Oil and Gas Investor

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PERMIAN PARADOX

Patterson-UTI Outgrows Workforce Deploying Fewer, Newer Rigs

EXXON MOBIL'S MOLECULAR TRANSFORMATION

THE OGI INTERVIEW

Exxon Mobil CEO Darren Woods Leans In On Low Carbon Solutions

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FEATURES

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On April 3, 2023, Ovintiv Inc. announced that it had entered into a definitive purchase agreement to acquire the assets of Piedra Resources, Black Swan Oil & Gas and PetroLegacy Energy from EnCap Investments L.P. in a cash and stock transaction valued at $4.275 billion.

This represents the largest M&A transaction in the Permian Basin in over 18 months. We congratulate EnCap, Piedra, Black Swan, Petrolegacy and Ovintiv on this important transaction.

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Oil and Gas Investor

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MIDSTREAM

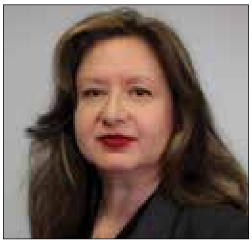
TECHNOLOGY

ABOUT THE COVER:
Houston-based Daniel Ortiz photographed the busy Exxon Mobil campus in April, capturing images of the supermajor's state-of-the-art LEED certified headquarters.


UNIVERSAL

Oil, Gas Companies Face Shareholder Reckoning this Spring

Shareholder proposals targeting top producers demand board, climate accountability.



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Proxy season represents a crucial reckoning for public oil and gas companies, perhaps now more than ever before as key headwinds—most specifically, the energy transition and all things ESG—dominate shareholder sentiment.

Proxy statements—filed in early spring with the U.S. Securities and Exchange Commission (SEC) as a form DEF14—provide a treasure trove of information to investors. Material statements on corporate performance, top investor holdings, executive compensation, board membership and general reporting can be found—that is, if you can muster the time and inclination to pore through the jargon written in fine print on 100+ page documents.

It's worth the bandwidth.

You see, these documents also list the shareholder resolutions that individual investors may approve or silence as well as the boards' recommendations.

These proposals may take aim at individual board members, corporate spending, the chief executive's duties, emissions reductions and diversity.

On the heels of the "great shareholder rebellion" against the E&P sector's growth-for-growth's sake spending and a perceived industry resistance to climate change, shareholder resolutions vetted during these annual gatherings have grown both in numbers and vitriol.

Some of these votes are non-binding, meaning that no action is required regardless of the outcome. Still, the outcome of a shareholder majority's vote on any given proposal amounts to a referendum on corporate behavior made by the folks who invest in the company.

And that's why individual executives—as well as the industry at large—should take note of a non-binding slap on the wrist.

Shareholder sentiment can disrupt even the mightiest of corporate boards.

Exxon Mobil is among the companies that has learned to take a shareholder challenge seriously. In 2021, an upstart activist investor group, Engine No. 1, began the year in dialogue with Exxon management to discuss the supermajor's market capitalization, which at the time was in collapse, and its role in the energy transition.

The meetings reportedly didn't go well, and Engine No. 1 took its push for additional board members at Exxon to the annual meeting. Holding a stake in the company of less than 0.02%, Engine No. 1 mustered support from major institutional investment firms. BlackRock, Vanguard and State Street voted with Engine No. 1. The influential proxy advisor Institutional Shareholder Services was in favor of the change.

Engine No. 1 won.

Exxon added three new independent members to its board—each at the behest of a tiny upstart hedge fund.

It's a modern-day David and Goliath story that likely emboldens others to hold even the largest of corporate behemoths to account for their actions, whether it's on climate concerns or shareholder returns.

The following are among the shareholder proposals scheduled at U.S. producers' meetings this month:

- **Greenhouse gas emissions reduction targets:** BP, Chevron, Enbridge, Exxon, Kinder Morgan, Royal Dutch Shell and Suncor
- **Lobbying/net-zero commitments:** Coterra Energy, CNX Resources, Devon Energy, Enbridge, EOG Resources and Kinder Morgan
- **Opposition to board member re-election:** ConocoPhillips, Chevron, Devon Energy, Exxon, Kinder Morgan and Occidental Petroleum
- **Climate-related/just transition planning:** Chevron, Exxon and Kinder Morgan
- **Methane measurement:** EOG Resources, Exxon and Marathon Oil
- **Risk:** Exxon
- **Energy transition reporting:** Exxon

  Proxy watchers say that as the season has heated up, climate concerns remain at the top of the 2023 trends. This extends to a surge of "anti-ESG" filings designed to counter several years' of "pro-ESG" proposals.

Proxy season begins in earnest in May and generally lasts through June. Watch closely. OGI

Think Decarbonization Has Been Derailed? Go Fly A Kite

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In 1755, Benjamin Franklin wrote: "Those who would give up decarbonization, to purchase a little temporary energy security, deserve neither decarbonization nor energy security."

Or something along those lines. I'm a little foggy on things pre-pandemic.

I'm also aware that plenty of folks would be fine giving up decarbonization and its attendant regulations in exchange for energy security. After all, it's a fair point to acknowledge that the energy security provided by abundant reserves of fossil fuels in this country goes well beyond "little" or "temporary."

And as long as we're on the subject of security, let's not forget national security. The shale revolution didn't just free the U.S. from reliance on the whims of unstable foreign regimes (and allow us to rely on the whims of unstable domestic regimes). It allowed exports of crude oil and natural gas so our allies could feel more secure, as well.

Those exports have come in handy, of course. When Russia attacked Ukraine militarily, it also attacked Europe economically by cutting supplies of oil and natural gas. Western European countries scrambled to secure imports of natural gas from the U.S. and others so inventories would be high enough to get through winter.

Meanwhile, Poland and Baltic countries—which had decades of up-close-and-personal experience with Russia—struggled mightily to not scream, "WE TOLD YOU SO!" (with mixed results).

The lesson taken by the European Union was that it had erred in its abrupt dismissal of fossil fuels and premature embrace of renewables. Clearly, adopting a plan while skimping on planning was not the best idea.

The lesson taken by U.S. producers was that the chastened Europeans had seen the error of their ways in depending on a hostile Russia for fuel. They had come to their senses and would shift their dependence to the U.S., putting off that silly energy transition stuff because it had been proved to be a lousy idea.

So, hurray for us. Except … a funny thing happened on the way to Smug Self-Satisfaction, that wondrous hamlet on the shores of Lake Condescension in the Valley of Snark. Turns out, not everybody views the lessons of the Ukraine war in the same way.

Much of the rest of the world—Europe, in particular—has been locked in on decarbonization for a while. From their perspective, the lesson from the past year was to accelerate the move away from fossil fuels, not shift to a different supplier.

Part of that stems from unrelenting Russian hostility. The other is the realization that true energy independence begins at home. For Europeans, who lack a bountiful resource like the Permian Basin, shifting to renewables like wind and solar makes a lot more sense.

Europe is not alone, of course. Decarbonization has become a lodestar in the global energy industry, even if renewed concern over energy security has thrown obstacles in its way.

"To be honest, internally, it hasn't slowed down our efforts toward decarbonization," Santiago Martínez Ochoa, head of sustainability and decarbonization at Ecopetrol, Colombia's national oil company, told me on the sidelines of CERAWeek by S&P Global.

"I think it balances, a bit, the conversation," he said. "If you think about Scope 3 [emissions], for example, everyone is pressuring us on having Scope 3. I think we're more hesitant to come up with a Scope 3 target, particularly in the medium term, because then it contradicts with energy security [concerns]."

Martínez Ochoa's counterpart at Saudi Aramco sees recent events as a hindrance, but they won't block the ongoing move toward decarbonization.

"When you incorporate nontechnical criteria—energy security or other stuff on the political agenda—you would actually negatively impact decarbonization," Hassan El-Houjeiri, Saudi Aramco's head of energy traceability & lifecycle analysis, told me at CERAWeek. "What we really need is support on the framework to actually enable the decarbonization technology application without differentiation."

El-Houjeiri is a scientist with a doctorate from Oxford University who did his postdoc work at Stanford University. He's all about figuring out solutions to the challenges of decarbonization and he clearly would prefer that the rest of the world get serious about it, too.

Ben Franklin, scientist from another time, offers hope to this effort. "Energy and persistence conquer all things," he said.

But Franklin offers another quote, one that can be taken as a warning as the world grapples with decarbonization and the energy transition: "You may delay, but time will not." OGI

▸ ENERGY POLICY

Belcher: Rules, Standards Key to Energy Transition

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

The energy transition has brought with it a slew of new activities, practices and technologies that are being applied by the energy industry in a race to decarbonize. In recent months, there have been numerous corporate announcements about new initiatives, funding sources and projects that are focused on areas including carbon capture and storage (CCS), hydrogen fuel and certified, lower carbon intensity natural gas.

At the same time the guidance and programs for the grants, loans, and tax credits outlined in the ~$740 billion Inflation Reduction Act (IRA) are being developed and implemented by federal agencies. Amid all the activity, state and federal governments are currently determining the roles that they will play in managing and regulating the enormous changes resulting from the energy transition.

The market for and availability of certified natural gas is growing rapidly as U.S. producers certify volumes to meet growing global demand for a cleaner, lower carbon natural gas. The cutoff of Russian gas supplies to Europe has accelerated this trend. With markets, especially in Europe, seeking a more consistent, minimum standard for categorizing clean natural gas, the U.S. Department of Energy (DOE) has begun engaging with the oil and gas industry and gas consuming nations to discuss an international standard for ensuring the performance of certified "clean" natural gas.

In fact, the DOE is seeking to have a standard ready to announce during the United National Climate Change Conference (COP28) in Dubai later this year. According to Assistant Secretary for Fossil Energy and Carbon Management Brad Crabtree, the DOE is working with stakeholders to develop an agreement on a measurement and verification framework to encourage methane and carbon dioxide emissions reductions throughout the natural gas value chain.

Relatedly, MiQ recently launched a certification program that provides a full life-cycle calculation of the greenhouse gas emissions (GHG) associated with the LNG supply chain. It will track GHG emissions from production all the way to regasification, allowing importers to compare LNG exporters "using one common framework," according to MiQ. Additionally, EQT announced it is partnering with Context Labs to bring verified lower carbon intensity natural gas products and carbon credits to market. The partnership will apply Context Labs' advanced climate data and analytics, machine learning and artificial intelligence capabilities to EQT's gas production to certify and register the carbon intensity of its operations.

As to hydrogen, U.S. Treasury and Internal Revenue Service officials are currently working to establish the rules on how to apply the massive IRA tax credits to clean hydrogen production and states, universities and companies have given their final pitches to the DOE in hopes of being chosen to participate in the DOE's program that will offer $8 billion in funding for at least six regional hydrogen hubs by 2028. The hubs will leverage local resources for clean hydrogen production, storage, transport and distribution infrastructure to be used in applications such as fuel cell electric vehicles, industrial processes and power generation. The DOE expects to announce the chosen hub recipients in early Q4 2023.

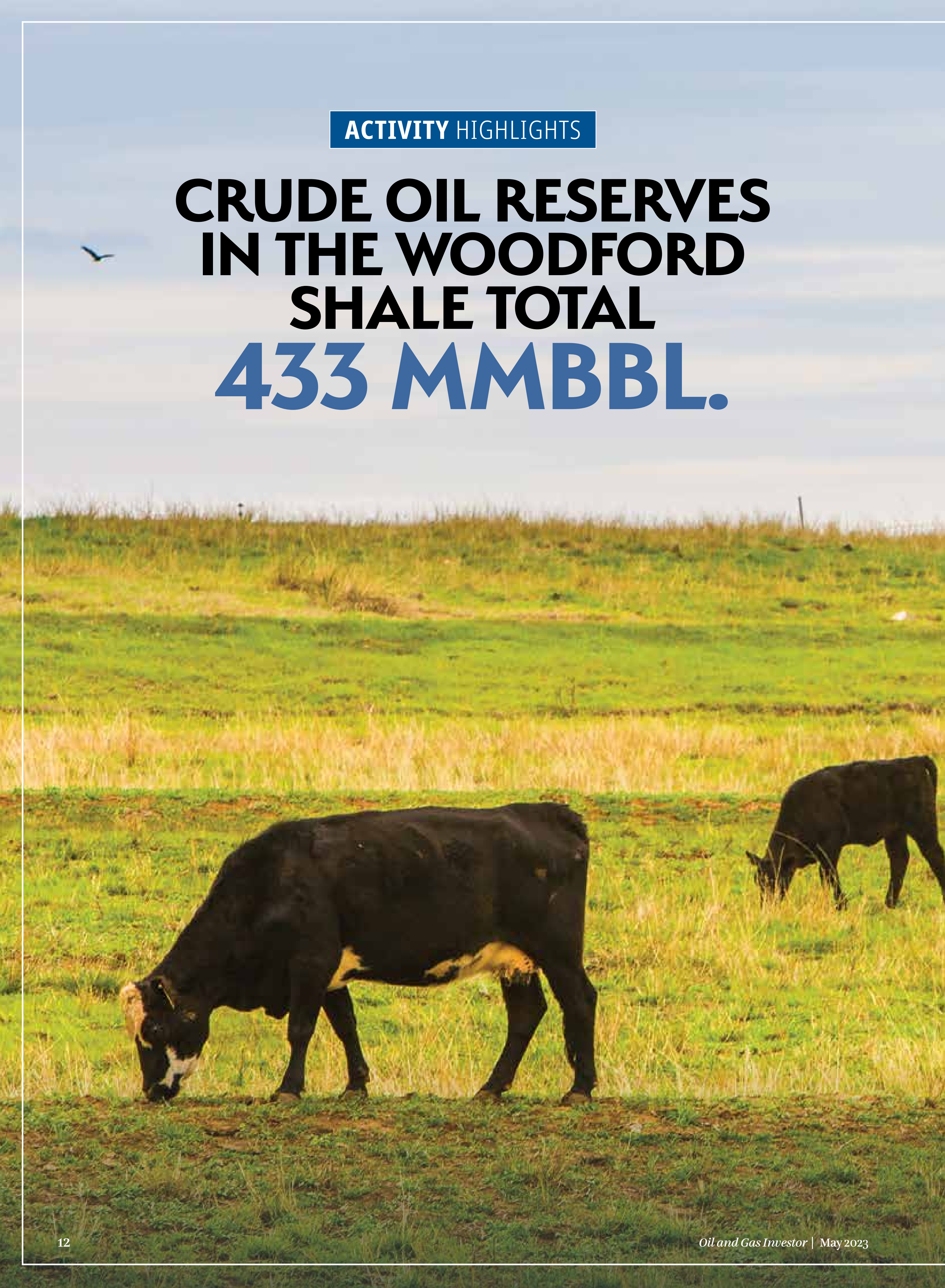
With several projects announced and dozens more being contemplated, both federal and state governments are also working to establish regulatory guidelines and incentives for carbon capture and storage projects. The IRA provides $3.7 billion for the construction of four direct air capture CCS facilities and includes expanded tax credits for CCS. There are also ongoing debates in state legislatures, including Louisiana and Texas, over the regulation of CCS.

The Texas Legislature is deliberating over which regulatory agency should exercise jurisdiction over CCS, how to determine ownership of pore space, and the contours of liability related to CCS operations, themes that are common in deliberations underway in other states.

Crafting laws and regulations is never easy. It involves long debates and compromises. The regulations and laws currently being developed to manage the energy transition address topics are quite complex. It is important that our policymakers take the time to address these complex issues appropriately, get the proper technical guidance from subject matter experts on these issues, and provide the energy industry with laws and regulations that are succinct, clear, fit for purpose and achievable. The best regulations are ones that emerge from industry best practices, things we have already applied in the field. Let's hope that we get the proper guidance from our leaders to help us successfully guide the energy transition. OGI

ACTIVITY HIGHLIGHTS

CRUDE OIL RESERVES IN THE WOODFORD SHALE TOTAL 433 MMBBL.

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▸ **ACTIVITY** HIGHLIGHTS

Permits

Martin County, Texas, sits atop this month's approved well permit leader board and ranks seventh among U.S. counties in barrels of oil equivalent (boe) production. About 70% of its roughly 8,000 wells are currently producing, according to MineralAnswers.com, at an average depth of 9,763 feet.

Martin plays host to numerous shale players, including Pioneer Natural Resources, Occidental Petroleum, Diamondback Energy and Endeavor Energy Resources, that have boosted oil production in the county by 383% since 2016. Natural gas output is up 507% in that time.

Anadarko, Continental Resources and Devon Energy are the top gun producers in Converse County, Wyo., the highest-ranking permit magnet outside of Texas. The number of wells in operation in Niobrara County, Wyo., grew by 15% last year to 2,658. In November 2022, production reached 4.66 MMboe.

Finally, erstwhile Bakken champ Dunn County, N.D., has WPX Energy and Marathon Oil gathering up approved well permits. Continental and Marathon are the production leaders in the county, which boasted output of 9.46 MMboe in November.

Permitted Wells By State

State	Well Count
Texas	550
Oklahoma	75
Wyoming	67
North Dakota	50
Colorado	39
Louisiana	22

Permitted Wells By Operator

Operator	Well Count
Oxy	66
Continental Resources	35
Endeavor	32
Double Eagle	30
Devon Energy	29
Grit Oil & Gas	26
ConocoPhillips	24
Pioneer	20
Chevron	20
Diamondback	19

Permitted Wells By County

County	Well Count
Martin, Texas	69
Reeves, Texas	51
Dimmit, Texas	47
Converse, Wyo.	46
Loving, Texas	44
Upton, Texas	40
Midland, Texas	35
Reagan, Texas	25
Andrews, Texas	25
Dunn, N.D.	23
Live Oak, Texas	22
Williams, N.D.	21
Campbell, Wyo.	14
Grady, Okla.	13
Kingfisher, Okla.	13
Canadian, Okla.	10

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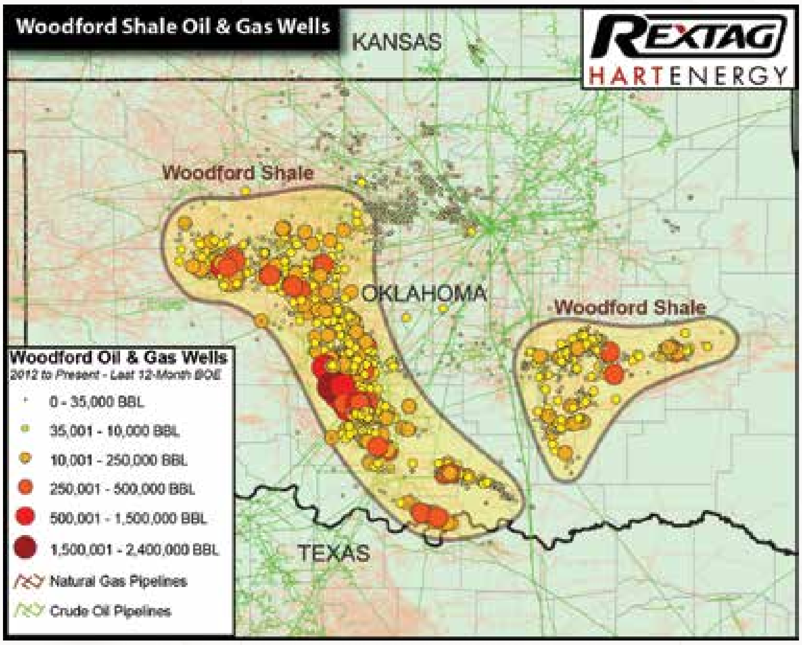
Focus on: Woodford Shale

The U.S. Energy Information Administration estimates that the Woodford Shale play holds crude oil proved reserves of 433 MMbbl and natural gas proved reserves of 20.8 Tcf.

Perhaps that is nowhere near Permian Basin or Marcellus Shale numbers, but it's not too shabby either. Woodford ranks just behind Niobrara and fairly ahead of Marcellus oil reserves. In gas reserves, Woodford is a bit behind the Utica but well ahead of the legendary Barnett Shale and the oily Bakken/Three Forks Shale.

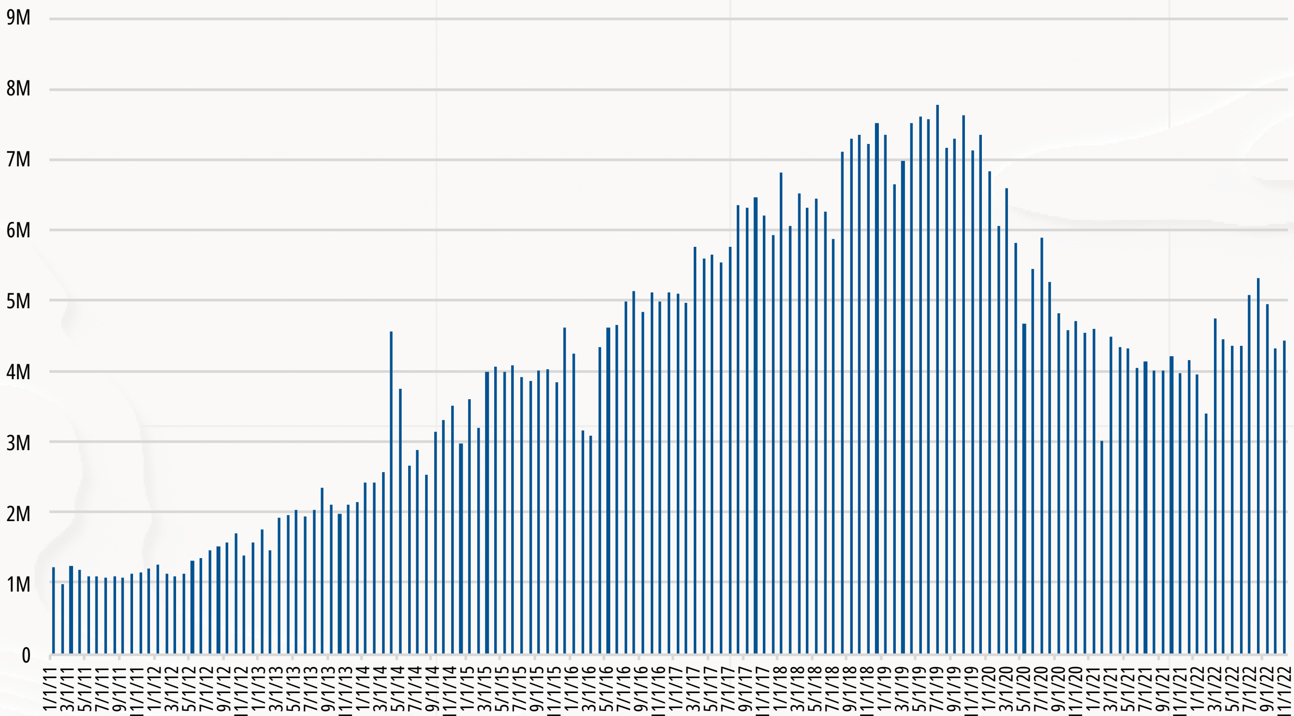
In mid-March, 31 rigs—all oil—were working in the Cana Woodford. That beat the Denver-Julesburg/Niobrara (17) and Utica Shale (11) and was in the neighborhood of the Williston (42) and Marcellus gas rigs (40).

Oil production in the Woodford rose 5.3% in the 12 months ending in October, compared to the previous 12 months. Continental Resources Inc. and Ovintiv Inc. are the leading producers in the play.



WOODFORD OIL PRODUCTION

BBL, MONTHLY, 2014-2022



Data from Rextag ENERGY DATALINK

DAY 2: May 23, 2023

Big Oil: ConocoPhillips
Kirk Johnson, Senior Vice President, Lower 48 Operations & Assets, ConocoPhillips

Decarbon: The North Dakota Project
James Powell, COO, Summit Carbon Solutions

Around Carbon: Panel
Nikhil Ati, Partner, McKinsey & Company
James Powell, COO, Summit Carbon Solutions

Permian Go-To: Earthstone Energy
Scott Thelander, Vice President, Earthstone Energy Inc.

The Environmental License: Civitas Resources
Civitas Resources Inc., **speaker TBD**

The Associated Gas
Brad Iles, President & CEO, Brazos Midstream
Dr. Ken Medlock, Senior Director, Baker Institute for Energy Studies
Hinds Howard, Portfolio Manager, Infrastructure, CBRE Investment Management

Red Bull: VTX Energy
Gene Shepherd, Founder & CEO, VTX Energy Partners LLC

The Fourth Double Eagle
Cody Campbell, Co-Founder & Co-CEO, Double Eagle IV

At the Pad: Tech Talk
Jeff Beach, Vice President, Universal Pressure Pumping Inc.
Jim Jacobson, Drilling Engineering Manager, IPT Well Solutions

SCOOP & Merge: Camino Natural Resources
Seth Urruty, CEO, Camino Natural Resources LLC

D&C'ing It & EOR'ing: Liberty Resources
Mark Pearson, CEO, Liberty Resources LLC

EOR & Refracs: EUR-Boosting
Bob Barba, President & CEO, Integrated Energy Services Inc.
Mark Pearson, CEO, Liberty Resources LLC
Akshay Sagar, President, Universal Pressure Pumping Inc.

Multi-Basin: Bayswater
Steve Struna, President & CEO, Bayswater Exploration & Production LLC

Made in the USA: World Energy Security
General Wesley K. Clark (ret), CEO, Wesley K. Clark & Associates

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DAY 3: May 24, 2023

Mega-Bakken: Chord Energy
Chord Energy Corp., **speaker TBD**

Blockchain Btu: The Carbon Option
Sam Holroyd, Chief Commercial Officer, ZeroSix

Capital, Carbon Trading, Inflation, Inventory & AI
Sam Holroyd, Chief Commercial Officer, ZeroSix

Tailwinds: Oil Futures
Amrita Sen, Co-Founder and Director of Research, Energy Aspects

OFS Panel: Diminishing Emissions
Saurabh Nitin, Senior Vice President - Emissions Technologies, ChampionX Corp.
Daniel Palmer, Commercialization Director, OGCI Climate Investments
Joe Quoyeser, Chief Commercial Officer, LongPath Technologies Inc.
Nick Rakic, Solutions Director, Welltec Inc.

At the Pond: Best Practices in Water
Duane Germenis, President, Intelligent Water Solutions
Gerard Cooke, CEO, Innov8 Systems Ltd
John Durand, President and Chief Sustainability Officer, XRI Holdings

World-Renowned: A Special Guest
In this must-attend session, Hart Energy LIVE, that has brought to DUG special guests President George W. Bush, General Colin Powell, Secretary Condoleezza Rice and more, is again proud to host this keynote address. Mark your calendar.

Additional speakers and sessions TBA.

Oil, Gas Price Volatility Slows Upstream M&A Market

A flurry of oil deals kicked off a strong start to 2023, but upstream dealmaking has slowed to a crawl due to low commodity prices and a banking liquidity crisis.

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Commodity price volatility and broader economic concerns have stifled the market for oil and gas deals that saw a hot start to upstream oil and gas M&A in 2023, analysts say.

Despite a significant slump in natural gas prices since late last year and more recent shakiness in crude oil prices, first quarter transactions were approximately $8.7 billion, Andrew Dittmar, research director at Enverus Intelligence, told Hart Energy. That would rank as the sector's best start to the year since first-quarter 2018, he said.

But those values belie a market that has since reeled from uncertainty.

"We were in that Goldilocks pricing scenario in the high-$70s/bbl, $80/bbl range where sellers were comfortable giving up the assets at that kind of pricing," Dittmar said. "Buyers, at the time, felt like they were relatively protected from the downside risk—maybe they saw a little more upside potential than downside risk there."

The Eagle Ford Shale in South Texas saw a flurry of oil-focused deal activity in the first quarter. Chesapeake Energy Corp. lined up two divestitures totaling nearly $3 billion to offload a significant portion of its oily Eagle Ford acreage.

And Canadian E&P Baytex Energy reached a deal to acquire Eagle Ford pure-play Ranger Oil for $2.5 billion earlier in March.

Since the second half of 2022, the Eagle Ford's resurgence has dominated M&A, with more than $10 billion in deal value, according to Mercer Capital.

"Significant volumes of wet gas, NGLs and rich condensate, combined with the proximity to the Port of Corpus Christi," has made the mature shale play a center of M&A activity, according according to a Mercer report this spring.

The report noted that the Corpus Christi port is the home of a processing and export market that hit an all-time high for crude oil exports in December 2022, exceeding 70 million barrels (MMbbl) in a month for the first time in its history. The Port of Corpus Christi accounted for roughly 60% of all U.S. crude oil exports for all of 2022, according to research firm RBN Energy.

The oil-heavy Permian Basin, as usual, continued to see sizeable M&A activity. In late March, VTX Energy Partners, the U.S. upstream arm of Swiss-based Vitol, closed an acquisition of 35,000 net leasehold acres in the Delaware Basin. The VTX deal, announced in January, was likely in the range of $1.5 billion to $2 billion, Dittmar said.

Other, smaller deals include Oklahoma City-based Riley Exploration Permian Inc., which agreed to pay $330 million in cash to acquire oil and gas assets on the New Mexico side of the Permian in February.

But the large value of those transactions has obscured a market in which deal activity has been thwarted by oil and gas volatility.

Crude crunch

Oil deals were flowing earlier during the first quarter, but market conditions have changed since the start of the year. A major banking liquidity crisis and multiple regional bank failures in the U.S. stoked fears of a broader economic recession, pushing oil prices lower.

WTI crude prices closed out at a 2023-low of $66.61/bbl on March 17—the lowest WTI has sunk since December 2021, according to the Energy Information Administration (EIA).

"I think [the banking crisis] is probably what's thrown a wrench in the market," Dittmar said. "It's just how rapidly oil prices collapsed, and how much uncertainty there is around the global outlook for economic growth through first and middle parts of 2023."

Oil prices have made up some of their losses in recent days; WTI futures for May traded up more than 5% at $72.81/bbl in late March. While oil prices aren't expected to reach levels seen in 2022, Dittmar said he thinks prices should continue to rebound back up to a more preferred pricing range this year.

On the flip side, if crude prices continue to fall, the market for energy acquisitions and mergers could heat back up.

"It will be interesting to see if there ends up being a significant slide in WTI prices if [M&A] gets picked up again," said James Taylor, senior analyst with East Daley Analytics.

Upstream deals in North America valued at more than $1B

Year	Number of deals	Value of deals ($/billion)
Texas	452	452
Colorado	119	119
Wyoming	68	68
Oklahoma	35	35
North Dakota	33	33
Louisiana	29	29

Source: McKinsey & Company

Gas gloom

U.S. crude oil prices have seen volatility in recent weeks. But natural gas prices have consistently spiraled downward since late last year due to oversupply and weaker-than-expected global demand.

After averaging $6.42/MMBtu in 2022, Henry Hub gas prices are expected to average around $3/MMBtu this year, according to the latest forecasts by the EIA earlier this month.

The extreme volatility in gas prices effectively shut down the market for M&A in gas-heavy basins this year, Dittmar said.

The only announced gas deal of consequence this quarter was Diversified Energy Co.'s acquisition of Texas upstream assets from Tanos Energy Holdings II LLC for $250 million, he said.

"At this kind of pricing, if they feel like they can wait it out, you get some relief in the next 12 to 24 months," Dittmar said. "I imagine that's probably what's happening on the gas side."

Several natural gas-focused players, such as Chesapeake and Marcellus gas giant EQT Corp., see a runway to higher global gas demand—and higher gas pricing—in 2025 and 2026, when new LNG export projects start up on the Gulf Coast.

"I think there are a lot of sellers sitting out that aren't willing to let their gas go at a $2.25/MMBtu price when they say that could be doubled in the next couple of years," Dittmar said.

Austin Chalk, Permian deals in play

A rebound in the gas M&A market might take time to recover, but don't be surprised to see deals centered around crude oil production later this year.

As part of Chesapeake's exit from the Eagle Ford, the company still has approximately 21,000 bbl/d of oil and NGL production and 80 MMcf/d of natural gas production remaining in its Eagle Ford position.

Chesapeake is in discussions with potential buyers for the remainder of its Eagle Ford footprint, which includes acreage in the Austin Chalk play. OGJ

Ovintiv's $4.2 Billion Permian Deal Improves Inventory Runway, Crude Output

Ovintiv's $4.2 billion bid to acquire three EnCap-backed E&Ps in the northern Midland Basin adds much-needed inventory and addresses key investor concerns, analysts say.

Ovintiv Inc.'s latest $4.275 billion acquisition in the Permian Basin adds highly sought-after core inventory and should be a boon in the eyes of investors, analysts say.

Ovintiv agreed on April 3 to acquire 65,000 net acres and 1,050 net horizontal locations in the Northern Midland Basin from three portfolio companies backed by EnCap Investments LP, Black Swan Oil & Gas, PetroLegacy Energy and Piedra Resources.

The cash-and-stock deal addresses the relatively short runway of core drilling locations Ovintiv had in its existing portfolio, a key concern for investors prior to the transaction, said Andrew Dittmar, director at Enverus Intelligence Research.

"Since investors are closely scrutinizing inventory life when valuing oil-focused E&Ps, adding the additional locations should help the company improve its equity multiple and rerate higher," Dittmar said in April

Some of the assets Ovintiv is picking up are a bit more fringe on the northern edge of the Midland, including in Andrews County, Texas, where there's historically been less drilling activity, Gabriele Sorbara, managing director of equity research at Siebert Williams Shank & Co. told Hart Energy.

Still, Black Swan, PetroLegacy and Piedra represented the highest quality remaining private-equity backed opportunities in the Midland Basin, Dittmar said. And a substantial amount of acreage was also acquired in Martin County, Texas. Martin was the second biggest producer of crude among Texas counties as of January 2023, according to the Texas Railroad Commission.

And at just over $20,000 per acre, after adjusting for production value, the purchase price reflects a competitive market for core acreage acquisitions in the Permian.

"The cost of high-quality acreage and drilling inventory has escalated substantially over the last year as public companies targeted acquisitions that could boost their runway and the number of opportunities remaining dwindled," Dittmar said.

Ovintiv also announced an agreement to sell its entire position in the Williston Basin's Bakken play to Grayson Mill Bakken LLC, another EnCap portfolio company, for $825 million in cash. The divestiture is expected to close on June 12, subject to customary closing conditions, according to an Ovintiv regulatory filing.

Offloading non-core Bakken assets with very little inventory remaining to pick up oilier acreage in the Permian was a good move for Ovintiv, Sorbara said.

"You get rid of a high-cost play like the Bakken and you deploy capital toward the Permian," Sorbara said. "Investors like the Permian."

"[Public companies are] not looking to grow volumes; they're looking to sustain them."

—**Andrew Dittmar,** ***Enverus Intelligence Research***

"You get rid of a high-cost play like the Bakken and you deploy capital toward the Permian."

—**Gabriele Sorbara,** ***Siebert Williams Shank & Co.***

Boosting oil production

Ovintiv's portfolio is still quite weighted toward natural gas, but the acquisition in the Permian deepens the company's footprint in crude oil production.

As of the end of last year, Ovintiv's estimated net proved reserves consisted of about 24% oil, 26% NGL and 50% natural gas, the company said in its latest annual report.

After integrating the EnCap-backed Midland Basin assets, that mix could look more like 28% oil, 23% NGL and 49% natural gas in the third quarter, Sorbara said.

Brendan McCracken, president and CEO at Ovintiv, said the acquisition will enable the company to nearly double Permian oil and condensate production to approximately 125,000 barrels per day (bbl/d).

"We add significant inventory depth, increase our oil mix and create a big enhancement to our capital efficiency and lower our cash costs," McCracken said during a recent call with analysts.

Ovintiv's existing Permian footprint—about 114,000 net acres—averages 115,000 barrels of oil equivalent per day (boe/d). The company produces 65,000 bbl/d of oil and condensate, of which 55% is oil.

The acquired 65,000 net acres and 75,000 boe/d of production has an 80% oil and condensate cut, Ovintiv said. That will boost the company's oil production profile in the Permian to about 65%.

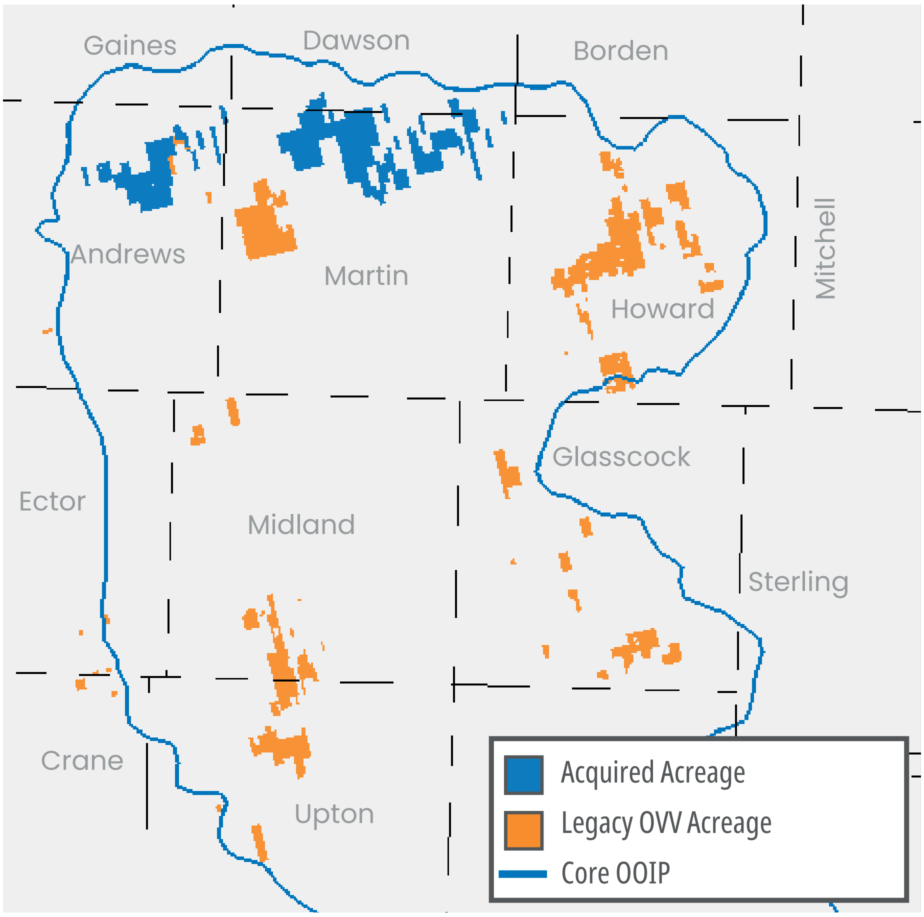
However, that mix should start to even out over time, McCracken said.

"As that base position matures and as we slow growth and flatten it out, we do expect that [the gas-oil ratio] is going to climb," McCracken said. "That's just the nature of the Permian everywhere, but inclusive of the northern Midland Basin."

Across the company's North American footprint, total oil and condensate production in 2024 is expected to grow to over 200,000 bbl/d, the company said. Ovintiv expects roughly 60% of its 2024 capital spend between $2.1 billion and $2.5 billion to be deployed in the Permian.

"Next year, we will spend roughly the same amount of capital at the midpoint as we guided to for 2023 pre-transaction, but that capital will produce an additional 30,000 bbl/d of oil and condensate," McCracken said.

Ovintiv Permian map



Source: Ovintiv

Slowing rig activity

Ovintiv plans to pull back on drilling activity in the new acreage after the deal closes, which is expected to occur by the end of the second quarter.

The company anticipates moving from a pro forma 10-rig drilling program in the Permian to a 5-rig program by the fourth quarter. Rig activity on the newly acquired assets is expected to dwindle from seven operated rigs down to two.

The three EnCap-backed operating companies have collectively run seven rigs, and oil production is on a ramp up through the first half of 2023, McCracken said.

"There will be a peaking of production in the third and fourth quarter this year," McCracken said. "Then we're going to run it at a more stable rate for free cash flow and returns going forward."

Dropping rig activity after a public-to-private deal like this isn't all that uncommon. Private operators tend to take a more aggressive approach to developing assets in general—particularly when one of those assets is getting close to hitting the market, Dittmar said.

"[Public companies are] not looking to grow volumes; they're looking to sustain them and use all that excess capital to generate shareholder returns and dividends," Dittmar said.

Another reason Ovintiv will pull back on drilling in the northern Midland Basin is to protect the life of its inventory—one of the company's main considerations for going after the deal in the first place.

"They don't want to have to burn through that quicker than they need to," Dittmar said.

Bolstering shareholder returns

Investors seem to like Ovintiv's deal to add more Permian inventory. After closing at $36.08 per share on March 31, Ovintiv's stock price ticked up nearly 12% to close at $40.38 per share on April 3, according to Yahoo Finance data.

But investors also like share buybacks and dividends. Ovintiv said it remains committed to delivering at least 50% of its post-base dividend free cash flow back to shareholders through buybacks or variable dividends.

On April 2, the Ovintiv board of directors declared a quarterly cash dividend of $0.30/share, up 20% from the company's dividend last quarter. The dividend will be payable on June 30 to shareholders of record as of June 15.

On top of the $4.275 billion Midland Basin deal, Ovintiv also announced completing another $200 million in what it called accretive bolt-on acquisitions during the first quarter.

While the company is open to higher-quality bolt-on deals in the future, Ovintiv is heavily focused on executing and paying down debt in the near-term, McCracken said.

"We've raised the bar for additional bolt-ons, and we expect minimal spending going forward while we focus on cash returns and debt reduction," McCracken said.

—Chris Mathews

Energy Transfer to Acquire Permian's Lotus Midstream for $1.45 billion

Energy Transfer's acquisition of Lotus Midstream's infrastructure adds about 3,000 miles of crude gathering and transportation pipelines from New Mexico across West Texas to Cushing, Oklahoma.

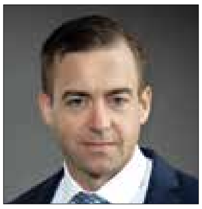
Energy Transfer LP will acquire **Lotus Midstream LLC** in a $1.45 billion cash-and-stock deal, the company said on March 27. The deal includes thousands of miles of pipeline, gathering and storage in the Permian Basin and paves the way for a connecting crude oil pipeline project from Midland to Cushing, Oklahoma.

The purchase, from an affiliate of **EnCap Flatrock Midstream** (EFM), continues a rash of midstream deals worth billions of dollars that began late last year and continued to build momentum in January. The transactions have ranged from smaller bolt-on deals to multi-billion-dollar transactions such as **Enterprise Products Partners'** acquisition of **Navitas** and **Targa's** acquisition of **Lucid Energy**, Stacey Morris, head of energy research for **VettaFi**, told Hart Energy.

"Energy Transfer's acquisition of Lotus is another example of a sizable acquisition of Permian assets, though this deal is different in that the assets are focused on crude gathering and transportation instead of natural gas," Morris said.

Energy Transfer will pay $900 million in cash and approximately 44.5 million newly issued Energy Transfer common units.

"The financing mix is attractive, given the issuance of equity to the seller, so—not all cash, not going to raise leverage," Hinds Howard, Principal and Portfolio Manager at **CBRE Investment Management**, told Hart Energy. "In general, this deal follows the trend we saw last year with large-scale bolt-on acquisitions for more than $1 billion by major midstream players. Navitas, Lucid, Trace all fit into the trend."



"The larger companies will continue to add assets in acquisitions, now that consolidation has happened and new project development isn't needed or is too challenging to complete."

