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E&P

JULY 2024

WHEN DRILLING IS TOO CLOSE FOR COMFORT

Avoiding parent-child production traps

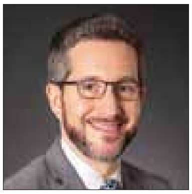
Oil Patch Enters the AI Era

Lengthy Laterals: Worth the Extra Mile?

Completions Trends on a Tech Trek

U.S. Shale Play Overview

The Proud Return of E&P



Jordan Blum
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The evolution of the shale boom is measured in feet and seconds.

In an industry with 4-mile wells fracked simultaneously at fewer than 30 seconds per lateral foot, every moment makes a difference that can be counted in dollars.

And every seemingly tiny technological advancement can make an outsized difference. Efficiency is king and eliminating non-productive time is the goal.

With that, we are thrilled to announce the return of *E&P* magazine in its print format for the first time since 2020. "Welcome back" to seasoned readers, and "Nice to meet you" to those of you joining us for the first time.

While *E&P* persisted during and after the pandemic in digital and newsletter forms, the return of the print magazine brings the publication back to its acclaimed history as an industry leader in onshore and offshore technology news and analysis.

> "Welcome back" to seasoned readers, and "Nice to meet you" to those of you joining us for the first time.

The weekly *E&P* email and digital newsletter will continue every Tuesday morning with leading technology news and trends. But it is great to add more in-depth analysis, features and contributed content with the old magazine that's fresh again.

The next print issue—as part of a series of special editions—will come out in late September.

This first issue back highlights all of the leading trends in enhanced oil recovery, new drilling records, water-handling technologies, completions automation and much more, including the rapid influx of new artificial intelligence systems with "AI" as the buzzword du jour.

The magazine features the latest in carbon capture and storage technologies and challenges, as well as the expansion of geothermal energy within the more traditional oil and gas space. We also explore the potential for more small modular reactors utilizing clean nuclear energy to power hydrocarbon extraction.

Top oilfield services players are highlighted, including Halliburton, Baker Hughes, Weatherford, Patterson-UTI, Liberty Energy and many more. But we also will feature some of the operators.

Growing Permian Basin producer Vital Energy takes us through its use of AI to churn out crude oil more efficiently as it transitions into a fully data-driven company.

And BPX Energy explains how the supermajor is now in shale growth mode in the Permian Basin and Eagle Ford Shale through new drilling techniques and refrac partnerships. The British energy giant is stepping up under new leadership with the pandemic in the rearview mirror and the BHP unconventional assets it acquired now more fully understood.

The shale revolution may have taken hold nearly two decades ago through the marrying of horizontal drilling and hydraulic fracturing, but, today, tiny evolutions are occurring constantly with the advancements of software adoption, the continued refinement of drilling and completions techniques, and the further exploration of new shale benches.

Please enjoy this first new issue of *E&P* that I'm beyond proud to introduce. E&P

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ABOUT THE COVER:
The cover features an Ulterra drill bit ready for action. Ulterra services more than 30 countries with sales, manufacturing and repair facilities throughout the Americas, the Middle East and Asia.

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Pinpointing Shale's Best, Remaining Inventory

Montney steals the spotlight in Enverus' play rankings.

TUCKER KEREN | PRINCIPAL CONSULTANT, ENVERUS • JARED KUGLER | PRINCIPAL CONSULTANT, ENVERUS

The North American play-level inventory rankings are always of interest, and Enverus is regularly tapped for insight on which plays have seen movement on our leaderboards. Operators and investors are more concerned than ever about remaining inventory. Who has it? Where is it? Will it be economic?

Basin Trends

Enverus Intelligence Research (EIR), a subsidiary of Enverus, noted a number of trends as we exited 2023. We saw revisions to the quantity of remaining locations from the previous assessment that came at the expense of quality, which appears to have fallen across the board. Cost inflation, productivity degradation, improved data and other development trends drove most of the inventory quality reductions, but those variables did not change uniformly across North American plays. Some clear winners and losers emerged.

- Tier 1 and 2 (PV-10 breakeven less than $50/bbl or $2.50/mcf) inventory dropped 30% since last year, but some plays are more resilient than others.
- Winners include the Montney, Eagle Ford, Denver-Julesburg (DJ) and SCOOP/STACK plays, which all moved up in the rankings.
- Losers include the Marcellus and Bakken, which slid down in the rankings.
- Permian plays still hold the most remaining Tier 1 and 2 locations, but the Montney has a longer lifespan of Tier 1 and 2 sticks due to less activity in the play.

Biggest Gain: Montney

Even with an increasing pace of development, the Montney has dethroned the Delaware for the top spot on sub-$50/bbl breakeven of Tier 1 and 2 inventory life. The Canadian play is no exception to the trends in degradation and inflation, but the quality of some Montney inventory received help from an improved Canadian Liquids Correction model in Enverus PRISM. The liquids-rich regions of the play now rank among the top North American plays, with sub-$45/bbl (or $2.25/mcf) breakevens according to EIR. Many

Tier 1&2 Inventory Life Leaderboard

Play	Inventory Life, 2023 rank	Inventory Life, 2022 Rank	Rank Change
Montney	1	3	Up 2
Delaware	2	1	Down 1
Midland	3	2	Down 1
Eagle Ford	4	10	Up 6
DJ	5	7	Up 2
SCOOP/STACK	6	11	Up 5
Bakken	7	4	Down 3
Marcellus	8	5	Down 3
PRB	9	6	Down 3
Utica	10	9	Down 1
Haynesville	11	8	Down 3

Tier 1&2 Inventory Count Leaderboard

Play	Inventory Life, 2023 rank	Inventory Life, 2022 Rank	Rank Change
Delaware	1	3	0
Midland	2	1	0
Montney	3	2	Up 1
Eagle Ford	4	10	Down 1
DJ	5	7	Up 2
Bakken	6	11	0
SCOOP/STACK	7	4	Up 1
Marcellus	8	5	Down 3
PRB	9	6	0
Utica	10	9	0
Haynesville	11	8	0

SOURCE: ENVERUS

The Montney, Eagle Ford, DJ and SCOOP/STACK plays all moved up in the rankings while the Marcellus and Bakken both slid down in the rankings.


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The largest Montney producer and the third-largest gas producer in Canada at 1.3 Bcf/day, ARC is continuing to invest in the Montney.

ARC RESOURCES

of EIR's top gas equity picks operate in these regions and have more than a decade of sub-$3 Henry Hub inventory. With about one-third the number of wells put on production each year as the Permian plays, the Montney has a long runway if activity levels hold.

Big Gains: Eagle Ford

The Eagle Ford play, including the Austin Chalk, moved up an astounding six spots on the inventory life leaderboard. Although rig day rates were up 18% from late 2022 to late 2023, operators continue to find material efficiency gains to offset inflation. EIR also expanded the extent of proven resource in the Austin Chalk and Upper Eagle Ford, adding some locations with surprisingly strong economics.

The story here is largely resiliency. The core of the Eagle Ford play still holds years of inventory, and those locations still break even in the low-$40/bbl range with some of the tightest spacing in North America. In the Austin Chalk, operators are also pushing some of the tightest limits of spacing, particularly in the Webb County condensate window.

Enverus ranked top Eagle Ford oil wells from the first half of 2023 by production volumes over the first three months, per 1,000 ft of lateral. The four top-ranked wells were all tight infill child wells drilled with a horizontal spacing of 300 ft to 350 ft and having parent wells that were on average six years older. Seven of the top 10 wells were tight infills. The success of these tight infill wells has provided Eagle Ford operators with a second chance to develop their assets, a luxury that Bakken operators do not have because of significant differences in the petrophysical properties between the two plays.

