

VA: When you detect these emission events, are they typically fairly simple and inexpensive to fix? Can you talk about more about the cost associated with solving some of these emissions events?

PE: They are very fixable. They are something that an operator could just make a visit and resolve pretty easily. Most of the time they don't really cost much to fix, if anything. Sometimes it's just a simple malfunction.

VA: Are there any best practices for emissions reduction you would highlight for others?

PE: No. 1, have a detailed inventory. No. 2, understand how everything fits together. No. 3, when you do your LDAR, make sure that it's fit for purpose. For example, the RMLD [remote methane leak detector] laser device does really good in windy conditions. This little handheld sniffer [GT44], not so much. Also, the [optical gas imaging] camera doesn't do so well in windy conditions. So, when you're planning how you're going to find leaks, it's very important that you look at the environment and that you look at the asset and the characteristics of an asset. I'll give you one more example. We have some areas where we have to use acoustic imaging. It listens for the sonic signature of a leak. It's ultrahigh pitched, probably beyond what the human ear can hear. We use that in environments where you might have some background methane concentrations because of normal operations. In a compressor building, you're going to have some expected emissions of methane from a packing or a valve or packing on a compressor. To find a leak in that environment, you've got to use something that is just going to hear the leak as opposed to try to measure it. The point is this: fit-for-purpose LDAR, then focus on elimination.... Do you really need that pneumatic? Is there another way you can do it? ... The last one is measurement. Don't use theoretical or factors if you can help it. Measure, measure, measure.

2020 baseline
1.6MT
CO_2e/MMcfe

2030
target reduction
0.8MT
CO_2e/MMcfe

7yrs
early target met

VA: The focus is high on emissions with intense scrutiny. Diversifed was at the center of a Congressional committee inquiry in December. Plus, satellites are watching and others are gathering data. How do you try to control the narrative? Is that even possible? What is your strategy?

PE: It's about education. You get a congressional inquiry, and you use that as an opportunity to tell your story. And that's what we do really well. Once people find out all the work we're doing and how we're leading, they say, "oh, gee, why did we even ask?" There's so much misinformation out there.

With satellites, when you increase distance, you decrease accuracy. When you decrease the frequency of making observations, you decrease accuracy. Even the EPA themselves said satellites cannot be used for reporting of emissions. They aren't good enough yet. But yet people persist. Hardly a week goes by without an article that says such and such about oil and gas having higher emissions, and then you look down in there and you say, oh, they didn't even peer review this. There's junk science out there.... We have to be the voice of education.

VA: What is your favorite emissions detection tool to use out in the field?

PE: All of them. It's really hard to pick. But the one that we've

Companywide Emissions Goals

TARGET	Reduce Scope 1 methane emissions intensity by 30% by 2026
TARGET	Reduce Scope 1 methane emissions intensity by 50% by 2030
GOAL	**Achieve Scope 1 and 2 net-zero absolute GHG emissions by 2040**

SOURCE: DIVERSIFIED ENERGY

really gotten a lot of benefit from is the Semtech Hi-Flow 2 and another one spotlighted in our sustainability report this year is Xplorobot. We partnered with them last year to do a series of field trials. I feel strongly, and I'm gonna geek out here on you, that this technology has the ability to leapfrog camera-based [optical gas imaging] at about half the cost and provide a digital twin, a 3D model, at the same time.

So why is that important? Look, if you're a LDAR technician and you had a fight with your wife last night and you didn't get much sleep, and then you come to work and you're looking at that camera looking for leaks. The quality of that is only as good as you are that day. If I have this laser-based [optical gas imaging] anybody in five minutes how to use it. And the quality of that would be 100% perfect because the machine does all that. There's no subjectivity left in it. So, I'm excited because it shows if you have a leak exactly where it is, how much it is, and then shows you–this is the important part–where you didn't have a leak, and it has a digital record of where you didn't have a leak. In this adversarial world we live in, being able to show where you were tight is important because otherwise he says, "hey, you got a leak. How long has it been going on?" Well, here's the paper trail.… We've got a level of technology that is going to be independent of the inspector.

VA: Is there anything else you want to speak on or share?

TO: At the end of the day, our goal is to keep those gas molecules in the pipe. We want to keep them in the pipe because we want to get them to a sales point, and we want to get them to meet the energy demand that's out there. From everything that we see, it's just a growing demand, so it's in our best interest. It's in the climate's best interests. It's in our neighbor's best interest when we can meet their energy demands, keeping that in the pipe. So that's what we want to do.

PE: We've been educating as many people who will listen. I took time last year to participate in a series of workshops to educate smaller operators on everything we've learned, everything we just finished talking about. Other operators presented too … just trying to share what we've learned and to help them to get better. So, it isn't just about us getting better, it's about us helping others to get better.… We're [also] actively collaborating with a lot of vendors in the development of their products and have played a part in perfecting their products. Why do I bring this up? It's not just about us. That's it. OGI

From Satellites to Regulators, Everyone Snoops on Oil, Gas

From methane taxes to an environmental group's satellite, producers face intense scrutiny.

MethaneSAT, a satellite developed by the Environmental Defense Fund, researchers at Harvard University, Ball Aerospace and others, was launched in March to monitor methane emissions in oil and gas basins. The data it collects will be publicly available.

METHANESAT

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Whatever you want to call it—shame campaigns, sneak peeks inside windows of operations or intense scrutiny for transparency's sake—the spotlight is on oil and gas companies when it comes to methane emissions.

And the data is being made publicly available.

Satellites are watching. The government is watching. Environmentalists and other concerned individuals are watching. Potential oil and gas investors are watching.

The attention comes as the U.S. rolls out methane regulations, even though they are exasperatingly incomplete.

With these programs, "you've armed a group of people that are not necessarily focused on improving the problem.… They're utilizing this information and this data to go to the individuals that want to provide new capital [for oil and gas] but are a little bit hesitant to do so to convince them not to do it," Dan Romito, consulting partner for Pickering Energy Partners, said during Hart Energy's DUG GAS+ Conference & Expo.

While proponents of such measures say the focus will help pinpoint problematic areas and even highlight successful mitigation efforts for some, others fear it is another attempt to eliminate the industry. Regardless, accurate data is needed alongside economic solutions to work toward a common goal of reduced emissions.

"Operators and the oil and gas industry as a whole right now [are] saying, 'OK, what can I do?' There's a lot of noise. 'Well, how do I move forward? How do I eat an elephant?'" asked Bunkie Westerheide, vice president of commercial development for Kathairos. "Well, you start chewing and the best first bite you can take is in those inventories. Go around your operations, count the number of devices, try to get an understanding of the situation internally before an external understanding of your situation is projected onto the company."

Kathairos, which provides methane emissions reduction technology, is focused on pneumatics—the top methane emissions source for oil and gas.

Emissions down, pressure up

The oil and gas industry has lowered its average methane emissions by nearly 66%

"You leave it to those outside maybe with other motives or agendas, you're going to get a definition. So, we need to be on the front lines talking about that definition of clean gas and dirty gases."

BUNKIE WESTERHEIDE, vice president of commercial development, Kathairos

"They will shame you," Romito said of people involved in gathering emissions data. "That is a real thing now. That is a part of everyday life from the oil and gas space."

DAN ROMITO, consulting partner, Pickering Energy Partners

across all seven major onshore producing regions from 2011 to 2021, according to API.

However, the sector, according to the U.S. Environmental Protection Agency (EPA), remains the largest industrial source of methane in the U.S.

Why does it matter?

Methane, the largest component of natural gas, is a potent greenhouse gas (GHG) that traps heat and contributes significantly to global warming. Its warming impact is 86 times stronger than CO_2 and it has an atmospheric lifespan of about 12 years, according to the Climate & Clean Air Coalition. Methane is a known precursor gas to ground-level ozone, which can be harmful to humans, plants and materials depending on exposure levels.

Regulators took aim at the pollutant with the EPA's final methane rule announced in December 2023. The requirements include elimination of routine flaring of natural gas that is produced by new oil wells. It mandates monitoring of methane from well sites and compressor stations, and it sets standards that require reductions in emissions from high-emitting equipment such as controllers, pumps and storage tanks.

The rules also require periodic inspections of well sites and compressor stations for methane leaks and gives third parties a way to monitor large methane releases and report them via the Super-Emitter Response Program.

Public shaming

MethaneSAT, a satellite developed by the Environmental Defense Fund, researchers at Harvard University, Ball Aerospace and others, was launched in March to monitor methane emissions in oil and gas basins.

"This is publicly available [data] and they will shame you," Romito said. "That is a real thing now. That is a part of everyday life from the oil and gas space."

Emissions data is being factored into M&A and reserve-based lending, added Westerheide, speaking on risks besides environmental hazards. "There's no doubt that this is going to end up in the financial reports whether assets get sold, divested or acquired," he said of emissions data.

The methane tax, Romito added, is a "liability on the balance sheet." Making the situation more frustrating, he said, is the industry awaits guidance on Subpart W of the regulations.

Subpart W of the EPA's Greenhouse Gas Reporting Program pertains to owners or operators of petroleum and natural gas systems that generate 25,000 metric tons or more of GHG emissions per year. Revisions in Subpart W could "make life even harder," he said, pointing out how the results of the presidential election could shift regulations.

"The cost of retrofitting is very expensive, but there's a reputational risk at play because if you underplay what that methane accountability is going to be, even if you do it on accident, once again, you run the risk of actually enhancing the risk profile," Romito said.

Nearly
66%
average reduced methane emissions, 2011-2021

Play defense

Romito suggested companies play "really good defense," push for empirical data and provide datasets that reflect economic reality.

Westerheide said what will drive value for operators and the industry "is the ability to produce empirical data while you're producing that informs the next step that you take for your reduction."

Some solutions are economic today, enabling them to be implemented first, he said.

Standardizing industry terms and definitions within the industry could also help, Westerheide said, pointing out initiatives such as the Oil and Gas Methane Partnership 2.0. OGMP is a partnership of oil and gas companies, international groups and governments working together to cost-effectively mitigate methane emissions.

"You leave it to those outside maybe with other motives or agendas, you're going to get a definition," he said. "So, we need to be on the front lines talking about that definition of clean gas and dirty gases."

Turning back to the methane rule, Romito said the industry must remain realistic. The odds are that it is not likely to go away regardless of who is in office, he said. "This is something that you're going to have to prepare for in perpetuity."

On a positive note, Westerheide said the industry is collaborating.

"If a solution works, operators are talking about it with each other," he said. OGJ

Hydrogen Proponents Work to Build Up Blue

The investments are there, but so far the offtake is not.

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Six years ago, Japan was the only country with a hydrogen strategy.

Since then, more than 50 other countries have developed strategies targeting the low-carbon fuel with decarbonization potential, pledging investments of over $300 billion with more than 1,000 projects announced.

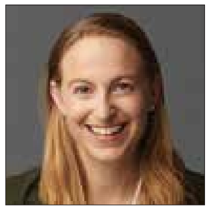
Rafael Fejervary

However, only 4% of these projects have made it past the final investment decision (FID) stage, according to Rafael Fejervary, global hydrogen director for SLB.

"Why? Because there is little offtake. Only 1% of these projects have a binding offtake agreement for the long term," Fejervary said during CERAWeek by S&P Global. "The reason for that is really the cost."

The discussion took place as many energy and world leaders look to reduce global greenhouse gas emissions. Hydrogen has been championed as a promising way to decarbonize hard-to-abate sectors such as steel and cement, while also serving as a low-emissions alternative in other areas such as transportation and energy storage.

Government policies that enable demand creation and technology to drive down costs are two ways to address costs concerns, according to Fejervary, noting SLB has been directly involved in first-of-a-kind hydrogen projects.



Eve Hanson

Projects that have reached FID are located in existing hydrogen markets, added Eve Hanson, senior vice president of research and innovation for investment firm Energy Impact Partners.

"Hydrogen is already a feedstock in ammonia, methanol, refining. We're seeing some of those projects go particularly in regions that have a carbon tax or some other incentive that's driving the demand," Hanson said.

"That's already a large industry to tackle."

She sees market demand emerging first in areas in which hydrogen can be used for green ammonia and methanol, such as for shipping fuels, or upgraded into sustainable aviation fuel (SAF). The aviation industry has shown a willingness to pay for SAF, she said.

SHUTTERSTOCK

Getting others to do so is among the ongoing challenges.

In the short term, demand will likely come from existing users, Fejervary added. These include those in hydrogen hubs, such as the seven hubs in award negotiations with the U.S. Department of Energy for $7 billion.

David Burns

David Burns, vice president of global clean energy for Linde, sees liquid hydrogen playing a role in the short term.

Hydrogen can be liquefied when cooled to below negative 423 F, according to the U.S. Energy Information Administration (EIA). Liquefied hydrogen can be used as a fuel in marine, rail, truck and rocket engines. However, it is an energy intensive and expensive process, the EIA says.

"Blue hydrogen is available at scale today," Burns said before addressing the importance of partnerships. The chemicals company has formed several partnerships to grow what the company has called its bread and butter. "We can do the production, carbon capture, work with experts on the subsurface.…"

Linde has collaborated with SLB on carbon capture and sequestration projects, with a focus on designing business and operating models that maximize value.

On the Gulf Coast, Linde is investing $1.8 billion to supply clean hydrogen to Dutch fertilizer giant OCI NV, the company developing what is being called the largest blue ammonia facility of its kind in Texas. As part of a long-term agreement, Linde will supply the hydrogen to OCI, which will upgrade it to produce blue ammonia at its 1.1 million tonnes per annum facility in Beaumont, Texas. OCI plans to begin operations in 2025.

"At the same time, I think we need to think of customers and offtakers as partners," Burns said.

Linde and Exxon Mobil in 2023 signed a long-term agreement for the offtake of CO_2 associated with Linde's new clean hydrogen production facility being constructed in Beaumont.

While producing more hydrogen with natural gas as a feedstock with CCS could give the sector a boost, panelists agreed that attention should be paid to upstream methane emission rates.

"If you want to have blue hydrogen have a strong decarbonization story, you have to manage the upstream methane emissions," Hanson said.

For the hydrogen production tax credit, known as 45V, an upstream methane intensity of about 0.9% has been set as the baseline for methane leakage during the natural gas recovery process and subsequent gas processing and transmission.

However, the U.S. Environmental Protection Agency estimates leak rates across the natural gas supply chain at about 2%-3%.

Not all natural gas has the same methane emissions intensity, and companies can show what differentiates their production.

"To me that's the mission critical challenge, [and] an opportunity for the entire industry," Hanson said.

Romito: Carbon Markets are the Industry's Silver Bullet

DAN ROMITO
PICKERING ENERGY PARTNERS

Dan Romito is a consulting partner at Pickering Energy Partners focusing on quantitative ESG strategy and implementation.

Unfortunately, the Biden administration has clearly set its goal to permanently codify decarbonization into the United States' regulatory fabric.

Decarbonization is generally considered a reasonable goal when presented within the context of a trend, as opposed to an absolute. However, the controversy lies with how the regulatory environment prescribes decarbonization in the form of net zero or bust.

The existing regulatory landscape fails to recognize that the U.S. represents only 14% of total global emissions, so it is not practical to prioritize net zero above our country's long-term economic well-being. In other words, a new set of costly consequences arise if the U.S. sacrifices economic efficiency solely for net zero.

This dynamic becomes increasingly complicated when we deliberate what the global economy will look like over the next two decades. At this point, the emergence of artificial intelligence (AI) is already overdiscussed, but it is critical to reinforce just how expansive AI technology will become.

By 2030, the AI industry is anticipated to experience a twentyfold increase, which equates to roughly a $2 trillion industry. Forbes expects AI will contribute a 21% increase to U.S. GDP by 2030. The regulatory market fails to acknowledge the exponential growth in power and energy the AI ecosystem will demand.

Ironically, the push for electric vehicles (EV) is partly responsible for the rise in AI. Forbes reported that 10% of vehicles will be driverless by 2030, a capability facilitated almost entirely by AI.

Overall, 64% of businesses believe that AI will help increase productivity. What is commonly left out of consideration is how energy, power and AI are directly connected. As of March, U.S. officials have earmarked nearly $30 billion in subsidies for advanced semiconductor manufacturing, aiming to bring cutting-edge AI chip development and manufacturing to American soil.

A single data center can consume the equivalent electricity of 50,000 homes. The U.S. will need more than one additional data center to facilitate that anticipated boom in AI. According to research firm Data Bridge Market Research, spending in the global AI infrastructure market–including data centers, networks and other hardware that support the use of AI applications–is expected to reach $422.55 billion by 2029, growing at a compound annual rate of 44% over the next six years.

The U.S. government actively subsidizes AI technologies, which directly conflicts with our administration's efforts to achieve net zero. Herein lies a very confusing, yet fascinating dynamic. It is clear these goals will not go away, so the market must identify a solution that allows policymakers to have their cake and eat it, too. Luckily, this solution already exists, although it is currently nascent.

Research suggests it would be foolish for the U.S. not to foster the economic prowess that derives from AI. That is not a controversial statement. Controversy continually enters the fold once the regulatory market overlaps a push to attain net zero.

Given the exponential increase in power demand, we also must remain intellectually honest about aggregated operational net zero, which is largely in direct conflict with a growing economy. While many companies are making headway, most global industries will never be adequately positioned to achieve true net zero.

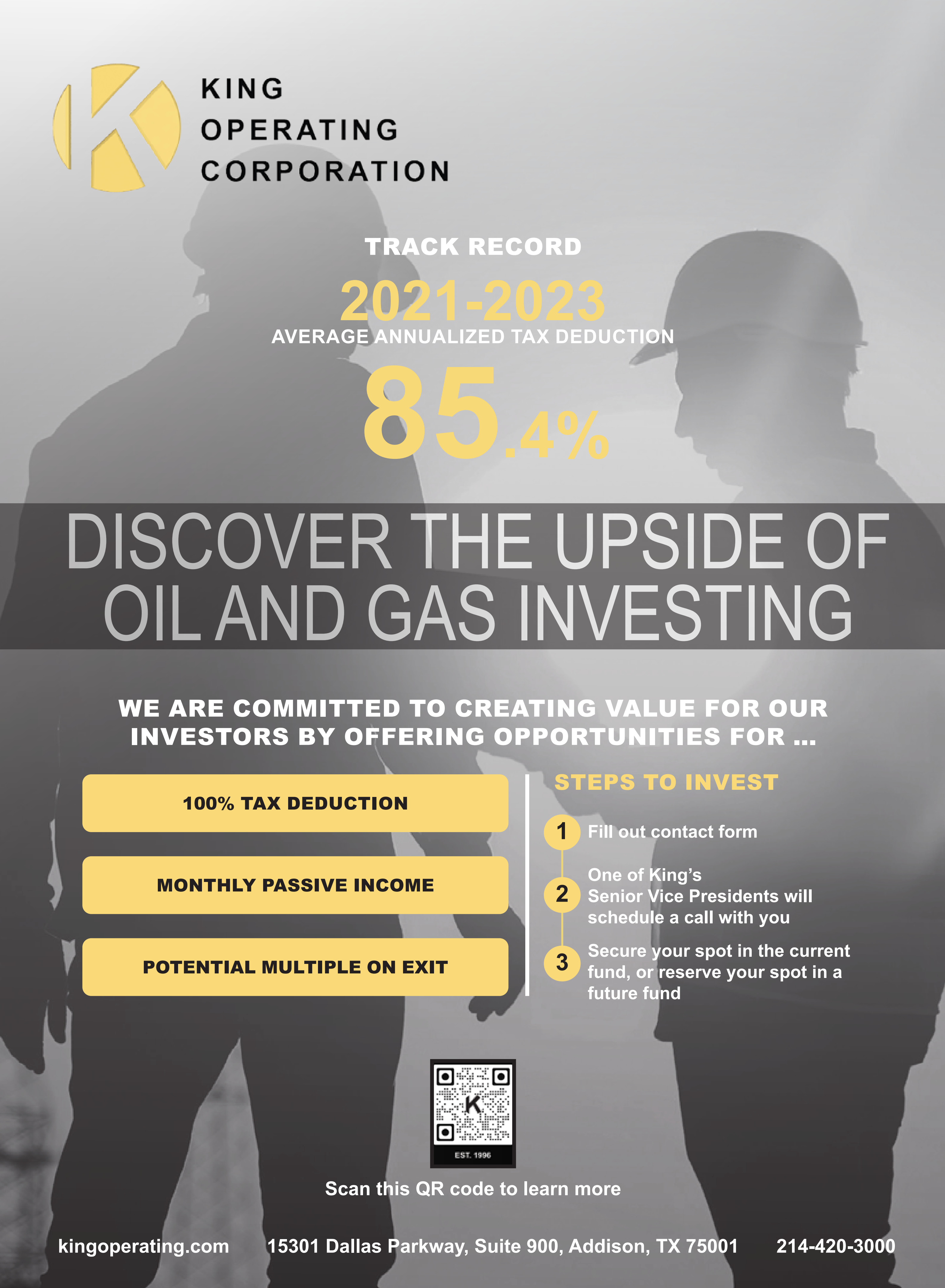
This dynamic represents the foundational premise for the rise of carbon credits. Reducing economic prowess does not serve shareholders or society at large. Simultaneously, the call to attain net zero, at least in some form, will likely not wane in the foreseeable future.

This forms the perfect recipe for the carbon credit markets. Several thought leaders anticipate a rapid maturation in this space. A high-quality, verified credit provides a management team wishing to expand economic output with a financial instrument that mitigates its carbon footprint.

Since the AI revolution will require vast incremental energy, the energy sector must increasingly understand how to participate in the carbon markets efficiently.

This focus also accomplishes two distinct adjacent capabilities. Companies can be more realistic and practical with their environmental goals, i.e., utilizing carbon credits to "fill the gap," thereby reducing greenwashing accusations. The impending carbon markets will also facilitate an expedited research and development curve in AI, i.e., less apprehension to pursue specific R&D and growth strategies associated with higher carbon emissions.

Though the carbon markets are in their early stages and remain far from perfect, they offer the proverbial "silver bullet" that mitigates the need to sacrifice economic output because of potential emissions implications. OGI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2021-2023
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85.4%
DISCOVER THE UPSIDE OF
OIL AND GAS INVESTING
WE ARE COMMITTED TO CREATING VALUE FOR OUR
INVESTORS BY OFFERING OPPORTUNITIES FOR ...
100% TAX DEDUCTION
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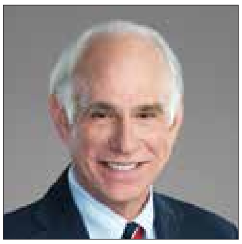
Hirs: Hidden Cost of the Transition



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Aspirations can be costly. Goals can be attained. Renewable energy advocates promise that cheap resources will lower the cost of electricity to consumers. The reality is that renewable energy developers do not pass along that cost savings, and accommodating their entry to the grid is also driving up costs.