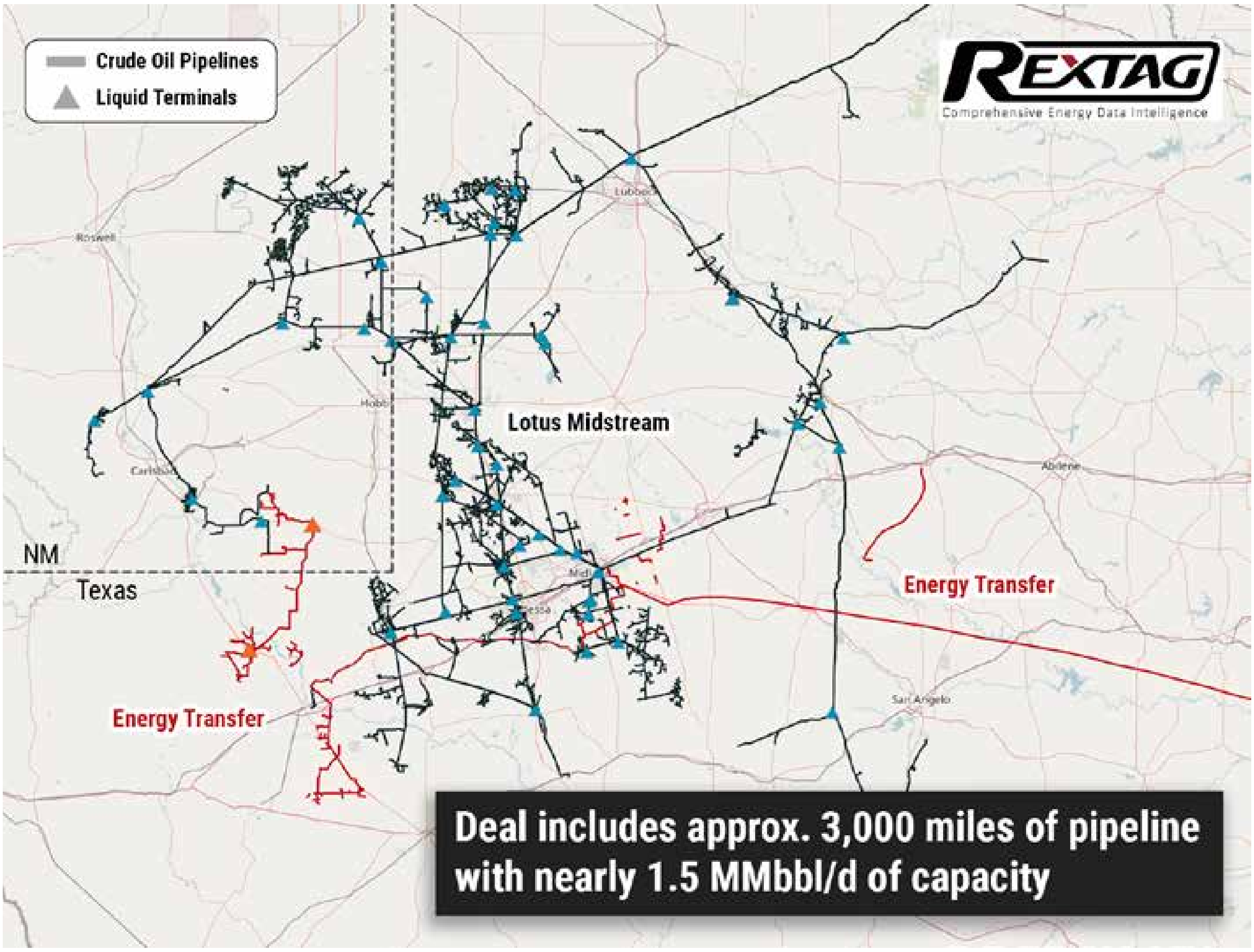
—**Hinds Howard,** *CBRE Investment Management*

The transaction is expected to be immediately accretive to free cash flow and distributable cash flow per unit. Lotus Midstream cash flows are supported by fee-based revenues from fixed-fee contracts.

"The larger companies will continue to add assets in acquisitions, now that consolidation has happened and new project development isn't needed or is too challenging to complete," Howard said.

Morris echoed that, noting that opportunities will increase as private equity companies exit their investments.

"The Permian remains an attractive area for deal-making



Source: Rextag, Hart Energy

as midstream companies look to enhance their existing positions in the most prolific producing region in the U.S.," Morris said. "With competition in the basin, growing footprints and enhanced connectivity to different markets can improve the offerings and transportation solutions that midstream companies can offer their customers."

Deal Details

Energy Transfer's acquisition, expected to close in the second quarter, includes Lotus Midstream's **Centurion Pipeline Company LLC**—an integrated, crude midstream platform located in the Permian. Centurion Pipeline Co. provides a full suite of midstream services, including wellhead gathering, intra-basin transportation, terminalling and long-haul transportation services, according to Energy Transfer.

The system consists of approximately 3,000 active miles of pipeline and serves major production areas of the Permian with nearly 1.5 MMbbl/d of capacity. Lotus Midstream's assets provide direct access to major hubs including Cushing, Midland, Colorado City, Wink and Crane. The system is anchored by large-cap producer customers with firm, long-term contracts and significant acreage dedications.

Lotus Midstream's Midland Terminal offers 2 MMbbl/d of crude oil storage capacity and additional supply and demand connectivity. The acquisition also includes a 5% equity interest in the Wink to Webster Pipeline, a 650-mile pipeline system transporting more than 1 MMbbl/d of crude oil and condensate from the Permian Basin to the Gulf Coast.

Upon closing, Energy Transfer expects to begin construction on a 30-mile pipeline project that will allow Energy Transfer and its customers the ability to originate barrels from its Midland terminals for ultimate delivery to Cushing. This project is expected to be completed in first-quarter 2024.

J.P. Morgan Securities LLC and **TD Securities** are serving as financial advisers to Energy Transfer. **Sidley Austin LLP** is acting as Energy Transfer's legal counsel on the transaction.

Jefferies is serving as financial adviser to Lotus Midstream, and **Vinson & Elkins LLP** is acting as Lotus Midstream's legal counsel.

—Darren Barbee, Joe Markman

Crescent Point to Buy Montney Assets in $1.28 Billion Deal

Crescent Point is buying Spartan Delta Corp.'s Montney assets in Alberta, Canada, a spread of 235,000 net acres.

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Crescent Point Energy Corp. announced in late March that it has entered into an agreement to acquire **Spartan Delta Corp.'s** oil and liquids-rich Montney assets in Alberta, Canada, for CA$1.7 billion (US$1.28 billion) in cash.

The acquisition includes average production of 38,000 barrels of oil equivalent per day (boe/d), 55% liquids, and adds total drilling inventory of 600 net Montney locations, which Crescent Point said would provide more than 20 years of inventory to sustain current production levels.

Spartan's acquired assets include approximately 235,000 net acres of contiguous land with Montney rights in Alberta within the Gold Creek and Karr area, as well as infrastructure and well licenses to support future development plans.

The assets are adjacent to Crescent Point's Kaybob Duvernay assets—an area where the company continued to expand since entering the play in February 2021 in following the acquisition of Shell's position in the play.

In December, Crescent Point announced a purchase and sale in the play to bolt-on production as well as midstream infrastructure for CA$375 (US$274 million) cash.

Crescent Point said it would target "additional non-core asset dispositions over time to further optimize portfolio."

The company said its leverage ratio, pro forma for the deal, would be 1.3x adjusted funds flow at closing and 1.0x at year-end 2023.

Spartan's type wells are expected to pay out in approximately 10 months from the initial on-stream date, based on wells booked by the independent engineers and assuming current commodity prices, Crescent Point said.

The company's transaction metrics assume WTI prices ranging between US$70/barrel (bbl) to US$75/bbl and $3.50 per million cubic feet of natural gas. Under those conditions, Spartan's production would produce:

- 3.2x to 3.4x annual net operating income;
- $44,740 per flowing boe; and
- $8.23 per boe of 2P reserves of 206.7 MMboe.

The wells are also economic at low commodity prices with breakevens below US$40/bbl WTI, the company said. The wells returns and economics will rank in the top quartile of Crescent Point's portfolio. Along with its Kaybob Duvernay asset, the company said the acquisition provides additional flexibility within the company's capital allocation framework.

Upon closing, Crescent Point's pro-forma decline rate is expected to remain below 30% and total inventory of premium locations to increase to 15 years, based on the long-term development plans for its assets.

"Over the past five years, we have fundamentally rebuilt and strengthened Crescent Point," said Craig Bryksa, president and CEO of Crescent Point. "As a result of our efforts, and after closing this transaction, our asset base will include significant inventory depth in both the Kaybob Duvernay and the Montney, while also maintaining significant low-decline assets in Saskatchewan that provide additional excess cash flow.

"The Montney acquisition is immediately accretive to our per share metrics, enhances our return of capital to shareholders and is aligned with our long-term strategy to focus on high-quality, scalable resource plays that meet our defined asset criteria."

The transaction is anticipated to close during second-quarter 2023, subject to regulatory approvals and customary closing conditions.

RBC Capital Markets is acting as financial adviser to Crescent Point on the transaction. **BMO Capital Markets** and **Scotiabank** are acting as strategic advisers to Crescent Point.

The **Bank of Nova Scotia** and **Royal Bank of Canada** are acting as co-lead arrangers and joint bookrunners on the company's new revolving credit facility.

—Darren Barbee

Brookfield, EIG Consortium to Acquire Australia's Origin Energy in Deal Worth $10.3 Billion

Brookfield plans to invest at least AUD$20 billion more during the next decade to construct renewable generation and storage facilities in Australia.

A consortium led by **Brookfield Renewable Partners** entered a deal to acquire **Origin Energy**, Australia's largest integrated power generator, valuing the company at AUD$18.7 billion (US$12.5 billion), including debt.

If the deal receives shareholders' blessings, clears regulatory hurdles and meets other customary closing conditions, the transaction could mark one of the largest private equity-backed deals for Australia. It will also usher in plans for AUD$20 billion in additional investment by Brookfield over the next decade to construct up to 14 gigawatts of renewable generation and storage facilities in Australia.

The companies said on March 27 they had entered a binding scheme implementation deed.

Brookfield and its institutional partners **GIC** and **Temasek** teamed with **EIG**-managed LNG pureplay **MidOcean Energy** to pursue Origin at a price of $8.91 per share, representing a 53.4% premium to the company's unaffected share price, Brookfield said. The purchase price of about AUD$15.4 billion (US $10.3 billion) includes net debt of about AUD$3.3 billion as disclosed in Origin's 2023 half-year report, according to Brookfield.

The bid was the third placed by the consortium in recent months, based on media reports.

"The significant premium placed on Origin by the consortium reflects the value of our strategy and our advantaged position to capture value from the energy transition," Origin CEO Frank Calabria said in a news release. "We believe this transaction is a great outcome not only for our shareholders, but for all stakeholders including our customers, employees and partners."

As part of the deal, Brookfield and its partners will acquire Origin's Energy Markets business. Brookfield said it is pursuing the acquisition through the Brookfield Global Transition Fund 1, with Brookfield Renewable expected to invest up to US$750 million via a combination of corporate debt, upfinancings of existing hydro assets and proceeds from asset recycling initiatives.

The acquisition will propel Brookfield's plans to decarbonize Australia's electric grid, replacing the country's largest coal-fired power plants with renewable energy.

"As the energy transition gathers pace, what's needed is increasingly clear: faster deployment of large-scale renewables, the accelerated, responsible retirement of coal generation and an interim, supportive role for gas as the dependable back-up fuel," said Mark Carney, chair of Brookfield Asset Management and head of Transition Investing. "Brookfield is determined that the new Origin Energy Markets will lead the way in all respects at this critical moment for the Australian economy."

The agreement includes EIG taking over Origin's Integrated Gas business—including its 27.5% stake in **Australia Pacific LNG** (APLNG)—through MidOcean Energy, the company said. MidOcean aims to continue boosting LNG and natural gas volumes to meet demand following its recent acquisition of Australian LNG assets from Tokyo Gas.

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As part of the deal, Brookfield and its partners will acquire Origin's Energy Markets business, while EIG-managed, LNG pureplay MidOcean Energy will acquire Origin's Integrated Gas business.

"Origin's Integrated Gas business adds world-class assets to our portfolio—assets that fit our strategy to create a high quality, diversified, global 'pure play' integrated LNG company," MidOcean Energy CEO De la Rey Venter said.

MidOcean added it has entered an agreement to on-sell a 2.49% interest in APLNG to **ConocoPhillips**, the current downstream and future upstream operator of APLNG, when the Origin deal is complete.

Origin's board has recommended shareholders approve the scheme, stating it's in their best interests and a superior proposal doesn't exist.

"The transaction represents a significant premium to the share price prior to the original indicative proposal and reflects the strategic nature of Origin's platform, its growth prospects and anticipated earnings recovery," Origin Chairman Scott Perkins said.

Origin and the consortium aim to implement the deal in early 2024. Origin has a nearly 25% market share of the Australian electricity market.

Citi and **MUFG** served as Brookfield's financial advisers, while **UBS** and **JP Morgan** acted as financial advisers for MidOcean.

—Velda Addison

North America

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- **Shell USA Inc.** has closed its acquisition of **Volta Inc.** and its network of electric vehicle charging locations.

Shell's $169 million cash acquisition of Volta includes a public charging network of more than 3,000 charging locations at destinations such as shopping centers, grocery stores and pharmacies in 31 U.S. states and territories.

Volta also has a development pipeline of another 3,400 charging locations.

Shell USA acquired all outstanding shares of Volta's Class A common stock for $169 million, or $0.86/share.

Shell also provided Volta with $20 million in secured term loans and repaid $11 million in Volta's third-party debt to support the company's balance sheet.

With the acquisition of Volta, Shell owns and operates one of the largest public charging networks in the U.S., the company said.

"As demand for EV [electric vehicle] charging continues to grow, destination sites will play a key role in meeting people where they spend a great deal of time: the store, the gym, and everywhere in-between," said István Kapitány, executive vice president of Shell Mobility.

Volta shareholders signed off on the combination with Shell USA at a special stockholders' meeting on March 29.

- **CorEnergy Infrastructure Trust Inc.** has retained an adviser for the sale of its MoGas and Omega systems, the company said in March.

The Kansas City, Missouri-based company said the marketing process had "generated a number of highly interested and qualified participants."

"Given the level of interest, the company expects to close the sale by early Q3 2023," the company said.

- **Omega Pipeline Co.** is a natural gas distribution system primarily serving the U.S. Army's Fort Leonard Wood in south-central Missouri through a long-term contract with the Department of Defense.

- **MoGas Pipeline LLC** is a 263-mile interstate natural gas pipeline system in and around St. Louis that extends into Central Missouri.

"We anticipate net proceeds from the sale of our MoGas and Omega systems will be sufficient to repay our bank facility in full," CorEnergy Chairman and CEO Dave Schulte said. "We also expect that the remaining proceeds, combined with a new credit facility and operating cash flow, will enable us to retire a material percentage of our outstanding convertible debt prior to maturity."

The company is also pursuing the sale of underutilized real estate with proceeds expected to be available for continued deleveraging, Schulte said.

- **Dawson Geophysical Co.** has purchased **Breckenridge Geophysical LLC**, a company owned by **Wilks Brothers LLC** that also holds controlling interest in Dawson, the companies said.

Breckenridge will receive consideration consisting of 7 million Dawson shares of common stock. At close, Dawson issued more than 1.18 million newly issues shared representing 4.99% of the Dawson's outstanding stock.

Dawson also issued Breckenridge a $9.88 million convertible promissory note. The note converts to roughly 5.8 million Dawson shares on June 30, 2024, but only following shareholder approval at a meeting Dawson will convene "as soon as practicable."

The transaction, effective immediately, will begin integration of Breckenridge's seismic data acquisition company as soon as possible. "Relevant employees" will be extended offers of employment with Dawson.

Appalachia

- **IOG Resources II** is growing its non-operated position in Appalachia through an acquisition in Carroll County, Ohio and Butler County, Pennsylvania.

IOG did not disclose the seller or financial terms of the acquisition.

The Dallas-based investment firm signed an agreement to acquire 66 producing wellbores and 7,000 net acres. The assets have a current net production of approximately 24 million cubic feet equivalent per day (MMcfe/d) and includes "a substantial liquids component," IOGR II announced this spring.

Shutterstock/JNix

But the deal represents the second investment by IOGR II and the 14th discrete investment by the IOG Resources platform across six U.S. production basins.

The IOG Resources investment platforms are sponsored by Connecticut-based energy private equity firm **First Reserve**.

The deal is expected to close during the second quarter. **Kirkland & Ellis LLP** served as legal counsel to IOGR II in connection with the transaction.

Texas

- **ACEN's** joint venture company **UPC Power Solutions LLC** agreed to a purchase and sale agreement with **GlidePath Power Solutions LLC** for the acquisition of eight operating wind projects in Texas, ACEN announced.

The 136-megawatt (MW) acquisition from GlidePath is expected to generate approximately 360 gigawatt-hour of wind energy per year and avoid around 127,000 metric tons of CO_2 emissions. The energy generated is enough to power up to 24,000 households.

The agreement is ACEN's entry into the U.S. renewables market outside the Asia Pacific region. The energy platform of the **Ayala Group**, ACEN has approximately 4,000 MW of total capacity from facilities in the Philippines, Vietnam, Indonesia, India and Australia.

ACEN, through its subsidiary ACEN USA LLC, announced in April 2022 that it formed a partnership with **Pivot Power Management** and **UPC Solar and Wind Investments LLC** to pursue renewable operating wind projects in the U.S.

Exxon Mobil Targets MultiTrillion-Dollar Low-Carbon Market

Exxon Mobil plans to use skills gained from its core petroleum and chemical manufacturing business units to grab part of an envisioned $6 trillion market built on abating carbon emissions.

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Exxon Mobil Corp. plans to spend about $7 billion through 2027 equipping its Low Carbon Solutions unit to help others lower emissions—and tap into a market that company executives say could generate billions in returns.

Exxon's focus is on carbon capture and storage (CCS), hydrogen and biofuels—technologies seen as critical to decarbonizing hard-to-abate sectors that account for the bulk of energy-related CO_2 emissions.

The investment represents about 40% of the $17 billion budget Exxon has planned for lower-emissions initiatives through 2027. The rest will go toward efforts to further reduce emissions from the company's own operations, Exxon said.

"We expect the Low Carbon Solutions business to generate reliable earnings under long-term contracts and, as it grows, deliver strong, double-digit returns," Exxon Mobil CEO Darren Woods told analysts during a webcast in April. "Global emissions markets have the potential to grow rapidly and reach a massive size. This, in turn, provides significant opportunities for our Low Carbon Solutions business, which represents an important and attractive element of our growth plans."

Executives for the Texas-based supermajor discussed the company's approach to the energy transition, spotlighting the company's low-carbon business.

Using skills gained from its core petroleum and chemical manufacturing business units, Exxon is set on capturing a piece of what it calls the $6 trillion molecules management opportunity by building foundational projects.

"We feel like we've gotten here at a really good time and are bringing our capabilities and expertise to bear in that marketplace. And that, frankly, is where the effort and the work is right now."

—**Darren Woods,** *CEO, Exxon Mobil Corp.*

"These are projects that work with today's policy, today's technology and today's infrastructure," Dan Ammann, president of Exxon Mobil's Low Carbon Solutions business, said while discussing the unit's first phase of growth spanning about five years. "And to demonstrate that these projects can attract customers and earn solid returns, the market at this stage could be in the tens of billions of dollars, with our annualized revenue on contract reaching the billions over the next few years."

At the same time, Ammann said the company will invest in new technologies that will help "unlock" future cost reductions.

Markets take shape

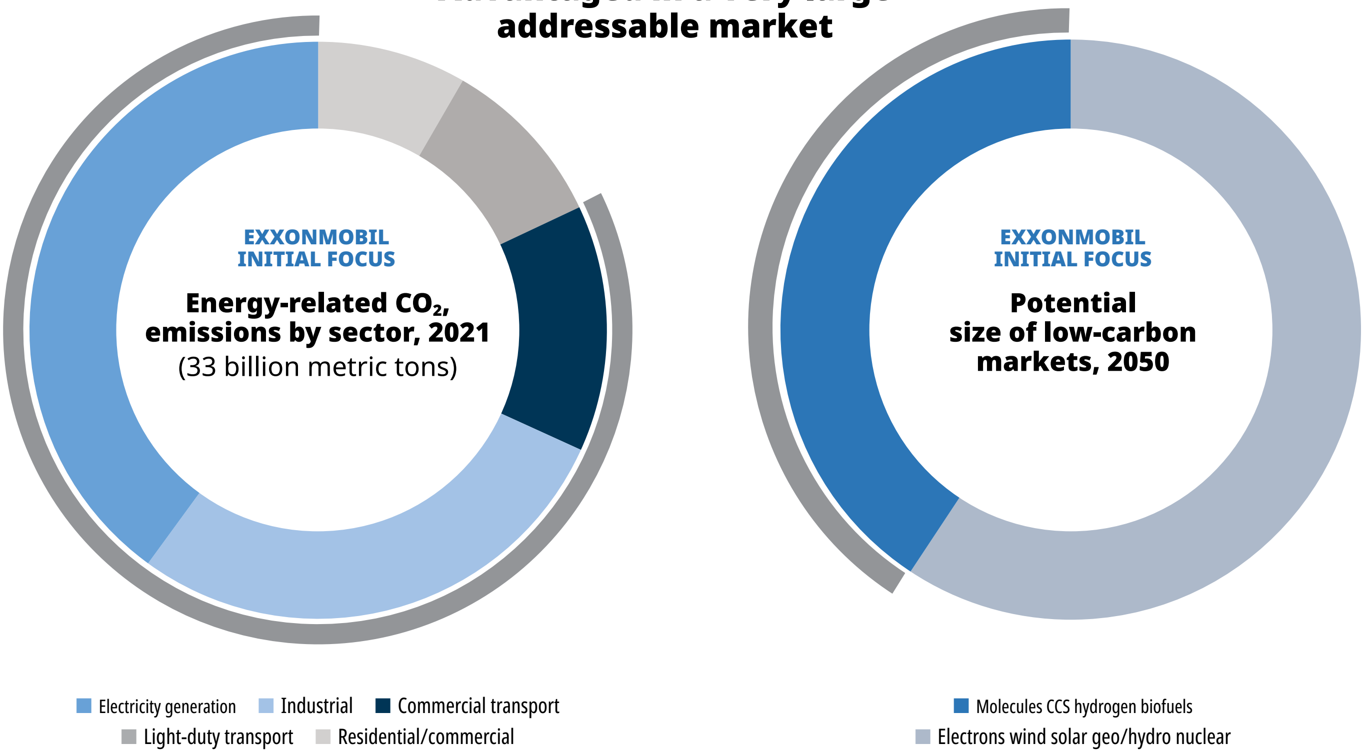
In Texas, Exxon Mobil is building what could become the world's largest low-carbon hydrogen plant when it starts up by 2028—producing about 1 billion cubic feet per day of hydrogen.

The Baytown, Texas, facility is expected to pave the way toward decarbonizing not only Exxon's operations but also other Houston-area facilities. Exxon sees demand for hydrogen coming from multiple different channels, Ammann said.

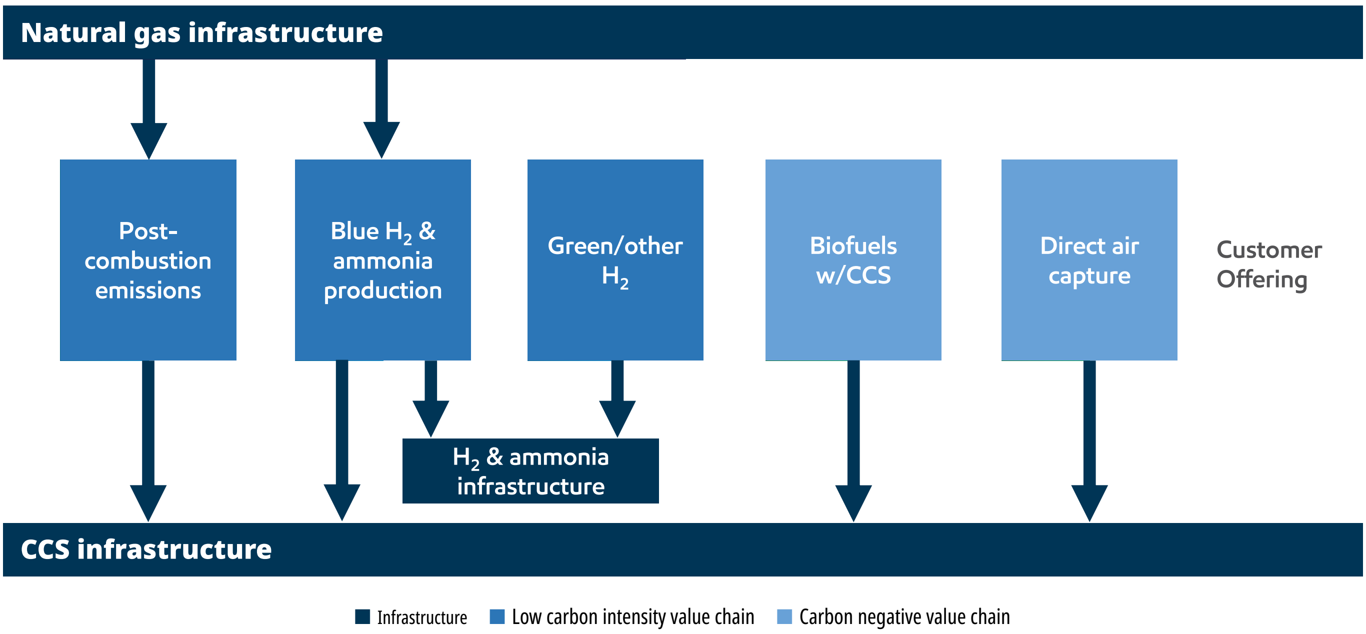
The next phase of growth for Exxon's low carbon unit—in about another five years' time—calls for scaling foundational projects by 10x.

By then, the market would have grown to "hundreds of billions of dollars" as carbon prices rise, while efficiencies of scale and technology improvements drive down abatement costs by 10% to 20%, Ammann said.

Advantaged in a very large addressable market



Expanding our advantage through integrated value chains



Source: Exxon Mobil

The business, mainly reusing and repurposing existing infrastructure, could bring in tens of billions of dollars in revenue annually on contracts, he added.

"Beyond this timeframe, we aim to grow another order of magnitude, from 10 to 100. Supporting conditions for this include a cost of carbon 2-3x relative to where it is today, and 30%-70% reductions in the cost of abatement versus today" Ammann said, again assuming technology breakthroughs and large-scale economies.

"The addressable market now could be in the trillions of dollars…and our business potentially measured in the hundreds of billions of dollars, and quite possibly larger than Exxon Mobil's base business is today as the world approaches net zero," he said.

Unlocking the potential market, however, will depend on the value of carbon. Right now, there's no pricing mechanism in the U.S. The cost of carbon could be determined through policy support, taxes or voluntary or compliance-based trading schemes—and end-market demand, the executive said.

Likewise, hydrogen markets are starting to emerge. Ammann said Exxon is seeing demand pick up in Asian

"These are projects that work with today's policy, today's technology and today's infrastructure."

—**Dan Ammann,** ***president, Exxon Mobil's Low Carbon Solutions business***

markets for cleaner hydrogen sources, such as ammonia—effectively displacing natural gas used to produce gray hydrogen. In February, Exxon and South Korea's SK Inc. signed their first heads of agreement for offtake supplies of blue ammonia from the integrated Baytown complex.

"That market's taking shape in real time and we're seeing that demand begin to manifest itself," Ammann said analysts. "We see that scaling into a very large opportunity."

Challenges, opportunities

Regardless of their potential, Low Carbon Solutions projects must compete for capital with other parts of the business, while driving earnings and cash flow.

"The investments in this business, like all of our investments, must be advantaged versus industry and deliver competitive returns to successfully compete for capital," Woods said.

Each project is evaluated based on the cost of supply, irrespective of the commodity cycle and how the market develops, he added, noting Exxon sees attractive opportunities in all three of its businesses.

Addressing analysts' questions about how Exxon will allocate investments in new businesses versus its legacy units, Woods said: "To date, we haven't been challenged to find something in one business or…[had] to trade something off for another business."

"The more successful we are, the more cash we generate, the more funds we'll have to invest and grow the business," he said.

Woods said that in some circumstances, partnerships and M&A might be merited. But for now, Exxon Mobil intends to lead its low-emissions efforts.

"What we're finding is that we're able to move in most cases more quickly by leading ourselves," Ammann said.

The challenges come in execution and putting all the pieces together.

"Ideas are easy. Execution is hard," Woods said. "As you look at the opportunities set out there today, we're not limited by dollars and capex.

"We're limited by putting together the incentives, putting together the elements and pieces of the value chain to construct something that generates a competitive return and delivers on emissions reduction at a cost that's competitive."

The market, he added, is in early stages of development.

But, "we feel like we've gotten here at a really good time and are bringing our capabilities and expertise to bear in that marketplace. And that, frankly, is where the effort and the work is right now." OGJ

National Energy President Talks Transition in Trinidad and Tobago

National Energy Corp. of Trinidad and Tobago President Vernon Paltoo speaks on the steps the twin-island country is taking to remain competitive while transitioning into a lower carbon future.

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MEXICO CITY—National Energy Corporation of Trinidad and Tobago president Vernon Paltoo says the twin-island country continues to advance development of its low carbon future and is focused on energy efficiency, renewable energy, and carbon capture and storage (CCS) to get to green hydrogen. Paltoo spoke exclusively with Hart Energy's international managing editor Pietro D. Pitts during the two-day AAPG-Energy Opportunities event in Mexico City to talk about steps the country is taking to remain competitive and relevant while it builds the framework for their energy transition.

Q&A

Pietro D. Pitts: What is Trinidad doing to transition further to cleaner energies?

Vernon Paltoo: Trinidad has traditionally been a gas economy since the late '80s into the '90s. Subsequently, [Trinidad] became a significant producer of gas-based products internationally—methanol, ammonia and LNG—and continues to be a leading player on a global scale in those areas. We're fully cognizant that as a country we need to remain competitive and relevant and have taken deliberate steps to build the necessary foundation and framework to transition almost seamlessly into a lower carbon future. I would dare say by using gas as a feedstock, we've already embarked on a low-carbon path, as opposed to oil, seeing that gas is the cleanest hydrocarbon there is.

Understanding that basis, we have looked at several key areas, not just as a company, but to extend it to the country in terms of driving a lower carbon future. This would involve energy efficiency as a low-hanging fruit, seeing where we could improve the current utilization and current wastage of gas and, for example, electricity and power production, etc. That is one of the projects we're looking at in terms of improving efficiency, and that involves a concept called Super ESCO [energy service company], looking at energy efficiency and all the entities that use gas, both on a commercial and industrial level, and how to improve the efficiency of gas and power utilization.

We are building a very comprehensive renewable energy program, and the first utility scale solar PV project is expected to begin construction in the next quarter. Lara, a 112-megawatt solar PV [photovoltaic] project, is a consortium of multinationals together with the state agency, ourselves. It will be the first utility-scale renewable energy project in Trinidad [and] the largest in the Caribbean. It's significant in terms of what we do and meeting our commitments to the Paris Agreement and our obligations where that is considered.

We are also advancing development of a low carbon future by deliberately producing a low carbon feedstock, and ultimately, we're looking to green hydrogen as that goal. We see CCS as a key step toward getting there. So, energy efficiency, renewable energy and CCS are our pillars that get us to green hydrogen. In November, working together with the Inter-American Development Bank [IADB], KBR did a study to prepare a roadmap to take us to the green hydrogen economy. Offshore wind resources have been identified that will allow us to produce as much as 57 gigawatts of power that could translate into 4 million tons (MMton) of hydrogen to supply our entire local industry, petrochemical industry, which uses gas, or replace the gas with green hydrogen. Beyond the 2 MMton we would use to satisfy local power and petrochemical [demand], we can actually export that and that's a long-term vision and plan.

We have hydrogen now, but it's gray hydrogen. Ultimately, we expect to remain competitive as carbon taxes become more prevalent, as that is where the industry is headed in terms of preserving our environment, and at the same

"We've always been leaders when it came to the production of methanol, ammonia and LNG and... that's the plan in terms of how we are approaching the low carbon hydrogen market."

—**Vernon Paltoo,** *president, National Energy Corporation of Trinidad and Tobago*

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time, balancing economics. This is a plan to ensure our industry remains competitive going forward and allows us almost immediately to begin that process of remaining competitive. We've always been leaders when it came to the production of methanol, ammonia and LNG and… that's the plan in terms of how we are approaching the low carbon hydrogen market. It would start from optimizing our existing resources in terms of efficiency, but gradually reducing the carbon footprint of the industry. More or less what you're doing is future-proofing the energy industry for Trinidad and allowing us to be in a position to provide low carbon hydrogen to the region in the coming years and decades to come.

PDP: Are there already visions for another project Lara in the future?
VP: Yes, those things are in the planning phases at this point and we're looking to see how we can introduce wind energy as well. At present, studies have been done establishing parameters and preparing demonstration plans on wind energy.

PDP: And solar, as well, I would assume since you are in the Caribbean?
VP: Absolutely! We have a good resource and good access. Our issue is land space because [we're] a small country, and that's why wind becomes more attractive, especially offshore wind. And that is where [KBR's] study would've identified the most appropriate resource for long-term large quantities of renewable energy power generation that will allow us to become competitive on a hydrogen scale. The reason the study identified us as being able to compete on a global basis [versus] other countries that may have lower-cost renewable energy is because we have a ready market for green hydrogen [within] our industry, which is not available in other countries that are producing large quantities of green hydrogen in pilot phases or planning to. [Also] we don't have to transport the green hydrogen to any great distances, it's right there.

PDP: Trinidad's gas production is around 2.8 billion cubic feet per day (Bcf/d) versus a peak of over 4 Bcf/d not long ago. Lower gas supply has already caused problems for some gas-dependent plants across the country. Is this an issue as the country eyes green hydrogen production in the future?
VP: I don't think that's an issue simply because these are two parallel streams that are advancing and more or less have a synergetic-relation with each other. As we go more into green hydrogen, the gas will always be important for us and the gas industry I dare say will remain very relevant in terms of our economy for many decades to come. We understand that and continue to maintain the relevance and importance of that industry. But at the same time, just as we did in the past, we want to think ahead and be prepared for when the changes and the transition come, to have that competitive advantage and remain competitive as a country.

PDP: Trinidad has a lot of gas production and some oil production. Is it fair to say Trinidad has energy security or does more need to be done to make sure that you can produce everything you need locally?
VP: What we're looking at is more [about] energy security from a regional perspective because from a country [point of view], we are fairly comfortable in terms of energy security. When we come together as a region, it's a stronger value proposition. When we talk about collaboration in the region, a lot of our intentions, plans and strategies are aligned toward working with other countries towards energy, and that involves oil, gas and low carbon energy. So, from the perspective of energy security, when we look at it from a regional perspective, we're in a much stronger position to deal with any matters that come along.

Transition in Focus

HYDROGEN

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The Ireland-headquartered Linde is an industrial gas and engineering company that serves multiple end markets, including chemicals and energy, food and beverage and health care.

Linde, Exxon Mobil Sign CO_2 Offtake Agreement

Hydrogen producer Linde and Exxon Mobil Corp. signed a long-term agreement for the offtake of CO_2 associated with Linde's new clean hydrogen production facility being constructed in Beaumont, Texas, the companies said.

As part of the agreement, Exxon Mobil will transport and permanently store up to 2.2 million metric tons (MMmt) of CO_2 annually—equivalent to the emissions from nearly 500,000 cars per year—from Linde's hydrogen production facility, according to a news release.

Dominion Energy Begins Hydrogen Blending in Utah

Dominion Energy Utah has started blending hydrogen into natural gas pipelines in Utah, marking the next phase of its ThermH2 project focused on no-carbon emissions fuel.

"An up-to 5% blend will be introduced to the city as well as to the surrounding towns of Oasis, Hinkley and Deseret, serving about 1,800 customers," Dominion said in a news release. "The project will begin with grey hydrogen and will upgrade to green hydrogen later this year. During the course of the project, the majority of hydrogen blended will be green hydrogen made from renewable energy.

The first phase, which lasted one year and focused on blending hydrogen in the utility's Training Academy, found that a 5% hydrogen blend was safe and compatible with current residential appliances and helpful in reducing emissions from appliances using natural gas, the company said.

The work is intended to help the company prepare its entire distribution system for blending by 2030.

Obsidian Collaborates on Potential Hydrogen-fueled Power Plant

Obsidian Renewables will work with Washington state's Grant County Public Utility District on the design of a potential hydrogen-fueled power plant with a storage and hydrogen production facility.

"This project kicks off the development of Obsidian's Pacific Northwest Hydrogen Hub plan to make low-cost renewable hydrogen available to large parts of Oregon and Washington," said Ken Dragoon, Obsidian's director of hydrogen development. "Renewable hydrogen will play an important role in the region's decarbonization goals, and we are proud to take this step towards a green energy future."

Solar energy would be used to produce the hydrogen.

The hub is one of the 33 projects that have been encouraged to seek funding from the U.S. Department of Energy.

"The proposed power plant design will use an onsite storage pipeline to hold enough hydrogen so that the plant can operate for up to one week on the stored renewable energy," the release said.

Grant County is already home to several industrial hydrogen users, which could use the hydrogen and surplus electricity generated.

SOLAR

TotalEnergies Plans to Develop 1-GW Solar Plant in Iraq

TotalEnergies is developing a 1-gigawatt (GW) solar power plant to supply electricity to the Basrah regional grid in Iraq.

The plan is part of an agreement reached recently with Iraqi authorities, confirming the terms of a development and production contract signed in 2021. As part of the agreement to move forward with the Gas Growth Integrated Project (GGIP), TotalEnergies and its partners will invest about $10 billion to recover flared gas on three oil fields to supply gas to power generation plants and build a seawater treatment plant for water injection for pressure maintenance. The investment will increase regional oil production along with the solar plant.

The French energy company said it will invite Saudi company ACWA Power to join the solar project.

The GGIP consortium will be comprised of TotalEnergies (45% interest), Basrah Oil Co. (30%) and QatarEnergy (25%).

Sun Pacific Lines Up Property for New Solar Plant

Sun Pacific Holding Corp. subsidiary Elba Power Corp. executed a contract to purchase property in Alabama for $2.95 million for its planned solar manufacturing facility.

The company plans to develop a 1.2-GW solar product manufacturing and clean power generation plant.

"We have been working diligently in obtaining our insurance wrap to protect our investment in the project, as well as receiving state approvals and executed agreements to proceed with acquiring the [200,000] sq ft property," Sun Pacific Holding CEO Nicholas Campanella said.

WIND

IberBlue Wind Gears Up for 1.96 GW Floating Wind Off Spain, Portugal

Iberia-focused IberBlue Wind has unveiled plans for two floating wind projects with a combined installed capacity of 1.96 GW off the Spanish-Portuguese border, the company said, enough to power more than 1 million homes.

Called Juan Sebastián Elcano and Creoula, the wind projects

IberBlueWind

The Juan Sebastián Elcan wind farm will be developed between 20 and 35 km off the Spanish-Portuguese border, while the Creoula wind farm will be about 20 km to 40 km from shore.

will have 109 turbines total spanning across 530 sq km off the coasts of Baixo Miño in Pontevedra and Viana do Castelo, IberBlue said.

The projects will help move the joint venture company—comprised of Simply Blue Group, Proes Consultores and FF New Energy Ventures—closer to its goal of developing about 2 GW of offshore wind energy capacity off the peninsula.

"It is very exciting to develop cross-border floating offshore wind projects and to collaborate with both Portuguese and Spanish governments on this positive opportunity for both countries," said IberBlue Wind Vice President Adrián de Andrés. "We have already engaged with both authorities when we presented our projects to the Spanish and Portuguese authorities, and we look forward to continued engagement."

Elcano, the smaller of the two wind farms, will have 29, while Creoula will consist of 80 turbines. Each turbine will be 18 megawatts (MW).

"It is estimated that the cost of their joint development could be 32% lower than if they were to be developed separately," IberBlue said in a news release. "This will maximize synergies in resourcing and economies of scale during both the construction phase and operation phases. Consequently, reducing energy prices for both countries, which operate as one within the Iberian Electricity Market—MIBE."

Ørsted, Google Ink Their First US Power Purchase Agreement

Ørsted

Ørsted also operates the Willow Springs wind farm in Texas.

Tech giant Google and renewable energy producer Ørsted signed a power purchase agreement for energy generated at the Helena Wind Farm in South Texas, marking their first such agreement in the U.S.

The 150-MW, 15-year agreement is expected to help Google move closer toward its goal to operate all of its data centers, cloud regions and offices on renewable power by 2030.

"Building a 24/7 carbon free energy portfolio requires us to blend various resources to optimize for hourly production, and that's exactly what this project helps us accomplish," Sana Ouji, energy lead for Google, said in a news release.

Located in Bee County, Texas, the 268-MW, Ørsted-operated Helena Wind Farm was commissioned in mid-2022. The wind farm features more than 60 Vestas turbines spanning about 15,000 acres in Pawnee, Texas. The wind farm is part of the Helena Energy Center, which also includes a 250-MW solar farm called Sparta.

The power purchase agreement is the second agreement globally between Ørsted and Google.

"As a trusted partner in providing clean energy solutions for our customers, we're proud to support Google's decarbonization goals on both a regional and global scale," said Monica Testa, head of origination for Ørsted Americas. "Google's leadership in the investment of renewable energy and commitment to advancing 24/7 carbon-free energy by 2030 sets a strong example for companies across the globe, and we look forward to helping them achieve that ambition."

DNV Begins JIP Focused on Wind Farm Control Technology

DNV has teamed up with several energy companies to launch a joint industry project focused on wind farm control technology, the Norway-based energy expert and assurance provider said.

The intent is to confirm the potential of wind farm control, which DNV said "covers the models and procedures required to control each turbine in a wind farm through approaches such as wake steering and induction control, in a way that optimizes the wind farm's total output or overall performance."

The technology enables operators to optimize loading across turbines and extract more energy.

"DNV launches this joint industry project to demonstrate the value of this promising wind control technology, which may become as common as energy yield assessment and equally necessary to wind projects," Ditlev Engel, CEO of energy systems for DNV, said in a news release.

Participating companies include EDF Renewables, Enel Green Power, Engie, Equinor, GE Renewable Energy, Greencoat, Iberdrola/Scottish Power, Pattern, RES, RWE, Shell, Vestas, Windey and Ørsted, according to the release.

Ocean Winds, Partners Reach FID on Wind Park Offshore France

Ocean Winds and partners have taken a final investment decision on the €2.5 billion (US$2.7 billion), 500-MW Îles d'Yeu and Noirmoutier wind farm project offshore France, the company said.

The project secured public and private financing led by the Japan Bank for International Cooperation and a syndicate of 16 banks, according to the release. The financing paves the way to the start of construction.

Developers said the project will supply nearly 800,000 people with electricity each year.

Initial offshore operations will begin this summer with installation operations commencing in 2024, Ocean Winds said in a news release. Commissioning is expected in the second half of 2025 following a 2.5-year construction phase.

Several companies have already been tapped to carry out work for the project. Chantiers de l'Atlantique will build the electrical substation and Louis Dreyfus TravOcean will install the first submarine cables. DEME and Jan de Nul will be responsible for the transport and installation of the foundations and wind turbines, which will be made by Siemens Gamesa and installed in 2025.

—Velda Addison, Hart Energy

Romito: ESG Data, Disclosures Dictate Market Access

DAN ROMITO
PICKERING ENERGY PARTNERS

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

Insurance giant Chubb announced a new mandate in March to incorporate evidence-based plans to reduce methane emissions in their underwriting guidelines. This marks continued evidence that ESG does not just impact equity and debt, but insurance as well. According to their news release, Chubb will continue to provide insurance coverage for clients that implement evidence-based plans to manage methane emissions including, at a minimum, having in place programs for leak detection and repair and the elimination of non-emergency venting.

Regardless of where you stand on the topic, the fact is that ESG impacts access to capital. Moving forward, insurance options will diminish if clear and quantifiable emissions-based directives are not implemented. This decision will also not remain unique to Chubb, and it will certainly expand across other providers quickly. As was the case with equity and debt, recent market precedent implies there exists a higher likelihood of broader adoption as opposed to aggressive pushback.