Tight infills are one of several strategies that we can broadly characterize as "redevelopment." Others include refracs, drillovers and even "horseshoe" wells. In 2024, EIR expects these late-life development strategies to be top of mind for operators in mature plays, but there is no blanket answer for which technique is the right choice. The optimal solution in each drill spacing

Top 10 Eagle Ford Oil Wells from the First Half of 2023

Rank	Well Name	Operator	bbl/1,000 ft production in first 3 months	Peak rate, bbl/d	Later legnth, ft	Parent/child, any zone	Breakeven, 20:1 WTI/Nymex, $/bbl
1	LP Butler B 12H	Devon	27,832	2,046	5,418	Child	$35.86
2	Wright Unit A 6	ConocoPhillips	25,064	1,790	4,932	Child	$37.43
3	Wright Unit A 2	ConocoPhillips	24,182	1,766	4,899	Child	$38.03
4	LP Buttler B 10H	Devon	23,713	2,012	5,211	Child	$41.53
5	Wright Unit A 3	ConocoPhillips	23,706	1,610	4,971	Co-Completed	$40.83
6	Seid B-Borch C USW C 1	ConocoPhillips	23,262	1,467	9,668	Co-Completed	$47.11
7	LP Butler B 11H	Devon	22,931	1,932	5,344	Child	$46.27
8	Wright Unit A 5	ConocoPhillips	22,107	1,460	5,039	Co-Completed	$40.95
9	LP Butler B 9H	Devon	21,517	1,875	4,779	Child	$48.58
10	Henkhaus Unit 18H	EOG	21,069	2,475	8,411	Child	$42.46

SOURCE: ENVERUS

Enverus ranked top Eagle Ford oil wells from the first half of 2023 by production volumes over the first three months, per 1,000 ft of lateral.

unit depends on a multitude of inputs and the operator's desired output.

Biggest Losses: Marcellus

Cost inflation between 2022 and 2023 in the Marcellus was among the highest in North America. Rig day rates were up 25% year-over-year in September, compared to about 15% across the Lower 48. Total well costs per lateral foot are up about 20% since early 2022, according to estimates within PRISM. Some operators have managed to minimize per foot productivity degradation by widening spacing, but at the cost of some inventory. Productivity degradation is worst in the Northeast Pennsylvania Core, according to EIR, meaning the area with the highest potential for Tier 1 locations must be risked down.

Big Losses: Bakken

The bulk of the remaining inventory in the Bakken is no longer in EIR's Tier 1 or 2 categories. Cost inflation has not been as kind to the Bakken as other Rockies plays, according to estimates in PRISM. The D-J Basin moved up in both inventory rankings thanks to efficiency gains offsetting inflation and minimal productivity degradation. Compounding the shift in non-core development strategies to wider spacing, longer laterals and less wells targeting the Three Forks intervals with a significant increase in the pace of development translates to a shorter Tier 1 and 2 runway and a drop in the leaderboard behind rival Rockies play, the DJ.

Looking Ahead

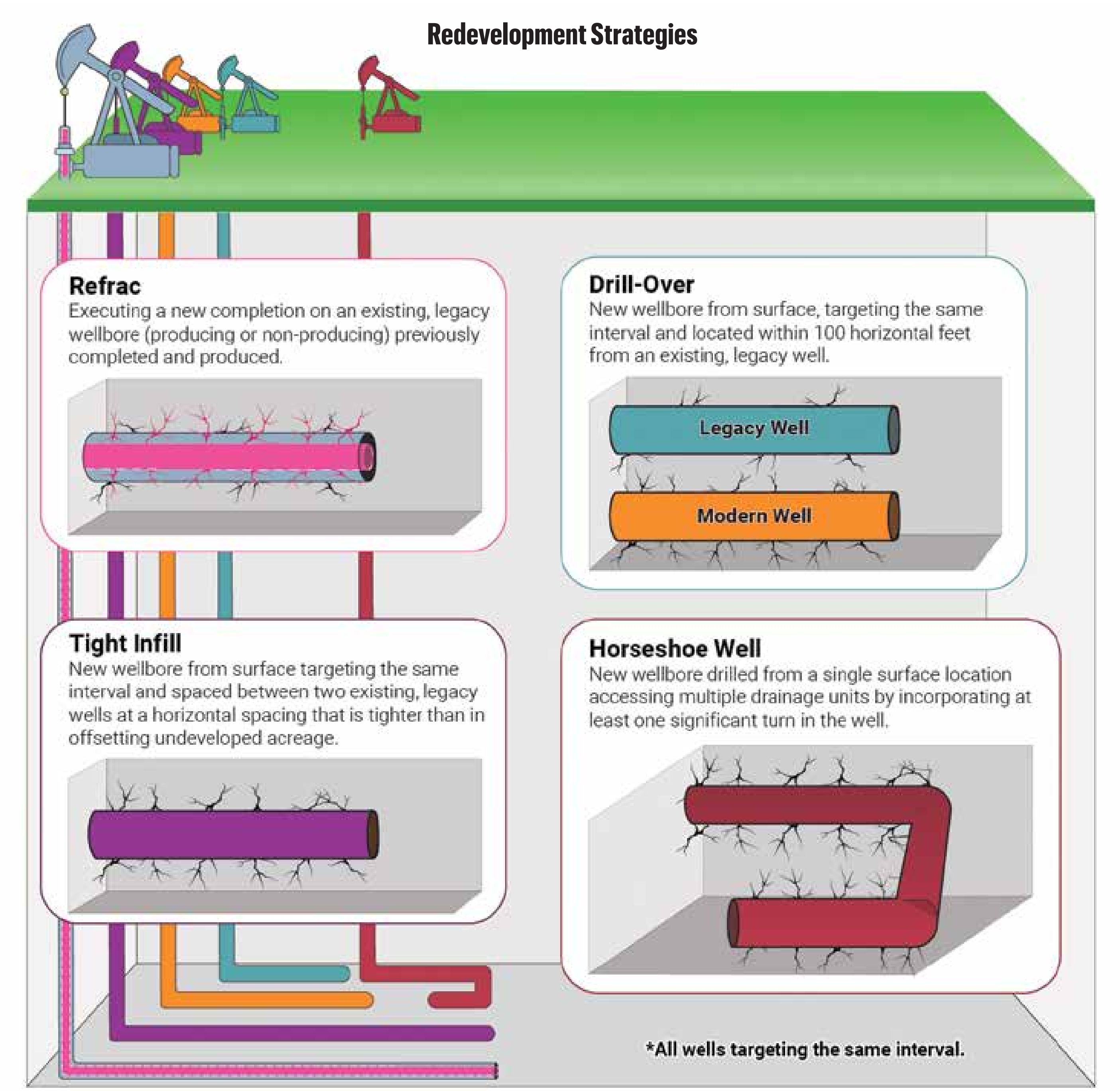
There are still opportunities for resource expansion, even within mature plays, to extend the duration of remaining inventory. This can come in the form of pushing the extents of viability in a play or target interval, or downspacing within a play, as previously covered in the Eagle Ford. Here's one of the many developments to watch around North America with potential to unlock new inventory.

Midland Basin/Barnett

EIR expects the Barnett Formation to continue to be delineated well into the core of the Midland Basin. When

Enverus Intelligence Research cited the resilience of the Eagle Ford Shale.

