Oil and Gas Investor

SPECIAL OGI REPORT

BIG BARRELS

The Utica Rolls On

THE OGINTERVIEW

FAMILY MATTERS

Old Money Takes New Interest in Oil, Gas

STRENGTH IN DIVERSITY

Coterra Energy CEO on the Firm's North Star Philosophy

NEW ATTITUDE

Mach Natural Resources' CEO Tom Ward on M&A Strategy

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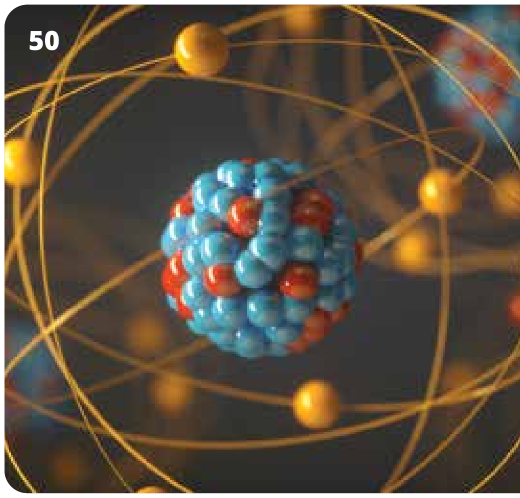
ACQUISITIONS & DIVESTITURES



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ABOUT THE COVER:
Advantage Video & Marketing's photographer captured this and other images of Encino Energy's Utica Shale operations.

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2024 EVENT CALENDAR!

The Industry's Comprehensive Resource for Live Content, Data and Analysis

The 2024 event schedule is designed to focus on the topics you want to hear about and to make scheduling your year even easier. We've decreased the number of events and pumped up the amount of content to make them larger, more informative and more engaging.

Save these dates and start planning your 2024 event schedule now!

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August 27-28
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INVESTMENT
ENERGY CAPITAL CONFERENCE
October 3
Dallas, TX

INVESTMENT
A&D STRATEGIES & OPPORTUNITIES CONFERENCE
October 23
Dallas, TX

SHALE
DUG APPALACHIA CONFERENCE & EXPO
November 7
Pittsburgh, PA

LEADERSHIP
DUG EXECUTIVE OIL CONFERENCE & EXPO
Nov. 20-21
Midland, TX

COMING 2025
SHALE
SUPER DUG CONFERENCE & EXPO
May 13-15, 2025
Fort Worth, TX

2024 CONFERENCE & EXPO BROCHURE

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Any Money Can Be Oil Money

Generational wealth from non-traditional sources is fueling growth in the oil and gas industry.

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Money is money is money when it comes to capital-intensive industries like oil and gas, which have faced some funding challenges in recent years. Investor angst over the industry's growth for growth's sake caused widespread panic during the previous decade—before E&Ps founded religion in the form of fiscal discipline.

The pandemic temporarily destroyed demand, and a skittishness toward the industry lingers. The vilification of fossil fuels sent generalist investors and some private equity running for the exits.

And new money in the form of old wealth is making an entrance.

Now investing in oil and gas with a hearty appetite for the space, firms like Stephens Inc. and Hall Capital began their investments in municipal bonds and the automotive industry, respectively. Others, like A.G. Hill Partners, which manages the wealth of legendary oil tycoon H.L. Hunt's descendants, have a longtime stake in the industry and are choosing to grow their positions, which has been split among industries including financial software, healthcare and personal products.

In this edition of *Oil and Gas Investor*, leaders at Stephens and A.G. Hill share their rationale for digging into the space, where almost a dozen other families, plus a handful of Europeans, whose roots spring from other industries are newly engaging. It makes for a fascinating story about outside interests picking up where the less faithful have fallen down.

We're also offering to you an in-depth interview with the CEO of Coterra Energy, the remarkably down-to-earth Tom Jorden. His vision of running a super successful enterprise—the firm has yet to underperform by any metric during any quarter—could be a playbook for how to run a meritocracy.

And I have to admit that noticing Coterra's tendency to name its Houston office conference rooms for a few dozen of my favorite musicians—think the Beatles, Aretha Franklin, David Bowie, Heart, Tom Petty and Ray Charles—made my heart sing just a little bit.

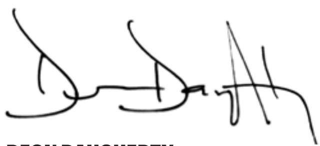
While we're on the subject of legends: Tom Ward, CEO of Mach Natural Resources, spoke exclusively with Chris Mathews, our senior editor for A&D and shale, and provided an intriguing look at the corporate strategy behind the company's MLP model and basin interests.

Rounding out a handful of my favorite stories in the following pages is a stellar look at the Utica Shale put together by Nissa Darbonne, Hart Energy's executive editor at-large. She took a field trip to the area to uncover details—and actionable ideas—that you won't read in any other publication.

But there's more.

Our team is covering the news online, too. At HartEnergy.com, you can keep a finger on the industry's pulse throughout the news cycle. And this fall, we're bringing the newsmakers to you.

Our annual Energy Capital Conference is returning to Dallas in early October, followed by the A&D Strategies & Opportunities conference. Both will feature top-notch speakers discussing the issues explored in the magazine and online. Plus, you'll be in good company for those critical networking opportunities and dealmaking dialogues. We hope to see you there. OGI



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exceptional results
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Belcher: How Overturning the Chevron Deference Will Impact Energy Regs

The decision will enable the industry to challenge an array of federal regulatory actions.

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The recent landmark decision by the U.S. Supreme Court (SCOTUS) in Lopez Bright v. Raimando (Loper) could have profound impacts on future and current rules and regulations in the United States, including those related to the energy industry.

The 6-3 decision overturned the 1984 Chevron U.S.A., Inc. v Natural Resources Defense Council, Inc. (Chevron) decision, which created the so-called Chevron deference that guided the way that courts deferred to federal regulatory agencies in decision-making. The new ruling has effectively changed the role that courts play in interpreting the intent of federal statutes, thus reducing the authority federal agencies use in interpreting regulations, increasing the role that courts play in that interpretation and putting greater pressure on Congress to be more prescriptive in writing legislation that will involve rulemakings.

Chevron deference was based on a belief that federal agencies consisted of experts more qualified than judges to determine how federal regulations should be implemented and how federal statutes should be interpreted. Many legal scholars felt that Chevron deference gave too much authority to the unelected bureaucrats who might have their own agendas about how to administer federal regulations. Energy companies were often critical of the authority that federal bureaucrats had over these decisions that are so consequential to the industry.

Chevron deference has been enormously impactful in terms of its overall effects on federal regulation. According to the Mobius Risk Group, there have been approximately 18,000 legal citations of Chevron since the original 1984 ruling. Circuit courts have applied it in 77% of agency interpretation cases, and have ruled in favor of federal agencies 71% of the time. It has been estimated that regulatory burdens and investment distortion resulting from Chevron have reduced U.S. GDP at an estimated annual

SHUTTERSTOCK

The Supreme Court's decision to overturn the Chevron deference could introduce uncertainty in the short term.

rate of 0.8%, erasing approximately $4 trillion from the economy between 1980 and 2012.

The SCOTUS majority ruled that Chevron deference was unsupported by the text of Article III of the U.S. Constitution (which establishes and empowers the judicial branch of government) and by Section 706 of the 1946 Administrative Procedures Act, which states that "the reviewing court shall decide all relevant questions of law, interpret constitutional and statutory provisions, and determine the meaning or applicability of the terms of any administrative action." In offering his opinion, Chief Justice John Roberts stated that "Courts must exercise their independent judgment in deciding whether an agency has acted within its statutory authority."

This dramatic shift will change the role that federal agencies play in setting policy and will have major implications for the oil and gas industry, which, for the most part, applauded the decision because it creates more opportunities for industry to challenge regulatory actions. However, the decision also creates more uncertainty and potentially more chaos in the short term. Some of the broader consequences of the decision include:

- It will require federal agencies, stakeholders and policymakers to adjust and readjust their expectations over time about what may be reasonable or possible to accomplish through the agency regulatory process;
- It will weaken certainty and confidence in long-established agency rulemakings that have held up for decades and are grounded in statute;
- It will open up litigation and legal challenges to decades of agency rulemakings, increasing uncertainty about current regulations;
- It has the potential to shift the balance of power and resources within the federal government away from the Executive Branch and toward Congress and the Judicial Branch;
- It will impact competitive federal funding programs where federal grant-making agencies are required to focus their grant implementation to align with congressional intent; and
- In the context of federal grant activity, it will create future questions over discrepancies between authorizing legislation and the corresponding Notices of Funding Opportunity

For the oil and gas industry, the decision will strengthen the ability to challenge federal rulemakings and decisions like federal oil and gas leasing and permitting, application of air and water regulations such as the methane rule, Endangered Species Act designations, application of the National Environmental Policy Act, and requirements for disclosure of emissions and climate risks. The decision will likely result in years of litigation over current federal regulations.

It is believed that the decision could give courts more say in a variety of ongoing issues impacting the energy industry, such as EPA's efforts to curb methane emissions from oil and gas operations, EPA's efforts to lower power plant emissions, and Federal Energy Regulatory Commission orders on pipelines and transmission lines.

Environmental organizations are expressing fear that the decision will have a negative impact on the environment and climate change by creating uncertainty about the validity of a host of environmental regulations. President Biden's climate policies are clearly at risk, including initiatives that were established and funded under the Inflation Reduction Act (IRA). Republicans may use the opinion to challenge IRA programs, which could actually hurt oil and gas companies that are pursuing investments in carbon capture and storage, hydrogen, and other decarbonization programs and technologies. It might also put at risk the notion that greenhouse gas emissions can be considered pollutants under the Clean Air Act.

> *"Challenges are also likely to be waged against ESG-related policies and rulemakings such as the Department of Labor rule that permits fiduciaries of retirement plans to consider environmental, social and governance considerations in investment decisions.*

Challenges are also likely to be waged against ESG-related policies and rulemakings such as the Department of Labor rule that permits fiduciaries of retirement plans to consider environmental, social and governance considerations in investment decisions. That rule has been described as a way to thwart investments in the oil and gas industry.

Another issue is the impact that it could have on global trade and U.S. products in overseas markets. As climate considerations such as a carbon index become more ingrained with trade policy, e.g., the European Union's Carbon Boader Adjustment Mechanism and the EU Methane Regulation, uncertainty over U.S. regulations and perceived weakening of U.S. climate policy could impact U.S. products, such as crude oil, natural gas and refined products, via the application of trade tariffs and other penalties.

Following the release of the SCOTUS opinion, White House Press Secretary Karine Jean-Pierre said that "[w]hile this decision undermines the ability of federal agencies to use their expertise as Congress intended to make government work for the people, the Biden-Harris Administration will not relent in our efforts to protect and serve every American."

As the U.S. presidential election approaches and the Biden administration faces numerous challenges, the decision to overturn Chevron deference serves to highlight the difficulties the administration has faced in moving forth its agenda.

For the Democratic base, it further adds to the frustration being felt by its inability to deliver on many promises. For Republicans who are hopeful for November victories in the presidential, House and Senate races, it sets up the opportunity to undo many Biden policies and create new ones in a second Trump administration.

For the oil and gas industry, it creates a new landscape for shaping future federal regulations and challenging existing regulations, some of which have been in place since Chevron deference was established in the 1980s. OGI


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BIG BARRELS:

MEET OHIO'S NEW UTICA OIL PLAY

After a false start in the early 2010s that went underwater with overwhelmingly low oil and associated-gas prices, a new group of Ohio drillers is going after the Utica's volatile oil window. They're talking now. Here's what they're up to.

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Ohio's new No. 1 oil producer, Encino Energy, refrained from talking about its success until now. "We knew no one was going to believe the hypothesis was proven until it had been proven–and it's proven now," Ray Walker, COO, told *Oil and Gas Investor*.

"So, I think it's time Utica oil has its due."

Six-month production from operators' 151 new Utica oil wells in 2023 grew to more than 5,000 bbl/1,000 lateral ft from some 3,000 bbl in 2022 and 2,000 bbl in 2020 and 2021, according to J.P. Morgan Securities, citing Enverus data.

Recognition of the Late Ordovician-age Utica's oil fairway has been more than a decade in the making, impeded by market forces rather than lithology and resource in place.

In the summer of 2011, Chesapeake Energy revealed it had put six horizontals and nine verticals in the rock, confirming nearly two years of industry rumors that it had been leasing.

It built the largest Utica position in the state: 1.25 million net acres.

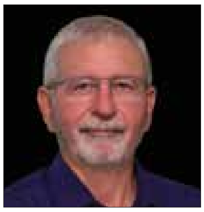
And it projected the package could be worth between $15 billion and $20 billion.

It had five rigs drilling the rock and planned to increase that to eight by year-end, to 20 by year-end 2012 and to potentially as many as 40 by year-end 2014.

WTI was $90 at the time and reached $108 in the summer of 2014.

Well Control

It had pulled 3,200 feet of core and looked at more than 2,000 logs through the formation.



"We're probably in the fourth inning of a baseball game from an optimization standpoint. There's a lot more we want to do. It just takes time."

RAY WALKER,
COO, Encino Energy

There was plenty of well control. Drilling in Ohio specifically for oil began in 1859 in Trumbull County a few months after the Drake well was made in Pennsylvania and launched what became the global oil industry.

(In 1814, the shallow Thorla-McKee well was drilled in Noble County with the intention of extracting salt. It produced salt, but it also produced oil, which the well's partners bottled and sold as a topical medicine: "Seneca Oil.")

(John D. Rockefeller, 20 years old in 1859, formed a transportation company that year in Cleveland and Standard Oil in 1870.)

And oil is found where it's been found before: In 1884, a discovery in the Trenton Limestone, which underlies the Utica, set off a boom in the state, lasting 20 years and culminating between 1895 and 1903 with Ohio ranking as the No. 1 U.S. oil producer.

In 1896, the state made a then-record 23 MMbbl or 63,000 bbl/d, according to the Ohio Department of Natural Resources (DNR).

Another 78,000 wells were made by the early 2000s in the Early Silurian-age Clinton Sandstone that overlies the Utica.

By 2011, there were logs of more than 220,000 productive verticals throughout the state and some 60,000 were still producing, according to the DNR.

Also by then, Ohio drillers had made more than 1 Bbbl and 9 Tcf from 69 counties and 30 formations–mostly limestone, dolomite and sandstone–ranging from Pennsylvanian to Cambrian at between 50 and 10,300 feet.

Patterson-UTI's walking rig #571 was making four laterals for Encino Energy in the area of Tuscarawas and Harrison counties, Ohio, in late May.

ADVANTAGE VIDEO & MARKETING

ADVANTAGE VIDEO & MARKETING

A pipeline snakes alongside a road in the Utica Shale, a play that is considered on par with the premier unconventional plays in North America.

'Uticulous'

When Chesapeake announced its Utica oil play in 2011, research analyst Michael Bodino, who is now with the investment-banking group at Texas Capital, took a look.

He declared it "Uticulous."

The first four horizontals each IP'ed more than 1,000 boe/d. "If the play wasn't on your radar screen before this announcement, it definitely should be now," Bodino reported.

By 2014, Chesapeake and others had landed 925 wells in the Utica.

But later that year, OPEC refused to pare its output, while Permian Basin shale was on a trajectory to what is 6 MMbbl/d today.

By early 2016, WTI was as low as \$26/bbl, according to historical EIA data.

The Utica oil window's associated gas' economics had tanked, too, as the Marcellus—and then the Haynesville—overwhelmed U.S. gas demand. The price fell below \$2/MMBtu in spring 2012 from as much as \$13/MMBtu in 2008, according to the EIA.

Rigs were stacked. Ohio's oil output fell from 73,000 bbl/d in 2015 to 55,000 in 2017, according to the DNR. In 2021, it was 44,910 bbl/d.

But the numbers have turned around in this decade. The state's first-quarter 2024 oil production was 79,423 bbl/d as privately held Encino, Ascent Resources and Infinity Natural Resources picked up past operators' fallow acreage and began making new holes.

Ohio Operators' Oil Production, 1Q 2024 (bbl)

Ohio Operators' Oil Production, 1Q 2024 (bbl)	
EAP Ohio LLC/Encino Energy	3,708,011
Ascent Resources Utica LLC	1,576,362
EOG Resources Inc.	564,044
INR Ohio/Infinity Natural Resources	540,096
Southwestern Energy Co.	398,963
Antero Resources Corp.	262,027
Gulfport Energy Corp.	148,916
Equinor ASA	19,770
Sound Energy Co. Inc.	4,346
Pin Oak Energy Partners	2,706
Northwood Energy Corp.	1,015
CNX Gas Co. LLC	746
Holbrook LLC	332
Diversified Production LLC	169
GeoPetro LLC	0
Hilcorp Energy Co.	0
EQT Corp.	0

SOURCE: HART ENERGY VIA OHIO DEPARTMENT OF NATURAL RESOURCES DATA

Still, investors hadn't been making much of what was underway, while the Permian was throwing shade on other Lower 48 oil plays and privately held E&Ps without Wall Street coverage dominated.

That was until November 2022: EOG Resources—famously choosy about where it will make new holes and typically spot on in its choices—confirmed that it had amassed 395,000 net acres in the Utica's volatile oil and black oil windows.

Also, it acquired minerals under 135,000 acres.

In May, it declared that the Utica oil window will "compete with the best plays in America" and wells are "very comparable to the Permian on a production-per-foot basis, both in oil and equivalent."

Encino's Origin Story

In the first quarter, Encino averaged 40,747 bbl/d, up from 19,765 in 2020.

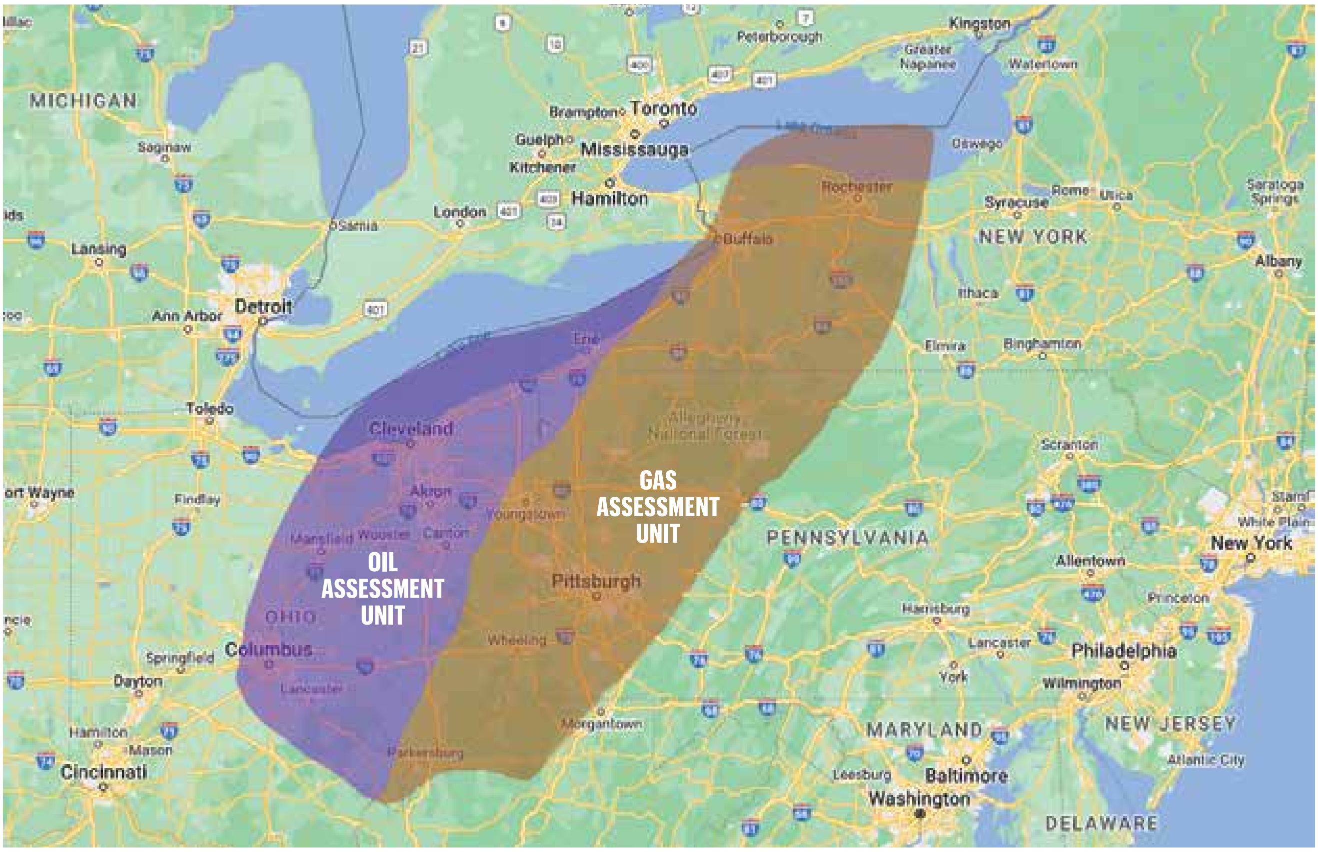
The company's Ohio oil story began in 2018.

Ray Walker was retiring from Range Resources, where he was COO, when he got a call from his old boss, John Pinkerton, Encino's executive chairman.

Encino had been founded in 2011 by Hardy Murchison,

Drilling operations underway at Encino's Berger pad and an e-frac underway at its Stocker pad.

Utica Shale Oil and Gas



SOURCE: U.S. GEOLOGICAL SURVEY

Encino Energy's Ohio Oil Portfolio	**1.1M** net acres	**1,000** wells	**95%** HBP acreage	**936** MMcf/d of associated gas and NGL	**40,747** bbl/d of oil

who had worked on portfolio investments at First Reserve and began his career as an energy investment banker. Murchison had worked for Pinkerton in the 1990s.

"Until about 2016," Walker said, "Encino had focused on smaller acquisitions, mineral interests, small things."

Pinkerton began his career with Range via a predecessor in 1980, long before shale development. Over the years, he had worked the Appalachian Basin's conventional oil and gas fields of Ohio, Pennsylvania, West Virginia and Virginia.

And Range eventually accumulated 1.7 million net acres.

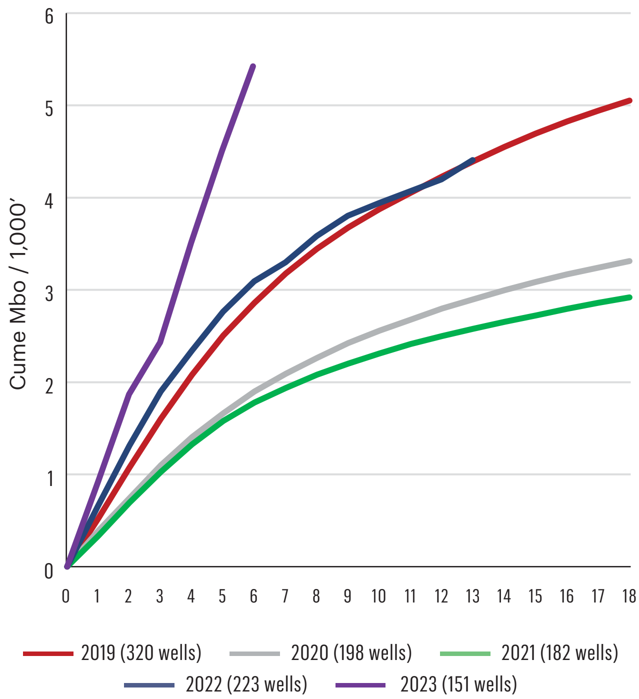
In 2004, it drilled an initial Marcellus well and launched full-field horizontal development in 2007. By then, Pinkerton was Range's president and CEO.

Walker had joined in 2006, opening the Pennsylvania office that would be headquarters for the Marcellus, which eventually became Range's entire portfolio.

Since Murchison had been at Range before Walker, they hadn't met, "but John was sort of the bridge," Walker said.

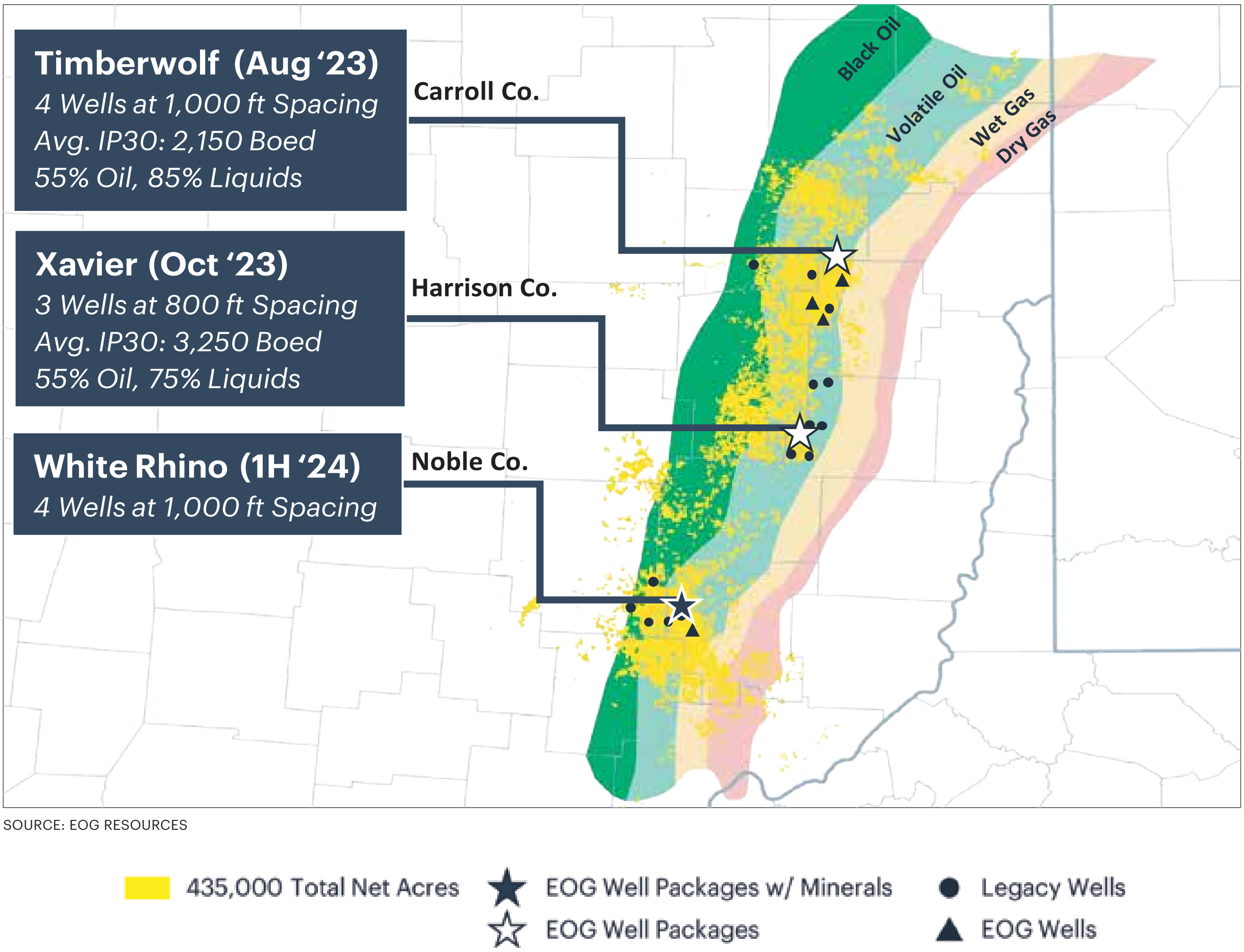
Pinkerton resigned from the Range board in the spring of 2016 to join Murchison at Encino, taking the executive chairman position. They began looking at large asset packages other operators might sell. Not only was WTI just crawling out of a $26 low, gas was still below $2.

Utica Oil Cumes - Annual



SOURCE: JP MORGAN

EOG Utica Wells



SOURCE: EOG RESOURCES

"These companies had multiple assets in different basins that were going to be challenged," Walker said.

Pinkerton and Murchison settled in on one particular target—one Pinkerton knew well and that both he and Murchison had worked in their time at Range many years before: Ohio oil.

Pinkerton had drilled through the Utica plenty of times in his earlier career, putting verticals in the Trenton Limestone. Some 16,000 wells targeted that formation through the early 2000s, according to Bernstein Research.

Chesapeake still had a large footprint of HBP'ed property in the volatile oil window. Its Utica oil production had declined in 2017 to 10,000 bbl/d, according to an annual report.

The behemoth investor Canada Pension Plan Investment Board (CPP Investments) liked the look of it, too. In June 2017, it showed up with a $1 billion commitment, forming Encino Acquisition Partners (EAP) for 98% interest. The Encino Energy team committed an additional $25 million.

"The Canada Pension Plan was key to the story," Walker said. "They were really attracted to the fact that John and Hardy had a big idea."

Encino signed a deal for the Chesapeake property in July 2018 for $2 billion. Walker rejoined Pinkerton in September. The deal closed in October.

"When we took over the Chesapeake asset, it was about 900,000 net acres and about 600 MMcfe/d from about 900 operated wells, all horizontal," Walker said. The leasehold was 85% HBP.

Today, Encino has 1.1 million net acres and 1,000 wells, making 40,747 bbl/d of oil and 936 MMcf/d of associated gas and NGL. Its acreage is 95% HBP.

Oil and NGL make up about 40% of the mix, "but about two-thirds of our revenue is oil and NGL. Liquids are worth so much more than gas," Walker said.

In this past first quarter, Encino produced 3.7 MMbbl of oil, averaging 40,747 bbl/d. Its 2023 oil production was 13.9 MMbbl, averaging 38,019 bbl/d.

It's running four rigs and two completion crews—the most among all operators in Appalachia, including those drilling the Marcellus in Pennsylvania and West Virginia, as of mid-June, according to Enverus data.

"We're the most active operator in Appalachia now and we're enjoying that," Walker said.

Modern Completion

As Chesapeake was putting its leasehold together, it also put together firm transportation (FT) and minimum-volume commitments (MVC) for the takeaway.

The takeaway is ample. The late Aubrey McClendon, Chesapeake's co-founder, "did a lot of good things," Walker said, "but one of the good things he did here is he

Encino Energy has established itself as the No. 1 liquids producer in the Utica Shale.

went really big.

"He leased a bunch of land. He came in with a bang, drilled a bunch of wells and bought a ton of FT very early on."

When Encino took over the asset in late 2018, it went to work on, at least, raising production to meet the FT and MVCs, which the property was underwater on. "It took us about a year to get things back in shape," Walker said.

And then COVID happened. WTI fell from a New Year's start of $60/bbl to about $40. In a trading anomaly, it closed at a negative $37 on April 20, 2020.

Natural gas demand fell, too: The price was $1.42/MMBtu and tankers of U.S. LNG were at sea without orders.

In 2021, though, WTI improved to $70.

"We started in earnest on the oil play because we knew there was a lot of potential there that was untapped," Walker said. Despite a decade of work by then, "people didn't know how to get it out."

While the dolomitic Middle Bakken oil play had been underway for more than a decade by 2011, it had two frac barriers: the Upper and Lower Bakken shales. Meanwhile, making economic wells in the Permian's oily tight rock had only just begun.

There wasn't a recipe for how to make an economically successful, stimulated, horizontal Ohio oil well, specifically.

Encino reentered a few Chesapeake Utica oil wells with a modern completion. But, with plenty of new-drill opportunities in its leasehold, "it's hard to justify [recompletions]," Walker said.

"It's just cheaper to go drill new wells and it's a better use of our capital."

CPP Adds $300MM

The new-drills are making headlines. Five wells on one Encino pad, the Burdette in Harrison County, took all Top Five spots in Ohio's first-quarter oil-production ranking.

Burdette was brought online Dec. 1. In its first four months, it produced 740,162 or 1,213 bbl/d of oil per well.

Meanwhile, Encino's Oliver pad's four wells in Carroll County produced 450,281 bbl in their first 91 days of full production.

In Columbiana County, Encino returned to the 2012 vintage one-well Sanor Farms pad in 2023 with four new-drills, producing 421,903 bbl combined in their first 184 days online.

In April, CPP Investments made another $300 million investment in Encino toward accelerating development.

The investment horizon is long. A private-equity fund typically aims to monetize an investment within seven years; a pension plan seeks returns from harvesting in situ–via dividends.

"They're very long-term focused," Walker noted. "And they focus a lot on [asset] sustainability, low risk and good, solid returns."

At Encino's current four-rig count, it has 10 years of core inventory–what works at $40 and $50 oil. It is continuing to lease. "And we're filling in holes in what we already have. But we're not looking to just buy somebody."

Infinity Natural Resources

Zack Arnold was among Chesapeake team members who drilled those Utica wells in the 2010s.

A petroleum engineering grad of Ohio's Marietta College, Arnold and four colleagues from his Chesapeake and Northeast Natural Energy days formed Infinity Natural Resources in 2017 with private equity from Pearl Energy Investments and NGP.

"We recognized quickly what EOG has now said out loud: These are high-quality oil wells."

ZACK ARNOLD, president and CEO, Infinity Natural Resources

No. 4 in first-quarter 2024 oil production

60K acres in Ohio

30K acres in Pennsylvania

Based in Morgantown, W.Va., the group–all career Appalachian drillers–kicked off by putting horizontals in the Marcellus in Pennsylvania.

In 2021, it went to work in Ohio, picking up a package in Carroll County from PennEnergy Resources for $32 million.

And, like Encino, Infinity came for the oil.

"We focused on well returns," Arnold, Infinity president and CEO, said. "In Ohio, that points you to the volatile oil fairway. If you're in a dry-gas or a wet-gas environment, your single-well economics are more challenged."

His and colleagues' familiarity with Ohio's Utica "gave us a bit more confidence in understanding how the rock would perform with modern techniques–the right fluids, sand loadings, landings and, then, longer laterals, of course," he said.

"We were confident that modern completion optimization would result in our wells outperforming the historical dataset."

The past demise of the Utica oil play wasn't because of the rock. "Each operator had its own focus."

Sometimes the priority was to fulfill MVCs. "Sometimes they spent the least amount of capex possible because they were having financial problems. Sometimes they were seeking gas; sometimes they were seeking oil.

"So, each of these operators had their own drivers."

All the data was there. "But it was kind of cloudy as to what anybody had done at any point in time and why they did it," he said.