In the Texas grid managed by ERCOT, the Electric Reliability Council of Texas, the fleet of wind and solar farms is the largest in the nation. For 2023, ERCOT also had the highest electricity prices, the most volatile electricity prices, and issued more conservation alerts than anywhere else in the nation.

Obstructive spin from activists and incumbent industries have combined to obscure the facts about the costs of the energy transition. The consumer is primed to wake up in five years' time wondering how the promise of the cheap wind and solar morphed into much higher electricity bills. As always, there are several contributing factors.

Electricity from wind and solar farms is intermittent. They are not yet sufficient to fully meet peak demand days for any grid, but they benefit from the pricing set by the last swing producer on any peak demand day, in very much the same way that the price of oil in the Permian Basin is dependent on OPEC+ actions. In Texas, there were numerous occasions in 2023 when the wholesale electricity price jumped to $5,000 per megawatt hour.

Not a straightforward swap

To accomplish the goal of electricity generated from 100% renewable resources, consider a simple example. Assuming 100% efficiency for everything, what will it take to replace a 1-gigawatt (GW) natural gas power plant?

Currently, solar farms have the cost advantage over wind farms due to relatively lower costs of construction and because the sun shines more frequently than there are favorable winds. On a 12-hour cloudless day—again, assume 100% efficiency—a 1-GW solar farm to power the grid is necessary, in addition to another 1-GW solar farm to charge three state-of-the-art four-hour battery packs to power the grid at night. A winter day with only eight hours of sun will require a third 1-GW solar farm and another battery pack.

Using costs from published Department of Energy data, replacing a $1 billion, 1-GW natural gas power plant will require at least $4.5 billion in solar farm construction costs, plus an additional $6.8 billion in battery packs. To this, one must add the cost of additional interconnects to the grid and additional transmission lines since solar farms, like wind farms, cannot be built in urban areas.

The nation is trying to keep up with the growth of renewable power resources, but before transmission lines can be built, the power plants must first have interconnects with the grid.

Most grids now track congestion costs to indicate the cost of inadequate transmission line capacity. For example, congestion costs are incurred when wind farm production is curtailed, and the grid operator must instead obtain electricity from a nearby natural gas power plant. The cost of electricity from that power plant is netted against the offered price from the wind farm to get the "congestion cost."

The wind farm operator points to the congestion cost to argue that new transmission capacity will be economically viable. It is a fallacious argument. Once a bottleneck is removed in a network, prices across the nodes will converge. The transmission fee is then added to the wholesale cost of electricity for the network. That is, there is no free lunch.

To build out the expanded transmission network, governments or consumers will have to foot the bill. State and federal policies regard transmission lines as common carriers entitled to allowable rates of return determined by tariffs. Because of this, transmission lines were historically built in an orderly manner, where the utilities had planned power plants delivering electricity to growing consumer regions, making it simple to calculate the sizing and cost of the transmission infrastructure.

Now, with the massive growth in distributed power plants across rural America, it is significantly more difficult to size and set the cost of new transmission lines. The new lines will, at least initially, not be fully utilized because of the intermittent electricity provided from new wind and solar farms.

Before the transition away from fossil fuel power plants began in earnest, grid studies, including one by former CAISO Co-Chair Mason Willrich, estimated that updating just the legacy infrastructure would be a $2 trillion investment for the nation. Additional costs relating to hardening the national electricity infrastructure against electromagnetic pulses (EMP) from nuclear weapons, cyberattacks and climate change would be included.

To this, we now add the cost of building and connecting widely dispersed wind and solar farms. Artificial intelligence data centers running 24/7, electric vehicles, and the push in some communities to go all electric will require an even greater buildout of infrastructure.

In orders of magnitude, as much as a *tenfold* increase in capital infrastructure is on the table for Americans, via either their taxes or their electricity bills. As Texas illustrates, the energy transition is not free, either in terms of price or service. State and federal policymakers should be honest about this with their voters and consumers. OGI

TRANSITION IN FOCUS

Biofuels/RNG

DG Fuels Selects Johnson Matthey, BP Technology for SAF Facility

DG FUELS/JOHNSON MATTHEY

Proposed DG Fuels plant in Louisiana

DG Fuels, which has proposed building a $4 billion sustainable aviation fuel (SAF) facility in Louisiana, has selected Fischer Tropsch CANS technology co-developed by Johnson Matthey (JM) and BP for the project.

The fuels company plans to convert sugar cane waste into about 600,000 metric tons of SAF annually. JM and BP's technology, as explained in a news release, converts synthesis gas derived from the sugar cane waste biomass to synthetic crude. That will be processed to produce the synthetic kerosene, which is then blended with conventional jet fuel to make SAF. JM said the plant would mark the largest deployment of the technology.

DG Fuels, which has already lined up agreements with Air France-KLM and Delta Air Lines along with a strategic partnership with Airbus, anticipates starting production in 2028. The facility will have a capacity of 13,000 bbl/d of SAF, which JM said is enough SAF for more than 30,000 transatlantic flights annually.

Strategic Biofuels Secures Investment from Japan-based Consortium

Strategic Biofuels said it secured an investment commitment from Magnolia Sustainable Energy Partners, a Japan-based investment consortium created by Sumitomo Corporation of Americas and JX Nippon Oil & Gas Exploration Corp.

The biofuels company is developing the Louisiana Green Fuels project, which will produce SAF in Caldwell Parish, La. The plant will convert forestry waste into SAF. The project also involves capturing and storing CO_2 onsite from the project's power plant and biorefinery, the company said in the release.

Strategic Biofuels said it plans to use the investment to advance the project. In addition to the financial commitment, the company said JX Nippon will contribute its carbon capture and sequestration expertise to the project. Construction is expected to begin in early 2025.

Chevron, Brightmark JV Opens RNG Facility in Arizona

Brightmark RNG Holdings, a joint venture between Chevron and Brightmark Fund Holdings, opened its Eloy Renewable Natural Gas (RNG) center.

Using anaerobic digesters, Eloy RNG captures methane from dairy operations at the Caballero Dairy in Arizona and turns it into pipeline-quality fuel, Brightmark said.

The facility, the JV's first in the southwestern U.S., also uses solar heating for farm lagoons. The company said the manure expected to be processed at the circularity center will be equivalent to planting over 37,000 acres of forest annually.

Carbon management

Chevron Adds to Carbon Capture Tech Portfolio with ION Investment

ION Clean Energy, a carbon capture and removal technology company, secured an investment from Chevron New Energies as part of a funding round that brought in $45 million.

Chevron, which led the funding round, said it intends to use ION's ICE-31 liquid amine carbon capture technology to service customers with high volume and low concentration CO_2 emissions. The energy company said the investment also gives it a chance to partner with ION customers on projects and help scale the technology.

Amine-based carbon capture uses an amine solvent to remove CO_2 from flue gas. Colorado-based ION says its solvent has great stability, bonds faster with CO_2 and requires less energy for operation.

SLB to Acquire Majority Stake in Aker Carbon Capture

SLB will pay about $380 million to combine its carbon capture business with that of Aker Carbon Capture, acquiring a majority stake in the Norway-based company, the energy services giant said.

The move to accelerate and scale decarbonization efforts was taken amid continued global focus on reducing greenhouse gas emissions. Carbon capture, utilization and sequestration (CCUS) are expected to play an important role.

The companies plan to combine their technology portfolios, expertise and operations platforms, looking to bring carbon capture technologies to market faster and more economically, SLB said in a news release.

As part of the agreement, SLB will pay NOK 4.12 billion (about US$380 million) for an 80% stake in Aker Carbon Capture Holding. The company said it may pay up to NOK 1.36 billion (about US$125 million) more during the next three years based on the performance of the business.

Subject to regulatory approval, the transaction is expected to close by the end of second-quarter 2024.

Energy storage

Green Li-ion Launches Recycled Battery Materials Plant

Battery recycler Green Li-ion opened its first commercial-scale plant to produce recycled lithium-ion engineered

BUSINESS WIRE

Battery-grade precursor cathode active material (pCAM) produced by the recycling unit in Atoka, Oklahoma

battery materials, the company said.

Located in Atoka, Okla., inside an existing recycling facility, the first-of-its kind plant in North America will process unsorted battery waste, also called black mass, from used lithium-ion batteries to produce battery-grade cathode precursor, lithium and anode materials.

Plans are to initially produce 2 metric tons of precursor cathode active material at battery grade, which Green Li-ion said is the equivalent of 72,000 smartphone batteries per day. The company aims to quadruple this capacity within the coming year.

Geothermal

Sinopec Completes Drilling of China's Deepest Geothermal Well

SINOPEC

Sinopec completes drilling of China's deepest geothermal exploration well at 5,200 m.

Sinopec (China Petroleum & Chemical Corp.) completed drilling Fushen-1 Well, China's deepest geothermal exploration well located in Hainan, South China.

Fushen-1, started in August 2023, has a depth of 5,200 meters.

Sinopec said the project has allowed adoption of technologies including the combination of dual-drive drilling and high-pressure injection to reach the temperature limit of hot dry rock under national energy industry standards.

Sinopec plans to carry out extensive research and field tests at Fushen-1 to establish the first platform integrating research, education and experimentation of deep geothermal in South China to help achieve the dual-carbon goal.

Hydrogen

Ballard Secures $54 Million in Tax Credits for Texas Gigafactory

Ballard Power Systems landed $54 million in investment tax credits that will go toward the buildout of a new fuel cell gigafactory in Rockwall, Texas, the company said.

The funding from the U.S. Internal Revenue Service is part of the Qualifying Advanced Energy Project Tax Credit (48C), which is included in the Inflation Reduction Act. The 48C program provides 30% investment tax credits for qualifying clean energy manufacturing projects.

The funding follows the company's award of $40 million in grants from the U.S. Department of Energy.

Called Ballard Rockwall Giga 1, the gigafactory will manufacture membrane electrode assemblies, bipolar plates, stacks and engines. Ballard said it will invest about $110 million (net of the grants and tax credits) for the facility's first phase. The company said it anticipates making a final investment decision on the project later this year.

TES Raises $152MM in Latest Funding Round

Electric natural gas producer TES said it raised €140 million ($152 million) in its third fundraising round.

The company, which combines green hydrogen with biogenic or recycled CO_2 to make e-NG, said it is creating a portfolio of large-scale e-NG projects across North America, the Middle East, Australia and Europe. Investors in the latest round included Azimut Group, Fortescue, E.ON, HSBC, O.G. Energy and Zhero.

"This newly raised capital will be used to advance the development of our upstream and downstream e-NG projects internationally," TES CEO Marco Alverà said.

Solar

United Power, NextEra Energy Seal PPA for 150 MW of Solar

Colorado electric cooperative United Power has signed a 25-year PPA with NextEra Energy Resources, according to a news release.

The agreement locks in output from NextEra's South Platte Solar project, which is expected to begin operations in December 2027. The project is designed to generate over 350,000 megawatt hours annually. It will add 150 MW of solar energy to United Power's electricity mix.

South Platte is located in Colorado's Morgan County, northeast of Denver.

Nexamp Raises $520 Million to Advance Solar, Storage Projects

Community solar developer Nexamp has raised $520 million in its latest funding round, the company said.

The capital raise was led by Manulife Investment Management and existing investors Diamond Generating Corporation and Generate Capital.

"This unprecedented investment reflects swelling confidence in the ability of independent renewable energy providers to reimagine outmoded infrastructure and reshape our grid," Nexamp CEO Zaid Ashai said in a news release.

The company, which has a portfolio of more than 1.5 GW of generating and in-construction capacity, plans to use the funds to accelerate deployment of its U.S. project pipeline as well as expand and develop partnerships in new and existing markets.

CIP Acquires Majority Stake in Solar Company Elgin

Copenhagen Infrastructure Partners' (CIP) flagship fund CI V acquired a majority stake in solar company Elgin Energy as it aims to become an independent power producer, according to a news release.

"Elgin is a perfect fit for CIP's investment strategy given its strong leadership and culture, market leading development expertise, high quality pipeline of scale and significant growth potential in markets with attractive fundamentals," Nischal Agarwal, partner in the CIP Flagship investment team.

CIP said it plans to invest £250 million (US $316 million) into Elgin, combining CIP's "industrial approach for procurement and construction with Elgin's high-quality development portfolio."

Wind

US Clears 2.6-GW New England Wind Offshore Project

AVANGRID

Located south of Martha's Vineyard offshore Massachusetts, Avangrid's wind project consists of the 791-MW New England Wind 1 and the 1.87-GW New England Wind 2.

Avangrid's New England Wind became the eighth commercial-scale offshore wind project to gain approval under the Biden administration in April.

Located south of Martha's Vineyard off of Massachusetts, the project consists of the 791-MW New England Wind 1 and the 1.87-GW New England Wind 2. Combined, the projects will produce enough energy to power nearly 1 million homes and businesses in the region, according to Avangrid, and bring $8 billion in direct investment to the region.

The project is expected to lower CO_2 emissions by nearly 4 million U.S. tons, the equivalent of removing about 700,000 cars from roads each year, the company said.

Shell Repowers Brazos Wind Farm in Texas

Shell Energy reopened the Brazos Wind Farm, which underwent a repower and site redesign.

Located in Fluvanna, Texas, the wind farm was originally equipped with 160 1-MW turbines. The repower upgrade boosted its capacity to 182 MW with 38 next-generation Nordex 5-MW turbines, Shell said in a news release. The project also included enhancing remote monitoring, data generation, and overall reliability and safety, the company said.

Shell operates the site and InfraRed Capital Investments has 60% ownership.

Renewables

RWE, WhiteRock Partner to 'Supercharge' US Renewables Growth

RWE

Globally, RWE has ambitions to grow its green technology capacity to more than 65 GW by 2030.

Renewable energy company RWE Clean Energy teamed up with specialist developer WhiteRock Renewables to speed the expansion of RWE's onshore wind, solar and energy storage pipeline in the U.S.

As part of the partnership, WhiteRock will originate and develop between 4 GW and 5 GW of onshore wind, solar and battery energy storage system projects, RWE said. It will have the option to acquire the projects once they reach maturity and are ready for a final investment decision.

"RWE is investing billions to expand our U.S. portfolio, which will make up 30% of the company's global green installed capacity by 2030," said Hanson Wood, senior vice president of utility-scale development for RWE.

RWE's current net installed capacity in the U.S. is about 9 GW but the company said it aims to increase that to more than 19 GW net by 2030. OGI

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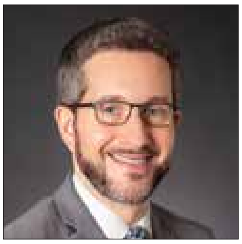
The Oil and Gas Chain Reaction

How record-breaking E&P consolidation is rippling into oilfield services, with much more M&A on the way.



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Amid a rapid, ongoing wave of E&P consolidation, Kodiak Gas Services closed an under-the-radar deal in April to acquire CSI Compressco and create the industry's largest contract compression fleet.

With fewer potential customers churning out oil and gas amid fragmented oilfield services and midstream sectors, contractors realize they need to catch up to do more business with the biggest players producing record-high U.S. volumes.

Led by mega deals from Exxon Mobil and Chevron, the upstream sector completed nearly $250 billion in M&A transactions from the beginning of 2023 through March. That leaves the OFS space now playing chase with E&Ps that don't seem interested in slowing the dealmaking race.

Mickey McKee

"I think scale does matter. We've got customers that are undergoing a consolidation phase," said Mickey McKee, Kodiak president and CEO. "I wouldn't say we have to keep up with them, but I think the smart thing to do is to keep up with 'em. You've got an industry right now that, for lack of a better phrase, has a tremendous moat around it because there's not a lot of new private equity money coming in."

Supply chains, labor and interest rates are all challenging, McKee said, so strategic acquisitions become more important. That's partly why Kodiak underwent a rare energy IPO last year for enhanced growth potential.

"You look at the majors that are operating the Permian Basin, and a startup company can't just go in with no safety history and work for ConocoPhillips or an Exxon Mobil," he said. "With interest rates where they're at right now, it's really tough to grow a small private business. When we were that size, we were borrowing money for free, basically.

"And so these mom-and-pop-type shops are probably going to get paid lower multiples than they have been in the past," McKee added. "That's going to be really difficult."

Earlier this year, James West, senior managing director for Evercore ISI, asked, "What happens when your customer base consolidates faster than you do?"

The answer: "You are deconsolidating and losing market power."

"We need to see a response to some of the major activity that's happened on the E&P side because we have fewer customers," West said of the OFS sector. "They [E&Ps] are going to have more market power, and that's not good."

On the other hand, services consolidation has finally begun to pick up steam, West said, especially courtesy of industry-leading juggernaut SLB. In early April, SLB agreed to pay nearly $8 billion to acquire ChampionX and substantially boost its offerings in production chemicals and artificial lift. That came just days after SLB said it would buy Aker Carbon Capture for $380 million.

Other recent or pending deals include the merger of Innovex Downhole Solutions with Dril-Quip, ProPetro acquiring Par Five Energy Services, Drilling Tools International buying both Deep Casing Tools and Superior Drilling Products, Forum Energy Technologies scooping up Veriperm Energy Services, Precision Drilling gaining CWC Energy Services, Atlas Energy Solutions acquiring Hi-Crush in a sand consolidation, and Select Water Solutions picking up Tri-State Water Logistics and Iron Mountain Energy, among others.

"I think, usually, deals beget more deals. So, it wouldn't surprise me if it unleashes some animal spirits here for people that want to get

"We need to see a response to some of the major activity that's happened on the E&P side because we have fewer customers. They [E&Ps] are going to have more market power, and that's not good."

JAMES WEST, senior managing director, Evercore ISI

ALL PHOTOS COURTESY THE COMPANIES

1 and 2: Kodiak Gas Services is growing in the Permian Basin with more gas compression facilities, including the new acquisition of CSI Compressco. 3 and 4: Liberty Energy has continued to expand as a top industry player in pressure pumping, including the acquisition of SLB's onshore hydraulic fracturing business in North America.

things done," West said of OFS consolidation. "I think that the industry is coming to terms with where we are in this cycle and what the duration looks like in this cycle, and it feels it's time to step up and make some strategic moves. And I would expect those to continue."

The current trend is for producers to desire bigger but more streamlined, and that means fewer OFS companies. SLB, Halliburton and Baker Hughes may not consume each other, especially after the federal government intervened when Halliburton attempted a Baker Hughes takeover a decade ago. But everything else is on the table.

"More customers, as they get larger and more sophisticated, want to interface with fewer vendors when they want a well delivered," West told *Oil and Gas Investor*. "They don't want to talk to 20 different people. They want one guy to talk to and have that well delivered on time or faster, and on budget or, preferably, under budget."

Start spreading the news

There is good news for the services sector, but it's going to create winners and losers, executives said. The winners could see more predictable profits and steady growth while expanding market share. The losers may fail or be pressured to sell with little to no premium.

It's an unusual conundrum because the number of producers is shrinking and activity is on the decline, but U.S. production volumes remain at or near all-time highs thanks to technology and efficiency gains. And, despite the ongoing energy transition, analyst projections recognize the need for more North American oil and gas for longer, including more crude exports and LNG to serve the world.

As such, Barclays reinitiated its E&P stock coverage in April, including an "Unapologetic oil and gas" message to hesitant investors.

Consolidation and pricing upside are big reasons for Barclays' bullish sentiments, but that means less upside for a larger pool of OFS players. After all, consolidation leads to "plateauing of U.S. shale production," which, in turn, helps with pricing.

"Sector consolidation has put more barrels in the hands of prudent public operators. We expect production growth from this group to slow down," wrote Barclays analyst Betty Jiang. "After a flurry of M&A, we have also seen private activity slow down materially."

“There will be some oilfield services providers who, ultimately, may not find a role going forward with these larger E&Ps. I think the number of those probably naturally shrinks and you see the world consolidate more around the bigger, maybe more vertically integrated oilfield services providers.”

RON GUSEK, president, Liberty Energy

The mantra is “Shale 4.0” with more consolidation, inventory duration and steady manufacturing mode to generate the most free cash flow and returns at modest capex.

”Capital discipline is here to stay,” Jiang added. “Value over volume has become the new norm, with management teams prioritizing return on capital and return of capital over production growth.”

A lot of this messaging sounds great to the biggest drillers, pressure pumpers and OFS providers that desire predictability and financially healthy customers. But it can also mean less business to go around.

Liberty Energy President Ron Gusek said in an interview that E&P consolidation creates wiser producers that, in turn, have higher expectations for their services providers.

“That probably changes the market a little bit. I think you see some natural consolidation as a result of that,” Gusek said. “There will be some oilfield services providers who, ultimately, may not find a role going forward with these larger E&Ps. I think the number of those probably naturally shrinks and you see the world consolidate more around the bigger, maybe more vertically integrated oilfield services providers.

“I think that has people thinking about what their place in that is going to be,” he added. “That’s probably on its way. Maybe we’re in the third or fourth inning. I don’t know that we’re halfway through that today. There’s lots of opportunity out there. I think there’s lots of stuff for sale.”

Naturally, he counts Liberty among those best-positioned top players. Liberty was ahead of the curve at the end of 2020 when it acquired SLB’s North American hydraulic fracturing business, then followed with more vertical integration by buying the PropX proppants business in 2021.

So, Gusek values working closely with larger, more predictable E&Ps.

“That makes planning your business much, much easier, rather than having to navigate the ups and downs of maybe a slightly more intermittent scenario where you’ve got to line up two or three or four customers to share a rig or a frac fleet or whatever it is that you’re selling,” he said. “Of course, one job doesn’t end exactly when the next job’s going to start, and you compare that to these larger operators where you get this steady cadence of one pad after another. And, certainly, in our case, as a frac provider, that’s incredibly beneficial.”

Efficiency gains win out

That “cadence” is benefitting from greater efficiencies gained with drilling longer laterals and completing wells more quickly and simultaneously.

For context, the U.S. oil and gas rig count peaked at 2,026 back in November 2011 when oil prices were comfortably hovering near $100/bbl, according to Baker Hughes. Production trails activity levels, of course, but U.S. crude production had freshly hit 6 MMbbl/d in November 2011, less than half of current volumes generated with only 30% of the rigs deployed almost 13 years ago.