It is imperative the absorption and interpretation of this directive are not relegated solely to the idealistic. The regulatory markets are quickly evolving in a manner that will adversely impact the companies that underplay the importance of ESG disclosure. This is most evident with the regulatory mandates in Europe, namely the Sustainable Finance Disclosure Regulation (SFDR).

The investable universe, including insurance, is quickly separating into three distinct areas which are defined by explicit ESG-related considerations: Article 6 (funds that do not integrate sustainability into the investment process); Article 8 (promotes certain environmental or social characteristics); and Article 9 (a sustainable investment or a reduction in carbon emissions as its objective). Article eligibility is determined by self-reporting the quantitative ESG-related data points necessary to validate a respective designation. To the earlier point on eligibility, Article 8 funds have been dominating capital flows over the last two years according to Morningstar and Goldman Sachs reports.

We anticipate SFDR to act as the baseline for the impending Securities and Exchange Commission greenwashing rules set to be released before the end of the year. The Chubb decree, unfortunately, marks only the start of a variety of future anticipated ESG-related mandates. To be fair, Chubb is most likely updating their approach to risk now that the Inflation Reduction Act formally introduces a methane tax to the market beginning in 2024. Facilities exceeding 25,000 metric tons of CO_2 per year will be taxed at $900/metric ton of methane in 2024. This tax increases to $1,200 and $1,500 per metric ton of CO_2 in 2025 and 2026, respectively.

Whether the energy industry likes it or not, ESG data and disclosure are now deeply embedded within the processes that determine eligibility for quality equity, debt and, now, insurance. All private and public companies are now expected to provide some degree of ESG-related material to remain eligible for capital markets participation. Moving forward, the industry's collective focus should emphasize the importance of quantitative non-fundamental trends as opposed to questioning the overall conceptual utility of ESG.

To properly prepare for the impending regulatory and market changes, and to convey the factual narrative, the industry must become more fluent in sustainability terminology. Incorrect interpretation of data primarily derives from the rating agencies and aggregators, who aggressively push their own variation. Therefore, it is critical all companies acquire a firm grasp of their non-fundamental data. Regulators have also increasingly placed energy within their crosshairs and enhanced their own sophistication with measurement and disclosure. Preparation and protection must include tracking the same data points regulators often use against energy companies.

To slow the trajectory of regulatory mandates, companies should play more offense and proactively establish the objective economic realities of the energy sector. Failure to do so will inevitably lead to failure of winning the pragmatic middle. Unfortunately, the adverse impact of this decision will have a greater impact on smaller private mid-market energy businesses. Ironically, the empirical fact remains the U.S.'s energy sector is leading the way in decarbonization, safety, efficiency, reliability and affordability. The narrative, however, is currently controlled by the detractor community.

Regardless, the math implies the U.S. has figured out how to decouple energy use and economic growth since U.S. gross domestic product has increased steadily while total energy use has remained flat over the last 25 years. The sector's empirical trend over the last quarter century is impressive, however, the industry continues to struggle in telling the collective story. The positive is that the U.S. is already the world's cleanest and most efficient energy producer. Controversy aside, we must acknowledge that ESG-related directives and data are now embedded within the global regulatory fabric. OGI

Analysts: Shale M&A Opportunities Shrink After Ovintiv's $4.2 Billion Permian Deal

With Ovintiv Inc. scooping up three EnCap-backed drillers in the core Midland Basin, public E&Ps have fewer places to look to add quality inventory runway, analysts say.

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After Ovintiv's $4.275 billion acquisition in the Permian Basin, opportunities for attractive, inventory-rich M&A in the Lower 48's premier shale play are shrinking, analysts say.

Ovintiv Inc. agreed to scoop up three EnCap-backed privates—Black Swan Oil & Gas, PetroLegacy Energy and Piedra Resources—in the Northern Midland Basin in a cash-and-stock deal valued at $4.725 billion, the companies announced in early April.

After first-quarter oil and gas deal activity rivaled COVID-19 lows, Ovintiv's acquisition kicked off a strong start to M&A in the second quarter, analysts at Piper Sandler & Co. wrote in an April report. The firm's detailed analysis of private Permian Basin E&Ps—including Hibernia Resources and Summit Petroleum—shows several middling operators remain on the outskirts of the core.

As Ovintiv President and CEO Brendan McCracken alluded to in a call with analysts the day of the announcement, attractive core inventory in the Permian Basin is becoming harder to find.

"With shale hitting the middle innings, the asset we are acquiring is a rarity," McCracken said.

Amid the mad dash to add inventory, many of the larger public oil and gas companies, including Ovintiv, Matador Resources and Diamondback Energy, have signed big deals with private E&Ps in the Permian in the last year.

Outside of the Permian, Marathon Oil Corp. completed a $3 billion acquisition deal of Ensign Natural Resources' Eagle Ford assets in December 2022. Gassier plays such as the Haynesville Shale have more runway than deals have in 2023 as prices remain depressed.

"There's just not that many big, strategic deals out there to be had if you look at the remaining private or private equity companies in the core of these basins that might sell."

—**Andrew Dittmar,** ***Research Director, Enverus Intelligence***

In fact, more than $30 billion worth of private companies and assets were sold to public E&Ps in 2022—accounting for about 60% of total upstream M&A activity last year, according to data from Enverus.

But analysts say opportunities to roll up higher-quality private operators with attractive core inventory are dwindling.

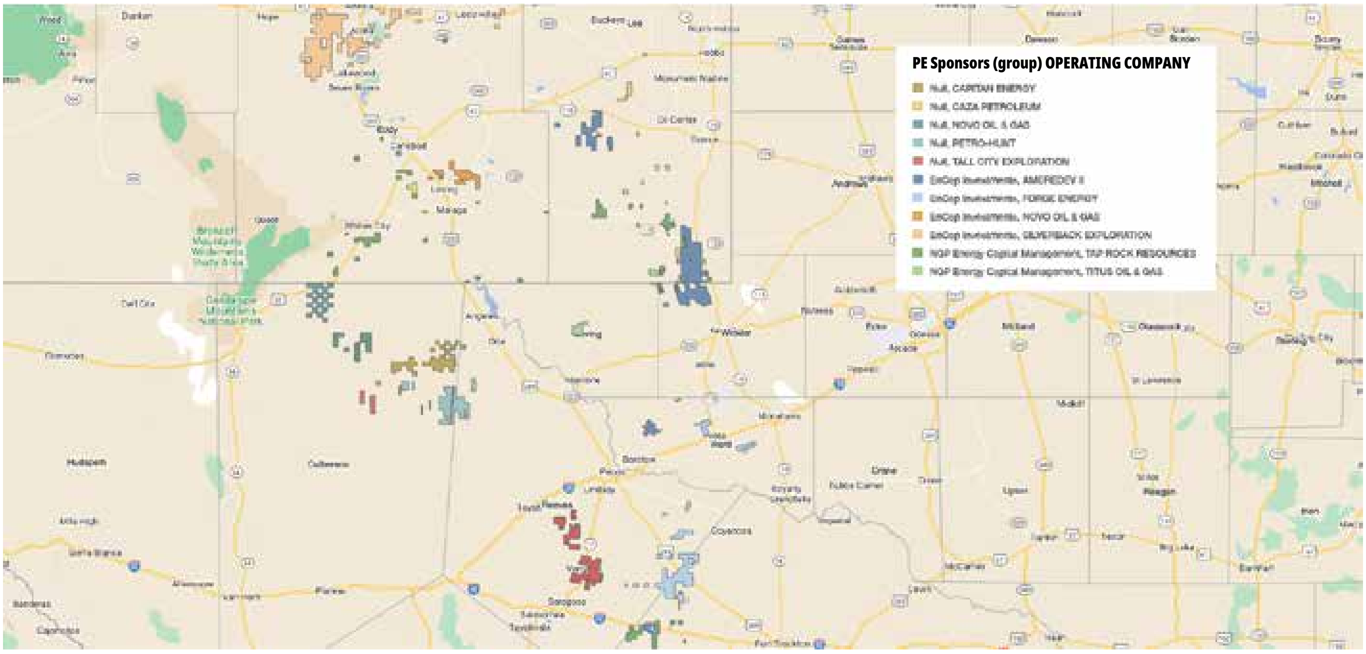
"There's just not that many big, strategic deals out there to be had if you look at the remaining private or private equity companies in the core

Top Permian Private Transactions, 2020+

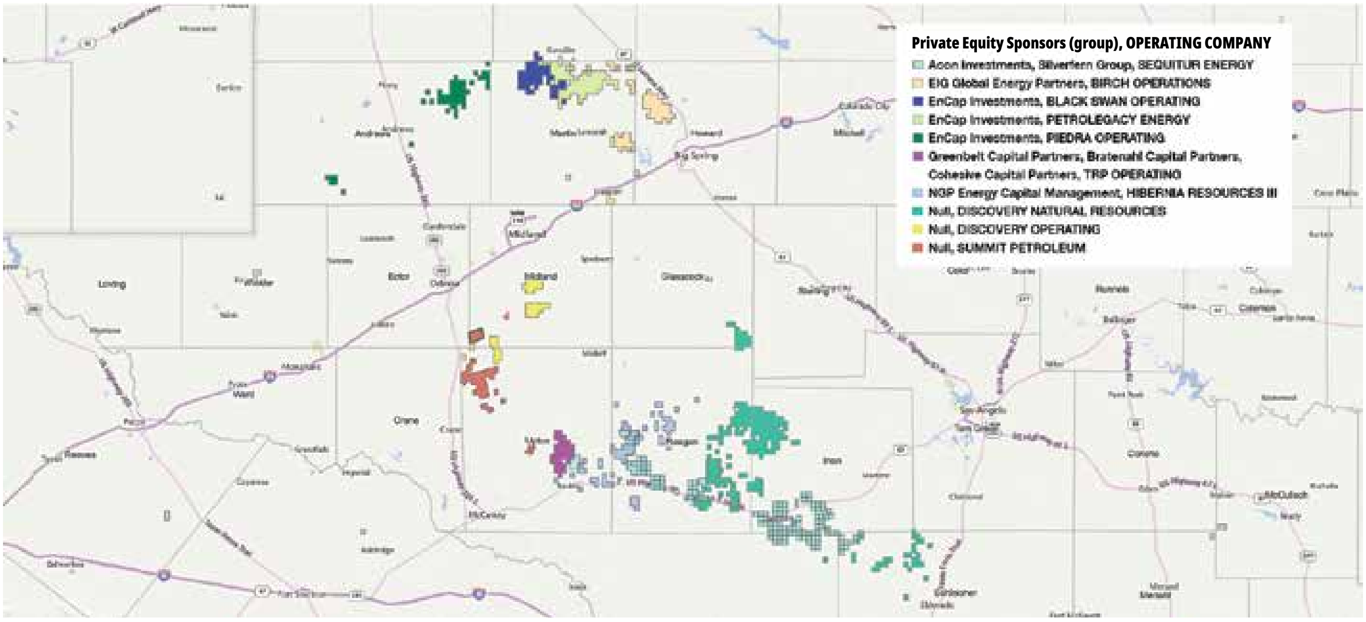
Announced	Seller	Value ($/billion)	Buyer	Net acres	Mboe/d
April 1, 2021	DoublePoint Energy	$6.38	Pioneer Natural Resources	97,000	100
April 3, 2023	EnCap portfolio companies	$4.28	Ovintiv	65,000	75
May 19, 2022	Colgate Operating	$4.17	Permian Resources	105,000	75
Jan. 24, 2023	Advance Energy Partners	$1.60	Matador Resources	18,500	25
Oct. 11, 2022	Firebird Energy	$1.59	Diamondback Energy	68,000	22
Nov. 16, 2022	Lario Oil & Gas	$1.55	Diamondback Energy	15,000	25

Source: Piper Sandler

Delaware Basin Private Operated Acreage



Midland Basin Private Operated Acreage



Source: Rextag/Hart Energy

of these basins that might sell," Enverus Intelligence Research Director Andrew Dittmar told Hart Energy. "There's lots of public companies out there that still need inventory, so we think it's a competitive market."

Hunting for inventory

Black Swan, PetroLegacy and Piedra's assets in the northern edges of the Northern Midland Basin represented some of the highest-quality private-equity backed opportunities in the area, Dittmar said.

"We have about an average $44 breakeven pricing on the inventory that …[Ovinitiv's] picking up, which slots into a very competitive set," Dittmar said.

With the three EnCap portfolio companies off the table, there are fewer quality opportunities for M&A to choose from. Public E&Ps will likely need to push further into the edges of the Midland and Delaware to find inventory deals, he said.

"That's just the nature of what opportunities are available in the market right now," Dittmar said. "The center, core-of-the-core portions of the basin have really been picked over, and even the good assets that are available are probably going to be a step out toward one of the margins."

High decline rates and the limited inventory held by private E&Ps in the basin pose challenges to public companies looking to add high-quality inventory, according to Piper Sandler.

"The core of both the Delaware and the Midland has basically been captured," Mark Lear, senior research analyst at Piper Sandler and one of the note's authors, told Hart Energy. "I think what we're really playing for is maybe smaller bolt-on opportunities in the core."

Out of 10 private E&Ps operating in the Midland Basin analyzed by Piper Sandler, the three companies Ovintiv is acquiring each showed strong productivity and sizable acreage positions. Together, they have a larger base of proved developed producing (PDP) reserves and acreage than most of the private E&Ps analyzed.

Though there is a shrinking number of top-tier M&A opportunities in the Permian, there are still some standout private companies operating in the Midland and Delaware, according to Piper Sandler data.

One is Birch Operations, which was the most productive private operator analyzed in the Midland despite owning a relatively smaller acreage position of about 40,000 acres.

Summit Petroleum and Hibernia Resources III also boast large, contiguous acreage positions in the Midland. But they've also shown signs of asset degradation recently, with Summit shifting activity in Texas from Midland County to Upton County. Hibernia has shifted from Upton to Reagan County, according to Piper Sandler.

Private operators also generally own more fringe positions and less core acreage in the Delaware Basin after years of industry consolidation.

Tap Rock Resources, backed by private equity firm NGP Energy Capital, has acreage in core Lea County, New Mexico, Piper Sandler noted.

Ameredev II, another EnCap-backed E&P, also has attractive blocky core acreage and a flat production profile across its Delaware position.

Larger private producers in the Permian that are unlikely to be sellers, including Mewbourne Oil Co., Endeavor Energy Resources and CrownQuest Operating, were not analyzed.

Haynesville M&A opportunities

Oil deals might be getting more scarce in the core, but there are abundant opportunities for deals with private E&Ps in the gassy Haynesville Shale, Lear said.

Haynesville operators, including Aethon Energy, GEP Haynesville II, Rockcliff Energy and Paloma Resources, have amassed sizeable inventories and scaled gas production in the basin in recent years, Piper Sandler said.

But gas-focused M&A activity has been effectively shut down in 2023 after U.S. natural gas prices plunged more than 50% compared to 2022.

Henry Hub natural gas prices are expected to average around $3 per million Btu (MMBtu) this year after averaging $6.42/MMBtu in 2022, according to U.S. Energy Information Administration (EIA) data. Henry Hub prices topped $9/MMBtu last summer, according to the EIA.

Natural gas futures for delivery in May were trading up over 1% at $2.13/MMBtu in afternoon trading on April 5.

TG Natural Resources, a unit of Tokyo Gas, was advancing discussions earlier this year to acquire Rockcliff in a deal worth $4.6 billion. But that deal reportedly fell apart due to weak gas pricing making deals more challenging, Piper Sandler said.

The only announced gas deal of much consequence last quarter was Diversified Energy Co.'s acquisition of Texas upstream assets from Tanos Energy Holdings II LLC for $250 million, according to Enverus data.

"I do think that there's a prevalent view that gas is still pretty abundant and easy to get—maybe not at $2, but certainly in that $3 to $4 ballpark," Lear said. "I think that's where a lot of things come into play." OGI

Kissler: Will There Be A Run In Crude Prices Later This Year?

Market Watchers

DENNIS KISSLER
BOK FINANCIAL SECURITIES

Dennis Kissler is SVP of Trading for BOK Financial Securities. He is based in Oklahoma City.

The two major forces that affect pricing in all commodities are supply and demand—but what may seem like simple economics becomes more complicated when you factor in the impact of monetary policy and geopolitical events.

In most of 2021 and 2022, the oil and natural gas markets became undersupplied after the U.S. and other countries re-opened from COVID-19 shutdowns, and negative prices in crude led to decreased production and delayed drilling programs.

But that undersupply proved temporary.

China's issuance of another complete COVID shutdown in January 2022 drastically changed the oil market back to an oversupplied environment. This oversupply in turn took crude prices from the $100 area in June 2022 to the $60 area in March 2023, a month after China began reopening.

Furthermore, the ongoing Russian/Ukraine war has impacted supplies less than what was anticipated. While certainly it has been a factor, it's not as much of a driving force because Russian crude is still being produced and sold to most of Asia. Currently, as of this writing, crude inventories in the U.S. are sitting at 34 million bbls above the five-year average. However, gasoline inventories are 9 million bbls below the five-year average and distillates (diesel) are over 11 million bbls below the five-year average.

Inflation and interest rates

Meanwhile, the U.S. is still experiencing the impact of the Federal Reserve drastically increasing the M1 money supply (liquid spendable funds) to mitigate the pandemic's destruction of the economy. The influx of money drove year-over-year inflation to a four-decade high of 9.1% in June 2022. Although that figure has come down somewhat, it's still three times the Fed's target, making it no wonder that inflation now has taken front-and-center attention.

Another related issue is, of course, interest rates. To combat persistent inflation, the Fed has raised the Federal Funds rate from near-zero to a range of 4.75% to 5%, as of the March FOMC meeting. Both inflation and rising interest rates take discretionary dollars from the consumer, which can impact demand for energy. Meanwhile, inflation and rising rates also impact the energy market directly by rising costs. It's no secret that everything from borrowing money to the costs of supplies and moving those supplies all have become more expensive.

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Supply and demand

So far, while U.S. and world production have recovered, so has demand—and it likely will be primary driver in the months ahead. Barring a U.S and or global recession, fuel demand looks to be rising mostly from China. That could change if COVID surges again in Asia; however, even if it does, China probably won't lockdown as extensively as it has done in the past.

And what about supply?

Given the latest turmoil in the financial services industry, one major concern will be tightened lending practices, which will most likely impact the oil patch. Tighter lending usually equates to less drilling, which means less production.

Additionally, the shale production in most areas is nearing a peak—with most analysts anticipating this peak to come as soon as 2024 or 2025. Meanwhile, newer discoveries are seeing steeper depletion curves. OPEC+ also has nine of its participants underperforming current quotas.

Yet even with these questions concerning supply, the major key to prices will be global demand, meaning higher interest rates and inflation will remain a threat. That said, a steep pick-up in Asian demand and a U.S. economy that even just holds steady will mean that crude and fuel prices have the potential for another late 2023-2024 run in prices, as production and refining capacity lag. OGI

NEW FINANCINGS

Scan to see the New Financings database.

EQUITY

Company	Exchange/ Symbol	Amount ($MM)	Comments
NGL Energy Partners LP	NYSE: NGL	$112	Announced completion of marine asset sale with total cash consideration of roughly $112 million received on March 30. NGL prepaid the associated marine equipment note of approximately $39 million, with remaining proceeds used to repay outstanding balance on the asset-based loan facility.
Ring Energy, Inc.	NYSE: REI	$9	Announced that 14,512,166 of its outstanding warrants have been amended to lower their exercise price to $0.62 per share in exchange for early exercise of the warrants, resulting in gross proceeds of $8,997,543 and the issuance of 14,512,166 shares of common stock. After the full exercise of the above warrants, there remain outstanding warrants to purchase 78,200 shares of common stock. Truist Securities acted as exclusive financial advisor.
Genesis Energy LP	NYSE: GEL	N/A	Announced a distribution on its common units and Class A Convertible Preferred Units attributable to the quarter ended March 31. These distributions will be paid on May 15 to holders of record at the close of business on April 28. Each holder of common units will be paid a quarterly cash distribution of $0.15 ($0.60 on an annualized basis) for each common unit held of record. With respect to the preferred units, Genesis will pay a cash distribution of $0.9473 ($3.7890 on an annualized basis) for each preferred unit held of record.
Global Partners LP	NYSE: GLP	N/A	Announced a cash distribution of $0.609375 per unit ($2.4375 per unit on an annualized basis) on Series A preferred units for the period from February 15 through May 14. The company also declared a cash distribution of $0.59375 per unit ($2.375 per unit on an annualized basis) on Series B preferred units for the period from February 15 through May 14. These distributions will both be payable on May 15 to holders of record as of the opening of business on May 1.
Perma-Pipe International Holdings, Inc.	Nasdaq: PPIH	$8	Announced it has been awarded two contracts with a combined value in excess of US$8 million. One contract is with Fanshawe College in London, Ontario, Canada. The second contract is with China Petroleum & Chemical Corp.

DEBT

Company	Exchange/ Symbol	Amount ($MM)	Comments
Western Midstream Partners LP	NYSE: WES	N/A	Announced an offering of $750 million in aggregate principal amount of 6.150% senior notes due 2033 at a price to the public of 99.728% of their face value. The offering of the senior notes was expected to close on April 4, subject to the satisfaction of customary closing conditions. Net proceeds from the offering are expected to be used to repay borrowings under WES Operating's revolving credit facility, and for general partnership purposes.
Enlink Midstream, LLC	NYSE: ENLC	N/A	Announced the pricing of its offering of $300 million aggregate principal amount of its 6.500% senior notes due 2030 at a price of 99.000% of their face value. The sale of these notes was expected to close on April 3, subject to customary conditions. These notes are being offered as an additional issue of EnLink's existing $700 million aggregate principal amount of 6.5% senior notes issued in August, 2022, due in 2030. EnLink intends to use the net proceeds from the offering to repay outstanding borrowings under its revolving credit facility.
Matador Resources Co.	NYSE: MTDR	$500	Announced that it has priced a private offering of $500 million of 6.875% senior unsecured notes due 2028 at a price of 98.960% of their face value. Matador increased the size of the offering from the previously announced $400 million to $500 million.
CrossAmerica Partners LP	NYSE: CAPL	$925	Announced that it entered into an amended and restated five-year revolving credit facility agreement with a syndicate of lenders led by Citizens Bank, N.A.. The amended facility provides borrowing capacity up to $925 million, an increase from the previous revolving credit facility capacity of $750 million. The amended facility matures on March 31, 2028, and, subject to certain conditions, may be increased by an additional $350 million.

Smith: EPA Sets Sites on Oil, Gas Emissions

JAMES SMITH
CRAIN CATON & JAMES

James Smith is shareholder in the Crain Caton & James law firm, where he focuses on environmental and safety issues. He is based in Houston.

Recent action by the U.S. Environmental Protection Agency (EPA) indicates that air emissions, especially of methane, will continue to be a priority at oil and gas production facilities. Also, EPA's demands to settle cases involving illegal discharges to water and failure to have adequate spill control measures appear to be increasing.

Air emissions enforcement

An extensive effort by EPA and the state of New Mexico, which included flyover surveillance and field investigations, found failure to control emissions from storage facilities; failure to comply with inspection, monitoring, and recordkeeping requirements; and failure to obtain required air emission permits at 25 oil and gas locations. To settle the resulting air pollution enforcement case, the company in this case—Matador Production Co.—will pay $1.15 million in civil penalties, spend at least $1.25 million on a supplemental environmental project (SEP), and incur at least $2.5 million in costs to upgrade its facilities.

For the necessary upgrades, the company must install new tank pressure monitoring systems to provide advanced notification of potential emissions and allow for immediate response action by the company. It must also make extensive improvements in design, operation, maintenance, and monitoring. The SEP will include replacement of diesel engines, aerial monitoring for leaks at the company's facilities, and an $800,000 program to reduce emissions from pneumatic devices and vapor recovery units.

EPA's proposed methane rules

In November 2022, EPA announced a supplement to its November 2021 proposal for controlling methane.

"Oil and natural gas operations are the nation's largest industrial source of methane, a highly potent climate pollutant that is responsible for approximately one-third of current warming resulting from human activities," the agency said.

The November 2022 supplement will require "more comprehensive requirements" for "hundreds of thousands of existing oil and gas sources nationwide." It will also "promote the use of innovative methane detection technologies and other cutting-edge solutions." The supplement envisions a "super-emitter response program" that would "require operators to respond to credible third-party reports of high-volume methane leaks." The proposed rules will also set a "zero-emissions standard for pneumatic controllers and pneumatic pumps."

These enforcement and rulemaking efforts indicate EPA—as well as state agencies in energy producing states—will continue to view methane and other air emissions from oil and gas facilities as an enforcement priority.

Spill control measures

Summit Midstream Partners settled criminal charges stemming from a rupture of its produced water gathering system that served 37 well pads, resulting in a 29-million-gallon discharge. While the company had already paid $20 million in civil penalties, its plea agreement required payment of an additional $15 million in criminal fines plus three years of probation. According to the Joint Factual Statement submitted by the government and the company as part of the plea process, the rupture "continued unabated for five months" before the company confirmed the leak.

Two other cases serve as a reminder that companies face enforcement action, including significant penalties, even when they have no illegal discharge. When EPA inspections show required release control structures and plans are not in place, expect enforcement.

The EPA found that Phoenix Petroleum's Spill Prevention, Control, and Countermeasures (SPCC) were inadequate; its secondary containment for its oil storage tanks was deficient and it did not have a complete facility-wide SPCC Plan. The company submitted an adequate SPCC Plan, upgraded the containment structures, and agreed to a $50,000 penalty as part of a settlement, according to EPA's news release.

And at AES Hawaii, the EPA said the firm had an inadequate Risk Management Program; the company's documents did not show adequate training, nor did they show employees were provided written normal and emergency shutdown procedures. This company paid almost $200,000 to settle, according to EPA's news release.

EHS auditing

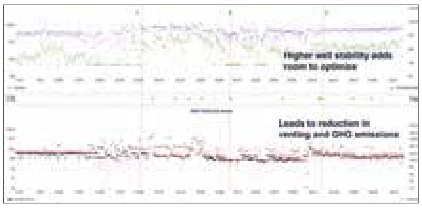
Penalties and fines of eight figures and six-figure penalties for inadequate documentation indicate oil and gas companies face increasing sanctions for unlawful air emissions, spills or failure to have proper spill measures in place. Penalties for noncompliance items discovered during an Environmental, Health and Safety (EHS) audit are generally reduced, provided they are quickly resolved. OGI

2023 E&P Meritorious Awards for Engineering Innovation

This year's Meritorious Awards for Engineering Innovation (MEAs) recognize 17 technologies for engineering excellence in the upstream petroleum industry. Hart Energy's MEA program highlights new products and technologies that demonstrate innovation in concept, design and application.

The expert panel of judges included engineers and scientists from operating and consulting companies worldwide. Judges were excluded from categories in which they or their companies have a business interest.

ARTIFICIAL LIFT



Ambyint

The data-driven, cloud-based solution helps operators find setpoints likely to increase productivity and avoid unnecessary downtime across all types of artificial lift.

Product: InfinityPL

Company: Ambyint + AWS with CNX Resources

Ambyint's InfinityPL, which runs on Amazon Web Services (AWS), helps increase production in wells. The data-driven, cloud-based solution combines advanced physics and subject matter expertise with artificial intelligence (AI) to automate operations and production optimization workflows.

The platform helps operators find setpoints likely to increase productivity and avoid unnecessary downtime across all types of artificial lift, including electric submersible pumps (ESP), plunger lift, rod lift and gas lift. While plunger lift systems are mechanically simple, they produce vast amounts of data that can be leveraged to optimize performance. Data analysis required to uncover insights can be time-consuming and manual.

CNX Resources sought to optimize production and reduce the number of liquid loading events across its horizontal Marcellus Shale plunger lift wells. The CNX operations team vented wells regularly to remediate liquid loading, which led to increased emissions and reduced productivity and efficiency. To overcome these challenges, CNX worked with Ambyint and AWS to deploy a solution that optimized well productivity through improved analytics and autonomous management.

Ambyint deployed InfinityPL to CNX's plunger lift wells, leveraging the AWS cloud environment for data integrations with CNX's existing SCADA and production accounting systems. Through automation and proactive management, CNX was able to improve well stability, which led to opportunities for performance optimization, and a reduction in venting events and greenhouse-gas emissions by 48%.

Predictive maintenance and autonomous management of control system settings also resulted in a 4% increase in gas production. Based on the success of the 26 pilot wells, CNX expanded the work to an additional 120 wells.

CARBON MANAGEMENT

Product: nanO$_2$® Fuel Enhancer
Company: Canrig

The nanO$_2$ Fuel Enhancer from Canrig, when added to diesel, adds a combustion catalyst component that helps improve combustion while reducing emissions. Typical fuel enhancers and additives increase the cetane index and provide cleaning effects. Using a skid, nanO$_2$ connects to the fuel tank using a precision dosing unit that measures and mixes the appropriate ratio of nanO$_2$ during diesel refueling. The treated fuel is fed through the monitoring manifold, which records fuel consumption data, and

Nabors Industries

The Canrig nanO2 fuel enhancer from Nabors Industries, when added to diesel, adds a combustion catalyst component that helps improve combustion while reducing emissions.

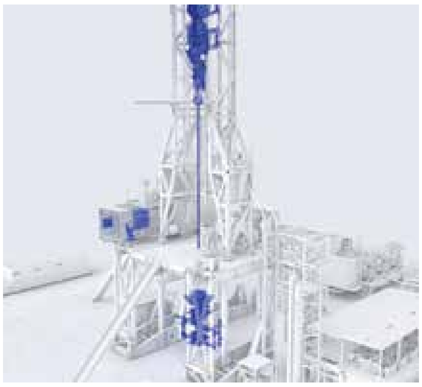
then into the generators from the existing fuel system.

The nanO$_2$ Fuel Enhancer has been deployed on onshore and offshore rigs and in completions operations using varying grades of diesel fuel. It has resulted in up to an 8% increase in fuel efficiency over the baseline. Canrig said its customers save more than $600 per day with the 8% increase in fuel efficiency, based on an average land rig using 2,200 gallons per day (gal/d) at $3.50 per gallon.

The nanO2$_2$ Fuel Enhancer was deployed on a drilling rig in East Texas. Canrig used kilowatt-hours per gallon (kWh/gal) as the standard to evaluate the rig's efficiency, fuel usage and electrical power. Fuel usage was recorded daily using tank level readings and cross-checked against indicated fuel delivery. Engine power data and the number of online generators were captured by rig controls, and the data was analyzed.

Testing resulted in a 5% increase in fuel efficiency over the baseline, saving 5,425 gal of diesel over the 73 days that the rig used nanO_2. The fuel savings equate to an estimated reduction of 55.6 metric tons of CO_2 equivalent.

DIGITAL OIL FIELD



SLB

SLB's Neuro Autonomous Solutions system Solutions uses advanced cloud-based software coupled with intelligent systems to deliver steering autonomy for directional drilling.

Product: Neuro Autonomous Solutions

Company: SLB

SLB's Neuro Autonomous Solutions system creates a continuous feedback loop between the surface and downhole to increase the efficiency and consistency of E&P operations while reducing human intervention.

During well construction, Neuro Solutions employs advanced cloud-based software coupled with intelligent systems to deliver steering autonomy for directional drilling. Steering sequences are self-determined using AI with surface and downhole automation workflows to deliver the well trajectory on plan. As the well is drilled, a real-time continuous feedback loop between an intelligent downhole system and a surface advisory system automates downlinks, reducing control loop time. The instantaneous correlation between downhole and surface actions in accordance with the well plan reduce risk, refine precision and increase efficiency while reducing associated drilling emissions.

During well intervention, Neuro Solutions at the edge ensures safer, more efficient and dependable operational execution and connectivity, eliminating internet reliance for significantly higher execution performance at the wellsite.

Furthermore, actionable insight from acquired log data is available within hours at the wellsite, shrinking the decision timeline.

An operator in the Middle East used Neuro solutions to autonomously drill a well from 22-degree to 90-degree inclination with a 2,500-ft curve section and a 5,400-ft lateral section. For both sections, the operator used autonomous-capable rotary steerable systems that contributed to the balance between surface and downhole autonomy, enabling a 36% reduction in downlinks compared with offset wells drilled in manual mode, while achieving a 13% increase in rate of penetration.

DRILL BITS

SLB

SLB's Aegis 3D-printed armor comprises of individual strips applied to the blade face of steel-bodied bits, replacing traditional hard facing and providing a shield against erosion from drilling fluid jetted from the bit's nozzles.

Product: Aegis 3D-printed Armor

Company: SLB

SLB's Aegis 3D-printed armor is 400% more erosion resistant than traditional hard-facing metalwork and 40% stronger than matrix bit material. The armor comprises of individual strips applied to the blade face of steel-bodied bits, replacing traditional hard facing and providing a shield against erosion from drilling fluid jetted from the bit's nozzles. Aegis 3D-printed armor increases erosion resistance in the areas surrounding the cutter pockets, prolonging bit life and decreasing production cost and average cost per run.

The improved blade face and cutting element protection delivers more strength for aggressive bit designs to improve overall bit performance as well as better erosion resistance. This enables angling the bit nozzles toward the blades and cutting elements for more efficient cuttings evacuation enforced by drilling fluid flow, resulting in faster ROP, more footage, and increased bit durability.

An Alaska North Slope operator planned a well with a large-hole curve and extended lateral intermediate section. The interval traversed formations of soft, sticky shale mixed with silt and sandstone with a high tendency for bit balling, and the planned well profile required a 31-degree to 82-degree inclination for the curve. SLB recommended adding Aegis 3D-printed armor to the blades. The bottomhole assembly (BHA) included a Rhino XS2 reamer, the PowerDrive Xceed RSS, and a fusion-bodied bit with Aegis armor. The combination drilled an interval of 3,712-ft measured depth (MD) at an ROP of 81.2 feet per hour (ft/h) with an inclination that ranged from 24.3 degrees to 81.5 degrees and a maximum dogleg severity of 3 degrees per 100 ft in one run without bit balling.

DRILLING FLUIDS/ STIMULATION

AquaShear

AquaShear mixers achieve near-instantaneous hydration, dispersion, mixing, blending, and shearing, which reduces additive product volumes and stabilizes drilling fluid properties.

Product: AquaShear Drilling Fluids Mixer

Company: Johnson Specialty Tools

AquaShear drilling fluid mixing technologies from Johnson Specialty Tools have been applied in the Permian Basin to reduce the volume of additive products by up to 20% per well and to cut the rig time associated with mixing and equipment maintenance by 50%.

AquaShear mixers achieve near-instantaneous hydration, dispersion, mixing, blending, and shearing, which reduces additive product volumes and stabilizes drilling fluid properties. They also eliminate the sludge at the bottom of tanks, which lowers cleanout times and cost. Rig crews and mud engineers have reported that high volumes of lost circulation materials can be mixed without particle clogging, and there is no need to continuously adjust fluid properties to maintain viscosity levels for effective hole cleaning and high ROP. The units optimize powdered mud additive yield and oil mud and packer fluid emulsions, with no loss of undissolved materials across the shakers.

Customers using AquaShear reported the unit reduced their mixing time for a 300-bbl batch from two hours to half an hour and that drilling mud costs dropped by an average of 27% as a result of improved dispersion and hydration of all drilling fluid components.

One customer used the AquaShear unit to quickly add 800, 50-lb sacks of barite to a kill fluid that was needed on a well taking a high-pressure kick. The time saved was significant and there was no hopper plugging. In another field trial, a customer reported substantially reduced mixing times and no fisheyes.

DRILLING SYSTEMS

SLB

GeoSphere 360 service acquires 360-degree tensor data and sends it uphole in real-time via mud pulse telemetry and wired drillpipe.

Product: GeoSphere 360

Company: SLB

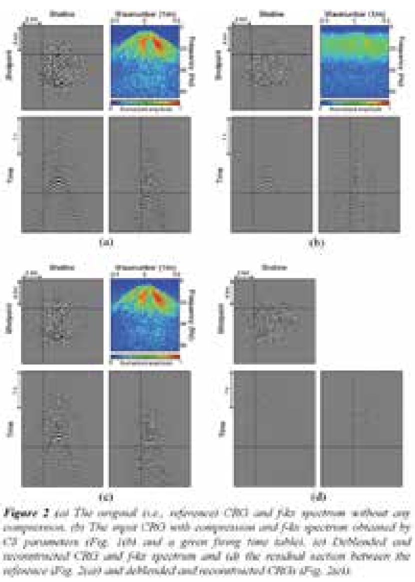
SLB's GeoSphere 360 3D reservoir mapping-while-drilling service maps fluid volumes, bodies and faults at reservoir scale.

The GeoSphere 360 service maps the reservoir boundaries and features, which allows for enhanced completion designs and production using fewer, better wells. The service extrapolates shapes that are impossible to see at the wellbore scale for better reservoir understanding in heterogenous or complex reservoirs—and not just 3D structural delineation but also 4D fluid-movement evaluation.

GeoSphere 360 service acquires 360-degree tensor data and sends it uphole in real-time via mud pulse telemetry and wired drillpipe. Real-time cloud computing inverts the large datasets with a 2D azimuthal pixel-based algorithm. GeoSphere 360 service produces 3D-resistivity volumes that are filtered to understand the geometrical relationship of the resistive geobodies around the wellbore, calibrating the seismic data and feeding into reservoir modeling workflows.

Equinor used the GeoSphere 360 3D reservoir mapping-while-drilling service to provide a complete 3D structural understanding from the landing zone to inside the main section of the horizontal interval in a North Sea Paleocene field. By improving azimuthal geosteering decisions, Equinor extended the well inside the reservoir section and delivered nearly 100-m MD of extra net pay interval. Due to the complex nature of the reservoir, the capability to map structural and stratigraphic changes both vertically and laterally was crucial for the success of the well. Applying GeoSphere 360 enabled steering away from the planned trajectory toward the sweet spot, which was located sideways from the planned trajectory.

EXPLORATION/ GEOSCIENCE



Saudi Aramco

Saudi Aramco's BlendSeis integrated seismic acquisition and processing technology yields high-resolution subsurface images for accurate geologic interpretation and reservoir characterization.

Product: BlendSeis: Advanced Seismic Data Acquisition and Processing

Company: Saudi Aramco

Saudi Aramco's BlendSeis integrated seismic acquisition and processing technology yields high-resolution subsurface images for accurate geologic interpretation and reservoir characterization. BlendSeis employs compressive sensing of seismic data in time by combining simultaneous sources and continuous recording and in space by non-uniform undersampling of source and/or receiver locations or concurrently in both domains.

Aramco used a source blending approach to develop a joint deblending and wavefield reconstruction via sparsity-promoting inversion algorithm. During an onshore field survey acquisition, Aramco reported achieving three times higher productivity obtaining superior 3D subsurface images than a conventional seismic crew.

Aramco demonstrated the concept of compressive sensing in time and space on a seismic survey covering 100 sq km acquired with eight simultaneous sources and 50% of the originally designed sources points. The optimal non-uniform sampling of the original source points was determined by minimizing the mutual coherence. During repeated random realization, a jittered undersampling scheme that supplements random undersampling to avoid nonexistent local information raised by unnecessarily large intervals is applied with the whole survey area divided into a number of small 2D windows for local optimization of the sampling operator.

The data can be examined in a common receiver gather domain, with blended shooting of sparsely deployed sources at optimally sparsified locations. To obtain the results, an underdetermined system of equations is solved by a joint deblending and reconstruction algorithm using an l2-norm objective function with additional constraints. These results demonstrate that the proposed algorithm effectively handles noisy and partially sampled seismic data.

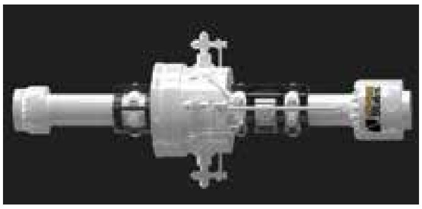
FLOATING SYSTEMS AND RIGS

Product: MPD-Ready Jack-Up Riser

Company: Oil States Industries

Oil States' MPD-Ready Jack-Up Riser System has built-in automation capabilities along with a package of controls, umbilical and topside equipment.

With downhole pressure control drilling in managed pressure drilling



Oil States Industries

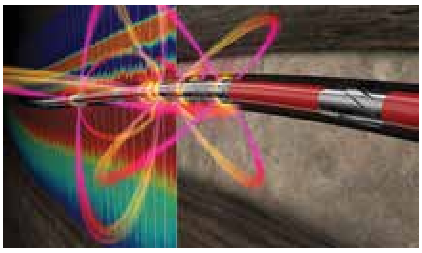
Oil States' MPD-Ready Jack-Up Riser System has built-in automation capabilities along with a package of controls, umbilical and topside equipment.

(MPD) mode, mud is less likely to be lost into the formation and formation fluid is less likely to enter the riser. The MPD system features an 18 3/4-inch thru-bore MPD joint and dedicated, quick-closing annular packers for unplanned bearing change-out, eliminating the need to rely on the BOP annular.

The MPD joint runs through the rotary table from the drill floor to the BOP stack, during which it locks into the hands-free flowline connector. Avoiding reliance on the BOP annular allows the MPD-Ready Jack Up Riser to reduce costs, safety risks and nonproductive time.

The MPD-Ready Jack-Up Riser is rated for temperatures ranging from -29 C to 121 C. The system can withstand up to 3,000 pounds per square inch (psi) for the MPD section above the BOP and up to 15,000 psi for the BOP and components below.

FORMATION EVALUATION



Halliburton

The StrataStar deep azimuthal resistivity service from Halliburton provides high fidelity maps of the reservoir in real-time.

Product: StrataStar® Deep Azimuthal Resistivity Service

Company: Halliburton

The StrataStar deep azimuthal resistivity service from Halliburton provides high fidelity maps of the reservoir in real-time.

With a spacing of 12 ft, the StrataStar service combines the largest electromagnetic signal deployed on a single collar with a sophisticated processing algorithm to reveal, while drilling, the positions, thicknesses and resistivities of interbedded rock and fluid layers up to 30 ft away from the wellbore. With more than 5,000 electromagnetic measurements acquired from a 24-ft long collar every 12 seconds, it provides a detailed image of the surrounding formations and fluids as well as accurate petrophysical evaluation of the reserves in place, including electrical anisotropy.

Real-time visualization of the surrounding geology and fluids allows operators to accurately lock onto geological bodies from far away and precisely steer the well while maintaining the desired distance from unproductive water flooded or shale zones. The StrataStar service also provides shallower multi-frequency measurements to enable petrophysical analysis across a range of fluids and rocks.

Halliburton deployed the StrataStar service alongside an existing azimuthal resistivity tool in a 6 3/4-inch BHA to steer a 10,000-ft horizontal section of an Alaska North Slope well with a goal to verify comparable, if not better, downhole data. The StrataStar service trial demonstrated perfect alignment of inversion data with the established independent tool. It also provided additional high-value details, such as multiple resistivity boundaries and a clear, easy-to-understand representation of the geology. The new mapping capability revealed variations in sand thickness and lateral variability in the formations consistent with the depositional environment.

HSE

Shepherd Safety Systems

The Digital Gas Monitoring Ecosystem from Shepherd Safety Systems is a digital toxic gas detection solution that integrates multigas sensors, wearable personal monitors and a field communications and command platform that allows onsite and offsite personnel to monitor crew safety and emissions from any location.

Product: Digital Gas Monitoring Ecosystem

Company: Shepherd Safety Systems

The Digital Gas Monitoring Ecosystem from Shepherd Safety Systems is a digital toxic gas detection solution that integrates multigas sensors, wearable personal monitors, and a field communications and command platform that allows onsite and offsite personnel to monitor crew safety and emissions from any location. The equipment can detect CH_4, H_2S, LEL, CO, SO_2 and O_2. On request, sensor packages for ClO_2, HCl, HCN, NO, NO_2, O_3, and PH may be integrated into the Shepherd Digital Gas Monitoring Ecosystem system.