SHUTTERSTOCK



SOURCE: ENVERUS INTELLIGENCE RESEARCH

Enverus Intelligence Research expects late-life redevelopment strategies like tight infills, refracs, drill-overs and "horseshoe" wells to be top of mind for operators in mature plays in 2024.

we first heard about a Barnett play in the Midland Basin, we figured it would be mostly gas at those depths. But even in some of the deepest parts of the basin, like Martin and Midland counties, resource expansion in the Barnett is attracting a plethora of capital from several large operators, in large part because it's so oily.

These producers are finding volatile oil at depths greater than 11,000 ft, with initial gas-oil ratios around 3,000 cf/bbl, or 67% oil.

There are already more than 100 producing wells in, or adjacent to, the Midland Basin, with consistent sub-$50/bbl breakevens. Roughly 60 permits and wells-in-progress are on their way, including initial tests and downspacing trials. E&P

BPX EXPANDS ITS SHALE GAME

BPX CEO Kyle Koontz delves into development plans in the Permian, Eagle Ford and Haynesville.

JORDAN BLUM | EDITORIAL DIRECTOR

BP finally dove more heavily into the U.S. shale game when it acquired the onshore assets of BHP in 2018 for $10.5 billion—its largest deal this century—formally launching the BPX Energy brand for the British supermajor.

What followed was a rapid race to save leaseholds, a trudge through pandemic-era price swings, the sale of non-core assets in Colorado, New Mexico, Wyoming and Oklahoma, and an infrastructure buildout in the BHP-purchased Permian Basin position.

Now, under the leadership of new CEO Kyle Koontz, BPX can finally focus on ramping up the volumes in its core basins in the West Texas Permian and South Texas Eagle Ford Shale. Activity will pick back up in the Haynesville Shale as soon as natural gas prices recover.

"There's renewed purpose, and it's

"We love the portfolio. We're kind of hitting our stride, so to speak. We've been mostly doing lease-obligation drilling for the last couple years, but we're now in growth mode."

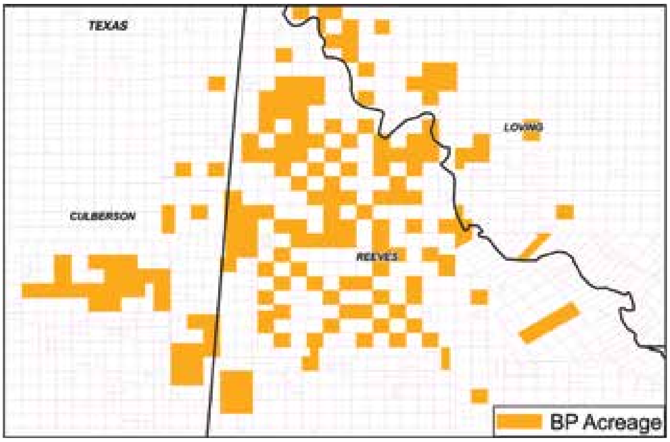
KYLE KOONTZ, CEO, BPX Energy

MICHAEL CIAGLO

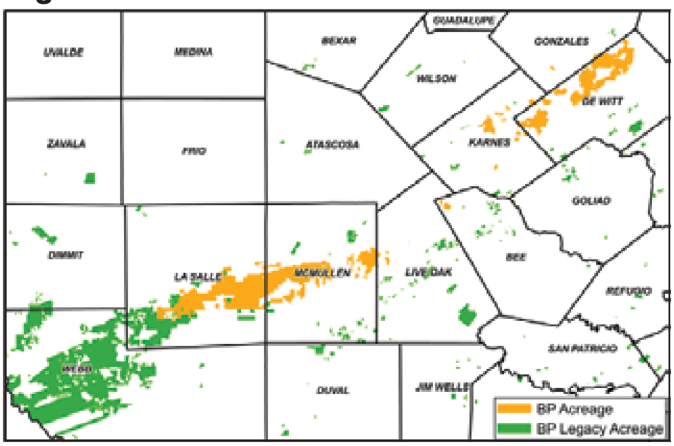
BPX Energy CEO Kyle Koontz stands outside his office in the BPX headquarters on the outskirts of downtown Denver.

BPX Acreage in the Permian, Eagle Ford and Haynesville

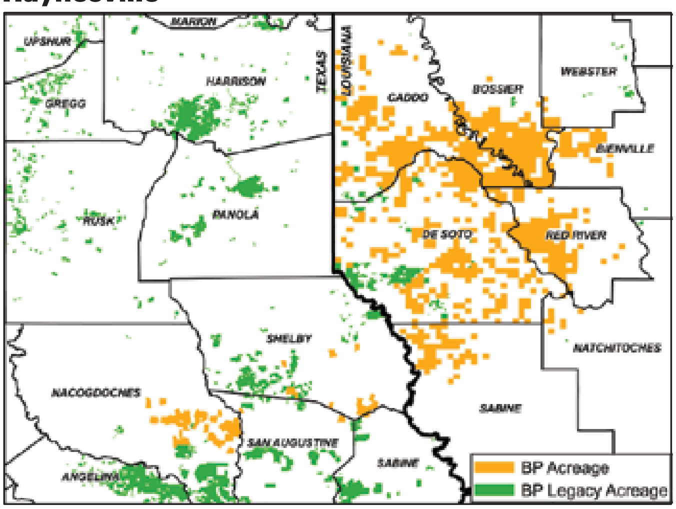
Permian



Eagle Ford



Haynesville



SOURCE: BPX

Permian, Eagle Ford and Haynesville acreage maps combining BP's legacy acreage and BHP assets at the end of 2018.

shown in the numbers in the business," Koontz said. "We're ahead of schedule in our production growth plans, and it's showing up big for BP."

BPX's production averaged 406,000 boe/d in fourth-quarter 2023, up 28% from 318,000 boe/d in the final quarter of 2022. The stated goal is to hit 650,000 boe/d by 2030, more than double the 2022 volumes. And BP is committing an average of $2.5 billion in annual capex to BPX from now through 2030, compared to $1.8 billion in 2022.

Koontz and Clark Edwards, BPX vice president and COO of development, spoke exclusively with *E&P* to discuss their field development plans in each of the three core basins.

"We love the portfolio. We're kind of hitting our stride, so to speak. We've been mostly doing lease-obligation drilling for the last couple years, but we're now in growth mode," Koontz said during an interview at BPX's Denver headquarters.

"We bought elite, top-tier acreage from BHP back in 2018. What you see right now is our strategy to go out and develop that acreage position and to really maximize on it."

CLARK EDWARDS, vice president and COO of development, BPX

"I like the focused, concentrated position. I think it fits well with where we're headed with BP focusing on just high-quality assets and then delivering on those assets. That's kind of where BPX's head is right now. I don't see any big changes happening. I do think we are going to need to add inventory," Koontz said. "Renewals of assets is always a strong part of the growth strategy, but one of the benefits of having the core position and the size of the BHP deal is we have the luxury of time. We're not pressed to do anything, so we really want to make sure we buy right."

Prior to the BHP deal in 2018, BP's very gassy onshore U.S. production only churned out 5% crude oil. While it still skews gassier, BPX is leaning into liquids and aiming for a more balanced mix, especially in this current environment of weak gas prices.

The stronger emphasis on U.S. shale also coincides with parent BP more vocally embracing hydrocarbons again after emphasizing renewable energy.

"Oil and gas have always been the cornerstone of the strategy. I think we've learned some lessons, and


BPX

CEO Kyle Koontz tours BPX's Grand Slam centralized processing facility in the Permian.

we are now going to move at the pace of society, and we're going to be pragmatic about it," Koontz said. "BPX fits within that. It's the resilient hydrocarbon strategy. Not only do we need to be profitable, but we need to be environmentally sensitive and conscious about how we impact the Earth and the communities around us."