With drilling rig programs and completions strategies so different from that era, comparing rig count numbers is, if not apples to oranges, at least apples to applesauce.

The modern, post-pandemic peak occurred at 784 rigs in November 2022 and has steadily declined since, plunging more than 20% to 617 rigs as of mid-April. But, U.S. crude volumes still were at the near-record of 13.1 MMbbl/d.

As much as drilling techniques and simul-fracs are helping operators produce more volumes with less activity, so, too, is consolidation playing a role as the more blocky, contiguous acreage allows for longer horizontal laterals to extend three or four miles, said Andy Hendricks, president and CEO of Patterson-UTI Energy, in an interview.

Andy Hendricks

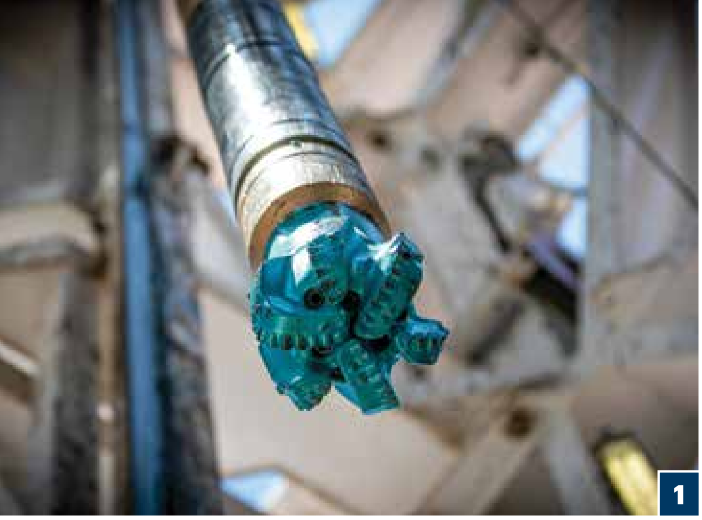
“What’s interesting about what they’re doing in the U.S. is they’re looking for acquisitions where they can pull lease and land holdings together where they can be more efficient, where they can connect better to their own infrastructure, where they can delineate their lease lines out in the Permian so they can drill longer laterals,” Hendricks said.

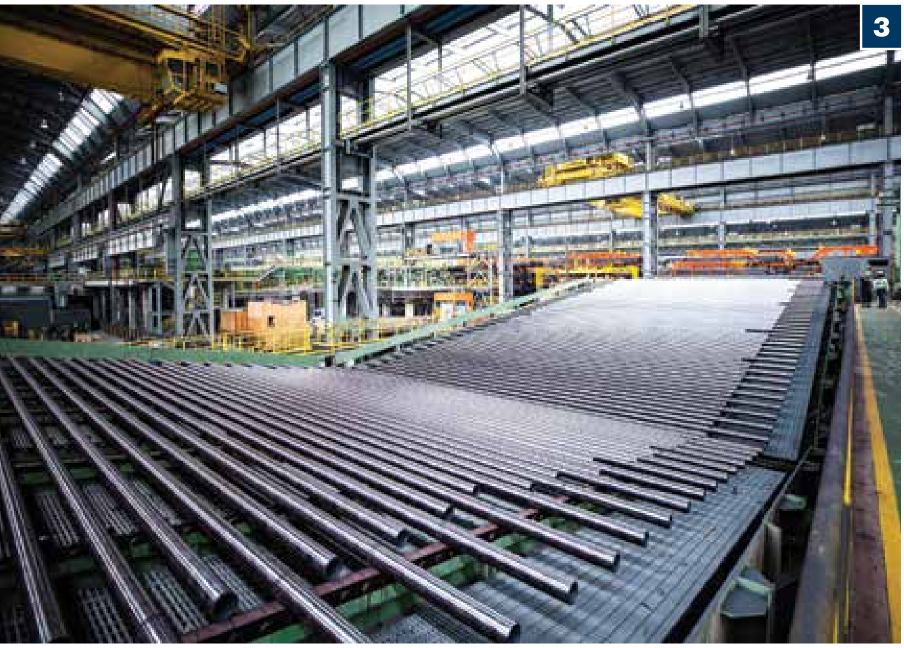
“And we hear different things from different E&Ps who are in the middle of their consolidation, not necessarily closed on their acquisitions yet,” he said. “Some of them are saying, ‘Yeah, as soon as we get our arms around this company, we can redraw some of these lease lines. We can drill longer laterals. We’re going to accelerate our activity.’ You’ve got others that are saying, ‘Well, we’re going to pull it all together. Then we’re going to maybe take a pause.’ So, different, not a pause in activity, but a pause in growing activity. They’ll still stay busy. It really depends on what the E&P’s strategy is for their acquisition.”

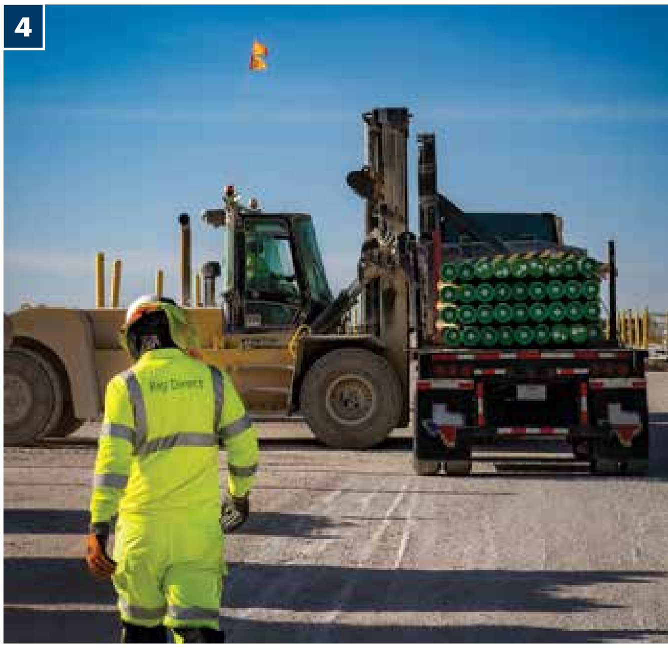
These trends mesh with Patterson-UTI’s decision last year to acquire NexTier Oilfield Solutions in a merger of near-equals, and then to further scoop up Ulterra Drilling Solutions.

Hendricks elaborated that the lower activity trends are tied to efficiency and capital discipline. Much of the E&P consolidation wave is fresh and many of the deals, including the biggest ones, have not even closed yet. The consolidation impacts will begin to come late this year and into 2025.

Luca Zanotti, the U.S. president for Tenaris, largely agreed. He said he looks forward to operators pivoting to predictable manufacturing modes, because that fits nicely with Tenaris’ role as an oil country tubular goods (OCTG) manufacturer.







ALL PHOTOS COURTESY THE COMPANIES

1 and 2: Patterson-UTI Energy expanded greatly in 2023 by acquiring Ulterra Drilling Technologies and by merging with NexTier Oilfield Solutions. 3 and 4: Tenaris took a big step toward expanding the domestic OCTG market when it opened its massive manufacturing mill outside of Houston.

Luca Zanotti

The concern is waiting to see whether the smaller E&Ps and the sellers ever return to higher activity levels, including whether the selling management teams return with new startups at all, Zanotti said.

But Hendricks is confident those teams will come back, especially as the larger consolidators pivot to sell non-core acreage in the months ahead.

"You've got teams of E&P execs today that are working those deals to try to pick up the pieces that fall out of the large acquisitions," Hendricks said. "That means more drilling rigs are going to go to work on their properties. There's a lot of moving pieces. It's not just two big companies coming together. Sometimes, you also have to consider what falls out of those large consolidations to experienced E&P execs who will drill and bring value to those properties."

Despite the lower rig activity, Zanotti said, Tenaris is balanced out by more drill pipe, casing and tubing being used in each well.

"The number of days needed to ready wells is decreasing over time, and laterals are much longer," he said. "Our estimation is 650 rigs today are equivalent to more or less 950 rigs in 2019. This is the kind of efficiency that the industry has in terms of pipe consumption. This is also enabled by the fact that we develop new technologies, new connections that are easier and quicker to run. And they can allow longer horizontals, longer laterals."

Zanotti said he would like to see more consolidating in the OCTG space, apart from the pending merger of Nippon Steel and U.S. Steel, but that it is challenging because 50% of the OCTG products consumed in the U.S. are imports, and the foreign players play by uneven tariffs. While Luxembourg-based Tenaris is not a U.S. company, it manufactures much of its OCTG products in the Houston area.

Spreading overseas and subsea

Apart from issues with foreign players, the OCTG space is one of the most consolidated within the realm of OFS. So is the world of high-spec drilling rigs and, after more recent deals, pressure pumping, according to Evercore ISI.

But other areas remain much more fragmented, including rig equipment, wireline services, inspection and coating, artificial lift, specialty chemicals, sand and more.

There just isn't always a clear path in those areas because of the potential lack of buyers and the growing absence of private equity in the OFS space, Hendricks said.

He is, however, quite bullish on the consolidation occurring in completions, especially the role he's played. NextTier was formed through the combination of C&J Energy Services and the Keane Group in 2019. Today, NexTier is newly part of Hendricks' company.

"Now you've got a completion pressure pumping market that's showing almost as much discipline as the drilling rig market, and that's really positive for the shareholders of those companies," he said.

Despite Hendricks' optimism on continued U.S. growth, part of the consolidation trend also is about embracing greater potential for international upside amid higher crude pricing. That was a big factor in Patterson-UTI's Ulterra acquisition.

About 30% of Ulterra's revenue is overseas, especially in the Middle East. Ulterra is currently expanding a drill bits manufacturing facility in Saudi Arabia to do more business with Aramco and other regional players.

That global vision also factored into SLB's acquisition of ChampionX, especially the ability to use SLB's breadth to deliver ChampionX's products and services around the world, said SLB CEO Olivier Le Peuch in a conference call.

"I believe that the market and the strategic priority of our customer is increasingly turning toward production and recovery," and SLB's goal here is to "address this to scale and provide integration capability there the same way we do across the rest of the life cycle."

Wayne Prejean

Arguably the most fragmented space is in oilfield tools and equipment. And that's where President and CEO Wayne Prejean wants his Drilling Tools International to emerge as a consolidator in the U.S. and internationally.

DTI went public last year when it merged with a special-purpose acquisition company, called a SPAC, and has been on a tear since, acquiring Deep Casing Tools and Superior Drilling Products this year. Prejean values scale and product and geographic diversity. But the deals still have to make sense.

"The right strategy is not to do a smash and bring companies together just for the sake of consolidation," Prejean said. "But to instead focus on a particular space or segment or specialty, and make sure you have all the portfolio of tools or products or services or technologies that fit within a certain culture. You can more efficiently execute in that family of tools as opposed to just being a purveyor of all sorts of things."

Companies not only need to consolidate, he said, but they also must scale up in terms of machine learning and analytics to offer the most efficient services. Small, local OFS firms often cannot offer that.

"You have to run your business now and be efficient off of data-centric, capital allocation decisions, not just with good old-fashioned Johnny Hustle experience," he said, arguing that DTI will continue to acquire.

Likewise, Forum Energy Technologies in January closed on the acquisition of Canada-based Variperm Energy Services for nearly $200 million to offer more downhole technology solutions and a greater geographic footprint.

"Consolidating producers are going to find efficiencies in their capex spend and, in the U.S., they're going to drop rigs and frac crews," said Forum President and CEO Neal Lux. "So, one plus one is less than two on the activity side. For a small company, that's more challenging.

"While we may get fewer frac crews and rigs, the ones that are working are burning through their equipment at a much faster rate than before," Lux added. "That's where FET comes in. Our products and solutions are meant to increase the efficiency of our customers' operation. So, we're there helping our customers make their equipment last longer."

The offshore sector, on the other hand, has seen slow, but steady OFS consolidation in recent years amid weaker activity and underinvestment. The big three drillers–Transocean, Noble Corp. and Valaris–have all helped, buying up Songa Offshore, Ocean Rig, Pacific Drilling and Maersk Drilling from 2018 through 2022. Valaris emerged in 2019 through the combination of Ensco and Rowan Cos.

But there are plenty of subsea sectors that remain fragmented, including companies that operate in the shale and deepwater realms. One brand-new, but pending

▸ RECENT OILFIELD SERVICES DEALMAKING

April – SLB acquiring ChampionX for about $8 billion

April – Kodiak Gas Services acquires CSI Compressco for $854 million

April – Turnco buys Drill Spec Services (terms undisclosed)

March – Dril-Quip and Innovex Downhole Solutions merging for about $800 million to create new Innovex International

March – SLB buying Aker Carbon Capture for $380 million

March – Drilling Tools International acquires Superior Drilling Products for $32.2 million and Deep Casing Tools (terms undisclosed)

March – ChampionX acquiring RMSpumptools for $110 million and Artificial Lift Performs (terms undisclosed)

March – Clean Harbors buys HEPACO for $400 million

March – Danos Group buys Performance Energy Services (terms undisclosed)

March – JMR Services merging with A-Plus P&A (terms undisclosed)

February – Atlas Energy Solutions buying Hi-Crush for $450 million

February – DXP Enterprises purchases Kappe Associates (terms undisclosed)

January – Forum Energy Technologies acquires Variperm Energy Services for $190 million

January – Select Water Solutions buys Tri-State Water Logistics and Iron Mountain Energy for $90 million

January – Voyager Interests buys Aegion Coating Services (terms undisclosed)

December – ProPetro acquires Par Five Energy Services (terms undisclosed)

December – Tenaris acquires Mattr's pipe-coating business unit for $182.6 million

November – Precision Drilling acquires CWC Energy Services for nearly $100 million

October – Expro buys PRT Offshore for $106 million

October – SK Capital buys Milestone Environmental Services (terms undisclosed)

October – EnergyMark acquires Crown Energy Services (terms undisclosed)

October – Eastern Energy Services buys Conquest Completion Services (terms undisclosed)

September – Patterson-UTI Energy merges with NexTier Oilfield Solutions for $5.4 billion

August – Patterson-UTI Energy acquires Ulterra Drilling Technologies for $780 million

SOURCE: OIL AND GAS INVESTOR

ALL PHOTOS COURTESY THE COMPANIES

1 and 2: Dril-Quip and Innovex Downhole Solutions are merging to create the renamed Innovex International. 3: Forum Energy Technologies in January closed on the acquisition of Variperm Energy Services. 4: Drilling Tools International recently bought Deep Casing Tools and is now acquiring Superior Drilling Products.

combination in both the onshore and offshore space is the merger of Innovex Downhole Solutions and Dril-Quip to create the renamed Innovex International.

Innovex formed in 2016 through the triple merger of Antelope Oil Tools, Team Oil Tools and Isotech. Backed by AmberJack Capital Partners, Innovex continued to be acquisitive, especially during and after the pandemic, scooping up Rubicon Oilfield International, Applied Oil Tools and Pride Energy Services in recent years.

Adam Anderson

But the biggest deal was saved for March with the roughly $800 million merger of near equals with Dril-Quip. Formally, Dril-Quip is acquiring Innovex. But, in reality, Innovex CEO Adam Anderson will take over as CEO of the renamed Innovex to be public traded under the "INVX" stock ticker.

"The OFS industry has historically been quite fragmented," Anderson said. "However, in the case of Innovex and Dril-Quip, we tend to operate in product and service offerings that have a 'big impact, small ticket' dynamic. Our products represent a relatively small part of the cost of the well but have an outsized impact on the performance of the well. Consequently, our customers are much more focused on product performance than price. So, our businesses have not been as susceptible to the fragmentation that is present in other OFS product and service offerings."

As the shale boom took off more than a decade ago, so did OFS fragmentation for services, steel, labor and more, said West of Evercore ISI. As shale matures, so many players simply aren't needed any longer.

The message is to scale up or differentiate yourself with disrupting or upgraded technology. If that's not possible, bluntly stated, the future isn't bright.

"If you're not in the financial position to be able to do that—whether it be frac or drilling rigs or something like that—to meet that next-generation demand, ultimately that's a tough spot to be in given a potential sunset for the technology that you bring to the table," said Gusek of Liberty. "Consolidating a smaller player whose technology or frac pumps are a past generation just doesn't make a ton of sense." OGI

Assets & Trading Prowess: A Marriage Made in the Permian

Exxon and Vitol execs love how upstream investment adds value to the crude trading business.

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Vitol forecasts show global crude demand peaking early next decade, but the global commodities trader still sees value in owning upstream production.

Russell Hardy, CEO of Vitol, the world's largest oil trader, said the firm is projecting crude oil demand to flatten and peak in the early 2030s.

"We are generally pushing [peak demand] out a little bit further at the moment because of some of the complexities of energy transition," Hardy said during the CERAWeek by S&P Global conference in March.

"Getting projects done, getting grids decarbonized is taking longer than probably most people anticipated," he said.

Outside of the trading realm, Vitol has journeyed into buying its own energy assets over the past decade, including upstream, downstream, refining and power generation assets.

And the U.S. has attracted a significant amount of Vitol's upstream investment. The firm backed two upstream E&P companies in the Permian Basin: Vencer Energy in the Midland Basin and VTX Energy Partners in the southern Delaware Basin.

Last year, Vencer agreed to a $2.11 billion cash-and-stock buyout by Colorado-based public Civitas Resources.

Vencer, funded by Vitol in 2020, owned interests in around 44,000 net acres across Midland, Martin, Upton, Glasscock and Reagan counties, Texas–some of the cheapest areas to drill in the Midland Basin.

VTX Energy, the second Permian producer backed by Vitol, has consolidated a sizable footprint in the southern Delaware Basin since securing funding in 2022.

After selling Vencer to Civitas Resources, Vitol is considering adding assets to its portfolio through a new upstream platform.

Vitol has found that connecting its upstream and other energy-related investments to its trading business "has added value in different ways for different sectors," Hardy said.

The firm also aims to take advantage of the disparity between values in public markets and private markets.

"Ultimately, investment in our space is limited in comparison to what it was a few years ago," Hardy said. "That limited appetite

XTO operations at a Wolfcamp drill site in the Permian Basin.

EXXON MOBIL

"Ultimately, investment in our space is limited in comparison to what it was a few years ago."

RUSSELL HARDY, CEO, Vitol

for investment in the hydrocarbon space is effectively weighing on multiples."

Exxon Mobil, one of the largest oil and gas producers around the world, is working to grow its own trading capabilities.

Liam Mallon, president of its upstream business, said Exxon's trading capabilities were wrapped up in upstream up until about a year ago. But the supermajor realized it could leverage unique insights from its global portfolio of energy assets to expand its own commodity trading capabilities, Mallon said at CERAWeek.

"In fact, we were told that many times: that [Exxon is] in the most unique position to leverage insights better than anybody else," Mallon said on the panel.

"We're hiring a significant amount of new people," he said.

The expanding reach of a juggernaut like Exxon's into the trading realm doesn't scare Vitol, however.

"There's plenty of space for everybody," Hardy said. "Obviously, it's getting more competitive."

Married in Midland

Exxon is getting deeper into trading, but it's also getting deeper into Permian upstream production.

Exxon's $64.5 billion acquisition of Permian pure-play Pioneer Natural Resources, once closed, will cement the supermajor as the basin's top producer.

Closing the Pioneer acquisition is going "basically to plan," Mallon said, including Federal Trade Commission requests for additional information about the proposed combination.

When it comes to transition planning and integration, Exxon wants the Pioneer acquisition to feel more like a marriage and less like a $60 billion player getting eaten by a $450 billion giant.

"In reality, we're the same size in Midland, which is what we're really acquiring," Mallon said. "We viewed this as a merger of equals."

After the Pioneer acquisition, Exxon's oil and gas production is forecast to rise to nearly 7% of total U.S. output–from about 750,000 bbl/d to 1.3 MMbbl/d–according to an analysis by the U.S. Energy Information Administration.

Exxon plans to boost output to 4.2 MMboe/d by 2027, up from about 3.8 MMboe/d in 2024.

The growth will be primarily driven from gains from Exxon's Permian Basin acreage in West Texas and New Mexico, and from the company's foothold offshore Guyana.

Mallon has been involved with Exxon's exploration offshore Guyana since Exxon first started exploration activities in the country in 2008.

"In my 40-year career, I have never worked on anything so exciting and prolific," he said. OGI

POLICY & REGULATIONS

Belcher: Brace for the Onslaught

A raftload of rulemakings, executive orders and policy decisions affecting energy are headed this way.

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As we move further into an election year, the likelihood of Congress passing legislation that impacts the U.S. oil and gas industry becomes smaller and smaller.

While prospects for a badly needed federal permitting bill are still alive, it will most likely need to wait until the next Congress. In the absence of legislation, we are witnessing a slew of executive actions through rulemakings, executive orders and policy decisions that will impact energy.

While the impacts of these actions will be mixed, most of them will not be good for domestic oil and gas production. Cumulatively, they will have a significant impact on the U.S. oil and gas industry, which is getting hit with 1,000 paper cuts.

Earlier this year, the Biden administration set the stage for executive action when it issued a "pause" for new LNG export licenses to non-free-trade-agreement counties. The pause has become a highly politicized issue, with House Speaker Mike Johnson (R-La.) tying passage of the Ukraine aid passage to the lifting of the pause.

Such action, if successfully signed into law, would merely be symbolic since it would not force the administration to issue licenses. The pause itself, however, has created uncertainty for U.S. LNG producers and companies and governments that need future sources of LNG.

The SEC rule

On March 6, the administration released an 886-page Securities and Exchange Commission (SEC) rule that requires all public companies to include climate-related reporting in their SEC filings. The rule, which the SEC has been developing for over two years, requires public companies to report their Scope 1 (emissions from their operations) and Scope 2 (emissions from purchased electricity, steam heat or cooling) and other climate-related materials, including climate-related risks and material impacts, climate risk management processes and climate-related targets and goals.

The rule issued was pared back from an earlier proposed rule by the removal of Scope 3 (emissions from actions upstream and downstream of a company or facility's value chain), limiting Scope 1 and 2 greenhouse-gas (GHG) emissions disclosure requirements to large accelerated filers and accelerated filers (other than smaller reporting companies and emerging growth companies), and only requiring such disclosure if emissions are material, and removal of financial impact metrics from disclosure requirements related to financial statement effects.