Except for Chesapeake, that is. Because Arnold had worked on many of those Utica oil wells, "I got to see a lot of what they did and I understood some of the context."

Perry Pad

Upon closing the PennEnergy deal, Infinity picked up a rig and drilled three Perry pad wells in Carroll County, bringing them online in November 2021.

"We really liked the return profile and were excited to confirm our view of the play," Arnold said. "We recognized quickly what EOG has now said out loud: These are high-quality oil wells."

The three Perry wells' first-36-day average was 628 bbl/d each and production through this past March 31 totaled 520,414 bbl, or 202 bbl/d each, in their first 28 months, according to the DNR file.

First-quarter production was 80 bbl/d from each.

From its anchor position in Carroll County, Infinity began bolt-on leasing. In October, it added Utica Resource Operating's portfolio, gaining 49 wells, all producing oil and 39 of them in Guernsey County. The price is undisclosed.

Among the adds is the two-well Stillion pad in Guernsey County that Utica Resources brought online in April 2023. First-361-day production was 341,200 combined or 473 bbl/d per well, according to DNR data.

Adding the portfolio to its own, Infinity held the No. 4 rank in first-quarter 2024 oil production, overcome by EOG, which had three pads for a total of 11 new wells online before quarter-end and rising to the No. 3 position.

To further add to its Guernsey position, Infinity won a bid earlier this year to drill under Ohio's Salt Fork State Park, picking up 5,705 net acres.

It now has 60,000 net acres in Ohio and 30,000 net in Pennsylvania.

Its Ohio oil output on June 30 was some 14,500 bbl/d gross and 10,000 bbl/d net from 111 operated horizontal wells.

It's looking to continue to add leasehold.

The Frac Recipe

Operators are landing in the porosity-enhanced dolomitic Point Pleasant member of the Utica Formation. (The Ohio Supreme Court sent a lease dispute back to a lower court recently that questioned whether leasing the Utica includes rights to the underlying Point Pleasant.)

Like Chesapeake had estimated in 2011, Encino's Walker said the Utica compares more to the Eagle Ford than it does the Permian's Wolfcamp in reservoir characteristics. The formation has no water, he added.

"The only water that we produce out of these wells is what we put in them. That's an added advantage to the economics: We don't have a lot of produced water to get rid of," Walker said.

In comparison with the Marcellus, Infinity's Arnold said, "the TOC of the Marcellus tends to be higher, near 6%, and the Utica tends to be closer to 4%."

Typically, Infinity pumps about 2,200 pounds of sand per foot in the Utica.

"We're doing a very similar job as most of our neighbors. I think we all have non-op positions in each other's wells in Ohio once you get a meaningful scale," Arnold said.

The frac formula is consistently similar when moving north and south, east and west, he added. "Each operator probably has its own flavor, but I don't think there's a widely variable design at this point in the volatile oil window."

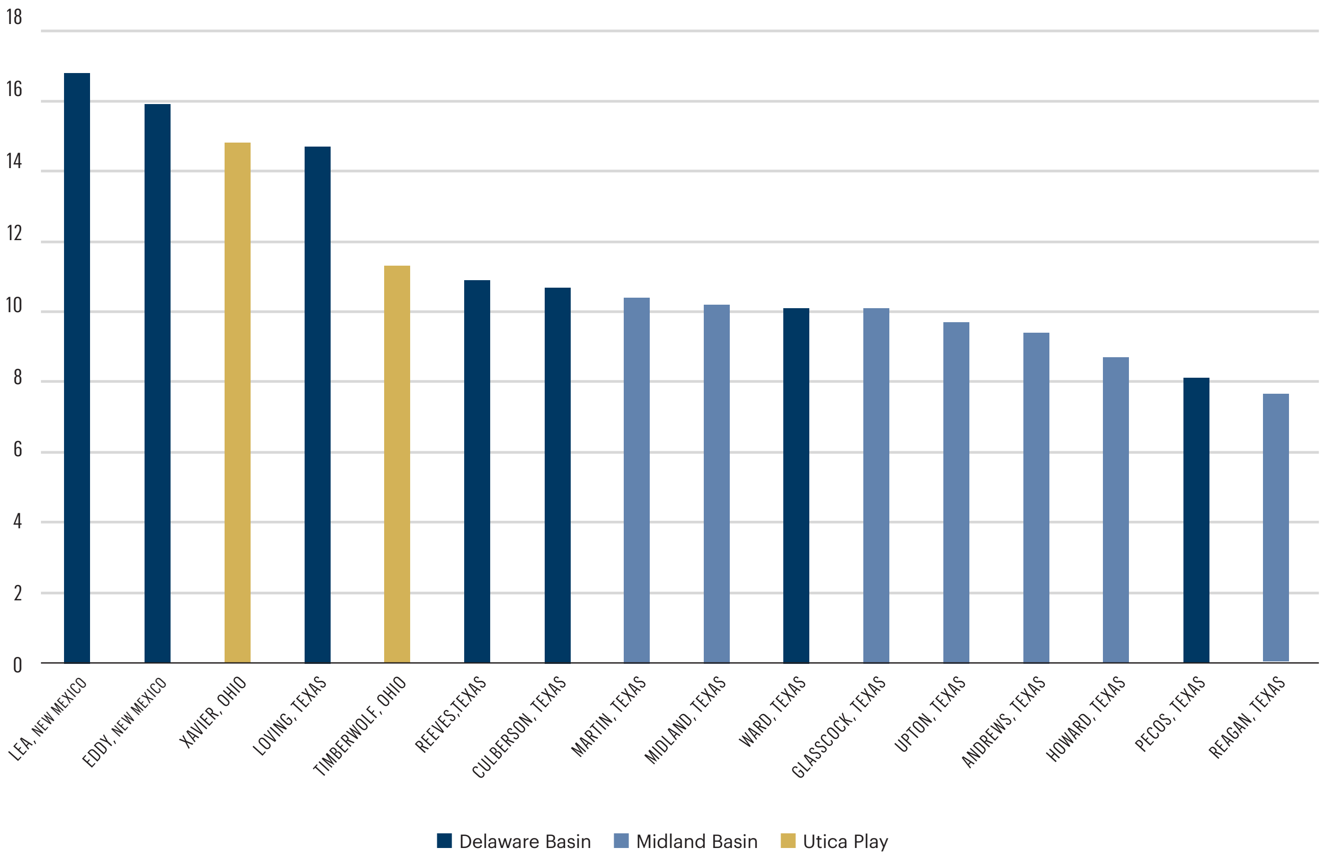
Any change in the formula is more likely to come from whether it's completing wells at 700-foot spacing or 900-foot spacing. "Or are we co-developing?" Arnold said. "Those philosophies are going to drive our recipe much more than which county we're in."

The Bauer Pad

Meanwhile, Encino is keeping its current D&C recipe tight but Walker said the formula will vary from well to well.

EOG Resources Utica Wells vs. Permian Wells

bbl/ft, 2022-2023



SOURCE: ENVERUS

At its Bauer pad in Carroll County, the five wells were completed with 2,225 pounds of sand and 70 bbl of slickwater per foot in stages some 200 feet apart. Spacing was 800 feet.

Lateral length averaged 18,600 feet. The wells made 1.68 MMbbl through March 31 since coming online in July of 2022, according to the DNR.

One of the wells had a first-30-day IP of 1,948 bbl/d. Reserves are 875,000 bbl per well or 47 bbl/ft. Cost was $650 per lateral foot.

Encino's IRR at $60 oil and $3 gas is 84%. Drilling averaged 2,100 ft/d.

Wells on the pad prior to Encino taking over the lease had been completed with 1,812 pounds and 27 bbl/foot. The fluid was gel. They averaged 9,400 ft in lateral length.

Spacing was 1,000 ft for four wells. The cost was $900/lateral foot. Reserves were 367,000 bbl per well or 39 bbl/ft.

The IRR was 5% at $60 oil and $3 natural gas. Drilling averaged 1,500 ft/d.

"We're not necessarily focused on making the most production or the biggest barrels per foot or even getting the lowest cost per foot," Walker said. "We're truly focused on the best economics rather than just looking at the oil rate for the first 12 months."

Big IPs make headlines, "but if you spent too much money, it was a bad economic decision."

More than 200 wells into the oil play now, Encino's results are "still getting better," he added. "We're probably in the fourth inning of a baseball game from an optimization standpoint.

"There's a lot more we want to do. It just takes time."

Geologically Quiet

The Utica is mostly homogenous across the oil window in contrast to some other oil plays, but there are variations, particularly when moving west.

Walker said, "It's a gradual change from the [far eastern] dry-gas side of the field to the [far western] black oil side of the field. You're changing depth."

But the formation is quiet. "There's not a lot of structural complexity. There's not a lot of geohazard." Wells are landed in a 10- to 15-foot window.

Arnold said the Utica oil fairway is an easier drill than Infinity's Marcellus wells in Pennsylvania—again, because the Utica fairway is geologically quiet.

"We can do very long laterals with very few changes to our directional plan."

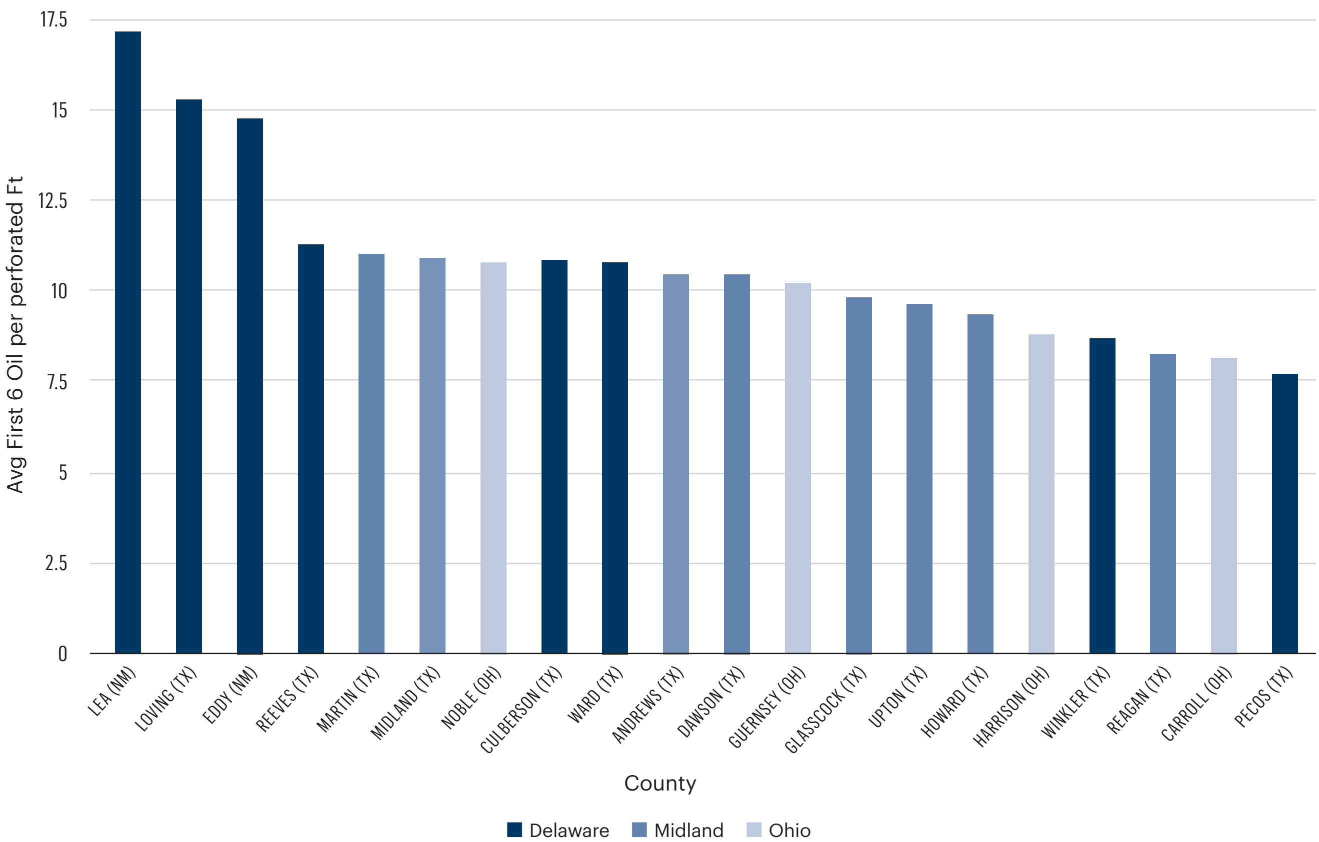
Infinity TD'ed a 14,000-footer in mid-June that stayed in the 3.5-foot zone the entire time.

"That's hard to do in some areas of the Marcellus because you have more complexity and you have to chase that formation a little bit more," Arnold said. "We don't have to do that in Ohio."

Still, the difference isn't meaningful. "It just might save you a day on rig time."

That particular well is on a pad that had four existing wells. "It's what we do right now—return to pads that have

First-Six-Month Ohio and Permian Basin Oil Average Per Lateral Foot by County



SOURCE: PIPER SANDLER

some development on them," Arnold said.

Infinity's optimal lateral is between 14,000 and 20,000 feet.

At Encino, Walker said, "We're routinely drilling 4-mile laterals now."

Its average lateral length this year will likely be 17,000, plus or minus. "Some 14,000 and some 22,000. But we try to shoot for around 18,000, just from a design standpoint," he said.

Enter EOG

In May, EOG declared the Utica's volatile oil window can "compete with the best plays in America."

It now has 435,000 net acres, acquired for an average of $600 an acre–all in the volatile-oil and adjacent black-oil fairways 140 miles north to south.

It owns the minerals under 135,000 acres, blocked up in the south, for $1,800 an acre. There, it has 100% net revenue interest, "which makes those 135,000 acres extremely attractive," COO Jeff Leitzell said at a J.P. Morgan Securities conference in June.

The leasehold and minerals were bought in 2022 from Encino and Artex Energy Group for $500 million, according to J.P. Morgan Securities, citing Enverus. It came with 18 legacy wells.

Walker said the attention EOG has brought has given validation to the oil window's economics. When the play had its first start in 2011, it "was kind of the last one and it was in the shadow of all those other big oil plays [in the Permian, Bakken and Eagle Ford].

"So, it got a bad rap upfront."

Like Encino, Infinity had been working on the down low. With EOG's entry and Infinity's recent state lease win, "We've lost anonymity," Arnold said. "A lot of people ask us what's going on."

EOG has brought "a credibility to the play that it hasn't really had outside of Ohio over the last several years," he said. "EOG brought a legitimacy and a focus the play deserves and the operators in the play deserve as well."

Raising capital, such as last fall to buy Utica Resources, was "a little bit easier than before as our investors saw the results we were generating in the play," he said.

EOG's Wells

EOG had one rig drilling the play in early July. At the June conference, Leitzell noted, in telling the back story on its initial look at the Utica, that U.S. oil-producing basins are well understood at this point of the industry's 165 years.

But many have been drilled with old technology and recipes–including technology as young as just 10 years. "Technology has evolved so much that you can go in … and you can get just absolutely outstanding returns," Leitzell said.

Initially, EOG drilled four delineation wells to test performance with new tech and to identify the formation's structural features.

Its findings were similar to Encino's and Infinity's: The target zone is consistent, allowing for a precise landing at the most productive depth, even with extra-long laterals.

Since then, it's put three multi-well pads online: Timberwolf, Xavier and White Rhino.

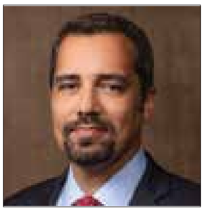
In Harrison County, the three-well Xavier made 667,366 bbl in its first 179 days online, averaging 1,243 bbl/d each. First-88-day production was 1,536 bbl/d each.

The IP-30 production mix was 55% oil, 75% liquids, according to EOG.

In Carroll County, its four-well Timberwolf pad came on in the third quarter and made 780,068 bbl through first-quarter's end, averaging 886 bbl/d per well in their first 220 days. First-37-day production averaged 1,214 bbl/d per well.

Its newly online four-well White Rhino in Noble County made 30,800 bbl in its first eight days, averaging 963 bbl/d per well.

The Xavier wells were placed at 800-ft spacing; Timberwolf and White Rhino, 1,000-ft. The wells are 3-mile laterals.



"[The Utica] will be competitive with the premier unconventional plays across North America."

EZRA YACOB, chairman and CEO, EOG

'Comparable to the Permian'

EOG's Xavier and Timberwolf wells are comparable to Permian wells' bbl/ft, the company told investors in May.

Xavier's first-six-month bbl/ft is 14.8/well. When including NGL and natural gas, it's 25.1 boe/ft. At Timberwolf, the average is 11.3 bbl/ft and 20.3 boe/ft.

Timberwolf and Xavier "are fantastic," Ezra Yacob, EOG chairman and CEO, told investors. "They're exceeding what we initially had in our type curves and they're more than confirming some of our early thoughts on spacing."

Keith Trasko, senior vice president, E&P, said, "We see that these compete with the best plays in America–very comparable to the Permian on a production-per-foot basis, both in oil and equivalent."

Yacob added that the Utica "will be competitive with the premier unconventional plays across North America."

EOG plans 20 net wells in the Utica this year throughout the volatile-oil window, north to south. Its Ohio leasehold is more than 90% HBP.

Not Quite Midland

Piper Sandler securities analyst Mark Lear reported in June that, so far, "the Utica oil window is close but still not on par with Midland [Basin] oil productivity."

Noble and Guernsey counties–the southern part of the Utica volatile oil fairway–produced better cumulative oil than the northern fairway, he added, and EOG's minerals ownership in its leasehold there should boost returns.

"While difficult to compare with Permian well productivity, the basin does benefit from a lower royalty regime, the ability to drill extended laterals of up to 4 miles and significantly less produced formation water …," Lear reported.

He estimates EOG's returns in the oil fairway in the 50% range at $70 oil and $3.50 gas based on 15-month payback and D&C of $1,150 per lateral foot.

Private operators are making wells for $750 per foot, he added.

The Utica's reservoirs share characteristics with those in the Eagle Ford.

The Black-Oil Phase

When Chesapeake announced its Utica oil discovery in 2011, it noted that the rock has four phases, west to east: black oil, volatile oil, wet gas and dry gas.

It likened the phase changes to those in the Eagle Ford, “but economically superior,” it reported.

In the Utica’s black oil window, EOG plans to shoot seismic before beginning delineation. “It does shallow up a little bit,” Leitzell said in June. “But it is also just as thick and it looks like very, very good rock.”

The lower thermal maturity of the black-oil phase will mean less pressure, which typically “reduces the well productivity a little bit,” Yacob said in May.

“But it also reduces costs. So, your economics are still really comparable to all the other portions of the play.”

That the window hasn’t been developed yet is a result of efforts in the past decade that focused on the volatile oil and wet-gas fairways, Infinity’s Arnold said. “People were doing things that they needed to do for other reasons.”

But nothing suggests the black oil window won’t work, he added.

“I haven’t seen anything that makes me call that we found the western boundary of economics. We’ll sit back and watch. We’re excited to see what they do [at EOG].”

Six-month production

(bbl/1,000 lateral ft)

5,000
2023

3,000
2022

2,000
2020-2021

A ‘Pro-Business’ State

“The operating environment in Ohio is constructive for oil and gas development,” Arnold said. “There’s a clear permitting and regulatory process, which guides how to operate, how to get permits, how to function.”

The state also implemented unitization in 2019. That has helped in consolidating and extending operators’ acreage positions, Arnold said.

Like in Texas, for example, Ohio’s rules make sure mineral owners can develop their resources, while also assuring the resources aren’t wasted.

“It’s a strength of Ohio,” Arnold said. “The regulatory environment in Ohio is clear. That puts us in a position to operate with clarity, which is what every operator wants.”

Encino’s Walker said that, in Ohio, “people are extremely pro-business.

“Ohio is probably closer to Louisiana, Texas and Oklahoma [in sentiment toward oil and gas],” he said.

The attitude in Ohio is “‘Let’s figure out how to do this correctly.’ It’s not immediately, ‘We can’t do it,’ or, ‘Let’s figure out how to not do this at all,’ like in some other states.”

‘The Right Guardrails’

The rules make sense, Arnold added. When Infinity begins drilling under Salt Fork State Park, “You won’t know we’re there because we’re not permitted to operate in the park.”

The vertical hole will be made outside the park’s perimeter. The deal also requires water-quality testing and restricted drilling times.

Drilling, completion and other oilfield equipment are largely prohibited from traveling through the park. Light pollution is to be mitigated.

“The state’s done a good job of making sure the operators have the right guardrails so their lands are protected, while we’ll also be able to develop their resources,” Arnold said.

State parks are operated by the DNR. In February, Infinity won the 5,705 Salt Fork acres for $10,250 an acre, totaling $58.5 million.

The royalty is the standard 12.5%. Infinity sweetened its offer with an additional 7.5%.

Separately, Encino placed the high bid, $3,500 an acre, on 302.3 acres in Valley Run Wildlife Area for $1.1 million along with the 12.5% royalty and an extra 5.5%. It also won 66.2 acres in Zepernick Wildlife Area for $3,500 an acre, totaling $231,700, and also with an extra 5.5% for a total royalty of 18%.

An example of the state’s support for oil and gas production: In 2022, it declared natural gas a green energy.

“It doubles down on where the state’s elected officials are,” Rob Brundrett, president of the Ohio Oil & Gas Association, said at Hart Energy’s DUG Appalachia conference in November.

He estimated energy investments during the past decade have been more than $100 billion.

“And [most of] that money is going into eastern Ohio,” Brundrett said. “I can’t overstate the importance of that kind of … investment in, really, one of the poorest regions in our state.”

The Last Oil Frontier

Walker views Ohio as the Lower 48’s last oil frontier—one that works at sustainable oil prices. More formations could work at higher oil prices, but $150 oil doesn’t last long; demand shrinks.

Ohio oil works at current oil prices, he said.

Consolidation in other oil basins is as operators are looking for more well inventory. Ohio’s oil window, on the other hand, is in just the beginning of its modern development.

“All the other big oil plays are completely leased up,” Walker said. “There’s just not a lot of opportunity for people to grab inventory anywhere else.”

Walker’s oil and gas career began in 1975, working summers and winters as a roughneck to pay his way through engineering undergrad studies at Texas A&M.

Is Utica oil easy in comparison with all the other fields he’s worked in his 49-year career?

Utica oil “feels pretty easy,” he said. “But I’m also a lot smarter and wiser than I used to be. So, I don’t know.”

Modern equipment and technology do “make it seem a lot easier. I don’t remember many times in my career where I’ve done over 200 wells as fast as we’ve done them and not had some kind of failure.”

In the Cotton Valley in the 1990s while he was with Union Pacific Resources, Walker and others screened out in those years, for example. “We don’t do that very often anymore,” he said.

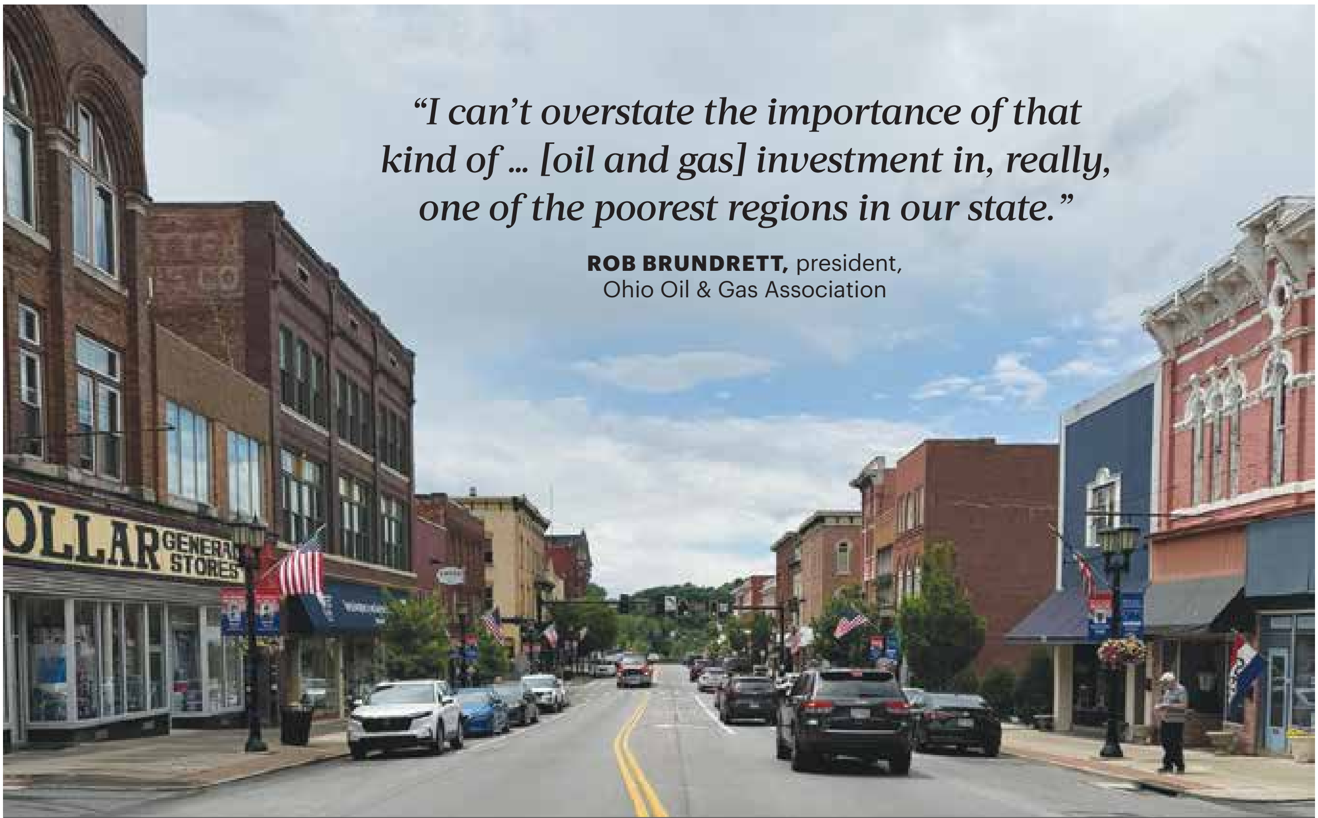
His first Marcellus well after joining Range in 2006 took 30 days to drill and it was a 3,000-ft lateral.

“Now we’re drilling 18,000 feet in 72 hours. It’s hard to even compare how far we’ve come—and even just in the last 10 years.”

And today, after drilling an 18,000-ft lateral in three days, the rig lifts itself, walks a few feet over and makes the next hole. OGI

"I can't overstate the importance of that kind of ... [oil and gas] investment in, really, one of the poorest regions in our state."

ROB BRUNDRETT, president, Ohio Oil & Gas Association

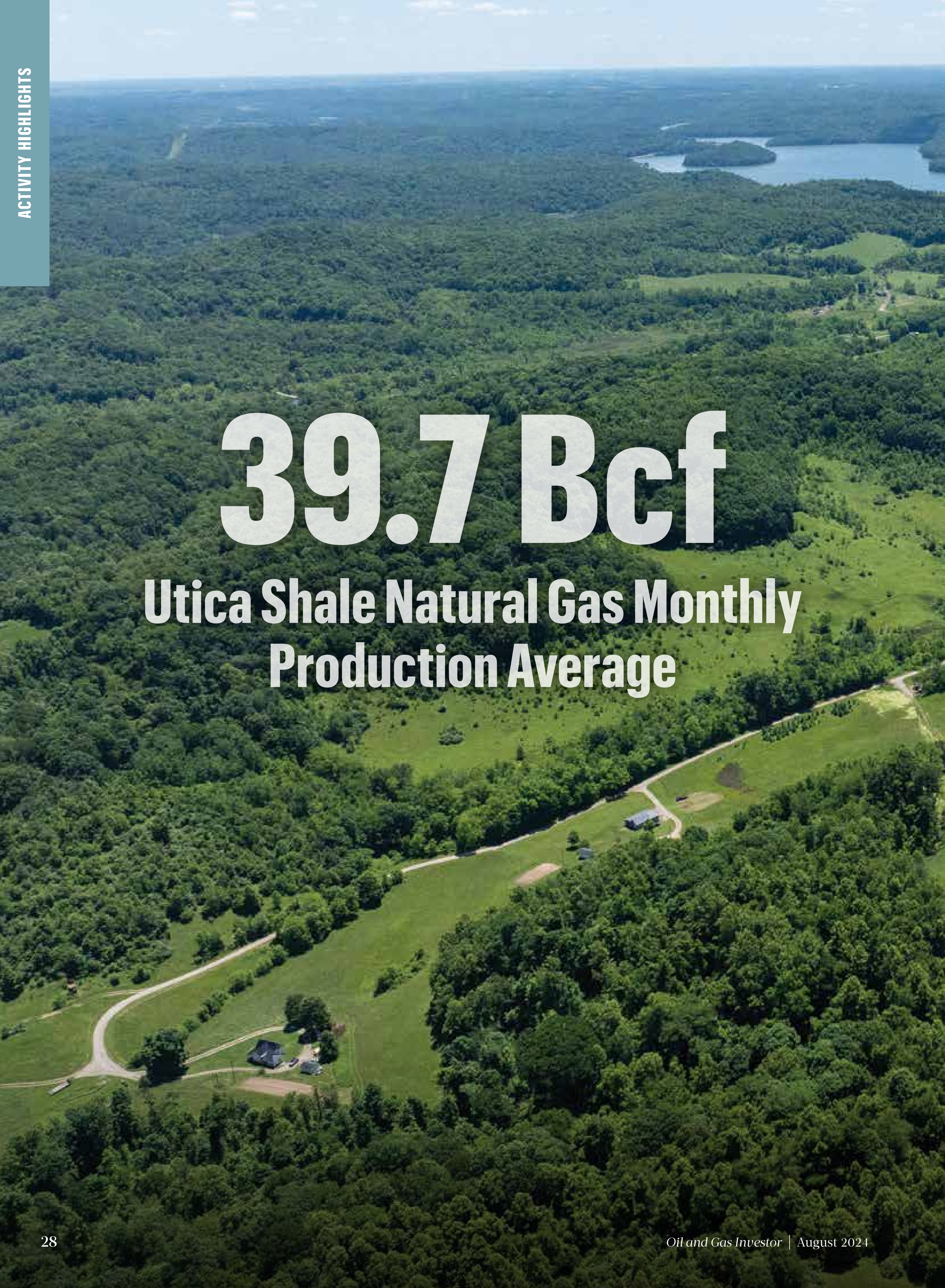


Ohio has proven to be a constructive regulatory environment for oil and gas development, according to Infinity Natural Resources President and CEO Zack Arnold. To double down on where the state's officials stand, in 2022, Ohio declared natural gas a green energy.

NISSA DARBONNE/OIL AND GAS INVESTOR

In February, Infinity Natural Resources won the rights to drill under Salt Fork State Park in Ohio. The state's favorable regulatory environment has laid out specific guardrails that will both ensure the lands will be protected and allow their minerals to be developed.

OHIO DEPARTMENT OF NATURAL RESOURCES



39.7 Bcf

Utica Shale Natural Gas Monthly Production Average

An e-frac job underway in late May at Encino Energy's Stocker pad in Harrison County where it added four new wells this spring to four that came online in April of 2023.

ADVANTAGE VIDEO & MARKETING

BASIN FOCUS: UTICA SHALE

Pittsburgh-based EQT Corp. has established a dominant position in the Utica, with production more than double that of Range Resources, the No. 2 producer in the play.

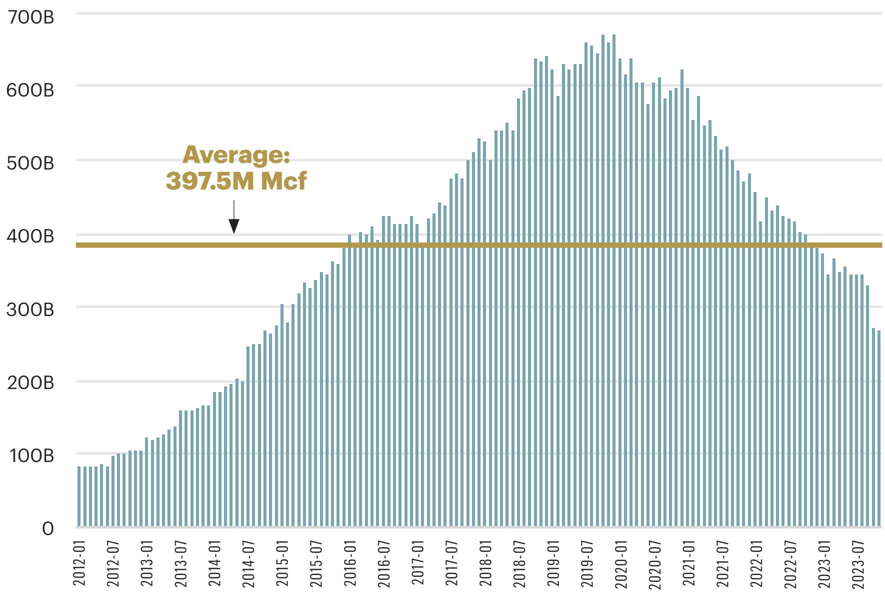
Utica Operators

Rank	Top Operators	Natural Gas, Mcf, last 12 months
1	EQT Corp.	541,958,722
2	Range Resources	261,031,281
3	Ascent Resources Utica	165,065,840
4	CNX Resources	132,531,082
5	National Fuel Gas Co.	131,631,065
6	Antero Resources	113,585,846
7	EAP Ohio/Encino Energy	110,060,578
8	PennEnergy Resources	89,178,368
9	Gulfport Energy	68,031,872
10	EQT Chap Oil and Gas	66,347,895

Utica Production by County

Rank	Top Producing Utica Counties	Natural Gas (Mcf)
1	Washington, Pa.	453,508,749
2	Greene, Pa.	354,694,875
3	Belmont, Ohio	158,589,338
4	Butler, Ohio	118,684,571
5	Harrison, Ohio	79,626,040
6	Jefferson, Ohio	87,209,903
7	Monroe, Ohio	86,663,098
8	Carroll, Ohio	47,085,620
9	Allegheny, Pa.	56,906,857
10	Tioga, Pa.	50,984,931

Utica Shale Natural Gas Production



SOURCE FOR CHARTS AND MAPS: REXTAG.COM

PERMITS

Texas counties in the Permian Basin lead all other areas in approved well permits.