One E&P company deployed the Shepherd Digital Gas Monitoring Ecosystem as a way to manage multiple tasks. The company wanted to monitor, manage and reduce methane emissions; increase the depth of monitoring levels; and protect the health and safety of team members. The monitoring system pinpointed methane releases in a production location. Gas leaks were discovered and reported in ppm in real-time, enabling the E&P's team to quickly verify and repair emissions of ~100,000 standard cubic feet per day.

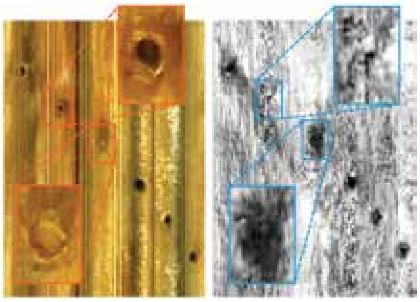
For a drilling location, $150,000 in nonproductive time was eliminated by reducing the number of false alarms when traditional H_2S sensors showed high readings when pressure washed by the rig crew. Because Shepherd sensors are named by location, the incidents of false alarms and stop work orders dropped from the previous year's levels.

HYDRAULIC FRACTURING/ PRESSURE

Product: ClearVision™

Company: EV

EV's ClearVision integrated array video and phased array ultrasound scanning tool combines 360-degree video and phased array ultrasound technologies for 4D evaluation of wellbores. ClearVision enables operators to see and measure 100% of perforations—including small dimension perforations and those plugged with sand. The tool delivers unambiguous information regarding perforation erosion and proppant placement trends, empowering engineers to improve frac designs for better well performance and increased hydrocarbon production.



EV

ClearVision simultaneous capture of array video (left) and phased array ultrasound (right) for a single cluster, with perfs 4 & 5 missed by ultrasound.

For a well in the Permian Basin, the tool string was deployed on coil tubing and data was acquired for the 3,000 ft and 16 stages of the lateral section closest to the heel. The well included some untreated base holes, providing in-situ dimensions used as a reference to calculate the eroded area of the treated perforations. The previous technology used by the operator resulted in 56% of the 16 stages missing perforations from two or more clusters, which invalidated the data for analysis purposes. In contrast, when the operator used ClearVision, 100% of the perforations were measured, delivering valid data for all stages to ensure accurate analysis.

ClearVision enabled the operator to identify the best-performing stage design and apply it to all the stages of the next well, which improved reservoir stimulation and delivered an additional $1.4 million of production revenue for a single well in its first year of production. This economic gain was further enhanced by the resulting increase in stage length and subsequent reduction in operating time, which yielded $350,000 in savings.

IOR/EOR/REMEDIATION

Product: Welltec Puncher 218

Company: Welltec

The Welltec Puncher 218 provides an e-line conveyed, non-explosive method for equalizing pressures between tubular strings. It is available with an outer diameter of 2.125 inches. The slim non-explosive puncher is capable of creating multiple perforations on a single run. Using a fast, drilling technique, the Welltec Puncher produces a precise, uniform hole. The puncher can be run slick to any depth in the well or equipped with a "no-go" for a hole punch at an exact depth. Multiple holes can be drilled in a single run, and it can

Welltec

The Welltec Puncher 218 provides an e-line conveyed, non-explosive method for equalizing pressures between tubular strings.

be deployed independently or with other tools. It can combine with the Well Tractor for punching in highly deviated or horizontal wells.

During plug and abandonment preparation offshore Denmark, TotalEnergies wanted to circulate trapped gas from a well by creating multiple perforations in the 4 ½-inch tubing. The chosen solution had to be capable of creating a predetermined number of uniform holes in the 28-Cr alloy tubing chosen for the completion due to its resistive qualities in a sour well environment with a high concentration of hydrogen sulfide (H_2S).

Welltec deployed a mechanical tool suite including the ultra-slim Welltec Puncher 218 using a fast, surface-controlled drilling technique to produce precise and uniform holes with depth control to avoid damaging the casing behind. The plan was to create five, 12-mm uniform perforations below the production packer.

The Welltec Puncher 218 was run in hole and created all five perforations within a 3-ft interval on a single run without damaging the casing behind.

MACHINE LEARNING AND AI

Halliburton

The LOGIX autonomous drilling platform from Halliburton combines physics-based 3D modeling, machine learning techniques, and digital twin technologies.

Product: LOGIX® Autonomous Drilling Platform's Auto Steer Module

Company: Halliburton

The LOGIX autonomous drilling platform from Halliburton combines physics-based 3D modeling, machine learning (ML) techniques, and digital twin technologies. The LOGIX platform is composed of several modules, including the Auto Steer autonomous directional drilling module.

The module uses ML to generate real-time adjustments to steer the well according to the well plan while also automatically incorporating reservoir target changes based on real-time formation evaluation and reservoir mapping geosteering data. To date, more than 6 million ft were drilled autonomously on the LOGIX platform in more than 2,500 runs, reducing well delivery times by up to 25% and personnel on board requirements by up to 60%.

LOGIX Auto Steer's first autonomous job to land a well with geosteering integration was performed in Ecuador. The well profile was a complex 3D well with a build interval, followed by a tangent and then a build-and-turn interval to get to the reservoir section. The well had to maintain a dogleg severity of less than 1 degree per 100 ft in the 300-ft tangent section where the ESP would be placed and achieve the landing target based on real-time geosteering interpretation to maximize reservoir exposure. Using LOGIX Auto Steer, the team drilled the curve and tangent, maintaining 0.85-degree dogleg severity or less.

The original well plan was followed until the geosteering team confirmed a change in the geology, resulting in a new landing target. LOGIX Auto Steer steered to the new well path autonomously and successfully landed the well. A total of 87.4% of the length was autonomously drilled using LOGIX Auto Steer.

NON-FRACTURING COMPLETIONS

Product: Fuzion®-EH electro-hydraulic downhole wet-mate connector

Company: Halliburton

Halliburton's Fuzion-EH electro-hydraulic downhole wet-mate connector makes it possible to disconnect and reconnect the upper completion and retain complete control over interval control valves and communication with electrical gauges below the production packer. The Fuzion-EH wet-mate connector reduces the complexity of removing failed upper

Halliburton

The Fuzion-EH wet-mate connector reduces the complexity of removing failed upper completion equipment, such as electric submersible pumps, subsurface safety valves, and gas lift mandrels.

completion equipment, such as electric submersible pumps, subsurface safety valves, and gas lift mandrels.

Fully compatible with the SmartWell intelligent completion systems, Fuzion also enables efficient lower completion deployment on drill pipe without the need for flatpacks when running SmartWell completions in extended reach wells or in wells with high fluid losses.

The Fuzion-EH downhole wet-mate connector is run with the completion above the production packer and is equipped with seven independent hydraulic control lines and one electric line. Once the packers are set, the upper portion of the tool (male) can be removed from the lower portion (female) multiple times with full isolation of the tubing to the annulus and each individual control line.

The Fuzion-EH wet-mate tool was successfully installed in two deepwater wells offshore Brazil in 2022. Using the tool's single-trip configuration, it was possible to replace a failed subsurface safety valve (SSSV) later without the need to cut and release the three zonal production packers or lose the ability to control and monitor the SmartWell completion. Without this tool, the operator would have to curtail production if a SSSV failed and would have to plan a multi-trip deepwater workover operation.

ONSHORE RIGS

Product: FlexRig Flex3 Walking Rig Million Pound Mast

Company: Helmerich & Payne

Helmerich & Payne's (H&P) FlexRig

Helmerich & Payne

Helmerich & Payne's FlexRig Flex3 Walking Rig Million Pound Mast is customized for mobility and agility in the Middle East terrain for unconventional pad drilling.

Flex3 Walking Rig Million Pound Mast is customized for mobility and agility in Middle East terrain for unconventional pad drilling.

Unlike most conventional rigs, the Flex3 walking rig is a side-saddle configuration to reduce flat time during common rig activities: drilling, pad-to-pad rig moves and well-to-well rig walks. A hookload of 1 MMlb, a 720,000-lb setback capacity, and the capacity to set almost 24,000 ft of 5 ½-in. Drill pipe in the racking board equips the rig for complex lateral wells. It can walk 500 ft in a straight line or multiple rows within a 200 ft by 50 ft box. With the H&P BoomBox, the rig can remain energized during the walks because there is no need to break electrical connections.

The introduction of the new rig design has contributed to reducing cycle times by more than 35% from 2016 to 2022. What was once a three-to-five-hour release to spud skid is now as low as an hour and a half through the use of walking technology. The accumulator skid relocation away from inside the rig substructure ensured compliance with standards without giving up mobility and modularity. Expanded substructure and BOP handling capabilities enabled handling larger Middle East BOP equipment and complied with well control standards.

SUBSEA SYSTEMS

Baker Hughes

Baker Hughes' REACH wireline-retrievable safety valve (WRSV) makes it possible to bring ultra-deepwater wells with failed tubing-retrievable safety valves (TRSVs) back online faster, safer, and more economically than through a deepwater workover.

Product: REACH wireline-retrievable safety valve

Company: Baker Hughes

Baker Hughes' REACH wireline-retrievable safety valve (WRSV) makes it possible to bring ultra-deepwater wells with failed tubing-retrievable safety valves (TRSV) back online faster, safer, and more economically than through a deepwater workover. The surface-controlled REACH WRSV is capable of operating at the low pressures required in subsea wells.

It has the ability to operate within the limitations of the existing hydraulic system, which eliminates the need to pull the upper completion to replace the failed TRSV. As such, control lines or smart completion accessories remain intact and operable when the intervention is complete.

The REACH WRSV requires a riserless lightwell intervention (RLWI) vessel to perform the job, which avoids the high cost of a workover and can expedite schedules as RLWI can typically be deployed more quickly.

Building on the design principles of the existing REACH TRSV, the REACH WRSV is rated to 12,500 psi at 300 F and exceeds API 14A requirements. The company estimates using the REACH WRSV can save operators $50 million per well compared to a major workover.

A client in the Gulf of Mexico (GoM) was operating an ultra-deepwater well with a nitrogen-charged tubing retrievable safety valve (TRSV). When the TRSV failed, Bureau of Safety and Environmental Enforcement regulations required the well to be shut-in until the TRSV could be repaired or replaced. The client approached Baker Hughes about deploying a REACH WRSV via light well intervention. It was tested in February 2023 at Baker Hughes' test rig in Tomball, Texas, and will be installed in the GoM well in August.

WATER MANAGEMENT

Product: Zero Liquid Discharge (ZLD) Produced Water Management Project

Company: Saudi Aramco

Saudi Aramco's Zero-Liquid Discharge (ZLD) produced water management solution desalinates produced oilfield water by transforming its ionic properties that can be injected into the reservoir for pressure maintenance and increase the efficiency of oil recovery.

ZLD water can also be used as frac-water for tight gas and unconventionals, wash water for crude oil desalting and in other applications including the irrigation.

Saudi Aramco

Saudi Aramco's Zero-Liquid Discharge produced water management solution desalinates produced oilfield water by transforming its ionic properties that can be injected into the reservoir for pressure maintenance and increase the efficiency of oil recovery.

ZLD uses a pretreatment system to remove residual hydrocarbons and H_2S plus a dynamic vapor compression (DyVaR) unit for salt removal from hypersaline oilfield produced water. The pretreatment system uses a vent gas scrubber and chemical scavenger to lower the dissolved H_2S from produced water, while dissolved gas floatation with nitrogen gas removes dispersed hydrocarbons.

The pretreated produced water is then processed in DyVaR to effectively remove salts from produced water. The DyVaR unit is equipped with "cyclones" to accomplish water evaporation at a temperature of about 175 F. The water vapor is then condensed to generate the low salinity water. The reject brine is continuously recycled to mix with feed pretreated produced water to achieve up to 80% to 90% water recovery. The concentrated salts obtained from ZLD technology were processed further to recover purified salts or directly used to formulate drilling fluids, which results in zero waste discharged into the environment.

The ZLD pilot unit has a 225 bbl/d capacity and was able to remove the residual hydrocarbons and dissolved H_2S to less than 1 ppm and lower the salinity of produced water from 90,000 ppm total dissolved solids to less than 100 ppm to 200 ppm total dissolved solids to essentially generate fresh water with a consistent recovery factor of about 80%. OGI

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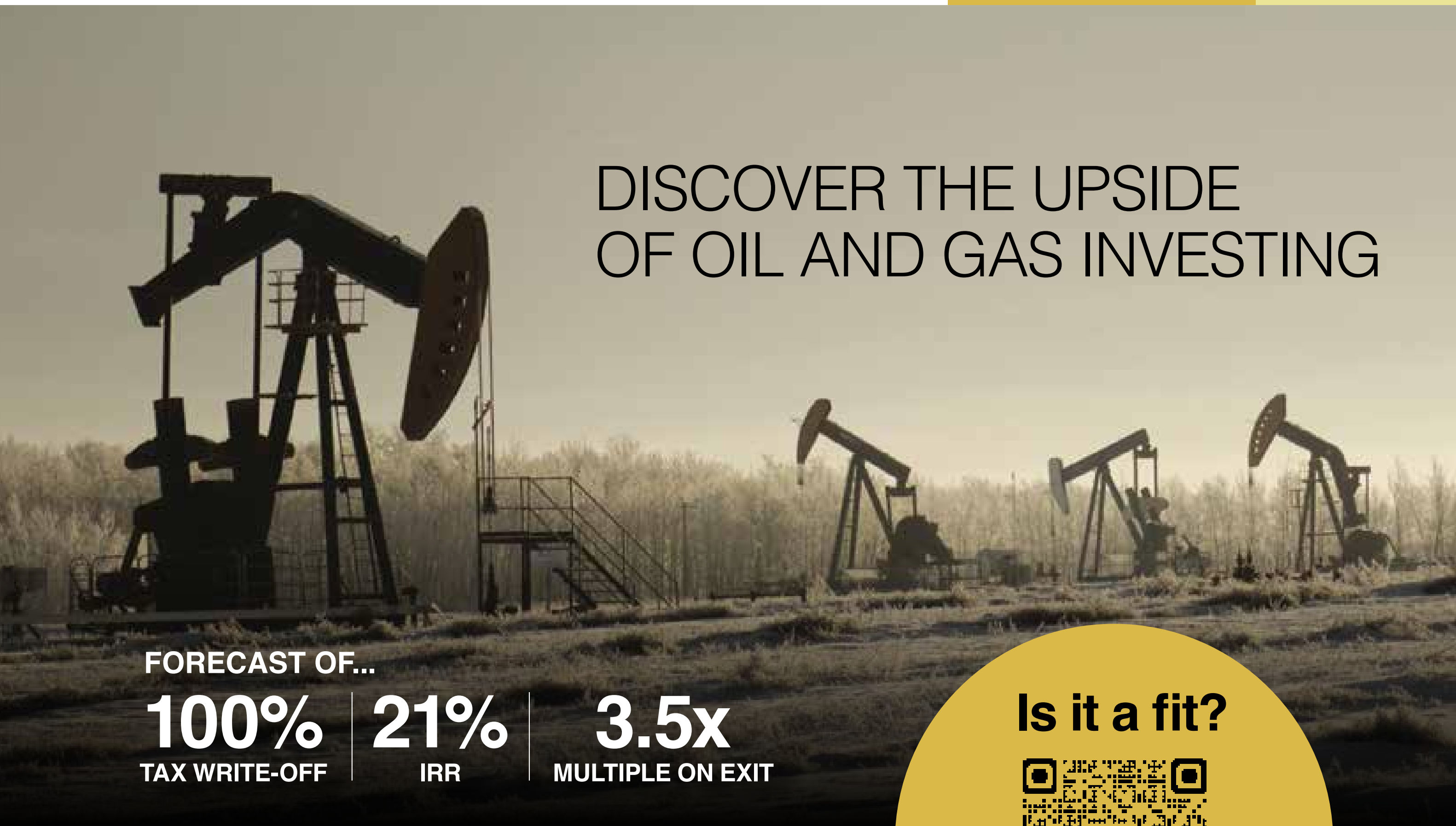

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The foregoing financial illustrations are “forward looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995 and are based on numerous variables and assumptions which, although believed in good faith to be reasonable, may prove to be incorrect and could cause actual results to differ materially from those projected. Please refer to the King Operating Partners I LP Confidential Private Placement Memorandum dated January 3, 2022 for a description of some of the risks and uncertainties to which the foregoing financial illustrations are subject.”

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MOLECULAR TRANSFORMATION

CEO Darren Woods discusses Exxon Mobil's expansion plans in the Lower 48 and managing the energy transition in The OGInterview.

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The Exxon Mobil precursor Standard Oil was first listed among the 30 blue-chip companies in the Dow Jones industrial average in 1928. By 2007, the fossil fuel behemoth peaked as the largest publicly traded company in the world—in any industry—with a market capitalization of more than $500 billion.

But then came the Great Recession and the tech boom and the energy transition and, finally, the pandemic. The bottom seemingly fell out and Exxon Mobil was unceremoniously dumped out of the Dow in 2020 with a market value of just—relatively speaking—$178 billion.

But then came vaccines and demand resurgence and the war in Ukraine and record-breaking profits of $56 billion in 2022. Now, Exxon Mobil's market cap again inches closer to $500 billion and the Texas juggernaut easily leads the way as the largest investor-owned energy company in the world.

The developed world again seems to recognize the value, or at least the necessity, of oil and gas, and Exxon Mobil is front and center.

With the purchases of XTO Energy and the Bass family holdings, Exxon Mobil has transformed itself into a shale powerhouse, especially in the booming Permian Basin. And the company emerged as an exploratory pioneer in South America, turning tiny Guyana into an important part of the global oil landscape.

Despite pulling out of Russia for political reasons and seeing somewhat disappointing results in Brazil, Exxon Mobil is on an upward trajectory, aiming to hit 1 MMboe/d from the Permian and 1.2 MMboe/d from Guyana by 2027.

Chairman and CEO Darren Woods, a 30-year Exxon Mobil veteran and Texas A&M University alum, came up on the refining side of the business. So, he sees the whole value chain and prioritizes the Growing the Gulf Initiative of pipeline, petrochemical, refining and LNG growth along the Texas and Louisiana Gulf Coast. There are major chemicals and plastics expansions at the Baytown and Baton Rouge complexes, a new petrochemical campus near Corpus Christi, historic refining growth in Beaumont and the construction of Golden Pass LNG.

The Permian growth is helping to feed the downstream expansions and that West Texas footprint could rapidly expand if Exxon Mobil seals the deal on a longtime flirtation with the top Midland Basin driller, Pioneer Natural Resources, in a sale that could easily exceed $70 billion.

And Exxon Mobil is now leaning into the energy transition—not with wind and solar, but with carbon capture, hydrogen, renewable diesel and more.

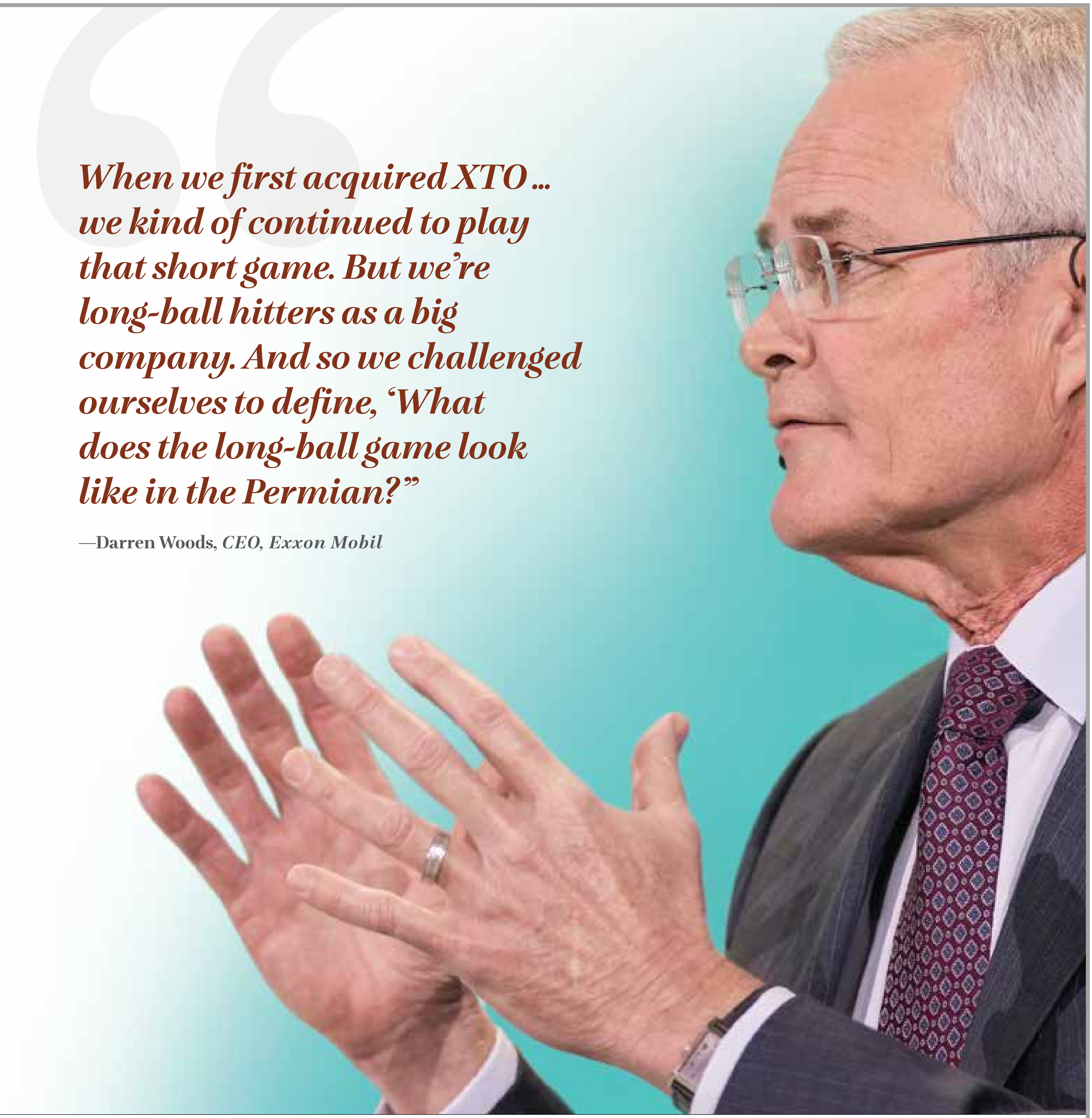
Hart Energy Editorial Director Jordan Blum sat down with Woods in an exclusive interview to discuss all of the successes and challenges. This interview was conducted before the speculative mid-April Pioneer news, which Exxon Mobil declined to discuss.

Q&A

Jordan Blum: Big picture, how is Exxon Mobil focusing more and more on North and South America, especially given the rise in global demand, the withdrawal from Russia and European taxation concerns?

Darren Woods: That's where the opportunities that we have in our portfolio are most attractive and most competitive, so that's where we're putting our emphasis. My expectation would be that, over time, that will change based on where the opportunities present themselves. We continue to look all around the world. The nice thing about our industry is it's connected. It's a pretty efficient market, so we go where the resources are, and where we can bring a competitive advantage and differentiate ourselves.

So, our approach will be fairly diversified. We actually think from a risk management



When we first acquired XTO … we kind of continued to play that short game. But we're long-ball hitters as a big company. And so we challenged ourselves to define, 'What does the long-ball game look like in the Permian?'"

—Darren Woods, *CEO, Exxon Mobil*

Andrea Hanks/CERAWeek by S&P Global

standpoint, given some of the uncertainties associated with governments and how administrations change with time, that having a portfolio that's not dependent on any one place to be successful is a good strategy, which I think proved true with the assets that were expropriated in Russia. If you look at the size of that ($3.4 billion impairment charge), in the scheme of everything else we were doing, certainly the company was able to manage through that.

JB: In North America, obviously, the Permian is king. Exxon Mobil is roughly a top-five producer in the Permian and a very active driller. What's the current importance of the Permian, along with production goals and targets?

DW: A key success factor in our industry and for us as a company in producing oil and gas is ensuring that, from a cost-of-supply standpoint, we're on the low side, the left-hand side of the cost-of-supply curve. So, as we're going through the cycles, irrespective of how low the price goes, there's a price setter that's out there that has a higher cost to produce than we do, which gives you a guaranteed margin.

In the Permian, several years back we used this phrase

Woods said the challenge in the Permian Basin is not in finding the resource, but figuring out the best way to extract it.

ExxonMobil

using a baseball analogy: small ball. And, when we first acquired XTO and participated in that, we kind of continued to play that short game. But we're long-ball hitters as a big company. And so we challenged ourselves to define, "What does the long-ball game look like in the Permian?" In the Permian, you know where the resource is. It's not a question of going out and finding the resource. It's really a question of, how do you most effectively extract the most of it? That's the big challenge in the Permian.

And so, we set ourselves up to approach this as a manufacturing issue and drive efficiency and effectiveness, and bring technology here into play in the Permian to try to maximize the recovery. We're still on that journey. But the work that we've done in bringing that new approach to the Permian has driven our performance to lead the industry, and driven our cost of supply well below $40/bbl, which then makes it resilient. So, it's a critical part of the portfolio and one where we think we bring some unique advantages that we haven't fully realized yet. So, I see a lot of upside to the Permian.

JB: I know you're doing more with automated rigs and you have the 1 MMboe/d production goal, but is there much concern about drilling inventory shortages and the core-of-the-core areas being drilled up?

DW: I would go back to when we thought about the approach we wanted to take here. At the time, I would say broader industry was very focused on high initial production rates, so they were drilling the sweet spots and getting those rates high. We, actually, in looking at it, said what we want to do is maximize recovery. That's the right answer from an NPV (net present value). Rather than focus on the sweet spot and get high initial production rates, we focused on maximizing recovery, which led to this cube development that we've been working on and continuing to optimize.

The intent there is to drill in a way that maximizes full recovery, so we didn't go down the path of sweet-spot, high-production rates. So we're not seeing the same challenges as many others out there that kind of went for the best. As you hit your sweet spot, you're taking energy out of system, so to speak, so recovery becomes harder and harder. I think we've avoided the problem that a lot of people are talking about. We have a pretty deep well inventory, so I think we feel pretty comfortable with the plans that we have in place.

By the way, we don't really set targets. We develop plans. In my expectations, we're going to meet those plans (laughs). In my organization, they understand that. So, we've got a really good plan we've been delivering on pretty consistently. So, I've got a lot of confidence we'll hit that 1 MMboe/d by 2027.

JB: I know it's not super obvious for everyone from the outside looking in, but can you elaborate on how the Permian is feeding growth across the value chain?

DW: Yeah, we've got a lot going on. If you look across our businesses, on the oil side of the equation, it's obviously a depletion business. There's growing demand and depleting resources, so it's a big challenge to make sure we're investing to try to certainly offset depletion, but then to grow production in total, which we've been fairly successful at doing here lately.

If you look at the chemical business, it's a growing business. The challenge there is less about depleting resources and more about growing the market, and to maintain market position, and to penetrate deeper with our performance products. You've got to keep investing in that space.

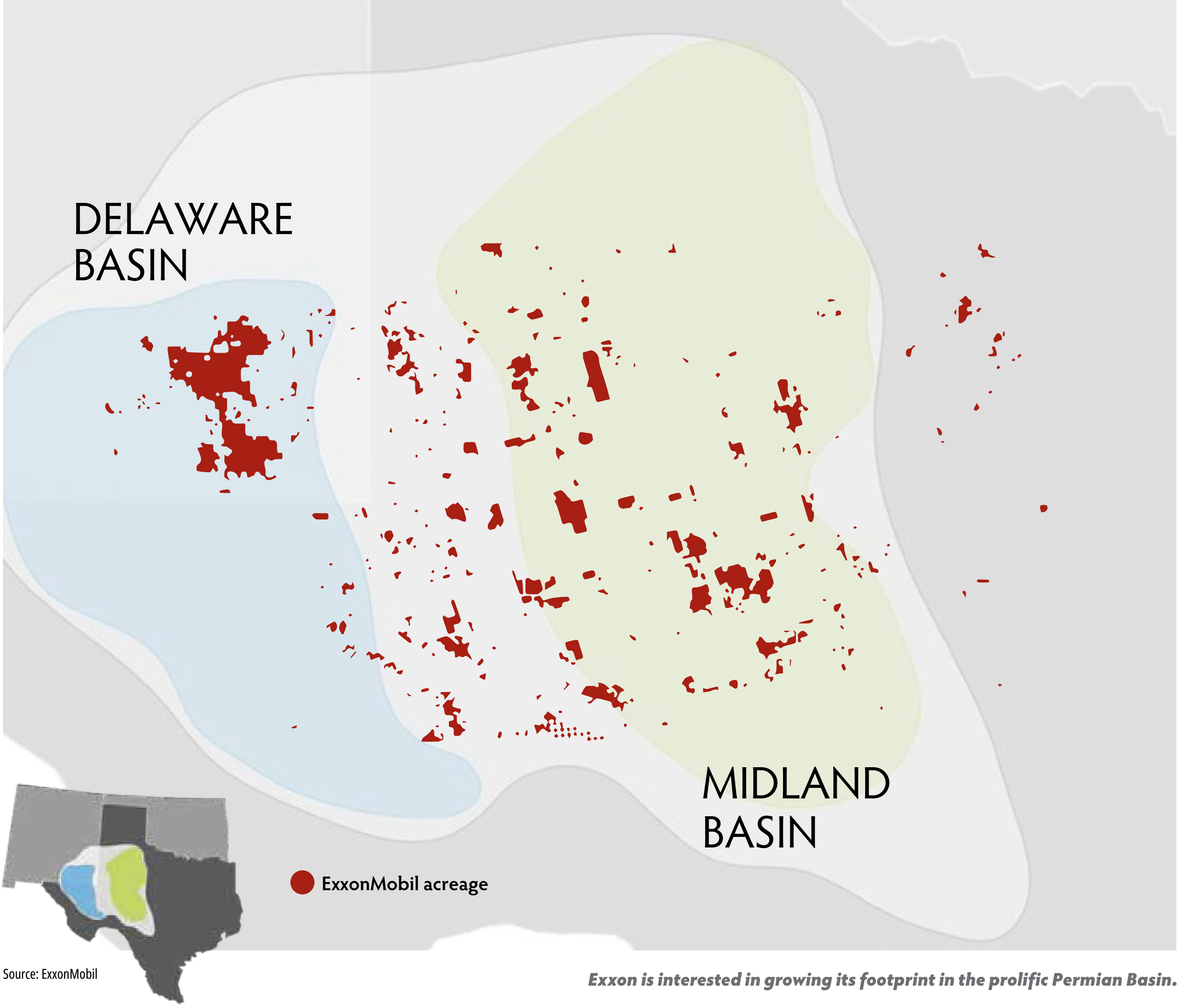
And, then, in the refining business, it's less about growth and more about evolving your production profile and your yield patterns to meet the evolving demand and the mix of products, so, higher-value products and lower-carbon products.

As we looked across all that, the Gulf Coast in the U.S. has elements of each of those things. As we were looking into the

>28 Koebd	**30 %**	**450 Kta**	**250 Kbd**
Upstream production growth despite signicant divestments and Sakhalin -1 expropriation	Production growth in Guyana and Permian	Baton Rouge polypropylene unit started up in 4Q22	U.S. refining capacity expansion mechanically completed; largest U.S. addition since 2012

Source: ExxonMobil

Building a Winning Business in the Permian



Source: ExxonMobil

Exxon is interested in growing its footprint in the prolific Permian Basin.

opportunities there, we saw a lot of synergy in connecting all of those. And understanding the quality of the crudes that we're bringing on, and maintaining that quality as we ship it through the pipelines, and delivering it into our refineries and taking into account that quality allows us to optimize the operation. We become more efficient and get better yields on our plants to run more stably. One of the advantages with our big footprint is you can leverage a lot of the existing infrastructure and capacities in place. So, it lends itself to the incremental investment that we've made versus a grassroots plant somewhere else in the world.

JB: In that same vein, with macro demand, how important has LNG become for Exxon Mobil with Golden Pass LNG and other potential projects?

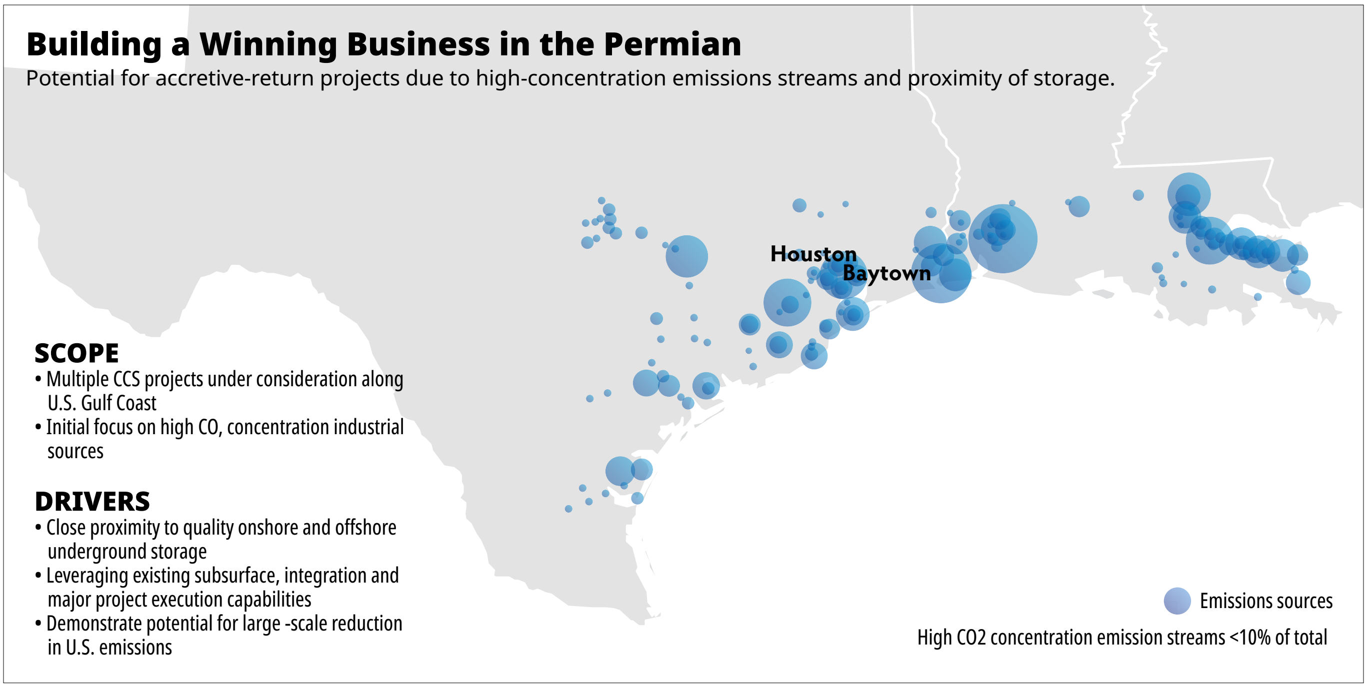
DW: We felt for as long as I've been in this job (January 2017) that Golden Pass LNG was going to be an important part of the mix. We never wavered from that concept. We felt like that was a logical extension of our portfolio. Our view was the LNG market would grow bigger and deeper, which would lead to more opportunities to trade. So, the Golden Pass opportunity really allowed us to lean into what we believed would be a rapidly growing market with more liquidity and more tonnes moving around from different regions. We also believed that the U.S. would be the marginal source of supply, so having an advantaged LNG facility on that marginal production layer gave us an opportunity to build that. So, we stuck with that. Even as we went through the pandemic, that was one of the few projects that we did not pause, because we recognized that was going to

100 %
Elimination of routine flaring in Permian Basin operations

>40 %
Reduction in methane intensity since 2016

2 million
Metric tons of third-party CO_2 per year expected to be captured and permanently stored in Louisiana by 2025

80 million
Pounds of annual advanced recycling capacity started up in Baytown, Texas



Source: ExxonMobil analysis of EPA Facility Level Information on Greenhouse Gases Tool, 2019 data as of Feb 15, 2022.

be needed.

The big challenge with LNG is production comes on in fairly large chunks, so you have these periods of real tightness, which we certainly saw last year. Then we'll get into some point in the future where there's a whole lot of supply, and oversupply in the market, and the market gets weak. Our strategy is not to try to time those cycles, but to make sure what we build is resilient to the bottom of those cycles.

JB: Pivoting to the Low Carbon Solutions business, you're not doing a ton specifically with renewables, but you're doing a lot with the broader energy transition. Going through some quick hits: there's the low-carbon hydrogen facility in Baytown, advanced plastics recycling center, the carbon capture partnership with Mitsubishi, renewable diesel with Imperial Oil in Canada, and more.

DW: Let me start with your observation that we're not going into renewables. One of the misconceptions when people talk about us being an energy company, they think power generation. Well, we're not in the power-generation business. We're not in the electron business. We're in the molecule transformation business. We've looked at wind and solar and whether it makes sense to get into the electron business. But we don't have a particular competency in that space. If there isn't an advantage we can bring to that marketplace, then why pursue it? Others can do it just as well as we can. If they need money, we can write checks. If you look at molecule transformation, we have for 140 years effectively found and transformed hydrogen and carbon molecules into products that the world needs. If you think about us powering gasoline cars or diesel trucks, we make products that people use every day. I don't think I can make it through an hour without touching some product that comes out of our chemical plants. That's all about this molecule transformation.

So what are we focused on? Carbon capture and storage. That's capturing CO_2 molecules and transporting them and storing them underground and using our subsurface understanding to do that effectively.

Hydrogen is the same thing. It's using our project capabilities, technology and partnerships to develop hydrogen. Renewable diesel is the same thing too. Those are just a different type of hydrogen and carbon bonds.So, there's a synergy that exists with our core capabilities and competencies, and that's where we're making our investments. We're using the exact same criteria that we're using in our base business, which is, first and foremost, it's got to generate a return. At the end of the day, we've got a responsibility to generate a return for our shareholders.

JB: Some of these low-carbon ventures are mega projects in their own rights?

DW: Absolutely. Our Baytown hydrogen project by most definitions is considered a mega project at $7 billion.

JB: Going south a bit, how is Guyana progressing? The announcements have slowed a bit, but the discoveries keep coming. Is it hard to understate the importance of Guyana to Exxon Mobil right now?

DW: As (Hess Corp. CEO) John Hess said, it's one of the largest finds in the last decade. So, I think it's important for the world and, obviously, very important for the Guyanese and the wealth and investment it will bring to Guyana, which, on a per-capita basis, is a poor country.

For us, it's obviously a very important growth piece of our portfolio, like the Permian is. I think we worked really hard to do that in the most responsible way and in a way that's capital efficient. But, at the same time, quicker. If you look at what we've done there, we're actually bringing that resource to market at a rate that, frankly, most in the industry haven't been able to achieve, let alone sustain over the course of several projects. So, we've got a really good rhythm going, and that was the intent is this idea to just stay focused and keep cranking. We have this enormous resource that gives you the luxury of developing, call it a programmatic approach to capital projects. It's not that we're not tailoring each project to the resource. But, having a consistency of purpose in that space, I think, brings great benefit, which allows us to continue on a very efficient pace of bringing those resources in. It's a big part of our growth engine, so it's very, very important. But, as I said, we look at it in context of, while it's very important, it can't be a singular focus. We've got to continue to look for opportunities all around the world to have a diversified portfolio to continue to fill that pipeline.

JB: Any thoughts on the Guyana government talking about having tougher political negotiations going forward as they become more learned and with more companies getting involved?

DW: I think there's a dialogue that gets reported on quite a bit. I won't comment on that. But I'll just say we have a really, I think, sound and effective relationship with the government. I've been there several times for meetings. Our management teams are there. I think they recognize the value that we brought. I think, above and beyond the production, it's not just what we've done, but how we've done it. The integrity and value system that we bring, the straightforward approach we take in discussing the opportunities with them, the transparency we bring. I think we've established a level of trust, and we've gained a lot of credibility with what we've delivered. We've done exactly what we said we were going to do. Those relationships evolve with time and that will continue to happen as more interest and more success comes to Guyana. It's the natural evolution.

JB: Looking at geographic boundaries next door, are you still pretty bullish on Suriname as well?

DW: The fundamental value driver when you look at these opportunities is the quality of the rock. You don't know that until you drill these wells and get into the rock. So I would say our bullishness of any area is really a function of the quality of the rock. You can see some structures and have a view of what you think might be there, but until you get the holes down and see what you've got, I try to maintain a level of calm, so to speak (laughs). I try not to get too excited about these things because it's a challenging business and there's a lot of uncertainty you've got to manage.

> *"We're in the molecule transformation business ... We make products that people use every day. I don't think I can make it through an hour without touching some product that comes out of our chemical plants. That's all about this molecule transformation."*
>
> —Darren Woods, *CEO, Exxon Mobil*

JB: With a global focus and all the shale learnings with XTO, does that translate much, whether it's in the Vaca Muerta in Argentina or somewhere else?

DW: One of the things I've been very focused on since getting this job is the size of our company and the business that we have across the spectrum. The way we were organized, historically, we actually had a lot of that capability siloed off in different areas of the business. It made the learning and transferring more difficult. If you see the transformation we've been making in the company, we've established now three businesses (Upstream, Product Solutions and Low Carbon Solutions) and have centralized the capabilities that are common to these businesses and are critical to the delivering of these businesses.

We have consolidated all of our technology organizations into one corporate technology organization and the alignment around capabilities. So, the common capabilities required in the Permian, believe it or not, some of those technical capabilities are also relevant to what we're doing in our refineries and in downstream. The same people are working on those things because they're now working based on capabilities. It makes their jobs a hell of a lot more interesting and satisfying because they're able to move from one area of the business to another and apply their expertise in a way that brings value to different businesses. But, at the same time, it allows them to get better by learning from different experiences and the work they're doing across the portfolio.

JB: You mentioned marginal barrels earlier. How has the market changed since the shale boom with the marginal price of barrels and how that influences your low cost-of-supply strategy?

DW: If you go back in time before shale, the world was short crude. So, the view at the time, and I would say our own organization fell into that, was the market will bear whatever cost is required to bring a needed resource on. At that time, there was a lot of heavy oil coming out of Canada, so the marginal cost of supply was much, much higher. I think the potential of shale was not fully realized in terms of just how far you can drive that cost down and make that the new marginal supply. That's been a huge shift in the marketplace. If you look structurally at the resource that sits on the end of the cost-of-supply curve, that shale coming in at the lower end of the cost of supply has pushed all the other resource types out and really brought down that marginal cost of supply. As demand moves around, you're now at a structurally lower price point in the marketplace. That really influences how we think about where we need to be positioned on that cost-of-supply curve, and why we're so focused on having a resiliency to very low prices because of that role that shale has played.

JB: In terms of emissions, you're aiming to hit net zero in the Permian by 2030 and then worldwide in 2050, in terms of operated assets from scope 1 and 2 emissions. Can you elaborate on how you get there?

DW: Net zero in the Permian, we're well on our way to achieving that. So, the business has developed that plan to execute and achieve that. It basically requires replacing a lot of equipment to reduce emissions, and then electrification, and also working with power generators to get in renewable power. You've got to do the math, in terms of understanding what it's going to require, and then you've got to have a plan to execute that math. We've done both of those things. So, our organization knows exactly what it needs to do to achieve that. I feel really good about what we're doing. It's not some pie-in-the-sky concept. It's happening—steel in the ground—demonstrating that.

I think it's very important to show you can grow production and reduce emissions. Those are not mutually exclusive things. Thinking longer term, to the extent that the world continues to focus on net-zero and moving to a lower-carbon economy, developing value chains that have very low carbon emissions, if not zero, I think plays into what will be in demand in the future. So, setting ourselves up along that value chain to be positioned to develop products with no carbon footprint, I think will position us for what could lie ahead in the future. OGI

E&Ps Keeping Production Flat, Hedging Amid Gas Price Slump

Executives from E&Ps such as GeoSouthern Energy and New ASEAN Energy said they are adjusting drilling and hedging strategies in the Haynesville Shale after a rapid collapse in U.S. natural gas prices.