It also extended safe harbor protections to disclosures surrounding transition plans, scenario analysis, internal carbon pricing, and targets and goals and extended compliance timelines. Several states, companies and trade associations have filed lawsuits in several jurisdictions to overturn the rule, arguing its provisions are too stringent, place too much burden on industry, and are unevenly applied and impactful to certain industries. Those lawsuits have been consolidated into one review before the 8th Circuit Court of Appeals, which has issued a stay on SEC enforcement, and the SEC itself has issued its own stay pending a ruling.

The EPA rule

On March 22, the Environmental Protection Agency (EPA) issued a final rule, Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles, that is heavily focused on lowering GHG emissions with a goal of reducing gasoline- and diesel-fueled vehicles and transitioning the U.S. fleet to electric vehicles (EVs).

The rule, which was modified to be less stringent after U.S. automakers protested initial requirements, now requires EVs to make up 56% of new vehicle sales by 2032, with an additional 13% being plug-in hybrids, partially electric vehicles, or gasoline-powered cars with higher average miles per gallon.

The rule is viewed by the oil and gas industry as another attack on fossil fuels, but it also presents even greater challenges to the U.S. electric grid, which is already facing supply-side/reliability challenges and a surge in demand from new industrial activity, artificial intelligence and data centers.

EPA is also in the process of implementing its methane rule, released last December, that creates a new methane monitoring and reporting program that goes into effect this year. The rule phases out routine flaring at new oil and gas wells, with certain exceptions in the early years. One of the more controversial features of the methane rule is the establishment of a super-emitter program that establishes a program where third-party groups would monitor methane emissions around the country for large methane emissions leaks.

Many comments were received by EPA expressing concerns about how this program would work and how EPA would certify and

With the chance of congressional action diminished during an election year, the oil and gas industry will be subject to a slew of executive actions.

THE WHITE HOUSE

ensure the legitimacy of the third parties and the accuracy of their reporting. Due to the subjectivity of this program, many lawsuits are being filed challenging EPA's authority to initiate it. Additionally, many states are challenging the methane rule in court. Texas has filed a legal challenge in the D.C. Circuit Court of Appeals.

The BLM rule

Separately, the Bureau of Land Management (BLM) has issued a final rule that sets limits on methane emissions associated with oil and gas development on federal lands. The rule makes companies pay royalties for "wasted gas" and it caps the amount of gas that can be vented or flared when no pipeline options are available. BLM believes that it can collect $50 million per year in added natural gas revenue from the rule. There will be lawsuits filed in the coming weeks to challenge the BLM rule.

Beginning in 2025, a methane fee, or waste emissions charge (WEC), will be collected by EPA for methane emissions over a certain threshold. The fee was established through the Methane Emissions Reduction Program that was included in the Inflation Reduction Act. It will be assessed each year on the prior year's leaked methane in excess of 25,000 metric tons of CO_2 from oil and gas systems. The fee ratchets up over time starting at $900 per metric ton in 2024 and reaching $1,500 per metric ton in 2026 and beyond.

Moving further downstream into the power generation markets, EPA has opened up a "non-regulatory" docket that will allow public input into planned GHG emissions rules for existing natural gas-fired power plants. The announcement precedes a series of future rulemakings where EPA will issue more stringent restrictions of GHG emissions, air toxics and emissions of nitrogen oxides from natural gas turbines in the power sector.

Finally, the administration is pursuing a broad and encompassing initiative known as natural capital accounting, whereby the government would incorporate the purported impacts that activities have on nature into every federal decision requiring cost benefit analysis. While this concept is in its early stages and has not been widely reported, it is being pursued throughout the federal government and could have an enormous impact to future federal decision making with huge potential implications for the oil and gas industry. It is definitely one that we should all keep our eyes on, along with all of the other pieces of this regulatory onslaught. OGI

Kissler: Mideast Tension Elevates Crude Prices—But for How Long?

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On April 1, Israel conducted an air strike on Iranian top military brass in Syria. Iran responded with a barrage of drones, cruise missiles and ballistic missiles—almost all of which were intercepted. These events could cause a spike in Brent and WTI prices—but the duration of such a spike may be short-lived.

If we do see a dramatic conflict escalation, a price spike to as high as $100/bbl is very possible. For comparison's sake, WTI was near $86/bbl and Brent was near $90/bbl in mid-April.

Is an oil price spike to three figures a barrel a good thing for producers? Not so, in my opinion, at least in the long term. Price spikes, such as WTI moving into the $100/bbl area, are normally short-lived from a demand perspective because global economies tend to contract very quickly in response to these higher prices. For example, travel demand tends to drop suddenly, and near-term inflationary cycles kick back in with higher interest rates eventually leading to a hard-landing recession.

OPEC+ production

Another factor to consider is OPEC+. In March, OPEC+ said it would extend its output cuts of 2.2 MMbbl/d into the second quarter. Although that decision was widely expected, the announcement also included Russia's decision to cut its oil production and exports by an extra 471,000 bbl/d in the second quarter, which was a surprise to many.

Given these production cuts, OPEC+'s spare capacity is nearly 20% above its normal average. This means the cartel has 20% more production it could add to the market if it needs to—that is, if members decide to eliminate these voluntary production cuts. Higher oil prices could very easily encourage them to make that decision, which would bring that spare capacity, totaling approximately 6 MMbbl, onto the market.

Follow natural gas?

There's also the record production of U.S. and Canadian crude to consider versus the level of global demand. In 2023, the U.S. and Canada produced more oil and gas than any other region, including the Middle East. Then, in February of this year, U.S. crude oil exports reached an 11-month high. Some analysts believe the global spare capacity is somewhere near 6 MMbbl/d. If oil prices spike to triple digits, we probably will learn the accuracy of these estimates, as any spare capacity will show up very quickly.

The old saying that the cure for high prices is much higher prices in the near term may ring true once again. Just look at natural gas. Two years ago, it traded near $10/MMBtu. In mid-April, that figure was $1.68/MMBtu. Is crude on the same path? Only time will tell, but producers should be aggressive in locking in desirable crude oil prices on this abnormal market strength. OGI

Missiles on display at a military museum in Tehran, Iran. An oil price spike resulting from Israel-Iran strikes could be damaging for the global economy.

SHUTTERSTOCK

GLOBAL ENERGY

Threading the Geopolitical Needle

Trinidad and Tobago Energy Minister Stuart Young on navigating the murky waters as an 'honest broker' between Venezuela and the U.S.

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Q&A

Stuart Young, Trinidad and Tobago's Minister of Energy and Energy Industries, sat down with Hart Energy International Managing Editor Pietro D. Pitts at CERAWeek by S&P Global to discuss the restructuring of Atlantic LNG, the geopolitical noise around inking deals with U.S. sanctioned Venezuela, and plans to source gas from Venezuela and Suriname as Trinidad's gas production continues to decline.

PIETRO D. PITTS: You've restructured Atlantic LNG, but looking at recent ministry data, Train 1 is still offline. What was accomplished with the restructuring if Train 1 is still offline? Was it all worth it?

Stuart Young: Atlantic LNG, you have to recall, is decades old now. Train 1 was the first train to come on around 1995, and had reached the end of the 30-year liquefaction license. We were at the cusp of restructuring conversations with BP, Shell and at the time CIC, Chinese Sovereign Wealth Fund, who also had a 10% [interest] in Train 1.

The truth is, as we've said very openly since 2011, domestic natural gas production in Trinidad has declined. So, there simply were not enough molecules at the time for Train 1. And then, of course, the way these companies operate, the commercial arrangements for [Trains] 2, 3 and 4 were continuing for them. Whilst we believe that initially there was some excess gas in particular that NGC [National Gas Co. of Trinidad and Tobago] had available that we could have put through Train 1, that didn't come into reality. But what we did, as the Prime Minister [Keith Rowley] said within recent times, is we used Train 1, as a negotiating part of the package to restructure the whole thing.

I don't see Train 1 coming back online, but that's something that we negotiated away. We've gotten across 2 and 3 where we never had a shareholding before. We had an 11% [interest] in 4. We've now got a 10% shareholding across the whole of Atlantic, and the whole of Atlantic now is [Trains] 2, 3 and 4. That kicks in from October of this year. Our shareholding has gone up because if you had done a pro rata, we would've been down about 5%. We've gotten 10% and we haven't had to pay out, pay any money for that. So that's the first part.

The second part is what we've done with the formula we use for restructuring. We've opened up the market outside of others who are already in the market in Trinidad because there's third-party access of gas to Atlantic. Of course, when people are looking now at future gas E&P, one of the offtakes they want is LNG. Now Atlantic LNG, with what we've restructured and negotiated, allows for third-party access. That now allows other players, not only in Trinidad but also regionally to say, "hey, if I explore and produce gas, I have a market to take it to: Atlantic LNG." That's big. That opened up the opportunity for future investment in upstream.

What it also does is it allows a conversation with the cross-border gas, as we've been doing with the EU. [We've said] "hey, Trinidad now has an opportunity to become part of your diversified gas supply." Because, of course, when you're in their positions, you don't ever want to find yourself dependent on one source of gas again. Whilst the U.S. has been able to step in there, they are looking for a diversified gas portfolio. We've had very good conversations with the EU and they now understand the potential that Trinidad has once it has the access of cross-border gas into LNG. But of course, that wouldn't have existed before the restructuring.

Now what we've done is we've restructured it in such a way that the shareholders, BP and Shell, now have an extension of life in a facility that they're now partnering only with the government. It's just BP, Shell and the government and that gives them the incentive to continue investing in Trinidad, both in country, which they're doing, but also now across as well and looking in the rest of the region.

PDP: Could you give us an update on bid rounds in Trinidad and Tobago?

SY: The last bid round that we did that was successfully concluded was the onshore/near-shore bid round. We had an oversubscription for that. We've awarded the blocks, they're just a couple that we're still negotiating some terms with the preferred bidders. That went well. We're right now out with the shallow water.

The Cabinet agreed to extend the date to give us a little bit more space. But another thing, we revised the PSC where we've made our PSC, our production sharing contract terms, a lot more attractive in line of where

"We remain engaged with the government of Venezuela, we engage with the EU because they have understood now that there's an alternate supply of gas. In life, there's very little certainty on anything. But what we've managed to do is be the honest broker in between all of these huge political geopolitical entities."

STUART YOUNG, Trinidad and Tobago Energy Minister

we are as a province. I'm expecting a good subscription and some good tenders to come in.

PDP: Guyana has a lot of oil and some gas. The initial response before about getting that gas from Guyana to Trinidad was the pipeline is too long, it's not feasible. Suriname could also be a potential source of oil and gas. Which country are you eyeing now as a potential gas source for Trinidad?

SY: Both the prime minister and I spoke at the Guyanese Energy Conference just a few weeks ago and basically summed it up. Trinidad is open for business. We offer the opportunity for the quickest monetization of gas. Right now, Guyana is still in a negotiation with Exxon Mobil phase. One wonders how much gas availability there is. A pipeline would be feasible and it wouldn't be from Guyana. What we're discussing and what we've been discussing with Suriname is a pipeline up from Suriname, because it appears as though the blocks that are bordering Guyana and Suriname are really gas blocks more than liquid blocks. Right now, it's looking at the feasibility of how much gas exists there to then do financial feasibility, which on the back of the envelope it is possible to build a pipeline all the way up from Suriname passing through Guyana and Venezuela. You can have tie-ins at all of those jurisdictions to bring gas to market in Trinidad. It's a simple proposition and it is for the governments to decide what it is they're going to do with their resources for them to negotiate.

But our proposition is the quickest way to monetize your gas—bring it via a pipeline that we can all be partners in to build up an onshore based industry, especially in the current global climate. I mean we've just come to the end of CERAWeek where you're not hearing people talk about new investments. Who is going to spend billions of dollars to invest in a new industry? And also from a government perspective, what you need to consider is if I manage to attract investment to build an onshore industry, don't you have to offer incentives? Don't you have to offer moratoriums on taxation? Don't you have to offer lower prices, et cetera? Whereas you already have

Offshore oil rig and drilling vessels in Chaguaramas Bay, Trinidad and Tobago, working on oil industry projects at sea. Trinidad and Tobago are floating the idea of an offshore pipeline route with tie-ins from Suriname and Venezuela, according to Energy Minister Stuart Young.

SHUTTERSTOCK

the opportunity for market, literally global market prices for your gas to be monetized in Trinidad. And that's really the policy decision that needs to be made. We stand ready to work with anyone and from what we did in our preliminary, a pipeline is very possible.

PDP: Just to confirm, this would be a completely onshore or offshore pipeline?
SY: Offshore. This is the offshore fields and for example, if people were to decide from a policy point of view to go that route, you're looking at a pipeline offshore to bring gas from those various jurisdictions straight to plants.

PDP: Where do you stand in terms of tapping Dragon gas from Venezuela and when do you expect to finally have your first molecule coming from Venezuela?
SY: The first molecule can't come quick enough. The Dragon one is a done deal. What you saw towards the end of last year, on Oct. 17, the U.S. government through OFAC gave a full green light for a two-year period. That OFAC specific license is completely separate to General License 44 [and] allows the government of Trinidad to work with Shell to bring Dragon gas through and that expires at the end of October 2025. A significantly long enough period to get this done and to take FID [final investment decision]. That was the first step.

The second step was on Dec. 21 last year, where we secured, we have in hand, it's been published in the Venezuelan Gazette and in accordance with [Venezuelan] laws, a 30-year E&P license for Dragon. The Dragon gas field is now an E&P license to Trinidad through the angles of Shell and NGC. That exists. Right now, there is work to be done. I've met with Shell during this week [about] how quickly we [can] get a survey ship in there. We're hoping to have the award of a contract for a survey ship to just give us the latest data and then you can determine where wells will be drilled, et cetera, by the end of April of this year. That's very, very soon. There's progress made there. As far as I'm concerned, Dragon is a done deal. You have elections in Venezuela in July, you have elections in Washington, D.C. in November of this year. And those are two important elections. But we have the blessings of the U.S. government and we are working with Venezuela to keep everything on track.

PDP: From the outside looking in, one sees Venezuela under U.S. sanctions, the Russians and Chinese still in Venezuela, while Chevron is the last standing U.S. company there. Then one sees neighboring Trinidad negotiating with Venezuela. In a heated geopolitical environment, which is Venezuela, you've been in discussion with the U.S. and Venezuelan governments, is there anything that worries you or are you feeling very confident in discussions from both sides?
SY: There's a constant element of uncertainty because, as you say, the geopolitics of it. But what I can say is, Trinidad is well-respected by the government of the U.S. I mean we've been in constant conversation, and this week alone I've had some excellent conversations with the U.S. government. We remain engaged with the government of Venezuela, we engage with the EU because they have understood now that there's an alternate supply of gas. In life, there's very little certainty on anything. But what we've managed to do is be the honest broker in between all of these huge political geopolitical entities.

PDP: Any fears about a change of U.S. government and whether that could derail what you've been doing to date in Washington and Caracas?
SY: We will continue to be engaged with whoever is [in] the U.S. government. The current administration has been a great partner, but let's wait and see what the U.S. election brings. With every democratic country, you always have to factor in what could happen after an election and you just pick up yourself and you do the work. You continue to do the work regardless of who's there. As we said in the height of the sanctions against the President [Nicolas] Maduro government. Hey, when you pick up the phone and you call Miraflores, it's whoever answers the phone, that's who you deal with. OGI


Cameron LNG

SEMPRA™ INFRASTRUCTURE

Sempra Infrastructure, headquartered in Houston, is focused on delivering energy for a better world by developing, building, operating, and investing in clean power, energy networks, and liquified natural gas (LNG) and net-zero solutions that are expected to play a crucial role in the energy systems of the future. Through the combined strength of its assets in North America, Sempra Infrastructure is connecting customers across the globe to modern energy infrastructure to source and transport renewables and natural gas while advancing carbon sequestration and clean hydrogen. For more information about Sempra Infrastructure, please visit **www.SempraInfrastructure.com.**

Our mission is to be North America´s leading energy infrastructure company through three business lines:

Energy Infrastructure	Clean Power	LNG & Net Zero Solutions
+4,700 Miles of natural gas transportation and distribution pipelines	**+1,600 MW** of power generation capacity, of which 1,044 MW are from renewable sources	**2 Regasification Terminals** in operation
+250 Miles ethane and liquified petroleum gas pipelines	**2 Wind Farms** in operation +1 in development	**1 Liquefaction Terminal** in operation
+154,000 Customers natural gas distribution	**5 Solar Parks** in operation + 1 in development	**2 Liquefaction Terminals** under construction + 3 in development
6 Fuel Storage Terminals in operation and under development	**1 Battery Storage Project** in development	**2 Carbon Sequestration Projects** in development
1 Liquified Petroleum Gas storage facility	**1 Combined Cycle Power Plant** in operation	**1 e-Natural Gas Project** under evaluation

Pitts: Let the LNG Olympic Games Begin!

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If you believe the numbers published by the U.S. Department of Energy (DOE), the U.S. will easily retain its ranking as the world's leading exporter of LNG by 2030.

By then, back-of-the-envelope calculations from projects under construction alone point to U.S. LNG export capacity reaching 196 million tonnes per annum (mtpa) or 25.9 Bcf/d versus Qatari LNG export capacity of around 142 mtpa (see table).

The U.S. gets there by adding 87.8 mtpa of capacity from five projects under construction at Corpus Christi, Golden Pass, Port Arthur, Venture Global Plaquemines and Rio Grande LNG. This compares to existing operating capacity of 108.4 mtpa, according to the DOE. This will allow the U.S. to boast an 81% liquefaction growth rate between now and 2030.

Qatar gets there by adding 65 mtpa of capacity to come from its North Field West project. This compares to existing operating capacity of 77 mtpa, or agrowth rate of just 84%.

Still, one needs to take into account that the average annualized utilization rate in the U.S. was 94% in 2023, compared to around 104% in Qatar, according to Kpler.

In the LNG exporting space, the U.S. will outpace its fiercest competitor, Qatar, and both countries are expected to outpace Australia. As it stands for the LNG export Olympics, the medals would be awarded in 2030 like this: the Americans, gold; the Qataris, silver; and the Aussies, bronze.

And this will be the case despite the infamous "Biden pause" announced in January. And it's no small feat, considering the U.S. joined the LNG exporter's club as recently as 2016 with the start of the first export train at Sabine Pass.

The pause is designed to give the DOE time to review applications for permits to export LNG to non-free trade agreement (non-FTA) countries, as well as update economic and environmental analysis to assess whether the applications were in the public interest.

The temporary nature of the pause was again stressed by Energy Secretary Jennifer Granholm during CERAWeek by S&P Global in late March, when she said that within a year, the pause would "be well in the rearview mirror."

And the numbers for the U.S. only get better.

Taking into account authorized projects not yet under construction, the U.S. has another 123.6 mtpa of export capacity tied to pending final investment decisions or FIDs.

That said, total U.S. export projects–operating, under construction and authorized–with non-FTA countries is 319.8 mtpa, a massive volume. And that doesn't include 41.8 mtpa tied to LNG projects located in northwest Mexico that will source feedgas from the Permian Basin and serve LNG demand centers in Asia.

No doubt, the Biden pause has generated strong reactions within and outside the U.S. as future LNG demand estimates are large and tied not only to Europe, but to Asian countries continuing to switch from coal to gas. By 2040, LNG demand is expected to reach 625-685 mtpa, Shell revealed in a recent study, up from 404 mtpa in 2023.

Executives from American gas producers and LNG exporting entities continue to argue the benefits of U.S. energy. They say American energy helps allies and other countries lower their greenhouse gas emissions while providing energy security, especially in the aftermath of Russia's invasion of Ukraine in 2022, which drastically interrupted the flow of gas to Europe and Asia.

While the Biden pause is real, it's important to remember its temporary nature and the possibility of outright abandonment during the tribulations of a presidential election year. The U.S. and Qatar liquefaction build-outs are also real and the numbers point to the U.S. winning on that front by 2030 and even by 2050. Maybe it's not a blowout, but it will still be a U.S. win and "The Star-Spangled Banner" will still play during the medal ceremony. OGI

LNG Exporters: U.S. vs. Qatar

	Existing		Under Construction		Authorized		Total	
	mtpa	Bcf/d	mtpa	Bcf/d	mtpa	Bcf/d	mtpa	Bcf/d
U.S.	108.4	14.3	87.8	11.6	123.6	16.3	319.8	42.1
Qatar	77	10.1	65	8.6	0	0.0	142.0	18.7

SOURCECS: U.S. DOE, QATAR ENERGY

GLOBAL ENERGY

Paisie: Crude Prices Rising Faster Than Expected

Supply cuts by OPEC+, tensions in Ukraine and Gaza drive the increases.

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.

Last month we reiterated our view that the price of Brent would move toward $90/bbl in the second quarter. And we have now seen the price of Brent crude reach that level in early April. At the same time, the price of WTI has moved above $85/bbl.

The increase in oil prices has been supported by several factors:

- Oil supply that has been constrained this year with additional supply cuts of 2.2 MMbbl/d by OPEC+ to go with the previous supply cuts of 3.7 MMbbl/d. There have also been lower supply increases from non-OPEC producers, including supply from the U.S.
- Concurrently, demand growth has been moderately stronger this year than expected. We have recently increased our global demand forecast for 2024 from 1.3 MMbbl/d to 1.41 MMbbl/d. Consequently, demand has been outpacing supply.
- The sentiment of oil traders is becoming more bullish. The net long positions of WTI traders have increased significantly with net long positions doubling since early February and are now at the highest level since October 2023 when the price of WTI was nearly $90/bbl.
- Geopolitics are providing a boost for oil prices with the conflicts in Ukraine and Gaza escalating—and while crude oil and oil products continue to flow, the possibility of disruption is increasing, which is resulting in a risk premium with respect to oil prices.

So, where are oil prices heading?

Obviously, oil prices will spike higher if the geopolitical situation spins out of control. The most influential development would be closure of tanker traffic at the Strait of Hormuz because of the volume of oil that passes through this chokepoint, which is in excess of a combined 20 MMbbl/d of crude oil, condensate and oil products.

Restricting oil-related exports from Iran or Russia would also be a significant development. At this point, we think the probability of either of these developments occurring is still relatively low. Until its mid-April attack against Israel, Iran had exhibited restraint since the beginning of the Israel-Hamas conflict. We think that the U.S. will put pressure on Israel to limit further direct attacks on Iran, as well as take other steps to deescalate the tensions.