Overall Strategies

BPX is currently running a nine-rig program with four each in the Permian and Eagle Ford and one in the Haynesville—with the ability to scale up as needed. A fifth rig in the Permian was recently eliminated because efficiency gains had led to equivalent well completions with fewer rigs.

"We basically want to run as few rigs as possible and get the same volume and profile," Koontz said. "That's not what our drilling partners want to hear, but that's how we try to optimize the business."

He said the goal is to drill as few wells as possible to drain the section.

"We typically try to up-space as much as we can for that reason. In the Eagle Ford and the Permian, there's usually three to five wells per pad, and we'll do a full pad at a time. In the Haynesville, it's been a little bit more spread out because it was underdeveloped relative to the other assets. So, we had some catching up to do. We had to drill around the field to shore up all of our leases and finish all of our obligations. We'll shift into next year, and it'll be more multi-well per pad," he said.

Edwards is helping lead the charge into the oilier portions of the Permian and Eagle Ford.

"We are dramatically increasing our liquids content through 2025 and 2026. Then, post-2026 and toward the latter part of the decade, the investment shifts a little bit back into more gas in the Haynesville if the strip holds," Edwards said.

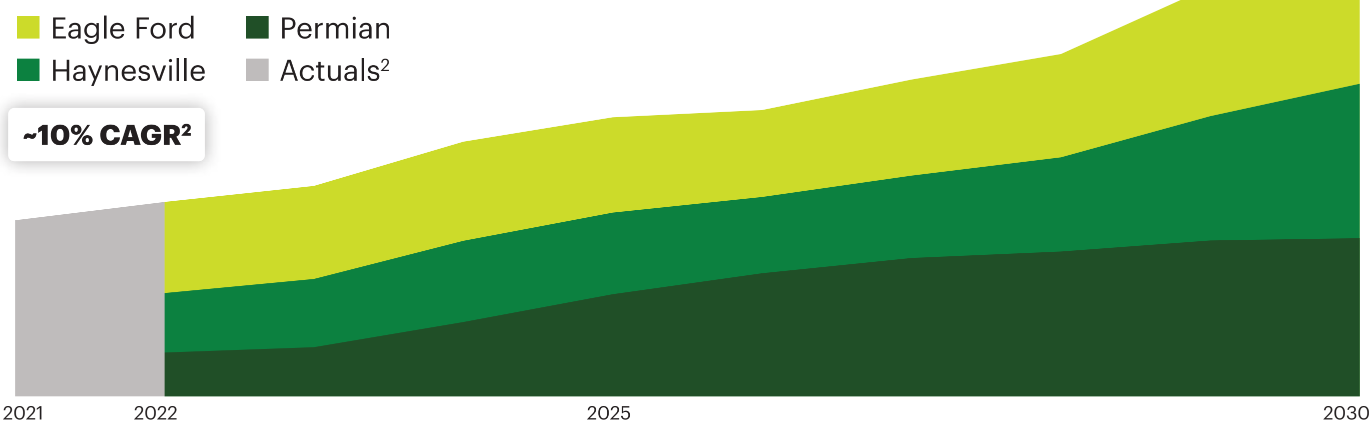
"Our opinion—and my opinion—is that we bought elite, top-tier acreage from BHP back in 2018. What you see right now is our strategy to go out and develop that acreage position and to really maximize on it," he added. "We've been able to go in and organically develop those assets, and our growth profile continues to fit that strategy. We are planning to grow in a significant way through the bit."

BPX is leaning on a mix of longer laterals, more intense zipper fracs and additional proprietary tools to maximize efficiencies and gain advantages, such as its RTAN system (rate-transient analytics for frac designs).

"It's allowing us to better define the efficiency of our fracs and exactly how we are interacting with that SRV [stimulated reservoir volume], and what are the most efficient ways to complete

Production to 2030[1]

(mboed)



SOURCE: BPX
(1) 2025 TARGET AND 2030 AIM
(2) 2022 TO 2030

these wells," Edwards said. "You're constantly solving for the efficiency of your frac and the efficiency of the economics of those wells. It's not always the biggest well that creates the best value. Sometimes, a smaller, less expensive frac can be a more valuable well, and there's tension there all the time. This proprietary suite of tools that we use allows us to solve that tension in a way that gives us a competitive advantage."

The best advancement on the drilling side, according to Koontz, was the Drilling Automation Software (DAS) system developed by Exxon Mobil, which is licensed through Pason. Cycle times were reduced by 20% as a result, he said.

"It is primarily looking to solve for weight on bit," Koontz said. "Our guys in the field may have had a mentorship-style experience that says we should put 45,000 pounds of weight on bit. But now they're putting 80,000-plus because they're setting boundary conditions, but they're letting the algorithm—the smart drill—solve for what's the best weight on bit."

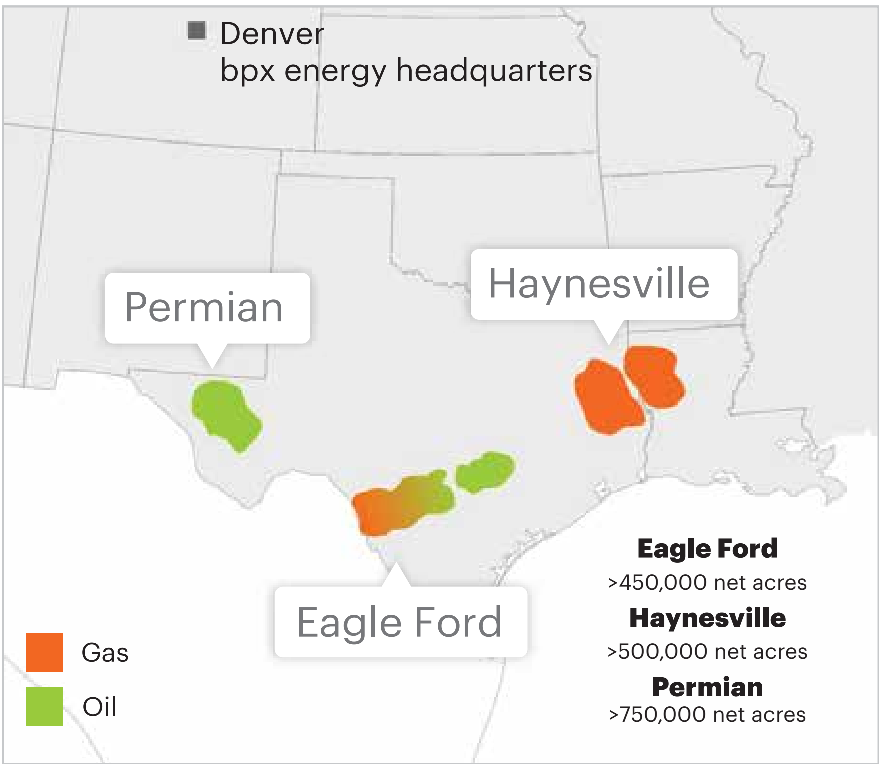
Edwards broke down some of the challenges by basin.

"In the Haynesville, you're dealing with temperature and fairly weak rock. Those two things work against you because you've got high pressure, and you need heavy mud. And the heavy mud breaks down the rock. You're kind of constantly in this tenuous balance between how do you solve for those things.

"In the Eagle Ford, it's understanding how tight you can go on redevelopment spacing and how those parent-well fracs affect the area that you're drilling. It's really a question of lateral stability and how much mud weight you can apply to keep a stable lateral without breaking down something in the shallow part of the well.