Permitted Wells by County

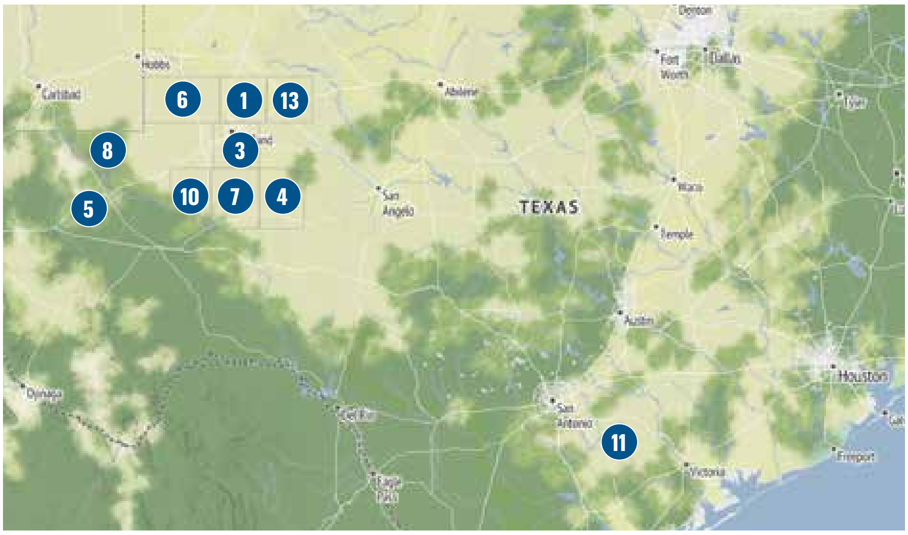
Rank	County	Well Count
1	Martin, Texas	119
2	Weld, Colo.	82
3	Midland, Texas	75
4	Reagan, Texas	60
5	Reeves, Texas	49
6	Andrews, Texas	40
7	Upton, Texas	33
8	Loving, Texas	32
9	Dunn, N.D.	31
10	Crane, Texas	30
11	Karnes, Texas	30
12	Sweetwater, Wyo.	30
13	Howard, Texas	25
13	Converse, Wyo.	25

Permitted Wells by Operator

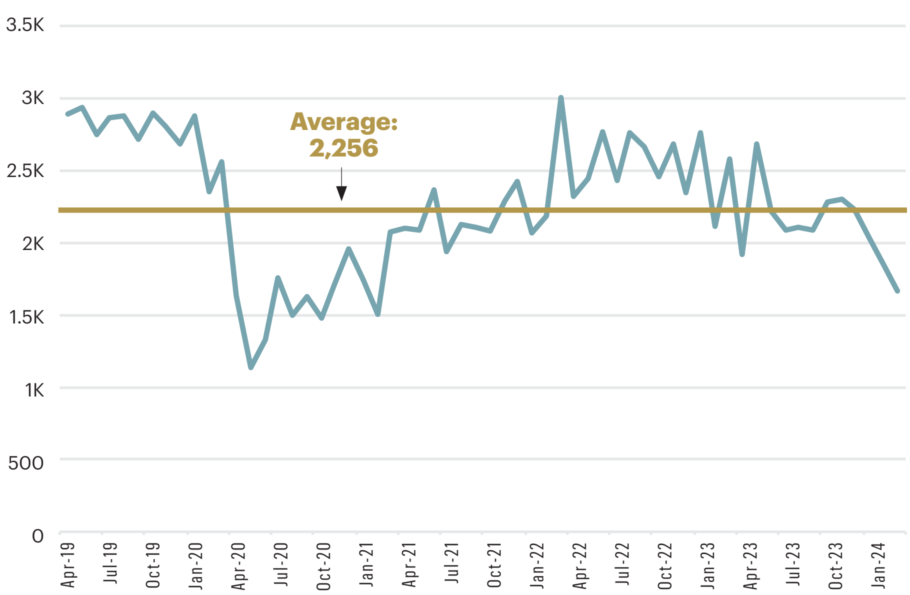
Operator	Well Count
Pioneer Natural Resources	58
Diamondback Energy	51
Endeavor Energy	44
XTO Energy	30
Blackbeard Operating	27
DE IV Operating	27
COG Operating	24
Occidental Petroleum	21

Permitted Wells by State

State	Well Count
Texas	800
Colorado	114
Wyoming	89
North Dakota	57
Louisiana	25
Oklahoma	19



U.S. Permits Issued Monthly



SOURCE: RAILROAD COMMISSION OF TEXAS, WYOMING OIL AND GAS CONSERVATION COMMISSION, NORTH DAKOTA INDUSTRIAL COMMISSION, COLORADO ENERGY & CARBON MANAGEMENT COMMISSION, REXTAG

THE OGI INTERVIEW

Strength in Diversity:

Coterra Energy CEO Tom Jorden

Coterra Energy took an against-the-grain stance on consolidation long before merger mania hit the U.S. E&P space, and it's paying—to its shareholders—meaningful dividends.

DEON DAUGHERTY
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Q&A

Two years before basin consolidation swept across the Lower 48 with mergers including Diamondback Energy and Endeavor Natural Resources, Chesapeake Energy and Southwestern Energy, and a record-setting list of basin-specific asset deals, leadership at Cimarex Energy and Cabot Oil & Gas were looking for more than oil and gas scale.

They wanted scope, too. And they didn't want to rely on the fortunes of one commodity over the other.

The firms found each other and, in 2021, completed an all-stock "merger of equals" under the Coterra Energy name and "CTRA" ticker symbol on the New York Stock Exchange.

Coterra achieved scale and diversity at its onset: an enterprise value of $17 billion, a top-tier asset base of 664,000 net acres across the Marcellus, Permian and Anadarko shale plays and base production of 605,000 boe/d.

Now nearing its third anniversary, Coterra's enterprise value is close to $22 billion—an increase of almost 30%. The firm routinely beats Wall Street's quarterly expectations and its commodity-agnostic philosophy is working in its shareholders' favor. The company has scaled down its natural gas activity with the relative weakness in prices; meanwhile, Truist Securities analysts say that next year could see a repeat of its current 10% year-over-year oil growth.

It's all upside, really. Coterra is on track to generate more than $2.5 billion in free cash flow for 2025.

"We really do believe in decentralization, being in multiple basins, but also having a diverse revenue stream," Coterra CEO Tom Jorden told Oil and Gas Investor *(OGI). "If you can tell me which commodity will be the best one in the long run, then I'll pick that and we can be a one-commodity company. But we've never been very astute at picking. I don't know that anybody has. So, we made the decision to try to diversify our revenue stream between gas and oil and then seek to have very low cost of supply in both commodities."*

Headquartered in Denver, Cimarex had mostly produced from Permian Basin operations in both Texas and New Mexico, as well as in the Anadarko Basin. Cabot leveraged a portfolio of some 173,000 gas-weighted acres in the Marcellus Shale.

Clearly, Coterra's forebears were onto something that the supermajors and large integrated firms have long understood: diversification matters. Since the Coterra closing, SM Energy has entered the Uinta Basin with its acquisition of XCL

Coterra Energy has focused operations in the Permian Basin, Marcellus Shale and Anadarko Basin.

COTERRA ENERGY

“We’ve taken machine learning from something that people were initially a little suspicious about, and we’ve turned it into a technology where, here at Coterra, there’s no meaningful operational meeting where machine learning isn’t at the table.”

TOM JORDEN, CEO, Coterra Energy

Resources; Civitas Resources took a few steps outside its Denver-Julesburg base with its 2023 buys of Vencer Energy, Hibernia Energy III and Tap Rock Resources.

And, in a deal that captures both the diversification and pure-play strategies, Continental Resources made a splashy debut in the Permian Basin when it bought Pioneer Natural Resources’ entire Delaware portfolio, leaving Pioneer a Midland Basin pure play, in late 2021. Pioneer has since been absorbed by Exxon Mobil.

The making of Coterra checked a lot of boxes: revenue and geographic diversity; low-cost supply and high-value assets; and low debt.

“Putting the two companies together was really structured around that philosophy: diversity of assets, diversity of revenue and low cost of supply. It was certainly unanticipated [by the market], and I’ll say a bit of a breaking from the herd at that point in time,” Jorden said. “But we’re really pleased with where we sit right now as a consequence of that merger.”

OGI *visited Jorden at Coterra’s Houston headquarters for an afternoon discussion about the company’s strategy and culture.*

Deon Daugherty: How did you find the wherewithal to go against the grain of what everyone else was doing with regard to M&A back in 2021?

Tom Jorden: We have convictions. We have a North Star as a management team. We really believe that the way to run a company is to first and foremost manage a company by return of invested capital. And so, we seek to have the highest returns we can, irrespective of commodity type. That was our guiding principle and the merger of the two companies certainly offered that to us.

We are agnostic on commodity and, from time to time, that’s not an easy discipline to maintain. But our experience tells us that gas and oil can cycle. At times it's coupled and at times it's decoupled. But what we saw in forming Coterra was the opportunity to have a very consistent revenue stream so that we weren't subject to the vicissitudes of these cycles.

If you go back [several] quarters, natural gas was our dominant revenue source. And then over the last four or five quarters, oil's been our dominant revenue source. But if you look ahead to the strip and look at what people are projecting for '25, oil and natural gas will be about equal as revenue sources. And that's exactly what we wanted to establish: a balanced revenue stream that would allow us to manage our business with greater predictability and greater consistency. It's as simple as that.

DD: Coterra has produced success, outpacing expectations just about every quarter since closing. Tell me more about your management philosophy, this "North Star" and how it guides your team.

TJ: Well, there are several elements to it. First and foremost, we believe that proper management of an E&P company is [based] around allocation of invested capital. We don't manage by commodity type. We don't manage by production growth targets. We look to see how much capital we're going to invest and we really seek to find the highest returns on that capital.

Now, that also has several elements. First and foremost, you have to have a price file prediction. At whatever price file we look to see high returns, whether it's the strip or a flat price file or a mid-cycle price file, we run them all. The second critical element is how much windage do you have between whatever price you forecast and how low you think the price could fall. That … provides your insurance, that provides your protection. If you make that investment, you will not destroy capital over those cycles because we've seen that in our business.

We've seen companies pull out the stops when prices are high and costs are high. They make massive investments and then the price falls and those investments end up destroying capital.

Then the third element is repeatability. You really think you have great repeatability. So those are really foundational elements of our capital allocation decisions.

But I'll go further in answering your question. We really believe in the role of technology. We really believe in the power of human intellect when teamed with like minds or even unlike minds. So, at Coterra, we're strong believers in a very open culture. We're strong believers in a culture where people are not only welcome to disagree, but expected to disagree.

DD: How does that work in a room filled with experts?

TJ: If people have a contrarian viewpoint, we want to hear it—in real time. When we're all in the room, we manage by eye contact. We make sure that people feel connected and therefore are empowered and trust that, if they disagree, that viewpoint's welcomed.

We really do tolerate a high degree of technical debate. It's foundational to our company. One of our North Stars is that people are expected, if they have a viewpoint based on the data, [to] bring it on. And I don't care whether it's somebody that's a 30-year career person or somebody that's three weeks out of school. If they're in the room and they have a viewpoint based on data, we really want to hear that. We work hard with a shared conviction that our company be a true meritocracy of ideas, and that there are as few barriers to really bright people sharing their viewpoints as we can possibly muster.

DD: That sounds very unusual.

TJ: Well, it's not for everybody.

It can be very uncomfortable. In my experience, anything in life that you want to accomplish—be it business, physical fitness, spirituality, relationships, education—ultimately it comes down to a very simple choice between progress or comfort.

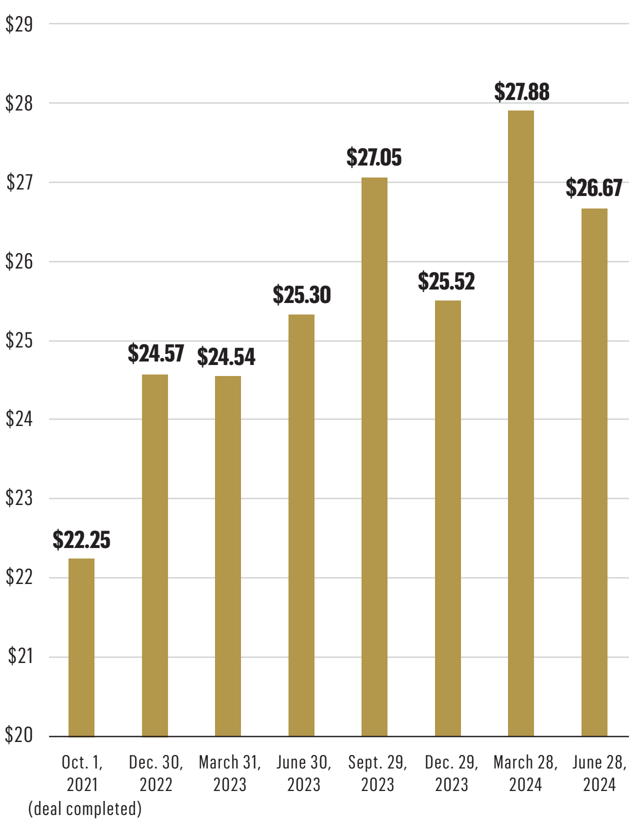
If you want to make progress, you have to be prepared to be very uncomfortable. And we do not strive for Coterra to be a comfortable place to work. And we say that unapologetically, but not uncomfortable politically because we don't tolerate politics.

It's all on the tabletop. We make eye contact, we have a commitment that the worst thing we're going to say is when we're making eye contact and in person and it works.

DD: So, give me an example of how one of those conversations might play out.

TJ: We tell our board and our organization that we've been very successful—and we're worried sick over it. We never want success to get in the way of future innovation. Good is never good enough. There are always ways you can push the envelope. You have

Coterra Energy's Quarterly Stock Price



SOURCE: NEW YORK STOCK EXCHANGE

to have a certain amount of pride, but also humility because we work in an industry with some really bright people and some great organizations. We look at our competitors and we try to learn from them.

We try to be willing to change our minds constantly on better ways to do things. And we have a lot of examples of that. We're altering our spacing right now in the Windham [Row] project, which is in Culberson County [Texas]. We talked on our recent earnings call that most of our prior experience tells us that in the Delaware Basin, where we have multiple target zones stacked on top of one another, depending on the vertical distance between these zones, that we can develop them one at a time and come back later and get the zones above or below.

But this isn't true for everywhere in the Delaware Basin. We recently saw some data that suggested that that may not be wholly true, so we're rethinking it and going back to looking at some stack tests.

We've also been very forward in the adoption of artificial intelligence or machine learning. That can help one be objective. I won't say it doesn't have bias, but I'll say it has very manageable bias, whereas with humans, it's harder to manage our biases.

DD: What are some of the ways that you're using artificial intelligence?

TJ: We started by applying it to subsurface modeling. Then we said to ourselves, if we could get artificial intelligence to do a good job at well prediction, then that would be the Holy Grail. There may be 15 or 20 different parameters when you drill a well that govern the production response depth, lateral length, completion type, geological parameters, spacing, parameters.

Generally they fall into three main categories: geological; completion and spacing; and geometry. But within those three major buckets, there may be 15 impactful parameters, and these are very expensive experiments. If you're doing them in the field, you may permeate one or another, but you will exhaust yourself financially to try all different iterations.

Machine learning gives you the ability to say, "Well, here's this combination of the 15 parameters; how well did it actually do in practice?" We have a lot of different wells with machine learning, we can look at how each one of them had the geology, the completion, and the spacing, and see how good a job we can do at predicting that outcome.

Because if you can nail that, you get to the point where you give me the 15 parameters that govern that well, and I can do a very effective job of predicting what it should have produced. And if that is truly a good match over what it did produce, then I'm off to the races. I don't have to spend $10 or $15 million on every iteration of those parameters. I can let the machine do it and I can find the optimum solution, not only optimize my production, but optimize my return on capital.

We've really instituted that heavily here. It's changed our thinking across the board. We've taken machine learning from something that people were initially a little suspicious about, and we've turned it into a technology where, here at Coterra, there's no meaningful operational meeting where machine learning isn't at the table. And our operations people insist on it because they've seen the value and the illumination it brings to any meaningful problem set.

Look, we didn't get it right straight out of the shoot. We had some false starts, but we really found a rhythm where today our machine learning on predicting well performance is outperforming our best and brightest reservoir engineers.

DD: And this is being applied across your assets?

TJ: Yes, across the assets.

DD: What has that done to your growth plans?

TJ: It helps us more effectively complete our wells. It helps us get more per well. We've talked about some of our spacing. In the Permian and the Delaware Basin a couple of years ago, we talked at length about that. We thought—and again, not everywhere, but in many places—we thought we were able to drill fewer wells in some cases, fewer wells than our competitors, and recover the same volumes. And we've demonstrated that time and time again where we'll be next door to an operator that may be drilling one or two additional wells, and yet our drilling spacing unit is producing equivalent volumes to the one next door. We're doing it with $15-$20 million less investment.

Now, that's not true everywhere. But I will say that the application of machine learning has really given us a more sophisticated understanding of spacing and completion efficiency

DD: I want to dig in a bit more on how Coterra has managed to outperform by almost every metric during every quarter.

TJ: Certainly by having an open organization; the power of that is remarkable. Now, every company has their own culture and every company believes in their own culture. Or if they don't, they should reform their culture.

I heard it said years ago, and it's been attributed to many, … but the quote is, "In the long run, the only source of competitive advantage a company has is its culture."

And that has absolutely been my experience. Assets will come and go, and much as I hate to say it, people will come and go. But if a culture can survive that and be organic, then that can be the heartbeat of a company. I think Coterra is a meritocracy. We really encourage open collaboration amongst our people, either across business units or vertically. We don't silo people, nor do we have a viewpoint that says management is command and control.

You put that philosophy in with a multi-basin approach and all of a sudden you have a place where good ideas spread like wildfire. An innovation in the Marcellus can quickly find its way to the Anadarko or the Permian, or vice versa. We have a lot of collaboration going on every day between our business units, sharing best practices, querying one another on problem solutions, and it's given real dividends.

Certainly, we have a great field staff, very dedicated field staff, but we really have a very focused organization that sets a standard of excellence for one another. That may sound trite, it may sound arrogant. But we really do have an expectation of one another that is based upon a shared commitment to excellence.

CEO Tom Jorden says the firm's success is based on its culture, which encourages "a high degree of technical debate."

COTERRA ENERGY

At the end of 2023, Coterra had a total of 1,083 producing net wells in the Permian Basin and operated about 89% of them.

COTERRA ENERGY

DD: So, taking that approach is how Coterra returned 90% of its free cash during the first quarter? Is that size of return sustainable?

TJ: Well, we've committed to 50% plus, but we've refused to get into an arms race on cash return promises.

We've seen that companies will say 50%, then another company will say 75% and another company will say 90%. And we've just refused to make those promises because, simply put, we really believe in commitments and that's why we make so few of them. We don't want to make commitments that we're not going to honor. And so, we've returned in advance of what we've telegraphed, but we're happy to do that. We have a tremendous balance sheet, great cash flow, low cost of supply, and quite frankly, the last few years have been really good years in our business.

DD: During the first-quarter call, you discussed being optimistic about natural gas. It's been especially volatile, so how do you hold that disposition?

TJ: Well, it's hard not to be optimistic about natural gas as you look ahead in the future. We're kind of all born optimists in this business because we're in a business where you can do everything, and yet it can go really badly. The commodity price can fall out from underneath you suddenly and without warning. Or you can have terrible mechanical problems and overexpend or lose holes, or we have weather events. Just a lot can go wrong in this business.

Our psychological defense against that is our optimism, and we're an optimistic group generally in our business. Sometimes, when you find optimism, it's just kind of people's stubborn reaction to reality. But when it comes to natural gas, I will say it's very difficult to look at the fundamentals of either U.S. or global energy and not see a really strong role for natural gas.

DD: How do conversations about phasing out fossil fuels figure into your calculus?

TJ: It depends on who's doing the talking. Are there NGOs [non-governmental organizations] or environmental groups doing that talking? Are there government officials and regulators doing that talking? Or is the consumer doing that talking? Because those are all very different voices.

When we look at the consumer's behavior and the marketplace, we see very strong future for our products, both oil and natural gas, particularly hardened by the growing conversation around electricity generation, about the need generated by data center growth and artificial intelligence adoption and what that'll mean for U.S. power demand and the role of natural gas in satisfying that demand.

So, you give me the choice between all of those voices, I'm going to take the marketplace, and I think the marketplace is sending us pretty clear signals that our products will be needed for many decades to come. And it will be a healthy business within a certain behavior set that is responsible, that attempts to deliver our products as emissions-free as we can, and that is not tone deaf to the energy transition. I mean, all of that is true simultaneously. OGI

A Family Way

Key family offices whose wealth began in other industries are filling in oil and gas investment gaps left by endowment and institutional investment flight.

DEON DAUGHERTY
EDITOR-IN-CHIEF

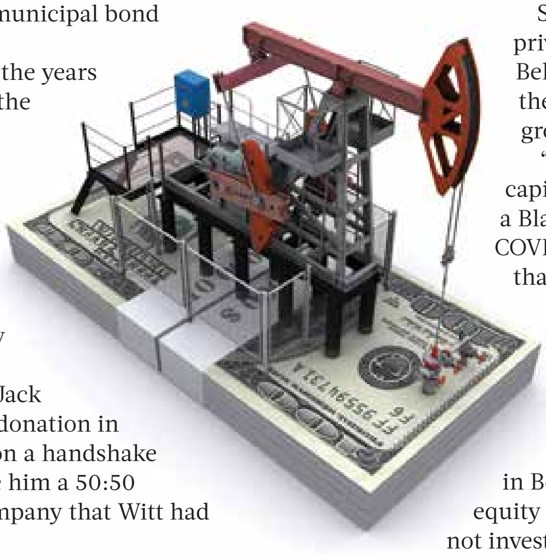
Generational wealth has long been invested in oil and gas, but it has generally come from families whose fortunes were found in the field. That's changing. Or, it's branching out.

And old money earned in other industries is making its way to oil and gas now more than ever.

In some cases, it starts with a handshake.

Witt Stephens founded Stephens Inc. in 1933, betting on municipal education and Arkansas highways bonds.

"That was really the first slug of capital that came into the family," John Stephens, Witt's grand-nephew, told *Oil and Gas Investor*. "[The bonds] were trading at pennies on the dollar during the Great Depression. He bought them in 1933, they paid off in '43, so he used that initial source of capital to build a business in a municipal bond space."



Witt made other investments in the years that followed. Meanwhile, he saw the potential in his brother, Jack, who was 16 years younger than Witt, and sent him to college. Jack–John's grandfather–graduated from the U.S. Naval Academy in an accelerated class in 1946, then went to work on Wall Street. (The academy named the football field at Navy-Marine Corps Memorial Stadium "Jack Stephens Field" after Jack made a donation in 2003.) Jack returned to Arkansas on a handshake deal with his brother, which made him a 50:50 partner in the municipal bond company that Witt had built.

The firm made its first oil and gas investment in 1948. Inside a decade, the industry became a business unit of the firm, and in 1956, Witt began to manage those investments and others, such as real estate. Still a partner with the original firm, that branch–Stephens Natural Resources–remains in business and the founder's heir, Witt Stephens Jr., is chairman of the board.

Stephens Inc. continues to invest in oil and gas through its family office, Stephens Capital Partners. The industry represents about 25% of the portfolio.

"We all agreed that felt right," John Stephens said. "I would add that, given the themes we're seeing and our conviction in the space as an investment area right now, I think that could grow over the next five to 10 years as a portion of our overall portfolio."

John Stephens is a managing director of the investment banking group, working in family advisory services where he specifically covers family offices.

"And the best calls we can make is when we call people and say, 'We're excited about this, we're doing it ourselves. Would you like to come into a deal with us?' That's what's happening in the oil and gas space," Stephens said.

Stephens has long been keen on the private placement of equity, said Keith Behrens, managing director and head of the firm's energy investment banking group.

"Historically we would place that capital with private equity funds like a Blackstone or an EnCap. [But] during COVID, and even a little before COVID, that investment activity with private equity funds slowed down. The funds were holding onto investments that they couldn't sell. They had a hard time raising capital," he said.

Brad Nelson, a managing director in Behrens' group, said that the private equity groups along the coasts were "really not investing in conventional hydrocarbon transactions anymore, or certainly had reduced the amount and the number of deals" under consideration.

"The important part of that, from our perspective, was that it had a meaningful impact on valuations. And so, when you have that amount of capital, and pretty much leave the space, valuations came down, which I do think was impactful on families that eventually came into the sector–and are still looking at opportunities in the sector," he said.

“The best calls we can make is when we call people and say, ‘We’re excited about this, we’re doing it ourselves. Would you like to come into a deal with us?’ That’s what’s happening in the oil and gas space.”

JOHN STEPHENS, managing director, Stephens

“We’ve had a lot of luck in finding non-oil and gas family offices that are looking to make big commitments, $100 million-plus commitments to a particular deal. And really, John Stephens has been key in that effort.”

KEITH BEHRENS, managing director, head of energy and clean energy transition, Stephens

“... when you have that amount of capital, and pretty much leave the space, valuations came down, which I do think was impactful on families that eventually came into the sector—and are still looking at opportunities in the sector.”

BRAD NELSON, managing director, Stephens

“We’re investing capital generationally—not for a specific fund of life.”

JOE O’BRIEN, president and CEO, A.G. Hill Partners

Stephens’ family advisory group was going strong, and so the energy investment team began working more closely with them.

“We still wanted to do private placements and source that type of capital for our clients, but we just wanted to find alternative sources of equity capital given the slow down with PE funds,” Behrens said.

The teamwork has grown into a coordinated effort. John Stephens’ group had identified other families that liked investing in oil and gas, and Behrens’ group includes four petroleum engineers and a geologist who bring technical expertise to the investments.

“We found that to be very important to help families in their evaluations. They kind of rely on those folks to help them do their technical due diligence and help on their technical due diligence. That’s important,” Behrens said. “The fact that we’re putting our own money in deals, I think gives us a lot of credibility with family offices like [A.G. Hill Partners].”

Stephens’ backstory was compelling to the leadership at A.G. Hill Partners, a family office that manages the wealth of Al Hill Jr., the grandson of legendary oil tycoon H.L. Hunt.

“We’ve always had an investment exposure to the sector, but things really started to change noticeably around the time of COVID and immediately following COVID,” said Joe O’Brien, president and CEO of A.G. Hill Partners.

O’Brien said the change was brought about a confluence of three things: the large amount of capital the sector had lost between 2014 and 2020; the temporary price destruction wrought by COVID; and the ESG pressures on endowments and foundations to reduce or eliminate their allocations to the energy sector.

“As all of those things came to together in late 2020 and early 2021, we saw increasing opportunities for us to deploy capital into deals with very established, successful entrepreneurs. These were people we never otherwise would had the opportunity to back or meet or invest with because they were always backed by private equity previously,” he said. “We made the decision in 2021 to focus a lot of our time and capital or resources on the energy sector. Today, energy represents about a third of our private equity exposure in total, and it represents about 20% of our public equity exposure. We’re a broad family office with real estate, private equity and public equity, and energy is an important piece of the private and public part of what we do.”

Family-Sized

Last summer, O’Brien’s team anchored a group of five family offices and two private equity firms to establish the PW Consortium to pursue acquisition of PureWest Energy, the largest natural gas producer in Wyoming. The $1.8 billion buy required more than $400 million of equity capital. The collective pooled funds and then did asset financing with Wincoram Asset Management for additional capital that funded the deal.

“There was a banker representing the seller, there was a banker who represented us as the buyer. It was somewhat competitive,” O’Brien said. “There were a couple of other bidders looking at it, and ultimately we prevailed with the syndicate that we put together.”

The consortium has since disbanded, but the concept remains, he said,

Behrens said private placement deal size hasn't changed much since the days of teaming with private equity.

"They're generally from $150 million to about $500 million. We're still working on the same size deals, but we used to go down the street to EnCap or to a Blackstone and they would take down the whole deal. They'd make a commitment for all of that capital," he said. "Now … it's a syndicate of family offices generally that are making that commitment and they're led by a family office like Joe's family office."

The "anchor" of a family office with the reputation for excellence and experience with oil and gas, such as A.G. Hill, it key to bringing other generational wealth–that doesn't have energy industry expertise–to the table.

'[Those families] get a lot of comfort in that, and so that's how a lot of these deals are playing out," Behrens said.

"We've had a lot of luck in finding non-oil and gas family offices that are looking to make big commitments, $100 million-plus commitments to a particular deal. And really, John Stephens has been key in that effort. If it was just Brad and I calling, I don't know if we could get through. That's been a really important point in trying to bring big syndicate together."

Branching Out

Last year, Stephens Capital Partners brought together a couple dozen families to round out the equity needed for a deal involving a landfill in Lea County, N.M., which serves as a waste management element of the oil and gas industry, Nelson said.

The firm has an upstream deal in the works and has a committed "anchor" family. While it has momentum, it's not complete and so the parties are not ready to publicly discuss it, he said.

There are a few reasons that generational family wealth managers outside of oil and gas have had the temerity to venture into the industry. They see the returns, which despite the existence of general market angst, remain compelling.

Regardless of where the wealth originated–municipal bonds, aviation or the automotive industry–generational investors are looking to win the long game.

Private equity firms engage deals with an exit strategy in mind, Behrens said.

"You had to time everything right to have a good return on your investment if you're only holding investments for three to five years," he said. "But family offices don't have time limits on their funds. John mentioned investments we've made in the '50s that the Stephens family still holds."

That enables those families to hold their investments through various cycles.

"It's one way I think the families get it right, and that the private equity funds always had challenges with," Behrens said.

A.G. Hill follows the same longer hold policy, O'Brien said.

"We're investing capital generationally–not for a specific fund of life. And so, as Keith points out, many private equity funds typically have a 10-year life. They have an investment period, they have a harvesting period, and so they may not be able to ride that commodity curve through longer cycles the way a family can," he said. OGI

Hall Capital: Driving in New Directions

DON CALHOUN

Fred Jones

In early 1916, Fred Jones arrived in Oklahoma City, eager to begin his career as a cutlery salesman. But the brand new Ford Motor assembly plant west of downtown captured his imagination.

According to family lore, a toothache led him to a dentist who introduced him to another of his patients: the plant's manager. When Ford's Model T plant opened in April 1916, 24-year-old Jones was the first employee to punch the clock.

But fundamentally, Jones was a businessman. After World War I temporarily shut in the plant, Jones was assigned to work with Ford dealerships. In 1920, he took over one and tripled its sales. Then he acquired another one. He kept going. Over the next 46 years, he sold more than 300,000 cars and became one of the world's largest Ford dealers.

During those 46 years, his growing stature as a businessman positioned him to join the board of directors of a bank, leading to his appointment as chairman of the board at Braniff Airways. He created another successful business reconditioning automotive parts. Jones invested in some local oil and gas E&Ps, bought real estate and set up a farm, then a cattle operation in Oklahoma.

During the 1980s, Jones' three grandsons—Fred Hall, Kirkland Hall and Brooks "Boots" Hall Jr.—gained ownership and control of the firm, according to information from the firm. By the late 1990s, the brothers had diversified Fred Jones Industries away from its automotive focus.

By 2000, the company fully divested from parts remanufacturing and auto dealerships. The Hall brothers pooled their resources with those of the Catalyst Group in Houston to launch investment funds in 2002. They rebranded the firm as Hall Capital, a family-owned private investment company with three main categories: automotive, real estate and private investment.

It's the private investment arm that holds Hall's oil and gas ventures. Today the firm is invested in almost a dozen oil and gas companies.

Hall Energy is the oil and gas affiliate of Hall Capital. It is the platform for management of a portfolio of non-operating and royalty interests, primarily in Oklahoma and Texas.

Hall Energy is also the point of contact for:

- Brooks Hall Enterprises
- HBH Energy
- Brooks Hall Oil
- Zener Electronics
- Oklahoma & Northwestern Co.
- Andeck Resources
- Tellus Oil
- HJOC Inc.
- Pine Ridge Energy
- Grand Avenue Partners

Mach Eyes Other Plays as Midcon Tightens

CEO Tom Ward is keeping his M&A options open as both competition and prices increase.

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When Midcontinent E&Ps were going bankrupt and exiting the SCOOP/STACK plays, Mach Natural Resources dug in and hunkered down, waiting for the market to recover.

Today, Oklahoma City-based Mach Natural Resources is one of the most active E&Ps remaining in the Midcontinent.

But as Mach searches for future acquisitions, the upstream MLP is keeping an eye on new basins as prices and competition in the Midcontinent start to heat up, CEO Tom Ward told Hart Energy in an exclusive interview.

The company is organized as an MLP, set up to distribute all available cash to unitholders each quarter after subtracting costs, expenses and reserves.

Instead of using a fixed distribution model like the upstream MLPs of yesteryear, Mach uses variable distribution. Distributions fall as commodity prices go down, but investors reap the upside of the cycle as commodity prices improve.

Mach's top focus is enhancing distributions to its shareholders, Ward said. To do that, Mach needs to lower drilling costs and acquire discounted, free cash flowing assets.

"We bought 16 acquisitions up and through the IPO," Ward said, "but we were able to buy all that at discounts to PDP PV-10."