Additionally, we think it is unlikely that the U.S. and allies will attempt to place additional sanctions on oil exports from Iran, as well as Russia, in part because of concerns of pushing oil prices even higher. Furthermore, imposing additional sanctions are made more complicated by China being a major destination for the exports. There appeared to be movement toward sanctions against Iran's missile program by the European Union as well as financial sanctions by the U.S.

We are expecting that the supply/demand fundamentals will be somewhat supportive of oil prices, but without a geopolitical shock, we are forecasting that the price of Brent will drop into a range between $86/bbl and $88/bbl during the second half of 2024.

We are forecasting that liquid supply (including crude oil, NGL and biofuels) will increase on average by 1.24 MMbbl/d during the last three quarters of this year (in comparison to 2023) and crude supply will increase by on average by 0.99 MMbbl/d.

Capex shortfall

Crude oil production from the U.S. is one of most significant risks associated with the supply forecast. Last year, the U.S. was able to increase supply even though the rig count declined throughout the year because of improved drilling efficiencies, longer lateral lengths and the increased use of proppant, but also because of a significant drawdown in drilled uncompleted wells (DUCs).

Increasing production this year will be more difficult and will be more dependent on the level of capital expenditures. In response to the commodity price decline in late 2023, many of the E&P companies increased focus on optimizing capital efficiency and maximizing cash flow generation. Based on our analysis of a set of top producers, planned capital expenditures for 2024 are about 11% below that of 2023.

With respect to demand, we are forecasting that oil demand will increase on average by 1.22 MMbbl/d during the last three quarters of this year.

Demand growth from China is one of the most significant risks associated with the demand forecast. During the last three quarters of this year, we are forecasting that China's oil demand will increase on average by 0.44 MMbbl/d. Our demand forecast for the

Saudi Aramco's operations in Ghawar, the largest conventional oil field in the world.

SAUDI ARABIAN OIL CO.

remainder of 2024 is based on China's economic growth remaining relatively weak because of the challenges stemming from a debt-ridden real estate sector, declining direct foreign investment and tepid demand from export markets.

Recent economic data indicate some improvement in China's economy. The official PMI for manufacturing in March increased from 49.1 in February to 50.8 in March, which is the highest level in 13 months. It is also the first reading above 50 (which indicates expansion) in 12 months. Additionally, the index for new orders increased from 49 to 53 and the new manufacturing export order index increased from 46.3 to 51.3.

Furthermore, the composite PMI (including manufacturing and non-manufacturing) increased from 50.9 to 52.7, which is the highest level since May 2023. While the latest PMIs are showing some improvement in China's economy, the U.S. and other Western countries are still concerned about the possibility of China pushing out "cheap" exports—especially with respect to EVs, renewable energy and semiconductors. As such, China is still facing the likelihood of additional tariffs and other trade barriers, which will hamper its economic growth. OGI

AROUND THE WORLD

North America

ChampionX Buying RMSpumptools

ChampionX plans to buy RMSpumptools, a business unit of the energy division of U.K.-based James Fisher and Sons, which designs and manufactures highly engineered mechanical and electrical solutions for complex artificial lift applications.

Integration of RMSpumptools technology will enhance ChampionX's production and automation technologies portfolio and strengthen its presence in the Middle East, Latin America and global offshore developments, ChampionX said in a press release in March.

The net purchase price is about $110 million at current exchange rates, inclusive of net working capital adjustments. In 2024, ChampionX anticipates that RMSpumptools will achieve around $65 million in revenue and around $18 million in adjusted EBITDA.

South America

US Decision on Venezuelan License to Dictate Production Flow

Venezuela's oil production, which has recently been on an upward trend, could continue to rise or stall, once Washington decides on the direction of General License No. 44, according to a recent study by Rystad Energy.

"As things stand, the U.S. looks more likely to keep sanctions lifted than re-impose them," Rystad Senior Vice President Jorge León wrote in a research report in April.

"If the U.S. does not reimpose [oil] sanctions, Venezuela could surpass the 1 million bbl/d threshold as early as December, rising to 1.12 million bbl/d by the end of 2025," León said. "If sanctions are reimposed, production is expected to remain flat at about 890,000 bbl/d."

In January, U.S. State Department spokesperson Matthew Miller said that Washington could decide not to renew the license, issued by U.S. Office of Assets Control (OFAC) on Oct. 18 to assist the OPEC country rebuild its oil and gas production capacity, citing "anti-democratic actions" in the lead-up to presidential elections this year.

The State Department has already revoked sanctions relief for Venezuela's gold sector.

"However, the U.S. could choose to issue a cosmetic reversal of the sanctions that looks good politically but still allows crude to flow out of the country," León said. "For instance, Venezuela could continue to sell crude to international customers, but instead of in U.S. dollars, they would sell in Venezuela's national currency, the bolivar, through debt relief payments."

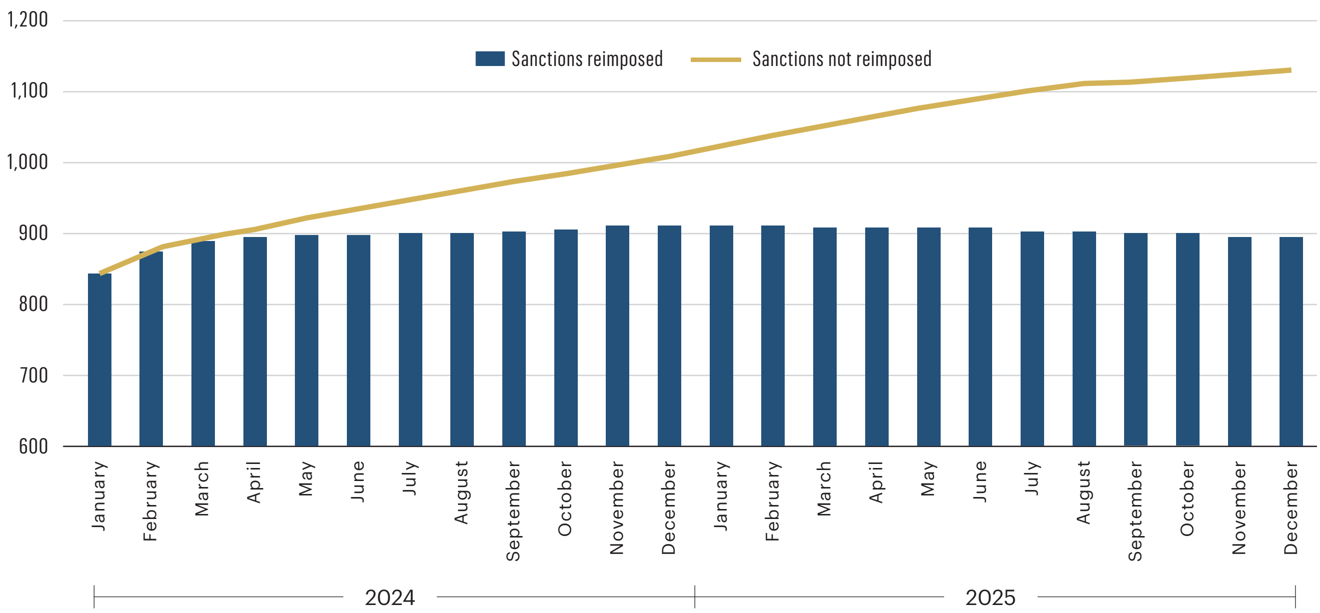
Venezuela has struggled to get its production to surpass 800,000 bbl/d on an ongoing basis amid U.S. sanctions and years of oil sector mismanagement. Venezuela produced around 3.23 MMbbl/d in 1997.

León said new sanctions could further tighten an already constrained global oil market and add additional upside price pressure and raise pump prices for U.S. consumers.

"As we approach summer and the expected spike in gasoline demand, you have to think that keeping pump prices subdued will be a major priority for President Joe Biden's administration."

Venezuelan Crude Production Scenarios

Thousand barrels per day



SOURCE: RYSTAD ENERGY RESEARCH AND ANALYSIS

Exxon Ups Guyana Production Target by 100,000 bbl/d

Exxon Mobil now expects its six offshore Guyana projects to generate gross production of 1.3 MMbbl/d by 2027, the company said in a press release in April. The revised production is 100,000 bbl/d higher than earlier production estimates of around 1.2 MMbbl/d.

Previously, Exxon and New York-based Hess Corp., partners in the Stabroek Block, said they expected the earlier production figure to come from six FPSOs planned to come online by the end of 2027. The number of FPSOs necessary to reach the figure hasn't changed, just the production estimates.

The companies maintain that the discovered resources to date on Stabroek—slightly more than 11 Bboe—will underpin potential for up to 10 FPSOs.

The announcement came the same day Exxon took a final investment decision (FID) for its Whiptail development offshore in Stabroek.

Whiptail is Exxon's "sixth multi-billion-dollar project in Guyana," Exxon's upstream president, Liam Mallon, said in the release, and production is expected to begin in 2027. The higher production estimates were revealed by Exxon as part of details around its $12.7 billion FID for Whiptail. The project will have a 250,000 bbl/d gross production capacity. The FID was taken after receiving government and regulatory approvals.

Exxon's affiliate, Exxon Mobil Guyana, operates the 6.6-million-acre Stabroek with 45% interest on behalf of partners Hess Guyana Exploration with 30% interest and CNOOC Petroleum Guyana with 25% interest.

GeoPark to Buy Interests in Argentina's Vaca Muerta

GeoPark submitted a binding offer to buy a non-operated working interest in unconventional blocks in Argentina's Neuquén Basin's Vaca Muerta formation from an undisclosed seller.

GeoPark agreed to pay $200 million for the interests, plus an additional carry of between $110 million to $120 million (gross) over two years related to certain exploration activities, GeoPark said in a press release in April. At closing, the acquisition will add more than 5,000 boe/d of net production to GeoPark.

The offer has been accepted by the seller, which is working with GeoPark on an exclusive basis toward executing definitive agreements, GeoPark said. Subject to those agreements, the transaction would close in the third-quarter 2024.

GeoPark expects to fund the acquisition with available cash on hand and credit facilities, as well as new financing. After the acquisition, GeoPark expects its net debt to adjusted EBITDA ratio to remain below 1.1x.

Europe

North Sea Well Confirms Gas Discovery

Harbour Energy and its partners confirmed a gas discovery in well 15/9-25 in the North Sea.

Gas was first proven in wells 16/7-2 and 16/7-10, drilled in 1982 and 2011, respectively. The 15/9-25 well is the first one to be drilled in PL 1138, which was awarded in 2021, the Norwegian Offshore Directorate said in a press release in March.

MAERSK

The Noble Integrator rig, formerly Maersk Integrator, drilled the well in 84 meter water depth.

The overall gas volume is calculated at between 1-3 MMcm of recoverable oil equivalent.

Licensees Harbour Energy, Sval Energi and Aker BP will consider whether to tie the discovery into existing infrastructure in the area.

Water depth at the site is 84 meters. The well has been permanently plugged and abandoned.

Archer Buying Majority Stake in Vertikal Services

Archer is acquiring 65% of Norwegian company Vertikal Services, which provides inspection, installation and maintenance services for $2.36 million in cash and the contribution of Archer's offshore drilling facilities construction business in Norway.

"Vertikal's business aligns well with Archer's core oil and gas capabilities while opening avenues for growth in renewable sectors such as wind and hydropower," Archer CEO Dag Skindlo said in a press release in March. "We anticipate significant long-term synergies and growth potential from the acquisition."

The remaining 35% of Vertikal will be owned by existing management and key employees.

ROCS Ordered for Equinor's Irpa Project

Equinor awarded Optime Subsea a contract for two remotely-operated control systems (ROCS) for use at the operator's Irpa Field development.

Equinor previously ordered ROCS for use at its Rosebank Field, west of Shetland, U.K., Optime Subsea said in a press release in March.

The ROCS eliminate the need for both the umbilical, which traditionally connects the surface to the seabed for controlling the tubing hanger in subsea well completions, and the topside hydraulic control unit.

Optime Subsea will manufacture the two systems at its headquarters in Notodden, Norway, and deliver them to Equinor's offshore base at Sandnessjøen in northern Norway in 2025.

Equinor will use one system for a well completion campaign at Irpa—formerly Asterix—that is planned for 2026, while the other will be a back-up system. Irpa, in 1,350 meters of water in the Norwegian Sea, is being developed as a subsea tieback to the Aasta Hansteen FPSO. OGI

Gas Prices in a Summer of Discontent

In February, prices dropped below $2 and stayed there. How is the market handling it, and when will the price pick back up?

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Josh Viets told the audience at the DUG GAS+ Conference and Expo in March that, since joining Chesapeake Energy, he has become much, much more interested in the daily temperatures.

"I find myself checking the weather at least a couple of times a day and, unfortunately, this winter we have continued to be disappointed," Viets, Chesapeake's COO since 2022, said. "We just didn't see it show up."

December 2023 was one of the warmest Decembers on record, according to the National Oceanic and Atmospheric Administration. A polar vortex in mid-January was not enough to bring average temps for the month down below normal. February finished among the top 10 warmest on record for the month.

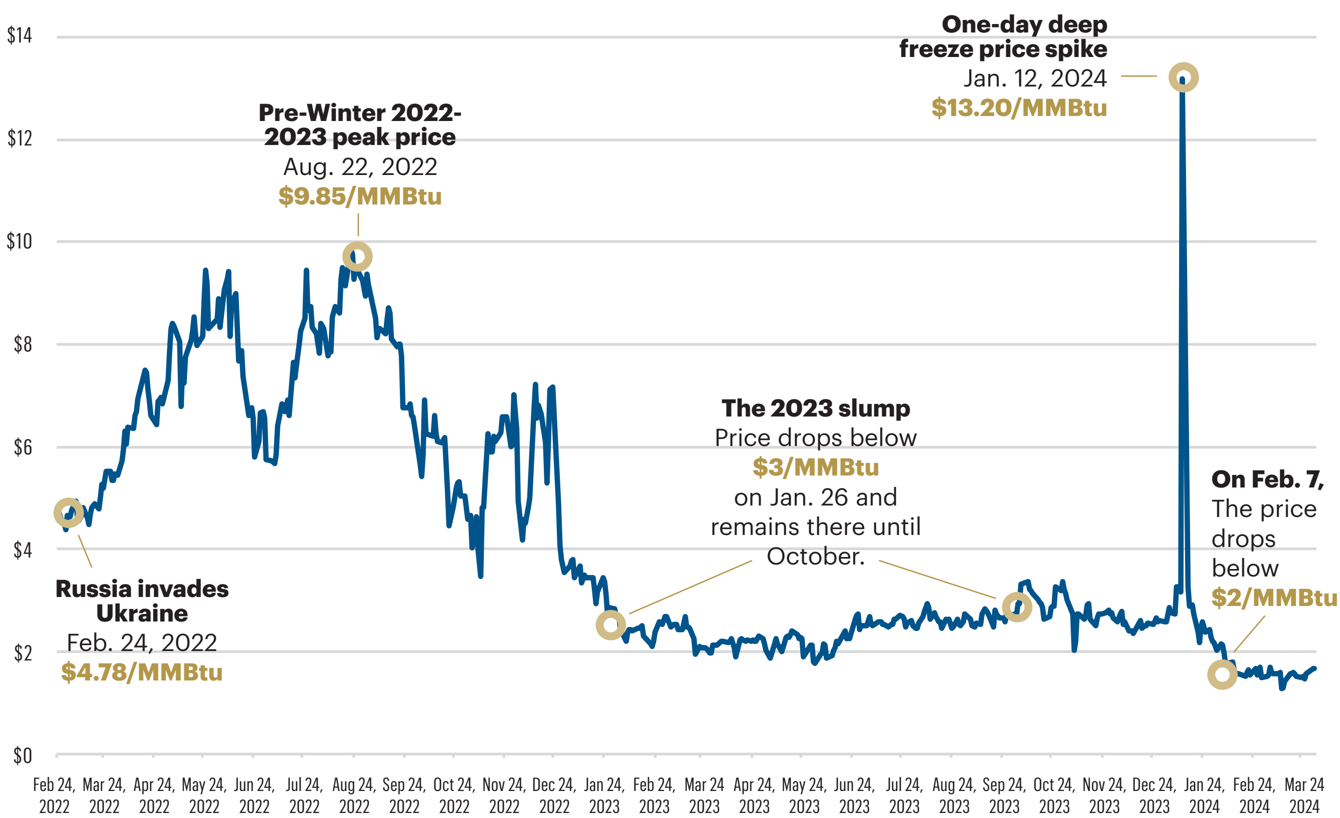
With record amounts in storage and production hitting new highs, the price of gas tanked in January to below $2.50/MMBtu at Henry Hub, and under $2/MMBtu in February and March, a price not seen since the COVID era in 2020. Most analysts believed the prices would remain low in the short term, with differing ideas on when the market would finally pull natural gas out of the doldrums.

"All of us that are in the natural gas business are pinching as many pennies as possible," Viets said.

Natural gas-focused companies have been pinching pennies for close to two years, and the latest price drop did not come as a surprise to people who watch the industry.

Henry Hub natural gas prices climbed above $9/MMBtu in August 2022. Russia had invaded Ukraine six months earlier and European countries were searching for non-Russian natural gas sources ahead of the winter.

Henry Hub Natural Gas Spot Price
($/MMBtu)



SOURCE: ENERGY INFORMATION ADMINISTRATION, OIL AND GAS INVESTOR

"I find myself checking the weather at least a couple of times a day and, unfortunately, this winter we have continued to be disappointed. We just didn't see it show up."

JOSH VIETS, COO, Chesapeake Energy

However, the winter of 2022-2023 was almost as mild as 2023-2024, and prices fell under $3/MMBtu by the end of January and stayed there for most of 2023.

In October 2023, NOAA recategorized the ongoing El Niño as "strong," which generally means warmer winters for residential heating customers in the northern regions of the country. In December, researchers at East Daley Analytics predicted natural gas prices would hit $2.50/MMBtu in first- or second-quarter 2024.

But other factors sway the market beyond the weather. One is supply.

In March, the Energy Information Administration (EIA) reported that the U.S. produced an average of 124 Bcf/d of natural gas, a new record for the month. Overall for 2023, gas production hit a new record of 37,883 Bcf, despite dropping prices.

Permian's downward pressure

The Permian Basin produced about one-fifth of U.S. natural gas in 2023, according to the EIA. In 2023, gross natural gas production in the Permian rose by 2.6 Bcf/d to an average of 23.3 Bcf/d. Permian Basin gas is almost all produced in association with crude extraction.

The price for a barrel of WTI crude fell to $68.61/bbl on Dec. 12, 2023, and had risen above $80/bbl by mid-March. Break-even prices for Permian crude through 2023 averaged about $60/barrel, according to a Dallas Fed survey, so producers kept extracting crude and the gas that came along with it.

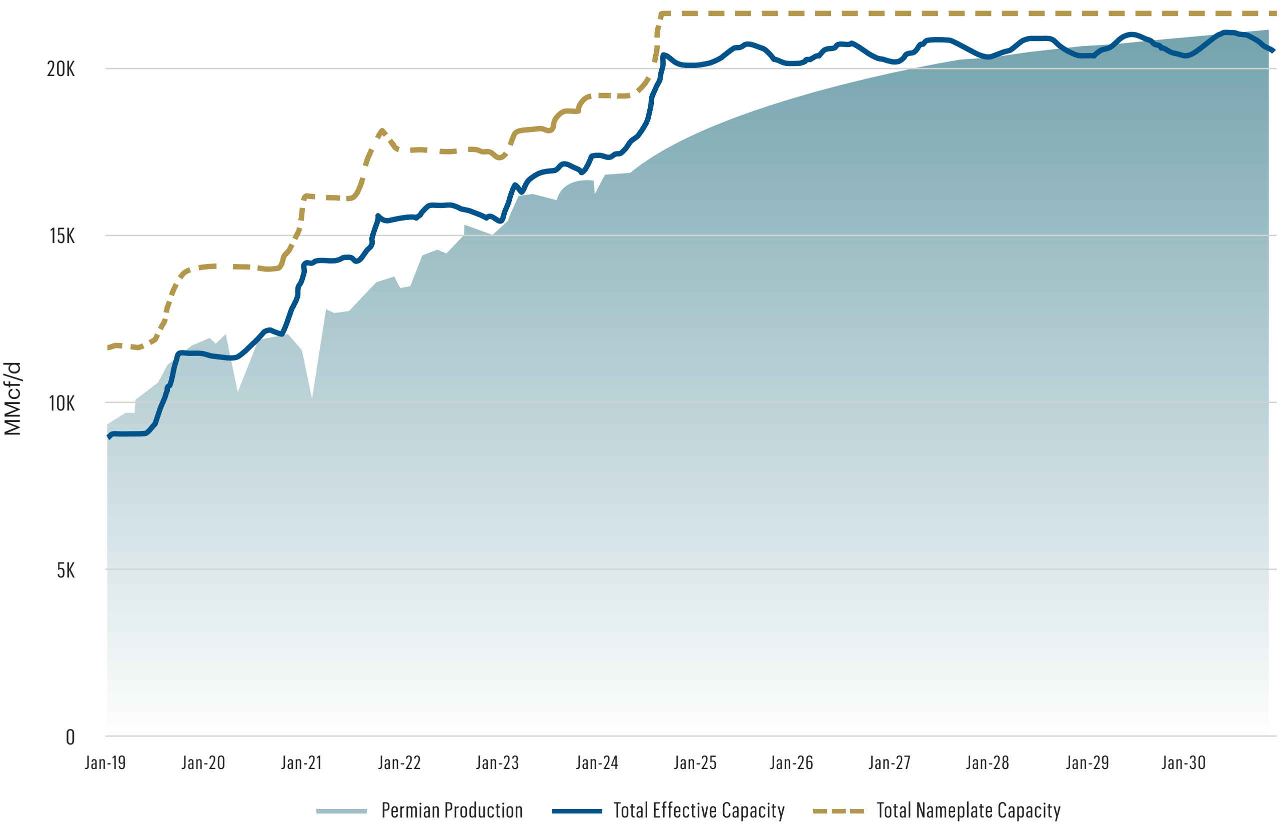
"Roughly a third of all the gas produced in the U.S. is coming from associated gas, primarily in the Permian, where you have break-evens (for natural gas) that are essentially zero," Viets said.

Prices at the Waha hub, a regional price point near Pecos, Texas, went negative in early March, trading below $1/MMBtu. Natural gas takeaway capacity from the Permian is usually running at capacity, said Jack Weixel, senior director at East Daley Analytics.