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Operators in the gassy Haynesville Shale region are slowing production and hedging their price risk after a sharp drop in commodity prices.

"We're going to try to keep our production flat, maybe go down a little less than what we've got," said Meg Molleston, president of GeoSouthern Energy GP LLC during a March 28 session at a DUG Haynesville Conference panel.

GeoSouthern, which has inventory in the Haynesville and Mid-Bossier, plans to reduce drilling rig activity and is "reluctantly hedging" in the current price environment, Molleston said.

Rob Turnham, former president of Goodrich Petroleum Corp. and a board director at New ASEAN Energy, said hedging via costless collars gives operators protection against downside risk while allowing them to participate in upside potential.

Gas producers are adjusting as natural gas prices have tumbled significantly since late last year. After averaging $6.42/MMBtu during 2022, Henry Hub gas prices are expected to average around $3/MMBtu this year, according to the latest forecasts by the U.S. Energy Information Administration (EIA).

U.S. gas futures for delivery in April were trading down over 1% at roughly $2/MMBtu in late March.

Less than a year ago, U.S. natural gas prices topped over $9/MMbtu, per EIA data. But the current commodity price environment has E&Ps in gas-heavy basins, like the Haynesville in Louisiana and East Texas and the Marcellus in Appalachia, thinking differently about operating, executives said at DUG Haynesville.

Service cost inflation also a drag

Apart from plummeting prices, E&Ps are facing sky-high drilling and completion costs due to service cost inflation.

Upstream operators, both in gas and oil basins, have been willing to pay inflated service costs more in line with $80 oil and $5 gas, analysts at Tudor, Pickering, Holt & Co. wrote in a recent research note.

Molleston said GeoSouthern has seen service costs to drill and complete wells increase by between 25% and 35% in the last year.

"You might not complete wells and spend the capital on wells, so you build a [drilled but uncompleted well] inventory," Turnham said. "That allows you to hook those wells up at the appropriate time."

Market moves vs. Permian associated gas

Analysts and executives are generally bearish on U.S. natural gas prices in the near-term.

Bernadette Johnson, general manager of power and renewables at energy analytics firm Enverus, said at the conference that the firm sees gas prices staying low until about 2026, when demand from new liquefied natural gas export projects on the U.S. Gulf Coast start to come online.

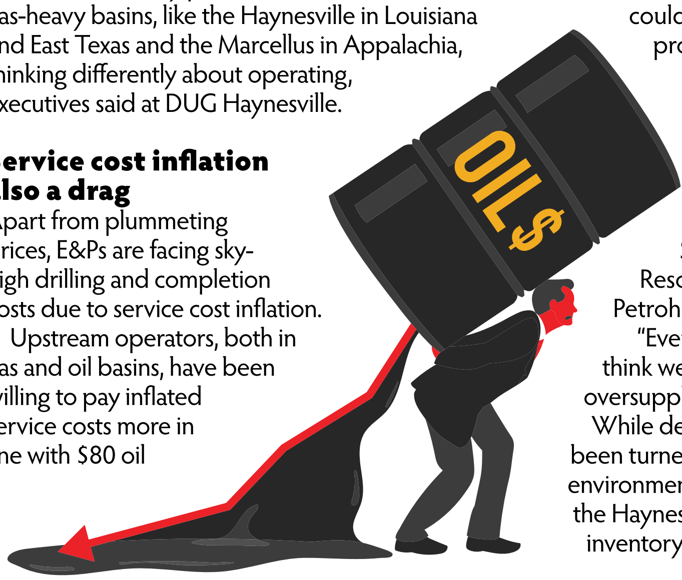
"At the macro picture, we certainly see a lot of the incremental gas production growth will come from the Permian associated gas, but also the Haynesville and the Eagle Ford," Johnson said. "It's really a collective story of the whole region in what feeds LNG."

However, hiccups in the development process for those Gulf Coast LNG export terminals could cause future issues for upstream gas producers, Molleston said.

For some amount of time—whether it's six months, nine months or even 18 months—E&Ps will face depressed gas prices until the global supply-demand dynamics are sorted out, said Dick Stoneburner, chairman at Tamboran Resources and formerly COO for Petrohawk Energy Corp.

"Even with [Freeport LNG] back online, I think we're maybe balanced or still a little bit oversupplied," Stoneburner said.

While dealmaking in gassy basins has effectively been turned off this year due to the low price environment, there's still room for consolidation in the Haynesville as operators search for attractive inventory, Johnson said. OGI



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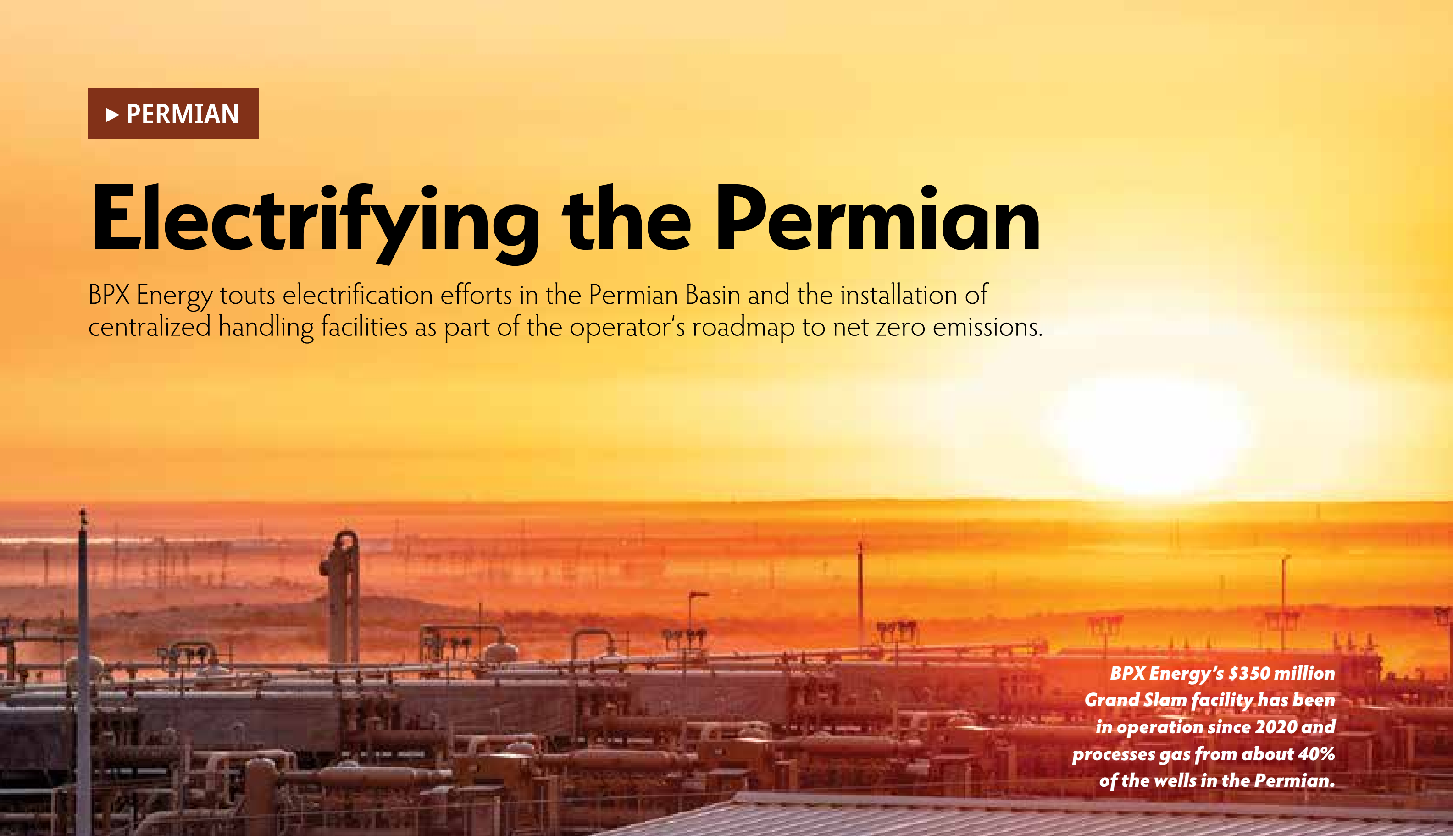
Electrifying the Permian

BPX Energy touts electrification efforts in the Permian Basin and the installation of centralized handling facilities as part of the operator's roadmap to net zero emissions.



BPX Energy's $350 million Grand Slam facility has been in operation since 2020 and processes gas from about 40% of the wells in the Permian.

Marc Morrison/BPX Energy

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BPX Energy is closing in on its goal of zero routine flaring from its onshore operations as it increasingly relies on electrification and eliminates engines, flaring and other equipment prone to leaks.

BPX, which is BP's upstream oil and gas operator in the Lower 48, initially targeted zero routine flaring by 2025 from onshore operations and pieced together several strategies to do so.

One piece of that puzzle is the company's Grand Slam facility in Texas.

Grand Slam is an electrified central oil, gas and water handling facility that reduces operational emissions, in part by replacing gas-driven equipment, compressors and generators at individual well sites.

The company said it has made strides since 2018, when BP purchased BHP's shale assets in the Permian for $10.5 billion. The supermajor committed to reducing emissions from acquired assets while also increasing production.

Since then, BP's flaring intensity has decreased dramatically. As recently as fourth-quarter 2019, flaring in the Permian Basin was around 16%. Today, it's less than 1% and dropping, Dave Lawler, CEO of BPX and BP America president and CEO, said during a conference call with journalists.

"The overall trend is significantly down," he said, with BP's current average for Permian operations below 1% and sometimes as low as 0.1%.

In BP's fourth-quarter 2022 results, the operator said Permian methane flaring intensity averaged "<0.5%" in 2022, the lowest recorded in BPX Energy's history.

"We're very close to announcing that we'll have zero routine flaring ourselves. There's very little flaring, if any, in our business at all," Lawler said.

He attributes a lot of the progress at emissions reduction to electrification.

Cleaning up the Permian

When BPX took over the Permian assets, the acreage was largely single-well locations with typical flares, tanks, gas-driven compressors and no electricity.

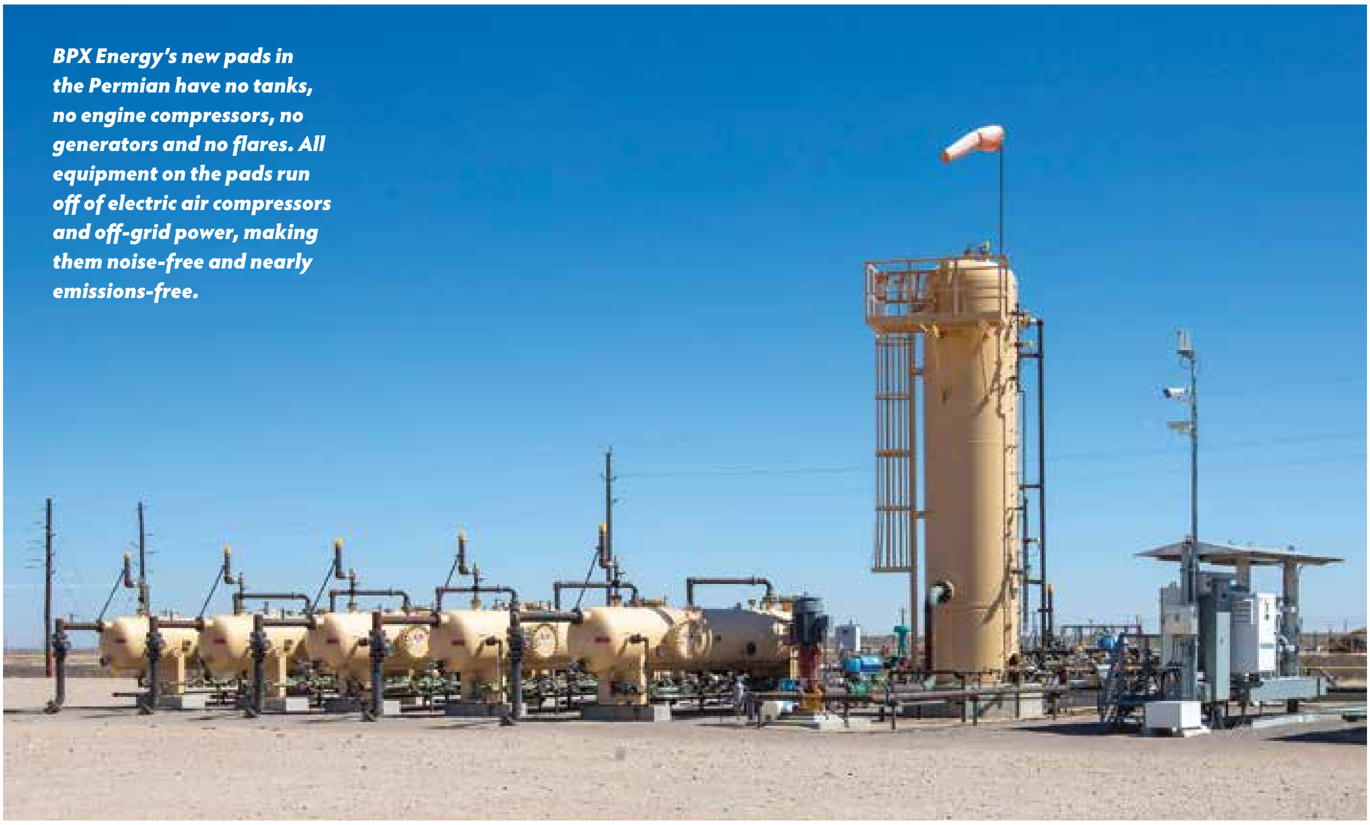
There was "a lot of equipment that can be problematic in trying to manage it for methane emission and flaring," he said. There were "a lot of emissions" from the engines, tanks, flares and equipment.

BPX spent around $800 million to update and electrify the pad sites. The new pads have no tanks, no engine compressors, no generators and no flares. All equipment on the pads run off of electric air compressors and off-grid power, making them noise-free and nearly emissions-free, he said.

"We're on our way to about $1.4 billion in total infrastructure, but it will be an electrified infrastructure," Lawler said.

BPX has installed a 400-megawatt substation to power the field.

"Because we have this very advanced electrical distribution system that we own in our field, we can take massive loads off the high wires and then transport that electricity for, in some cases 10, 20 miles," he said. "This



BPX Energy's new pads in the Permian have no tanks, no engine compressors, no generators and no flares. All equipment on the pads run off of electric air compressors and off-grid power, making them noise-free and nearly emissions-free.

Marc Morrison/BPX Energy

"We're very close to announcing that we'll have zero routine flaring ourselves. There's very little flaring, if any, in our business at all."

—Dave Lawler, *BPX and BP America*

is a proprietary advantage that we have because of the massive loads that we can take onto our own system."

BPX is able to take advantage of the power infrastructure to supply power to the drilling rigs on site.

"The overhead power allows us to stimulate or frac the wells with electric frac spreads," he said. "We pump the wells with electric submersible pumps. We compress the gas with electric driven compressors, and we operate the controls of the system with compressed natural gas from an electric source as well."

Often, Lawler said, when companies say they are e-fracking, they are using LNG to power the generation for the electricity.

BPX is using a specialized technology to redirect power into frac trucks.

"Because we've built this massive electrical infrastructure, we're using that technology direct from the power lines straight to the pumps," he said.

BPX is running three electric drilling rigs in the Permian in 2023, and one or two that are not electrified.

"As the development gets further along, that will enable the complete use of electric driven equipment," he said.

By the end of 2023, 95% of BPX wells in the Permian Basin will be electrified, he said. At the time of purchase, only 4% of the wells were electrified.

BPX is also using a hub for certain processes through an electrified central oil, gas and water handling facility, which reduces the infrastructure needs at each pad.

'Field of the future'

The operator's $350 million Grand Slam facility has been in operation since 2020 and processes gas from about 40% of the wells in the Permian.

Grand Slam's capacity is 35,000 barrels per day and 130 million cubic feet per day, and it can be expanded as needed.

"You don't see massive flare stacks, you don't really see anything. It's largely an emissions-free" facility, he said, suggesting that it is "the field of the future."

BPX plans to build three more such facilities in the Permian over the next decade. The second centralized delivery system, Bingo, is expected to go online in June or July and handle volumes similar to those at Grand Slam.

Bingo will only feature "small tweaks" to the Grand Slam design, Lawler said. Those tweaks will mostly come in the form of fine-tuning vessel sizing and equipment efficiency.

In addition to its efforts at minimizing emissions, BPX is also deploying methane detection technologies. The operator uses sensors, devices and alarms across the system to detect "something going wrong with the well in advance," Lawler said.

BPX's efforts in the Permian are part of BP's overall goal to reduce carbon emissions. The supermajor had initially targeted a 40% reduction in emissions by 2030, but in March said it was pulling that target back to a 10% to 15% reduction by 2025 and 20% to 30% by 2030. The operator still expects to reach net zero emissions by 2050. OGI

Sabine's Looking For Acres: 'If You Have Any Ideas,' Get In Touch, CEO Says

The pureplay operator Sabine Oil & Gas is in the market to buy—preferably to add to its East Texas portfolio—but is also open to gassy assets in the Eagle Ford, Oklahoman Woodford and Utica.

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SHREVEPORT, La.—East Texas Haynesville and Cotton Valley gas pureplay Sabine Oil & Gas Corp. is expanding its hunt for more leasehold beyond East Texas, looking at the Eagle Ford, Oklahoma's Woodford and the Utica.

"Of course, our No. 1 play we like the most is East Texas and that's where we prefer to grow," Doug Krenek, Sabine president and CEO, told Hart Energy's DUG Haynesville 2023 attendees in Shreveport.

The company's budget is between $100 million and $150 million, he added. "Y'all may say, 'Well, that's not a lot of money.' But again, we're trying to grow organically. We don't want to buy a bunch of PDP [proved developed producing].

"So if you have any ideas that fit our bill, [contact us]."

Might Sabine try adding that to its portfolio? "You saw the number [we have], though: $100 [million] to $150 million," Krenek laughed. Rockcliff is estimated to be worth $4.6 billion and is producing 1.2 billion cubic feet per day. Between what it's worth and what Sabine has to spend, he laughed, "That bid/ask spread is too big, probably."

East Texas pureplay Rockcliff Energy might be for sale, after a rumored deal with TG Natural Resources didn't manifest earlier this year amid collapsing natural gas prices.

Oil or gas?

In the Eagle Ford, which phase window?

The oil window is likely shut to Sabine, a subsidiary of Osaka Gas USA.

"Osaka is committed to ESG, so we really don't want to enter oil plays, just because of the carbon intensity associated with them," Krenek said. "We're mainly looking for a gas window and maybe with some liquids, but not a big portion."

Chesapeake Energy Corp. has its rich-gas Austin Chalk play for sale in the Eagle Ford in the southern Dimmit and northern Webb counties, Texas.

"That would be something we'd probably look at. Again, remember the number I'm working with," he laughed. "Maybe I could … buy a piece of it; I don't know. Or we could do a JV [joint venture] for part of it; I don't know."

The gassy window of the Eagle Ford and the gas-weighted window of the Woodford are interesting to Sabine because Texas and Oklahoma have a friendly regulatory environment, he added.

As for the Utica, "we just think it has a lot of untapped potential, [although] it may have tougher regulatory and takeaway issues."

In East Texas, Sabine is producing 450 million cubic feet equivalent per day (MMcfe/d), 93% gas, from 1,016 wells on 237,382 net acres (306,323 gross) of leasehold. The well count is 31% horizontal; the balance is legacy vertical wells that the company has been divesting. Plans are to put another package on the market later this year.

Year-end 2022 reserves were 1 billion cubic feet equivalent (Bcfe) PDP; 2.8 trillion cubic feet equivalent (Tcfe) proved; and 6.6 Tcfe 3P.

In the past three years, the $950 million it's invested in its property has been with only $30 million in outside capital infusion.

Sabine currently has two rigs drilling its 46,000 net Haynesville acres along the Texas-Louisiana border. In Texas, that includes in Harrison and Panola counties, and one making hole in its 60,000 net Cotton Valley acres west of that in Rusk, Gregg, Upshur and Smith counties.

At the current rig count, it has 10-plus years of inventory—157 Haynesville wells; 165 Cotton Valley.

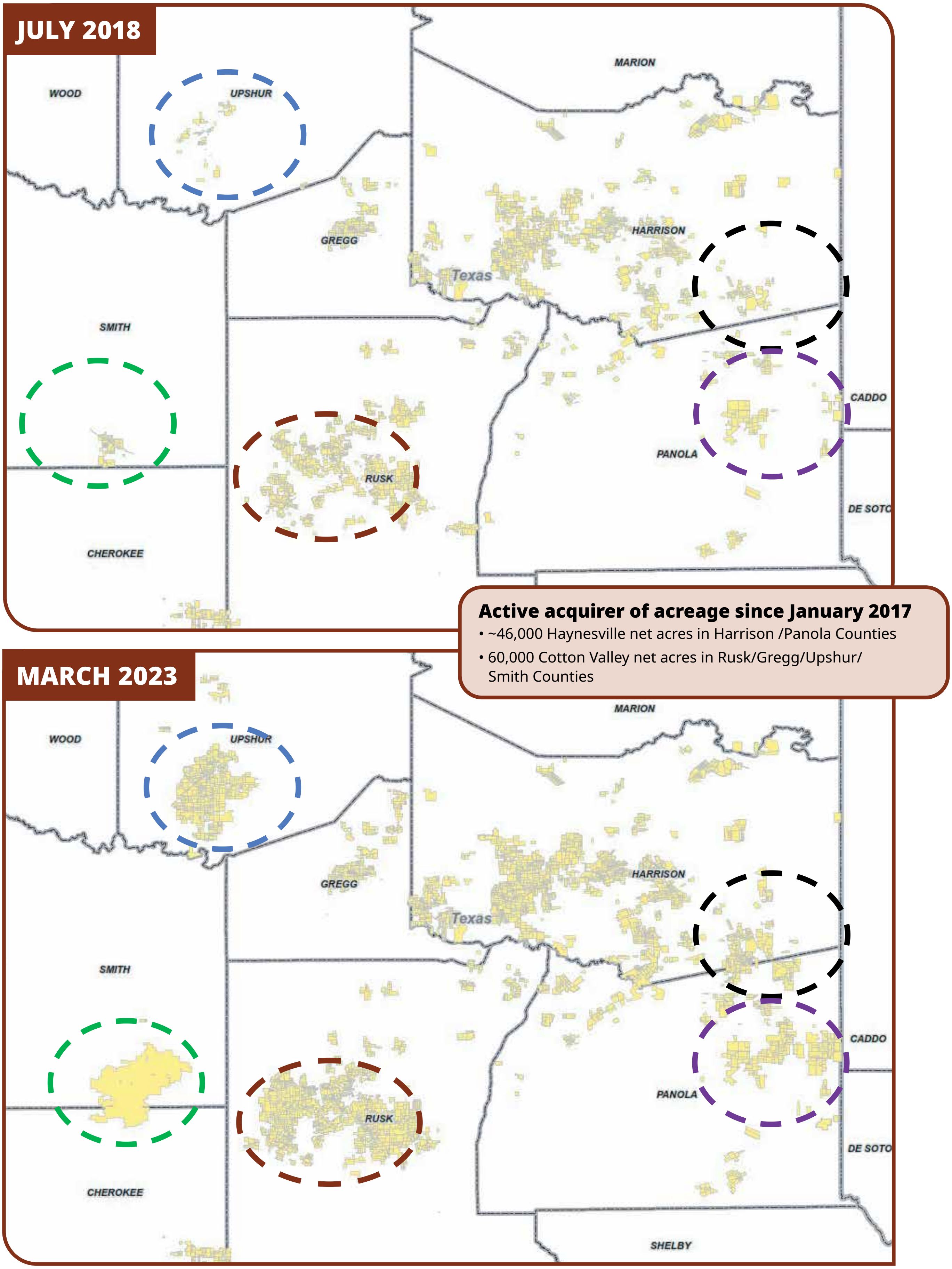
Execution in the Haynesville has improved, but the Cotton Valley is "a tough one to crack when it comes to drilling the lateral," Krenek said. "We're going to be working on that one real hard now too."

For acquisitions, "we budget money every year. We like to grow organically through the drillbit," he said. "There are PDP players out there. We're not one of them. So when it comes to deals, we like to get acreage we can drill.

"If it's got low-impact, marginal wells on it, we really don't want those in our portfolio. So we'll take them, but we'll flip them out after we get them." OGI

Sabine historical acreage expansion

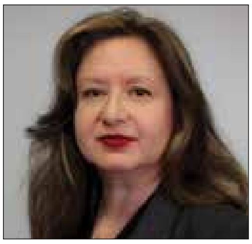
While actively buying and selling in East Texas, Sabine Oil & Gas Corp.'s goal is to continuously shed old wells, particularly old-tech vertical Cotton Valley wells.



Source: Doug Krenek, Sabine Oil and Gas

Brazos Midstream Bets on the Permian's Prowess

Brazos leadership reckons there will come a time that entering the public sphere makes sense, but for now, the partnership's strategy reaps the rewards of private perspective.



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FORT WORTH, Texas—Brazos Midstream has grown its scope and scale exponentially in less than a decade. Founded as an opportunistic startup in 2015, the firm landed the "the perfect midstream starter kit," with the acquisition of Jetta Operating's natural gas gathering system, as Stephen Luskey, chief commercial officer, describes it.

Brazos later closed on two acquisitions from Permian Basin juggernaut Diamondback Energy that added the Pecos and Mustang Springs gas gathering systems to its infrastructure base, making Brazos one of the largest privately held midstream companies in the region.

The firm's four founding partners—Luskey; Brad Iles, CEO; William Butler, CFO; and Ryan Jaggi, COO—had all worked together in one form or another previously in the Permian before deciding to join forces. But eight years ago, they wanted to create a new story via their combined entrepreneurial leanings. And their faith in the Permian remains boundless today.

The team shared their story and plans for Brazos' coming chapters with Hart Energy's Deon Daugherty, Oil and Gas Investor's editor-in-chief, this spring during a traffic jam in North Texas—which ironically accentuated another sort of infrastructure limitation in the Lone Star State.

Deon Daugherty: You've grown significantly in a relatively short period of time during a volatile cycle. Was high growth in the Permian part of your initial plan?

Brad Iles: In Brazos' early days in 2015, we really didn't have the luxury of being too picky. We knew we loved the Permian Basin, and that's ultimately where we wanted to be. But initially we looked at a number of deals across the country.

The Permian was a place we kept coming back to because it's where our past successes and relationships were, so we were obviously optimistic and hopeful that we would find an opportunity in this region.

The Delaware had been somewhat productive in the past through vertical development, but the horizontal technology had not necessarily been applied to yet. And so we uncovered an opportunity in the Delaware Basin in the early stages that wasn't without risk by any means, but we felt like it fit the criteria that we were looking for, and it was in familiar territory with all of us having worked in the Permian before. It was easy to get excited about it.

William Butler: We took a fair bit of risk early on. We got acreage dedicated to us, but there wasn't a lot of existing production associated with that. We really were stepping out and sharing in the volumetric risk with the producers on the acreage dedication contracts.

There's no guarantees for the volumes that the midstream provider is going to get. And so it was certainly a venture capital type of risk profile initially, and we were able to start with a good acquisition of a crude gathering system from Jetta Operating, who was our upstream partner initially, and then were able to grow our gas business from there, starting with a 20,000-acre dedication that helped underwrite a 60 million cubic feet/day plant.

We've continued to earn additional business through hard work and effort and delivering on our promises to producers. That's something that I think differentiated us and help us grow to the size of the company we are today in the Delaware.

Brazos completed its Comanche III processing plant in early 2019.

Andrew R. Slaton

28	540K	460M	104	800	75K
customers in the Delaware Basin	dedicated acres	cubic feet/day processing capacity	employees	miles of intrastate natural gas, NGL and crude oil gathering pipelines	barrels of crude oil storage

Source: Brazos Midstream

"The world is our oyster in the sense that we can go look at other assets in other basins, but it's terribly difficult to compete with the Permian Basin."

—William Butler, *CFO, Brazos Midstream*

The world is our oyster in the sense that we can go look at other assets in other basins, but it's terribly difficult to compete with the Permian Basin. That's why we keep coming back to it; there's no better place in our minds to operate and be a gas gatherer and processor. Going forward, we think the gas growth of the Permian Basin is really going to be the story even more so than oil growth in the future.

That was the other philosophy starting with Brazos is that we were in the oil window in the Texas Delaware by design. We wanted our underlying volumes and economics tied to the oil wellhead economics of the producers, and we were simply getting the associated gas as a byproduct versus if you go out to other areas, it's really natural gas prices that drives the wellhead economics of the producers.

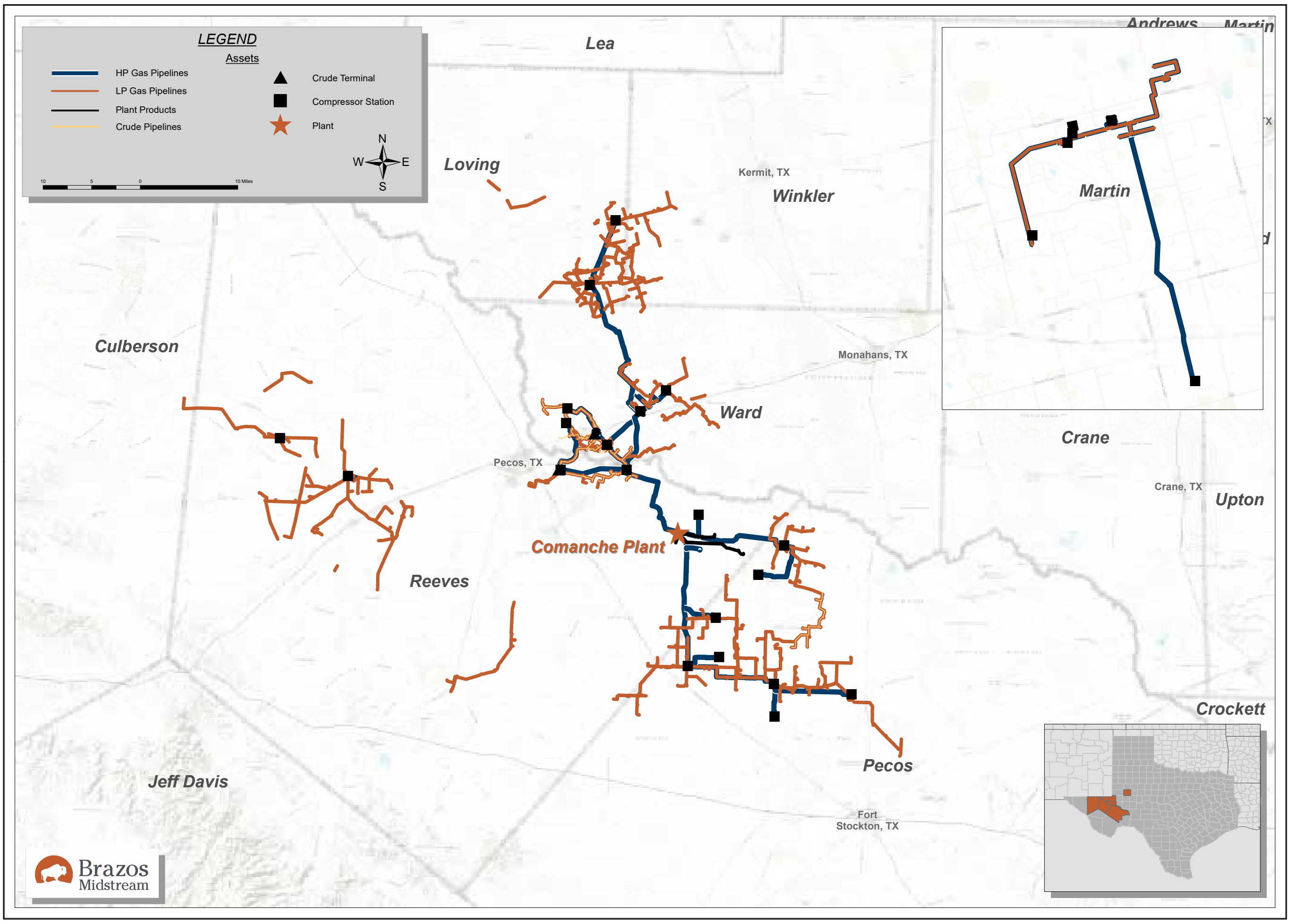
DD: How did you manage the production changes during COVID?

WB: Rigs may have fallen away for a few quarters, but producers continued their completion activity. We really never saw a massive dip in our volume. We've had good steady volume growth on that asset business for the last three years, in particular. We're growing at two-to-three times the rate of the basin.

DD: How is such growth sustainable, especially in a capital intensive sector?

WB: With over half a million acres dedicated, our contracted producers have got decades of drilling inventory remaining. We were able recently to refinance our term loan, which was put in place originally back in 2018 when Morgan Stanley Infrastructure purchased the business from Old Ironsides. That had a few years of maturity left on it, but we found a window in the capital markets back in February and we'd recently got upgrades from the ratings agencies based on our

Brazos Midstream's Permian Footprint



Source: Brazos Midstream

Brazos Midstream is looking to expand beyond the Delaware Basin and into the Permian's Midland Basin this year.

> ***"We're in the business of ensuring our customers move their gas all the time. Our philosophy is really not to ever lose sight of that even when times get difficult."***
>
> —**Brad Iles,** ***CEO at Brazos Midstream***

strong financial performance. So we took that opportunity when the markets were conducive to refinance that term loan for another seven years.

That's an $800 million term loan; it was $900 million originally, but we are reducing the size of it somewhat because we have free cash flow to pay down debt today. And then we also have a $150 million undrawn revolving credit facility on top of that. The business is generating free cash flow, and we will continue to do that going forward. So we view the Brazos Delaware business as being in a very enviable position and on very solid financial footing.

BI: As I reflect over our success and how we got to where we are … a large percentage of our team has worked in the upstream business prior to Brazos, and I think that producer mindset is deeply ingrained in us as a company.

In today's world, a lot of the midstream companies really enjoy the processing business, but unfortunately they don't necessarily like the difficult work of getting connected back to individual wellheads and providing field compression services as well. We want to do the hard work.

We don't hesitate to build system expansions or set standby compression. We're in the business of ensuring our customers move their gas all the time. Our philosophy is really not to ever lose sight of that even when times get difficult.

And, we see an opportunity to apply that same mindset in the Midland Basin. So we are building a 200 MMcf/d processing plant that will be operational in 2024. We see a need over there that is similar to what we have been successful doing in the Delaware.

DD: It seems that Brazos saw the opportunity to grow Permian capacity before the general panic regarding the

disparity between gas volumes from associated gas and infrastructure availability.

BI: One of the unique things about these basins is the gas production seems to increase over the life of a well relative to oil volumes. So particularly in the Midland, things are pretty short from a capacity standpoint. There's a ton of infrastructure planned that is currently being built and executed. But we don't necessarily see that as a short-term problem; this is really a long-term problem that requires a lot more infrastructure.

Midstream operators in the Delaware have done a pretty good job to date of building out in front of capacity needs, but we anticipate that will become a problem in the Delaware in the next few years. It's a more acute problem at the moment in the Midland Basin. And given the level of activity anticipated, we see it continuing to be a problem well into the future.

In the midstream space, there has been a tendency to be slow to expand, only once the volumes materialize. And in our view, that's too late for a midstream company. Our job is to stay ahead of our producer customers, and that requires taking a level of risk that not all midstream companies are comfortable with.

DD: What are the challenges—and the opportunities—of being a private midstream company? And would you consider going public?

WB: We are tremendously fortunate to have Morgan Stanley Infrastructure and Chris Ortega, who joined their team in the last few years, as our sponsor. We had a monetization event back in 2018 when they came in to own the business. We would liken that to our IPO—our opportunity to get a mark-to-market on the business and roll with it as well doing with private money.

Through the commodity downswing and COVID, they had our back the whole way. Now the business is generating substantial free cash flow, so quite frankly, we don't really need to go public. Certainly that business is now of a scale where it can go public, but we think we can also convert the Delaware platform to distribution mode.

Morgan Stanley Infrastructure is an infrastructure fund—by definition, it's a long-term holder and it is patient capital. There is no clock ticking in anyone's mind, so we can afford to be patient for the right market opportunity.

BI: With regard to the Delaware in particular, there will certainly come a time where it needs to be in the public markets—whether that's Brazos taking it public or whether that's us selling some day to a strategic buyer.

The public markets have the tendency to grade your performance on a quarterly basis. There's unintended consequences of that.

For example, there have been cases where we built larger diameter pipe because we believe the long-term view of a certain acreage position or a certain area is going to be greater than what we have line of sight to today. And had we not been private, it probably would have been challenging to do that—although that was the right economic decision for the long run. Someday this business will make sense in the public hands, but it's been to our strategic advantage to remain private.

Analysts, Insiders Question Viability of Tellurian's Driftwood LNG project

Tellusian Inc. wants to double its authorized shares amid search for equity funding; meanwhile, Charif Souki, executive chairman, unloads 25 million shares.

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Will Tellurian Inc. find the necessary financing to move the Driftwood LNG LLC project forward? That's the $14 billion question.

Houston-based Tellurian, which is developing the project in Lake Charles, La., is now eyeing shareholder approval to double its authorized share count as well as a potential equity injection of up to $2 billion.

The company is also working on an agreement to divest 800 acres to be used for the Driftwood terminal for $1 billion that would be leased back to the company.

Tellurian's board is seeking "approval and adoption by the stockholders" to boost the number of authorized common shares from 800 million to 1.6 billion for certain immaterial revisions, the company said in its 2023 proxy statement filed in April with the U.S. Securities and Exchange Commission.

Tellurian had 563 million shares outstanding and 105 million shares subject to reserves other than for the company's equity at-the-market offering program as of April 7, according to the document.

The annual stockholders meeting is slated for June 7, and the board is cognizant of the potential negative impacts from its request to boost Tellurian's share count.

"For example, in the absence of a proportionate increase in the company's earnings and book value, an increase in the aggregate number of outstanding shares caused by the issuance of additional shares would dilute the earnings per share and book value per share of all of the existing outstanding shares of Tellurian common stock," the proxy said.

The share issues details come after Wilmington Trust National Association on Feb. 7 exercised its right as administrative agent pursuant to a loan agreement to become a substituted shareholder in the company, which caused 25 million pledged shares held by Tellurian Executive Chairman Charif Souki to be transferred into its account.

Tellurian envisions development of the Driftwood LNG project in two phases. Phase I could provide 11 million tonnes per annum (mtpa) by early 2026, while Phase II could provide another 16.6 mtpa, according to the company's website.


Charif Souki

Construction has started, but the lingering issue is getting the funding squared down.

Seeking $2 billion in equity

Driftwood LNG is considered an important U.S. export development that could help to boost LNG exports to global markets short of gas, owing to reduced flows from Russia following sanctions imposed on Moscow for invading Ukraine in February 2022.

Souki, who was responsible for Sabine Pass and Corpus Christi LNG projects, says the estimated cost for Driftwood LNG Phase I would be around $14 billion.

In a global environment of $14 MMcf to $15MMcf gas prices today and a price of around $2 in the U.S., the margin is sufficient to finance a project, Souki said during an April video interview in New York with Bloomberg News.

"We're down to looking for the last $1.5 billion-$2 billion, that will happen sometime pretty soon," Souki said, adding that the funding would come from equity partners.

In recent months, Souki has cited partners and funding as key headwinds.

Divestment and leaseback

Tellurian recently entered into a binding letter of intent (LOI) with an unnamed New York-based institutional investor for the sale and leaseback of approximately 800 acres of land owned and/or leased by Driftwood. The acres were to be used for the proposed LNG terminal, Tellurian said on April 4 in a Form 8-K release.

The deal would include the divestiture of the acres by Driftwood for $1 billion upon closing of a 40-year lease. The lease

Tellurian has until July 14 to identify offtake partners for its Driftwood LNG terminal.

Source: Driftwood LNG

would have a capitalization rate of 8.75%, an annual rent escalator of 3% and would require Driftwood to post a letter of credit equal to one year of rent.

"We've created some real value [at the site]. [Tellurian co-founder] Martin [Houston] and I bought this site six years ago for about $30 million and today it is worth a lot more than that," Souki said in a Tellurian video posted on the company's website in April.

Nevertheless, the LOI terminates on July 14 if Driftwood LNG fails to identify offtake partners for the project. Currently, Tellurian has sold 3 mpta in offtake—roughly 27% of the Phase I supply—to Gunvor and there is no equity partner, according to Stifel research.

"As a result, this does not alter our view that the project has virtually no chance of moving forward," said analyst Benjamin Nolan in a note to investors. OGI

▸ EXECUTIVE Q&A

Permian Paradox: Patterson-UTI CEO Says Fewer Rigs Demand More Workers

CEO Andy Hendricks says stabilizing commodity prices brighten long-term U.S. industry outlook.

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Oilfield services firm Patterson-UTI has emerged from the pandemic with its business growing, its balance sheet thriving and its innovation driving the industry. Its six-month average operating rig count of 131 matches pre-COVID activity, and its share price has bounced more than 20% during the same period, remaining table during the first quarter at 2019 values.

In an exclusive interview with Oil and Gas Investor editor-in-chief Deon Daugherty, Patterson's president and CEO Andy Hendricks discussed the company's strategy in the Permian Basin and throughout the nation, where Patterson is deploying state-of-the-art rigs capable of producing greater volumes faster and more efficiently.

Deon Daugherty: What are the biggest opportunities that you see in the Permian Basin?

Andy Hendricks: The biggest opportunity is around people and the workers. The industry has been ramping up so fast over the last couple of years that we've all had a fair amount of turnover. Even though we're still going to grow in the Permian, going forward, it's going to be more moderated. And I think that'll give us a chance to get some stability in the workforce.

DD: And now, what are the biggest challenges you face in the near term?

AH: We have to plan for both the near-term and the long-term. Overall volatility in commodity prices and the recent decline in natural gas prices has created uncertainty for our E&P customers in the near-term, depending on the basins where they operate. And while the overall rig count is down since the beginning of the year, the Patterson-UTI rig count has been nearly steady as we only operate AC high-spec rigs. In fact, we are at a higher level of activity than in January 2020. The decline in the overall rig count this year is due to releases of older mechanical and SCR rigs. Those declines don't affect us, as we are well positioned in multiple basins with higher technology and have strong partnerships with customers as well a diverse customer mix.

However, this near-term environment of operator concern creates some challenges for us to plan our forward activity, which is important for us to be able to update our resource plan and ensure we have the training for crews in progress to either sustain or grow activity levels. Planning forward activity is also crucial for our capital budget for the remainder of the year and to get ahead of long-lead items such as drill pipe and structural steel.

The longer term outlook is more positive, and it is still early in the year. If oil prices recover to a reasonable level, even with the gas market soft, based on discussions we are having we could see an increase in the industry AC high-spec rig count and an increase in the frac spread count before the end of the year, which means our activity could still increase. We always adjust as needed, but we have to be ready as well.

DD: One of the industry's key refrains is that it's a 'cyclical' industry in which people get hired, make a lot of money quickly, and then they get laid off because there's a downturn. How does that affect your ability to hire whenever there is an uptick – especially in the Permian?

Jay Brittain

"We do have automation doing different things in the field, but it's not replacing people. We've actually increased the headcount by a few people per rig."

—**Andy Hendricks**, ***Patterson-UTI***

AH: It's the hottest basin and so the local workforce is generally tapped out. You have to bring in people from outside of the basin. One thing that's different now – as opposed to where it's been more challenging over the last decade – is, we're inside a multi-year cycle.

With the change in the dynamics of the commodity prices, the U.S. producers are no longer in a high growth mode; they're in a moderate growth mode. The U.S. is no longer out-producing the demand for oil, and so the commodity prices are less at risk now. This situation change over the last few years has put us in a multi-year up cycle.