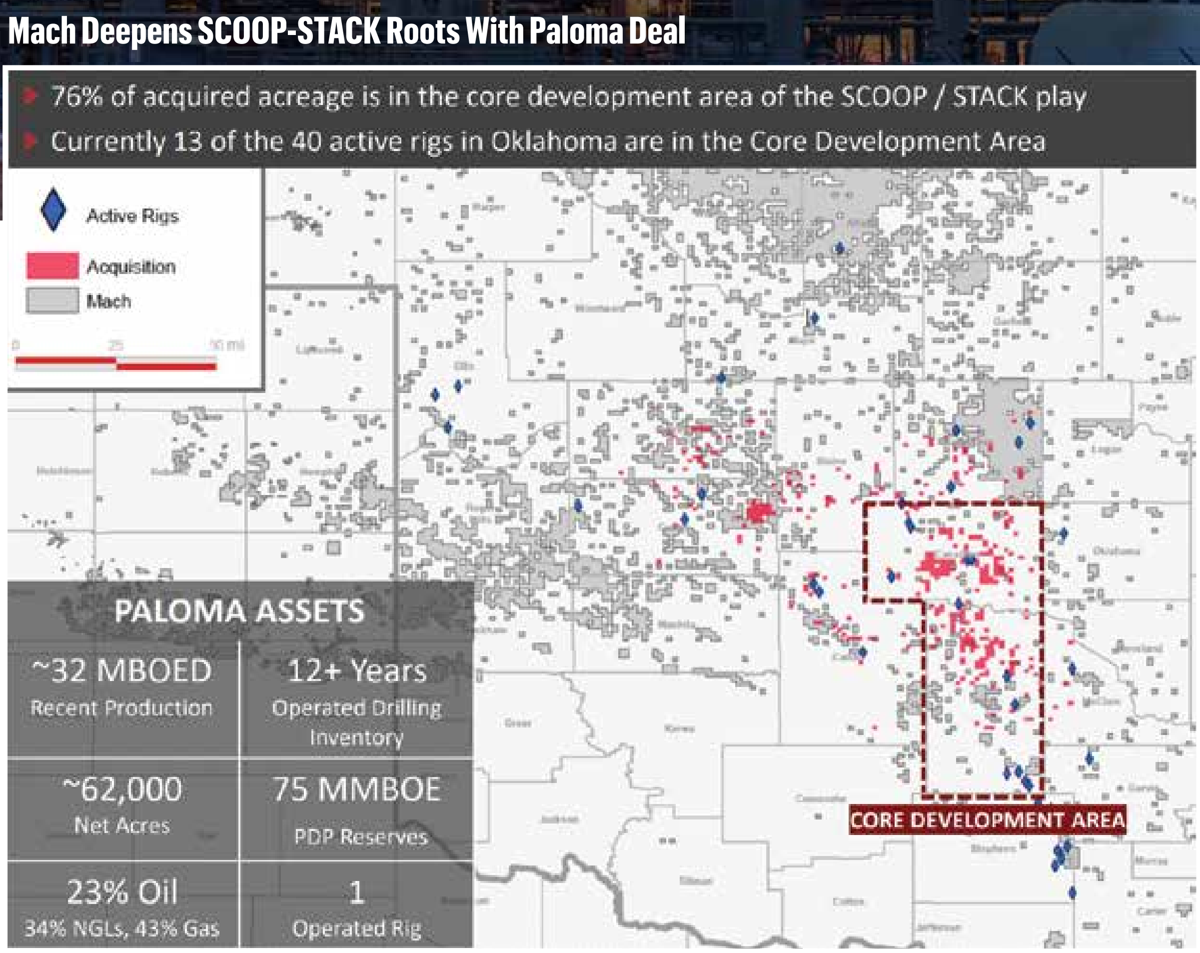
Ward is someone who knows his way around the Midcontinent: He previously co-founded Chesapeake Energy with Aubrey McClendon and served as the company's president and COO. He later helped form and lead SandRidge Energy and Tapstone Energy, both of which developed deep portfolios in the Midcontinent.

Mach, launched in 2018 with capital partner Bayou City Energy, has grown through a handful of notable acquisitions. In April 2018, Mach purchased Mississippi Lime assets in Oklahoma from Chesapeake, including producing properties concentrated in Woods and Alfalfa counties.

In 2020, Mach acquired upstream assets from Alta Mesa Holdings and midstream assets from

Mach Natural Resources, an aggregator in the Midcontinent, is keeping an eye on opportunities outside of Oklahoma.

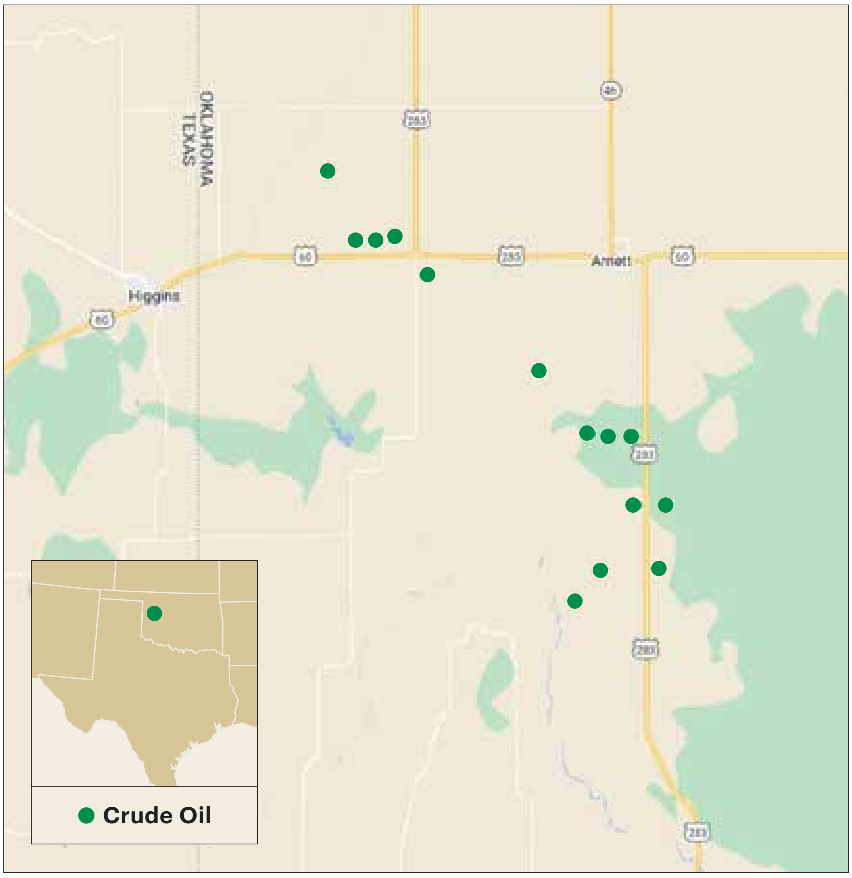
MACH NATURAL RESOURCES



SOURCE: MACH NATURAL RESOURCES

Mach's acquisition from Paloma Partners IV last year added around 62,000 net acres and 32,000 boe/d of production.

Cherokee Horizontals 2020-Present



SOURCE: REXTAG

Horizontal wells online since Jan. 1, 2020, targeting the Cherokee play, according to available Rextag data.

Kingfisher Midstream as part of Alta Mesa's Chapter 11 bankruptcy process.

Mach followed on last year with an $815 million acquisition of central Oklahoma assets from EnCap-backed Paloma Partners IV.

The company has around 1 million net acres of Midcontinent land in its portfolio today.

But as Mach, a self-described "acquisition company," hunts for its next acquisition, it may be looking outside of the Midcontinent plays the company knows so well.

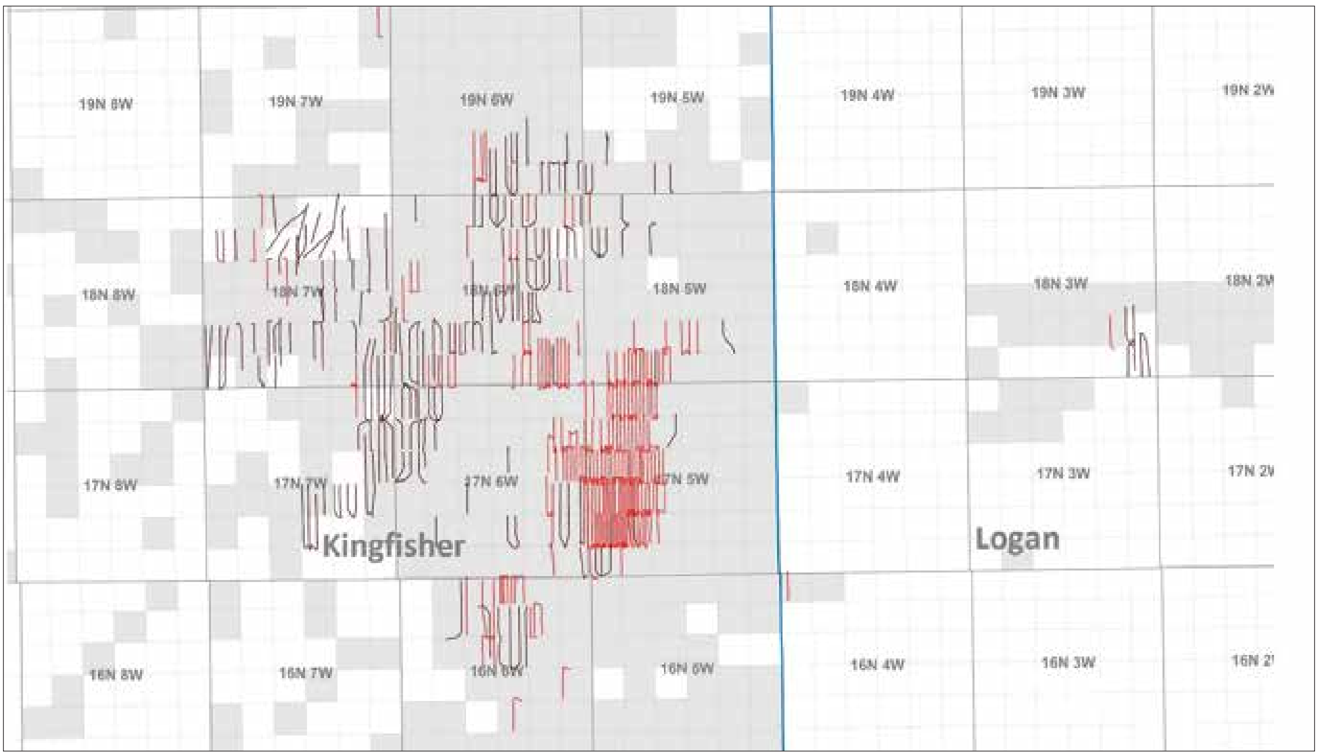
Competition for Midcontinent acreage and production is increasing, and pricing is creeping up, the company reiterated in its first-quarter earnings call.

"Our focus was always on the Midcon because it was the cheapest molecule in the U.S.," Ward told Hart Energy, "and that might be moving away from us."

As Mach evaluates potential deals in the Midcontinent, the company needs to compare them against free cash flowing assets in some of the outer portions of the Eagle Ford Shale, or with Permian Basin assets that haven't yet traded hands, Ward said.

"So, we are looking outside of the Midcon," he said.

Activating the Oswego



SOURCE: MACH NATURAL RESOURCES

Mach Natural Resources' Oswego drilling program in Kingfisher County, Okla., has been the company's most active area since 2021.

“Our focus was always on the Midcon because it was the cheapest molecule in the U.S., and that might be moving away from us.”

TOM WARD, CEO and director, Mach Natural Resources

Other upstream MLPs are on the hunt for accretive acquisitions, too.

TXO Partners, an upstream MLP founded by former XTO Energy leader Bob Simpson, made a roughly $300 million acquisition of low-decline Williston Basin assets in late June.

Before the Williston acquisition, TXO’s operations were primarily focused on the Permian Basin and the San Juan Basin of New Mexico and Colorado.

Midcon Drilling

Accretive acquisitions are key to Mach’s strategy of growing shareholder distributions. Lowering costs can help, too.

Bringing down drilling costs is another top focus for the upstream MLP, and Mach has pivoted its drilling program to make that happen, Ward said.

When Mach picked up Alta Mesa’s assets in central Oklahoma and Kingfisher County, the company started looking to drill the Mississippian intervals on the asset.

But Mach quickly pivoted to a shallower zone, the Oswego interval and the Pennsylvanian limestones. That allowed Mach to do away with proppants and use acid completions to save costs.

The Oswego program has been Mach’s most active since 2021.

“We’ve drilled nearly 250 wells in the Oswego,” Ward said. “That is completely different than anyone that’s been drilling across the Midcon.”

The company’s Oswego wells averaged approximately $2.63 million per well during the first quarter. Ward thinks drilling costs on the company’s newly acquired Paloma assets can be even more competitive.

The Paloma acquisition added approximately 62,000 net acres across Canadian, Grady, McClain, Caddo, Custer, Dewey, Blaine and Kingfisher counties, Oklahoma.

Mach plans to drill nine wells on the Paloma acreage this year, targeting a mix of Woodford and Mississippian wells.

The company is leaning more toward the 2-mile Woodford wells currently being developed, Ward said during first-quarter earnings.

Mach is also keeping an eye on emerging developments in the western Anadarko’s Cherokee play, near the Texas Panhandle.

Horizontal Cherokee drilling has been mainly developed out of Ellis County, Okla., by private companies Mewbourne Oil and Upland Operating.

But the play has been extended to the south into Roger Mills and Custer counties, Ward said.

“It looks very interesting,” Ward said. “We have close to 20,000 acres of leasehold that’s held by production and we’re just watching that play.” OGI

Come Together: Calif. E&Ps Merge for Scale, Drilling Runway

California Resources Corp. wants to expand drilling after acquiring Aera Energy, but faces pushback from regulators and environmental advocates.

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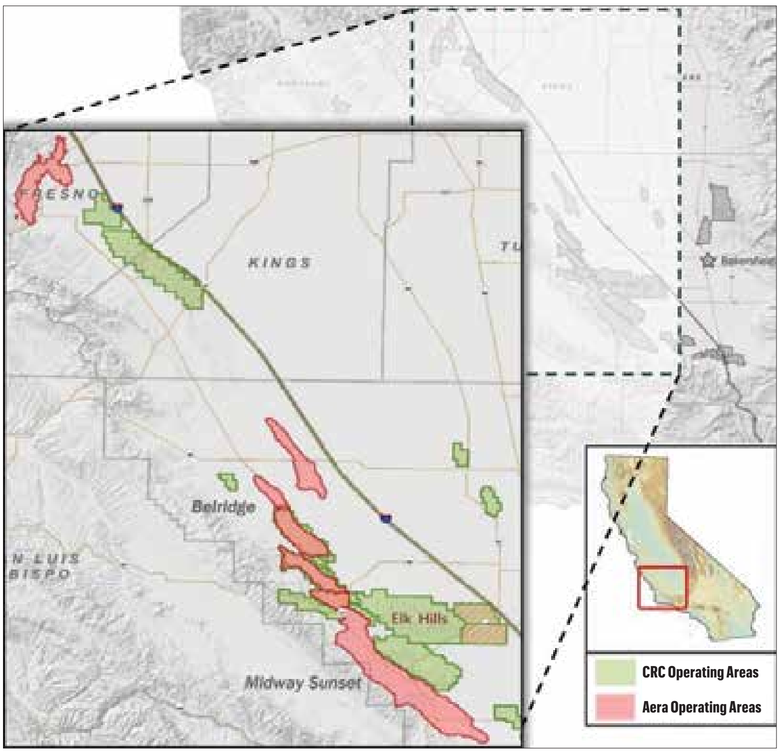
California Resources Corp. (CRC) still plans to run a one-rig program after closing a $1.1 billion combination with fellow California producer Aera Energy.

But Francisco Leon, CRC's president and CEO, envisions a future where CRC is running eight rigs across its massive land position.

Long Beach, Calif.-based CRC has an even larger acreage block to work with after acquiring Bakersfield, California-based Aera Energy.

Aera was previously a joint venture composed of the California assets of supermajors Exxon Mobil and Shell. International asset manager IKAV acquired ownership of Aera through separate transactions with Exxon Mobil and Shell in 2022.

Central Valley Scale



SOURCE: CRC

California Resources Corp. and Aera both hold large acreage positions in California's San Joaquin Basin, the heartbeat of the state's onshore oil and gas drilling activity.

CRC is a product of a 2014 spinoff of Occidental Petroleum's California conventional and unconventional assets.

The combination—through an all-stock transaction closed July 1—cements CRC as the largest oil and gas producer in the Golden State, leapfrogging fellow California-based rival Chevron.

Including debt, the $1.13 billion all-stock deal, announced in February, is valued at $2.1 billion.

While CRC has a grand vision for expanding California oil and gas production in the future, getting to that point will involve surviving one of the most stringent permitting and regulatory regimes in the nation.

"We don't see a line of sight this year to get back to permitting and getting to the eight rigs that we want to do," Leon told Hart Energy in an exclusive interview. "But what we do have is an ability to grow cash flow per share."

Kern County Permitting Pause

The permitting pain points come out of Kern County, in the heart of the prolific San Joaquin Basin in California's Central Valley.

The bulk of California's remaining proved onshore oil reserves are held within the San Joaquin Basin, with nearly 930 MMbbl in proved reserves remaining at the end of 2022, according to U.S. Energy Information Administration data.

"Kern County is like the Permian for us," Leon said. "It's the heartbeat of the industry."

The Kern River Oil Field has been producing oil and gas for over 125 years since the discovery well was hand-dug in the San Joaquin Valley in May 1899.

It's not quite as easy today for Kern County operators to drill new wells or to modify existing projects in the San Joaquin Basin.

The California Geologic Energy Management Division (CalGEM), the entity regulating the state's oil and gas drilling activity, stopped approving permits to drill new Kern County oil and gas wells in December 2022, state data show.

The freeze in permitting stems from a long-running challenge to Kern County's ability to rely on an existing environmental impact report to meet the county's obligations under California environmental regulations.

Operators have sought out alternatives; CRC

California Resources Corp. closed an acquisition of fellow California producer Aera Energy, adding conventional assets and scale in the San Joaquin Basin and Kern County, California

SHUTTERSTOCK

said it submitted applications for conditional use permits from Kern County for projects in its Elk Hills, Kern Front and Buena Vista fields.

"As a result of these issues and current lack of permits with respect to our Kern County properties, we plan to operate one active rig within Kern County in the first half of 2024 and have the requisite number of permits in hand to keep that rig active throughout 2024," CRC wrote in its most recent annual report.

But the permitting freeze is showing signs of thawing. In May, CalGEM approved 10 permits submitted by Berry Corp. to drill new wells in Kern County's Midway-Sunset field (Dallas-based Berry has also been an active consolidator in Kern County, closing a $70 million takeover of private E&P Macpherson Energy last fall).

The approvals by CalGEM drew condemnation from environmental advocacy groups, according to media reports.

For CRC, permitting in Kern County remains a challenge. The last permit CRC received to drill a new well in the county was approved in late December 2022, CalGEM data show.

The company reported experiencing "significant delays" in obtaining permits for sidetrack, deepening or rework projects throughout 2023, per investor filings. CalGEM approved around 100 rework permits for CRC in Kern County last year.

But CRC sees a resolution on the horizon. Leon said he thinks the permitting issues will get resolved by next year.

"So, we'll go back to drilling," Leon said. "We want to get to about eight rigs combined to offset the combined company decline."

CRC's production volume fell by 5,000 boe/d, or 5%, to 86,000 boe/d in 2023 from 91,000 boe/d in 2022, "predominantly as a result of natural decline," the company wrote in regulatory filings.

Leon said CRC can protect a lot of its base decline through water injection and steamflooding, which has been the "nuts and bolts" of CRC's activity today. Capital workovers and sidetracks are the most cost-effective, highest-return activities it can tap right now, he said.

CRC is also open to growing inorganically, like it did through the Aera acquisition. The pro forma net daily production of CRC and Aera averaged 146,000 boe/d (79% oil) during April and May of 2024. That's up from CRC's first-quarter average net production of 76,000 boe/d.

Moving forward, CRC is still open to making accretive acquisitions, bolt-ons and carve-outs inside California.

The Golden State obviously remains CRC's top focus, but there's also nothing stopping the company from evaluating potential M&A outside of California, Leon said.

He doesn't see CRC entering the tight shale arena, but conventional assets with CO_2-flooding opportunities could be attractive down the road.

"Eventually, we could look outside of the state if we have assets that are similar to ours," he said.

Moving Needles

As CRC waits to receive new drilling permits, the company is working to make strides where possible—like on cash flow per share, investor returns and other key financial metrics.

The Aera acquisition is expected to be immediately accretive to operating cash flow per share (45% improvement) and free cash flow per share (90% improvement).

Pro forma free cash flow is anticipated to more than double upon closing, allowing CRC to allocate greater volumes toward shareholder returns, paying down debt and developing its carbon management business.

The company has also identified around $150 million in annual synergistic cost savings by merging with Aera.

CRC wants to be a pioneer in the carbon capture and storage (CCS) space in Kern County. In 2022, CRC subsidiary Carbon TerraVault entered a joint venture with Brookfield to explore opportunities to develop carbon management projects in California.

Carbon TerraVault expects the U.S. Environmental Protection Agency (EPA) to approve its applications for Class VI CO_2-injection wells later this year.

They would be the first injection wells for permanent CO_2 storage approved in California. Leon said CRC has worked with the EPA and Kern County for over two years on the permitting process.

"This is a high bar. It's difficult to get those permits," Leon said, "but it's a competitive advantage once you're able to go through the process and do this." OGI

Devon Energy Finally Pulls the Trigger

Purchase of Grayson Mill Energy's Williston assets for $5 billion greatly expands its footprint in the basin.

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Devon Energy is the latest large-cap producer to jump into the M&A cycle, picking up Grayson Mill Energy's Williston Basin assets in a $5 billion deal.

Oklahoma City-based Devon is a bit late to the M&A party, but not for lack of trying. The company has evaluated several potential acquisitions across its multi-basin footprint over the past year.

Devon was reportedly targeting a potential takeout of Bakken-heavy E&P Enerplus Corp. earlier this year, but Enerplus was later acquired by Chord Energy for $4 billion.

In the Permian Basin, Devon also reportedly looked at acquisitions of private producers Endeavor Energy Resources and CrownRock.

Endeavor was ultimately acquired by Diamondback Energy for $26 billion; CrownRock by Occidental Petroleum for $12 billion. Both deals are still pending.

Devon also has asset footprints in the Anadarko Basin, the Eagle Ford Shale of South Texas and the Powder River Basin of Wyoming.

But Devon finally landed on a $5 billion cash-and-stock acquisition from Williston Basin E&P Grayson Mill, a deal analysts say will extend Devon's drilling runway and enhance shareholder returns.

The $5 billion Williston Basin acquisition—$3.25 billion in cash and $1.75 billion in stock—helps address Devon's inventory concerns, creates synergies and significantly expands the company's production base in the basin, Gabriele Sorbara, managing director of equity research at Siebert Williams Shank & Co., wrote in a July report.

The Grayson Mill acquisition adds another 307,000 net acres (70% working interest) to Devon's Williston Basin position.

The bolt-on is expected to boost Devon's inventory by around 800 gross locations, including approximately 300 refrac opportunities, the company said in an investor presentation.

Once combined, Devon will have around a decade of drilling inventory in the Williston Basin at a $80/bbl WTI oil price and a three-rig development cadence.

The majority of the 500 new well locations target the Bakken shale formation, while around 20% target the Three Forks interval, the company said on a call with analysts.

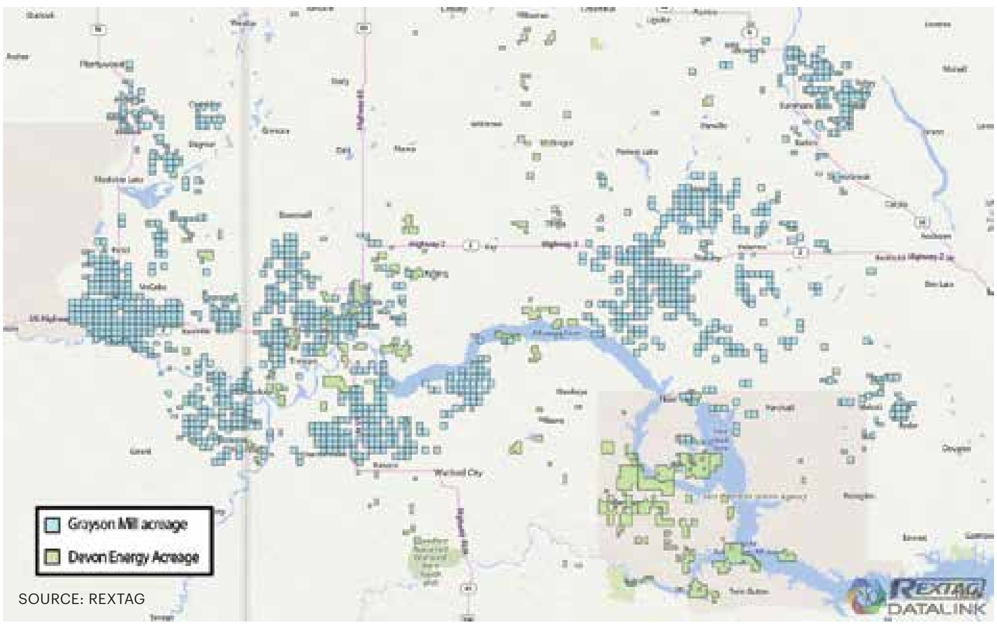
Around 40% of the new locations identified are 3-mile lateral wells; the rest are 2-mile wells.

The acquired Grayson Mill assets are expected to produce 100,000 boe/d (55% oil) in 2025, growing Devon's pro forma Williston production to approximately 150,000 boe/d (57% oil).

Other operators are hoping to find value and runway in the Williston Basin. TXO Partners, led by former XTO Energy executive Bob Simpson, recently announced entering the Williston Basin through acquisition.

TXO Partners' two Williston transactions—one with Eagle Mountain Energy Partners and the other with an undisclosed private seller—include assets in the Elm Coulee field of Montana and the Russian Creek field of North Dakota. OGI

Devon, Grayson Acreage in the Williston Basin



SOURCE: REXTAG

The Nuclear Option

In the Permian Basin and elsewhere, energy players consider adding small modular reactors and microreactors to their energy supply mix as electricity demand grows.

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In a politically polarized U.S. striving to lower greenhouse gas emissions while meeting seemingly insatiable electricity needs, a form of energy is shaking loose a longtime stigma.

Nuclear energy is gearing up for a potential rebirth.

But the technology is not the same as yesteryear.

Advanced small modular reactors (SMR), which typically pack up to about 300 megawatts (MW) of power, and smaller microreactors that usually have a capacity of less than 50 MW—are being weighed as an alternative power source by companies that include Permian Basin oil players and utilities in other parts of the U.S.

Championed for their smaller footprints, mobility and lower costs compared to larger nuclear plants, the nuclear reactor units are seen as a promising route to around-the-clock, emissions-free, baseload dispatchable power. Focus on nuclear energy has been gaining ground amid the continued drive to decarbonize while maintaining reliable access to power.

"There's a huge economic opportunity here to be an early player in these nuclear technologies for industrial applications because everyone's saying that demand is coming in very large quantities," Benton Arnett, senior director of markets and policy for the Nuclear Energy Institute (NEI), told *Oil and Gas Investor*.

Electricity demand in West Texas' Permian Basin alone is expected to increase significantly from 2022 to 2038, according to the Electric Reliability Council of Texas' (ERCOT) Permian Basin Reliability Plan Study that modeled loads that will need power. The study showed the load could reach nearly 23.7 gigawatts (GW) in 2030, more than double the 10.5 GW a 2021 Permian Basin study projected by 2030.

Of the forecasted 2030 load, Permian Basin oil and gas accounts for about 12 GW, while non-oil and gas—such as crypto, green hydrogen, commercial/industrial and data centers—accounts for about 11.7 GW. The non-oil and gas load was zero in the 2021 report, and ERCOT says that all but 6% of the anticipated 11.7 GW is confirmed by letter or contract.

"I do think we're on the cusp of a really big breakthrough in the industry."

BENTON ARNETT,
senior director of markets and policy, Nuclear Energy Institute

That's just the Permian Basin. The story of rising electricity demand is playing out across the U.S.

Higher anticipated demand is likely to bring along transmission needs, adding more stress to overwhelmed, aging electric grids.

"The question is, where's the generation going to come from? Who's going to build these generators? Who's going to build the poles and the wires to distribute all of that power?" said Nick Morriss, director of business development for Shepherd Power, the nuclear energy unit of NOV. "A lot of energy producers in West Texas are saying, well, we might have to do this ourselves."

In steps nuclear energy—more specifically, microreactors.

Evolving Technology

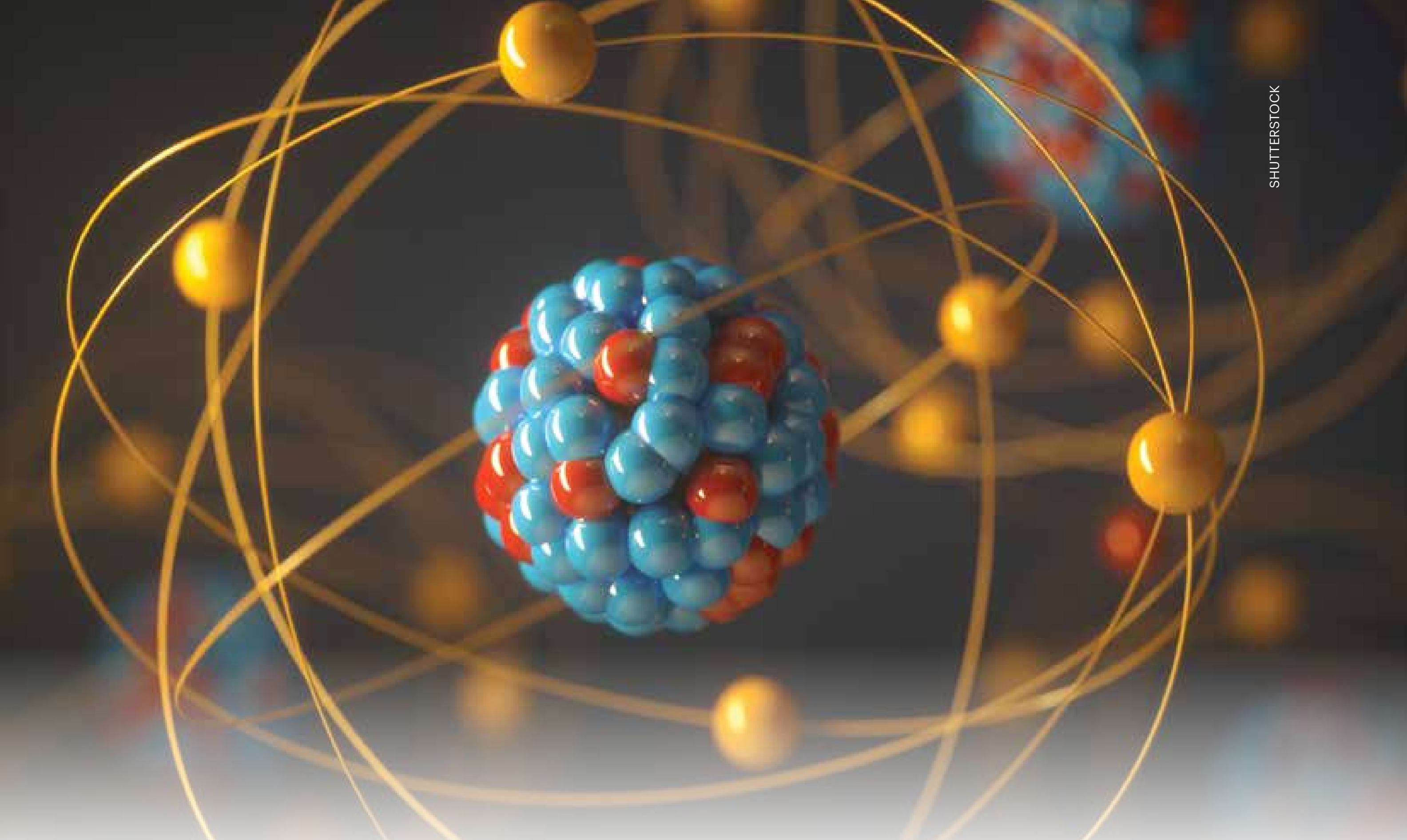
Talk of nuclear power revivals have surfaced in the past. However, costs, regulatory barriers and safety concerns lingering from a few accidents have prevented nuclear from taking off.

"What's different about this one, at least in our opinion, is that there's a really broad diversity of products that are in development right now," Morriss said, referring to SMRs, microreactors and other key technology breakthroughs in nuclear energy. "We think there's good potential there."

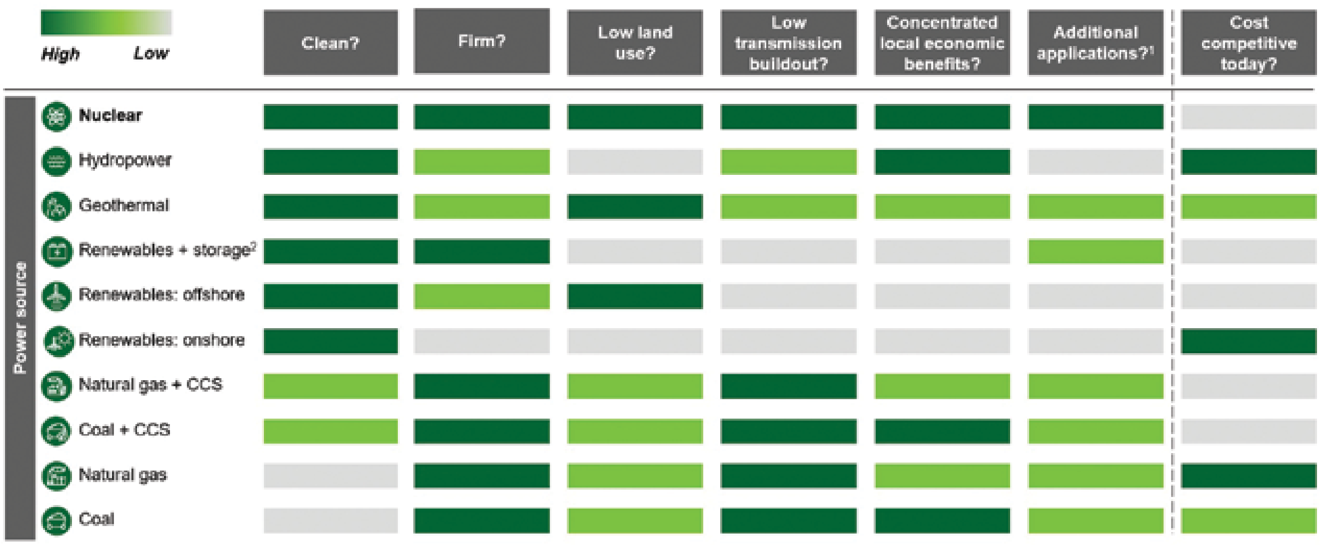
Among these advancements is TRISO fuel, which stands for tri-structural isotropic particle fuel.