The negative prices popped up when midstream company Kinder Morgan's maintenance on the El Paso Natural Gas Pipeline, one of the key takeaway lines for the region, combined with windy days driving up electrical production from the region's wind turbines, resulting in a reduction in the power load needed for West Texas electrical plants.

"You've got a really tight Permian market," said Jimmy McNamara, senior vice president at Enverus Intelligence Research, at the DUG GAS+ Conference. "It's going to

Permian Effective Capacity vs. Production



SOURCE: EAST DALEY ANALYTICS

The rapid growth of the artificial intelligence is driving increasing energy consumption to power large-scale data processing centers used to support the burgeoning industry.

SHUTTERSTOCK

continue to be the case in the Permian until they can get additional takeaway to the Gulf."

Other basins' different routes

Other gas-producing plays in the U.S. have reacted much more strongly to the market prices.

"We've seen suppliers respond pretty aggressively to lower prices in March," McNamara said. According to Enverus, natural gas supply fell by about 7 Bcf/d over the first three months of the year, primarily by producers in the Haynesville and Appalachia shales holding back on production.

Producers in each basin have taken paths to deal with a low market.

According to Viets, Chesapeake has continued work on its wells in Appalachia, creating an inventory of about 80 DUCs that can be brought online quickly once the market provides a more worthwhile price.

Other Appalachia producers are doing the same, while the number of DUCs in the Haynesville, located in Texas and Louisiana, has started to drop, McNamara said, thanks to a difference in the production costs in the basins.

Since prices started falling in 2023, Haynesville producers are down to about 32 active rigs, which is below maintenance level, McNamara said. The play would need about 40 rigs to keep current production levels flat.

Within the basin, private operators tend to aggressively raise and lower their well completions more than the public companies. The Haynesville tends to be more responsive to prices, as the break-even margins in the basin are higher than in other gas-focused areas. S&P Global estimated a \$2.67/MMBtu break-even price in the Haynesville in February, as the Henry Hub price remained below \$2/MMBtu.

"Private operators have really been driving and chasing price more than public operators," McNamara said.

In the Appalachia's Marcellus and Utica basins, different rules tend to apply. Production has remained flat even as prices have dropped. The basins in the Northeast have a lower cost of production, but far more takeaway constraints than the Haynesville, McNamara said. Production has therefore remained steady.

In February, Chesapeake announced it would cut production by about 20% in both the Haynesville and Appalachia regions to a total of about 2.7 Bcf/d. The disclosure came after similar announcements from Antero Resources, Comstock Resources and EQT.

Overall, natural gas producers in the U.S. have spent the last 18 months riding out thinning margins, positioning themselves for what it expected to be a massive increase in demand starting either at the end of 2024 or sometime in 2025.

A survey from advisory firm RBN Energy revealed that 12 natural gas-focused producers saw their profits decrease 87% from 2022 to 2023, from \$47 billion to \$6 billion, as a result of the decline in commodity prices.

"Adding insult to injury, many of the Appalachian hubs saw natural gas prices fall more than 70% and average less than \$2/MMBtu in 2023," RBN analyst Nick Cachionne wrote in the report.

However, 11 of the 12 gas-producing companies managed to post a profit in 2023, the report said, with only Southwestern Energy reporting a loss, which was tied to an impairment charge the company took prior to its proposed merger with Chesapeake Energy, which was announced in January. (An FTC probe into the merger was expected to delay the deal until the latter half of 2024.)

Gas producers have practiced cost discipline to keep finances steady, RBN reported. In 2023, depreciation, depletion and amortization (DD&A) costs were \$5.18/boe, only 1% higher than 2022.

However, gas-focused and diversified E&Ps are in a difficult position compared to crude-focused companies, RBN wrote. “Both groups’ fortunes will depend on the degree to which the gas shut-ins are successful in bringing supply and demand into closer balance.”

Waiting for the boom

U.S. producers are waiting for the balance to come around in a market that remains uncertain.

“For natural gas prices to trade better, that’s a tricky one,” said Hinds Howard, CBRE Group portfolio manager. “The simplest answer is time for the demand to catch up to supply.”

The U.S. began to export LNG in earnest beginning in 2016. In January 2024, exports totaled 396 Bcf, according to the EIA. In 2023, the U.S. exported more LNG than any other nation, averaging 11.9 Bcf/d over 12 months. By 2030, current export capacity is expected to grow to just under 25 Bcf/d, as multiple LNG export terminals along the Gulf Coast and in Mexico are slated to come online.

Analysts agree the trading price of natural gas will generally increase in the near future, but have different ideas on the timing.

East Daley Analytics expects Henry Hub prices to reach above \$3.50/MMBtu by year-end 2024. The current low prices should help the U.S. begin to drain the high level of natural gas in storage, which has been well over the five-year average since November 2023, according to the EIA. About 6 Bcf/d of LNG export capacity is expected to come online by October 2025.

Enverus’ McNamara said he did not expect Henry Hub prices to go above \$3/MMBtu before several months into 2025.

“It’s going to take some time to wear down on the inventory levels,” he said.

LNG abroad

Analysts are also unsure how foreign competitors will adjust in the same time period. The five countries that export the most LNG after the U.S. are: Australia, Qatar, Russia and Malaysia.

Qatar, which fights for second place in LNG exports with Australia, announced in February that it plans to expand its export capacity 85% to 142 MMmt/a by 2030, or about a quarter of the world’s LNG supply. Some market analysts believe the expansion could threaten the funding of several U.S. LNG projects that are waiting for permits from the U.S. Department of Energy, Reuters reported.

President Joe Biden’s administration put a pause on LNG permitting in January.

Russia, which drew U.S. and European sanctions following its invasion of Ukraine, is struggling to maintain its current level of exports and may soon run into more

Producers in each basin have taken paths to deal with a low market, some reacting more strongly than others. Natural gas supply fell by about 7 Bcf/d over the first three months of the year, primarily by producers in the Haynesville and Appalachia shales holding back on production.

SHUTTERSTOCK

trouble with moving product to the market.

Russia's Arctic LNG 2 suspended operations at the end of March in response to Western sanctions and a shortage of tankers, Reuters reported. Project managers had hoped to start commercial deliveries within first-quarter 2024. Russia is currently the world's fourth-largest LNG exporter at 32.6 MMmt/a.

Europe, which had been Russia's largest LNG customer, is considering further steps of separation.

At the end of March, European natural gas storage levels were at 58%, a record for the end of the heating season, according to Gas Infrastructure Europe. The surplus is causing pressure to grow from within the European Commission, where some players are calling to ban Russian LNG. (Russia supplied more than 16% of Europe's LNG from the start of 2024 through April 9, compared to less than 13% for the same period in 2023, according to S&P Global data.)

Rising domestic demand

Beyond the international market, producers are also seeing increasing demand at home, corresponding to the rapid growth of data centers and continuing retirement of coal-fired power plants. However, the growth in both sectors is difficult to predict, McNamara said.

Like natural gas, many utilities see coal as a cheap option which they are reluctant to eliminate, despite public pressure to decrease emissions of carbon and particulates. According to Enverus, whenever gas prices move above $4/MMBtu, utilities use more coal, causing the gas consumption to drop by about 1/Bcf/d.

"The main point we want to talk about here is just that, despite capacity going down, coal utilization is still pretty sticky," McNamara said.

The power increase caused by artificial intelligence (AI) data centers is more difficult to predict. There has been a "ton of hype around AI," McNamara said.

AI has received a great deal of attention from the energy industry because a rapid continual growth of the sector would require a massive increase in power supplies. In an October 2023 interview with Scientific American, data scientist Alex de Vries said that if everyone started using ChatGPT for internet queries instead of Google, the extra power requirements would be like adding a country the size of Ireland to the world's power grid.

However, determining the size of the electrical demand and a corresponding rise in gas demand has been difficult for analysts to calculate so far.

"We don't have certainty about what our power demand forecast would be for AI," McNamara said. "We're still running our numbers. There's definitely some uncertainty there."

What to look for

The problem for the natural gas industry's commodity prices, Howard said, is waiting for the factors to finally line up in its favor.

"Demand is longer cycle than supply growth," he said, "And will hinge on things like LNG export facility buildout, re-shoring of manufacturing that will lead to more industrial demand and hopes for demand growth due to generative artificial intelligence and data center growth."

With an almost certain increase in gas demand expected over the next year, Chesapeake is optimistic about its position for the industry's future, Viets said. Producers are keeping their eyes open to start taking advantage of their preparations to provide a larger supply.

"We need to see a few things happen," he said. "The timing of this is going to remain uncertain." OGI

Kinder Morgan Exec: Don’t Count Out Midstream in M&A Frenzy

Allen Fore believes 2024 should be an ‘interesting’ year for deals.

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The rash of blockbuster M&A deals consuming the E&P sector won’t spread beyond upstream, most midstream executives say.

Kinder Morgan’s Allen Fore is not among them.

“It is an interesting time in the industry and we are, every day, looking at opportunities where we can match our existing footprint and portfolio with other companies, with other assets, with related industries,” the midstream giant’s vice president for public affairs told attendees at Hart Energy’s DUG GAS+ Conference and Expo in March. “There’s a lot of opportunity out there and I think we are really well-positioned as a company to take advantage of a lot of these opportunities.”

Fore didn’t make any groundbreaking announcements at the conference. Past Kinder deals include its $38 billion purchase of El Paso Corp. in 2011, its $1.8 billion acquisition of NextEra’s South Texas gas pipeline assets in late 2023, buying renewable gas developer Kinetrex Energy for $310 million and North American Natural Resources for $135 million.

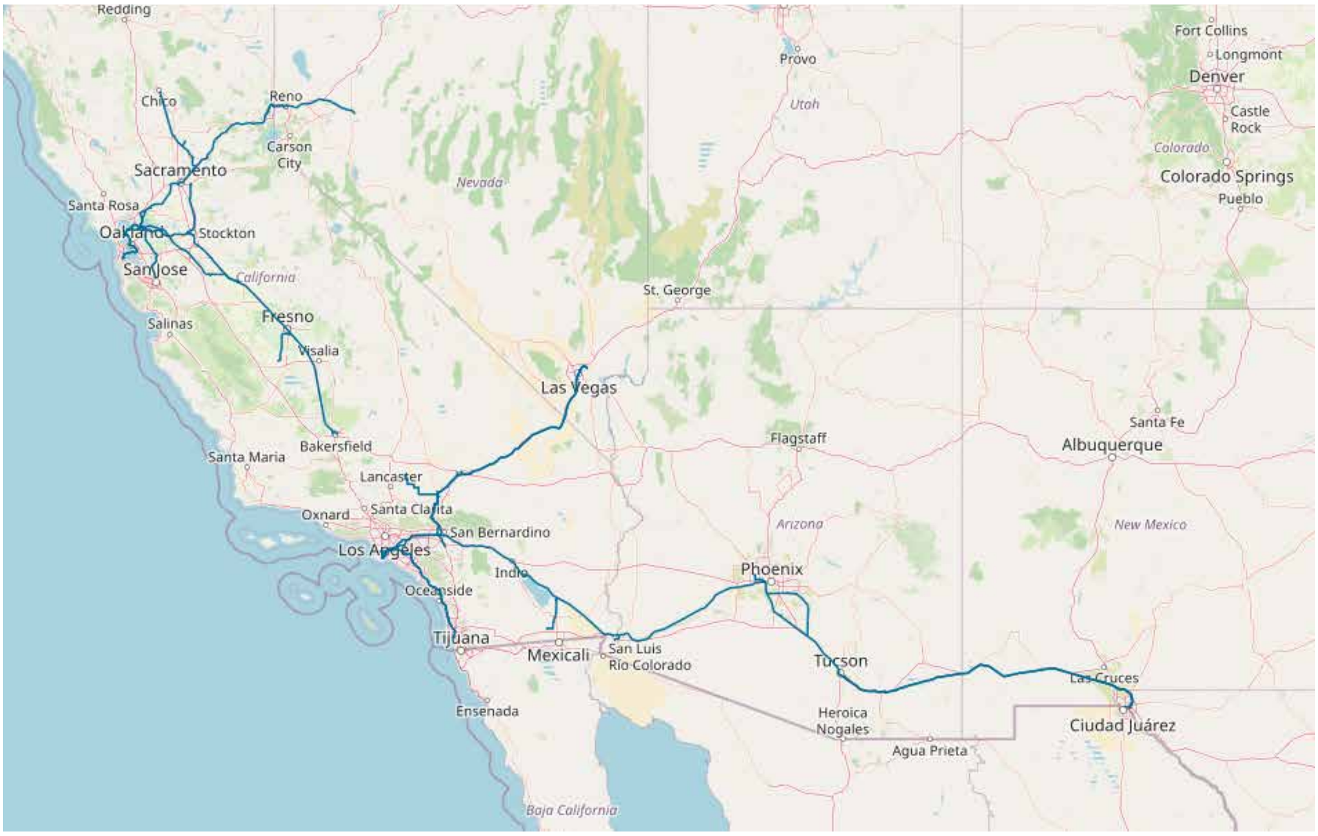
And Kinder Morgan’s cash holdings are not exactly burning a hole in its corporate pocket. Any transactions would have to make sense and complement existing assets, Fore said.

“Sometimes that’s building, sometimes that’s buying,” he said. “And we’ve done both of those and will continue to do both of those. So, I think 2024 is going to be an interesting year. And 2025.”

If you’ll permit us

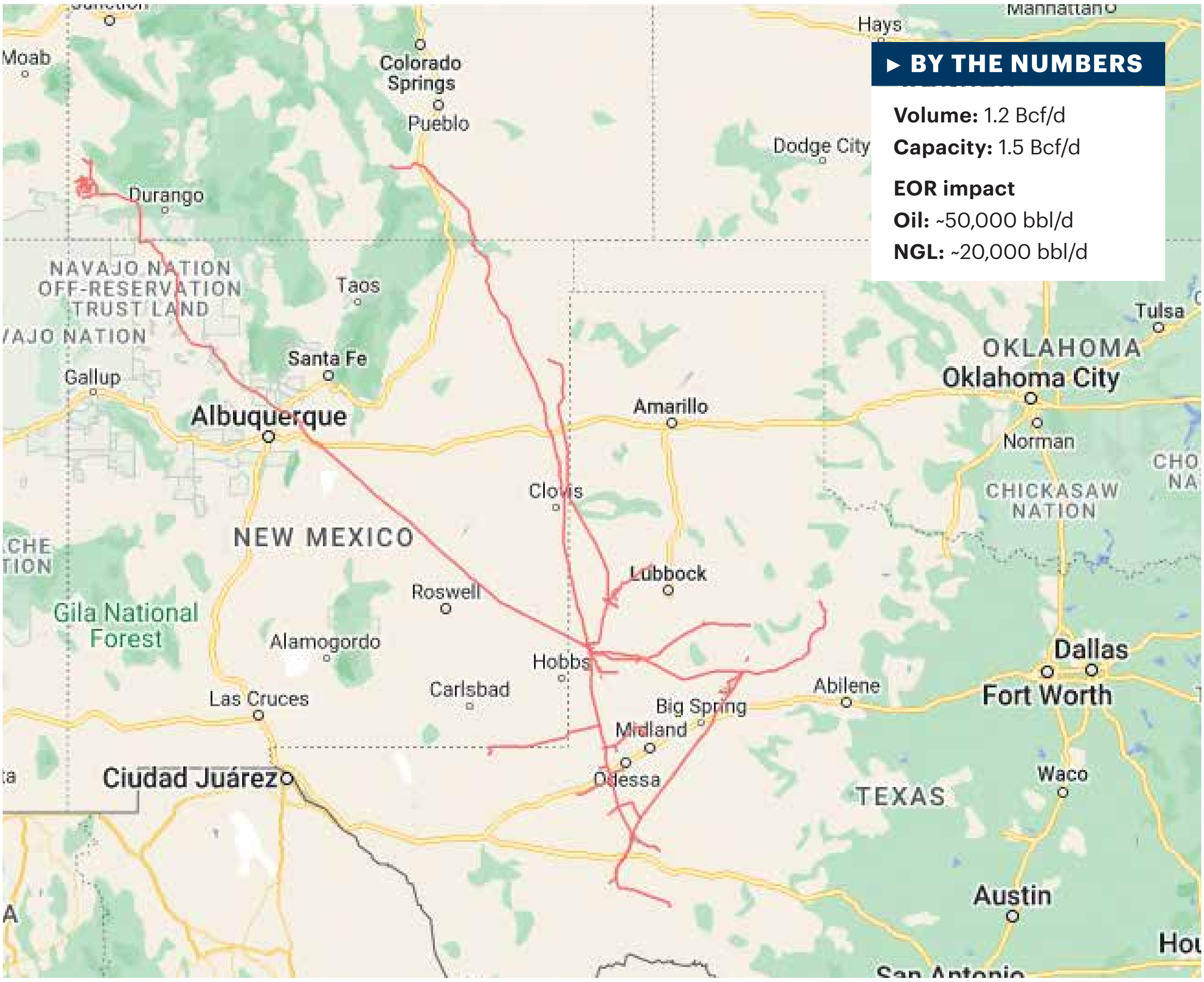
The building component of the growth equation is always tricky, and Fore believes that passage of permitting reform legislation in the current divided Congress is unlikely.

Kinder Morgan Refined Products Pipelines



SOURCE: REXTAG

Kinder Morgan's CO_2 Pipeline Network

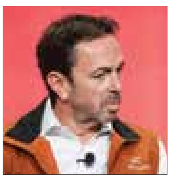


▸ BY THE NUMBERS

Volume: 1.2 Bcf/d
Capacity: 1.5 Bcf/d

EOR impact
Oil: ~50,000 bbl/d
NGL: ~20,000 bbl/d

SOURCE: REXTAG



"We can't move our assets out of California, Illinois or New York. They're there. We need to live and work and operate in the regulatory environment that we're in. Can it be better? Yes. Can it be more like Louisiana, Mississippi, Texas, Alabama or Florida? Sure, but it's manageable at the end of the day."

ALLEN FORE, vice president for public affairs, Kinder Morgan

There are, however, ways to manage regulatory roadblocks and Kinder Morgan has "yet to have a project that has not been able to move forward specifically because of permitting."

One of the company's success stories involves its operations in, of all places, California, where Kinder dominates the petroleum products transportation market.

"Now, we're not going to be building any new petroleum products lines in California," he said. "That's just not going to happen."

Maintaining the thousands of miles of existing pipelines, which provide jet fuel to airports in San Francisco, Los Angeles and San Diego, as well as gasoline and diesel jet fuel throughout the coastal California area, requires applying to the state for air quality and incremental pipe replacement permits.

"In our experience, is it complicated?" Fore said. "Yes, but is it doable? Yes, because the state of California understands the importance of keeping that product moving in a safe way. And if that's the way we talk about it, in most instances we can receive a fair consideration of what we were proposing to do."

The "doable" definition has changed over time. In 2009, Kinder put the Rockies Express pipeline into service. The

1,679-mile pipeline moves natural gas across eight states from Colorado to Ohio.

"You're not going to see a pipeline like that again," he said. "Think about that. Eight states, eight state approvals with a federal regulated project. That's just too big and too complicated and too risky."

What is more realistic in many ways in this era is incremental expansion, as in "this pipe will connect at this point and move this from one side of the state to the other, maybe from one state to two states," he said.

It's an easier message to communicate to regulators, said Fore, who served in numerous governmental roles including assistant attorney general of Illinois, before moving to the private sector.

"We can't move our assets out of California, Illinois or New York," he said. "They're there. We need to live and work and operate in the regulatory environment that we're in. Can it be better? Yes. Can it be more like Louisiana, Mississippi, Texas, Alabama or Florida? Sure, but it's manageable at the end of the day."

Room to grow

Sometimes, the permitting process with the government goes more smoothly, such as when the government is sponsoring the project. In Tennessee, Kinder is working with the Tennessee Valley Authority (TVA) to replace a coal-fired power plant with a natural gas-fired facility.

Kinder is in the final stages of state approvals and obtaining final land acquisitions. Cumberland is expected to begin construction later this year and the company is looking forward to future projects with TVA.

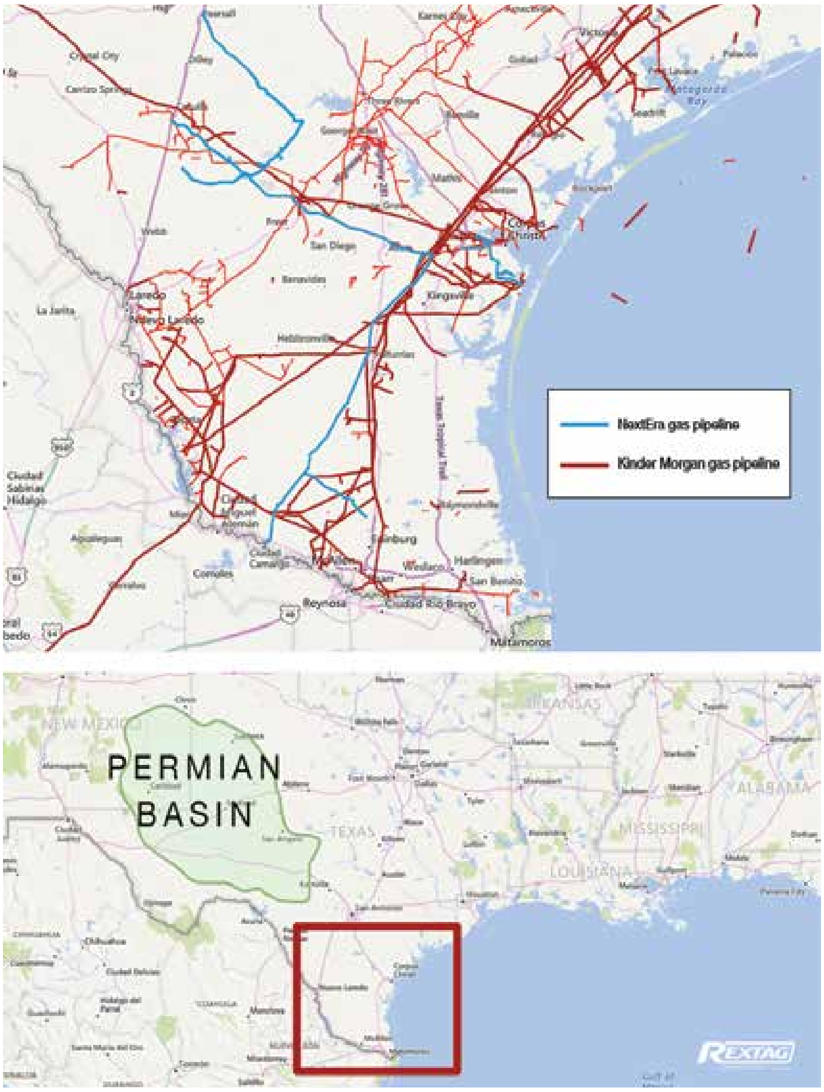
Fore said that Kinder Morgan is always looking for opportunities to expand its presence in the natural gas space, including its Gulf LNG expansion project in Mississippi and Elba Island in Georgia. He anticipates tremendous opportunities in LNG, even with the Biden administration's pause in project approvals.