"When you go to the Permian,

BPX's Core Positions



SOURCE: BPX

BPX

The Grand Slam central delivery point is one of BPX's three new centralized processing facilities in the Permian.

the drilling process from a rock perspective is not the complication. The complication there is just some of the pressure that we're seeing shallower in the wellbore, how we control that pressure and where that intermediate casing set point is. That is not something unique to BPX, and it's something that we're working on," he said.

Permian Plans

The Permian is BPX's smallest footprint, with slightly more than 75,000 net acres, but it's in the core of the Texas Delaware Basin in Culberson, Loving and Reeves counties.

Much of BPX's emphasis since the BHP deal has been on building out the infrastructure for electrification and efficiency—essentially, an electrical substation network and three centralized processing facilities with interconnected pipelines networks: the Grand Slam, Bingo and Check Mate facilities, the latter of which came online during the spring.

A gas compression station, Crossroads, which is scheduled to come online in 2025, is the final piece of the infrastructure puzzle.

As Koontz explained, the original plan was to build five central delivery points (CDPs), but BPX pivoted to save costs.

"As we blocked up acreage and fine-tuned the designs and the development schedule, we were able to whittle that down to three CDPs and one compression station," Koontz said. "The compression station will help us for increasing gas-to-oil ratio over time. The reservoir is just built where more gas will come out of solution as the pressure drops. That compression will give us the ability to service all of that gas to keep the oil utilization high. That's why it's the last project."

The company has electrified about 95% of its operated wells in the Permian, up from just 4% in 2018.

"We wanted to power the field, but we couldn't rely on a third party to build all that up for us," he said. "So, what we did is we made a deal with our utility partner to buy directly off the transmission line and then build out the system to step it down where we needed it and when we need it. And one of the unique advantages by doing that is we could customize the load design, and so we're able to run Halliburton's electric frac fleet off our grid, which is a big electrical load, and most local grids aren't designed for that. But we designed for that from the beginning to be able to do that.

"Almost all of our sites now are fracked off the grid with e-frac, and all of our drilling rigs are outfitted with transformers, with Nabors Drilling so that we can drill off the grid as well," Koontz continued. "We use the electricity to our advantage."

Edwards said BPX is preparing to experiment with deeper Permian benches, such as Wolfcamp B and deeper Wolfcamp benches. But, for now, the emphasis is mostly on Wolfcamp A and the Bone Spring.

"We still have a significant amount that we would like to better understand technically about the Bone Spring," Edwards said. "We are working that as we speak, and, obviously, you want to take a measured approach. One of our key philosophies is that we make very small bets, we evaluate the results, and then we figure out how we're going to apply that to the broader program. You won't see us go all in on any one bench and dramatically change the program where it could lead to an outcome that's not something we fully understand. We expect to move into the Bone Springs over the latter part of this decade and then, obviously, into the deeper Wolfcamp benches in parallel or shortly thereafter. We have tremendous runway in the Permian for sure."

In terms of field development, BPX designs its plans at least five years in advance for wells and then enters a more defined process 12-18 months ahead of spud, he said.

"My view is that, typically, somewhere between three and six wells is sort of optimized as it relates to the number of wells on any given pad," Edwards said. "There's the time from the initial investment to build that pad to when you start seeing volumes off of it is really important. And then derisking your program by allowing yourself to produce six wells as opposed to waiting for all 20 to be ready to come online all at the same time. I just generally prefer to have a little bit of a smaller subset that gives you a little bit of increased flexibility."

Koontz said BPX is drilling Permian laterals up to 13,000 ft long and that they've largely avoided well-spacing problems that have plagued much of the industry in recent years. BPX benefited somewhat from being later to the Permian game and had the benefit of learning from peers, he said.

And BPX isn't drilling any horseshoe laterals or unusual shapes, at least not yet.

"We're not doing anything exotic like some of the stuff you see published," Koontz said. "But, I will say this, when you build an innovative culture, you've got to be willing to hear what they have to offer. They've been throwing out some new ideas that I'm not a big fan of, but we've got to let them work and be creative and be true to the culture. So, we'll see. If it works, we're willing to look at it.

Eagle Ford Evolution

With more than 450,000 net acres in the Eagle Ford, BPX is focusing on the oilier portions for now in DeWitt and Karnes counties and also ramping up a new refrac program with partner Devon Energy, focusing mostly on wells at least 10 years old.

"The Eagle Ford continues to surprise us in the way of its productivity and what these wells are capable of producing," Edwards said. "We are bringing on refracs that are, quite frankly, better than the parent wells were, which is just kind of hard to believe. We just couldn't be happier with what we're seeing in the way of productivity there. There's a

BPX

CEO Kyle Koontz tours BPX's Grand Slam facility. BPX's emphasis in the Permian since the BPH deal has been building out the infrastructure for electrification and efficiency.

lot of technical horsepower that we can invest there between the Devon and the BPX side, and the well results are showing it."

The biggest challenge, he said, is going back in and downspacing between the parent wells.

"I think we are well on our way to solving it. But what is interesting is that the Eagle Ford would've been considered probably the simplest and most straightforward basin to execute in from a drilling perspective two or three years ago," he said. "And, as we move further into redevelopment, it becomes more and more complex."

BPX first experimented with Eagle Ford refracs in 2019, and the results were underwhelming, but educational, Edwards said. The new program for 25 wells this year is paying off.

"The fracs on those original parent wells where something like 500-pound or 600-pound per foot in the way of sand. The current fracs in the Eagle Ford are generally all 2,000-plus and probably approaching 3,000 pounds per foot of sand in some cases," he said. "So, ostensibly, frac sizes have grown four times over the last 10 or 15 years, and that's a remarkable thing. In these shale plays, you look at a well drilled pre-2010 and it's already a legacy well. Because of the steepness of the learning curve and the technology application, an old well is now 10 years old, and that's really quite remarkable."

And new wells are looking strong too, Koontz said. While BPX is more cautious with spacing in the Permian, the company continues to downspace in the Eagle Ford. A new well in the Blackhawk area came online recently at 3,500 bbl/d, which Koontz said may be a BPX record.

Koontz said BPX just added another Halliburton e-frac crew in June to the Eagle Ford that is running off of CNG. He cited 15% efficiency gains in the switch from diesel to CNG.

And the in-basin gas production will ramp up with pricing.

"The Hawkville, in the southwestern Eagle Ford, has got a ton of running room," Koontz said of the gassier acreage. "We continue to see that asset outperform, just very high gas rates, but also wellhead condensate. It's got a really strong profile of rich liquids there, and we continue to see the wells deliver above expectations. So, what we would call core, Tier 1 acreage is a growing footprint."

Haynesville Hopes

BPX's 500,000 net acres on the Louisiana and Texas sides of the Haynesville depend on gas prices, but BPX is bullish on global LNG demand and rising domestic power demand in the years ahead along with much of the rest of the industry.

"We slowed our activity down to obligation drilling, but it's a premium gas asset," Koontz said, noting the acreage quality is strongest in Louisiana. "We've got some of the best acreage in the play."

Despite the HP/HT shale, BPX is

BPX

BPX employees and contractors meet at the Grand Slam facility in the Permian.

drilling its longest laterals in the Haynesville.

"I think we've got a pretty good bead on the Haynesville. We're just looking to see how long of lateral length we can do in a well to find that sweet spot versus technical risk and operational efficiency," he said. "We've gone out to just under 15,000 feet on a handful of wells, and there's increasing success there. I think we're gaining confidence in being able to do that. So, we could see 3-mile laterals being more of a thing going forward."

Edwards also is quite bullish on technical gains in Louisiana.