Some past nuclear energy accidents were compounded when the fuel melted and radioactive elements released into the atmosphere, he said. However, TRISO fuel enables a step change in how fuels are manufactured, making them safer.

As explained by the U.S. Department of Energy (DOE), each TRISO particle—about the size of a poppy seed—is comprised of a uranium, carbon and oxygen fuel kernel, which is "encapsulated by three layers of carbon- and ceramic-based materials that prevent the release of radioactive fission products." The particles can withstand extreme temperatures and are more resistant than traditional reactor



Nuclear's Value Proposition



1. Additional applications include clean hydrogen generation, industrial process heat, desalination of water, district heating, off-grid power, and craft propulsion and power
2. Renewables + storage includes renewables coupled with long duration energy storage or renewables coupled with hydrogen storage

SOURCE: U.S. DEPARTMENT OF ENERGY'S ADVANCED NUCLEAR COMMERCIAL LIFTOFF REPORT

Six features contribute to advanced nuclear power's differentiated value proposition for a decarbonized grid.

fuels when it comes to neutron irradiation, corrosion, oxidation and high temperatures, according to the DOE.

TRISO fuels, which enable smaller designs and improved efficiency, are being used for SMRs and microreactors.

"We have a lot of industries that consume heat, not necessarily electricity. The reason why they've never really considered nuclear was because nobody wants to have a 500-acre nuclear plant next to their refinery or next to their industrial facility," Morriss said. "So, these microreactors that are fueled by this TRISO fuel form can be very small–like 20-foot shipping containers small in some cases. So, you can start to integrate them into different types of facilities. That fuel form is really one of the breakthroughs."

Gaining Interest

The advancements come as startups join more experienced manufacturers of nuclear components, working to roll out new tech and open facilities.

Nano Nuclear Energy, an emerging microreactor technology company, is advancing its technology following its IPO in May. Its technologies include Zeus, a solid core battery reactor, and ODIN, a low-pressure coolant reactor. Both are portable, on-demand capable, advanced nuclear microreactors.

California-based Oklo said it plans to deploy its first commercial advanced reactor in the U.S. before the end of the decade. The company's fuel source is "millions of times more energy dense, resulting in millions of times less land impacted by mining and increased reliability of fuel resources" compared to fossil sources such as natural gas and coal. Its fission power plants, which can run on recycled or nonrecycled fuel for decades without refueling, can be located wherever power is needed, according to the company.

Earlier this year, Diamondback Energy signed a 20-year power purchase agreement with Oklo for a 50-MW small nuclear reactor unit for its Permian operations. The company also landed a $10 million investment from U.S. pressure pumper Liberty Energy.

Longtime player Westinghouse, which has a 5-MWe microreactor called eVinci, is collaborating with Prodigy on floating nuclear power plants. BWX Technologies is assessing the viability of deploying small-scale nuclear reactors in Wyoming, among other projects. Dow and X-Energy Reactor are developing their first Xe-100 advanced small modular reactor plant at Dow's Seadrift, Texas, facility.

There are a "lot of different technology options for these players," Arnett said. Permian Basin operators are looking at microreactors, lured by their ability to serve as portable electricity generators that provide reliable carbon-free power.

Nano Nuclear Energy's Zeus nuclear microreactor is engineered to fit within a standard shipping container to facilitate its transport to remote sites.

"This isn't the only industry that we're seeing looking towards micros to create this kind of flexibility," Arnett said. "The Department of Defense has also been really active in developing microreactors for forward operating bases."

Virginia-based utility Dominion Energy put out a request for proposals from leading SMR nuclear technology companies as it evaluates using a SMR at the North Anna Power Station in Louisa County, Va.

Known for its oilfield equipment and technology, NOV established a unit focused on developing and deploying microreactors to help meet dispatchable power needs for not only oil and gas but also other industries.

"We are willing to buy, own and operate these microreactors in exchange for energy purchase agreements with oil and gas companies," Morriss said.

Shepherd Power essentially is a technology aggregator that builds the fleet of reactors and associated financial models for oil companies looking to electrify or build out new process heat systems for operations, according to Morriss. Shepherd will site, own and operate the reactors on behalf of the companies.

Microreactors can fit in any part of the oil and gas industry's main value chains: upstream, midstream and downstream. "It's not just the Permian," Morriss said, adding there's "no silver bullet just yet" in terms of applications.

Another advantage is that microreactors don't have to be connected to an electric grid. They can operate independently, part of a microgrid or as part of a grid.

Nuclear reactors have supplied about 20% of the power in the U.S. since the 1990s, according to the DOE. In 2023, nuclear power plants generated 775 billion kilowatt hours, enough to power more than 73 million homes.

GENSLER VIA OKLO

Oklo's Aurora powerhouse design is partially prefabricated and assembled onsite. The fast fission clean power technology and nuclear fuel recycling company has drawn interest from upstream E&Ps including Diamondback Energy, Occidental Petroleum and Liberty Energy.

Cost Considerations

Despite the growing interest and advantages, nuclear energy still has hurdles to overcome.

"Nuclear has a reputation of major cost overruns and timeframes. When you look at the Vogtle facility, which is the last large nuclear facility … just completed in Georgia, it was way over budget, way over a few years beyond when it was supposed to come online," said Jack Belcher, principal with Washington, D.C-based Cornerstone Government Affairs. "That is kind of the reputation hurdle that SMRs face. It's a different technology. We hope that it's a different risk profile, but it is new."

Decades ago, lowering costs and achieving economic viability typically meant building larger plants, Morriss said.

"There's another way to scale, and that is, you build a lot of them. And we've seen examples of this in countries like France," where units have been standardized and built at lower costs, he said. "In oil and gas, we experience this all the time. We built a lot of mega projects as an industry. And, NOV specifically [has] played a lot in offshore markets where we built drillships, for example, and we've lived serial production cost curve reductions over decades."

A similar path is required to bring down nuclear energy costs. The energy source wins on emissions but losses when it comes to costs when compared to natural gas, for example.

"You've got to remunerate early adopters with savings that are realized as those costs come down over time," Morriss said. "It's really a financial challenge more than a technology challenge."

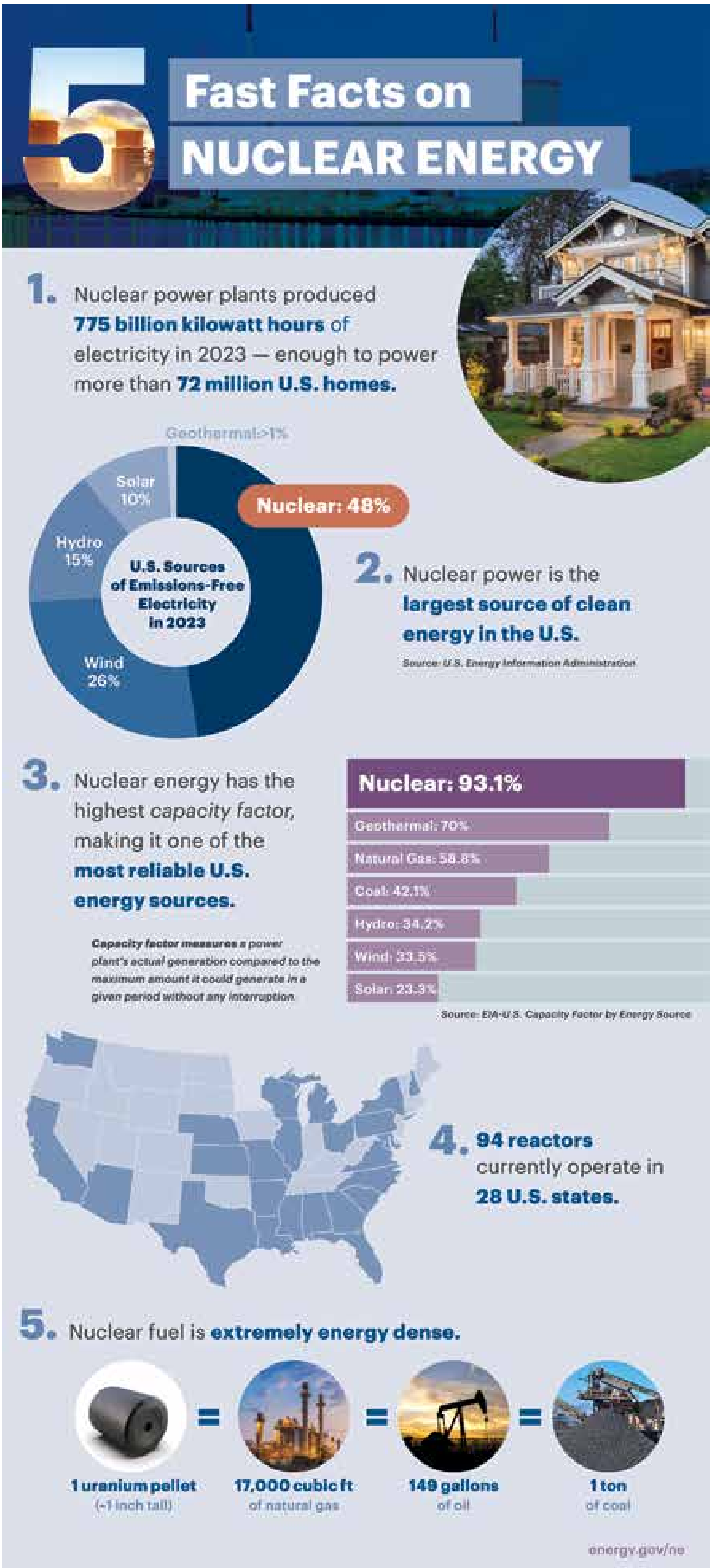
A study conducted by Lux Research showed the levelized cost of electricity of SMRs, for example, can be 25% to 60% lower than large-scale reactors, depending on location, if they are serially produced.

"Many developers are still in various stages of development and licensing, so it's hard to gauge if SMRs can climb the learning curve quickly and prove economic benefits," the study states.

Deployment of microreactors is also sensitive to production rates. Regulatory fees paid per reactor could hinder serial production rates, according to Lux.

Other Concerns

Then, there is the lingering stigma



associated with nuclear weapons, accidents and waste. A lawsuit involving the burial of nuclear waste is playing out in the Permian Basin.

As talk of microreactors and SMRs heats up, Arnett encourages folks concerned about nuclear energy to learn about the technology.

"The nuclear industry certainly needs to do a better job, I think, of telling that story. But, what we found is that when we go into communities and we start actually talking with folks about what the operational realities of these reactors are, the kinds of rigorous safety tests they go through," he said, "the kind of oversight they're going to continue to have both during construction and operation for the entire life of the reactor. And we look at the safety record of the nuclear fleet as a whole. I think folks really start to understand the technology and they get a lot more comfortable with it."

Plus, there are downfalls to all kinds of energy technologies, Arnett said, using air pollution and coal production as an example.

Regulations can help alleviate some of the risks.

"Right now, we are in a situation where … regulatory changes [are needed] to accommodate this new class of reactor. The Nuclear Regulatory Commission [NRC] designed all of their regulations around the idea of building these large, gigawatt-size style reactors, the old type of reactors that we used to build," Arnett said. Getting regulators to think about the differences and the inherent safety features will be important, he added.

Legislators appear to be on that path. Nuclear energy has emerged as one of the few topics that has bipartisan support.

Getting Aboard

The Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy (ADVANCE) Act overwhelmingly passed in the House and Senate.

"That's remarkable right now—in an election year, to boot," Morriss said.

The ADVANCE Act, signed into law by President Joe Biden in July as part of the Fire Grants and Safety Act, directs the NRC to lower certain licensing application fees for advanced nuclear reactor application reviews, authorizes more staff to carry out reviews and introduces prize competitions to incentivize deployment of advanced reactor technology. It also directs the NRC to develop guidance to license and regulate microreactor designs within 18 months.

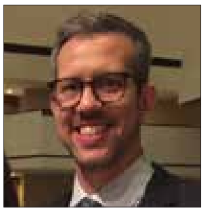
"We've finally seen the policy support in Washington from both sides of the aisle, strong bipartisan support … to move forward with nuclear as a solution," Arnett said. "I do think we're on the cusp of a really big breakthrough in the industry."

Efforts are also underway in states to advance nuclear energy. The Texas Advanced Nuclear Reactor Working Group was formed in 2023 to evaluate advanced nuclear reactors in the state, focusing on areas that include financial incentives, state and federal regulatory impediments to growth, Texas electric market impacts, technical challenges, and other factors, according to the Texas Public Utility Commission. Its findings and recommendations are due to Gov. Greg Abbott by Dec. 1.

"We're working to accelerate things in Texas from the regulatory side to incentives to utilizing state resources to get nuclear into Texas on a rapid scale," Belcher said. Nuclear energy's use in the oil and gas sector is among the group's areas of study.

"Oil and gas producers are looking at this in the same vein as manufacturers," Belcher said. "They can't afford to be without power and then when you look at isolated areas, SMRs make a lot of sense.… You can put them in remote areas and have reliable power."

Data centers are also considering SMRs as demand for AI grows, he added.



"We need to make these systems really small, really safe, and we need to make them applicable to a lot of industrial applications."

NICK MORRISS, director of business development, Shepherd Power

Moving Forward

Nuclear energy may be in a class of its own when it comes to delivering carbon-free reliable energy. Natural gas needs carbon capture and sequestration, a technology experiencing difficulties reaching scale, Arnett said, while renewables require batteries and transmission lines and geothermal has geographical limitations.

But moving nuclear energy forward and securing buy-in from Big Oil and other major energy users may ultimately come to cost.

"Our opinion is that a way to solve for that is to make these projects much, much smaller. And that's where microreactors come in.… The only thing standing in the way of making those economical is you've got to build a whole lot of 'em," Morriss said. "We need to make these systems really small, really safe. And we need to make them applicable to a lot of industrial applications."

He imagines a future—possibly 10 years from now—with SMRs at concrete plants, microreactors at drilling sites and maybe even small microreactors serving as a backup generator for grocery stores.

"People start to see these little devices in their daily lives. And that's ultimately what dispels the fear," Morriss said. "Then, we get to unlock nuclear energy for what it is, which is the most dense source of energy mankind's ever created. We need to be taking advantage of that, and we need to stop walking backwards into intermittent renewables and these Rube Goldberg carbon capture schemes. Let's get back to density, which is really the only form of energy transition that's ever worked. And, let's run head first in nuclear."

Arnett said he is most hopeful about the nuclear industry's partnership with the oil and gas sector.

"The nuclear industry certainly has a lot of knowledge to offer here, but the oil and gas industry's the best industry in the world with delivering projects. I think they're the only industry that delivers megaprojects on time, on budget," Arnett said. "We can learn a lot from their operational knowledge and project management knowledge and really work together to make this a really successful future." OGI

Major CCS Pipelines Inch Closer to Reality

Louisiana hands proponents a major victory for in-state development, but technical and political challenges remain.

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With the constant calls to reduce CO_2 emissions, you could be excused for thinking the U.S. was already building one of the proposed solutions: A pipeline network to transport the greenhouse gas to deep wells for storage forever.

Clearly, that hasn't been the case.

Some environmentalist groups say the projects will be ineffective. Some landowners have fought, successfully in one case, to kill projects before they began. The technical and economic issues required for a new type of line to deliver the project give some midstream companies pause.

However, at least two major interstate pipeline projects are on the drawing board in the Midwest, and the Louisiana state government recently completed a legislative overhaul to encourage the development of carbon capture and storage (CCS) projects that utilize the state's advantageous geography.

There are no major U.S. pipelines that ship CO_2 to permanent underground storage sites, but government and commercial actions over the first half of the 2020s has brought the new type of infrastructure closer to reality.

"Both 2023 and 2024 were big years as it relates to CCS," said Colleen Jarrott, an energy attorney with the New Orleans firm Hinshaw & Culbertson.

"Most folks are in the very preliminary stages of putting these projects together, which, as you can imagine, involve many steps before you even get to the construction phase."

COLEEN JARROTT,
energy attorney,
Hinshaw & Culbertson

On the Table

The Environmental Protection Agency (EPA) granted Louisiana primacy (primary enforcement authority) over Class 6 wells at year-end 2023. The EPA categorizes Class 6 wells as the deep wells needed for CCS.

The primacy designation allows the state to come up with a regulation regime over the projects, which legislators created and Gov. Jeff Landry signed into law in June.

"We did go ahead and change a number of our regulations that we had on the books, both in the 2023 legislative session and again in 2024," Jarrott said. "This most recent legislative session was to tighten up our regulatory scheme here in Louisiana to make sure that these projects are going to be safe and that they won't negatively impact the environment."

Critically for midstream companies, the legislation set up policies allowing for eminent domain in certain circumstances. The laws give pipeline developers more authority to secure rights to a pipeline pathway.

Louisiana is an ideal spot for developing CCS networks, Jarrott said. The state has one of the stronger energy industry sectors in the U.S., and its geographic make-up provides plenty of the "pore space" needed for permanent storage.

The idea is not new to the state. The legislature passed the Louisiana Geologic Sequestration of Carbon Dioxide Act in 2009, but it had little effect because CCS projects did not catch much attention at the time.

Over the last few years, however, companies have developed plans for intrastate CCS pipelines. About 30 carbon capture projects have been proposed in Louisiana, according to a tracker maintained by environmentalist group Clean Air Task Force.

Jarrott said it will take time for CCS pipeline and well developers to break ground on the proposals.

"Most folks are in the very preliminary stages of putting these projects together, which, as you can imagine, involve many steps before you even get to the construction phase," she said. "They are probably about a year or more out from granting the first application just because they do have to do a very intensive review, and the state wants to get it right."

Only two states besides Louisiana–Wyoming and North Dakota–have primacy for Class 6 wells, and both have major CCS projects in development.

Among the technical challenges facing construction of CCS pipelines is the complications CO_2 causes during pressurization, which means CO_2 transport pipes have to be built underground under normal conditions.

SHUTTERSTOCK

Tallgrass, one of the largest independent midstream companies in the U.S., plans to convert its 436-mile natural gas Trailblazer pipeline into a backbone for a regional network that would gather CO_2 for well injection in Wyoming. The line would have a yearly CO_2 capacity of 10 million tons/year and serve industries in Nebraska and Colorado, as well as Wyoming.

Tallgrass announced the plan after reaching an agreement with ADM in 2022 to take away CO_2 from ADM's corn-processing complex in Nebraska, according to analytical firm RBN. Tallgrass announced an open season for available capacity on Trailblazer in May.

As the midstream company with rights of way for Trailblazer, Tallgrass has a major advantage over other companies that are starting a pipeline network from scratch.

In Iowa, Summit Carbon Solutions is a company focused solely on creating a CCS network. Summit has planned a CO_2 gathering network that will run through five states before depositing the gas in North Dakota. The company has planned more than 40 overall capture facilities, tied primarily to ethanol plants in the corn belt.

The project made news in June, when the Iowa Utilities Board granted Summit permission to build in the state. None of the other states along the line have given Summit permission to build, and opponents of the network have announced their plans to take the Iowa board to court, possibly delaying any further progress until next year.

The federal government has also become an active participant in CCS projects. According to the Congressional Budget Office, the Infrastructure Investment and Jobs Act of 2021 increased federal spending on CCS to $4 billion in 2023. Most of the funds were for low-interest loans for eligible pipeline projects. The Inflation Reduction Act of 2022 also increased a federal tax credit for carbon capture from $50/ton to $80/ton for industrial removal and $180/ton for direct capture.

Old Tech, New Times

Carbon capture has been in use since the 1920s, when scrubbers were used to separate marketable gases in the oil and gas industry, according a study published by the Environmental Law Industry.

In the 1960s, the energy industry discovered that CO_2 could be injected into productive oil wells to enhance recovery. In 1972, Chevron put into service the world's first large-scale CO_2-enhanced crude recovery project in Scurry County, Texas.

The usage of CO_2 to enhance crude production is widespread today. CO_2 is the most commonly used material in the enhanced oil recovery process, according to the Congressional Research Service.

Jarrott said the CO_2 networks currently in use to produce more oil are different from those that will permanently store gas underground. The infrastructure requirements are not as resilient and require a Class 2 well instead of a Class 6 well.

According to the EPA, Class 6 wells are usually about 1 mile below ground. The rock in the area needs to be porous enough to absorb CO_2 like a sponge absorbs water. Proponents of CCS point to the potential a nationwide system could have in reducing the amount of greenhouse gas emissions produced in the U.S.

In 2017, the EPA estimated that the U.S. has underground space to store 1 trillion to 4 trillion tons of CO_2. The U.S. produced 6.3 billion tons of CO_2 in 2022.

Unsure Implementation

Despite the potential, the plans face challenges from several sectors of the public.

Last year, prior to the COP 28 Conference in Dubai, the International Energy Agency threw cold water on the likelihood of CCS developing rapidly enough to meet global standards.

"The industry needs to commit to genuinely helping the world meet its energy needs and climate goals–which means letting go of the illusion that implausibly large amounts of carbon capture are the solution," said Faith Birol, International Energy Agency executive director. Birol made the comment in November 2023, when the IEA released a report called "The Oil and Gas Industry in Net Zero Transitions."

The report stated the energy industry was not doing enough to cut emissions overall, and current reduction plans would not come close to the targets set by the Net Zero by 2050 goals.

"Carbon capture, currently the linchpin of many firms' transition strategies, cannot be used to maintain the status quo. If oil and natural gas consumption were to evolve as projected under today's policy settings, limiting the temperature rise to 1.5 degree C would require an entirely inconceivable 32 billion tons of carbon captured for utilization or storage by 2050, including 23 billion tons via direct air capture," Birol said in his statement.

"The amount of electricity needed to power these technologies would be greater than the entire world's electricity demand today."

The pipeline projects also face opposition from local opponents.

A third CCS project on the table, Navigator CO_2 Ventures' Heartland Greenway pipeline, died in October after the South Dakota government denied a permit. The project would have had a capacity of 15 MMmt/y of CO_2 from Midwest ethanol plants.

The opposition to these projects tends to consist of people typically on opposite ends of the political spectrum–environmentalists and people concerned about land rights.

In Iowa, opposition groups announced in mid-July that they would continue to fight Summit's plan. The groups include Republican legislatures and the Sierra Club.

"Our allies are our allies," said state Rep. Charley Thomson, who is part of a group of Iowan Republican legislators who have challenged Summit's permit application, according to a report in the Iowa Capital Dispatch. "I'm not going to pick a fight with the Sierra Club because we differ on some other issues. We are going to march together."

Carbonized Complications

Another concern for developers is the actual product. Shipping CO_2 through pipelines is not as straightforward as shipping natural gas.

CO_2 has almost three times the weight of methane, the primary ingredient in natural gas. CO_2 also has a much lower freezing point than methane, meaning that the greenhouse gas can turn to ice during pressurization and depressurization activities, said Ashutosh Nischal, a senior director of the low-carbon energy sector at Worley Group.

The technical challenges facing CO_2 pipelines are significant, he said during a session at the Carbon Capture Technology Expo in June at the NRG Center in Houston. Companies also face the problem of a lack of experience handling long-haul CO_2 pipelines.

"There's limited experimental data available for the designers, the manufacturers and the operators to use, which obviously stretches the confidence level of the industry," Nischal said.

One of the biggest problems researchers are currently studying is the reactivity of impurities within the CO_2 stream. Any water that is not filtered out of the CO_2 will tend to create inorganic acids, including sulfuric acid, he said. Corrosion will therefore tend to be a larger problem on CO_2 pipelines, as opposed to natural gas lines, which do not have the same kind of reactivity.

CO_2 also causes different problems during pressurization. The high pressures required to move the product essentially do not give midstreamers the option of building the pipe above ground under normal circumstances, he said.

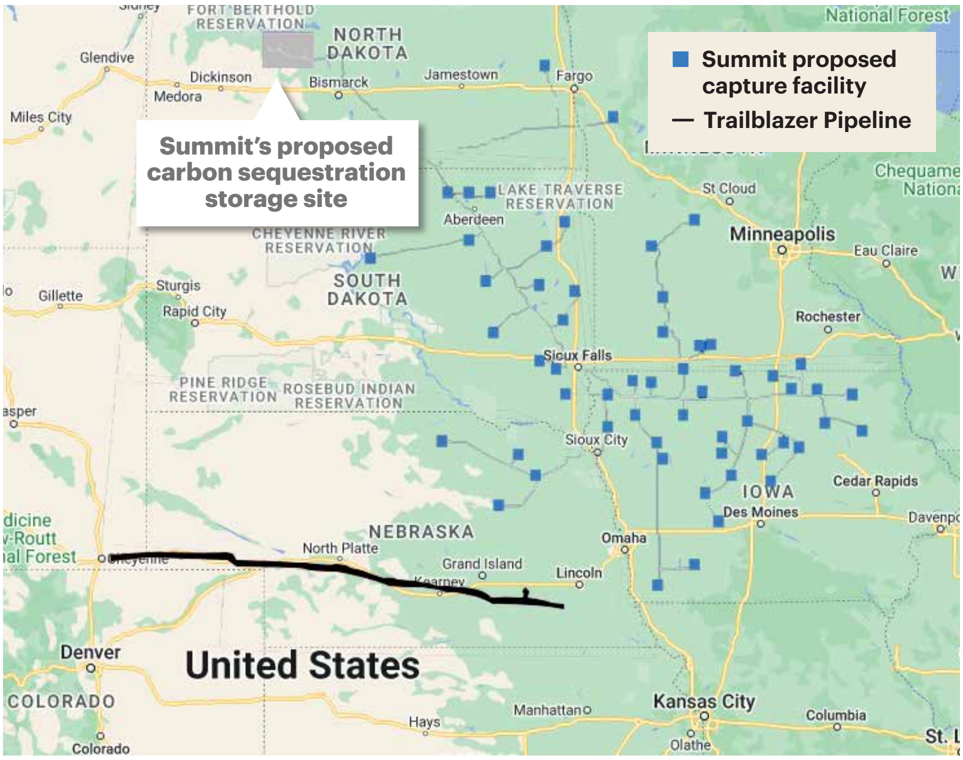
Midstream companies will therefore have to make strong effort to take into the new technical information for the systems.

"If you're not aware of it, then obviously you won't design for it," he said.

Nevertheless, Nischal said his company sees a strong market developing for CCS networks. The key for those entering the sector will be getting over the learning curve.

"We see a lot of interest by organizations trying to set up a carbon management business that is tapping into the ever-increasing demand of CO_2 transport," he said. "The industry data shows that the pipelines are one of the best-suited and most efficient ways of transporting the CO_2. Hence, there's an urgent need to facilitate pipelines for carbon management." OGI

Tallgrass, Summit Projects



SOURCE: SUMMIT CARBON SOLUTIONS, TALLGRASS

TRANSITION IN FOCUS

Carbon Management

Occidental's 1PointFive Agrees to Sell Carbon Credits to Microsoft

Carbon capture and sequestration company 1PointFive entered a deal to sell 500,000 metric tons (mt) of direct air capture (DAC) carbon removal credits to tech giant Microsoft.

As part of the six-year agreement, enabled by the STRATOS DAC facility being built by 1PointFive in Texas, captured CO_2 will be stored underground and not used to produce oil and gas. The agreement marks the largest single purchase of CO_2 removal credits enabled by DAC to date, according to 1PointFive, the CCUS business unit of Occidental Petroleum.

It is also expected to help push Microsoft toward its goal of becoming carbon negative by 2030.

Shell Takes FID on Carbon Capture, Storage Projects in Canada

Shell said it has taken final investment decisions on its Polaris carbon capture project at the company's Scotford refinery and chemicals complex in Alberta, Canada, and the Atlas Carbon Storage Hub with partner ATCO EnPower.

The moves are part of the company's plans to invest between $10 billion and $15 billion from 2023 to 2025 on low-carbon energy solutions.

Both projects are expected to start operations near the end of 2028, Shell said in a news release.

Designed to capture about 650,000 tonnes of CO_2 annually from the Shell-owned Scotford refinery and chemicals complex, Polaris' initial phase could reduce Shell's direct emissions by up to 40% from the refinery and by up to 30% from the chemicals plant, the company said.

Heirloom Makes Plans for Two DAC Facilities in Louisiana

California-headquartered Heirloom Carbon Technologies said it plans to create two DAC facilities at the Port of Caddo-Bossier in northwest Louisiana.

Construction of the first facility, located in Shreveport, La., is expected to start by the end of 2024. The facility is expected to remove about 17,000 tons of CO_2 from the atmosphere starting in 2026. The company said it intends to invest $475 million during the project's first phase.

The second facility, part of Project Cypress, will utilize up to $550 million from the U.S. Department of Energy. The regional DAC hub is being jointly developed in West Calcasieu Parish with Battelle, an applied science and technology nonprofit organization, and Swiss DAC specialist Climeworks. The hub's goal is to ultimately capture more than 1 million metric tons of existing CO_2 from the atmosphere when the facility reaches full capacity.

Heirloom's technology uses limestone to suck CO_2 from the atmosphere. Once absorbed, the CO_2 is extracted from the limestone material using a renewable energy-powered kiln and stored permanently underground, the company said in a news release.

Geothermal

Fervo Executes Two Geothermal Agreements with Southern California Edison

Houston-based Fervo Energy announced two geothermal power purchase agreements totaling 320 megawatts (MW) with Southern California Edison (SCE), according to a press release.

The two 15-year agreements will provide carbon-free geothermal energy for the equivalent of 350,000 homes across Southern California.

SCE will purchase the power from Cape Station, Fervo's 400-MW development in Beaver County, Utah, with the first 70-MW phase of the project expected to be operational by 2026. The second phase will be operational by 2028.

SLB, Ormat Technologies Form Geothermal Partnership

SLB and geothermal company Ormat Technologies plan to develop and deliver integrated geothermal projects with a focus on traditional and enhanced geothermal systems (EGS), the companies said.

Global energy services company SLB will utilize its knowledge on reservoir characterization, well completion and production technology for the projects, while Ormat will bring its geothermal field and project development, power plant design and manufacturing, operations and engineering, procurement and construction capabilities, according to news release.

As part of the partnership, SLB will license Ormat's EGS patent.

Hydrogen

Exxon Taps Air Liquide for Hydrogen, Ammonia Project

Exxon Mobil and Air Liquide entered an agreement aimed at producing low-carbon hydrogen and ammonia at Exxon's Baytown, Texas, facility, the companies said.

The project is expected to transport low-carbon hydrogen from the facility through Air Liquide's pipeline network. The project is on track to becoming the world's largest hydrogen facility and is slated to produce 1 Bcf of low-carbon hydrogen daily.

The companies expect the facility's ammonia production to reach more than 1 million tons annually while capturing 98% of associated CO_2 emissions.

RNG

FortisBC, EverGen Ink 20-year RNG Deal

Canadian utility company FortisBC signed a 20-year offtake agreement for renewable natural gas (RNG) from the Fraser Valley Biogas facility in British Columbia, RNG developer EverGen Infrastructure said.

FortisBC plans to inject the RNG into its natural gas system. The deal involves the purchase of up to 160,000 gigajoules of RNG annually, according to a news release. Fraser Valley Biogas uses anaerobic digestion and biogas upgrading to produce RNG. OGI

The ABCs of ABS: Technique Shows Flexibility and Promise

What can they do for an E&P? Quite a lot.

MARK DRUSKOFF
CONTRIBUTING EDITOR

Since their introduction, asset-backed securitizations (ABS) have caused some headscratching among E&P companies. At first, the big question was, "What are they?" But as the breadth and diversity of ABS transactions has grown, upstream companies are now beginning to ask, "What can they do for me?"

The answer, as it turns out, is quite a lot.

Getting Off the Ground

The first upstream oil and gas ABS took place in 2019 when EnCap Investments-backed Raisa Energy, an owner of non-operated assets, closed the industry's first rated securitization of oil and gas wells.

There was skepticism whether securitization could even work in oil and gas because similar structured financings had been tried with volumetric production payments, but it was difficult to get those rated by rating agencies, said Daniel Allison, partner with Sidley Austin.

The initial Raisa deal was followed by three more that ultimately resulted in Raisa raising $1 billion in gross proceeds through securitization of almost 13,000 wells in 60 counties across 10 states, according to company materials.

With ABS deals, producing assets are dropped down into a special purpose vehicle and production is protected with aggressive hedging–up to 90%–out five to seven years. That hedging enables ABS deals to secure a better rating from the ratings agencies, BBB or better, resulting in a lower interest rate.

Since 2019, dozens of ABS deals have been completed in the upstream space. While eye-catching, these deals have colored the general perception of what can and can't be done with ABS.

"If you take it back to the initial deals, the first few were conventional gas assets," said Victor Mendoza, managing director and head of oil and gas securitizations at Donovan Ventures. Although some investors will invest strictly in gas, most are agnostic, Mendoza said.

Rather, a primary driver for those early deals came down to deal flow, Mendoza said. Natural gas producers, particularly those with conventional wells, needed to monetize, yet M&A or A&D were not open to them, he said. So, they turned to an ABS. "It's a financing tool that can be used as a monetization tool," Mendoza said.

The futures curve also plays a significant part, said Anuj Bhartiya, senior managing director of Guggenheim Securities. Natural gas' future curve makes issuers more willing to lock in prices than they would with oil producers, he said.

While returning capital to investors is one of several uses of ABS proceeds, issuers have used proceeds to refinance RBL debt, cover capex or corporate development costs or, more recently, acquisition financing.

Maturing Market

As the number of ABS deals has grown, so has investors' confidence with the asset and the types of deals they are willing to underwrite.

Publicly Disclosed ABS Deals

Company	Play	ABS Amount
Diversified Energy	Appalachia	$2+ billion
Raisa Energy	Various	$1 billion
PureWest Energy	Green River	$965 million
Johan Energy	Green River	$750 million
Maverick Natural Resources	Anadarko	$640 million
Presidio Petroleum	Midcontinent	Not Disclosed
Caerus Oil & Gas	Rockies	$565 million
Terra Energy Partners	Piceance	$525 million
Vine Oil & Gas	Haynesville	$525 million

SOURCE: OIL AND GAS INVESTOR

PureWest Energy used an asset backed securitization in a sale of assets to a family office.

PUREWEST ENERGY

"The trend has absolutely changed to allow both unconventional and oilier deals," Mendoza said. "Investors have definitely shifted focus and the pipeline of transactions that are getting closer to market are more liquids heavy," he said, noting he is currently working on a 100% liquids deal.

Mendoza said he's aware of deals that have been done involving unconventional wells in the Permian Basin, and Eagle Ford and Barnett shales. California, with its significant conventional production, might also see an ABS, he noted.