One of the company's biggest areas for growth is in renewables, he said. Kinder Morgan controls 10% of the renewable diesel market in California, with plans announced to build hubs in the Sacramento and Los Angeles areas

Kinder CO_2

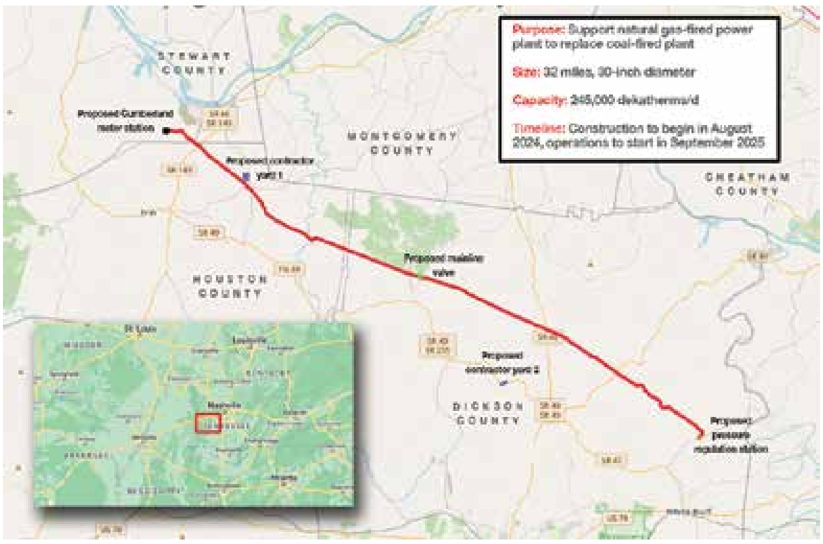
Kinder Morgan also is one of the largest transporters of CO_2, Fore said. "That's in our wheelhouse to get into that space and we've got a number of opportunities we're looking at in that regard." OGJ

Kinder Morgan, NextEra Gas Pipelines



SOURCE: REXTAG

Cumberland Project



SOURCE: REXTAG

Kinder Morgan's project with the Tennessee Valley Authority would supply natural gas to a proposed power plant after a coal-fired plant is retired.

MIDSTREAM

Gas Execs: US Pipe Dreams 'Not Dead'

Securing permits is challenging, but regulators could pivot as market signals change, natgas value-chain leaders say at CERAWeek by S&P Global.

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The chance of adding more long-haul pipe in the U.S. "is not dead. It's challenging," an Enbridge executive said at CERAWeek by S&P Global in March.

To get more gas now to additional LNG export trains and other demand centers, "all pipelines pretty much are full," said Cynthia Hansen, Enbridge president of gas transmission and midstream.

An act of Congress was required last year to complete the Mountain Valley Pipeline project, which will get more Appalachian gas into the southeastern U.S. beginning this year.

But the similarly southeasterly directed Atlantic Coast Pipeline (ACP) was scrapped by its developer in 2020 after 98% of easements were already acquired and some pipe already laid.

Hansen said opportunities currently are in existing-pipe expansions—via increased compression—and laying new pipe along existing right of way.

"That gives you some opportunities … but anything right now that has to go through permitting will have challenges," she said.

"It is hard to build new right of ways. So, you look at how you can maximize your existing infrastructure. Can you upgrade it? Can you add compression or can you do the looping?"

Skittish developers

Pipeline developers are skittish today about giving a new project a try, seeing the impasses others have met, said Corey Grindal, COO of LNG exporter Cheniere Energy.

"[With] Mountain Valley being a perfect example [and] ACP basically calling it quits with a lot of the opposition that they got," he said.

"But I don't think that it's dead. I'm a believer in market economics."

More U.S. gas-production potential is known and demand for it is growing—from LNG export facilities, power generators and industries that are re-shoring in the U.S.

"You're going to start seeing the market send signals and, at some point, the signals will get to where people are willing to take the … risk to develop additional infrastructure," Grindal said.

Skittish regulators

Regulators themselves are also skittish, said Martin Hupka, president of LNG and net zero, Sempra Infrastructure. Those "market signals that may come may be worse than regulators are looking for."

"Those market signals that may come may be worse than regulators are looking for."

MARTIN HUPKA, president of LNG and net zero, Sempra Infrastructure

The U.S. power grid is increasingly unstable already, according to a senior executive with Vistra Corp., which produces and distributes power in 26 states. And additional experts expect demand to surge from more electric vehicles and growth in energy-intensive AI-chip data centers, further stressing the grid.

At the same time, U.S. LNG exports are 14 Bcf/d with an additional 17 Bcf/d under construction on the Gulf Coast. Further, 16 Bcf/d has received federal permits and is nearing construction, totaling more than 30 Bcf/d of additional demand coming online during the coming decade, according to developers' reports and the Federal Energy Regulatory Commission.

"LNG occurred because the [U.S.] resource was there," Cheniere's Grindal said. "It was economic, the world needed LNG and the U.S. had the cheapest price at the time. So, yes, I think that it can continue to grow."

Gas as decarbonizer

Grindal added that he doesn't see the growth of LNG or power as being in opposition to decarbonization.

"LNG is essentially a decarbonizing tool for the world," he said.

The advent of U.S. shale gas production and existing pipe—some of it more than 100 years old—are "what allowed us to displace so much coal with gas-fired power plants."

Since shale gas, power generation coal-to-gas switching has driven annual U.S. greenhouse-gas emissions down more than 1 billion metric tons, according to the Environmental Protection Agency.

But coal remains one-third of the world's fuel

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CYNTHIA HANSEN, president of gas transmission and midstream, Enbridge

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COREY GRINDAL, COO, Cheniere Energy

stock, Grindal noted.

"If there is that much coal still operating in the world, LNG is part of the decarbonization process to get countries and companies off of coal to using natural gas."

Expansions, efficiencies, simple physics and engineering will drive down the gas supply chain's emissions. "We'll be able to get more from the [gas] production that we have, from the pipelines that we have [and] from the LNG facilities that we have," Grindal said.

Sempra's Hupka said LNG developers are looking in real time at what "your molecules need to look like in 2030," so LNG that's been decarbonized–via methane reductions, carbon sequestration and other net-zero means, "could be the most attractive molecules on the market."

The permit pause

In the midst of the greater call on U.S. natural gas from allies abroad, the White House has suspended permits to additional LNG trains while reviewing LNG's carbon footprint.

Grindal said it's encouraging that the Department of Energy is taking public comment in its review. "This is the third one of these analyses that they've done. This is the first time they've given the public a chance to comment.

"So that's where [Cheniere] will get involved–when that comes out."

Qatar will produce the LNG the U.S. won't deliver, he added. But he thinks the U.S. will figure it out.

"If you look at what the U.S. has been so good at for a long time, it's taking something and making it better," Grindal said.

When project engineer Bechtel Corp. gave Cheniere the keys to its first nine LNG export trains, "They said, 'Here. These things will [each] produce about 4.5 million tonnes [of LNG per annum]."

Grindal's motto is to "never sell short an engineer."

"Those trains now produce 5 million tonnes," he said. OGI

MIDSTREAM

Segrist: The LNG Pause and a Big, Dumb Question

Trying to understand the White House's decision. Is it just a red herring?

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Well short of a year into the business of covering the energy industry, I don't kid myself about having raised my knowledge of the ins and outs of the gas and pipeline world to anywhere near sufficient levels.

The business is deep, complicated and enormous. There are days when, after learning about the existence of a major industrial sector I previously knew nothing about, I feel like I've somehow managed to go backward.

On the other hand, one of my journalism professors at the University of North Texas said that you have a couple of advantages when you start out: freedom to ask anything and take risks that more experienced reporters would avoid. He did not add that this was because no one expects you to know anything, but I filled in that blank.

Even though I heard it decades and two or three careers ago, the lesson about asking the big, dumb question came to me when I was thinking about the White House's LNG pause and about the further implications.

Mainly: Does the LNG pause also target the Permian crude business?

Quick answer: No, it does not.

More on that in a bit, but here's how the question popped up in my head.

In January, the White House announced that the Department of Energy would pause awarding permits to new LNG export facilities seeking to sell to countries without a free-trade agreement with the U.S. Since all LNG terminals do business with countries without a trade agreement, the pause essentially delays the completion of any new non-permitted U.S. LNG projects.

The government said it needed time to study the community effects caused by a facility that contributes to greenhouse-gas emissions, and that the pause would not have a large impact on LNG export capacity before it ends.

The energy industry says the move will cause more pollution as potential customers turn to coal or other, not-as-environmentally-conscious producers in place of LNG. Energy advocates said the pause sent a signal that the LNG industry was facing more political scrutiny, and the ultimate effect would be to chill further development overall.

Publicly, the move came off as a straightforward political sop to the environmentalists President Joe Biden needs to win re-election, as noted in most of the stories that announced the decision.

"This pause on new LNG approvals sees the climate crisis for what it is: the existential threat of our time," Biden said about the decision. The White House posted a press release touting the decision, with quotes from young environmental leaders and TikTok influencers above the statements of senators and senior administration officials.

Whereas I am sure that "Hulk" actor Mark Ruffalo ("THIS IS A BIG DEAL! @POTUS…") is sincere in his support of the decision, I suspected the groundswell of support was not entirely organic.

The White House rolled out the decision in the public, yet opaque, way that causes a lot of people to resent modern journalism. "Unnamed sources with knowledge" discussing the policy change first appeared in multiple stories in Politico, Bloomberg and the New York Times starting in early January.

The publications all released stories early on Jan. 27, the day the White House formally declared the policy.

It was the largest policy announcement for the administration since the Environmental Protection Agency had released new guidelines on methane emissions in December 2023, during climate talks in Dubai.

As both of these policies came right one after the other, I thought they might be connected.

Seeking connection

The new methane regulations seek to curb emissions through the reduction of flaring and monitoring of facilities related to the production of oil and gas. The policy continues to be developed and adopted by some other federal agencies. On March 27, the White House released finalized rules for methane emissions on public lands overseen by the Department of the Interior.

Federal lands account for almost 10% of oil and gas production, primarily in western states, such as New Mexico.

Both the LNG pause and methane regulations will have a major effect in the Permian Basin. The Permian produces more crude than any other region in the U.S., and

Freeport LNG's liquefaction construction, shown as a model, could be hindered by election year politics.

SOURCE: FREEPORT LNG DEVELOPMENT

thanks to the chemical makeup of the play, the basin also produces a lot of associated natural gas.

About one-fifth of U.S. natural gas was produced in the Permian in 2023, according to the Energy Information Administration. In 2023, gross natural gas production averaged 23.3 Bcf/d.

Takeaway capacity in the region is extremely tight—so tight that spot natural gas prices at the Waha Hub went into negative territory over a period of two weeks in early March. Prices had fallen while Kinder Morgan performed maintenance on one of the region's primary egress lines, the El Paso Natural Gas pipeline.

Producers in the region, and throughout the U.S., are waiting for more LNG export plants to come online to vacuum up the country's oversupply of natural gas. The EIA has been recording new storage records since December.

The thought hit me after the Waha Hub news broke: Could methane regulations and a stifling of LNG export growth cause such an oversupply of natural gas that crude producers would curb operations?

According to the analysts I asked, the answer is no, as the situation is more complicated. First, extra natural gas takeaway for the Permian is expected soon. The Matterhorn Express Pipeline is slated to come online sometime in 2024.

"As Matterhorn comes online there will be a window of excess gas capacity through 2027, preventing the Permian from having a need for excess flaring," said Alex Gafford, an analyst with East Daley Analytics.

East Daley also believes Permian natural gas production growth will slow from 2023 to 2024, thanks to the industry consolidation in the area. Public producers, with a larger market share, will probably have more conservative drilling operations.

Hinds Howard, a portfolio manager for CBRE, said he could see natural gas restrictions curbing production in the Permian, but not in the immediate future.

"There is a chance someday that associated gas production levels could be so high that, if there were restrictions on flaring, it could restrict production in the Permian Basin," Howard said. "But I don't believe the LNG export pause will be the catalyst that leads to that outcome."

I learned one lesson from asking the dumb question. The LNG pause is most likely about election year and LNG market politics. I was reminded that complicated problems can lead to creative solutions.

"If there is abundant free natural gas in West Texas for a prolonged period of time, some enterprising business people will figure out a way to use it before it becomes so abundant as to restrict oil production," Howard said. OGI

Bakshani: Midstream Has Symptoms for M&A Fever

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The midstream sector has started the new year with a burst of merger activity, a trend East Daley Analytics expects to continue in 2024. In our recent Dirty Little Secrets annual outlook, we identified several market factors that point to further consolidation ahead.

Sunoco and NuStar kicked off the 2024 dealmaking in January, announcing an all-stock merger valued at $7.3 billion. In February, Western Midstream sold off interests in six assets to multiple buyers for $790 million. Then, in March, leading gas producer EQT Corp. reached a deal to acquire Equitrans Midstream (ETRN) for $5.5 billion.

The recent announcements continue momentum from last year. In 2023, The Williams Cos. acquired Cureton Midstream and the remaining 50% stake in Rocky Mountain Midstream, and Kinder Morgan purchased NextEra Energy Partners' South Texas natural gas pipeline assets.

As the midstream sector transitions into an environment of slower growth and increasing regulations, East Daley expects the pace of merger activity to continue. We expect companies will continue to use mergers to gain scale, better position themselves to take advantage of growing export markets and optimize existing assets in the ground. Larger companies will need to source volumes to keep long-haul transportation assets highly utilized, while small-to-midcap (SMID) companies need downstream exposure to extract more fees as production growth slows.

Midstream is ripe for consolidation

The era of consistent double-digit growth is clearly over for midstream. Production forecasts have re-rated post-2020, and environmental regulations have become more stringent. Even in areas where development is needed, such as the Northeast, onerous permitting makes development unfeasible. The impact to midstream is lower demand for new greenfield projects, and slower growth.

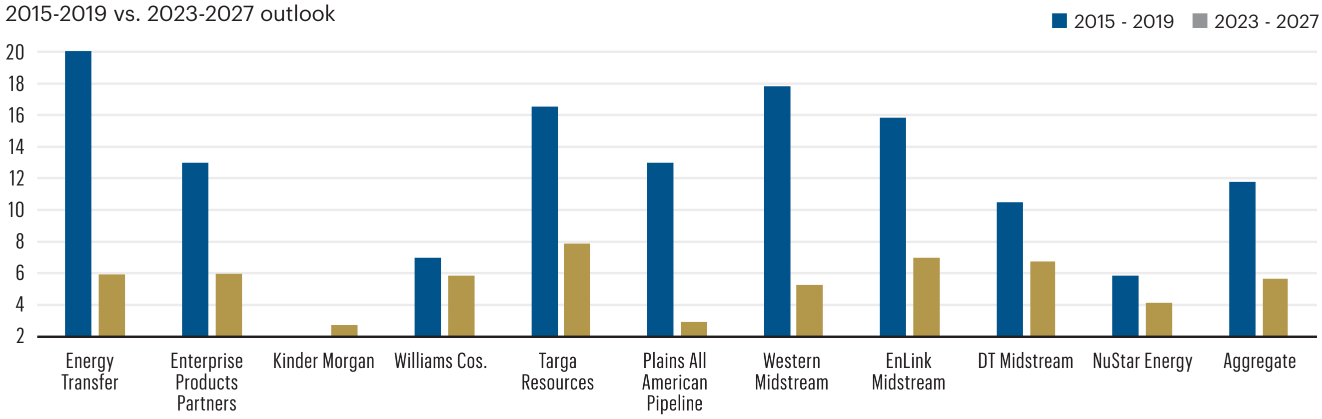
However, this state of affairs does not mean that the industry is in poor financial condition. In fact, it is the opposite case: the midstream sector is generating significant free cash flow. Most companies were on track to generate positive free cash flow after distributions for fiscal year 2023, with the median at $205 million versus -$663 million in 2019.

East Daley highlighted this wave of cash flows in 2022. We noted there were fewer opportunities for the sector to spend capital, allowing free cash flow to go to debt reduction and shareholder returns. Since then, leverage ratios in our coverage group declined to 3.8x in 2023. Balance sheets are healthier than ever within midstream. At the same time, distributions have increased 17% since 2021 to $35.6 billion (a 9% increase year-over-year in 2023 alone) and are well above 2019 levels of about $31.8 billion.

In line with lower growth expectations and concerns over terminal value, EV/EBITDA multiples for the companies we focus on are a full turn below 2019 levels. However, with limited new development opportunities, pipes in the ground will only grow in value as production grows (just not as fast) along with demand. Given improved balanced sheets, more stable production growth versus 2019 and lower multiples, the focus of capital allocation is ready to move from debt reduction and dividends to M&A.

Midstream Sector's EBITDA Growth (%)

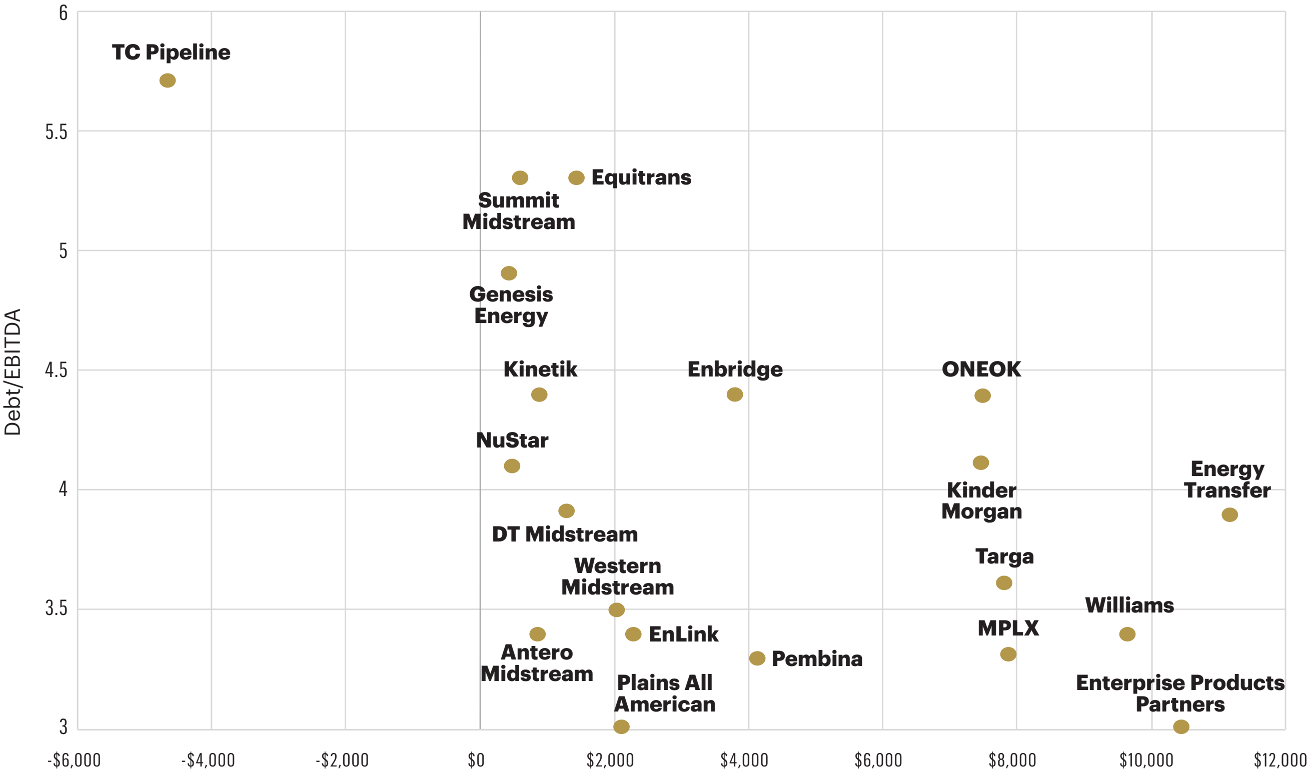
2015-2019 vs. 2023-2027 outlook



SOURCE: EAST DALEY ANALYTICS

Projected Free Cash Flow After Distributions

2023-2027 vs. leverage in 2023



SOURCE: EAST DALEY ANALYTICS

Scale, growth, longer-term value

In a slower-growth environment, midstreamers will need to look to M&A to drive growth and leverage existing assets in the ground. Scale is of utmost importance as the focus shifts from getting a slice of a growing pie to taking market share from other companies.

Vertical integration is one strategy to achieve this scale. We have already seen this happen within the NGL subsector, where major NGL players like Enterprise Products Partners, Energy Transfer and Targa Resources have spent $22.5 billion on acquisitions of G&P-focused companies. The moves indicate a shift in strategy from 2015-2020, when midstream focused on reducing price and volumetric risk by investing more in contracted, long-haul infrastructure. G&P assets have become a way to secure flows through the rest of the asset base. Vertical integration also drives the EQT-Equitrans deal, which will see Equitrans return to the fold of the parent company.

Larger companies will need to source volumes to keep long-haul transportation assets highly utilized, while SMID companies need downstream exposure to extract more fees as production growth slows. Enterprise and Targa's acquisitions of Navitas Midstream and Lucid Energy highlight this trend, as the two companies can leverage dominant Permian G&P positions to drive volume growth through their integrated NGL businesses.

Moreover, lower growth does not mean no growth. Exports, in particular, is one area that is growing across crude, natural gas and NGL. Midstreamers need to align their strategies and businesses around export demand growth, and M&A will be key to doing that as greenfield projects become increasingly difficult to build. Midstreamers have already started to use M&A to boost their exposure to this tailwind, such as Williams with its acquisition of Trace Midstream and Energy Transfer with its acquisition of Enable Midstream Partners.