"We are seeing opportunities to drill 20,000-ft laterals. Those kinds of things are constantly under evaluation. Do you get to a tipping point? Yes. Do I think we're there yet? No. I think that there's significant efficiency gains that we can have that we're not necessarily seeing today," Edwards said.

"From a completions perspective there, what's been amazing to me over the last couple of years is just generally speaking how efficient these frac crews have become, and just how many rigs it takes to sort of keep them fed and full and continuously operating through the year," he added. "In the Haynesville specifically, the way we drill, complete, produce these wells is quite remarkable. The 50-plus MMcf/d IP maxes are almost commonplace at this point, and that is just a dramatic improvement over thinking about where we were three to five years ago."

Because of pricing, BPX is letting some Haynesville DUCs build up temporarily. But Edwards said this is not part of some big DUC program, at least not compared with what Chesapeake Energy and some of the bigger Haynesville players are doing.

He explained: "The difference is, there are DUCs that are being completed now and not brought online. That's not really a DUC because DUC in and of itself is a drilled but uncompleted well. These are drilled and completed wells that are essentially ready to flow, but not flowing. We are not necessarily in that camp. We are running a rig right now. We are completing wells in 2024. We will exit the year with some DUCs, but we are not building a massive DUC inventory. And we are not building an inventory of wells that are drilled and completed, and we just need to open the valve when prices allow for it. I do think that is a difference now compared to what you've seen over the last few years where historically the wells were drilled and then remained uncompleted.

"It'll be interesting to see how those wellbores respond with significant amounts of frac water sitting in the formation for what appears to be months at a time before they come online," Edwards said. "It would be an approach that I would definitively study and make sure we fully understood technically before we took it. I just think that's a bit of a wild card that'll just be interesting to watch in the industry over the next six to 12 months. How does that physical hedge on gas prices play out?" E&P

Nuclear in a Box: Small-Reactor Fission May Answer Permian's Power Ask

A top Permian producer has signed up for a small-footprint nuclear plant. A top pressure-pumper has invested in the developer. Industry members say interest in Permian nuclear is hot.

NISSA DARBONNE | EXECUTIVE EDITOR-AT-LARGE

Rich with Btu's from oil and gas, the Permian Basin is megawatts-short. Meanwhile, the basin's producers are looking for offsets to their carbon-rich products that are weighing on Scope 1 scores.

Enter nuclear—and a top Permian producer, Diamondback Energy, and a leading U.S. pressure-pumper, Liberty Energy.

Diamondback signed in April a 20-year power-purchase agreement with California-based Oklo Inc. for a 50-megawatt (MW) small nuclear reactor unit for its Permian operations.

Separately, Liberty made a $10 million investment last year in Oklo.

Chris Wright, Liberty chairman and CEO, told Hart Energy in April that Oklo is a next-generation nuclear company "that's another potential adder to the world energy system."

The shale revolution has allowed world energy use to expand to 600 exajoules per year, he said.

"If we're going to produce 800 exajoules in 2050, where's that extra 200 coming from?" he asked. "We need new shale basins, continued development of existing shale basins [and] maybe some new nuclear technology."

'Continue to Increase'

Diamondback President Kaes Van't Hof told Bloomberg, "Small nuclear reactors could make sense as a low-cost, low-carbon, high-reliability alternative energy source for a company like Diamondback, whose energy needs continue to increase."

"Are we in the midst of an energy transition that we hear so much about? The data says that the answer is 'No.'"

CHRIS WRIGHT, Chairman and CEO, Liberty Energy

Diamondback currently produces 463,000 boe/d net from the Permian Basin. It had 13 rigs at work in late April, and plans to add fellow Permian producer Endeavor Energy Resources to its portfolio later this year, bringing its total production to 816,000 net boe/d.

Permian producers could generate electricity in-basin with associated gas, which they were paying up to $3/Mcf to offload in April as the Waha spot price collapsed. But those with reduced-carbon targets would be piling on more carbon if they use natural gas for power generation in producing carbon-based Btu.

Meanwhile, there is a growing in-basin market for electricity for all purposes, energy research firm Enverus reported in April. Its findings are that far West Texas' power demand will more than double by 2040.

"Within the next few years, the Far West will need a large power generation build-out to meet the forecasted load growth," said Riley Prescott, senior associate at Enverus Intelligence Research. "Without it, we expect power prices in the area will rise significantly."

Fast-Breeder

Oklo's model is a metal-fueled fission plant that can be sited where power is needed without requiring expensive and lengthy power-line transmission, according to the company. The reactor is liquid-metal cooled and non-pressurized. The plant is partially

"Within the next few years, the Far West will need a large power generation build-out to meet the forecasted load growth. Without it, we expect power prices in the area will rise significantly."

RILEY PRESCOTT, senior associate, Enverus Intelligence Research prefabricated and assembled onsite.

The technology is based on the Idaho National Laboratory's Experimental Breeder Reactor (EBR) that, in 1951, was the first nuclear power generation plant; at the time it was known as the National Reactor Testing Station.

A liquid-metal, fast-neutron (fast-breeder) reactor is unmoderated and uses liquid metal as the coolant. "Breed" is used in its description because it produces more fuel than it consumes.

In 1964, its successor, the fast-reactor-model EBR-II demonstrated a closed fuel cycle. It was operational for 30 years.

The Oklo technology is similarly a fast-reactor. In tests, "starting from full power, the intermediate coolant pump was turned off while the control rods were prevented from inserting. The reactor temperature automatically stabilized within minutes," Oklo reported.

In terms of scoring environmental points, carbon emissions are zero, and the fission fuel is recycled, a hallmark of the fast-reactor fission model.

Oklo has letters of interest for more than 50 of its plants, ranging in size from 15 MW to 50 MW. The 15 MW size costs less than $60 million.

And investors have shown interest in small nuclear.

In May, Oklo went public via a merger with blank-check AltC Acquisition Corp. Another firm, Nano Nuclear Energy, IPO'ed in early May in a six-week sprint from its initial filing with the Securities and Exchange Commission.

Nano's Zeus reactor mobilizes in tractor-trailer fashion: The reactor sits on a trailer that is hooked up to a tractor.

NANO NUCLEAR ENERGY

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

'A Hot Item'

Longtime oilfield services analyst Jim Wicklund, now an investment banker with PPHB, reported in April that "small nuclear reactors are becoming a hot item."

PPHB hosted a breakfast in Midland to address several subjects, but talk was lit with nuclear. The growing availability "has spurred oil companies such as Diamondback to at least consider it as an alternative to diesel or natural gas" in field operations, Wicklund wrote in his weekly newsletter.

As for near-term deployment in the field, "we will take the 'under,'" he added. But "just the fact that it is being discussed is a positive to me."

In comparison with large nuclear plants, small modular reactors (SMRs) are less expensive, have a smaller footprint, use less fuel, have lower emissions, and are quickly installed, according to Fort Collins, Colo.-based DataHorizzon Research.

"These advantages are anticipated to drive significant adoption of [SMRs], fueling a notable upward trend in the market," the firm reported in April.

It expects the market for SMRs will be $7.5 billion by 2032, with North America leading demand.

SMR and other nuclear developers include Brookfield Renewable, Fluor Corp., General Atomics, General Electric, Holtec International, Mitsubishi Heavy Industries, Rolls Royce, TerraPower, Terrestrial Energy and X Energy, the firm added.

'Quite Interested'

The new interest in small reactors by the oil and gas industry has not surprised Jeff Merrifield, chairman of the U.S. Nuclear Industry Council, which represents some 80 operators in nuclear development.

"I think this has been bubbling along for some period of time," he told *E&P*. "I think there are a number of folks in that industry who've been looking at this."