DD: One of Patterson's 'calling cards' is the development of high-tech, super spec rigs that may reduce the number of rigs needed to drill more wells. Walk us through that implementation in the Permian and tell us how it's impacted your workforce needs.

AH: Over the last four or five years, we've almost doubled the amount of wells that we drill, per-rig in the Permian, using our Tier 1 Super Spec rigs. It provides more efficiency for the program of operators that drill year-in, year-out on large acreage footprints. It allows them to bring production forward, and that's the real economics.

It does cost us more to operate one of these rigs and so it costs the E&P more to have one of these rigs drilling for them. But you get more wells per year so you bring more production in from what you normally would have done. And so it's an economic win for the E&P to have the most efficient in drilling and completion systems out there.

In terms of personnel, I think that there's a bit of a misnomer because we actually have more people working on that drilling rig now than we did five years ago because the pace and the intensity of the operation is so much faster – and we need to do it safely. It does take more people to coordinate.

We do have automation doing different things in the field, but it's not replacing people. We've actually increased the headcount by a few people per rig.

DD: How can the services sector as a whole best manage inflation?

AH: The challenge for our E&P customers is that as drilling contractors and service providers, our costs have risen significantly over the last couple of years, and we historically must pass those increases on to our customers. Although the industry has seen recent declines in commodity prices, service costs aren't a function of commodity prices.

Service costs, whether it's drilling rigs or frac spreads, are a function of equipment availability, wages that are competitive in the overall U.S. market, and the costs for goods and materials needed to activate and maintain equipment.

We have had to give two wage increases over the last two years. The first was a market adjustment as the industry activity increased, as many of our field personnel had only seen steady wages for a given position for the previous five-plus years. Then the second increase was directly related to the overall cost of living inflation in the economy.

Similarly, while service costs are increasing, E&Ps are benefitting from the shared achievements in improved efficiencies through technology and process improvements. For example, our super-spec rigs in the Permian are now drilling approximately double the footage-per-year versus four years ago. That means each drilling rig now produces twice as many wells per year on average for the E&Ps.

DD: How do you view consolidation in the basin?

AH: Consolidation within our customer base has always been a big part of our industry and that trend will continue as drilling inventory becomes depleted over time. Our strategy has always been to maintain strong partnerships and have a broad customer base. This coupled with high performing operations across our businesses allows us to be well positioned before and after potential mergers.

DD: How has the tight labor market affected your operations?

AH: We have not missed any work and have been able to staff our operations at safe levels, but it has not been without challenges to achieve this. The labor market in the U.S. has been very tight since the world emerged from the pandemic and businesses resumed and increased activity. With the growing demand for oil and gas, we have had to broaden our geographical searches in this tight labor environment and have had to incur additional costs in order to find, recruit, train and onboard the new employees in order to support our high level of operational excellence.

As a result, we have essentially doubled our activity level over the last two years. We are committed to supporting the growth, development and career advancement of our employees and excited to have them with our company.

DD: How do you see your role in the energy transition?

AH: We have a leadership position in low-emissions solutions for drilling and completion operations, and we are focused on continuing to implement and enhance these technologies. For example, our EcoCell lithium battery solution replaces a diesel generator at the wellsite, and when combined with our GenAssist power management automation software, these technologies can reduce overall fuel usage and emissions at the wellsite by up to 30%.

In doing so, we are helping E&P companies to move towards their goals of reducing emissions. OGI

▸ **PERMIAN** HISTORY

Santa Rita: The Historic Permian Well That Almost Wasn't Turns 100

The Permian Basin's first gusher hits the century mark on May 28.

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In the early hours of May 28, 1923, an oil well that almost wasn't roared to life in the sparse West Texas landscape, spraying crude over the top of the derrick and covering a spread of 250 yards with the black, sticky stuff.

It was the Santa Rita #1 and its namesake—the patron saint of impossible things—had finally delivered to World War I U.S. Army veteran Frank T. Pickrell.

Oilmen of various expertise had been poking around in the Permian Basin since 1920 with nominal success. The W.H. Abrams No. 1 well, a small endeavor in Mitchell County, marks the beginning of the basin's inauspicious beginnings.

But it was the Santa Rita—a producer until 1990 when it was plugged after 67 years—that put the Permian on the map and set the stage for it to become the most prolific play in the nation and among the top oil-producing basins in the world.

Located in Section 2, Block 2, on University of Texas land in Reagan County, the Santa Rita proved that oil was indeed underground. It took four years to come online after its initial promotion in January 1919 by Reagan County lawyer and World War I veteran Rupert Ricker.

He and four associates applied for leases on 431,360 acres of UT land in Reagan, Upton, Irion and Crockett counties, and ponied up the $43,136 filing fee, according to the Texas State Historical Association (TSHA). The men had 30 days to promote the deal and sell enough leases to cover the fee.

But as the deadline closed in, Ricker had no takers. Pickrell, an Army buddy from El Paso, Texas, offered $2,500 for Ricker's plans, maps and the preliminary holdings.

Promoting the acreage proved just as impossible for Pickrell as it had for Ricker. Pickrell and his partner, Haymon Krupp, opted to develop the acreage on their own. They incorporated as Texon Oil and Land Company and sold certificates of interest in a 16-section block at $200 each for a .0004882 interest.

The firm raised more than $100,000 and used much of the cash to rent and buy used drilling equipment. Their first test well was the Santa Rita, spudded on Jan. 8, 1921, by experienced driller Carl Cromwell, who was paid $15/day and in company stock.

Bob McSpadden

In 1940, the Texas State Historical Association relocated the Santa Rita's original drilling equipment to the University of Texas campus in Austin.

For 646 days, Cromwell ran a two-man crew and bailed the hole, averaging 4.7 feet/day, according to TSHA.

It wasn't easy work nor was it peaceful living. The Santa Rita was next to the tracks on The Orient railroad, a track of more than 730 miles that moved freight and passengers from Kansas to Texas.

"The crews working on remote projects like the Santa Rita typically brought their families with them," Bob McSpadden, a retired engineering technician from Shell Oil Co., said. "They usually 'camped' in tents nearby."

McSpadden worked as a control electrician in McCamey, Texas, about 35 miles west of the Santa Rita, during the 1970s. He was friendly with Dee and Nora Locklin; Dee was on Santa Rita's drilling crew.

After Dee Locklin had passed, McSpadden said he asked Nora if she was the last living person who was around when the Santa Rita well came in.

"Her reply was classic: 'I'm the last one with any sense,' and she left it there," he said.

On May 27, the crew drilled into the dolomitic sands, right around 2,050 feet down into the "Big Lime." Hours into the following day, the Santa Rita convinced area residents as well as scouts from major oil companies of the region's riches.

The Santa Rita was spud in the southern part of the Midland Basin, which now produces for Permian juggernaut Pioneer Natural Resources, pure play Diamondback Energy and supermajors Exxon Mobil and Chevron. OGI

Chesapeake Intentionally Reducing Haynesville Gas Production, Rigs

The Oklahoma City-based E&P is intentionally letting Haynesville natural gas production fall off this year as the industry faces a volatile supply-demand imbalance.

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SHREVEPORT, Louisiana—Chesapeake Energy Corp. plans to reduce natural gas production in the Haynesville Shale as the industry faces a gas supply glut and weak global demand.

The Oklahoma City-based E&P is currently operating seven drilling rigs in the gas-rich Haynesville region. By early April, that number was slated to fall to six drilling rigs, said David Eudey, Chesapeake's vice president of Haynesville operations, at the DUG Haynesville conference on March 29.

The company plans to further reduce drilling activity down to five rigs during the third quarter.

Chesapeake typically needs to run six drilling rigs and two frac crews in order to maintain flat production in the Haynesville. Eudey said production is expected to fall under the planned five-rig drilling program later this year and into 2024.

"We think the market is telling us that it doesn't need as much gas here in the near term," Eudey said. "We're going to intentionally let production fall some this year and into next year before we re-ramp and grow again into that LNG demand coming in 2025 and beyond."

Looking ahead to future demand for LNG projects in development along the Gulf Coast, Chesapeake is bullish on the Haynesville Shale's role in the global LNG sector.

"The long-term outlook for natural gas, and specifically to Haynesville that will feed a lot of this is very rosy," Eudey said.

Gassy goals

Chesapeake is prioritizing natural gas production and being LNG-ready when demand picks up from Gulf Coast liquefaction terminals.

As the company assessed its portfolio over the past few years, Chesapeake saw that its best assets were in the Haynesville and the Marcellus, Eudey said.

"We like gas a lot. We think it has a lot of tailwinds for us," Eudey said. "But the strategy is not just gas—the strategy is premier assets."

To that end, Chesapeake is offloading oily assets that no longer align with its strategy, like the company's sizable position in the Eagle Ford Shale in South Texas.

"We like gas a lot. We think it has a lot of tailwinds for us, but the strategy is not just gas—the strategy is premier assets."

—**David Eudey, *Chesapeake Energy Corp.***

During the first quarter, Chesapeake has lined up two divestitures totaling nearly $3 billion to sell a considerable portion of its Eagle Ford acreage.

But the company still has approximately 21,000 bbl/d of oil and NGL production and 80 MMcf/d of natural gas production remaining in the Eagle Ford, including acreage in the Austin Chalk. The company is actively engaging with potential buyers interested in its remaining Eagle Ford acreage.

Price slump

While long-term outlooks for U.S. upstream gas are bullish, operators and analysts are bearish in the near-term.

Several operators in gas-rich basins, from large, publicly traded E&Ps to smaller, privately held drillers, are working to keep production flat and reduce rig activity.

After averaging $6.42/MMBtu in 2022, Henry Hub gas prices are expected to average around $3/MMBtu this year, according to the latest forecasts by the U.S. Energy Information Administration.

U.S. natural gas futures for April delivery were trading down around 2.4% at $1.98/MMBtu in the late afternoon on March 29.

The months-long outage at Freeport LNG following an explosion and fire last summer, as well as a warmer-than-expected winter season, have contributed to weak gas demand.

Chesapeake believes it will take time for prices to rise again.

"We think it will be 2025-ish time period before we start to see a nice rebound in prices," Eudey said. "Maybe at the end of '24, but we really think probably '25." OGI

▸ OFFSHORE

Chevron Dominates Long-Awaited GOM Lease Sale

High bids increased by $72 million in the first GOM sale in two years.

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Chevron Corp. dominated the first Gulf of Mexico offshore lease sale in 17 months in March, accounting for 41% of the $264 million in winning bids as it secured tracts in the Keathley and Green Canyons.

Thirty-two companies submitted 353 bids totaling $309 million on 313 tracts covering 1.6 million acres, the Bureau of Ocean Energy Management said. Other top bidders included BP, Shell, Equinor, Exxon Mobil, Beacon Offshore, Anadarko Petroleum and Hess.

The sale was required by the Inflation Reduction Act of 2022 and was termed "needlessly overdue" by Erik Milito, president of the National Ocean Industries Association.

"Companies need lease opportunities to explore and potentially develop domestic energy resources," Milito said.

Lease Sale 259 offered 13,600 blocks across 73.3 million acres on the U.S. Outer Continental Shelf.

Oil and gas majors bid on 70% of the available blocks and accounted for 77% of the total high bids. Exxon Mobil added 69 blocks to its Gulf of Mexico lease holdings, while Chevron's $108 million in high bids represented more than the other majors combined.

The sale also attracted controversy.

A lawsuit led by environmentalist group Earthjustice was filed in March "to vacate the unlawful decision to hold Lease Sale 259 and to vacate or enjoin any leases issued or actions taken pursuant to the unlawful Lease Sale 259."

The plaintiffs in the suit said the sale, which is predicted to result in production of 1.12 Bbbl and 4.4 Tcf of natural gas over the next 50 years, violates the National Environmental Protection Act and the Administrative Procedure Act. The sale could result in the emission of 381,517 tons of CO_2-e over the life of the projects.

An Earthjustice said the "excessive and reckless scope of today's oil and gas lease sale demonstrates how badly our federal leasing program needs reform." It described the sale as unlawful and said the Biden administration is "succumbing to the wants of a profit-rich industry over the well-being of Gulf communities, vital ecosystems and our urgent climate goals."

But the American Petroleum Institute (API) said that the Gulf of Mexico is best positioned to deliver energy needs while supporting goals for lower carbon emissions.

"Operations in the U.S. Gulf of Mexico adhere to the highest safety and environmental standards. The multitude of companies involved in offshore energy development are working collaboratively to shrink an already small carbon footprint," Milito said.

He added that oil produced from the Gulf has a carbon intensity one-half that of other producing regions, and the technologies used in deepwater production place the

Chevron Corp. dominated the first Gulf of Mexico offshore lease sale in 17 months in March.

Shutterstock/iurii

Top 10 Companies by Total Number of High Bids

Company	High Bids	Sum of High Bids
Chevron	75	$107,957,492
Exxon Mobil	69	$9,779,750
BP	37	$46,609,286
Shell	21	$20,147,556
Equinor	16	$18,347,168
Beacon Offshore Energy	13	$9,003,885
Anadarko US Offshore	13	$8,549,144
Red Willow	13	$3,768,834
Hess	12	$8,257,592
Woodside Energy	12	$6,255,474

Source: U.S. Bureau of Ocean Energy Management

Top 10 Highest Single Bids

Company	Block	Water Depth (feet)	High Bid
Chevron	Keathley Canyon 96	800-1,600	$15,911,947
Chevron	Green Canyon 724	1,600+	$10,891,423
Chevron	Green Canyon 160	800-1,600	$7,123,712
BP	Keathley Canyon 340	1,600+	$6,503,103
Houston Energy, Beacon Offshore, Red Willow, Westlawn	Mississippi Canyon 804	800-1,600	$5,025,777
Chevron	Green Canyon 629	1,600+	$4,551,942
Chevron	Keathley Canyon 53	800-1,600	$4,111,947
Chevron	Keathley Canton 97	800-1,600	$4,111,947
Chevron	Green Canyon 169	800-1,600	$3,811,936
Equinor Gulf of Mexico	Walker Ridge 148	1,600+	$2,099,199

Gulf of Mexico among the lowest carbon intensity oil-producing regions in the world.

The number of bids increased 38% from Lease Sale 257, the previous Gulf of Mexico lease sale. The number of deepwater blocks that received bids increased by 30%. Chevron had the highest bid of the sale and the highest bid since 2019, spending $15 million on Keathley Canyon Block 96.

Atwater Valley Block 6 and Mississippi Canyon Block 386 were the most sought-after blocks with four bids each. They were won by Shell and Murphy, respectively.

"While today's lease sale is a belated but positive step toward a more energy-secure future, it should not take an act of Congress to get us to this point. Continued production in the Gulf of Mexico is essential for delivering the energy the world needs while supporting lower carbon goals," Holly Hopkins, vice president of upstream policy at API, said. "It is well past time for the Department of the Interior to finalize a five-year program for federal offshore leasing that will empower U.S. energy producers to meet the needs of consumers here at home and around the world." OGI

▸ **SHALE TRENDS**

Haynesville to Lead Gas Production Growth in 2023

Haynesville expected to lead gas production growth in 2023 and then fall thereafter before growing again between 2025 and 2027, said Enverus General Manager Bernadette Johnson.

Enverus General Manager of Power & Renewables Bernadette Johnson spoke at Hart Energy's DUG Haynesville conference in March regarding the firm's "bearish" near-term outlook for LNG.

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SHREVEPORT, Louisiana—The Haynesville Shale is expected to lead gas production growth in 2023, Enverus General Manager of Power & Renewables Bernadette Johnson said on March 29 at Hart Energy's DUG Haynesville Conference.

Bernadette Johnson

"As you fast forward to 2024 it shrinks pretty significantly," she said of production growth. "Basically, from where we are today, we expect it [production] to stay pretty level until we get some additional demand and takeaway capacity."

Johnson said more Haynesville production growth was expected in the outer years between 2025 and 2027.

"And that's tied really closely with the price pressure we are seeing today and the market working," Johnson said, adding that Enverus also envisions some inventory challenges in the play by the end of the decade.

In 2022, gross gas withdrawals in the Haynesville region in Louisiana and Texas rose by 2 billion cubic feet per day (Bcf/d) to 15.3 Bcf/d, or around 13% of total U.S. gross gas withdrawals, the U.S. Energy Information Administration (EIA) reported on March 29.

The Haynesville offers operators a strategic location to drill for gas due to its proximity to the U.S. Gulf Coast, where demand from U.S. LNG export terminals and industrial facilities has been growing, EIA said.

Russia's invasion of Ukraine in February 2022 boosted demand in Europe for U.S. LNG imports amid a reduction in energy imports from Russia, which has faced continued sanctions from Western powers from the EU to North America.

Within the U.S. southern region, Johnson said, "Permian associated gas will grow this year, [and] we'll continue to keep an eye on infrastructure and takeaway options out the region, but we're seeing bottlenecks start to rematerialize in the late 2026 timeframe."

Bearish outlook

Permian natural gas production associated with oil drilling will overwhelm the market until 2025 or beyond as new LNG projects continue to ramp up.

Enverus expects almost 15 Bcf/d of new gas to show up by the end of 2027, with two-thirds of that demand tied to LNG demand.

Johnson said Enverus is bearish on the strip until LNG buildouts start to erode storage surplus.

"Storage is a strong indicator that we have too much gas," she told attendees to the conference. "We are bearish on the near-term until around 2026, then we are quite bullish."

"Demand is the constraint. Demand is the ceiling," Johnson said. OGI


EMBRACE
~~Avoid~~
volatility

Stephens Execs: A Tale of Two Insurance Markets

It was the best of markets; it was the worst of markets.

DAVID ZARR AND JOSEPH PRESLEY
STEPHENS INSURANCE

David Zarr is executive vice president at Stephens Insurance where he focuses on the energy industry, and Joseph Presley is an executive risk specialist. Both are based in the firm's Houston office.

Directors and officers liability (D&O) rates are softening and buyers will experience some relief in 2023. In contrast, property and casualty (P&C) rates are hardening. Why is this happening? What are the specifics? What can executives do to take full advantage of opportunities in D&O while mitigating some higher P&C prices as well as restrictive terms and conditions?

Property and casualty

Given the current challenges of the hardening energy insurance market, where insurers are limiting D&O capacity and premiums are increasing, it is more important than ever for E&P and midstream firms to get an early start and obtain as many viable options as possible for energy package, named windstorm and third-party liability insurance programs.

Decreased investment

In recent years, key insurance providers have withdrawn significant amounts of capital from the market. For example, the largest reinsurance carrier in the world stopped writing E&P business via its Lloyd's of London syndicate, the industry leader. This decrease in available capital, primarily due to ESG concerns, coupled with large increases in reinsurance rates, is causing an uptick in energy package rates (e.g., control of well and property) as well as a tightening of terms and conditions. This same Lloyd's syndicate currently leads almost all E&P firms' named windstorm insurance programs, with significant participant lines.

Accordingly, Gulf of Mexico E&P firms may experience large premium increases at their next named windstorm renewal.

Déjà vu all over again

Other energy segments have experienced hardening insurance rates over the past years. But E&P firms were mostly isolated from the large excess liability premium increases, primarily due to availability of capital from several domestic insurance programs. However, as these E&P excess liability insurers have started pulling back the amount of excess liability limit provided for any one E&P client, E&P firms are now experiencing increases similar to those of midstream firms. Some E&P firms are seeing premium increases of more than 40% at their excess liability renewals.

D&O insurance

D&O insurance will continue to have competition this year on consequential D&O policies, such as primary and low excess layers. This is driven by an influx of new and rejuvenated capacity that has entered the market since the end of 2020. Further, reduced capital market activity last year sidelined some capital.

Underwriters of D&O are aggressively pursuing opportunities to deploy dry powder capital. This should be especially true for energy firms that consistently have a low number of D&O claims brought against them. Potential headwinds remain, but dry powder and low claims are expected to lead to positive D&O pricing.

SEVERAL CHANGES ARE EXPECTED THIS YEAR:

Pricing

Rates decreased materially in 2022—particularly in the second half (10.8% in Q3, according to global credit agency AM Best)—with the entrance of some 20 insurers and a slowdown in the capital markets. Excess layers drove the competition in 2022. Look for competition to heat up on primary D&O and low excess layers for the rest of 2023.

Coverage

Competition on the primary increases will make coverage as much as a part of the renewals as clients and brokers are willing to push. To win business, underwriters may include material coverage grants such as entity investigations coverage. Of actions filed in the last decade against energy firms, 20% include regulatory action.

Capacity

Underwriters displayed a willingness to consider higher limits than their expiring layers. This will pick up steam in 2023. Look for agreeable underwriters to increase their capacity from $5 million to $10 million or from $10 million to $15 million. Consideration will also be given to $25 million layers.

Retentions

In 2022, D&O attempted to hold the line on self-insured retentions. As primary layers come under more pressure in 2023, underwriters may have increased flexibility with retention levels, particularly for clients with favorable claims history. OGI

Bearish Energy Execs Growl To Fed Over Inflation, Uncertain Outlook

The Dallas Fed's Q1 survey of oil and gas executives reveals concerns over inflation, growth and future uncertainty.

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Growth has stalled, production is sluggish, costs are up and oil and gas executives are grumpy, the Federal Reserve Bank of Dallas reported in its first-quarter energy survey.

The business activity index plunged to 2.1 in the quarter from 30.3 in fourth-quarter 2022, indicating that activity grew little in the first three months of the year. For more than two years, activity had been on the rise in double-digits, and the drop, based on responses from energy executives, is due to the cloud of uncertainty hanging over the industry. The index is the survey's broadest measure of conditions facing energy firms in Texas, northern Louisiana and southern New Mexico.

Inflation and the health of the global economy will have the most influence on profitability this year, executives at 136 oil and gas companies said in response to the Dallas Fed's survey earlier this month. Access to and the cost of capital, government regulations and supply chain issues ranked further down the list.

Comments by executives reflected uncertainty colored by dread:

- "It is extremely difficult to plan for the future with so much of the base data we are used to using being all over the board. Seems like business patterns go against trends proven over the last 30-40 years in the oil and gas industry as a whole and the oil and gas service business specifically."
- "Outside investors seem to be losing interest in hydrocarbons. The worldwide macroeconomic and political outlook is cloudy. The road ahead looks difficult but passable. We expect another 'muddle through' period in a cyclical business where more players will be winnowed out."
- "Oilfield inflation has to be the No. 1 problem. Capital expenditure increases are soaring well past consumer price index data. I'm noticing apparent quality problems beginning to plague new projects; specifically, I've never seen so many cases of parted tubing with new tubing, particularly with poor quality collars, as I'm seeing in recent months."

Price Outlook

Across the regions where the surveyed companies operate, the average WTI price needed to cover operating expenses for existing wells ranges from a low of $29/bbl in the Midland Basin to $45/bbl in U.S. non-shale areas. The average price of $37/bbl was up from $34/bbl in 2022.

The price of WTI needs to be $62/bbl, on average, to warrant drilling a new well, the executives surveyed said. That price is above the $56/bbl average of last year. Average breakeven prices across the regions in the Permian Basin and Eagle Ford and elsewhere range from $56/bbl to $66/bbl. In the Permian Basin, the $61/bbl average is $9/bbl higher than last year.

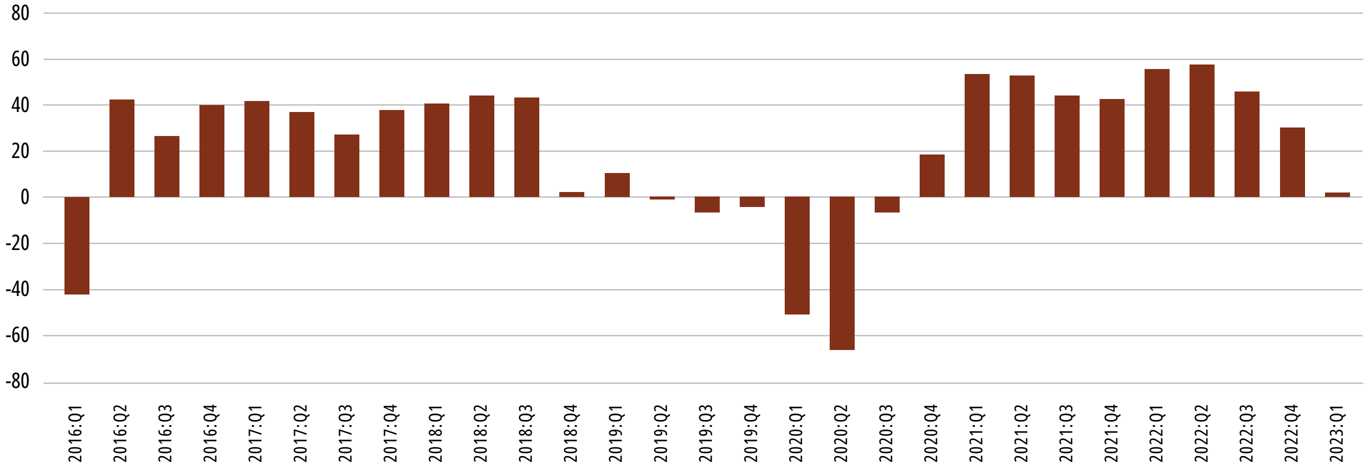
Size does matter when it comes to breakeven pricing. For large firms that produce 10,000 bbl/d or more, the average is about $55/bbl across all regions. Smaller companies require a WTI average price of $64.

Comments from executives on pricing:

- "Oil price correction is adding pressure on the continuation of drilling and frac activities. [We] expect the activity level to be flat to down in 2023 versus 2022's exit."
- "Service costs and authorization for expenditures keep climbing. The latest commodity price action feels like the sword of Damocles is back; where is oil going to bottom this time?"
- "Overall, prices have impacted the revenue but not yet costs. We are still waiting for costs to catch up with the new pricing levels. We do not expect prices to increase significantly." OGI

Dallas Fed Energy Survey's Activity Index

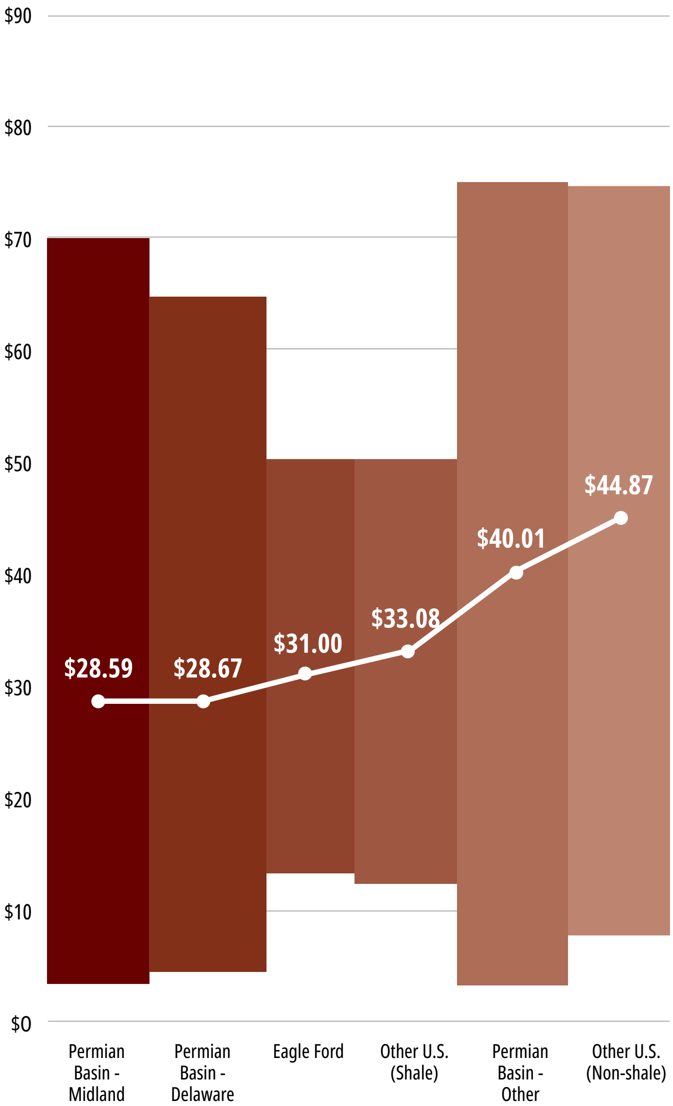
The first-quarter of 2023's 2.1 increase broke a streak of double-digit growth dating back to fourth-quarter 2020.



Source: Federal Reserve Bank of Dallas

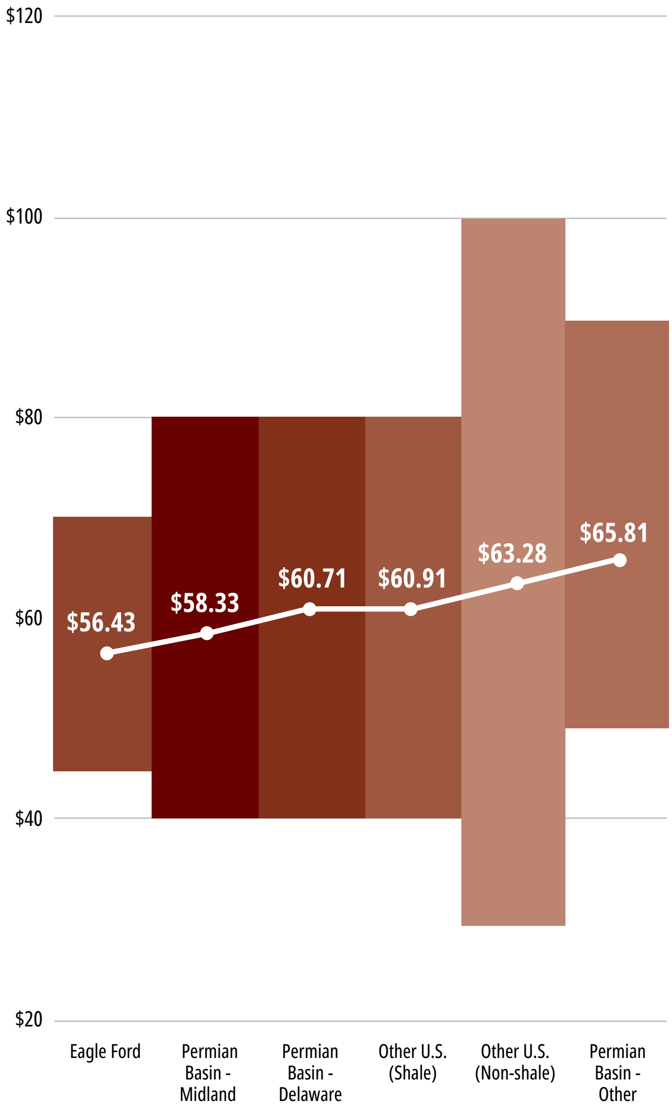
In the top two areas in which your firm is active: What WTI oil price does your firm need to cover operating expenses for existing wells?

Lines show the mean, and bars show the range of responses. The average response was $37/bbl. Executives from 83 E&Ps responded to this survey question.



In the top two areas in which your firm is active: What WT oil price does your firm need to profitably drill a new well?

Lines show the mean and bars show the range of responses. The average response was $62/bbl. Executives from 80 E&Ps responded to this survey question.



Source: Federal Reserve Bank of Dallas

MIDSTREAM

Williams Hopes Gas Pipeline Project Gives It Leg Up In Transition

Williams' LEG gas pipeline project is a key component of its low-carbon strategy.

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SHREVEPORT, La.—The Louisiana Energy Gateway (LEG), a natural gas pipeline project that will connect the Haynesville Shale with Gulf Coast natural gas customers, will also be a conduit for the Williams Cos. decarbonization strategy.

The 1.8 Bcf/d pipeline, scheduled to be in service in late 2024, is a lynchpin of the company's "wellhead-to-water" strategy that will deliver gas to LNG export terminals primed to come online during that time, as well as Williams' Transco pipeline system that transports gas to the East Coast.

It also presents the opportunity to develop carbon capture and storage (CCS) infrastructure and decarbonize the natural gas value chain, said Larry Larsen, senior vice president of Williams' gathering and processing operations, at DUG Haynesville on in March.

The project, which received its final investment decision in June 2022, is expected to enter service at a pivotal time.

"Right in time for when you see a lot of that next wave of LNG projects coming online," Larsen said. "And right in time when I think, hopefully, we'll start seeing the [gas market] start to balance out, so we're really focused on making sure we get this executed in a timely manner."

In the grand scheme of the energy transition, Williams is carving out a grand role for itself. It includes the acquisition from Quantum Energy Partners of Trace Midstream's assets in the Texas side of the Haynesville in March 2022. The deal also brought Quantum's Rockcliff Energy into a long-term capacity commitment to the LEG project.

From the start of 2021 to the end of 2022, Williams' legacy assets in the Louisiana side of the Haynesville saw a 50% growth in gathered volumes as the industry came out of the pandemic. When the Trace Midstream assets on the Texas side are added, the volume tripled in that 24-month period.

Williams is also moving aggressively in monitoring and certification technology, Larsen said. It has invested in Orbital Sidekick, a company that in the second quarter will launch a satellite laden with emissions monitoring equipment. Another technology partner, Context Labs, has developed a platform aggregate and they analyze all the monitoring data gathered in the profile.

"We see this as an opportunity for us to really validate all the way across the value chain, all the way from the wellhead through our assets, and be able to demonstrate exactly what our emission profile is," Larsen said. It's not just about Williams reducing its own emissions as an operator, but providing certified natural gas to LNG exporters and other markets on the Gulf Coast.

"At the end of the day, as we work to parallel this with the CCUS project that we are in development alongside LEG, it's targeted toward the potential of having net-zero deliveries at the end of the day in the LNG space," he said.

The goal is to remove 2 million tons of CO_2 a year from the Haynesville Shale. The company plans to accomplish this by transporting gas from the Williams gathering network to a treatment and recovery facility, then piping the CO_2 to a long-term storage facility. OGI

Williams assets in the Haynesville

Source: Hart Energy/Rextag from Williams presentation

The Williams Cos.'s legacy assets in the Haynesville—Springridge, Mansfield and South Mansfield gathering systems—are in Louisiana. The Texas assets purchased from Trace Midstream have been rebranded Haynesville West.

Howard: Midstream Moves from Building Empires to Building Resistance

HINDS HOWARD
CBRE INVESTMENT MANAGEMENT

Hinds Howard is a portfolio manager at CBRE Investment Management where he evaluates listed energy infrastructure and transportation companies in North America and coordinates research of listed transportation companies globally. He is based in Wayne, Pa.

In my column from the March issue of *Oil and Gas Investor*, I laid out the current state of the midstream sector in business school terms, with a trend towards fewer companies with greater scale and bigger competitive moats than in the past. This time, I want to talk about how that happened and the implications for midstream from here. Every year investors ask the question: Is this the year midstream consolidation happens? The funny thing is that in hindsight, for most years since 2014, the answer has been yes.

How did we get here?

The sector has undergone an incredible amount of consolidation and rationalization, fully reversing the incredible expansion of the number of companies in the midstream space in the decade prior to 2015. Through mostly related-party M&A and incentive distribution rights (IDRs) elimination transactions, we have cleaned up the mess that the sector put itself in with 75 IPOs from 2005 to 2015.

The era of contraction began in late 2014 with the simplification transactions by Kinder Morgan that eliminated Kinder Morgan Energy Partners and El Paso Pipeline Partners. Several other simplification deals followed in 2015 and 2016, as the MLP space moved to eliminate the burden of IDRs. There were also several third-party M&A transactions, like Enbridge's massive purchase of Spectra Energy and MPLX's acquisition of MarkWest Energy Partners.

Consolidation peaked in 2018, with more than 20 transactions for overall value of approximately $137 billion, with $135 billion of those mergers being between related parties. Highlights from that year included the roll up of Enbridge Energy Partners, Spectra Energy Partners, Williams Partners, Energy Transfer Partners and Boardwalk Pipeline Partners, among many others. Around 20 of the 50 consolidation deals from 2015 to 2019 were "simplifications" that eliminated IDRs and stepped up tax basis for corporate acquirers. Rationales for other M&A seemed to be related to growing footprints, expanding into other geographies or new lines of business (like MPLX expanding into Marcellus gas processing with MWE).

Our current state

2022 saw the pace of consolidation slow, but those were replaced by asset acquisitions that accelerated to around $30 billion, the highest dollar value since 2017. This transition makes sense, because IDRs have been cleaned up, balance sheets have been shored up, and opportunities to grow "organically" through building new assets are scarcer. That environment is the perfect set up for $1 billion+ "bolt-on" acquisitions like those announced by Enterprise (Navitas), Williams (Trace) and Targa (Lucid) in 2022. Expect similar transaction to continue in 2023, because the dynamics remain in place.

Asset acquisitions should lead to the remaining publicly traded midstream companies growing stronger, gaining more scale and ultimately gaining more stability due to reduced competitive dynamics over time. For producer customers, that could mean higher rates on third party infrastructure, which could lead to more producers opting to build their own infrastructure.

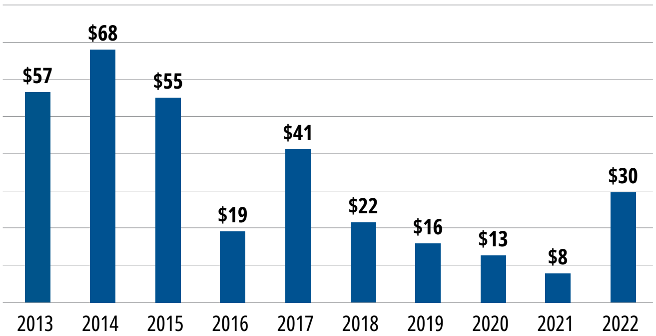
Valuations for asset acquisitions averaged 9.1x in 2022, recovering to around the long-term average after a dip down to 7.5x in 2020, but not back up to the heady double digit forward EBITDA multiples we saw back in the early 2010s when shale growth and low cost of capital permeated the space. Valuations should continue to be fairly reasonable given the current (lower) growth outlook and limited pool of potential buyers.

Organic growth has also slowed due to the push for midstream operators to be more disciplined with their spending of late. Midstream operators are less willing to build infrastructure that's only partially contracted, less willing to bet on production growth filling up that infrastructure over time. Investors are also less likely to respond well to aggressive spending. Asset acquisitions have been tolerated by investors, especially when the acquired assets are contiguous to existing footprints, where potential synergies and downstream benefits can be realized.

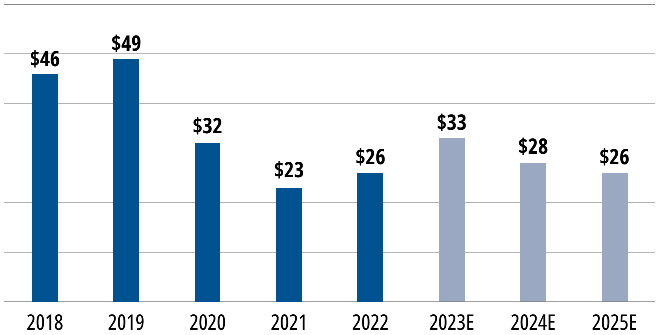
Where is infrastructure still needed?

There are still pockets of infrastructure constraints in North America that will lead to new infrastructure. Gas processing and new gas pipelines are needed every few years to move Permian Basin gas to the Gulf Coast. Production growth in the Permian should continue to drive development of NGL infrastructure. LNG export facilities are being built, which should continue over the next decade. In the Bakken, additional gas

Midstream Asset Acquisitions
($ bn)



Growth Capex Outlook
($ bn)

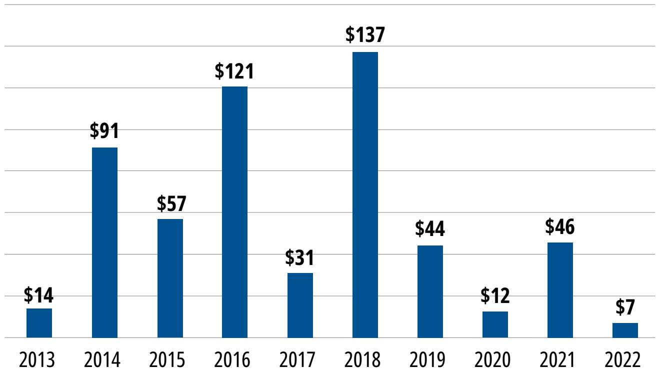


pipeline and NGL pipeline capacity may be needed in the next few years. Big dollars are being spent in Canada to complete massive gas and oil pipeline projects that have been under development for years. The combination of all of the above should see growth capital for midstream increase in 2023 vs. the last few years of capital discipline.

But overall, opportunities for investment are fewer and the scale is generally smaller than prior to 2020. There is also little interest from midstream companies (and from their investors) to build large scale pipeline projects, especially given the huge cost increases and permitting challenges we've see with projects like the Mountain Valley Pipeline.

In summary, this next era will be characterized by less new infrastructure, less big M&A, higher utilization and more bolt-on acquisitions, all of which should lead to lower debt, higher free cash flow and more resilience for midstream. OGJ

Midstream M&A Transactions
($ bn)



Source: Wells Fargo

Voices

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The OPEC+ consortium, which includes Russia, shocked the markets in April when the cartel and its allies announced additional production cuts aimed ostensibly at stabilizing oil prices. Experts throughout the industry weighed in as the news sank in and questions arose about the motivations behind the market manipulation.

"Oil prices are being lifted by signs of increased demand in China which is helping offset warnings from OPEC."

—Fiona Cincotta, *analyst, City Index*

"It's pretty clear they wanted a higher oil price over a year ago ... [OPEC knows] how many chips they hold, they know what their cards are. They also know what yours are and how many chips you have."

—Ed Hirs, energy fellow, *University of Houston*

"What if Saudi Arabia ends up developing closer ties to Russia, Iran and China at the expense of the U.S.?"

—Matthew Iak, *executive vice president, U.S. Energy Development Corp.*

"These cuts may be signaling that OPEC+ believes that there are enough recessionary indicators in the market ... (and) will further tighten the oil market for the rest of the year and could push prices above $100 per barrel."

—Jorge Leon, *senior vice president, Rystad Energy*

"In this case, it is in the interests of world energy to maintain world prices for oil and oil products at the proper level. This is what you need to focus on. And whether other countries are satisfied or dissatisfied—that's their own business."

—Dmitry Peskov, *presidential press secretary, Russia*

Excelerate Energy's Steven Kobos Talks LNG, Fuel-Switching and China

The CEO of Houston-based Excelerate Energy, spoke with Hart Energy about the LNG industry in the aftermath of Russia's invasion of Ukraine and why Chinese demand is the biggest outlier for 2023.

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Excelerate Energy's CEO Steven Kobos spoke with Pietro D. Pitts, Hart Energy's international managing editor, in March at CERAWeek by S&P Global. Kobos, whose company boasts the world's largest portfolio of floating LNG terminals, discussed how the LNG industry has adapted to war and commodity price volatility—and what lies ahead for Europe, in particular. Europe's gas storage levels following a mild winter are better than expected, but a challenge remains in refilling without the "benefit of six months of Russian gas."

Kobos also addressed fuel switching caused by the Russia-Ukraine conflict and ways to help emerging economies avoid the "temptation to pivot to coal."

The havoc that outages can create—most prominently, the disruptions at Freeport LNG's Texas facility—can lead to volatility beyond what anyone expected, he added.

"For the next few years, more so than ever, any anticipated disruptions will have a bigger impact on volatility," he said.

Kobos also weighed in on possible demand destruction and what he sees as the biggest potential outlier for natural gas in 2023: China.

Q&A

Pietro D. Pitts: What is your outlook for the LNG industry amid Shell Plc's forecast, which envisions a large gas supply gap to fill?