Some of the first wells Raisa Energy securitized were oil heavy, Bhartiya said, so oil has been a part of the ABS story from the beginning. Another example is Midcontinent-focused Presidio Petroleum, which completed a securitization on wells that were more than 50% oil, he said.

Although commodity, well type or geography are not constraints, one area that does concern investors is well diversification.

In earlier deals, there was the notion that thousands of wells were necessary to allay investor concerns, "but that is definitely not a must-have in deals anymore," Mendoza said. Mendoza has seen an issuer with fewer than 200 oil producing wells secure an investment-grade rating from a rating agency.

The main issue is how much PV-10 value is concentrated in any single well, he said. If a single well represents one-quarter of the total value, it doesn't mean a deal can't get done, but it does mean the ABS will need to be priced for the greater risk, which means a lower advance rate. Excellent well diversification will result in higher advance rates of up to 65%, and in some situations even higher, but greater well risk will reduce that rate.

The wells also need to have been drilled and producing to show their stability, said Bhartiya. "The wells need some seasoning on them," he noted. But issuers need not be active producers. Bhartiya noted that Raisa was a non-op owner, and that he has also seen minerals owners that have used ABSs to monetize some of their holdings.

What's Next

Early ABS deals were notable for the length of time, 12 months or more in some cases, needed to complete and higher legal costs, said Sidley's Allison. But the duration and costs have come down dramatically.

ABSs have been completed in a little as six weeks, making them competitive with more traditional senior secured loans or high-yield offerings, he said. That opens up the ABSs to a wide range of potential issuers.

Because ABSs have been used in other industries, innovations from those other sectors are being introduced for oil and gas issuers. One emerging trend is the master trust, which enables serial issuance of securitizations as new assets get dropped into an existing structure, Allison explained, further lowering costs and transaction times.

Donovan Ventures' Mendoza envisions improvement in terms for E&P companies, such as an easing of the stringent hedging requirements.

Guggenheim's Bhartiya noted that more flexible hedging arrangements can be put in place so that producers can retain optionality with regards to changing commodity prices. Such flexibility will likely impact other parts of the structure, and could result in lower advance rates, he noted.

One area Bhartiya sees as promising is the use of ABSs for acquisition finance. Guggenheim helped put together an ABS to enable PureWest Energy to sell assets to a family office.

"I don't think it would necessarily be something that could be applied in all acquisitions. But where you have a willing buyer, a willing seller, and the timeline matches, it's definitely something we expect to see being used in future acquisitions in the right scenario." OGI

M&A Values: Permian Still No. 1

But the U.S. average has declined sharply, according to J.P. Morgan Securities.

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Permian Basin M&A remains the onshore Lower 48's priciest market in terms of dollars paid per flowing barrels of oil equivalent per day, while values in all other regions have fallen this year, according to a J.P. Morgan Securities analysis.

In 2024 deals, including the $26 billion Diamondback Energy bid for the Midland Basin's Endeavor Energy, the average winning offer is $38,398 per boe/d, analyst Arun Jayaram reported.

Jayaram reviewed deals valued at more than $100 million in Enverus' database.

The 2024 price for Permian barrels and associated gas is up from an average $36,778 per boe/d in 2023, which included Exxon Mobil's winning $64.5 billion bid for Midland Basin-focused Pioneer Natural Resources.

In Enverus' Rockies region, which includes the Bakken, and the Powder River and the Denver-Julesburg basins, values fell by 5%. Data show Rockies M&A values averaging $34,952 per boe/d value so far this year, down from $36,778 in 2023.

In the Midcontinent, which includes Oklahoma's Anadarko Basin, values declined to $24,167 from $27,149, or 11%.

And the Gulf Coast, which includes the Eagle Ford, has received winning bids averaging $27,181 per boe/d, down a precipitous 41% from $36,694 in 2023.

The gas-weighted Ark-La-Tex area, which includes the Haynesville Shale, has seen its value decline in step with gas futures. Deal values fell to $9,120 per boe/d so far this year compared to 2022's $15,492. Natural gas spot prices rocketed in 2022 due to new European demand for LNG as a result of the start of Russia's newest attempt to annex Ukraine.

More M&A Underway

Overall, the average price paid this year per boe/d throughout the U.S., including Alaska and the Gulf of Mexico, has declined sharply to $30,364 per boe/d from the 2023 average of $35,109 and 2022's $39,765, according to Jayaram's analysis.

But more dealmaking is underway, he added.

"At the J.P. Morgan energy conference in mid-June, most E&P operators echoed expectations of further consolidation activity in the industry," he reported.

Two major deals have been announced since the mid-June conference: SM Energy's $2 billion bid for Uinta Basin-focused XCL Resources and Devon Energy's $5 billion bid for Bakken-focused Grayson Mill Energy.

"An additional observation from our analysis is a decline in the mix of gas-focused transactions in 2024 vs. 2023 … while the share of 'oil+gas'-focused transactions has increased in 2024," Jayaram reported.

But 2024's profile may be updated before 2025, he added. "We caveat these metrics by noting that deal activity trends may change as the year progresses." OGI

A&D Activity by Year

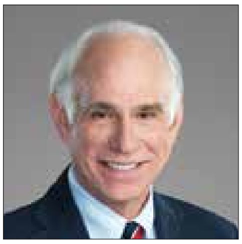
$ per Daily Boe

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024
Alaska	$45,600	–	$38,948	$58,002	–	–	–	–	–
Ark-La-Tex	$18,429	$17,550	$21,395	$13,500	$9,188	$10,552	$15,492	$13,180	$9,120
Eastern	$16,184	$15,880	$17,421	$19,205	$9,665	$9,000	$17,300	–	–
Gulf Coast	$30,264	$31,432	$44,633	$12,403	–	$33,023	$35,861	$36,694	$27,181
Gulf of Mexico	$19,125	$53,936	$36,528	$35,608	$29,249	$33,226	$45,375	$61,856	$43,000
Midcontinent	$20,226	$26,626	$22,226	$14,685	$16,638	$16,064	$27,692	$27,149	$24,167
Multi Region	$24,921	$49,680	$39,873	$31,298	$29,143	$22,878	$45,838	$33,499	$25,966
Permian	$31,271	$36,589	$36,388	$42,834	$20,666	$29,129	$46,640	$36,778	$38,398
Rockies	$28,323	$30,625	$36,749	$33,173	$12,163	$25,524	$35,668	$36,942	$34,952
West Coast	$25,944	$54,316	$38,435	$88,000	–	$28,333	$41,321	–	$27,632
Average	**$26,111**	**$31,812**	**$33,273**	**$30,273**	**$19,125**	**$24,301**	**$39,765**	**$35,109**	**$30,364**

SOURCE: J.P. MORGAN SECURITIES, CITING ENVERUS DATA

Hirs: Peak Oil Demand—Where Upstream Diverges from Downstream

The impact of peak oil demand is the same regardless of the sliding timelines published by the experts.



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Goldman Sachs' recent report finding that "peak oil demand" of 110 million bbl/d is not expected until 2034 is important mostly for what it implies: minimal progress toward reducing greenhouse gas emissions from a reduction in the consumption of oil; increased demand from developing countries will offset the declining emissions of industrialized nations' transition from hydrocarbons; and the U.S. downstream sector will shrink–increasing pain at the pump.

Most such projections assume a business-as-usual approach and simply extend current trendlines for energy intensity, such as gross domestic product (GDP) per barrel of oil equivalent. These projections show declining use of hydrocarbons in the U.S. being offset by increasing population in Africa, China and elsewhere with energy making up a fixed proportion of GDP. That energy supply will come from the least expensive resource–oil.

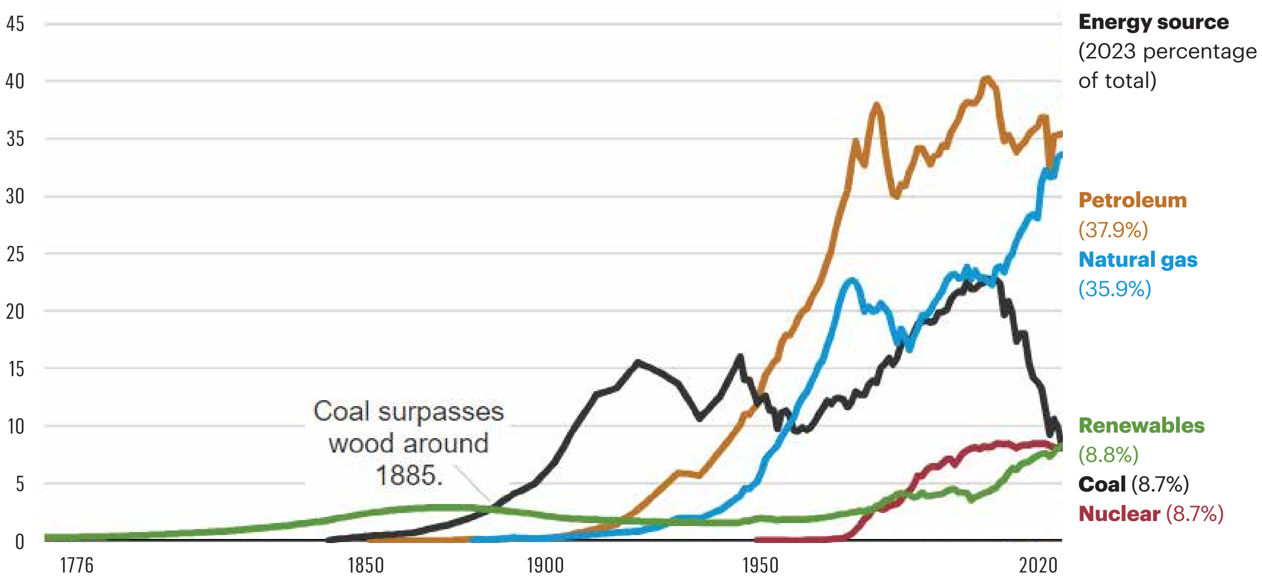
But whether the peak fits the Goldman year or slides down the timeline to 2045, as the OPEC Secretary General puts it, the impact will be the same: U.S. consumers will pay the price.

The market already is reacting. Global appetite for oil is growing and Western nations are grappling with how to help developing countries decarbonize without sacrificing the benefits of wider access to reliable sources of energy.

As with all commodities, the dynamics of the global oil market will be driven more by swing producers than by marginal producers. The swing producers, those that export their excess production, can create market conditions like those economists expect at peak demand. At this moment, these swing producers appear not to be as keen on replacing production as they once were. Baker Hughes reports

Annual U.S. Energy Consumption (1776-2023)

quadrillion British thermal units



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, MONTHLY ENERGY REVIEW. PRE-1949 DATA BASED ON ENERGY IN THE AMERICAN ECONOMY, 1850-1975: ITS HISTORY AND PROSPECTS AND U.S. DEPARTMENT OF AGRICULTURE CIRCULAR NO. 641, FUEL WOOD USED IN THE UNITED STATES 1630-1930

NOTE: DATA USE CAPTURED ENERGY APPROACH TO ACCOUNT FOR WIND, HYDRO, SOLAR, AND GEOTHERMAL.

the Middle East oil rig count was 259 at the end of May versus the pre-pandemic level of 324 at the end of January 2020. What is the right rate of replacement for production?

The OPEC+ countries can take comfort in these projections. Their unrealized wealth in the ground still has a robust future, but the prospect of stranded wealth is looming sooner rather than later. From a gaming perspective, the OPEC+ nations and other national oil companies, which control more than 80% of global oil reserves, will have to manage carefully to maintain market share. But first, they may want to eliminate the higher-cost producers and repeat the oil price war of 2014-2016. That would be devastating to U.S. producers.

U.S. producers also face the prospect of stranded wealth. A rush for the exits by U.S. producers and OPEC+ nations will drive down the price of oil. One considers the long decline of the U.S. coal industry, the bankruptcies, the restructurings, and now the cleanups as a prospect for domestic producers.

The higher-cost producers are in a precarious situation. The majors and Wall Street have run the math. Fields and refineries have been written off, as the owners simply harvest as much cash as possible. This increases the risks even for high-yield investors because they know the owners are no longer committed to reinvesting in the businesses.

> *“Market power will shift downstream to distribution and retail at the expense of upstream.”*

While the wellhead price may fall, U.S. gasoline and diesel consumers may not realize much benefit, even without the imposition of carbon pricing. Reduced domestic demand will accelerate the reduction in outlets and promote higher retail prices due to a lack of competition. Intersections with multiple gasoline stations are already a relic of history, and one can anticipate having to drive extended distances to refill a tank. Market power will shift downstream to distribution and retail at the expense of upstream.

Lower wellhead prices will make it exceedingly difficult for the developed nations to dictate carbon reduction mandates to developing countries. Price matters, and these developing societies will demand a bang for their buck and turn to oil, the least expensive energy resource.

Wealthy nations pursuing a low-carbon future need to act now to head off this demand growth. They will have to subsidize low-carbon energy resources for developing countries and the additional 3 billion in population growth expected by 2070.

We have come a long way from worrying about Hubbert’s Peak Supply to now worrying about Peak Demand for oil. The prospect of a future industry decline means fewer financial and labor resources will be forthcoming. That, by itself, may accelerate the decline. OGJ

Kissler: Protect the Petrodollar

No, the petrodollar isn't dead, but its demise would have far-reaching implications.

DENNIS KISSLER
BOK FINANCIAL SECURITIES

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

Recent reporting that Saudi Arabia would abandon the 50-year "petrodollar" agreement with the U.S. went viral on social media, though some have since called it "fake" news. Still, it's an idea worth examining and, more importantly, what losing close oil-market ties between the U.S. and Saudi Arabia could mean for the global oil market and the U.S. currency.

In the mid-to-late 1970s, Saudi Arabia and the U.S. agreed to work together to stabilize oil prices. Remember, during that time, the U.S. had incurred gasoline shortages and higher priced crude due to embargoes. As a result, the U.S. was looking for oil prices to stabilize. Meanwhile, the Saudis, who now had vast oil-producing assets, were looking for stable military protection and a safe haven to park their cash. And so, Saudi Arabia agreed that oil would be priced in U.S. dollars. In return, the U.S. agreed to add a larger presence of military force protecting Saudi Arabia.

Fast forward, around 50 years later: In January 2023, Saudi Arabia indicated that it was open to trading in other currencies. It seems that the Saudis are evaluating where they're parking their own money. In the 1970s, they wanted safety, so their needs were a good match with the U.S.'s. However, recently Saudi Arabia has been hearing a lot of noise from parts of Asia.

This noise all goes back to manufacturing. In the 1970s, the U.S. was the manufacturing powerhouse of the world by far. Now, China, India and other Asian countries are becoming manufacturing powerhouses and thus large oil consumers. When you add in Russia, which also has been gaining in manufacturing and commerce and is a major producer of oil, the result is that all of these countries (and especially China) can possibly help diversify Saudi Arabia's economy.

End of an Era?

For the U.S. and the oil market in general, the potential of the U.S. losing close ties with Saudi is concerning from a longer-term perspective. If the price of oil stops being traded in U.S. dollars and instead starts being trading in yuan, rubles or a new BRICS currency, that could destabilize the oil market.

So, why the potential destabilization? It's important to remember that there are worldwide service companies that base their payments in U.S. dollars. If they have to switch into having balances in multiple currencies, it would likely cause some instability, at least at the beginning. In fact, this potential instability is one of the reasons why I think the U.S. needs to be proactive in taking steps to keep close oil ties with Saudi Arabia and protect the petrodollar.

Potential Impacts

Another reason I think the U.S. needs to be proactive is the potential impact to the dollar's status as the world's reserve currency. If substantial amounts of oil go on the global market and are priced—that is, auctioned—in currencies other than the U.S. dollar, it could leave the dollar vulnerable to wider pricing swings. When this occurs over the longer term and in bigger volumes, it could give other countries the opportunity to strengthen their valuation versus the U.S. dollar. If that happens, it could pull investment dollars away from the U.S.

Moreover, if the worldwide service companies that base their payments in U.S. dollars switch currencies, a lot of the dollars that are floating around the globe could come back to the U.S. If that happens, it would most likely devalue the dollar and reignite inflation in the U.S.

Still a Lot of "Ifs" at Play

Now, will all this happen? Again, there are a lot of what "ifs" here, so nothing is certain. After all, foregoing the petrodollar has potential downside for Saudi Arabia, too. Keep in mind that the U.S. is the largest oil producer and still the largest oil consumer, so for Saudi to step out of that box could also trigger policy changes by the U.S. For instance, while U.S. refineries mostly rely on Middle East oil at this time, the U.S. could become more self-reliant, which could cause a backlash financially to Saudi.

All that said, oil sales out of the Middle East likely will still be a major factor for the U.S. for the next 20 years, so it's important to protect the petrodollar.

The Bottom Line

The fact that the recent story reporting the end of the petrodollar went viral highlights the sensitivity around currency shifts and the importance of avoiding devaluation. If we get a looser U.S. dollar due to our current rate of printing money, it could lead to inflation and devaluation. A lot of the money sent to Ukraine, although it was for military aid, could eventually make its way back to the U.S., which is also inflationary.

And so, while things may seem a little uneasy, nothing pertinent is likely to happen in the near term. But it is something the U.S. needs to address. I think the U.S. is going to stay the biggest oil producer and consumer on the world stage, but other countries, especially India and parts of Asia, are catching up quickly. If the U.S. keeps sending our manufacturing overseas without balancing it by producing things domestically, it will eventually work against us. OGI

New Mexican President, Same Reliance on Permian Gas

While Sheinbaum leans toward a stronger Pemex, U.S. producers are likely to maintain their relevance in Mexico.

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MEXICO CITY–An abundance of production from the Permian Basin has allowed Texas producers to find a welcoming natural gas export market in Mexico. That situation isn't likely to change under Mexico's next president, Claudia Sheinbaum Pardo, who takes office on Sept. 1. This bodes well for Texas producers and developers behind liquefaction plants on Mexico's Pacific Coast that will continue to tap the Permian for LNG feed gas.

The market for U.S. piped-gas exports to Mexico has remained robust for years owing to ongoing operational and financial woes at state-owned Petróleos Mexicanos (Pemex), which has struggled to revert declines in gas production. Pemex's domestic production continues to fall short of Mexico's demand for gas, necessitating imports.

"Importing gas, especially from Texas, makes tremendous economic sense–at least in the timeframe required to attract investment and develop Mexico's gas deposits," Mexico Business Forum President Roberto Salinas León told *Oil and Gas Investor (OGI)* from Mexico City.

"In my view, this should not merely continue, but in fact should be facilitated even further, especially if new nearshoring investments materialize. LNG processing and production represents a real opportunity for massive investment. That would also help diversify sources of gas and lessen dependance on spot market purchases," Salinas said.

Sheinbaum won Mexico's June presidential election by an overwhelming majority. The former mayor of Mexico City received 60.7% of the votes, according to Mexico's National Electoral Institute (INE). With her victory, the president-elect from the Morena Party will be the first woman president of Mexico and the first woman president of a North American country. Sheinbaum is a physicist of Jewish heritage and holds a doctorate in energy engineering from the National Autonomous University of Mexico (UNAM).

Sheinbaum has said that she doesn't believe in the "absolute privatization model," which she said hasn't worked in Mexico. And Sheinbaum plans to continue with national and sovereign development plans for Pemex and the Federal Electricity Commission (CFE). Her stance aligns with Mexico's outgoing President Andrés Manuel López Obrador (AMLO), who founded the Morena Party.

"Mexico's policymakers need to consider not only a lack of continuous and available energy, but also that sources of energy comply with their own corporate and buyer commitments."

ERICK SÁNCHEZ SALAS,
vice president of business development, Rystad Energy

Mexico's membership in the United States-Mexico-Canada Agreement (USMCA)–which entered into force on July 1, 2020, and which succeeded the North America Free Trade Agreement (NAFTA)–provides Mexican producers of goods and services direct access to the U.S. and Canadian markets.

Mexico's cheap labor is facilitating a nearshoring boom able to compete with China. Tesla CEO Elon Musk has revealed plans for the U.S. electric vehicle maker to build a massive plant in Mexico's northern Nuevo León state to take advantage of Mexico's manufacturing capabilities. Mexico's nearshoring boom is already helping to support an uptick in industrial, commercial and service building construction.

"Mexico's policymakers need to consider not only a lack of continuous and available energy, but also that sources of energy comply with their own corporate and buyer commitments," Erick Sánchez Salas, Rystad Energy's vice president of business development, told *OGI*.

"Our expectations are that global gas and LNG demand will continue to grow and, in the case Mexico is successful in capturing

President-elect Claudia Sheinbaum Pardo, left, and Head of Government-elect Clara Brugada wave at an event in Mexico City. U.S. natural gas exports are likely to continue to be welcomed in Mexico by the incoming Sheinbaum administration.

SHUTTERSTOCK

What to Expect Under Sheinbaum

Concept	Sheinbaum's Stance
Vision for Pemex	Policy continuity—Pemex at the center of the sector; however lower oil production targets compared to predecessor.
Government's support for Pemex	Ongoing, potentially linked to Pemex performance with respect to flaring, venting.
Natural resources nationalism/energy security	Supports resource nationaliism in fuel and natural gas independence.
Participation of private producers in the market/bidding rounds	Very limited potential of resuming bidding rounds, however a more technocratic approach could create a more favorable environment for private producers.
Independent market regulators	Unlikely to ensure independence of energy market regulators.
Energy transition objectives	Somewhat ambitious.
Environmental regulations	Tightening of environemental regulations for upstream producers, focused on routine flaring/venting & downstream assets performance.

SOURCE: CARBON BRIEF, BMI, A FITCHSOLUTIONS COMPANY

more relocating investments and industries, this will grow more," Sánchez said. "This again should be a call to action, not only for increasing gas production, but also [increasing] storage for strengthening energy security."

Sánchez continued: "There are a lot of areas of national integrated gas transportation and storage system (SISTRANGAS) that will be in need of expanding capacity. And in line with strategic projects such as the Transistmico [infrastructure project to connect the Pacific Ocean and the Gulf of Mexico], the demand for gas on the development poles will increase the national average and force investments to bring gas to the soon to settle industries in such poles."

Private Sector Involvement

Given resource constraints Sheinbaum will inherit, she will likely be more open to the participation of the private sector across various sectors of Mexico's economy.

Pablo Zárate

"It's true that there is continuity in the thinking that the state should play a much more significant role," FTI Consulting Senior Managing Director Pablo Zárate told *OGI*. "But Sheinbaum has been much more vocal in the need for private investment–and when you look at the fiscal constraints that both Pemex and the administration face, it's clear that there is no way in which she will be able to make progress on her broader economic objectives, such as advancing nearshoring, without it," Zárate said.

"Given the objectives, and Sheinbaum's background, it's reasonable to expect a much sharper focus on energy transition and the power sector than in E&P," Zárate said. "But, depending on how those play out, the last CSIEE or incentivized integral service contracts awards from Pemex could build up some momentum to talk again about the role of private investment in E&P—hopefully through also some form of farmouts and JVs with Pemex. So far, there have not been any announcements about incentivizing gas investments."

AMLO was elected with a campaign promise of a Fourth Transformation, which aimed to end corruption and reduce violence while boosting economic growth, expanding infrastructure and social programs designed to reduce poverty and inequality. The other three transformations include the Mexican Revolution, the reforms of Benito Juárez and Mexico's independence, AMLO said in early July.

Sheinbaum's election translates into continuity of the Fourth Transformation, Conor Beakey, associate director with BMI Consulting, said in May during a webinar.

Conor Beakey

"While Sheinbaum is an environmental scientist by training, she is also both a pragmatist and a leftist. The former means she recognizes that fossil fuels have a role to play for the foreseeable [future] and the latter [means] that she would rather domestically produce those fossil fuels rather than importing them from the U.S.," Beakey said.

Outside of oil and gas, Beakey said Sheinbaum has reaffirmed her support for the government's existing plans to double green energy production by 2030 with solar, in particular, likely to play a big role.

Sheinbaum's initial foreign policy test will relate to the November presidential election in the U.S., which is of critical importance for Mexico.

"We are going to see in Mexico over the next weeks and months to come until September, namings on the rest of the president-elect's cabinet," Rystad's Sánchez said. "This will be a first sign of the route [her] policies will take."

Gas Demand to Keep Rising

In 2020, Mexico had estimated gas reserves of 6.1 Tcf, according to data published in BP's Statistical Review of World Energy. That's just enough to last another 5.9 years. And gas-short Mexico imported an average 6.6 Bcf/d of gas from the U.S. during the week ended June 26, according to data from the U.S. Energy Information Administration (EIA).

Mexico's internal gas demand will continue to grow through 2032, according to Mexico's Energy Secretariat (Sener). In 2032, Mexico's gas demand could reach 9.9 Bcf/d, according to the Sener, up from around 8.9 Bcf/d expected in 2024. The rise in gas demand will primarily be dominated by the electric sector, which will represent around 53.3% of total demand in 2032, followed by industrial (24.3%), petroleum (20.2%), residential (1.4%), services (0.7%) and transport vehicles (0.1%).

Mexico's domestic production will be insufficient to cover domestic demand through 2032, according to Sener's estimates. This, despite higher expected production from Pemex, which will force Mexico to continue to rely on gas imports from the U.S. or other destinations.

Sheinbaum has indicated she would facilitate higher domestic gas production to ensure Mexico's gas independence. However, Mexico will continue to rely on U.S. piped-gas imports due to ongoing financial and operational headwinds that confront Pemex that are likely to hamper such efforts, BMI Consulting Senior Oil and Gas Analyst Dominika Rzechorzek said during the firm's webinar in May.

"In our view, Sheinbaum will most likely continue AMLO's policies in facilitating investment in export infrastructure."

DOMINIKA RZECHORZEK,
senior oil and gas analyst, BMI Consulting

"Sheinbaum will likely maintain Pemex's dominant position in the upstream and downstream markets, although we could see her tightening regulations for Pemex, in particular environmental standards for the upstream operations. We expect Sheinbaum to continue supporting Pemex as it is in-line with her resource nationalism stance," Rzechorzek said.

In terms of private companies and their participation in the market, Sheinbaum is expected to be more technocratic than her predecessor, AMLO. This approach will likely improve the relationship between the Mexican government and international oil companies (IOCs), according to Rzechorzek. However, Sheinbaum is not expected to resume bidding rounds or facilitate higher participation of private producers in the market.

While Mexico will continue to lean on the U.S. for piped-gas to fulfill increasing domestic demand, it will also need additional volumes to support plans by a handful of developers looking to build liquefaction export capacity on Mexico's west coast.

Mexico is making a big bet on LNG exports, especially from its Pacific Coast, which provides a direct route to the Asian markets with their increasing appetite for LNG and especially from North America. Mexico's LNG projects will source low-carbon feed-gas from the Permian and will avoid the need to send cargoes through the Panama Canal.

Five projects proposed by Sempra Infrastructure, Mexico Pacific and LNG Alliance Pte Ltd. Singapore have potential to bring to market 59 million tonnes per annum (mtpa) of liquefaction capacity, or around 7.8 Bcf/d over the short-to-medium term, according to data compiled by *OGI*.

But getting there won't be easy and Mexico's LNG exporting success depends on the completion of liquefaction plants and crucial pipelines from the Permian.

BMI sees relatively limited risk to Mexico's LNG forecast, and like Poten & Partners, expects Mexico to become a net exporter of LNG in 2024.

"In our view, Sheinbaum will most likely continue AMLO's policies in facilitating investment in export infrastructure," Rzechorzek said. "However, we highlight lingering challenges primarily [related to] lacking midstream and road infrastructure which could delay some of those projects in pre-FID stage."

U.S.-Mexico Bilateral Relations

Mexico is the U.S.' largest trading partner, surpassing even Canada and China, AMLO boasts almost daily during his "mañanera" or early morning press conference with the media.

U.S. bilateral trade in goods with Mexico reached $779.3 billion in 2022, the Section of Economic Affairs of the Embassy of Mexico to the U.S. said in a report in March 2023. Of that, Mexican imports totaled $454.9 billion with exports of $324.4 billion. The robust trade is a result, among other factors, of global supply chains specialized in the electric and industrial machinery sectors, as well as automotive, according to the embassy.

In fact, bilateral trade between southern U.S. states and Mexico is larger than the U.S.' trade with all of South and Central America combined. Mexico's largest partner is Texas, which boasted bilateral trade of $285.6 billion in 2022, according to the embassy.

Petroleum and coal products, as well as oil and gas exports from the U.S. to Mexico represented 18% of the north-south trade flows. However, U.S. oil and gas imports from Mexico represented just 5% of the south-north trade flows.

"AMLO managed to avoid conflict with [former U.S. President Donald] Trump and [President Joe] Biden, the former through appeasement and the latter through circumstance," said BMI's Beakey.

A Biden reelection would pave the way for a continuation of the status quo, while a second Trump presidency poses meaningful downside. Republicans view border issues as Mexico's problem and have advocated imposing economic sanctions should this situation fall to improve, Beakey said.

A Trump reelection will not entirely undermine near-shoring since the USMCA was Trump's deal, Mexico will retain significant cost advantages and Sheinbaum will adopt a conciliatory tone.

"Mexico buys more from the U.S. than any other country in the world and it sells more to the U.S. than any other country in the world," Mexico Business Forum's Salinas said. "The opportunity to take North American integration to the next level is reason enough to care deeply about what happens in Mexico, the U.S. and Canada." OGI

MEXICO ELECTION IMPACTS ON US-MEXICO ENERGY TRADE

Q&A

Mexico Energy Forum President Roberto Salinas León shared his thoughts with Oil and Gas Investor *on a number of themes related to recent elections in Mexico, the direction Mexico's next president could take on different policy fronts as they relate to the CFE, and Pemex. Salinas studied at Hillsdale College in Michigan from 1979 to 1983 and earned a Master of Arts and Ph.D. in philosophy from Purdue University in Indiana.*

Pietro Donatello Pitts: If Claudia Sheinbaum Pardo continues with the ideas of AMLO to strengthen CFE and Pemex and others, what opportunities are there then for U.S. investors interested in Mexico's energy sector? Will there be opportunities in the upstream (E&P) or pipeline sector or renewables?

Roberto Salinas: In truth, not many. The misguided nostalgia for returning Mexico to 1970s energy statism constitutes a misplaced understanding of "national sovereignty." Pemex is de facto bankrupt, with over $105 billion in outstanding debt and another $37 billion in other liabilities–suppliers, taxes and "other costs."

Moreover, production has declined from 1.8 MMbbl/d to 1.5 MMbbl/d. There is no possible way to reconcile this stubborn ideological adherence to state monopoly in energy with the need for greater investment that could materialize under the window of opportunity afforded by the nearshoring phenomenon. Pemex has absorbed over 1 billion pesos in taxpayer money to keep it afloat in the AMLO sexenio or six-year term. This is unsustainable.

CFE reflects a similar story. Mexico will not be able to keep up with overall demand without new private investment in production, transmission lines and distribution. Nearshoring opportunities will lose out to other investment regimes capable of supplying affordable and reliable electricity inputs. No reliable electricity? No Tesla, no Amazon, no new nearshoring investments. Perhaps even Mexico Pacific. Is this how political dinosaurs construe "national sovereignty" and self-sufficiency?

Roberto Salinas León, president of the Mexico Energy Forum, believes private investment is essential for the Mexican energy industry to succeed.

ROBERTO SALINAS LEÓN

Sheinbaum will need to maneuver a U-turn on both these policy fronts. There is, in addition, tremendous opportunity in renewing rounds in the upstream sector and pipeline infrastructure, especially in the southeast region. Sheinbaum could rather swiftly revitalize the enormous interest that materialized in renewable energy investment prior to the destructive onslaught launched by the AMLO administration, particularly solar energy in states like Baja California, Chihuahua and Sonora. Moreover, it behooves Sheinbaum to adopt a more open and pragmatic stance in energy investment, especially in light of the forthcoming revision on USMCA in 2026.

PDP: Are there any problems related to pipelines that currently export U.S. gas to Mexico and how do you view future expansions to handle at least a doubling of gas exports if the Mexico LNG plants move forward and eventually come online?

RS: This is an issue of cost-benefit analysis, which the AMLO regime wantonly abandoned and the Sheinbaum era will hopefully reinstate. What if all the massive amounts of resources earmarked to the Maya Train had been invested instead in a pipeline project to facilitate transport of gas to the southeast region? Sheinbaum will need to think out of the box and neutralize the ideological radicals in the Morena party to capitalize on such badly needed infrastructure needs.

PDP: As China and other countries try to take advantage of the U.S. Inflation Reduction Act (IRA) and USMCA to get access to the U.S. and Canada markets via Mexico, what are the biggest headwinds China and other countries or companies face with that strategy? Is a lack of reliable energy at the top of the list? What about issues around water scarcity?

RS: The main obstacles surrounding all forms of nearshoring investment opportunity are: water scarcity, unreliable energy and electricity inputs, human capital development and availability, and rule of law. The latter is arguably at the top of the list, as organized crime has sought to infiltrate and profit from the advent of new investment projects linked to nearshoring. The presence of Chinese investment projects will also represent a serious issue for discussion in the renewal of USMCA, especially if Donald Trump wins.

PDP: Assuming a Trump victory in November, how do you see U.S.-Mexico trade issues evolving? What about under another Biden term?

RS: There is, paradoxically, a very good opportunity for Mexico if Trump wins, given the persistence of the U.S.-China "trade war." Mexico is the obvious and natural ally to consolidate what is already the most competitive region in the world, namely, North America. Trump needs to abandon the useless and silly principle that interprets trade as a zero-sum game, or as an exercise in corporate bookkeeping, and insist instead on resolving disputes in energy and other matters, all that have remained unanswered under an increasingly (and highly disappointing) protectionist Biden administration. OGI

Mexico's Zama Drama Endures for Talos, Other IOCs

The Block 7 consortium could make FID on the offshore field development in the next year, but it continues to encounter obstacles.

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MEXICO CITY—In shallow waters offshore Mexico, the Zama field development in Block 7 has been granted "strategic project" status by both the country's federal government and the state-owned Petróleos Mexicanos (Pemex), according to the project's former operator Talos Energy.

But despite the importance placed on Zama to up Mexican oil production and secure energy security for the country, the consortium developing the field continues to run into headwinds.

The Zama field is located within Mexico's Sureste Basin, a prolific proven hydrocarbon province off the coast of Tabasco state. Identified in 2017, the Zama field discovery was the first find in Mexico made by an international consortium. At the time, Talos was the project's operator, along with partners Sierra Oil and Gas, and Premier Oil.