Merrifield was appointed by President Bill Clinton to serve on the U.S. Nuclear Regulatory Commission in 1998 and named to a second term in 2002 by President George W. Bush. He served through 2007. During that time, he visited all 104 of the then-operating U.S. power reactors and toured more than 140 abroad. Prior, he worked for the U.S. Senate Subcommittee on Superfund, Waste Control and Risk Assessment and was a legislative assistant to two U.S. senators. Currently, he leads the Pillsbury law firm's nuclear energy practice.

"Where there are a number of folks who are quite interested [in nuclear application] is the developing market for mobile and micro-nuclear reactors," Merrifield said.

The U.S. Army's Project Pele has funded two demonstration reactors that would produce between 1.5 MW and 5 MW.

"Something of that size, you could put on the back of a tractor trailer in a container box," he said. "Put them in a C-17, fly them halfway across the world and have them up and operating within 72 hours."

Expectations are for beta demonstrations within a couple of years.

"That [mobile reactor] is a market that I think a number of folks in the exploration industries would find interesting because they really are suited for remote operations where you don't have a localized power source," Merrifield said.

"That [mobile reactor] is a market that I think a number of folks in the exploration industries would find interesting because they really are suited for remote operations where you don't have a localized power source."

JEFF MERRIFIELD, chairman, U.S. Nuclear Industry Council

Carbon-Free

Among attendees at the Advanced Reactors Summit XI in Houston in April were more than 30 oil and gas company representatives. Among speakers, including Merrifield, was Caleb Tash, director of sustainability for Diamondback Energy.

Tash "made it quite clear they think this is a market for them and one that will help them meet their power operations, but do so in a carbon-free way," Merrifield said.

Also speaking at the conference was Nick Morriss, director of business development for Shepherd Power, a business unit of oilfield services provider NOV Inc.

Another type of nuclear reactor is a small light-water design that produces some 300 MW. These are well suited to the growing power demand by data centers and for the replacement of coal plants.

"Light-water reactors basically use tap water for their cooling and moderation," Merrifield said.

Then there are the non-light-water reactors, which include high-temperature gas reactors, molten-salt reactors and sodium fast reactors, all of which were developed by the Atomic Energy Commission in the 1950s.

Among all types of reactors, "I think for the oil and gas industry—and by extension the petrochemical industry—the interest is initially going to be in micro-reactors," Merrifield said. "They will be the closest to actually being deployed in larger numbers. And then I think some of the high-pressure gas reactors and molten-salt reactors will be interesting and potentially deployable."

Other potential oil and gas applications for nuclear include powering petrochemical plants and using the heat byproduct in cracking. Large offshore oil platforms could use a small nuclear reactor, he added.

Already in Use

Mobile reactors are in use already. "We have a lot of portable reactors," Merrifield noted. "People just don't think about them: Every U.S. submarine has a nuclear power plant."

The specs on those are classified, but what is public is that the U.S. Navy design for submarines is roughly a 20 MW plant using a pressurized-water reactor.

"But it is of a much different design than anything in the civilian world," he added.

Aircraft carriers use two plants, each of which is roughly 40 MW. Altogether, the U.S. Navy has about 100 sub- and carrier-based mobile reactors in operation.

"We've been deploying mobile nuclear power plants as a country for 60-plus years," he said. The design being considered for use in oil and gas operations "is something we have a lot of experience with."

The first one deployed by the U.S. outside of strictly military purposes was a 15 MW to 20 MW reactor at McMurdo Sound in Antarctica as part of the U.S. Army nuclear power program. Another was a barge-mounted reactor deployed in the Panama Canal; another, a tractor-borne mobile reactor deployed in Greenland.

"So we've been doing this for many years," he said. "If you can have a

SOURCE: GENSLER VIA OKLO

Oklo's Aurora powerhouse design is partially prefabricated and assembled onsite.

power source that you can bring in on the back of a tractor trailer and provide the power you need for that remote operation, that's a pretty desirable thing."

The Exajoules

Liberty's Wright was in the nuclear and solar business before being part of the team that successfully tried a light-water frac on the Cotton Valley in East Texas in the mid-1990s. Mitchell Energy & Development Corp. picked it up and tried it in the Barnett, resulting in the shale breakthrough.

Wright's undergraduate degree from MIT was in mechanical engineering; graduate studies in electrical engineering were at University of California at Berkeley and MIT.

He concluded a recent quarterly earnings call with a summary of global advancement in energy supply.

"Are we in the midst of an energy transition that we hear so much about? The data says that the answer is 'No,'" he said.

"This is not an opinion or a preference," he continued. "Heck, I work in other areas of energy and began my career in nuclear and solar. This is simply an honest reading of the data."

Of the 100 exajoules of energy added to global supply in the past 12 years, some 40% came from natural gas with half of that coming from U.S. shale. Oil provided 24%, also from U.S. shale. Another 14% came from coal; wind, 9%; solar, 4%; and hydro, 4%.

In short, 63% of energy supply growth came from oil and gas—"an increasing market share," he said.

"How can we call this a transition …? Don't get me wrong. I'm not celebrating this fact. I'm just calling out others for pretending it isn't so."

To supplement global supply, particularly to populations with none, "it would be very helpful if nuclear, which saw zero growth over the last 12-year period, geothermal and any other affordable, reliable energy source could contribute much, much more," Wright said.

'Tremendous'

A securities analyst asked Wright during the earnings call for the rationale behind the $10-million Oklo investment. Liberty is also invested in a geothermal developer, Fervo Energy Co.

While Liberty's investment in Fervo is "barely a move at all from our core business, Oklo is definitely more of an outreach," Wright said.

Its Liberty Power Innovations unit, which supplies natural gas-fired power generation onsite, is "to deliver gas and electricity where it's needed. And today, that's in the oil field, running our frac fleets, … then it's going to grow to other oilfield applications."

The interest in Oklo's technology as a small-grid solution "is tremendous" in the power generation business at large, he said. In the Permian in particular, "we held an event in Midland," he said. Interest there was similarly piqued.

Liberty also has invested in Natron Energy, developer of sodium-ion batteries used in frac-site power storage. Wright said lithium-ion batteries "have some fundamental problems." Natron's sodium-ion brick is better suited to a frac job.

"It can discharge faster. It can recharge faster. It can live longer. It does not have the fire hazard" that lithium-ion batteries carry, he said. Of course, it has a lower power density, "so it doesn't win on everything, but it wins on the things that matter for us," Wright said. E&P

EXXON MOBIL

Exxon Mobil operations in Midland County, Texas. Exxon is a frontrunner in longer lateral drilling, with notable successes in pushing the limits of lateral length.

Surge of Longer Lateral Drilling

With energy demand growing, operators look to supply hydrocarbons by drilling longer wells.

JAXON CAINES | TECHNOLOGY REPORTER

In the changing landscape of the oil and gas industry, one trend stands out as a beacon of efficiency and innovation: the continuous push for longer laterals. As the demand for hydrocarbons continues, operators are extending their lateral lengths to maximize recovery from oil reservoirs.

According to industry experts, lengthening lateral wells is one of the most basic ways to enhance recovery because extending the horizontal reach allows access to more of the reservoir.

"In general, things continue to get longer and longer. Increasing lateral length is one of the most straightforward ways that E&Ps have been able to improve the efficiency of their operations," Steve Diederichs, director of oil and gas research at Enverus, told *E&P*. "Across every single basin where operators have the opportunity to do so, we see them pushing laterals longer where they can."

> "Across every single basin where operators have the opportunity to do so, we see them pushing laterals longer where they can."