Steven Kobos: [There's] obviously not a lot of new production coming online; it's rather flat. You've pointed out the key distinction to last year is China, and there are a few distinctions obviously. Europe's starting from a much better place than before [and] they're likely going to end the winter at 60% storage, give or take. However, they won't have that benefit of six months of Russian gas that they saw in 2022. Europe is obviously using flexible import infrastructure, added to their capacity and their ability to receive LNG when needed without the bottlenecks you saw last year. [Also], their logistics are going to improve on getting volumes into Northern Europe, which is another positive.

All told, Europe did push some other buyers out of the market when prices reached the levels that they did last summer. We clearly see prices [have] come down and I'm really pleased because you see countries like Bangladesh reentering the spot market. They've just gone out with four different spot cargo tenders. It's not an ideal price for non-OECD [Organization for Economic Cooperation and Development] markets, but it's at least something they can afford and it's competitive with other fuels.

PDP: The start of the Russia-Ukraine conflict last year led to a lot of fuel switching. How do you see that playing out this year amid lower gas prices?

SK: I think this past year what we saw was fuel switching. And of course, we're all concerned from an energy transition point that prolonged fuel switching could, in fact, lead to long-term demand destruction. However, we don't personally see that yet. Many of these countries already have good gas infrastructure. The countries that are moving to coal—there are some countries like India that's 80% of coal fired power generation—they've already made that move, they've built that infrastructure. Provided prices can moderate, I don't see a lot of the non-OECD countries pushing backward to coal.

But that's the challenge that we all have. We need to get LNG into these non-OECD markets, support their economies and induce them to avoid the temptation to pivot to coal. I don't think we have demand destruction for gas or LNG yet. It's just something that we need to manage carefully the next couple of years, and those non-OECD countries recognize they need to contract long term for LNG. They were doing well for years optimizing by having significant spot volumes. But I think they've

CERAWeek by S&P Global

seen that the cost of optimizing through heavy use of spot when things go pear-shaped is not a good outcome. So I think you will see non-OECD markets seeking more long term contracting of LNG as the next production waves come on.

PDP: How do you view talk about Europeans not wanting to lock into long-term gas contracts while the Asians are seemingly willing to do so?
SK: We've obviously moved some of our infrastructure into Europe [and] we've been selling some cargoes through Finland and our Finnish gas marketing subsidiary. We don't believe there's one strategy that's right for everyone. So frankly, whether Europe would like medium or longer term volumes or some spot, we'd like to accommodate that through our flexible infrastructure. That's the narrative but you also hear different things out of Europe about their appetite for longer term.

PDP: What did the Freeport LNG outage last year tell us about the LNG market's ability to react under those circumstances? Could that trigger the U.S. to move quicker to push forward LNG projects?
SK: I don't know if it's the driver in of itself, but that's my concern. We've seen that single disruptions can lead to enhance volatility beyond what people expected. And we do need to be mindful of that, especially as you pointed out for the next couple of years as we have a fairly tight supply demand balance.

PDP: What are you hearing about the pace of the Russia-Ukraine war and how that's going to continue to impact Europe's energy demand?
SK: We think that flexible energy infrastructure is part of the long-term answer for Europe, regardless if Europe wants to flow lots of LNG through those terminals… The takeaway is it was unfortunate that there wasn't an alternative infrastructure at the outset. That being said, you have to congratulate the Europeans on how quickly they've executed, sometimes going from contract signing to importing volumes in 200 days. That's about what the Finland terminal that we worked on did. And that's been matched at other locations in Europe. And it's impressive.

PDP: Europe's made it through its first winter amid the Russia-Ukraine war. What is Europe's ability to get through next winter considering what many countries are doing to procure new gas supply?
SK: Anyone with a fragile energy system like this should be concerned. The Europeans are [worried and] I don't see anyone being cavalier about the challenges in front of them. At the same time, they saw they could enter the market and buy what they needed if they had to. So they must feel good about that. But I don't see anyone letting their guard down or just taking the future for granted just because they had a warm winter.

PDP: What's your view on European companies tapping more gas supply from Africa. Is that also a good source that Europe should pursue?
SK: The solution for Europe is multifaceted. Obviously, it's maximizing pipe deliveries from Africa, maximizing pipe deliveries from Norway and it has to be an all of the above strategy. There's no doubt that rapid deployment of floating import infrastructure like Excelerates' is going to be one of the key differentiators. The pipeline capacity is what is has been [and] the import terminals are what've been added to the equation. If they can maximize further pipeline deliveries through existing infrastructure, that's fantastic. But the real upside has to come through LNG.

PDP: Is the ship building side of the LNG equation on pace with new developments in the U.S., Qatar and beyond?
SK: I'm focused on our own particular needs and we have new FSRU [floating storage and regasification units] under construction with Hyundai. So we're pleased with where we are for our own building program. In general, you've seen the real drivers in the shipyard program [related to Qatar and its] expansion of the

North Field and the tonnage required for that is taking up a lot of shipyard capacity, and the U.S. FIDs [final investment decision] are stacking on top of that. At the same time, at least in the past few years, you've seen Japanese yards depart the space, [and] I'm not sure if that's permanent or temporary phenomenon. you see more reliance on the Korean yards than you might have seen in the past compared to the total tonnage. I have confidence in them to continue to scale and to do what they need to do to deliver a fantastic product. Our fleet is all Korean built and we've always been happy with their ability to deliver as promised.

PDP: With an abundance of gas supply in the U.S., are you concerned about the U.S.' ability to supply the various planned export LNG plants in Mexico?
SK: In our business, we want to see more LNG on the market. Obviously, we want there to be as much out there as possible because we want to be the point of interconnection that allows a new market to receive it. We're advantaged as much as the LNG industry can succeed. In turn, the LNG industry is helped when actors like Excelerate can open new markets that have not been consumers in the past. So we clearly have a symbiotic relationship with LNG in general, [and] each project has its own challenges.

PDP: Excelerate has been in Argentina for well over a decade. Recently, the Neuquén Energy Minister Alejandro Rodrigo Monteiro told me he doesn't expect Argentina to 'bring on LNG in magnitude' before 2028 to 2030. What's your view on Argentina?
SK: We've had very good experience in Argentina that whole time. It's a complex energy system. We were happy to be a part of that for however long that they need it. There are other pressures coming to bear in the region [and] if we're talking about Argentina and Brazil, we have to talk about Bolivia and what the potential curtailment of those gas volumes means for others and for energy security. The Southern Cone is going to need energy security for some time, regardless of the production in the south.

PDP: Argentina is looking to import around 30 cargoes this year. What does that tell you about the LNG industry and the Argentine's ability to find cargoes?
SK: We're interested in anything Argentina does relative to LNG, and helping them succeed in their plans. The real point that I'd emphasize about Argentina in those 30 cargoes is, a year ago or last summer, people would have suggested that a country like Argentina wouldn't be able to compete with Europe. And here we see somebody coming in and competing very effectively and obtaining all of the LNG they need. So there's really more of a headline there on what Argentina has achieved with those cargoes.

PDP: What should we keep our eyes on in 2023?
SK: That would be some unexpected or disruptive event, whether that's a Freeport, whether that's some unanticipated direction the war takes in Ukraine or really we're all talking about Chinese demand coming back on, that can be an enormous driver. They have a lot of alternatives and often behave in a purely mercantile way in terms of pricing, which was good for the rest of the world last year [related to] fuel switching and opting to sell cargoes into Europe that they perhaps didn't have to, so that softened the impact. What happens with Chinese demand is the single biggest outlier for 2023.

Pitts: Asian Companies Keen on US Gas Supply, Access and LNG

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The Russia-Ukraine war may still reign as the world's most topical geopolitical event, but energy security has become the reason behind both the 'what' and the 'why' driving how numerous companies, especially Asian ones, are doing business in the energy space across the U.S.

The Asian umbrella covers large population and energy demand centers like China and India, but it also includes countries like Singapore and Thailand, as well as LNG importers, including Japan and South Korea.

Putin's war on Ukraine sparked higher demand in Europe for LNG. The result was a price spike that pushed LNG cargoes out of reach for most of South Asia and onto the shores of European countries desperate for stable supply.

No wonder many countries across Asia and beyond turned heavily to coal usage last year.

Now that Europe has survived the winter threat with no harsh energy rationing, and China has reopened after strict covid-19 lockdowns, LNG prices have retreated.

South Asia is still worried about energy security and is increasingly contemplating markets where energy supply is abundant and relatively unrestrained.

Enter Tokyo Gas Co. and Osaka Gas Co. just for starters.

Both companies have upstream oil and gas activities in the U.S., most notably in Texas. And both participate in LNG projects that are key components of U.S. plans to continue to supply principally LNG to energy-starved markets impacted by the war in Europe.

Both Asian producers are willing and able to go "where the molecules are to invest in projects when possible," Paul Everingham, CEO of the Singapore-based Asia Natural Gas & Energy Association (ANGEA) told me recently in Houston.

Tokyo Gas, Japan's largest gas utility company, is already in Texas. As part of a U.S. subsidiary, the firm has access to the Barnett and Eagle Ford shales, as well as assets in East Texas and North Louisiana acreage in the Cotton Valley and Haynesville shales. Tokyo Gas also participates in the Cove Point liquefaction project on the U.S. East Coast.

Osaka Gas is active in upstream operations in East Texas and the Cotton Valley Sand and Haynesville shale formations through its interest in Sabine Oil & Gas. Osaka also participates in the Freeport liquefaction project on the Texas Gulf Coast.

Despite their holdings, both companies continue to seek out other opportunities in line with their mandates to maintain stable energy supply back home. And that bodes well for continued foreign direct investment in the U.S. upstream, midstream and downstream sectors.

Tokyo Gas is looking to acquire additional North American assets and operating companies in shale gas and renewables. The firm is also eyeing moves into the decarbonization sector with renewable gas and related businesses in energy services.

Osaka Gas looks to integrate its overseas energy business into its major earnings driver to achieve stable operations and sustainable growth. In that vein, the company wants stable procurement, supply and wide use of natural gas.

While the Permian Basin in West Texas has garnered most of the attention in terms of production potential and M&A, the Haynesville has also attracted the attention of Tokyo Gas and Osaka Gas, among other international oil companies (IOCs).

Tokyo Gas recently failed to execute a $4.6 billion deal to acquire Rockcliff Energy. But along with Osaka Gas, Toho Gas and Mitsubishi Corporation, the firm has agreed to undertake a feasibility study for synthetic methane in Texas and Louisiana, which would be liquefied at Cameron LNG for transport to Japan.

All told, energy pundits argue that the Japanese and South Koreans aren't satisfied with being just offtakers to U.S. LNG projects. They are keen on other opportunities as well.

IOCs are looking at the Haynesville for upstream and LNG prospects, Greenhill & Co. Managing Director Jeet Benipal said at Hart Energy's DUG Haynesville event in Shreveport, La. Energy Advisors Group partner Adrian Goodisman said during the same event that he foresees additional acquisitions by Tokyo Gas and Osaka Gas in the Haynesville, without citing a likely time frame.

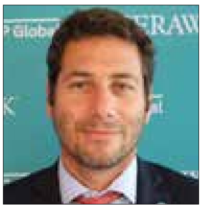
With numerous U.S. and Mexican LNG projects queued up, one thing is for sure: Japan and South Korea are still interested in North American gas supply and that scenario is not likely to change anytime soon. OGI

Global Roundtable: Latin America in Focus

ARGENTINA

ARGENTINA PLANS RAMP UP OF PRODUCTION, EXPORT OIL TO CHILE

Argentina plans to restart oil exports to neighboring Chile once the 110,000 bbl/d capacity Oleoducto Trasandino Argentina SA (OTASA) pipeline finally reopens, Aleph Energy Managing Director Daniel Dreizzen told Hart Energy in March on the sidelines of CERAWeek by S&P Global.



Daniel Dreizzen

"With the rehabilitation work along the pipeline, we are estimating that in three or four months we will be able to transport around 40,000 bbl/d to Chile," Dreizzen said.

Dreizzen expressed optimism about seeing more Argentine oil exports in the future.

"It's good news we have a plan, and it's not only a plan on paper. It's happening at our speed, but it is happening," Dreizzen said. "We're going to export oil through Chile to the Pacific and to Asia and that's going to happen this year."

The OTASA pipeline spans from Argentina's Puesto Hernández Field in the Neuquén Basin to the Chilean city of Talcahuano. It stopped operating in 2006, when its only client, the ENAP refinery in Concon, Chile, no longer needed the supply, the Neuquén Province government revealed in details posted on its website.

The South American country is also moving forward with plans to expand capacity to ship oil from the Vaca Muerta formation to Puerto Rosales (Bahia Blanca).

By 2024-2025, Argentina plans to boost oil production and exports. The incremental oil production will be destined for export and boost the country's foreign currency earnings, according to Dreizzen, who previously served as Argentina's Secretary of Energy Planning between 2018 and 2019.

Argentina's oil production reached 617,000 bbl/d in Dec. 2022 (of which 335,000 bbl/d was conventional production) and has grown in recent years but is still far from a peak 800,000 bbl/d reached in 1999, Aleph reported in its Feb. 2023 Oil and Gas Monthly Report.

Argentine LNG exports of scale: not this decade

The Vaca Muerta, or 'Dead Cow' formation, is home to recoverable resources of 308 Tcf, according to the U.S. Energy Information Administration (EIA). This compares to 297 Tcf in the Permian and 304 Tcf in the Haynesville, according to Rystad data.

"The potential is immense and [investors can compete]—as the Vaca Muerta is as competitive as the Permian now—and there's less competition than in the U.S." Dreizzen said.

While Argentina is far from Europe and the energy crisis provoked by Russia's invasion of Ukraine in February 2022, the South American country normally has excess gas production available for export during its summer months when Europe is experiencing its winter and most demand for gas.

Argentina's situation is expected to improve as more infrastructure is completed and production rises, many energy pundits say. But political uncertainties remain with presidential elections again on the near-term horizon.

The first tranche of the Néstor Kirchner gas pipeline could be ready at the end of Argentina's winter in August 2023 and boost capacity by 11 MMcm/d. A second tranche could push capacity above 40 MMcm/d, Dreizzen said.

Argentina produced 129 MMcm/d of gas in December 2022, of which conventional was 59 MMcm/d, tight was 20 MMcm/d and shale was 50 MMcm/d, according to Aleph.

Despite rising gas production in recent months and plans to boost pipeline takeaway capacity from Vaca Muerta, Dreizzen said Argentina wasn't likely to be a year-round LNG exporter of scale this decade.

"The potential is there, but we need to do the homework. I don't see that by 2030. [We] have to be competitive with the U.S. because [our] gas is not on the coast, it's in Neuquén, so you have to transport, liquefy and transport it to Europe," Dreizzen said. "It's a difficult decision for a company to decide where to put their money in shale gas here. It's good the government and the YPF, the state oil company, are planning this... it's important but difficult."

BELIZE

BELIZE EYES ONSHORE EXPLORATION AND FUTURE PRODUCTION POTENTIAL

Belize, which reported its first commercial oil discovery in 2005, is hoping new discoveries onshore will help boost production.

Belize only has two fields in production, with the assistance of Belize Natural Energy Ltd. (BNE), the Spanish Outlook Oilfield and the Never Delay Oilfield—but both are in decline. New exploration by independents may change that.

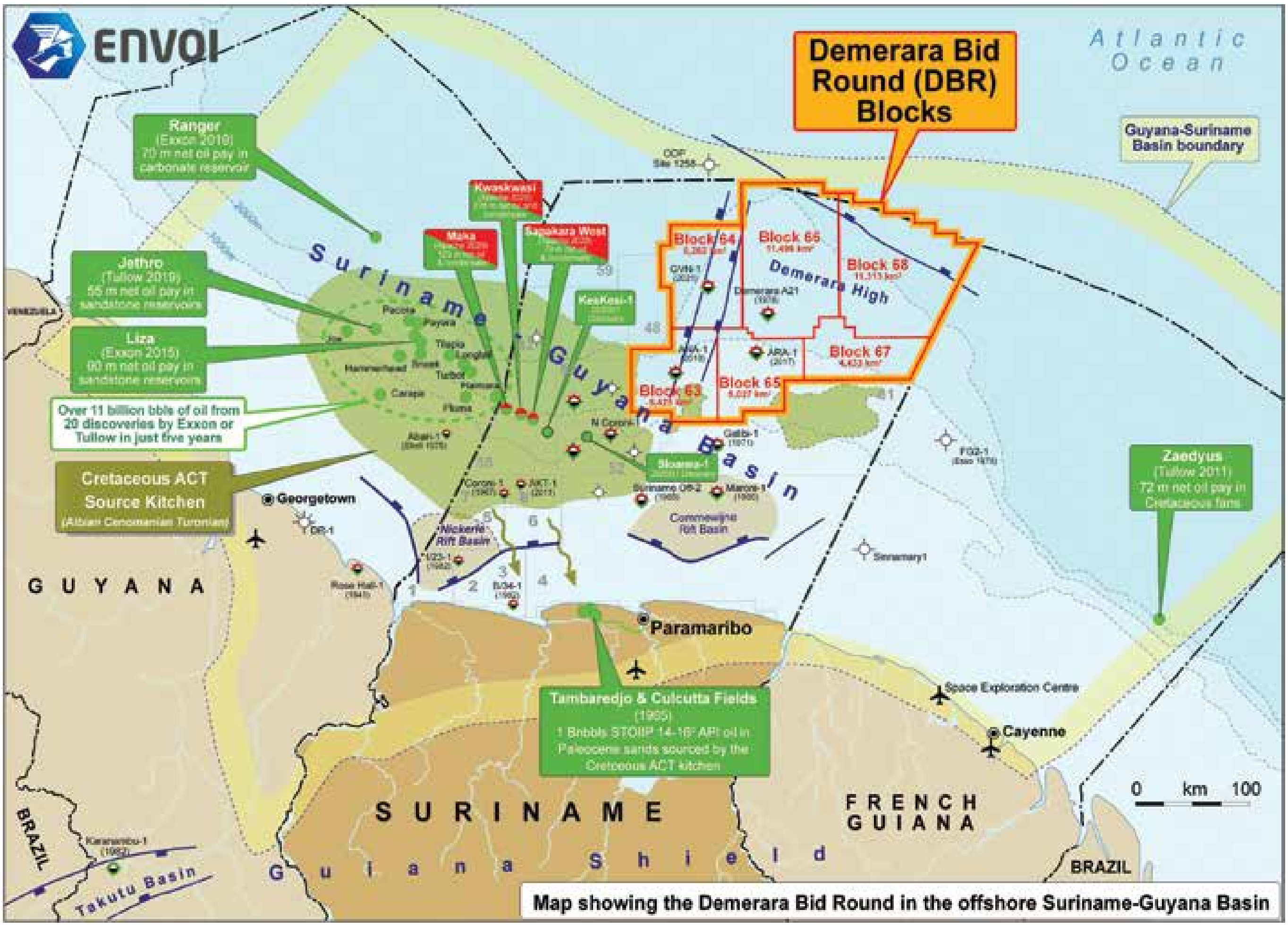
"Spanish Outlook at its peak produced 5,000 bbl/d and is currently at 500 bbl/d. So, we need to make some new discoveries," Belize's Ministry of Natural Resources, Petroleum & Mining Director Andre Cho told Hart Energy at the AAPG-Energy Opportunities event in Mexico City. Never Delay is producing less than that, he said.

Andre Cho

Belize is home to about 441,000 citizens and boasts a stable democracy and an area of 22,966 sq km, including offshore territory. Belize's GDP was an estimated \$1.8 billion in 2021, according to its natural resources ministry.

Currently, BNE is Belize's sole producer, although five small independents hold onshore exploration licenses: USCapital Belize Corp., Saba Energy I Holdings LLC, Princess Petroleum Ltd., BelGeo Ltd. and FCRL Belize.

Belize has three onshore geological provinces: Corozal Basin, Maya Mountains and the Belize Basin. It also has one province



Source: Envoi

Suriname's onshore, shallow and deep offshore basins

offshore where there's a moratorium on exploration.

In the Belize Basin, there are oil seeps, hydrocarbon shows and available exploration blocks.

In the Corozal Basin, there are oil seeps in the south near producing fields. Recent basin modeling shows possible migration pathways and potential hydrocarbon accumulations, according to Cho. There are also vacant exploration blocks in the basin.

An eye on exploration and production potential

BNE's oil is sold locally or exported to the U.S. Gulf Coast. Belize has road transportation routes to Mexico and Guatemala and one petroleum export terminal in southern Belize. Petroleum was once Belize's No. 1 export, and the natural resources ministry is looking for oil to regain that positioning, Cho added.

In the south, USCapital Belize Corp. is preparing to shoot seismic and drill three wells. The company's last well encountered hydrocarbons at about 10,500 feet.

"It seems that they were off structure and they want to shoot new seismic to have better imaging and then drill a new well," Cho said. "So we expect the next discovery to happen in the Belize Basin."

The other companies are preparing to shoot seismic and drill wells, potentially between 2024 and 2025.

"We are in the process of completing a basin study in the Corozal Basin, being our producing basin… and are looking at the source reservoir and seal for the three different oils that we have in the basin, since it identified some areas with potential commercial accumulation," Cho said.

SURINAME

SURINAME'S STAATSOLIE HOPEFUL OF APA, TOTALENERGIES OFFSHORE 2024 FID

Suriname's vertically integrated state-owned company Staatsolie Maatschappij Suriname N.V. expects a final investment decision (FID) regarding offshore Block 58 sometime in 2024, Staatsolie's exploration and non-operated ventures asset manager Patrick Brunings told Hart Energy during the AAPG-Energy Opportunities event in Mexico City.

Block 58 partners, Paris-based TotalEnergies (50% working interest, operator) and U.S.-based APA Corp. (50% working interest), have two key appraisal wells now drilling, Brunings said.

Patrick Brunings

"It's more a volumetric objective they're trying to achieve, getting the right volumes," Brunings said. "So far everything is going accordingly, but in terms of the strategy, we know that they're very close to their objective [and] they want to start big… that's the strategy of TotalEnergies together with APA."

The companies look to replicate, to some degree, the development success an Exxon Mobil-led consortium in neighboring Guyana—which includes Hess Corp. and CNOOC—has had in the adjacent Stabroek Block. Currently, Stabroek has two developments online producing over 360,000 bbl/d from two FPSO units, according to recent comments from Exxon and Hess on their year-end quarterly conference calls.

"So far they like where they are, and hopefully within two to three months we'll have all the data in and they will announce where we stand also in terms of declaring commerciality and then ultimately, of course, FID somewhere, I think next year if everything goes accordingly," Bruning said. "We're happy with what we're seeing, so we're very enthusiastic."

Staatsolie has an option to take a 20% interest in Block 58. The company continues to seek financing for its participation in the development. Beyond that, Staatsolie is concentrating on two important opportunities to attract international investors to its Demerara and shallow offshore bid rounds.

Demerara bid round: better basin understanding

Staatsolie Hydrocarbon Institute (SHI), a wholly owned subsidiary of Staatsolie, launched a competitive bid round in November of last year for six new blocks in the sparsely explored Demerara area offshore Suriname. The blocks offered are located east of current offshore discoveries and located in water depths ranging from 400 m to 3,500 m.

The Demerara round is based on an integrated study conducted by Staatsolie to better understand the basin. Brunings said the state entity used the analysis to set up the bid round.

"We were very confident there are new opportunities in the Demerara area, which is the deeper part of our basin, and it's a new province. So it's not the same province as we have in the West, but we see it has new insights and we're making use of those new insights. There's a lot of enthusiasm," Brunings said.

The data room containing data and information on the open Demerara acreage was scheduled to close to new bidders on April 28, 2023, with bids to be submitted by May 31, 2023, according to Staatsolie.

"All the major IOCs [international oil companies] are basically registering, so it's going the way we want," Brunings said. "They're visiting the data rooms and the only thing that we're now waiting for are the actual bids."

Central shallow offshore and great new 3D seismic

Staatsolie is equally excited about Suriname's shallow offshore, as was evidenced by a successful bidding round for blocks in this area, which generated strong interest from IOCs, including Chevron Corp.

The shallow offshore has seen discoveries in the west of the basin. Staatsolie currently gets all its oil production from onshore fields and says oil has migrated toward and through the shallow area, Brunings said.

In efforts to incentivize investors, Staatsolie generated its own new data, as well as entering into multi-client agreements.

"The first investors were in the west where four blocks were contracted, and now we're concentrating on more of the central part of the shallow offshore also with this great new 3D seismic coverage," Brunings said.

Armed with better knowledge of the basin and new data, Staatsolie is now targeting its shallow offshore bid round by the end of the year, likely by Nov., according to Brunings.

URUGUAY

URUGUAY'S ANCAP EYES OFFSHORE POTENTIAL, SECOND ENERGY TRANSITION

Uruguay's state-owned regulator ANCAP is still in discussions for offshore exploration deals that could be finalized later this year with four international oil companies (IOCs) regarding six awards related to the Open Uruguay Round bidding process in 2022.

"These awards are still under negotiation between ANCAP and the companies, but we are very close to signing [them]," ANCAP energy transition professional Cecilia Romeu told Hart Energy at the AAPG-Energy Opportunities event in Mexico City.

Cecilia Romeu

"Hopefully, within this year, 2023, we will have these contracts signed," Romeu said.

Last year, Uruguay awarded bids to the Challenger Energy Group (CEG) for the OFF-1 area, Shell (OFF-2 and OFF-7), Argentina's state owned YPF (OFF-5), APA Corp. (OFF-6) and a consortium of both APA (operator) and Shell (OFF-4).

At the moment, the only area available for future bidding rounds is area OFF-3, Romeu said.

ANCAP runs the Open Uruguay Round, which includes two bid rounds per year. The process offers a predictable schedule; companies had time to present all the documentation to qualify up until the last working days of April for the first round and October for the second round.

"I think the main strength of this regime is the predictable schedule. Companies already know the dynamics and it's easier to follow," Romeu said. "This regime has been in place since 2019, and we've had very good results."

The round offers very moderate work commitment requirements and companies could have an area for six years before committing to a well, ANCAP announced in statements on its website.

E&P production projects are subject to Uruguay's national environmental regulations, and ANCAP promotes the adoption of the industry's best practices and technologies aligned with such regulations and with an aim on conducting sustainable activities, according to ANCAP.

"As a consequence of all these new contracts, we are going to have new exploratory activities that will include workstation studies, more assessment of the petroleum geology, evaluation of the respective resources and reprocessing of existing data from an enormous database available, and also licensing of data by companies," Romeu said.

Uruguay's second energy transition

Uruguay is a small country of just over 3 million people that is tucked away in southern South America and bordered by Brazil to its north and Argentina to its south.

Over the last four years, in terms of its electric power generational matrix, about 97% of its energy has come from renewable sources: hydro, biomass and wind, Romeu said.

"So, we are good in terms of electricity… and that's why we say that we've had a successful first energy transition, for the power sector," Romeu said. "Now, the government's focus is on moving towards a second energy transition for the rest of sectors, mainly transport and industry, where it's more difficult to reduce the greenhouse gas emissions."

Green hydrogen is seen as the energy source to drive Uruguay's second energy transition.

"We believe green hydrogen production will be the key for achieving this decarbonization goal for the rest of the sectors," Romeu said. "So we are focused on that project, which is very important not only for ANCAP but at a country level." OGI

—Pietro D. Pitts, Hart Energy

Around the World

NORTH AMERICA

Equinor

Illustration of the floating production storage and offloading (FPSO) unit

Equinor Awards Bay Du Nord FPSO LOI

Equinor Canada has given KBR Industrial Canada Co. a Letter of Intent (LOI) for the FEED of the topside facilities of the new Bay Du Nord FPSO to be located in deep waters offshore Newfoundland, Canada, KBR announced in April.

The agreement includes an option to continue detailed design and procurement management services through to final completion of the FPSO. The FEED scope comes on the back of the pre-FEED engineering carried out by KBR in 2022 and will further mature the engineering and execution planning, working towards a FID with first production expected in the late 2020s, the company said. KBR will execute the work scope jointly with Canadian subcontractor Hatch Ltd.

QatarEnergy Enters Offshore Canada Licenses

QatarEnergy has agreed to participate in two of Exxon Mobil's exploration licenses offshore the province of Newfoundland and Labrador in Canada.

Under the farm-ins deal, QatarEnergy gains a 28% working interest in license EL 1167, where the Gale exploration well and associated activities are planned, the state-owned company said in March. Exxon Mobil Canada operates the license and holds a 50% working interest while partner Cenovus Energy holds a 22% working interest. QatarEnergy also gains a 40% working interest in license EL 1162, which Exxon Mobil Canada operates with a 60% working interest.

Located offshore Eastern Canada, EL 1167 and EL 1162 lie in water depths ranging from 100 m to 1,200 m. EL 1167 covers approximately 1,420 sq km and EL 1162 covers 2,400 sq km. The transaction has completed all necessary formalities with the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).

Hi-Crush to Deploy OnCore Unit for Pioneer

Hi-Crush Inc. announced in March that it had entered into an agreement with Pioneer Natural Resources to deploy Hi-Crush's sixth OnCore mobile mining unit to supply frac sand for use in Pioneer's well completions activity in the Midland Basin. This will be Hi-Crush's second OnCore deployment with Pioneer following the successful start of operations at OnCore #4 in Sep. 2022, and Hi-Crush's fifth OnCore deployment within the Midland Basin.

Hess Picks DecisionSpace 365

Halliburton Co. announced in March that Hess Corp. had selected Halliburton Landmark's DecisionSpace 365 Well Construction applications to plan, design and construct wells.

With DecisionSpace 365 powered by iEnergy hybrid cloud, Hess can leverage predictive drilling analytics using artificial intelligence and machine learning to gain comprehensive oversight across the entire well construction lifecycle, Halliburton said.

EUROPE

Neptune Orders Two New Digital Twins

Neptune Energy announced in April an agreement with U.K.-based Eserv to create new "digital twins" of two offshore platforms in the Dutch sector of the North Sea.

The deal expands Neptune's portfolio of digitized assets to 14. The twins enable engineers to carry out traditional offshore work from an onshore location, accelerating work schedules and reducing costs.

Eserv, which previously created digital versions of 12 platforms in the Dutch and U.K. sectors, will digitize the Neptune-operated D15-A and K12-C platforms.

Equinor Extends Transocean Rigs

Equinor has awarded contracts for the use of Transocean Encourage, mainly in the Norwegian Sea, and Transocean Enabler for the Johan Castberg Field, the operator announced in March.

The rigs have been on eight-year contracts with Equinor that expire on Dec. 1, 2023, and Apr. 1, 2024. The drilling program in the Norwegian Sea consists of nine wells to be drilled on the Tyrihans, Verdande, Andvare and Vigdis fields located in the Tampen area of the North Sea.

Verdande and Andvare will be tied in to the Norne Field. The drilling program also includes exploration wells, and may be further extended, adding six wells. The estimated total value of the nine wells is about $191 million, and the drilling campaign is expected to start on Dec. 1, 2023.

In the Johan Castberg Field, Transocean Enabler will have a fixed drilling program of 19 wells and options on another eight wells. The total contract value is estimated at $415 million, with fixed drilling accounting for $295 million.

Transocean said that as part of the Enabler and Encourage contracts, each rig will receive customer-paid upgrades to digital management systems, robotics and operational automation. These upgrades are expected to further reduce emissions from the rig and enhance personnel safety.

Equinor and Transocean have also signed a strategic collaboration agreement to drive improvements in technology and innovation related to safety, efficiency and greenhouse-gas emissions.

Neptune Plans P&A Work

Neptune Energy expects to spend $112 million on decommissioning activities across its global portfolio in 2023.

The operator announced in March that part of that—$23 million—will be for a targeted decommissioning program in Germany this year, plugging and abandoning (P&A) wells that have ceased production and removing associated infrastructure.

Operations are complete on the P&A of a well in the Bentheim gas field in western Lower-Saxony, with a second well on the field due to be decommissioned later in 2023.

It follows the recent P&A of two wells in the Itterbeck-Halle Field.

Last year, Neptune spent $12 million on abandonment and renaturation activities in the country. Plans are also being developed for decommissioning operations in the Fronhofen gas field, the Reitbrook West oil field and the Victorbur mud pit.

LATIN AMERICA

Petrobras Chartering Two FPSOs for Sergipe

Petrobras said in April it will charter two FPSOs for its Sergipe deepwater project in the Sergipe-Alagoas Basin.

The FPSOs will each be able to process up to 120,000 bbl/d of 38- and 41-degree API oil. Together, they will be able to handle up to 18 million cubic meters per day (MMcm/d) of gas.

The project is in water depths of 2,500 m to 3,000 m.

The first FPSO will serve the Agulhinha, Agulhinha Oeste, Cavala, and Palombeta fields, located in the BM-SEAL-10 and BM-SEAL-11 concessions. Petrobras operates BM-SEAL-10 with 100% interest and BM-SEAL-11 with 60% interest. IBV Brasil Petróleo LTDA holds the remaining 40% interest.

The second FPSO will serve the Budião, Budião Noroeste, and Budião Sudeste fields, located in the BM-SEAL-4, BM-SEAL-4A, and BM-SEAL-10 concessions, respectively. Petrobras operates BM-SEAL-4 with a 75% working interest on behalf of ONGC Campos Limitada with a 25% working interest. Petrobras operates BM-SEAL-4A and BM-SEAL-10 with a 100% working interest.

Petrobras Picks Halliburton Subsurface Platform

Halliburton Co. announced in March that Petrobras will use the Landmark iEnergy digital platform to address subsurface challenges. The companies executed a contract that gives Petrobras access to the entire Halliburton Landmark DecisionSpace 365 Geoscience Suite.

The iEnergy digital platform powers DecisionSpace 365 cloud applications. The hybrid cloud platform is designed to deploy, integrate and manage sophisticated cloud applications for geology, geophysics and engineering in a public cloud, along with high-performance processing and machine learning. OGJ

—Pietro D. Pitts, Hart Energy

GeoSouthern Energy Partners Talks Haynesville II

President Meg Molleston shares a rare look inside the firm's strategy of developing a second Haynesville portfolio, including in the middle Bossier with wells that are proving to be just as enormous.

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SHREVEPORT, La.—The wildcat-develop-and-sell operator GeoSouthern Energy Partners is working on its third shale development after selling its early-days Eagle Ford package to Devon Energy Corp. in early 2014 for $6 billion and, more recently, its first Haynesville portfolio to Southwestern Energy Co. in 2021 for $1.85 billion.

Oil and Gas Investor executive editor-at-large Nissa Darbonne talked with GeoSouthern Energy Partners, Meg Molleston, president, during Hart Energy's DUG Haynesville 2023 conference in March. Following is an amalgamation of intel she shared about the company's newest Haynesville portfolio during chats onstage and offstage.

Nissa Darbonne: Meg, after selling your Eagle Ford portfolio to Devon, how did you come to choose the Haynesville as your next play?

Meg Molleston: In 2015, [Ovintiv's] block was for sale. It was making about 17 MMcf/d. That was it. The wells had been sort of on the back burner. They were all first-generation wells—in single-well units.

And we got busy. The first wells we placed online were in April of 2017 with 7,500-foot laterals. We brought them in at about 13 MMcf/d.

Fast forward, we sold that block, which was 100,000-plus acres, to Southwestern in November of 2021. At the time we sold it, it was making about 750 Bcf/d.

ND: Tell us about your newest Haynesville portfolio that's south of Mansfield, La.

MM: Our second block—the one we're working on now—was a farm-in from Williams Cos. in August of 2021 on a drill-to-earn basis. We're very fortunate to have them as our partner. They had acquired it from Chesapeake Energy Corp. and it was making about 15 MMcf/d.

Now, we are bringing in wells that are producing 50 MMcf/d—[up from] originally 13 MMcf/d [in the first block back in 2017].

We're producing around 600 MMcf/d out of [Block 2].

And we're drilling 15,000-foot laterals. Most of our acreage allows us to do that. We're fortunate in the configuration of the block. We found the longer the lateral length, the more economic the wells.

In all in the past eight years, 170 wells are what we've drilled and 1.3 million lateral feet, total.

ND: In just 20 or so months, you're at nearly three quarters of a Bcf/d again?

MM: I think that we made these strides just through a lot of hard work. And, you know, we obviously got the low-hanging fruit first. And we went to longer laterals and bigger fracks.

But I think there's a long way to go. The team is continuously studying this, doing some choke management and other [techniques]. And the inventory remains robust.

All the credit goes to the team. They've just chopped a lot of wood and really studied the formation.

ND: It wasn't low-hanging fruit at the time you entered.

MM: No, it wasn't. A lot of people shied away from it.

We've had some [operators] come up to me later and tell me, "We really didn't like the acreage. We didn't know about the middle Bossier."

We had the good fortune to have drilled some Bossier wells in our other block, so we knew [how to go] about it. It certainly was not without risk, but with the good partner we have in Williams, we've done okay.

We have about 350 wells—Tier 1 wells—in our inventory now, about half Haynesville, half middle Bossier.

We have been very, very happy that we went and took the chance. You know, we didn't know what kind of CO_2 we were going to get. We didn't know whether the Bcf per lateral foot was going to be equal to or better than the [core] Haynesville.

But we're finding that it is. It's really looking quite good these days.

ND: What is the CO_2 content?

MM: It's manageable. It's nothing that we've had to put any extra facilities in or do

"All the credit goes to the team. They've just chopped a lot of wood and really studied the formation."

—**Meg Molleston**, *president, GeoSouthern Energy Partners*

anything other than manage it.

ND: Williams happens to be adding a CCS [Carbon Capture and Sequestration] component to its newbuild pipe out of the Haynesville. Are you participating in it?
MM: We're not actually participating in the build. Certainly we will be supplying product. And then hopefully the geology in South Louisiana will lend itself to the CO_2 sequestration.

ND: What could be the implications for a CO_2-free product? Do you get a premium price for your gas? Do you have access to greater credit—because so many banks are interested in everyone's green score?
MM: Well, hopefully that will be the case. We have gone to Project Canary and others to separately monitor our gas so that we can get into the European and the Asian market.

We've done it voluntarily, as have many of our neighbors.

Again, we're fortunate that we have Williams as our partner. There's one thing we've run into: The gas-treating [facilities in the block] are old. They were put in 10-plus years ago. They were designed for 10- and 13-MMcf-a-day wells.

[Our] wells are producing 50 MMcf/d.

So Williams has helped us in that regard. It's been quite an obstacle.

We're fortunate. I know that a lot of the operators are dealing with that.

ND: It's profound to think that the Haynesville code's been cracked to the point that 10-year-old facilities may be outdated.
MM: It is. [But like in] dog years, 10 years equal 70 in oil and gas. And it feels like it some days.

ND: Does GeoSouthern hedge?
MM: I don't much like the 'h' word. We have a little bit hedged right now.

ND: Is GeoSouthern interested in exploring the deep Bossier that Comstock [Resources] is drilling north of Houston?
MM: We looked at [it] about a year ago. I think [the gas is] there, but we didn't see how we could make any money at it. We thought we had better [economics] where we are.

I certainly think it's challenged due to depth. And we need more work on some completion techniques [and] tools, so they don't burn up at these [deep] temperatures.

But I don't think it's insurmountable. I think it's all going to be a function of [natgas] price.

Naturally [these deep Bossier wells are] going to cost more. But that's what you do: You get into new areas—into Tier 2, Tier 3 acreage—as price allows. OGI

A Tale Told By AI

From robotic dogs to well interventions to artificial intelligence, Occidental Petroleum's Shauna Noonan wants to reframe the narrative to tell the story of wireline crews, the "unsung heroes" of oil and gas.

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THE WOODLANDS, Texas—Technology is remaking how the oil and gas industry gets things done, from inspection techniques to well interventions. And perhaps tech could one day ghostwrite its own story in the annals of oil and gas innovation.

For Shauna Noonan, Occidental Petroleum's fellow and senior director for international and Gulf of Mexico supply chain effectively telling the story of that technology in the industry—whether it's robotic inspections or the impressive operations in a wellbore—is essential to attract fresh talent to the industry.

"It's time to reframe the well intervention narrative," Noonan said in March during a keynote luncheon at the SPE/ICoTA (Intervention and Coiled Tubing Association) Well Intervention Conference and Exhibition in The Woodlands, Texas.

Technology is opening new possibilities all the time: 3D printers can make food, something that was once a sci-fi idea, she said. It's now possible to replace some oilfield workers with robots. Even scripting the tale of new and fantastic technologies can be told by the technology itself, via artificial intelligence (AI).

Jennifer Pallanich/Hart Energy

Oxy's Emerson Toloza with Spot at the SPE/ICoTA Well Intervention Conference.

Training Spot, the robotic dog

Occidental has been trialing the use of Spot, a robot dog developed by Boston Dynamics, for visual inspections and emissions detection at onshore and offshore facilities.

"He's sensor-ed up to see things we can't see, and also to see things we can see," Noonan said.

Emerson Toloza, a robotics specialist at Occidental, is one of Spot's handlers. Like most dogs, Spot had to be trained.

"You first manually walk through the platform facility. You teach it what you want it to look for," he said.

Now Spot's capable of doing visual inspections and emissions detections, and it uses different types of sensors and recording equipment.

"Autonomous inspections, that's our goal," Toloza said.

So far, Spot's field trial has been a success, he said.

Occidental is expanding its robotic dog pack. Noonan said the operator had purchased additional Spots from Boston Dynamics for direct air capture (DAC) facilities.

"One of those plants has over a 60-acre footprint. They're massive," Noonan said. "In order to do proper and timely inspections, we've actually purchased a couple more" robots.

'The unsung heroes of oil and gas'

Google doesn't make well intervention sound like an interesting career.

Noonan said changing the narrative of technology in well intervention will help draw in the next generation of talent.

As an experiment, she checked for definitions of wireline intervention with two sources.

First, Google, which produced a definition that was accurate but boring. Google dutifully reported that intervention prolongs the life of producing wells.

Enter ChatGPT, an AI interface that responds to text questions and generates natural language responses.

ChatGPT described wireline intervention as trying to thread a needle deep underground—but a needle that is on its side and twisting.

"It's not just a matter of lowering the wire down the wellbore, it's like trying to steer a ship through a minefield while blindfolded," Noonan said. "The crew has to contend with curves, angles and deviations in the wellbore that can cause the wire to kink, buckle or even break."

In the end, ChatGPT's version suggested that wireline crews are "the unsung heroes of the oil and gas industry."

In short, she said, "ChatGPT gets it."

Part of what that new AI technology gets, she said, is how many different things can be done in wellbores.

"The interesting thing is even people in our own industry don't realize how complex and advanced and how challenging of a job [they] have," Noonan said. "That's the story we need to get out there." OGI

Game On: Interacting With the Subsurface in Virtual Reality

3D visualization technologies up the game for the oil industry's reservoir modeling.

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Immersive gaming technology is opening up the mysteries of the subsurface for oil and gas companies.

The industry has long battled the siloing of information. Geoscientists and drilling operations teams typically don't have easy access to the same information, which can be a detriment to communication, production and safety.

Access is only half of the equation. Being able to understand or visualize 3D subsurface data can take operations to the next level.

More than three decades ago—around the time the original Sony Playstation was state-of-the-art—companies started devoting millions of dollars to creating real-time operations centers complete with what were then advanced 3D viewing capabilities.

Users donned special glasses that allowed them to view 3D images on the screen, and they were able to discuss the visualized data with others in the room. However, these high-cost rooms were underused.

Now, virtual reality (VR), 3D visualization and related technologies have advanced enough that a drilling engineer in the field and a geosciences colleague in the office can concurrently view the same 3D subsurface data using gaming headsets, and their personalized 3D avatars can converse with each other while interacting with the 3D data visualization.

BaselineZ software was conceived as a way to bridge the gap between silos and improve 3D geological and reservoir modeling workflows. It originated when Microsoft first introduced the HoloLens headset in 2016.

"It was the perfect way to visualize complex subsurface data at scale, to see geology and to be able to present it to the stakeholders, the engineers, the management executives," said Jide Ayangade, business development manager for Cravtive Technologies BV, the developers of the BaselineZ software. "We just wanted to have a way to view 3D data easily and effectively, have it be readily available at all times and for teams to be able to collaborate."