Less than a decade later, Talos remains a mainstay within the Block 7 consortium, in addition to new names: Pemex, the U.K.'s Harbour Energy, Germany's Wintershall and most recently, Mexico's Grupo Carso.

Pemex is now at the helm of the project after being designated as operator by Mexico's Energy Secretariat (SENER).

The Block 7 consortium could take final investment decision (FID) for Zama in late 2024 or sometime in 2025, according to consensus estimates from analysts with U.S.-based consultancies Welligence Energy Analytics, Enverus Intelligence Research and Pickering Energy Partners. Recent estimates from the Paris-based International Energy Agency (IEA) concur with the latter date.

"The new [Claudia Sheinbaum Pardo] administration will have to get her team going, and that could entail more time on the runway before the first steel is cut for [the Zama] development," Josephine Mills, Enverus senior associate, told Hart Energy.

Zama ranks as one of the world's largest shallow water discoveries in the past 20 years and could produce up to 180,000 bbl/d, according to independent estimates published by Block 7. Such production would represent 7% of Mexico's equivalent production in 2023, which was 2.67 MMboe/d (1.85 MMbbl/d of oil and 4.9 Bcf/d of gas), according to Pemex data. From an oil production standpoint, Zama's production would represent 10% of Mexico's 2023 oil production.

180K bbl/d
potential production from Zama

Projects such as Zama are expected to counter the long-term production decline that confronts Mexico, Andres Armijos, Welligence's vice president and head of Latin America research, told Hart Energy. But the actual Zama production figure could be lower.

The IEA has pegged Zama's peak production at 150,000 bbl/d. Pickering Director Kevin MacCurdy told Hart Energy that initial production could be closer to 100,000 bbl/d.

Zama's production start date could be 2030 or before, based on consensus analysts' estimates. Its production is expected to be 94% oil of excellent quality, with API gravities between 26° and 29°, according to Talos.

30
years in production-sharing contract

Armijos views Zama as one of the emblematic projects for Mexico's energy reform. The plans were first announced by the administration of Enrique Peña Nieto, the president who preceded outgoing president Andrés Manuel López Obrador (AMLO).

"It's key to see how it succeeds," Armijos told Hart Energy. "I think the expectation is that [Zama will] go forward."

Sheinbaum takes over as Mexico's president on Sept. 1. The country's political pundits do not expect drastic changes to the its energy sector.

Sheinbaum has said she would continue with national and sovereign development plans for Pemex and the Federal Electricity Commission (CFE). Her stance aligns with AMLO's.

The incoming president holds a doctorate in energy engineering, which could translate into positive things to come for Mexico's energy sector, especially in the clean energy space.

Wintershall Dea operations on the offshore Mexico platform "Central." Along with Pemex, Talos and Harbour, Wintershall will co-lead different work groups to provide technical, operational and execution expertise to develop Zama oil field, one of Mexico's most important energy projects at present.

PHOTO CREDIT

"Zama breakevens will be paramount to the new Pemex administration. There is also a fair amount of pride of having a Mexican player involved now (Grupo Carso). Given Zama's material resource and low breakeven cost, we estimate Pemex will likely prioritize Zama over other capital projects."

JOSEPHINE MILLS, senior associate, Enverus Intelligence Research

Sheinbaum's more technocratic approach to policy making could result in an improvement in the business operating environment, which favors international oil companies (IOCs).

But bidding rounds aren't likely to return, Dominika Rzechorzek, senior oil and gas analyst with BMI, a Fitch Solutions company, said in May during a webinar. BMI expects Sheinbaum, an environmentalist, to pressure Pemex more on flare reduction and pollution.

The Zama Drama

In July 2015, Talos and its Block 7 partners Sierra and Premier executed a production-sharing contract (PSC) with Mexico's oil and gas regulator, the National Hydrocarbons Commission (CNH). The PSC was awarded during the first tender of Mexico's oil and gas fields in over 80 years. The PSC's term was for 30 years starting in September 2015, with the option to extend for two additional five-year periods. Talos originally had a 35% interest in Block 7.

In 2017, the consortium made a significant discovery after drilling the Zama-1 well. At that time, SENER estimated Zama's original oil in place to be between 1.36 Bbbl to 2 Bbbl. SENER also said it expected the resource base to contribute significantly to Mexico's energy supply over the next 25 years.

Following the Zama-1 discovery, Talos drilled three additional wells to further appraise the discovery. The company determined that the field likely extended into a nearby offshore block owned by Pemex.

The Block 7 consortium and Pemex engaged a third-party reservoir engineering firm to evaluate initial tract participation. The firm concluded that the consortium held 49.6% of the gross interest in Zama, while Pemex held 50.4%. SENER subsequently designated Pemex as the operator of the Zama unit, in effect replacing Talos.

An independent third-party reserve auditor estimated Zama's recoverable resources at 735 MMboe-950 MMboe, Talos said in March 2022.

The Zama drama seemingly took a positive turn for the consortium due to two events in 2023. In June, Mexico's CNH approved the Zama Unit Development Plan (UDP). In September, a key partner with deep pockets, Grupo Carso, joined Block 7. Grupo Carso is controlled by the family of Carlos Slim, with net worth estimated at $96 billion.

"Zama breakevens will be paramount to the new Pemex administration. There is also a fair amount of pride of having a Mexican player involved now (Grupo Carso)," Enverus' Mills said. "Given Zama's material resource and low breakeven cost, we estimate Pemex will likely prioritize Zama over other capital projects."

The Slim group joining the consortium is "certainly a positive in helping to de-risk the entire project," Pickering's MacCurdy said. "Any time you have a large [exploration] success and you're able to develop it and get some cash flow, it confirms the value proposition that you offer as a company."

Most recently, DORIS Group, a French engineering company, was awarded a FEED contract for Zama. DORIS will collaborate with the two Mexican engineering companies, NOMARNA and SUMMUM, to carry out the work, Wintershall said in June. When these studies have been finalized, the Zama Unit partnership will proceed with the tendering of engineering, procurement and construction contracts, followed by FID.

"Zama is currently one of the most important energy projects in Mexico, and we are very pleased to have reached the next milestone," Martin Jungbluth, managing director of Wintershall in Mexico, said in a press release.

But the drama is not over. Pemex, the world's most indebted oil company with around $101 billion in debt, will be put to the test soon. Heavy financial commitments to the Mexican government continue to restrain Pemex. Its production is well below historic peaks and accidents happen frequently.

"Pemex is naturally in financial problems, which is the main reason for the decrease in investments and the production levels as well," Holland & Knight Partner Rodolfo Rueda said in May during a webinar.

Also, Talos' drop to non-operator status means its ability to exercise influence over operations and associated costs will be limited, the company warned in its 2023 annual report.

None of the companies in the Block 7 consortium immediately responded to emails from Hart Energy requesting comments for this story.

Zama Development Plan

Pemex submitted the UDP to Mexico's CNH for formal approval in March 2023 and it was approved three months later. Modifications to the plan were approved by CNH in February 2024.

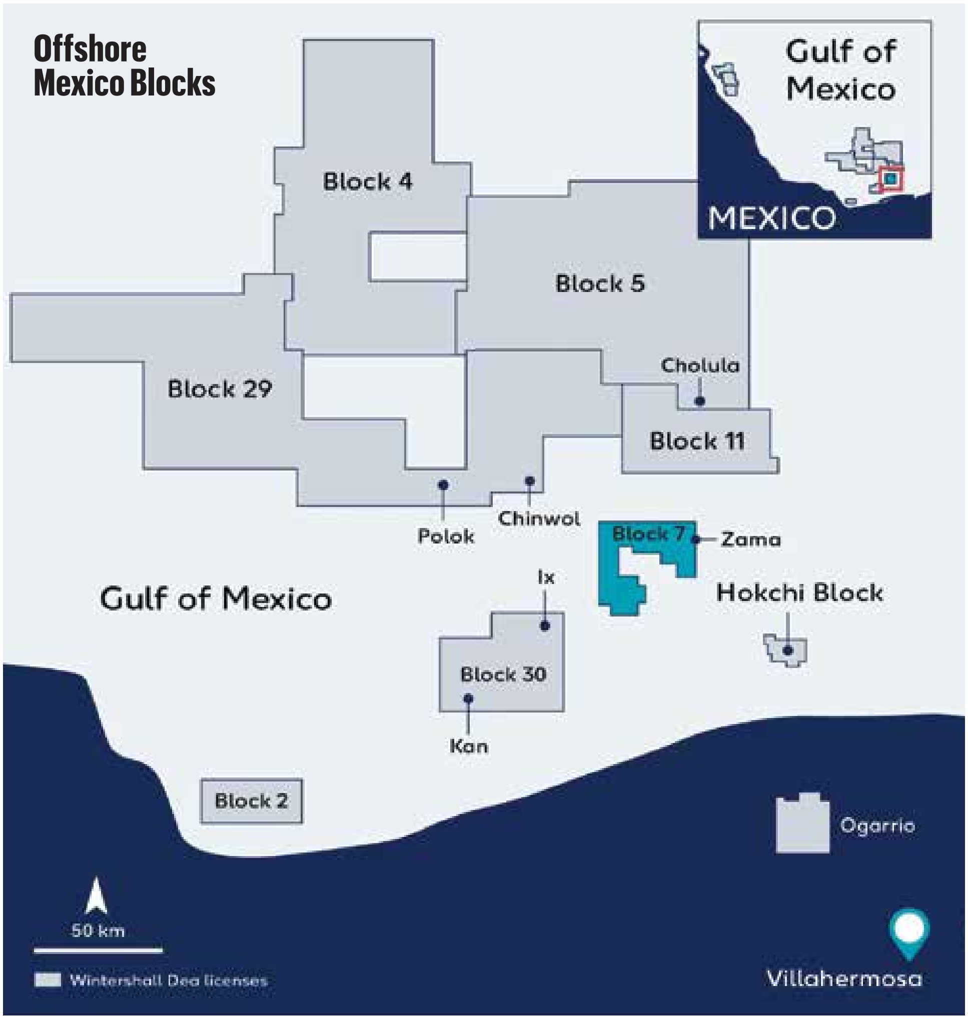
As part of the UDP, the Block 7 consortium also agreed to form an integrated project team that would allow it to pool the talents and competencies of all companies participating in the development of the field.

Wintershall, Pemex, Talos and Harbour will co-lead different work groups within the team, which will provide technical, operational and execution expertise.

The UDP proposes installation of two offshore platforms and the drilling of 46 wells. Offshore production will be shipped by two 68-km pipelines. Once onshore, the oil will be processed in new facilities fully dedicated to the Zama project in the Dos Bocas Maritime Terminal in Paraíso, Tabasco state.

Despite the positive advancements, international investors do not appear to be reassured. Welligence's Armijos called Mexico's not yet changing the terms of contracts a saving grace.

"The reality is that projects [like Zama and Woodside Energy's Trion] are coming online in this decade, but [Pemex] still has a problem with declining production across the country," Armijos said. "You have a huge set of assets that you could potentially find players who are better suited to develop them rather than Pemex." OGI



SOURCE: WINTERSHALL DEA

Dark Days for Golden Pass

The LNG export project is eight months behind schedule and some $2 billion over budget after its contractor filed for bankruptcy.

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QatarEnergy and Exxon Mobil's $9.25 billion Golden Pass LNG project has seen more golden days.

A bankruptcy filing by primary construction firm Zachry Industrial, a subsidiary of Zachry Holdings, has resulted in the 18 million tonnes per annum (mtpa) facility being eight months behind schedule and at least $2 billion over budget. Doha-based QatarEnergy owns 70% of Golden Pass and Texas-based Exxon Mobil owns 30%.

To move the project forward, QatarEnergy and Exxon Mobil will likely skip out on selecting a new lead contractor, East Daley Analytics energy analyst Oren Pilant told Hart Energy in July.

Zachry served as the lead contractor and was responsible for 52% of the work at Golden Pass, according to Pilant. McDermott International and Chiyoda International were the only other construction firms working on the project.

"They will probably move forward with McDermott and Chiyoda by splitting Zachry's scope of work between them," Pilant said. "Bringing in a new EPC (engineering, procurement and construction) contractor at this stage would be prohibitively expensive; cost overruns are almost a given so any new contract drawn up would be more expensive."

In an emailed statement to Hart Energy, an Exxon Mobil spokesperson said the company was cognizant of the potential impact to the Golden Pass timeline.

"Golden Pass is working with all stakeholders to consider all available options to implement a smooth transition between contractors and minimize any impacts," the spokesperson said.

QatarEnergy did not immediately reply to an email from Hart Energy seeking comment.

Golden Pass is located about 10 miles south of Port Arthur in Jefferson County, Texas, on the Sabine-Neches Waterway. The project entails the addition of liquefaction and export capabilities to an existing terminal and three liquefaction trains, Houston-based Golden Pass said on its website. The project will have utility infrastructure to power processing and storage facilities.

U.S.-based liquefaction projects like Golden Pass and others aim to continue to provide needed energy supply to world markets, especially U.S. allies in Europe and Asia.

At peak construction, Golden Pass will employ over 9,000 workers (across the three joint venture partners), and further utilize the goods and services of 400 contractors, vendors and suppliers, Golden Pass said in a June 18 filing with the U.S. Bankruptcy Court.

Exxon Mobil said in a statement on its website that preliminary estimates in 2019 by an independent study indicated that Golden Pass could generate up to $31 billion in economic gains in the U.S. alone and over $4.6 billion in direct federal, state and local tax revenues over the life of the project.

According to Golden Pass' original timeline, Zachry was required to complete Train 1 by Nov. 30, 2023, Train 2 by July 30, 2024 and Train 3 by Jan. 31, 2025.

The longer the project goes without seeing revenue, the harder it will be to recoup, Pilant said.

"The Commonwealth LNG CEO recently said the approximate one-year wait on the U.S. Department of Energy, lengthened by [U.S. President Joe] Biden's [LNG] pause, has cost the company $500 million, and construction hasn't even started yet. A one-year delay for Golden Pass would likely be several times more expensive," Pilant said.

Zachry's Bankruptcy Motion

In January 2019, Golden Pass LNG and Zachry, Chiyoda and CB&I, a McDermott International subsidiary, executed the EPC contract for construction of the Golden Pass export facility, which spans over 750 acres in Sabine Pass, on the Gulf Coast of Texas.

At that time, Golden Pass and the EPC contract partners entered into a $9.25 billion turnkey agreement that included "the detailed engineering, procurement, construction and commissioning of an LNG plant," Golden Pass said in its court filing.

The EPC contract partners divided responsibility for the scope of construction for Train 1 (including the associated utilities, offsites and existing plant modifications (brownfield) required for the production and export of LNG from Train 1), Train 2 and Train 3, among Zachry, and the non-debtors–Chiyoda and CB&I.

San Antonio-based Zachry officially initiated a voluntary court-supervised Chapter 11 process on May 21. The move aims to provide Zachry with time and flexibility to resolve issues related to Golden Pass. In particular, it looks to strengthen Zachry's "overall financial position," Zachry said the same day in a press release on its website.

Zachry claimed in its bankruptcy court filing that Golden Pass had since its inception

Golden Pass LNG is about eight months behind schedule and at least $2 billion over budget as a result of a bankruptcy filing by primary construction firm Zachry Industrial.

HART ENERGY

"been plagued with unexpected challenges that put it behind schedule and over budget. But Golden Pass and its owners were focused on completing the project on time, which required the contractors (especially Zachry) to accelerate work and accrue increased costs to get the project back on track."

By mid-2022, Zachry claimed that over $2.4 billion in additional funding was needed to complete the project on schedule according to Golden Pass' terms. "The cost was extraordinary, but so was the payday Exxon Mobil and QatarEnergy would receive once the facility was complete," Zachry said in the court filing.

Zachry said Golden Pass changed course in 2023 as its partners sought to slow the work as part of a move to reduce costs. In the filing, Zachry said "the cost reduction process did not work, however, as the contract payment structure never caught Zachry up from all the losses it incurred in prior years."

Zachry is seeking to recover over $1 billion in consideration given to Golden Pass.

"We are taking decisive actions to protect our business in light of what has transpired at Golden Pass," a spokesperson with Zachry told Hart Energy in an emailed statement. "We are working to resolve the matter through the court-supervised process. All of our other projects are continuing to proceed as expected."

Power Play?

On June 18, Golden Pass asked the court to compel Zachry to reject its interest in the EPC contract. Golden Pass is also seeking relief from the automatic stay.

"Zachry agreed that, if it was unable to achieve completion of an LNG train on or before its scheduled date, it was obligated to pay liquidation damages for the delay as set forth in the EPC contract," Golden Pass said in its court filing. "Zachry has abandoned the LNG facility and, in any event, is incapable of performing under the EPC contract. It is also beyond dispute that Zachry's actions have caused, and continue to cause, immediate and substantial harm that compounds on a daily basis."

Zachry has fired thousands of workers and stopped paying its subcontractors, according to Golden Pass.

The total damages caused by Zachry's breaches exceed $2 billion, Golden Pass claimed in the court filing, "including liquidated damages for delay, warranty claims, performance guarantees and additional costs Zachry is imposing on Golden Pass. Zachry has not and is incapable of curing these defaults."

Many saw the Zachry bankruptcy filing as a power play to force Golden Pass back to the negotiating table since finding a new EPC contractor would undoubtedly be more expensive and time-consuming, East Daley Analytics energy analysts Alex Gafford, Oren Pilant and Andrew Ware wrote in a research report. They said Golden Pass' filing to oust Zachry went against market talk of a settlement.

The latest uncertainty puts East Daley's in-service estimate for Train 1 of July 2025 in doubt. East Daley estimates a delay at Golden Pass would remove 219 Bcf of gas demand in the first half of 2025.

Last Ditch Efforts

Golden Pass began construction as an LNG import facility in November 2003 and the project was completed in 2010. Golden Pass received its first LNG cargo in October 2010, but the shale revolution and abundant natural gas production provided the impetus to build a liquefaction facility and export terminal.

The Golden Pass plant is comprised of five 155,000-cm LNG storage tanks, two marine berths capable of offloading various sized oceangoing LNG carriers and process facilities capable of regasifying LNG to produce 2 Bcf/d of gas. Part of the export expansion project includes making modifications to the existing facilities, expanding the facility's storm protection levee system and increasing other various safety and security assets, according to Golden Pass.

Construction work is 75% complete, the Exxon Mobil spokesperson told Hart Energy.

"The potential delay currently does not have an impact on our portfolio—we remain on track with our announced objective to double our LNG supply by 2030," the Exxon Mobil spokesperson added.

In the short- to medium term, LNG demand is expected to continue rising as the world increasingly shifts away from coal amid an energy transition.

"Global LNG demand is great enough that off-takers will secure volumes where they can find them, and won't preclude themselves from buying from U.S. projects," East Daley's Pilant said. OGI

Pitts: LNG Sector, Beware: Aramco is Coming

Loaded with cash, the Saudi oil powerhouse has embarked on a net-zero quest.

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For 91 years, Saudi Arabia's Aramco has best been known as an oil producer. But changing times and energy priorities—let's collectively call them the energy transition—have prompted Aramco to venture into new spaces. That, as the energy giant stays true to its first calling: oil.

It's no secret that Saudi Arabia is home to at least 297.5 billion bbl of proved reserves, second only to Venezuela with 303.8 billion bbl, according to the most recent data from the Statistical Review of World Energy.

But don't confuse the Kingdom's Aramco with socialist Venezuela's Petróleos de Venezuela (PDVSA). The state-owned companies are at the opposite ends of the production and financial spectrums, to say the least. Aramco continues to push its weight around inside and outside OPEC and is one the world's most profitable companies.

Aramco's corporate strategy supports the energy trilemma—security, sustainability and affordability—as well as an orderly and balanced energy transition.

To that end, Aramco has set an ambition to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions (GHG) across its wholly owned operated assets by 2050. Aramco's plan to get there will include technological innovation and the addition of lower-carbon energy to its portfolio.

Enter LNG.

On a Mission

In September 2023, Aramco made its initial foray into the LNG space with its $500 million acquisition of a strategic minority stake in MidOcean Energy, a company formed and managed by EIG Global Energy Partners. MidOcean is in the process of buying interests in four Australian LNG projects as part of its strategy to create a diversified global LNG business.

Aramco President and CEO Amin H. Nasser said in the company's 2023 annual report that the acquisition gave the company a strategic position in a commodity that it anticipated "will experience strong demand-led growth as the global energy transition plays out." Nasser said Aramco viewed LNG as a complementary asset to its portfolio since gas is also "a vital fuel and feedstock for various industries."

Since the MidOcean acquisition, Aramco has been on a mission to develop an integrated global LNG business, which it will pursue either through direct investments or joint venture opportunities or both.

In June 2024, Aramco signed non-binding Heads of Agreement (HOA) deals related to two U.S. LNG projects located in Texas: Port Arthur LNG Phase 2 and Rio Grande LNG.

Aramco and Sempra signed an HOA for a 20-year sale and purchase agreement for LNG offtake of 5 million tonnes per annum (mtpa) from Port Arthur LNG Phase 2. Importantly, the HOA further contemplates Aramco's 25% participation in the project-level equity of Phase 2.

Aramco and NextDecade signed an HOA for 20-year sale and purchase agreement for offtake of 1.2 mtpa from Train 4 of Rio Grande LNG in Brownsville, Texas.

And those are the small deals.

Broad Ambition, Deep Pockets

Aramco has reportedly been in talks with NextDecade regarding its 27 mtpa Rio Grande project as well as Tellurian, which continues efforts to develop its 27.6 mtpa Driftwood LNG project.

Reuters, citing unidentified sources, reported Aramco has visited the Driftwood site in Lake Charles, La., three times this year, including one trip with executives from Australia's Woodside Energy.

Aramco was reportedly competing with Shell to acquire the assets of Temasek-owned LNG trading firm Pavilion Energy, according to Reuters. But this time Shell came out on top.

Aramco's ambition to grow within the LNG space isn't far-fetched. The company's significant cash flow ($22.8 billion in the first quarter) is available to invest in LNG projects. And with some $65.1 billion in cash and cash equivalents at the end of first-quarter 2024, Aramco is a company to watch in the global LNG space in general and the U.S., in particular, with its long list of LNG projects waiting to move forward.

It might be time for international oil companies active in LNG, such as TotalEnergies and Shell, to look over their shoulders. A bigger spender has entered the space. OGI

Paisie: Oil Demand to Rise 1.2 MMbbl/d in Second Half

WTI's price expected to stay in the low $80s/bbl.

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

In alignment with our expectations, the price of Brent crude has moved into the range between $86/bbl and $88/bbl.

For the rest of the year, we forecast Brent to average $87.90/bbl during the third quarter, with WTI averaging $82.37/bbl. In the fourth quarter, we are forecasting that the price of Brent crude will average $86/bbl and the price of WTI will average $80.76/bbl.

We are forecasting that oil demand will increase by a net 1.2 MMbbl/d in the second half of the year in comparison to the second half of 2023. Asia's oil demand is forecasted to increase by 1.11 MMbbl/d. Other regions are expected to have moderate growth—while Europe's demand is forecasted to decrease by around 300,000 bbl/d.

Demand for jet fuel is forecasted to have the most significant increase in percentage and volume terms, followed by diesel fuel, while gasoline is forecasted to have much lower growth in demand.

We are forecasting that non-OPEC oil supply will average 1.17 MMbbl/d more in the second half of 2024 than in the second half of 2023. Additionally, we are forecasting that supply will be outstripped by demand in the third quarter by around 350,000 bbl/d. We are forecasting that supply and demand will be essentially balanced during the fourth quarter.

For the remainder of the year, it is our base case that geopolitics and the ongoing wars will have limited material impact on the volumes of oil available to the market. Geopolitical developments, however, do present a potential risk to the future flow of oil, as well as the outlook for oil demand.

More importantly, the developments have the potential to disrupt the stability of the geopolitical structure that has been in place for the last 30-plus years.

Risks

We see limited potential for upside to demand growth for the rest of the year, given that the economic data continue to be disappointing.

The latest data from China's National Bureau of Statistics (NBS) purchasing managers' index (PMI) for manufacturing came in at 49.5 in June and is the second consecutive month of reading below 50, which indicates contraction. New orders, raw material stocks, employment and new export orders were all in contraction. The non-manufacturing PMI (includes services and construction) showed a slowdown in growth with the PMI decreasing to 50.5 from 51.1 in May, which is the lowest since last December.

While the inflation rate is coming down in the U.S., economic growth is also slowing, with the job market cooling and consumers finding it more difficult to increase spending. In Europe, the largest economies—France and Germany—continue to struggle in the face of uncertainty.

The major economies continue to deal with their own short-term issues, and we see a limited likelihood of any major economic downturn occurring during the second half of this year. The risk of an economic downturn becomes more likely over time, in part, because the major economies will need to resolve their own specific structural factors that undermine their capabilities for sustainable economic growth.

From a supply perspective, there are upside and downside risks.

While we are forecasting that non-OPEC supply will increase during the second half of this year, it is possible that the extent of the increase will be less than our forecast, in part, because of U.S. production increasing at a lower level than our current forecast.

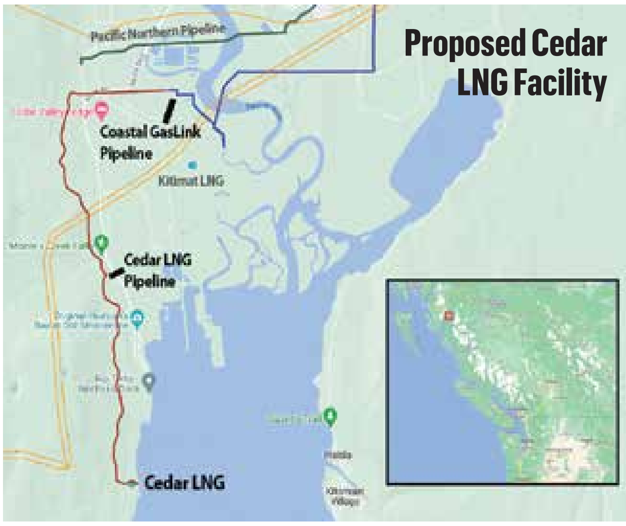
Last year, U.S. production increased significantly in the second half of the year. At the beginning of 2023, U.S. production was 12.2 MMbbl/d and production remained flat through most of May. By the end of 2023, U.S. production had reached 13.2 MMbbl/d. For 2024, increasing supply will be more challenging unless U.S. producers start ramping up capital expenditures and drilling programs beyond current plans.

There is also the potential that supply will be greater than forecasted because of additional supply from OPEC+ resulting from a breakdown in cooperation among the members. While there are inherent challenges to maintaining discipline and cohesion among the members, we are expecting OPEC+ to continue focusing on managing supply proactively to align with demand. One nagging concern is that the research arm of OPEC is still forecasting demand growth of 2.25 MMbbl/d for 2024, which is significantly higher than our forecast, as well as IEA's forecast. OGI

AROUND THE WORLD

Canada

Pembina, Haisla Nation Take $4B FID on Cedar LNG



CEDAR LNG, REXTAG

Canada's Pembina Pipeline Corp. and the Haisla Nation, partners in Cedar LNG Partners, have taken a $4 billion (CA$5.4 billion) final investment decision (FID) on their 3.3-million tonnes per annum (mtpa) Cedar LNG project.

Cedar LNG is 50.1% owned by the Haisla Nation. Pembina holds the remaining 49.9%. The floating LNG (FLNG) project, located on Canada's West Coast, is expected to start operations in late 2028.

The $4 billion estimated cost of Cedar LNG includes capital costs of $3.4 billion, of which about 70%, or $2.3 billion, is under a fixed-price, lump-sum agreement. The other $600 million includes interest during construction and transaction costs, Pembina said in June in a press release.

Cedar LNG secured 20-year take-or-pay liquefaction tolling services agreements with ARC Resources and Pembina for 1.5 mtpa each. Commercial discussions are ongoing with numerous other prospective customers for Pembina to assign its contracted capacity to a third-party, the company said in the release.

China

China Won't Resume Large Oil-backed Loans to LAC

China will not be resuming the mega oil-backed leaning of yesteryear across Latin America and the Caribbean (LAC) as its focus turns to debt negotiations, according to the Inter-American Dialogue and the Boston University Global Development Policy Center.

A decade ago, Chinese lending to the LAC region surpassed lending from the World Bank and the Inter-American Development Bank, the Inter-American Dialogue and Boston University said in June in a joint press release announcing the results of a recent study.

Between 2005 and 2023, China Development Bank and Export-Import Bank of China provided $120 billion via 133 loan commitments to LAC countries and state-owned enterprises. Of the total, energy projects investments accounted for $94.1 billion, followed by other projects ($12.1 billion), infrastructure ($12.1 billion) and mining ($2.1 billion). By region, the distributions were destined to four countries that received 93% of the financing: Venezuela ($59.2 billion, 49%), Brazil ($32.4 billion, 27%), Ecuador ($11.8 billion, 10%) and Argentina ($7.7 billion, 6%).

UK

IGU: Global Liquefaction Capacity to Grow by 75%

Global liquefaction capacity is expected to reach around 700 mtpa by 2030, up from 401 mtpa in 2023, according to the International Gas Union (IGU).

The expected 75% growth in global liquefaction capacity will be driven by new final investment decisions (FIDs) coupled with the start-up of projects currently under construction, the IGU said in June in a press release.

The expansion of liquefaction capacity in high-growth Asian markets will be driven by a switch from coal to gas, an important component in the region's decarbonization and air quality improvement strategies, the IGU said.

Despite the growth outlook, the supply-constrained market still faces major headwinds, according to the IGU. These include the Biden pause, which could delay over 70 mtpa of new capacity in the U.S.; sanctions on Russian LNG, which impact around 20 mtpa; Ukraine possibly not extending the Russian gas transit deal until late 2024; shipyard bottlenecks; ongoing security risks in the Middle East; and declining gas field supply.

Guyana

Former Exxon Exec's Company to Develop Guyana Gas Project

SHUTTERSTOCK

An FPSO floats offshore Guyana.

Little known U.S.-based company Fulcrum LNG has been selected by the government of Guyana to move forward a project to develop the country's offshore gas.

Guyana, which started producing oil offshore in late 2019, has around 17 Tcf of associated gas, which could spearhead the small South American nation's next energy wave.

RBAC Inc. said Guyana had been looking to develop its natural gas resources and has partnered with Fulcrum to assist in the process, the company said in June through a post on X, formerly Twitter.

Fulcrum LNG was formed by former Exxon Guyana executive Jesus Bronchalo, Exxon Mobil confirmed with Hart Energy. Baker Hughes and McDermott will team up with Fulcrum in the development process. Fulcrum LNG was picked from among 17 companies to develop a plan around the design and construction of gas facilities to commercialize Guyana's gas resources.

Fulcrum LNG boasts "experienced and industry-recognized professionals with more than two centuries of combined experience," according to details on its website.

Mexico

Refinery to Reduce Mexico's Reliance on US Fuel

State-owned Petróleos Mexicanos (Pemex) is expected to finish construction of its 340,000 bbl/d Olmeca refinery in Dos Bocas next year, significantly reducing Mexico's dependence on fuel from the U.S., according to the International Energy Agency (IEA).

The commissioning of Dos Bocas—located in Paraíso, Tabasco—continues to face start-up issues, but should be online "no earlier than the fourth quarter of 2025, with the full ramp-up taking several years," the IEA said in a report published in June.

Dos Bocas will produce 170,000 bbl/d of gasoline and 120,000 bbl/d of ultra-low sulfur diesel, Pemex said in a statement on its website.

Once operational, Dos Bocas will allow Pemex to reduce exports of its heavy sour Mayan crude to the U.S. Gulf Coast to instead be refined domestically, the IEA said.

The combined impacts will see Pemex's heavy sour crude exports average 130,000 bbl/d by 2030, down from 1.1 MMbbl/d in 2023, according to the IEA.

DORIS Group Awarded FEED for Zama Development Offshore

French engineering firm DORIS Group has been awarded the FEED for the Pemex-operated Zama development offshore Mexico.

A FID is forthcoming and first oil production could flow in 2027, Welligence Energy Analytics Vice President and Head of Latin America Research Andres Armijos told Hart Energy.

Partners in Zama include Houston-based Talos Energy, Harbour Energy, Wintershall Dea and Grupo Carso.

Zama is located in the shallow waters of Mexico's Salinas-Sureste Basin. The project will develop one of the largest offshore discoveries of the last decade, and the flagship find of Mexico's 2013 Energy Reform, according to Welligence. Under the preliminary plan approved by Mexico's National Hydrocarbon Commission (CNH), Zama will be developed via two fixed platforms.

Zama is expected to produce up to 180,000 boe/d at peak, which would represent around 10% of the current overall oil production in Mexico, according to Pemex and Wintershall.

Scotland

TotalEnergies Sells Gas Field Interests West of Shetland Islands

London-based Prax Group will buy all of TotalEnergies' oil and gas interests in multiple fields west of the U.K.'s Shetland Islands, TotalEnergies said in a June press release.

The Shetland Islands are an archipelago located northeast of Scotland. The assets, distributed in five fields, include an onshore gas plant and exploration licenses. The fields produce 7,500 boe/d. About 90% of the product is made up of natural gas, Paris-based TotalEnergies said.

SHUTTERSTOCK

Sullom Voe Oil Terminal and Gas Plant in Shetland, U.K. The plant handles production from UK oil fields in the North Sea and East Shetland Basin.

Employees working at the sites will be transferred to Prax.

"This transaction is in line with TotalEnergies' strategy to continuously adapt its portfolio by divesting mature non-core assets," said TotalEnergies' Jean-Luc Guiziou, senior vice president, Europe, for E&P.

US

The Biden Pause: LNG SPAs Fall 15% in First-Half 2024

Total volumes associated with LNG sales and purchase agreements (SPAs) are down 15% in the first half of 2024 compared to the same six-month period in 2023—primarily due to President Joe Biden's pause on LNG permitting, according to research by Poten & Partners.

"The number of SPAs completed fell significantly in March following the Biden administration's pause," Ben Gonzalez, Poten's head of data analytics, said during a July webinar. A U.S. District judge lifted the LNG export pause on July 1.

"Historically, you do see some lower SPAs during the [same six-month periods, specifically in 2020 and 2021] but nonetheless, yes, the Biden pause did impact the market significantly," Gonzalez said.