Dirty Little Secrets also highlights East Daley's positive outlook on Tier 2 basins. While the Permian and Haynesville continue to be the main sources of production growth, assets in those basins are fully valued. We believe midstream has an opportunity to bargain hunt in Tier 2 basins that could benefit from higher natural gas and LNG demand. The recent acquisitions by Williams in the Denver-Julesburg and Kinder Morgan in the Eagle Ford indicate that some are already pursuing this strategy.

Separating the sharks and minnows

When looking at which midstreamers could be good acquirers or sellers, East Daley focuses on companies with positive free cash flow and low leverage.

Energy Transfer, Enterprise, Targa and Williams screen as the most likely acquirers, especially given their already large asset bases that could always benefit from bolt-on transactions. Kinder Morgan is an outlier with leverage just above 4x but lacks the same EBITDA growth profile, so we expect it could also be an acquirer. Plains All American also stands out as a potential acquirer, especially given the limited growth capex opportunities.

One thing is certain: midstream is in a position in which the sector can afford to go on a buying spree. Growth capex (ex-M&A) declined 30% from 2019 to 2023, from $42 billion to $29 billion. Free cash flow after distributions has swung from negative to positive, and leverage has trended below 4x across East Daley's coverage. With excess free cash flow and a reduced need for large greenfield projects, companies can look to M&A to drive growth and improve their competitive positioning. OGI

Blankenship, Regens: More Demand, More M&A, More Regs

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The oil and gas industry is cyclical. With each cycle, the industry adapts and evolves to meet unexpected challenges and new demands. In 2024, the oil and gas industry is dealing with higher interest rates, armed conflicts in Europe and the Middle East, rising material costs, a decrease in Tier 1 acreage, and new policies and laws.

Market participants need to be nimble and respond quickly to rapid changes. This year, we are closely watching these issues:

- growth in demand;
- M&A;
- increased regulation of ESG matters across the oil patch;
- the energy transition; and
- the integration of technology.

Demand growth

We are not at peak demand. For the first time, demand rose beyond 100 MMbbl/d in 2023, as reported by the International Energy Agency (IEA) in its December Oil Market Report. To meet rising demand, global output rose to 101.9 MMbbl/d, including an additional 20 MMbbl/d from the U.S. Both the IEA and OPEC believe that both the demand for and the production of oil and gas will continue in the near term, with the IEA predicting a rise of more than 1.24 MMbbl/d and OPEC projecting 2.25 MMbbl/d. China and India are the primary drivers of new demand, and some market analysts expect India to account for more than one-third of demand growth until 2030.

M&A

In 2023 and early 2024, we have seen a surge in M&A transactions in the upstream, midstream and oilfield services sectors. Many of these have been large-cap transactions between publicly traded companies, including the $64.5 billion deal between Pioneer Natural Resources and Exxon Mobil related to their reverse-triangle merger and the $60 billion deal between Hess Corp., and Chevron related to their reverse-triangle merger. It appears that the market is responding to the lack of available and accessible resources for extraction on an economic basis. The access to premium Tier 1 acreage is becoming more limited.

Despite an increase in M&A activity, we still expect the oil and gas industry to contract because the pressure for diversification and capital efficiency will grow stronger over the near- and mid-terms. This may in turn stimulate even more M&A activity across the value chain, particularly with a focus on the acquisition of smaller or privately held companies.

ESG

We believe 2024 will see a continuation of the focus on ESG in the oil and gas industry, including the implementation of stricter targets and performance. Government regulators, including the U.S. Security and Exchange Commission (SEC), are proposing rules that would require companies to disclose climate-related information to the public.

Private actors, including investment institutions and proxy advisers, will continue to encourage sustainable business practices and easy-to-digest metrics to gauge a company's progress through its annual voting guidelines. Many investors are pushing for compensation metrics to be aligned with ESG targets, and we expect companies in the industry to continue to develop and track their own ESG goals.

Energy transition

Many major oil and gas companies have already rebranded themselves to the market as more generalized energy and energy-transition companies, and we expect this trend to continue and trickle down to smaller players.

As noted above, Tier 1 acreage is becoming scarcer, which has led to increased exploration costs and a decline in production. Companies are diversifying to continue to grow and bring long-term returns to shareholders. The industry will be a key player in the energy transition due to its experience in developing new technologies.

Technology

Finally, the oil and gas industry will continue to be a leader in technological advancement because the industry is a "black gold mine" of data.

Artificial Intelligence (AI) may be a game changer for E&P companies. If properly developed, AI could quickly analyze historical data to provide insight into where to place the next well, build 3D seismograph images, or detail best fracking practices and procedures for specific formations. We expect that new strategic partnerships between AI developers and E&P companies will be formed in 2024 to capitalize on the transcendent growth in AI capabilities.

However, with new technologies come new risks, and industry participants need to ensure that their cybersecurity practices are keeping pace with the pace of change.

In 2024, the industry faces a variety of challenges and opportunities. Future growth in oil and gas will be driven by increasing demand, adaptation to ESG regulation and policies, the energy transition and technological developments. OGI

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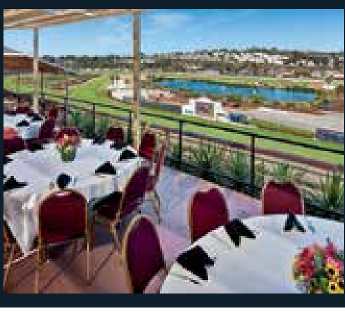

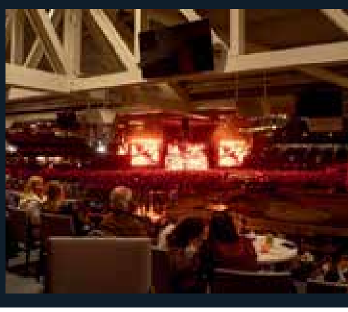


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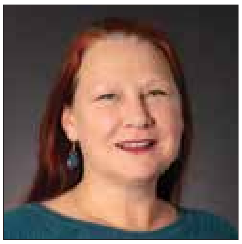
TECHNOLOGY

Tougher Tech Takes on Harsh Haynesville

The play's high temperatures and tough rock have forced drillers to evolve, advancing technology that benefits the rest of the industry, experts say.



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Challenging as it is, the Haynesville Shale's technical hurdles propel drilling and completions technology development that benefits the wider energy industry.

The Haynesville Shale, with its high temperatures and high pressures, is "not for the faint of heart," Neil Modeland, Halliburton's senior business development technology manager, said at Hart Energy's DUG GAS+ Conference and Expo in March.

High temperatures, he said, have made it difficult to acquire completion diagnostics.

"Temperature has made it difficult for any sensors, any diagnostic measurements, to go down there," he said, noting the need to rotate casing also rules out fiber optics on the backside of casing.

However, disposable fiber can be pumped into offset wells to help see frac interaction.

"You're not getting actual diagnostics from the well you're completing, but from that offset well," Modeland said.

Recent advancements with flow-through cameras make it possible to image perforations in high-temperature locations, he said.

Danielle Fuselier, well construction director for North America Land at Baker Hughes, said the Haynesville presents similar challenges to drilling operations as it does to completions. As a result, drilling rates in the Haynesville have historically been slower than in other basins.

"We've gone from mile-a-day wells in Appalachia to now 2.5- to 3-mile-a-day wells. Here in the Haynesville, it's a good day if you can do 1,000 feet," she said.

Harsh Haynesville

One of the biggest challenges in the Haynesville involves technology that can survive the play's harsh environment and deliver efficiencies common to other regions, Fuselier said.

Historically, the drill bit has been one of the limiters in drilling efficiency in the Haynesville, but advances in materials sciences, different geometries, non-planar shapes and flow that evacuates the cuttings all work to keep the cutting edge sharp and efficient, Fuselier said.

Drill bits have one of the fastest innovation

HART ENERGY

Danielle Fuselier, well construction director for North America Land at Baker Hughes; Neil Modeland, Halliburton's senior business development technology manager; and Hart Energy Editorial Director Jordan Blum, moderator, at Hart Energy's DUG GAS+ Conference and Expo.

SOURCE: HALLIBURTON

Halliburton says its simul-frac operations achieve greater drilling efficiencies and can double the gains in lateral footage. While the Haynesville has been home to some simul-fracs, they are not standard in that region like they are in the Permian, said Neil Modeland, Halliburton's senior business development technology manager.

cycles in drilling, she said, which has helped deliver some "phenomenal" gains in drilling. In the past, bits only lasted 2,000 ft to 3,000 ft when drilling the Haynesville's intermediate section.

"We're doing 6,000 ft [intermediate section] runs with one bit," Fuselier said. "From a technology standpoint, I'm pretty pumped about the future."

Materials science has also helped with mud motors.

Temperatures of 340 F are "no longer that critical threshold, and as we've coupled that with new power section designs, the high temp is not necessarily what's holding us back in those spaces," Fuselier said.

Advances in electronics have been a key enabler, she said.

"In terms of durable environment, we've come a long way. Electronics have become much smaller," she said.

Baker Hughes has been developing high temperature capabilities, she said, and some early testing in Mexico and China generated promising results. She said Baker Hughes is in the early stages of bringing some of that into the U.S. land market.

Under pressure

Completions in the Haynesville remain difficult, Modeland said.

"It's got probably the highest cost of completions just in the intensity of what we're doing. And then the pressure side, the horsepower requirement," he said.

While the Haynesville has been home to some simul-fracs, they are not standard in that region like they are in the Permian where there's tight well spacing, four- to six-well pads and shorter drill and completion cycle times, he said.

"You look at the Haynesville, the drill times and the completion times are a lot larger cycle time from capital spend to getting that return. Then the well spacing's wider. You might have a couple benches … but you don't have that massive amount of wells right there," he said.

But he sees some opportunity with simul-frac and trimul-frac for the region.

"That would really be a next step game changer if we can get the logistics" sorted out for such operations, he said.

But one of the biggest opportunities in the Haynesville is refrac operations, he said. It helps, he added, that Haynesville has historically had some of the best performing refrac wells in North America.

"The cycle time on a new drill is so much longer than the cycle time on just relining an existing well with a liner and then doing a refrac," Modeland said.

He believes drilling and completions across North America will continue to get deeper and exceed 400 F, but that the industry is innovative and creative enough to meet those challenges.

And the Haynesville Shale, where some of those technologies are being developed and finetuned, is "a good playground for helping out all the other areas as well," he said. OGI

AI Chips—Natgas' New Demand-Growth Center

Top gas producers anticipate up to 16 Bcf/d in additional demand to power AI-chipped data centers.

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Power-grid operators that are already scrambling to meet current U.S. electricity demand have another thing coming: the 30-times more energy-intensive AI chip revolution.

"They're incredibly power hungry," Josh Viets, Chesapeake Energy's COO, said at Hart Energy's DUG GAS+ Conference and Expo in March.

And since AI data centers work night shifts too, that requires on-demand power generation, such as with natural gas rather than solar—or explain to a 10-year-old gamer why Fortnite doesn't work after dark. (Or just shrug and suggest Googling it.)

Viets said AI data centers—particularly those loaded with GPU (graphic processing unit) chips—in the U.S. alone may require an extra 7 Bcf/d and up to as much as an extra 16 Bcf/d.

Current U.S. natgas consumption for all uses is some 100 Bcf/d as of early April, including exports, according to the Energy Information Administration.

"Of course, that is all predicated on how much natural gas contributes to the power sector," Viets added. "But 16 Bcf/d between now and the end of the decade is a really big number."

Chesapeake will be the U.S.' largest gas producer upon merging with Southwestern Energy, totaling 7.3 Bcf/d net, combined. The deal is expected to close later this year, after clearing a federal review.

Toby Rice, president and CEO of EQT Corp., currently the largest U.S. gas producer at 6.1 Bcf/d net, told Hart Energy in March, "When you think about [it], one of these AI chips will consume about as much electricity as a Tesla."

Nvidia Corp. reportedly has a 90% market share in GPU chips, which are the next-gen chip following the CPU.

"Nvidia plans to produce as many as 8 million AI chips a year," Rice said.

Altogether AI GPUs may consume as much electricity by 2030 as current residential demand. "That would be a 20% increase in electricity demand," Rice said.

New in-basin gas use

Locating more AI data centers in northern Virginia—known today as "Data Center

HART ENERGY

Chesapeake Energy COO Josh Viets said AI data centers—particularly those loaded with GPU (graphic processing unit) chips—in the U.S. alone may require an extra 7 Bcf/d and up to as much as an extra 16 Bcf/d.

Alley"—and nearby may be a workaround to trying to get Marcellus and Utica gas out of the Appalachian Basin, Rice added.

The basin is constrained to some 35 Bcf/d, while federal regulators have denied new interstate export projects.

The basin could produce 70 Bcf/d if unconstrained, Rice said. "That's a lot of energy we have."

U.S. electricity demand may grow 81% in five years on a compounded annualized basis, John Ketchum, CEO of powergen operator NextEra Energy, said at CERAWeek by S&P Global in March.

Rice told Hart Energy, "Tech moves at the speed of light and we may not have the time to wait seven or 10 years to get nuclear facilities built to support this growth.

"The only energy source that has proven to meet rapid demand expansion is natural gas."

Can the grid deliver?

Data centers' global power-draw was 460 TWh in 2022 and may be more than 1,000 TWh as soon as in 2026, credit-rating firm Morningstar DBRS reported April 1,

ADOBE FIREFLY

citing an International Energy Agency forecast.

"AI models and data centers are energy-intensive, requiring not only the direct use of electricity for data processing and storage but also energy for cooling systems to prevent overheating," Morningstar analyst Jasper Shi wrote.

"Additionally, the energy demand from AI technology is continuous, as many … run around the clock."

U.S. generating capacity is some 1.3 million megawatts (MW), according to the American Public Power Association.

Northern Virginia uses 2,500 MW of power. Shi noted that the area's provider, Dominion Energy, told center operators last summer it couldn't serve new facilities.

Grid operator PJM, which also serves Pennsylvania and all or parts of 11 other states, plus Washington, D.C., notified customers that it will be power-short within the next five to seven years, according to power generator Vistra Corp.

Warren Buffett warned in his annual letter to shareholders in February that he has an "ominous" outlook for future U.S. electric-power supply. "When the dust settles, America's power needs and the consequent capital expenditure will be staggering," he wrote.

Berkshire Hathaway Energy has 5.3 million power and natural gas accounts in 11 states. Its generating capacity, including in the U.K. and Canada, is 36,000 MW, including capacity under construction.

U.S., not Qatar

And demand growth for U.S. natural gas won't be just domestically: Allies want AI data centers of their own. So, the demand for U.S. LNG exports will grow, according to Rice and Viets.

Viets said, "At the end of the day, what this is telling us is that natural gas will continue to play a vital role in the energy mix going forward."

Could the U.S. see more industry reshoring as a result of natural gas supply?

"We're already seeing that," Viets said. "That's even outside of the computing and data infrastructure space.

"And the reason why we can support this going forward so much better than anybody else is because of the abundance of resource that we have."

In a Hart Energy interview, Viets added, "Combined with EVs, broader electrification across the residential and commercial sectors has just created additional [powergen] upside [for] the natural gas markets."

If not for U.S. natgas, would America's and its allies' data centers be in Qatar?

Rice: "Without the shale revolution, America would be in a very bad spot." OGI

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

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EVENT	DATE	CITY	VENUE	CONTACT
2024				
Offshore Technology Conference	May 6-9	Houston	NRG Park	2024.otcnet.org
SUPER DUG	**May 15-17**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**hartenergy.com/events**
IADC Drilling Onshore Conference & Exhibition	May 16	Houston	Hyatt Regency Houston West	iadc.org
10th Mexico Gas Summit	May 16-17	San Antonio	St. Anthony Hotel	mexicogassummit.com
2024 AGA Financial Forum	May 18-21	Palm Desert, Calif.	JW Marriott Desert Springs Resort and Spa	aga.org
ASES Solar 2024	May 20-23	Washington, D.C.	GW University	ases.org
Louisiana Energy Conference	May 28-30	New Orleans	The Ritz-Carlton	louisianaenergyconference.com
Global Energy Show Technical Conference	June 11-13	Calgary, Canada	BMO Centre at Stampede Park	globalenergyshow.com
URTeC	June 17-19	Houston	George R. Brown Conv. Ctr.	urtec.org/2024
IPAA Leaders in Industry Luncheon	June 18	Houston	Petroleum Club of Houston	ipaa.org
CIPA 2024 Annual Meeting	June 20-23	San Diego	TBD	cipa.org
Carbon Management Americas Conference	June 25-27	Denver	The Ritz-Carlton	commodityinsights.spglobal.com
IAEE International Conference	June 25-28	Istanbul, Turkey	Boğaziçi Üniversitesi	iaee2024.org.tr
SPE Artificial Lift Conference and Exhibition	Aug. 20-22	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
IMAGE	Aug. 25-30	Houston	George R. Brown Conv. Ctr.	seg.org
New Energies Summit	**Aug. 27-28**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
IADC Advanced Rig Technology	Aug. 27-28	Austin, Texas	Hyatt Regency Hotel	iadc.org
Forty Under 40 Awards	**Sept. 6**	**Houston**	**TBD**	**hartenergy.com/events**
Gastech	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
SPE/ATCE	Sept. 23-25	New Orleans	Ernest N. Morial Convention Center	atce.org
2024 Gas Machinery Conference	Oct. 6-9	Tampa, Fla.	Tampa Convention Center	southerngas.org
SPE Asia Pacific Oil & Gas Conference and Exhibition	Oct. 15-17	Perth, Australia	Crown Perth	spe-events.org
Offshore Windpower Conference & Exhibition	Oct. 28-30	Atlantic City, N.J.	Atlantic City Convention Center	cleanpower.org
SEG 4D Forum	Nov. 4-6	Galveston, Texas	Grand Galvez	seg.org
DUG Appalachia	**Nov. 6-7**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
International Geomechanics Conference	Nov. 18-21	Kuala Lumpur, Malaysia	TBD	igsevent.org
DUG Executive Oil	**Nov. 20-21**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

Oil and Gas Investor

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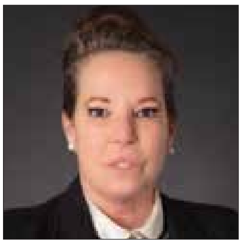
BlackRock: Live by ESG, Die by ESG



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Texas was kicking BlackRock out at press time of managing any of the $53 billion state school fund for lack of investment in Texas industries—namely, oil and gas production.

Mark McCombe, BlackRock vice chairman, replied, "Your actions put short-term politics over your long-term fiduciary responsibilities."

Meanwhile, BlackRock, which has $10 trillion under management, was getting pushback from shareholders that state it isn't "ESG" enough.

Reap what is sown?

The Texas Permanent School Fund (PSF) was set to withdraw $8.5 billion of assets from BlackRock by the end of April. The new managers will include Austin, Texas-based Dimensional Fund Advisors and Florida-based Intech, according to Bloomberg.

The PSF, formed by the Texas Constitution in 1845, dates back to a $2 million initial seed in 1854. Profits include more than $2.2 billion annually that help fund Texas K-12 schools.

Aaron Kinsey, chairman of the Texas State Board of Education, which oversees the PSF, wrote in an op-ed at RealClear in March, "What I might have guessed but didn't know for certain until I sat in the pilot's seat [in 2023] in oversight of the PSF is the astonishing rot permeating our country's financial industry….

"The nation's finance industry, headquartered on Wall Street, needs a public reckoning and that's a conversation I'm looking to start."

Blackrock, State Street Corp., The Vanguard Group and other large fund managers have proclaimed "Texas' signature industry—energy production—is evil and needs to be phased out," Kinsey wrote.

"These fund managers happily accept our money but believe that its source—the PSF is largely funded by royalties from oil and gas—needs to be eliminated in the next 15 years."

> *"The nation's finance industry, headquartered on Wall Street, needs a public reckoning …."*
>
> **AARON KINSEY,** chairman, Texas State Board of Education

Kinsey acknowledged that some fund managers have stated they are backing off ESG some but that he hasn't seen it in action yet.

Meanwhile, fund managers and the "finance ecosystem" at large, including credit-rating agencies, are sticking with "the ESG agenda, which seeks to undermine, and ultimately collapse, the economy of Texas," he concluded.

At BlackRock, the hard "G" or governance part of ESG is in plain view in its own bylaws. Three shareholder proposals are on the agenda for its May 15 annual meeting. The threshold to get in the queue is a few grand.

BlackRock's board is recommending investors vote "No" on all three.

In one, Washington, D.C.-based National Center for Public Policy Research (NCPPR), which has owned $2,000 or more worth of BlackRock stock for at least three years, wants shareholders to require BlackRock to report on "the potential risks associated with omitting 'viewpoint' and 'ideology' from its" employment policy.

"[Chairman and] CEO Larry Fink and BlackRock's executive suite make no secret not only of their own leftwing commitments, but of their intent to use their power to make other American corporations bow to their personal policy preferences," the NCPPR wrote to shareholders.

In another, London-based Bluebell Capital Partners, owner of at least $25,000 worth of BlackRock shares for at least one year, wants its fellow investors to require an independent chairman, writing that BlackRock doesn't do enough ESG-based investing.

"The lack of independent oversight within BlackRock's board can be evidenced by the numerous contradictions and inconsistencies between BlackRock's ESG strategy and its implementation," Bluebell wrote.

As examples, it cites these Bluebell investments in which BlackRock was also invested: a company increasing its thermal coal production; one that is polluting the Mediterranean; opposing 90% of owners of another company; backing a CEO who was convicted of financial fraud; and not filing suit against bank managers who systematically committed fraud.

"These examples are based on a small sample of companies," Bluebell wrote. "…. An exhaustive list might reveal a much longer list of ESG inconsistencies and contradictions."

The board replied that, under Fink's leadership as both chairman and CEO, "BlackRock has delivered … 9,000% total return since our IPO." It added that Bluebell is bitter about BlackRock not aligning with Bluebell's proxy campaigns on some investments.

And lastly, Missouri-based Mercy Investment Services, which owns at least $2,000 worth of BlackRock shares wants a review of BlackRock's voting record in its investments' shareholder proposals on climate-change matters.

"According to ShareAction, in 2022 BlackRock ranked 62nd of 68 asset managers, supporting only 28% of environmental resolutions," Mercy wrote.

BlackRock's board wrote that doing this wouldn't "be additive or yield meaningful new information." OGI