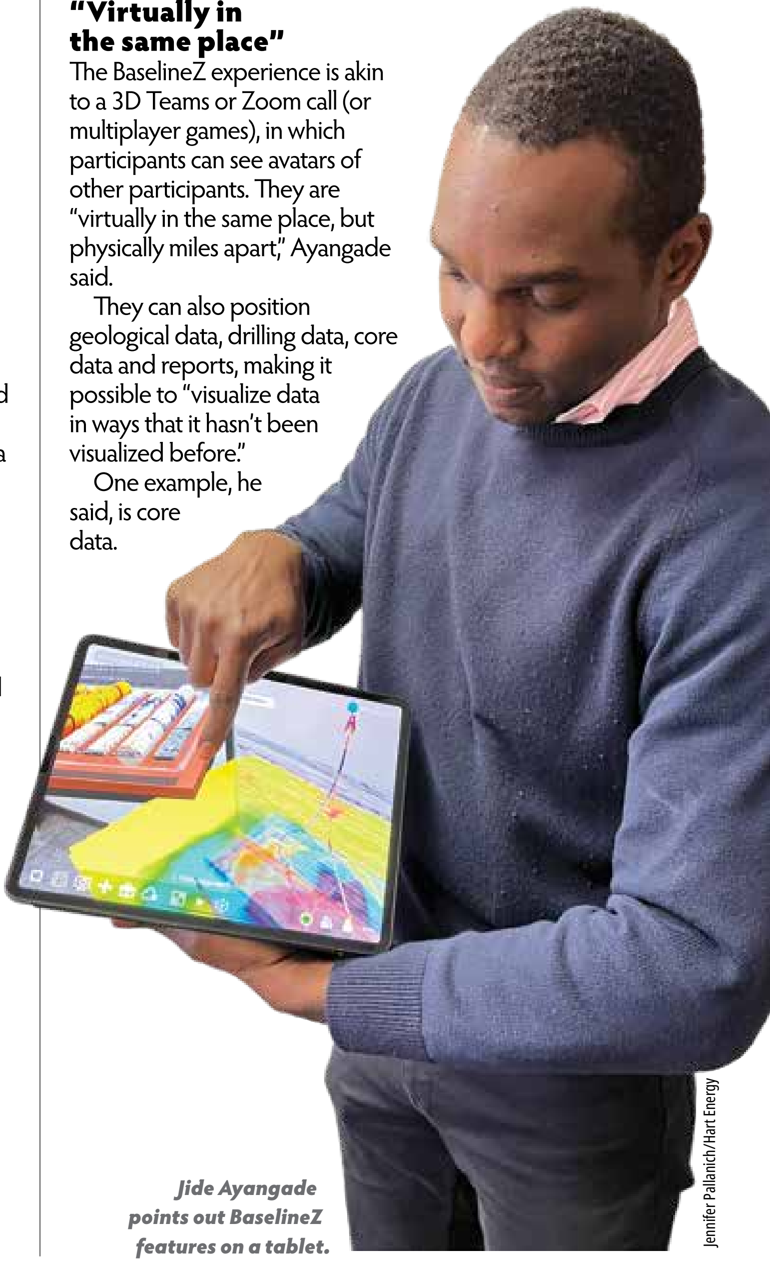
The goal was to put the drilling engineer, the subsurface geoscientists and the management team all on the same baseline, he added.

"Virtually in the same place"

The BaselineZ experience is akin to a 3D Teams or Zoom call (or multiplayer games), in which participants can see avatars of other participants. They are "virtually in the same place, but physically miles apart," Ayangade said.

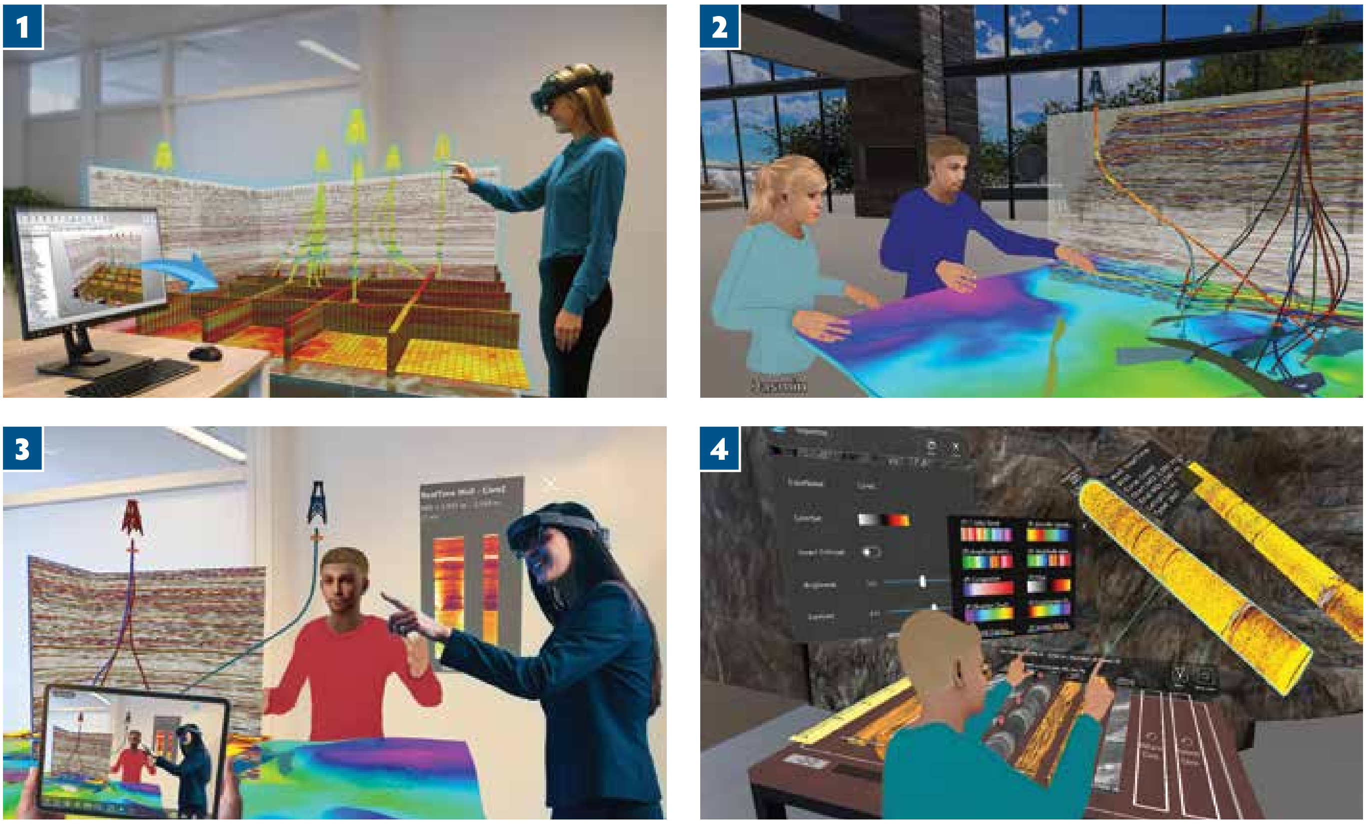
They can also position geological data, drilling data, core data and reports, making it possible to "visualize data in ways that it hasn't been visualized before."

One example, he said, is core data.



Jide Ayangade points out BaselineZ features on a tablet.

Jennifer Pallanich/Hart Energy



BaselineZ

1.) A user with a mixed reality headset views a 3D geological model at scale complimenting the PC workstation. 2.) The 3D avatars of two geoscientists participate in a field development meeting with another colleague (POV), around geological, geophysical and drilling data. 3.) A real-time collaboration meeting around geological model with two participants in person viewing model via mixed reality headset and handheld augmented reality device, while a third colleague joins the meeting as an avatar. 4.) A remote 3D meeting between a core specialist and participant (POV) on core data and contextual core information.

Geoscientists who wish to study core data typically have to go to a physical core repository location, although there is an effort underway by many operators to digitalize core data.

"The headsets provide a way to immortalize this core data in a way that is readily accessible," Ayangade said. The system, he added, makes it possible to visualize multiscale data across different domains in a very accessible manner.

BaselineZ has a seamless connection with Baker Hughes' JewelSuite Ecosystem and SLB's Petrel E&P Software Platform and direct data connector to standard data formats such as RESQML.

Ayangade said BaselineZ can be used for meetings, training or knowledge-sharing experiences in E&P operations, carbon capture and storage, geological storage, geothermal and mining. The software makes it possible to "very quickly and visually do a better resource assessment, potentially add more reserves and improve performance of drilling operations," he said.

Seismic data, he said, includes attributes, traces and volumes while well data includes deviation, trajectory and logs.

"We're not just putting in static 3D objects for visualization," he said. "We put in the whole data, the whole volume into the immersive environment, enabling true subsurface data experience at scale with interactions and data analytics possibilities."

Avoiding risk

Customer interest in using the technology is partly driven by a desire to avoid risk, particularly in high-value, complex assets, he said.

"If you are drilling a high-value well into a geological formation that you can't, as a subsurface specialist, communicate effectively to the drilling team, there's a risk of missing the target," he said. "What's the cost of that? There's a risk of going through a zone that might be over- or under-pressured, which may result in intervention costs."

BaselineZ has also drawn interest for use in geosteering to help keep wellbores in the zone and avoid collisions with other wellbores.

"We see true 3D visualization as being key to helping address some of that," he said.

BaselineZ piggybacks on three main technologies: cloud computing, wireless connectivity and visualization hardware. The goal is to provide a joint 3D subsurface viewing experience, he said.

Bridging the divide

Even though gaming technology is familiar to some demographics in the oil industry, industry, for others, working with the headsets is new, he said. BaselineZ uses the The Unity 3D visualization engine, which is also used in gaming. Unity 3D engine enables cross-device capabilities and multi-user interactions, he said.

BaselineZ, which is available in the iOS, Android, Microsoft and Meta app stores, is licensed on a software as a service (SAAS) model. It allows users to move their subsurface data from their computers to the Microsoft Azure cloud, and once the data is there, any device with the BaselineZ app and access credentials can see the data.

"It doesn't matter what device you're using, whether it's a head-mounted device or a mobile device, they can still view the same data," he said.

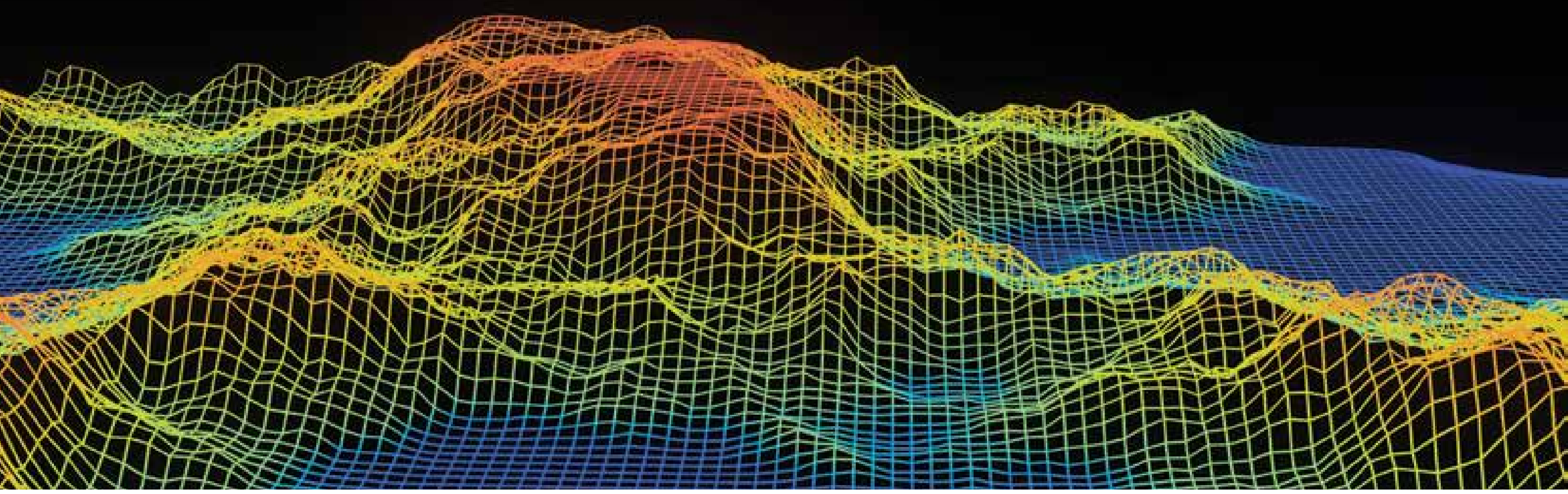
Ayangade said the software is accessible to technical and non-technical skillsets.

"We're seeing that this kind of visualization is helpful for bridging some of that divide," he said. OGI

▸ TECHNOLOGY

Reservoir Simulations Use AI to Change With the Times

Artificial intelligence and new simulation technologies are automating the modeling process for oil and gas, carbon capture and storage and geothermals.



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GALVESTON, Texas—The demands E&Ps are heaping on the shoulders of artificial intelligence (AI), cloud computing and machine learning are daunting. Good thing AI doesn't get nervous.

Among both the practical and fanciful goals of companies such as Exxon Mobil, Equinor, Chevron Corp. and others: using simulations to unlock frac geometry; accelerating greenfield and brownfield development; ever more automation; and even eschewing data to let AI play with engineers' ideas.

Just how reliant are companies on their technology? Exxon Mobil Chief Reservoir Engineer James Hacker calls reservoir simulation "the single most important tool we use in making every single upstream decision."

Oil and gas companies have long relied on reservoir modeling and simulations to plan E&P strategies. Now E&Ps are turning to the same tools to test carbon capture and storage (CCS) projects and geothermal exploration, experts said during a plenary session focused on the future of reservoir simulation at the SPE Reservoir Simulation Conference in Galveston, Texas, on March 28.

From supermajors to geothermal firms, companies are also turning to commercial software and open source solutions as they continue to experiment in the digital realm.

Exxon Mobil is exploring ways to build models faster, link simulations to other models and create simulations that can optimize a project's full life cycle. In doing so, the supermajor recently pivoted away from using its own proprietary full-field simulation software and started using a commercially available program, Hacker said.

"That was a difficult decision," he said. "We'd been building simulations in-house for more than 50 years."

But the supermajor decided a common software package made it easier to share models with partners and regulators. Plus, the talent pool for people able to build and maintain detailed simulators is shallow. And commercial tools now available are "very good," Hacker said.

In fact, he said, the programs make it possible to "take a sparse bit of data" and help the company understand unconventional oil and gas reservoirs to develop a concept around it.

Baris Guyaguler, Chevron's reservoir simulation development and environment chapter manager, said the operator wants to accelerate turnaround time for both greenfield and brownfield simulations, "automating the entire chain" to decrease project turnaround time and decision-making.

"We're trying to do more with less, trying to recover more with a low recovery footprint," he said, adding that simulations informing enhanced

Jennifer Pallanich/Hart Energy

Reservoir engineers discuss the future of reservoir simulation and modeling at the SPE Reservoir Simulation Conference in Galveston. From left, Hess's Sebastien Matringe, moderator, Chevron's Baris Guyaguler, Equinor's Ola Miljeteig, Exxon Mobil's James Hacker, Fervo Energy's Jack Norbeck and SLB's Shashi Menon.

oil recovery for unconventionals is important for the industry. "The percentage of reserves we leave behind in unconventionals is very disturbing."

Unlocking frac geometry

Hacker said he has reached the point where he is "starting to think of unconventionals as becoming conventional, because I think we understand it well enough that I think we can optimize it."

And the industry is getting "closer to understanding frac geometry" using simulations, said Fervo Energy co-founder and CTO Jack Norbeck.

Using simulations to understand frac geometry is important not just for unconventional oil and gas but also for geothermals.

"We need to encourage frac hits to occur," he said. "What's happening with far field frac connectivity between wells" controls the flow rates possible for geothermal wells and is a "big question that I think is one that is ripe for exploring in the R&D [research and development] community. I think we're getting closer to understanding frac geometry."

Norbeck said that in the world of simulations for geothermal activity, Fervo is interested in models that help with well spacing and optimizing completions design. Fervo just drilled a pair of high-temp geothermal wells and carried out stimulation treatments on them.

"The Permian, from my perspective, has a lot of data," he said, but that's not the case for geothermal. "When you really have almost zero field data, then simulation is really all you have to plan."

Reservoir simulations are also critical for CCS, said Shashi Menon, SLB vice president of digital.

"It's a different problem to solve than trying to produce oil and gas, versus sticking something back in" the reservoir, he said.

Companies use simulation technology to understand how CCS will affect the integrity of the formation and "make sure the carbon is going to stay there forever," he said. "I don't think anybody has cracked that problem yet."

Ola Miljeteig, Equinor's manager for CCS technology, said simulations for CCS purposes are "a little ahead of geothermal" but "still nowhere near where they are on oil and gas."

Mutually beneficial future

Equinor is working with open source simulations in both oil and gas and CCS in hopes that the community can help solve these problems together, Miljeteig said.

"Open source has a future," he said. "It can be mutually beneficial for both of us."

Likewise, machine learning could aid in carrying out computationally intensive simulations "at orders of magnitude less cost," Guyaguler said.

Hacker said he is "cautiously optimistic" about the possibilities machine learning brings to the table.

"I've seen machine learning mostly applied where we have actual data," he said. "I'm more interested in how we can apply those tools, including AI, to better replicate what's in our heads."

AI is also evolving, and the industry is increasingly embracing that technology. But what does it mean for workers?

"AI won't replace lawyers," Guyaguler said. "But lawyers using AI will replace lawyers not using AI, and something similar may happen in the reservoir engineering space." OGI

Well Interventions: Producing the Cheapest Barrels, Biggest Hassles

Innovations have made it possible for operators to bring wells back to life through interventions, despite disruptive neighbors, technological limitations and an occasional scarcity of data.

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THE WOODLANDS, Texas—Hydrocarbons produced after well interventions can be some of the cheapest barrels to produce. However, there are the obstacles: technological limitations, schedule disruptions and the persistent need for more data.

Still, innovations have made it possible for operators to bring wells back to life, panelists said in March at the SPE/ICoTA (Intervention and Coiled Tubing Association) Well Intervention Conference and Exhibition in The Woodlands, Texas.

But the challenges remain.

While operators tend to have a list of wells planned for intervention and integrity activity, sometimes those plans go awry. Emergency shut-ins of high-producing wells or the fracking activity of a nearby well can throw off the best laid plans of E&Ps.

"There's no doubt that intervention barrels are the cheapest barrels you can get out of the ground. The well's already drilled, it's already there. It just needs a bit of TLC, a bit of nurturing to get it back online," Tony Ryan, manager for well intervention and well integrity at ConocoPhillips, said.

Any number of problems can prompt intervention: corrosion or scale, safety valve issues, hydrates, sand production, stimulations to address well declines and water handling constraints.

Geography also matters, said Rebecca Ugalde, a continuous improvement engineer at BP.

"It depends on what area of the globe we're talking about, specifically for BP," she said. "Each region has its own challenges."

The type and location of the problem plays a role in determining whether to intervene in a well, and if so, how to carry out the well intervention.

Ugalde noted BP is seeking more capabilities from light well intervention (LWI), or riserless intervention, that eliminates the need to use a vessel with a high pressure riser.

Subsea, hydrates can plague flowlines, said Roger Roman, technical advisor for completions and well interventions at Petrobras. The first choice is to solve hydrates remotely in order to avoid the cost of remediating with a rig, he said.

But Petrobras' highly prolific sub-salt wells, which may average 50,000 bbl/d, make it worth the expense. "Whenever there is a problem, we get the resources," he said.

Onshore, Ryan said, there may be a tendency to gravitate toward using workover rigs because of the "sense of reliability" that they offer.

At ConocoPhillips, "we'll do everything we can to avoid the use of the rig offshore," he said. "But land workover rigs offer a sense of 'you get the job done.'"

'No plan survives contact with the enemy'

Operators handle the inevitability of interventions differently.

Some, such as Petronas, design with future troubles in mind.

Petronas tries to design wells that are "intervention friendly," said Mohd Abshar Mohd Nor, general manager for well intervention, workovers and well integrity at the state-owned company.

To that end, the E&P includes intervention specialists in the well's completion design phase.

"Every well drilled needs an intervention, at least one, sometimes 20 over the lifetime," he said. "Every well drilled eventually requires some measure of integrity, some patching, fixing a leak." Increased drilling is only going to drive up the need for more intervention specialists, Abshar added.

Petrobras takes a more box-of-chocolates approach.

"You don't know what you're going to find," Roman said. That means "we must be ready for pretty much everything."

Onshore, being ready for anything may mean shuffling the intervention schedule for wells.

Innovations have made it possible for operators to bring wells back to life through interventions.

Shutterstock

"Sometimes you have to look at your schedule and go and do a defensive installation of a plug because somebody's fracking down the street from you," Ryan said. "No plan survives contact with the enemy, right? And as soon as somebody starts fracking down the road, it's like somebody fired the first shot in a war. You need to react and be ready to deal with it."

Spotify for drilling

As a national oil company, Petronas faces particular problems related to technologies, Abshar said.

The company cannot always take advantage of technologies offered by international players because the company is focused on developing local vendors and resources.

"That means our toolbox is very limited," he said.

Petronas' intervention success rate has declined because the company has chiefly focused on the easiest fixes.

"We are running out of low-hanging fruits" to focus on, Abshar said.

Technologies that would make the biggest impact for intervention at Petronas are automation and digitalization, according to Abshar.

Automation would increase efficiency and safety while digitalizing the workflow to aid in the ability to carry out intervention work, he explained. And it would make more data available during operations.

Abshar, who has a drilling background, said the lack of real-time information during interventions means the specialists are essentially operating blindly.

One of the reasons more data is unavailable in interventions, Abshar said, is because drilling and intervention operations have different mindsets in terms of cost.

"Drilling is high cost. You pay for it," he said.

Instead, he said, operators try to trim costs from intervention operations, but this means they are missing out on the ways data could better inform their interventions.

Ryan said that, if it were possible, he'd have data available on every ConocoPhillips operation.

He sees a future where interventions will be digitized to a point where information "just flows freely" to specialists' phones and laptops in the way that music flows to them through their Spotify accounts.

At first, he noted, everyone signed up for free Spotify accounts, but many started paying for the premium service after they saw the benefit of the service.

"I think that's kind of how we should look at the data streaming services for well intervention. If it's there, we'll become addicted to it," Ryan said. "We'll start [to] need it, as opposed to it being nice to have." OGI

Tech Bytes

SLB'S CEMENT-FREE WELL SYSTEM DESIGNED TO MINIMIZE CO2 FOOTPRINT

SLB introduced its EcoShield geopolymer cement-free system to minimize the CO_2 footprint of a well's construction in March. SLB said the technology eliminates up to 85% of embodied CO_2 emissions compared with conventional well cementing systems, which include portland cement in their construction. The EcoShield system has the potential to avoid up to 5 million metric tons of CO_2 emissions annually, the service company said.

"The cement-free EcoShield system is a breakthrough that delivers industry-standard zonal isolation capabilities while significantly minimizing impact from upstream oil and gas production," Jesus Lamas, SLB's president of well construction, said in a press release.

The EcoShield system uses locally sourced natural materials and industrial waste streams in its composition. The cement-free system can be deployed throughout various phases of the well life cycle, including abandonment. It can also be deployed across a range of field applications and in corrosive environments.

Pioneer Natural Resources used EcoShield on an 18-well field testing campaign in the Permian Basin. SLB said field trials validated the ability of the technology to fit within standard oilfield cementing workflows without major changes to the design process, onsite execution or post-job evaluation.

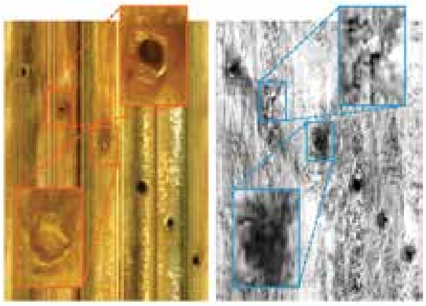
ENI VENTURE TO BOOST PIPELINE INTEGRITY

Eni has created the Enivibes venture to promote its proprietary e-vpms (Eni vibroacoustic pipeline monitoring system) technology, the Italian company announced in March. The e-vpms technology monitors the transport of hydrocarbons or water in pipelines and is aimed at protecting their integrity.

The technology performs real-time analysis and monitoring activities on new or existing pipelines using a vibroacoustic wave system that detects external interference, such as break-in attempts or accidental pipeline impacts, and flow variations, maximizing the efficiency of transportation systems. This solution uses high-sensitivity acquisition stations to enable rapid and localized interventions.

Eni owns 76% of Enivibes, Aresys owns 16% and Solgeo owns 8%. It is the first venture established as part of the activities of Eniverse, Eni's Corporate Venture Builder.

EV ANNOUNCES 4D EVALUATION SYSTEM FOR WELLBORE APPLICATION



EV

ClearVision simultaneous capture of array video (left) and phased array ultrasound (right) for a single cluster, with perfs 4 & 5 missed by ultrasound.

Downhole visual analytics company EV introduced its new ClearVision integrated array video and phased array ultrasound scanning tool technology in March.

ClearVision combines 360-degree video and phased array ultrasound technologies to offer an advanced 4D evaluation system for wellbore applications, enabling operators to see and measure 100% of perforations—including small dimension perforations and those plugged with sand. The information about perforation erosion and proppant placement trends makes it possible for engineers to improve frac designs, the company said.

It was deployed in the Permian Basin and delivered an additional $1.4 million in production revenue per well in one year alone, and operational cost savings of over $350,000 per well, EV said.

MIQ CERTIFIES BPX'S ONSHORE OPERATIONS

BPX Energy, BP's U.S. upstream onshore business, is expanding the certification of all of its onshore upstream operations. MiQ announced in March that it had independently audited and certified BP as the first energy major in the U.S. to verify the methane intensity of its entire U.S. onshore portfolio of natural gas.

The certification, completed in March, gives BPX a more granular understanding of its methane intensity and source emissions, which enables ongoing and additional methane emissions reduction, according to MiQ.

BPX earned certification for its South Haynesville facility in late 2021, and the certification now includes natural gas facilities in the Permian Basin, Eagle Ford and Haynesville shales.

SHELL, ENTEQ TOOL ACHIEVES AT-BIT STEERING IN FIELD TRIAL

Enteq Technologies announced in March it had used the steer-at-bit Enteq rotary tool (SABER) to drill through 100 m of granite during field trials to qualify the tool.

Shell created the concept and Enteq developed the SABER tool. Rather than using pads or plates for steering, the SABER tool uses an internally directed pressure differential system across the bit face. By removing these external contact points, the tool reduces wear and improves reliability, while also achieving true at-bit steering. The sleek, plain collar design also allows for a smoother borehole, further improving reliability, uptime and cost efficiency.

During testing, Enteq's engineering team identified minor enhancements for the control system and ensured the tool is suitable for use in extreme conditions and non-traditional applications, like geothermal drilling. The company said SABER can reduce operating costs for oil and gas operators.

The next test for SABER is to drill a softer formation in the U.S. that more closely mirrors expected operational conditions.

BAKER HUGHES, BP TEAM UP ON GOM ASSET PERFORMANCE

Baker Hughes announced in March that it will collaborate with BP to further define and develop Baker Hughes' Cordant suite of solutions for asset performance management and process optimization.

Cordant enables the standardization of asset health and strategy by integrating operational data within a probabilistic model. As part of the collaboration, BP will deploy OnePM, a Cordant asset strategy solution, in select locations across its Gulf of Mexico production assets, where Baker Hughes currently has a large installed base of rotating equipment, controls and associated digital services.

Baker Hughes initially announced Cordant as an offering earlier this year.

HALLIBURTON UNVEILS RESERVOIR OPTIMIZATION CHARGES

Halliburton Co. in March introduced the RockJet family of reservoir-optimized shaped charges.

Developed at the Advanced Perforating Flow Laboratory at the Halliburton Jet Research Center, the RockJet charges are certified using the American Petroleum Institute's (API) new perforation witnessed test protocol.

Halliburton

RockJet casing perforation tool in use

Halliburton said its RockJet shaped charges help increase production and improve well productivity and injectivity by improving reservoir contact through deep and clean tunnels that extend beyond the damage zone. When tested at downhole conditions, they delivered 22% higher penetration and an 83% increase in area open to flow.

"In the perforating business, optimizing penetration depth and flow area is the key," said Chris Tevis, Halliburton's vice president of wireline and perforating services. "A lot of companies may have charges that are tested on the surface, but how they perform in downhole conditions is difficult to prove. By following the API's new test protocol, we can provide our customers with confidence that the RockJet charges, custom engineered at JRC's Advanced Perforating Flow Lab, will perform downhole."

AGR LAUNCHES DRILLING DATA ANALYSIS APPLICATION

AGR Software announced in March it had launched its P1ANS application to help drilling professionals better understand time, cost and risk when planning wells.

P1ANS, which builds on AGR Software's P1 application, uses Monte Carlo probabilistic simulation techniques to analyze thousands of data points before predicting a range of possible outcomes. Designed for drilling and well engineers and managers, digitalization leads and cost controllers, P1ANS helps ensure time and cost for single wells and drilling campaigns are thoroughly planned and consider all risks, AGR said.

—Jennifer Pallanich

▸ OFFSHORE

Offshore Drillers See Rigorous Selection Process

With the offshore drilling market on a positive upswing, rig providers focus on keeping up with E&P demand while adding the latest bells and whistles to their fleets.

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With rig cross-compatibility, some drilling companies have begun to tailor their rigs to operators in order to set themselves apart and attract contracts.

Rig providers are tailoring innovations, equipment and even crew-worn accessories to set themselves apart as they vie to win contracts from operators. But the offshore market remains especially busy, making the competition for business more challenging.

Leslie Cook, upstream supply chain analyst at Wood Mackenzie, told Hart Energy that "what makes this year unique is availability."

Rig "utilization is very high. There are very few rigs that are just sitting around waiting for work, which is different from what was going on from 2015 all the way through COVID."

This increased deployment of the offshore fleet has led to a stressed importance on the vintage of rig equipment when it comes to selecting a rig to operate certain projects. State-of-the-art sixth- and seventh-generation rigs now make up approximately 90% of the operating fleet, according to Cook. That comes as rig providers continue to push the envelope for more bespoke rigs.

"There was this huge new build cycle from 2008 to 2014 where operators needed a new style of rig that had better efficiency and more IoT [Internet of Things] capabilities," she said. "Everything from adding sensors to monitor equipment, to remote sensing for drilling. There were just a lot of upgrades technology-wise during that time. And now those rigs are the rigs that occupy over 90% of the operating fleet."

Shutterstock/Noomcpk

Since fully autonomous rigs aren't available yet, the safety, wants and needs of a rig's crew are strongly considered when operators are selecting drilling rigs.

"There are very few rigs that are just sitting around waiting for work."

—Leslie Cook, *Wood Mackenzie*

In the Gulf of Mexico, all rigs are newer seventh-generation models, Cook said. These rigs are better equipped to handle the specific regulations that the region requires. Since the Deepwater Horizon Macondo well blowout in 2010, new requirements were put in place for more preventative solutions, including multiple BOPs on all rigs. Many regions have different requirements for drillings rigs based on the areas where they operate.

When choosing a rig to operate, location plays a key role, especially in places with an incredibly harsh environment like Norway, which has its own set of specialized rigs, says Cook.

"There are several sixth- and seventh-generation rigs, but they're all semi-submersibles because of the harsh environment," she said. "They're more stable and they've always been highly regulated."

Terry Childs

And while other regions such as the southern coast of Africa and Eastern Canada also have rough waters, some rigs are able to be operated

Gen VI-VII Floaters

(excludes rigs working in harsh environment regions)

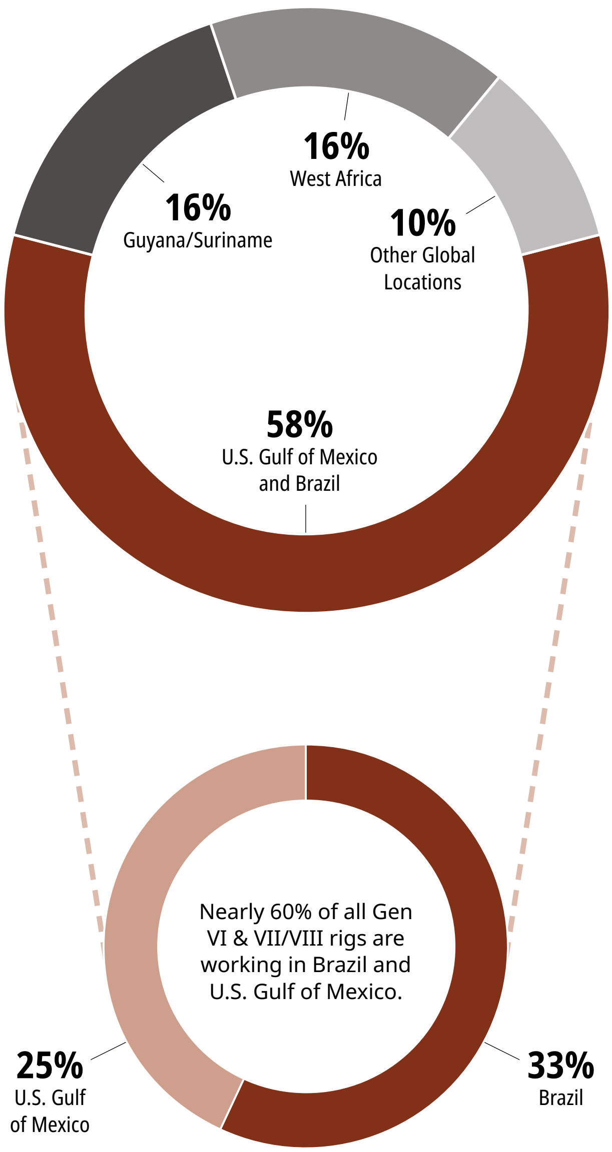
	Gen VI	Gen VII/ VIII*	Gen VII/VIII UDW Drillships
Contracted	49	37	37
Warm Stacked	14	5	4
Cold Stacked	22	5	5
Under Construction	2	4	4
Active utilization	78%	88%	90%
Average dayrates 2023	$274,000	$333,000	$425,000

Source: Wood Mackenzie

•Gen VII Ultra-deepwater Drillships are the most preferred rigs among operators

*Gen VIII: The Deepwater Titan and Deepwater Atlas are the first two rigs to be built as "Generation VIII" rigs. They were built to work in US GoM for upcoming drilling of the first 20k psi developments with Chevron, Beacon, and TotalEnergies.

Hot Spots For Gen VI & Gen VII Floaters



Source: Wood Mackenzie

interchangeably due to similar environments shared by different geographies.

"The Gulf, South America and Africa are pretty much interchangeable," Terry Childs, head of RigLogix at Westwood Global Energy Group, told Hart Energy.

"One rig that can work in the Gulf of Mexico can work off Brazil, West Africa or even Southeast Asia."

Rigs revamped to lower emissions

Cross-compatibility is just one way some drilling companies are choosing to distinguish themselves to get a leg up on the competition.

Lowering emissions is another avenue providers have begun to use for that purpose.

"One of the technologies that's quite prevalent now is the use of MPD, or managed pressure drilling equipment." Childs said. "In Europe, you see a lot of operators focusing on lowering emissions. A lot of the drilling contractors are revamping their fleets and adding equipment to cut emissions through various techniques."

MPD, which uses specialized equipment to control the pressure in a well being drilled, was initially seen as a luxury in the drilling market. Due to its ability to reduce both mud weight and amounts of drilling fluid needed, as well as minimize cost and greenhouse gases through the conservation of resources, MPD has evolved into a borderline necessity for deepwater rigs.

"If you have managed pressure drilling capability on your rig, you are going to be more likely to get a contract in the ultra-deep waters," Cook said.

From safety to 'war rooms'

Technological innovations are always attractive to operators when selecting drillings rigs, and MPD isn't the only newer technology being added to rigs. Predictive maintenance looks to be next in line to make the jump from luxury innovation to a requirement on drilling rigs.

"Improving efficiency and controlling maintenance keeps costs down, so now rigs are beginning to put sensors on all the critical equipment. They've also got these war rooms where they can monitor all the equipment on all the rigs at the same time and they can kind of do more predictive maintenance that keeps rigs up and running more," Cook said. "So there's a lot of technology around sensors and remote sensing."

Safety of the crew and safety of the rig are also heavily weighted when selecting a rig. Newer safety innovations are being unveiled around the industry to help rig providers secure more contracts.

"There's some really cool stuff that's being done around safety," Cook said. "Crew members might wear things that glow when they walk into a red zone. There's also more implementation and experimenting with artificial intelligence and the like, as operators would like to see the total unmanned rig that's controlled from the shore."

Since fully autonomous rigs aren't available yet, the wants and needs of the crew are also heavily considered when operators choose rigs they'd like to use.

"It's not uncommon for companies to poach people from different rigs, and a lot of that happens just for increased pay, so it's important there are other things that keep crews happy," Childs said. "Basic amenities that guys want could vary… Having gym equipment to work out with, having a movie room, having cell service to call your spouse or children or whoever. A lot of those things are important to guys out there." OGI

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2023				
API Pipeline Conference and Expo	May 1-3	Nashville, TN	JW Marriot Nashville	events.api.org
Offshore Technology Conference	May 1-4	Houston	NRG Park	2023.otcnet.org
Williston Basin Petroleum Conference	May 2-3	Regina, Saskatchewan	Delta Hotels Marriott Regina	wbpc.ca
ASA Energy Valuation Conference	May 11	Houston	The Briar Club	energyvaluationconference.org
AGA Financial Forum	May 20-23	Fort Lauderdale, FL	Ft. Lauderdale Marriott Harbor Beach	aga.org
Super DUG	**May 22-24**	**Fort Worth, TX**	**Fort Worth Convention Center**	**dugpermian.com**
Louisiana Energy Conference	May 30-June 1	New Orleans	Ritz-Carlton New Orleans	louisianaenergyconference.com
Mexico Gas Summit	June 6-7	San Antonio	St. Anthony Hotel	mexicogassummit.com
Cybersecurity In Energy Conference	**June 7**	**Houston**	**Norris Centers**	**hartenergy.com**
CIPA Annual Meeting	June 8-11	Tahoe, CA	TBD	cipa.org
Natural Gas Connect	June 12-15	Louisville, KY	Kentucky International Conv. Center	southerngas.org
Uncoventional Resources Technology Conference	June 13-15	Denver	Colorado Convention Center	urtec.org/2023/
Energy Infrastructure & Technology	**June 27**	**Houston**	**Norris Centers**	**hartenergy.com**
LNG2023	July 10-13	Vancouver	Vancouver Convention Center	lng2023.org
KIOGA Annual Convention	Aug. 20-22	Wichita, KS	Hyatt Regency	kioga.org
Texas Energy Forum	Aug. 23-24	Houston	Petroleum Club of Houston	usenergystreamforums.com
2023 OGA Annual Conference	Aug. 28	Norman, OK	Norman Hotel & Conference Center	okgas.org
SEG/AAPG IMAGE Conference	Aug. 28-Sep. 1	Houston	George R. Brown Conv. Ctr.	imageevent.org/2023
Energy ESG Conference	**Aug. 30**	**Houston**	**Norris Centers**	**hartenergy.com**
Carbon Management Conference	**Aug. 31**	**Houston**	**Norris Centers**	**hartenergy.com**
SPE Offshore Europe Conference & Exhibition	Sept. 5-8	Aberdeen, Scotland	P&J Live	offshore-europe.co.uk
Solar Power International	Sept. 11-14	Las Vegas	The Venetian Conv. & Expo Ctr.	re-plus.com
GPA Midstream Convention	Sept. 17-20	San Antonio	Marriott Rivercenter & Riverwalk	gpamidstreamconvention.org
America's Natural Gas Conference	**Sept. 27**	**Houston**	**Westin Gallaria**	**hartenergy.com**
Energy Capital Conference	**Oct. 2**	**Dallas**	**Statler Hotel**	**hartenergy.com**
A&D Strategies & Opportunities	**Oct. 3**	**Dallas**	**Statler Hotel**	**hartenergy.com**
Offshore WINDPOWER 2023	Oct. 3-4	Boston	Hynes Convention Center	cleanpower.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, TX	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, TX	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, TX	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, OK	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./ Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, TX	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

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Coming Soon to a Shale Near You: Blockchain OFS

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Blockchain in the energy industry is coming. And vendors to oil and gas operators will have to fall in line eventually.

First, this isn't Dogecoin. "We are not talking about cryptocurrency," Mike Green, manager of IT partner services for Chesapeake Energy Corp., said in a roundtable at CERAWeek 2023 by S&P Global.

Rather, "we're talking about a way that we can transact … with counterparties without a middleman," he said.

Chesapeake is among members of the Blockchain for Energy consortium that is identifying and testing uses of ledger-based transactions in oil and gas. Other members include EQT Corp., Devon Energy Corp., Pioneer Natural Resources Co., Chevron Corp., ConocoPhillips, Exxon Mobil Corp., Repsol and Saudi Aramco.

Raj Rapaka, ExxonMobil upstream digital transformation advisor, said applications are more than the current, most popular use: cryptocurrency. "Bitcoin is to blockchain what email was to the internet. When the internet started becoming popular, email was the first application.

"And people were blown away. 'Wow, this is so awesome.' But if you look at the internet right now—the amount of things you can do—it's far more than just email."

The consortium is developing an "enterprise blockchain," he said. "The runway beyond Bitcoin is really vast and it is as powerful as the internet. The use cases keep piling up the more you think about it."

One of the most immediate and profitable uses is in carbon offsets, said Raquel Clement, Chevron digital product line deputy manager for facilities and equipment operations. "We're going to have to trade it with the rest of the world."

What is available now, "this is not going to work," Clement said. "It's going to be easily hacked and it's not going to be as responsive as we need in this new environment."

The consortium has two applications (in chemical delivery and saltwater disposal), six programs (ESG, joint-venture management, digital contracts, seismic entitlement, commodity transport and digital identity) and 10 projects running, according to Rebecca Hofmann, consortium president and CEO.

Green said the water-hauling pilot "paints the picture of why blockchain is valuable."

Today, a vendor goes to the site, creates a ticket, gathers all the tickets, creates an invoice and sends that to Chesapeake. "We have to, then, process it and pay it," Green said.

The vendor has to track its work and payment as well. It's all a "very manual, cumbersome, slow process," Green said.

Instead, blockchain would use SCADA systems, GPS or other "validations that basically said, 'We can tell that this and this and this occurred.' So it's written to the blockchain and we can get to a point where we have automated payment."

In addition to cost efficiencies, "you're moving from a process today that goes from potentially 60 days to payment to real time."

Counter-parties will have to buy in, Green added. "Some of them will take years, [but] I think most vendors want to pay less and get paid faster. So it's a no-brainer there."

Rapaka said, "We're not just giving a small haircut. This is a step-chain business transformation that we're talking about."

In blockchain's use in commodity transport, think of Uber, Clement said. In Uber, there are three middlemen. "Every time we do a transaction, the bank gets a fee, Uber gets a fee, the driver gets a fee and everybody has to pay each other. Uber pays the banks, the banks pay Uber, and there's a lot of money that is in the middle there," she said.

"If we can remove at least some of this middle management … we can start saving a lot of money for our companies."

Eventual standardization will be a climb, Rapaka added. "Standards are like toothbrushes: Everybody has one and I don't want to use yours, right?"

Working through it is essential, though. "People don't want to deal with that much fragmentation," he said. "So there is a tension, [but] we are keeping pace with it."

Enterprise-resource planning (ERP) vendors, such as SAP, need to get their arms around it too, Green added. The blockchain that the consortium is developing isn't "completely replacing an ERP," he added; it would coexist with an ERP.

But "SAP better be looking at the fundamental technology that exists [like how] we are. These will get left in the dust if they don't." OGI