During the first half of 2024, gas-linked contracts accounted for 36% of all SPAs signed, according to Poten data. Of that percentage, Henry Hub-linked contracts accounted for 36.5%, Japan Korea Marker (33.5%), followed by the Canadian benchmark AECO (14%) and Waha (11%).

TXOGA Supports Ruling to Pause Biden's Pause

The Texas Oil & Gas Association (TXOGA) sided with a recent Louisiana court ruling that in effect halts the pause of LNG permits announced earlier this year by the Biden administration.

U.S. District Judge James Cain of the western district of Louisiana ruled on July 1 to put on hold the U.S. Department of Energy's (DOE) pause on LNG export permits, arguing that the DOE failed to justify why it needed to pause the approvals to review the process by which it permits projects, Poten & Partners head of data analytics Ben Gonzalez said in July during a webinar.

"The court's ruling to end the LNG export permit approval halt achieves the right result," TXOGA President Todd Staples said in July in a trade association press release.

The ruling deals "a legal blow to the Biden administration's climate agenda," Gonzalez said. OGI

Will Uinta Crude Railway Please the Court?

A lawsuit before the Supreme Court is part of a larger fight that could have implications for how FERC decides pipeline and LNG plant permitting.

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A proposed railway for Utah's Uinta Basin has evolved into a case to be brought before the U.S. Supreme Court, part of an ongoing battle over U.S. energy policy. The result could affect the permitting of pipelines and LNG plants.

The case concerns a proposed 80-mile line connecting the crude-producing basin to the Union Pacific Railroad in Kyune, Utah. From there, rail connections would deliver the oil to either refineries in Wyoming or along the Gulf Coast, according to an analysis by East Daley Analytics (EDA).

This fall, the Supreme Court will hear arguments over the U.S. Surface Transportation Board's (STB) approval of the plan and the subsequent denial by the D.C. Circuit Court of Appeals.

The Uinta needs a railway to meet the needs of the paraffin-rich crude the basin produces. The basin produces a waxy crude that is primarily solid at room temperature. Refiners prefer the product because of its low sulfur, metal and nitrogen contents, EDA analyst Kristine Oleszek wrote.

The problem is that the waxy crude can't be shipped through normal oil pipelines without first being diluted by about 6 bbl of light, sweet oil. Today, the product is shipped out of the basin via trucks.

Adding a railway would be a "game changer," Oleszek wrote, increasing the basin's oil egress capacity by 8,000 bbl/d.

The Uinta Basin Railway project was proposed by a coalition of seven counties in the area, according to an analysis of the case by Arbo, a firm that tracks government regulations and actions regarding the energy

Railway to Court

UINTA BASIN RAILWAY

A coalition of seven counties proposed a railway for crude delivery to a railhead in Kyune, Utah.

industry. In 2021, the project was approved by the STB.

The Eagle County, Colo., board of commissioners and the Center for Biological Diversity filed appeals of STB's decision to the D.C. Court of Appeals. The rail project became part of an ongoing battle over the role greenhouse-gas emissions should play in the federal permitting process.

According to Arbo, in several cases the appellate court, made up of three Democratic appointees, has suggested that government regulatory commissions should take a more active role in combatting the release of emissions.

The appeals court panel ruled that STB's decision should have applied the National Environmental Policy Act not only to the railway but also to related downstream and upstream operations.

The STB argued that upstream and downstream effects were beyond its jurisdiction and that determining the extent of greenhouse-gas emissions would place a massive regulatory burden on organizations trying to build railways in the future.

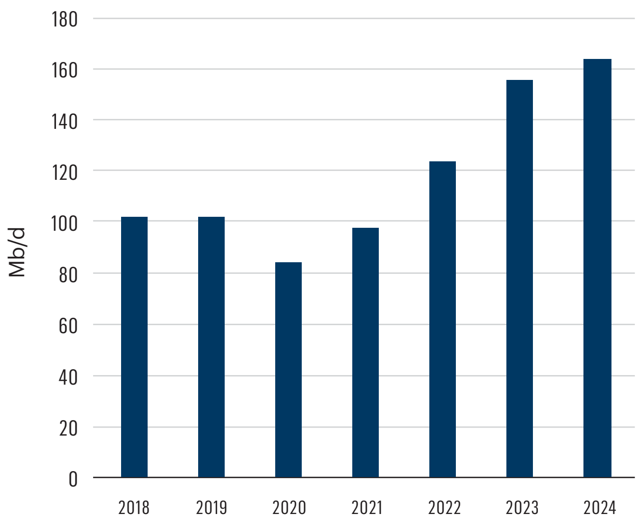
Arbo noted that the case could have implications well beyond railroads. The U.S. Federal Energy Regulatory Commission (FERC) has also encountered controversy as it weighed whether the effects of greenhouse-gas emissions on communities near a project should be considered in its decision-making process.

A ruling against the STB in the railway case could affect FERC's decisions on pipelines and LNG plants.

FERC Chairman Willie Phillips "is trying to walk a fine line between the hard left and the hard right as to the scope of FERC's review, but if the STB case is allowed to stand, it will be a hard shove to the left and may force him into an untenable position that will only lead to a very fractured Commission," Arbo's analysis said.

On June 27, FERC approved Venture Global's Calcasieu Pass 2 LNG facility in a 2-1 decision. The dissenting vote came from Commissioner Allison Clements, who argued that the commission needs to expand its consideration of CO_2 emissions when permitting LNG plants. OGJ

Uinta Basin Crude Oil Production



SOURCE: EAST DALEY ANALYTICS

Segrist: Gassed Up and Waiting to Go

The countdown clock for a surge in natural gas demand is ticking. Is the U.S. finally at the turning point?

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The first half of 2024 was a difficult time for natural gas producers.

The U.S. set records for monthly natural gas in storage. Breakdowns and construction delays at LNG export plants, and mild weather hurt demand in the U.S. and overseas. Prices crashed in January and stayed low into July.

It's a difficult situation, but the bad news isn't too much of a surprise to the companies most involved in the natural gas market and the analysts who track it.

If things go as planned, the summer of 2024 will be remembered as the natural gas industry's nadir of the 2020s, before decades-long infrastructure projects came online and long-awaited markets finally opened.

Two unconnected projects expected to come online soon are two small parts of the massive infrastructure being built to turn things around.

Energy, Energy Everywhere

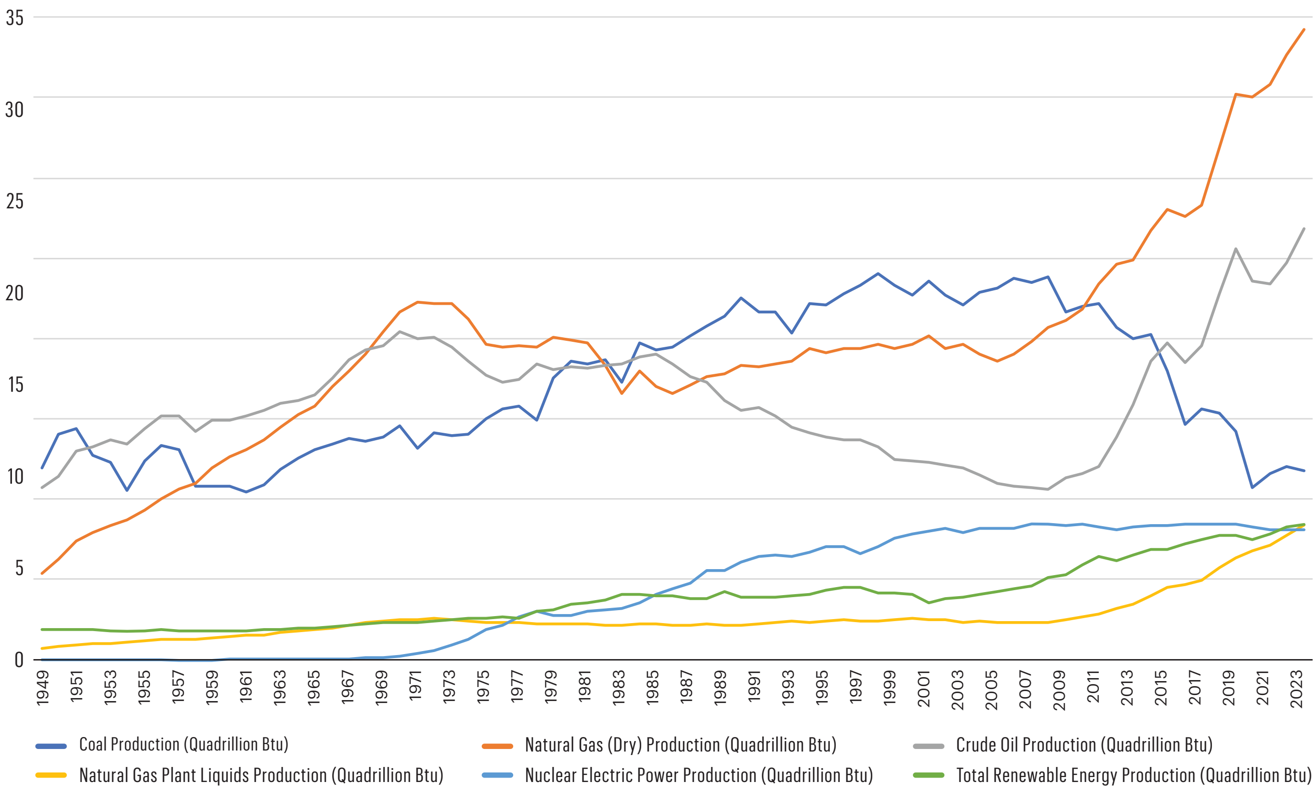
At the end of June, the U.S. Energy Administration (EIA) reported that the gap between the amount of energy produced in the U.S. had surpassed the amount of energy consumed by an all-time high in 2023.

The gap between production and consumption came to 9 quadrillion Btus (quads), the biggest gap since 1949—as far back that records go. Total energy produced amounted to 103 quads, while total consumption came in at 94 quads.

(The EIA uses Btus—British thermal units—as a means of comparison between the different ways of producing energy, such as coal, gas or solar. One Btu is the quantity of heat required

U.S. Primary Energy Production by Source

quadrillion Btu, 1949-2023



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION to raise the temperature of a pound of water by 1 F.)

Natural gas is easily the biggest contributor to U.S. energy production, responsible for 39 quads in 2023; second place went to crude oil at 27 quads.

Production of both had grown significantly from 2022—gas by 4% and crude by 8%. The continued growth in oil production makes sense, considering that prices have remained relatively stable and profitable over the last few years. Producing more oil in a favorable market is what E&Ps do.

It's not the same story for gas. Natural gas prices hit a high of $8.81/MMBtu at Henry Hub in August 2022, according to the EIA, and began a rapid drop soon after that. The high for 2023 was in January at $3.27/MMBtu. Prices have not reached that level since.

Yet gas production continued rising all through 2023. As the Henry Hub price languished at $2.52/MMBtu average over December 2023, natural gas monthly gross withdrawals hit an all-time high of 3.99 Tcf, according to the EIA.

Anyone familiar with the situation knows why production went up while prices cratered.

In the U.S., most gas producers don't have much of a choice over how much they produce, because most of them don't consider themselves gas producers in the first place. More than one-third of U.S. natural gas production comes from wells in which crude is the primary focus, according to the EIA.

The growth in associated gas has been a byproduct of the shale revolution, which naturally produces gas, along with other products. In 2010, none of the primary U.S. shale oil basins produced more than 1 Bcf/d of associated natural gas. By 2022, the Bakken, Eagle Ford and Niobrara all did. The Permian Basin produced more than 16 Bcf/d and is expected to hit 22 Bcf/d by the end of 2024.

Natural gas lines in the Permian have been running near capacity for almost a year. According to the EIA, prices at the regional Waha Gas Hub dipped as low as negative $4.60/MMBtu over the summer.

Of course, producers have been well aware of the situation and have invested billions to turn things around.

Matterhorn's Climb

The first two of many pieces for a much more profitable natural gas market are coming close to fruition.

With a 42-inch diameter, the 580-mile Matterhorn Express Pipeline is designed to take up to 2.5 Bcf/d of natural gas out of the Permian Basin. According to one analytical firm, the line could start doing so as soon as September.

In early July, East Daley Analytics noted that the pipeline, owned by a joint venture and operated by Whitewater Midstream, could start taking line-fill service before August, "ramping up to the full 2.5 Bcf/d in September."

The Matterhorn Express is a crucial part of decreasing the natural gas bottleneck regional producers face. It's the first major natural gas pipeline to come out of the Permian since WhiteWater Midstream and MPLX's Whistler Pipeline began service in 2021.

The line will end near Katy, Texas, in an area close to Houston for processing and, potentially, LNG export.

Matterhorn Express Pipeline

SOURCE: MATTERHORN EXPRESS

The Matterhorn Express Pipeline is an approximately 580-mile intrastate pipeline designed to transport up to 2.5 Bcf/d of natural gas from the Permian Basin to the Katy area near Houston, Texas.

VENTURE GLOBAL

Located in Plaquemines Parish on the Mississippi River, near the Louisiana Gulf Coast, at capacity, Venture Global's Plaquemines LNG facility will export up to 20 million tonnes per annum of LNG, adding about 3.4 Bcf/d of new natural gas demand in the region.

Meanwhile, in Louisiana

In the next state over, Venture Global's Plaquemines LNG is expected to start a long-awaited commissioning process, an analytical firm reported July 1.

The liquefaction and export facility is in Plaquemines Parish on the Mississippi River, near the Louisiana Gulf Coast. At capacity, the plant will export up to 20 million tonnes per annum of LNG, adding about 3.4 Bcf/d of new natural gas demand in the region.

The massive plant will be the largest addition to U.S. LNG export capacity since Sabine Pass opened in 2019.

TPH & Co. noted in July that several pipelines that will serve the Plaquemines facility were gearing up into supply mode. In June, Enbridge's Gator Express Pipeline flows indicated that the plant had received a small amount of natural gas, indicating that commissioning had potentially started.

The news matched an earlier forecast from Venture Global that LNG production at Plaquemines would start before the end of the summer. According to a July 3 study by analytical firm RBN, the facility is expected to be fully online in 2026.

The study was headlined, "Big Wave–A Tsunami Of New LNG Export Capacity Is Coming, With Broad Implications For Gas Markets."

The Pipelines and the Plants

Both projects showcase the primary movement within the natural gas industry since the 2010s to transform U.S. natural gas into an international commodity through LNG trade, thereby boosting the value of gas that has been so cheap that producers sometimes had to pay people to take it away.

"The new LNG export capacity coming online in North America over the next few years is sure to have a significant impact on gas products on gas flows and gas prices–in both the U.S. and Canada," RBN analyst Housley Carr wrote.

"Given that all the U.S.'s incremental export capacity is located along the Gulf Coast, gas produced at crude oil-focused wells in the Permian–often selling at negative prices at the Waha Hub lately–will have new outlets, which should have a positive effect on gas prices there."

The Matterhorn Express is just the largest current pipeline project slated to bring natural gas to the Gulf Coast. The Louisiana Energy Gateway project by Williams Cos. is a gathering and pipeline system expected to bring an extra 1.8 Bcf/d of natural gas to Southern Louisiana.

Besides Plaquemines, one other LNG export terminal is expected to begin production by the end of 2025.

Cheniere Energy's Corpus Christi Stage 3 project will add 1.4 Bcf/d capacity for liquefaction. Cheniere executives said in June that overall construction is 60% complete and ahead of schedule and that LNG production may begin before the end of 2024, according to RBN.

East or West?

The future markets for the growing LNG export capacity aren't set in stone.

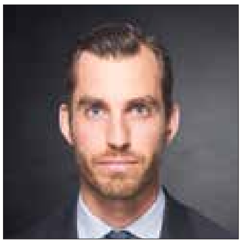
Europe saw a surge in demand following Russia's invasion of Ukraine in 2022. However, the European Union's Agency for the Cooperation of Energy Regulators reported in April that LNG demand would likely peak in 2024, as EU member nations focus on installing solar and wind energy.

Analysts say Asia, however, will see an increasing need for LNG. China is currently beefing up its LNG regasification capacity and expects LNG imports to rise 8.2% in 2024.

Considering all of the factors, it's difficult to predict the future. But, years-long efforts to provide a market for a glut of natural gas could begin to pay off, as 2024 starts winding down. OGI

Wilson: NGLs are America's Other Energy Export Boom

Robust outlook, interested buyers, willing investors—what's not to like?



ROB WILSON
VICE PRESIDENT OF ANALYTICS, EAST DALEY ANALYTICS

Rob Wilson manages a team of energy analysts that focuses on natural gas, crude oil, NGL and midstream capital markets.

Step aside, oil and natural gas. NGLs have become America's hottest export product. Terminals to export ethane and LPGs are running full throttle now, and new expansions under construction will bring big growth to markets starting in 2025.

NGLs are often lost in the discussion about the U.S. hydrocarbon export machine. Yet markets for purity products like ethane and LPGs (propane, normal butane, isobutane) have all the elements for a sustained run: a robust supply outlook, strong interest from international buyers, and investors willing to back new infrastructure to connect the two.

The engine for the boom is steady production growth from the oil patch. East Daley Analytics forecasts U.S. NGL production to grow by 600,000 bbl/d over the next three years, from 6.4 MMbbl/d in 2023 to over 7 MMbbl/d by 2026.

Operators in the Permian Basin in West Texas and New Mexico drive most of the gains in our NGL Hub Model. New investments in midstream processing plants and pipelines, led by the 2.5 Bcf/d Matterhorn Express Pipeline, enable rapid growth in Permian natural gas production over the next several years. The additional Permian gas must be processed, translating into more NGL production as bundled Y-grade. Other U.S. basins, including the Marcellus and Utica shales in the Northeast and the Eagle Ford in South Texas, also contribute to supply growth.

Led by the Permian, Y-grade supply available to Gulf Coast fractionators and export terminals increases to over 5.7 MMbbl/d by year-end 2026 in our NGL Hub Model, up from an average of 5 MMbbl/d in 2023. While petrochemical expansions on the Gulf Coast will absorb some of this new wedge of supply, we expect most of the NGLs to be bound for overseas markets.

NGL Exports are Big Business

Exporting NGLs has become big business for the oil and gas industry. In 2023, the industry exported 960.6 MMbbl (2.63 MMbbl/d) of ethane and LPGs, a record high according to Energy Information Administration (EIA) data. The latest EIA data show exports are on track to hit another record in 2024, averaging 2.79 MMbbl/d in the first quarter. About 80% of LPG exports take place in the PADD 3 Gulf Coast region, mostly in the southeastern Texas industrial corridor from Houston to Beaumont.

Profits are flowing for the midstream companies that operate the specialized docks for ethane and LPG exports. Enterprise Products Partners, Energy Transfer, Targa Resources and Phillips 66 are the big players, controlling almost 90% of export capacity in PADD 3. The companies in 2023 reported over $1.6 billion in combined gross margin for their LPG export operations. Yet these export docks have much greater intrinsic value for the companies. All of them run vertically integrated NGL operations, and more volume for exports equates to more fee-based cash flow for processing units, pipelines and fractionators along the NGL value chain.

China in 2023 became the largest buyer of U.S. propane, importing the product as feedstock for new propane dehydration units (PDH) to make propylene. The country's chemicals industry has been on a building spree of late, starting around 15 PDH facilities in 2023, according to industry estimates. These plants together would have the capacity to consume about 250,000 bbl/d of propane.

Dock Expansions

Exports of LPGs and ethane have grown so rapidly that many Gulf Coast terminals are operating at capacity. For example, Targa shipped 435,000 bbl/d of LPGs from its Galena Park export dock in fourth-quarter 2023, or about 98% utilization based on nameplate capacity of about 445,000 bbl/d. East Daley estimates Gulf Coast docks combined ran at 93% utilization in that period.

The industry is planning several dock expansions to address the constraint. Energy Transfer is spending $1.25 billion to add 250,000 bbl/d of export capacity at its Nederland, Texas, terminal, while Enterprise is expanding dock capacity by 120,000 bbl/d at the Enterprise Hydrocarbon Terminal. Enterprise is also planning a new NGL export facility on the Neches River near Beaumont, Texas.

We forecast LPG exports from PADD 3 will increase to 2.2 MMbbl/d by fourth-quarter 2026. The Enterprise and Energy Transfer dock expansions provide room for market growth to keep the U.S. export machine humming. The projects also support new NGL pipelines and fractionators in the works on the Gulf Coast. With so many moving parts, we expect volatility ahead in flows and prices for NGL purity products. OGI

How to Capture Revenue While Capturing Carbon

Biotech executives share insights into how CO_2 could be used for biofuels, fertilizer, food, proteins, plastics and even oil.

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Biotechnology companies are turning CO_2 into fertilizer, fuel, food proteins and other applications to help fight climate change and crack open potential new revenue streams.

With photosynthesis as inspiration, Florida-based Carbon Optimum uses CO_2, waste heat and wastewater to produce algae. Denmark-headquartered Novozymes, part of Novonesis, converts CO_2 into acetate, or vinegar, which is then put in fermentation tanks to produce proteins. Cemvita, the Houston-based company that includes Occidental Petroleum among its investors, engineers microorganisms that use waste streams and CO_2 as feedstock.

The end results: biofuels, fertilizer, food for livestock and humans, oil, proteins and plastics.


Yao Huang

"Most of what we're all trying to do is copy nature … We're trying to see this scale everywhere," said Yao Huang, investor and board member for Carbon Optimum. "And it has impact on multiple industries, from food to energy to farming. I think at least for the next 50 years, this is going to be quite meaningful."

Executives from the three companies spoke during a recent energy conference in Houston about biotechnology's role in carbon capture. The discussion took place as companies across the world aim for net-zero emissions targets, seeking sustainable alternatives to fossil-based products and new uses for the greenhouse gas that contributes to climate change.

About 230 million tonnes (MMtonne) of CO_2 is used annually, mainly in the fertilizer industry and for enhanced oil recovery, according to the International Energy Agency (IEA). However, new utilization pathways are gaining momentum with CO_2-based synthetic fuels, chemicals and building aggregates.

"The current project pipeline shows that just under 15 [MMtonne] of CO_2 per year could be captured for these new uses by 2030, including around 8 [MMtonne] of CO_2 in synthetic fuel production," according to IEA. "If all announced projects are commissioned, they could reach around two-thirds of the level of CO_2 utilization for synthetic fuel production by 2030 envisaged in the Net Zero Emissions by 2050 (NZE) Scenario."

However, that would require all CO_2 to be pulled from the air or from biogenic sources, such as that from biomass and its derivatives.

Biotechnology at Work

Carbon Optimum's proprietary technology harnesses photosynthesis at a high volume using captured CO_2, Huang said. Nitrogen oxides and sulfur oxides are scrubbed out of the CO_2, which is then piped into algae-filled tanks called photobioreactors. Here, algae consume the CO_2, carrying out photosynthesis, and grow.

Instead of sunlight, the company uses LED lights along with water and a small amount of nutrients to produce the algae. The biomass, harvested in about 24 hours, can be used as an ingredient in a variety of products such as biofuel, crude oil, human food, cosmetics and pharmaceuticals—to name a few, according to the company's website.

"We're working with a large U.S. energy company with 9 million tons per year. Cement factories with 2 million tons per year. We're working with a country to eliminate 30 million tons per year," Huang said. "We've got another coal energy conglomerate for another 230 million tons per year."

Carbon Optimum can flex to different scales because its algae tanks are modular.

"The beauty of this entire process is that the biomass taken out could be utilized into fertilizer, biofuels, food products, and it makes the whole thing extremely profitable," Huang said.

Cemvita essentially replicates what a soybean does in a lab, according to CEO Moji Karimi.

"Instead of having to have land and growing soybeans to crush it to get the oil out, you could actually engineer bacteria to give you the same exact profile of oil," he said.

The company uses synthetic biology to transform CO_2 into chemicals and alternative fuels such as sustainable aviation fuel (SAF). It has a partnership in place for SAF offtake with United Airlines, and Occidental—which is building one of the world's largest direct air capture facilities in Texas—is a longtime technology partner and top investor.

Enzymes form the core of Novonesis' technology.

"The enzymatic carbon capture process uses the biological enzyme carbonic anhydrase

Biotechnology companies are turning CO_2 into fertilizer, fuel, food proteins and for other applications to help fight climate change and crack open potential new revenue streams.

SHUTTERSTOCK

instead of conventional chemicals to extract CO_2 from the flue gas," Novonesis said on its website. The process is considered less expensive than conventional methods because it can use waste heat and it doesn't require special wastewater treatment.

Klaus Lassen, head of carbon capture for Novonesis, said the company is also using enzymes for enhanced rock weathering. The process involves removing carbon from the air and storing it in rocks.

Eyeing Economics

Carbon Optimum's technology is scalable and can be quite profitable, Huang said. But financing is still required to make it happen, she added.

Carbon credits compose an extremely small percentage of the revenue for such projects. Most of the revenue is based on the value of the commodities, be it fertilizer, biofuels, food products or something else, according to Huang.

"That profitability has driven a lot of partners that you normally wouldn't expect in this field to come on board for financial reasons," she said. "Europe's laws have driven a lot of demand, diverting taxes and fines from CO_2 emissions from the major emitters there."

Novonesis' Lassen pointed out the value of having a lower CO_2 footprint in production.

"You need to calculate these lower CO_2 footprints and issue CO_2 certificates on the voluntary market," Lassen said. "That is where you really can tell that you are doing something good for the sustainable future. And that is something that companies are ready to pay for."

Karimi sees a future in which there are no shortcuts to lowering emissions, more collaboration between companies and infrastructure designed to emit less waste and CO_2. A closed loop system could give CO_2 utilization a huge advantage, he said.

"With sequestration, of course you have the carbon markets, but there's really no inherent business model in that there's a product made and there's someone that is using the end product," Karimi said. "Whereas once the CO_2 utilization is scaled and competing with the other kind of low-carbon alternatives, naturally people are just going to do more of that. So, we just let capitalism do what it does best to scale up that industry without the reliance on government grants in perpetuity."

Like other new technologies, the panelists agreed that subsidies are needed in the beginning.

"You cannot expect new processes to have a competitive edge within 10 years. It's simply not possible," Lassen said.

Taking Responsibility

Asked whether dependence on CO_2 to make products could slow emission reductions initiatives, Huang said no.

"Most countries are shutting down their coal facilities. India is creating more. Cement factories will be there unless someone thinks of something else to build their skyscrapers with or something else," she added. "But in the short term, the next 50 years, we have whatever we have, and regardless of whatever we get rid of, there's still going to be CO_2."

Fertilizer shortages in parts of the world show the products are still needed, Huang said.

The panel discussion also swung to responsibility.

Lassen spoke about personal responsibility, saying individuals should lower their CO_2 footprint.

"It is not an industry that is destroying the climate. The industry is producing petroleum products for you that you consume. It is your CO_2 footprint," he said, later suggesting people pay for their own waste disposal.

Huang disagreed, saying "a company that produces it forces you to use that. … Maybe as a European or as a wealthy individual, you have choices, but the masses do not. They have to use the bus that is burning oil to get to work."

If the companies that produce plastic make a change, though it may cost more, then "you don't have to wait for 8 billion people to all decide the same thing," she said.

Facilities don't have to burn oil, Huang said; they could burn hydrogen.

"And if you make the whole thing profitable economically, it'll work," she said. "It's business in the end." OGI

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

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EVENT	DATE	CITY	VENUE	CONTACT
2024				
IMAGE 2024	Aug. 25-30	Houston	George R. Brown Conv. Ctr.	aapg.org
New Energies Summit	**Aug. 27-28**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
Permian Energy Dialogues	Sept. 4-5	Santa Fe, N.M.	Inn and Spa at Loretto	energy-dialogues.com/ped
Gastech Exhibition & Conference	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
GPA Midstream Convention	Sept. 22-25	San Antonio	Marriott Rivercenter on the River Walk	gpamidstreamconvention.org
SPE/ATCE	Sept. 23-25	New Orleans	Ernest N. Morial Convention Center	atce.org
SHALE INSIGHT 2024	Sept. 24-26	Erie, Pa.	Bayfront Convention Center	shaleinsight.com
Energy Capital Conference	**Oct. 3**	**Dallas**	**Thompson Dallas**	**hartenergy.com/events**
2024 Gas Machinery Conference	Oct. 6-9	Tampa, Fla.	Tampa Convention Center	southerngas.org
SPE Asia Pacific Oil & Gas Conference and Exhibition 2024	Oct. 15-17	Perth, Australia	Crown Perth	spe-events.org
A&D Strategies and Opportunities Conference	**Oct. 23**	**Dallas**	**Thompson Dallas**	**hartenergy.com/events**
IPAA Annual Meeting	Oct. 28-29	Boca Raton, Fla.	The Boca Raton Resort	ipaa.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
ADIPEC 2024	Nov. 4-7	Abu Dhabi, UAE	Abu Dhabi National Exhibition Centre	adipec.com
DUG Appalachia	**Nov. 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**
National Pipe Line Conference	Nov. 28-29	Houston	Omni Houston Hotel	plca.org
North American Gas Forum	Dec. 2-4	Washington, D.C.	TBD	energy-dialogues.com/nagf
SPE Thermal Well Integrity and Production Symposium	Dec. 2-5	Banff, Alberta, Canada	The Fairmont Banff Springs	spe-events.org
2025				
Floating Wind Solutions 2025	Jan. 15-17	Houston	The Marriott Marquis	floatingwindsolutions.com
Mexico Infrastructure Projects Forum	Jan. 22-23	Monterrey, Mexico	Hotel Camino Real Monterrey	mexicoinfrastructure.com
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
NAPE	Feb. 5-7	Houston	George R. Brown Conv. Ctr.	napeexpo.com
6th American LNG Forum	Feb. 10-11	Houston	Westin Galleria	americanlngforum.com
Oil & Gas Automation and Technology Week	Feb. 11-12	Houston	Hyatt Regency Intercontinental Airport Hotel	oilandgasautomationand technology.com
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

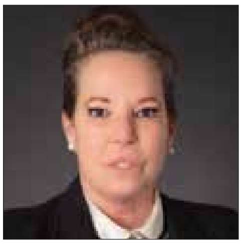
Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

In Ohio's Utica Shale, Oil Wildcatters Are at Home

The state was a fast follower in launching the U.S. and world oil industry, and millions of barrels of economic oil are still being found there today.



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For generations of wildcatters, the adage "Oil is found where it's been found before" has proven true. Today, it's proving true in Ohio, which has been producing crude since 1814.

That first well, the Thorla-McKee, was a shallow one and actually drilled for brine, a valuable commodity at the time, near Caldwell in Noble County. The salt was saturated with oil, though.

The well's partners, Silas Thorla and Robert McKee, decided to soak up the oil with blankets, ring it out and sell it as a topical medicine, calling it Seneca Oil.

In 1859, hole was made in Trumbull County in northeastern Ohio specifically for oil a few months after the global oil industry's opener, the Drake well in Pennsylvania.

John D. Rockefeller, a bookkeeper in Cleveland at the time, got into the business, forming Standard Oil Co. in 1870 and focusing primarily on refining and transportation: oil-hauling.

His myriad enterprises had a hand in some 90% of all U.S. crude by the turn of the century and were famously broken up 11 years later after losing an antitrust case before the U.S. Supreme Court.

More than a couple of centuries since that 1814 brine well, EOG Resources put four horizontals far deeper, landing them in the Ordovician Age's Utica Shale. These flowed a combined 30,800 bbl in their first eight days in March, averaging 963 bbl/d each.

Turns out, that EOG pad, White Rhino, is just a few miles from the 1814 Thorla-McKee.

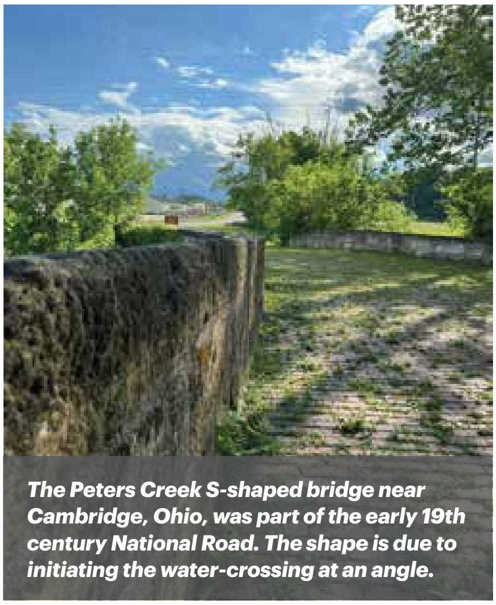
The EOG holes are among the southernmost tests of the new Utica oil play, in which operators are putting completions in laterals after other operators did the same during the past decade but with completion recipes that were minted at that time.

For example, a pad in Carroll County is being completed with slickwater today, while initial wells were pumped with gel in 2015.

In the renewed play, more than 700 horizontals have been landed in the Utica Formation's Point Pleasant since 2019—in the dry-gas, wet-gas and volatile oil phases.

Among those targeting oil are Encino Energy's three David Weaver holes in Harrison County, Stock township, near Tappan Lake.

Brought online in December of 2020, they made a combined 104,000 bbl their first 31 days online. They haven't sputtered out either. This past first quarter, they produced 30,000 bbl.



The Peters Creek S-shaped bridge near Cambridge, Ohio, was part of the early 19th century National Road. The shape is due to initiating the water-crossing at an angle.

NISSA DARBONNE/OIL AND GAS INVESTOR

Altogether, in 40 months online each, they've made 1.05 MMbbl through March 31. Solution gas totaled 6.5 Bcf; water, 379,000 bbl.

Some of Encino's wells in Stock are under Tappan Lake, a reservoir in the Muskingham Watershed Conservation District and named for the community that was displaced in 1938 by the damming along with Laceyville, which is now under the lake.

With royalties the district is earning from the oil and associated gas, a bar and grill was opened at one of the marinas in April and other improvements are underway in the 7,350-acre recreational area.

Back south, in the area of that 1814 well, is a Microtel Inn & Suites that advertises, "Close to [the] Utica Shale." It's in Cambridge, about a half-hour north of Caldwell and the Guernsey County seat.

Conversations are easily struck up in the area. Eventually, a local will ask, "What brings you to Ohio?"

In New York City, "oil and gas" typically prompts confrontation. In Ohio, the answer brings smiles. "They're drilling a well near my home!" one said, excitedly.

In Ohio, the oil and gas industry is at home. OGI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