STEVE DIEDERICHS, director of oil and gas research, Enverus.

From the Permian Basin to the Eagle Ford and beyond, operators are pushing the boundaries of lateral drilling, hoping to extract the maximum volume of hydrocarbons from their assets. And while the benefits of longer lateral drilling are evident, the process is not without its challenges.

Acquiring acreage and consolidating assets are among the top priorities for companies looking to expand their drilling operations and unlock the potential of lateral wells. Securing the acreage position to support long laterals poses a significant hurdle for some operators, as they need a "contiguous block of land that lets them drill at least 3 miles," Diederichs said.

Other challenges, such as equipment availability, also require careful navigation. Specialized equipment, such as extended-reach coiled tubing units, is essential for successfully drilling and completing longer lateral wells, yet it is often a struggle to find this equipment, he said. The completion of the toe, or the end of the horizontal leg, is another challenge that must be addressed.

"With longer laterals, there are often challenges with efficiently fracking the farthest portion of the well out in the toe. Operators have made some improvements in being able to better complete the toe of these longer wells, which improves their ability to not lose anything in terms of total resource capture with longer laterals," Diederichs said.

"When we look at the comparison between 2-mile wells versus 3-mile wells, the EUR, or estimated ultimate recovery, pretty closely scales directly up with those longer wells. So, you lose a little bit because of friction issues, but essentially your recovery per foot is quite consistent, moving from 2 miles to 3 miles."

Operators have made strides in enhancing the completion process to maximize resource capture from extended lateral wells. Breakthroughs in equipment and technology have addressed logistical challenges associated with drilling and cleaning out longer wellbores. Innovations in directional

On the Horizon: Exploring the Permian Basin's Longest Lateral Wells

With energy demand growing, operators look to supply hydrocarbons by drilling longer wells.

Maximizing hydrocarbon recovery is the constant goal of the oil and gas industry, and developing new technologies is the means to that end. Horizontal drilling is a case in point. After years of drilling vertically to reach reservoirs, innovative thinkers came up with a new strategy to get as much oil out of a field as possible—horizontal drilling. And when new challenges arose, creative engineers figured out how to extend lateral wells to access more of the reservoir for improved recovery and operational efficiency.

A look at the companies that are pushing the limits of horizontal drilling shows just how far the industry has come in developing technologies to extend well length and increase production.

NABORS INDUSTRIES

The Nabors X-29 Rig is in the same family of rigs as the X-12, which drilled the three longest wells in the Basin.

Exxon Mobil

In the Permian Basin alone, supermajor Exxon Mobil is responsible for five of the region's longest lateral wells, three of which are in Poker Lake, N.M.

At 22,211 ft, Poker Lake Unit 21 DTD 176H is the longest well in the Permian, with wells 177H and

Permian Laterals 2024

Company	Well	Length
Exxon Mobil	Poker Lake Unit 21 DTD 176H	22,211
Exxon Mobil	Poker Lake Unit 21 DTD 177H	22,138
Exxon Mobil	Poker Lake Unit 21 DTD 175H	22,136
GBK Corp	Red Hills Federal 504H	21,156
SM Energy	Clarice Starling Sundown D 4542WA	20,873
Franklin Mountain Energy	Green Light Federal Com 801H	20,765
Permian Resources	Ovation Federal Com 1318 241H	20,503
Pioneer Natural Resources	Frank-Sally 11K 111H	19,301
Exxon Mobil	Big Eddy Unit 5E Han Solo 100H	19,288
Exxon Mobil	John Braun A Unit 4 2527SH	18,951

SOURCE: ENVERUS

PIONEER NATURAL RESOURCES

Pioneer Natural Resources operations in Midland County, Texas. Exxon Mobil's acquisition of Pioneer Natural Resources has given Exxon access to a large swath of acreage with which to develop lateral drilling techniques.

drilling techniques, downhole tools and hydraulic fracturing methods have enabled operators to navigate complex geological formations and extract hydrocarbons more efficiently than ever.

"Typically, what we're seeing out of longer lateral wells is not a huge change to the EUR on a per-foot basis compared to 2-mile wells, but we are seeing changes to the shape of the production profile. So, because you have more reservoir being contacted by a single wellbore, there's a lot more hydrocarbons flowing back to surface, as operators are often avoiding overbuilding their surface facilities and instead choosing to flow these wells back less aggressively early in their life," Diederichs said.

This creates a slightly lower peak rate on a lateral length normalized basis but fairly similar ultimate recoveries on a per-foot basis, he said, explaining, "It essentially shallows the decline of wells with a slightly lower peak rate for longer lateral wells."

Meeting Regulatory Guidelines

Regulatory considerations are generally manageable, Diederichs said, with longer laterals potentially offering environmental advantages. By reducing the number of surface pad locations and consolidating drilling operations, longer lateral wells can minimize surface disturbance and mitigate environmental impacts.

From a regulatory perspective, longer lateral drilling projects may face similar permitting requirements as traditional drilling operations, with additional considerations for well spacing and setback requirements. However, the concentration of drilling activities on fewer surface pads can streamline the regulatory approval process and facilitate compliance with environmental regulations.

"The case could probably be made that these are better from an environmental perspective in that you'll have fewer surface pad locations for the same amount of lateral footage drilled," he said.

Diederichs pointed to Exxon Mobil as a frontrunner in longer lateral drilling, with notable successes in pushing the limits of lateral length. Acquisitions of companies like Pioneer Natural Resources have bolstered Exxon's position, providing access to extensive acreage for further development.

"Exxon is probably the name that we would view as being most likely to be a leader in longer lateral drilling. You can already see them having the top three wells," Diederichs said. "The acquisition of Pioneer gives them a very, very blocky acreage position with a lot of completely undeveloped units from the horizontal perspective, meaning they have a ton of high-quality acreage. That's a blank slate of how they want to develop it."

Other major operators, including Chevron and Shell, are also investing in longer lateral drilling projects, encouraged by the potential for enhanced resource recovery and improved economic returns.

Diederichs anticipates a continued trend toward longer laterals, driven by technological advancements and consolidation. As operators gain access to larger and better acreage positions, the potential for longer lateral drilling projects will continue to grow. Ongoing innovations in drilling and completion techniques are expected to further enhance the efficiency and cost-effectiveness of longer lateral wells, which will shape the landscape of oil and gas exploration for years to come. E&P

EXXON MOBIL

Exxon Mobil's Poker Lake, N.M. facility processes natural gas from some of the Permian Basin's longest lateral wells.

175H, the second- and third-longest wells at 22,138 ft and 22,136 ft. Wells 175H and 176H were spudded in first-quarter 2023, and 177H was spudded the following quarter. All three wells were drilled by the Nabors X12 rig.

Exxon's Big Eddy Unit 5E Han Solo 100H well, spudded in May 2020 in Eddy County, N.M., is the ninth-longest lateral well at 19,288 ft. The company's John Braun A Unit 4 2527 SH well in Midland County, Texas, is the 10-longest well in the Permian. It was completed in April 2023 at 18,951 ft.

GBK Corp.

Spudded in July 2020 by Tulsa, Okla.-based Kaiser-Francis Oil Co. subsidiary GBK Corp., the Red Hills 504H well is the fourth longest lateral well in the Permian, measuring 21,156 ft. The well, located in Lea County, N.M., began producing in 2021.

SM Energy

In the same year that the Red Hills 504H well came onstream, SM Energy held the record for the longest lateral well in the Permian, with Clarice Starling Sundown D 4542 WA in Howard County, Texas. The still-producing well, which took crews about 20 days to drill, is now the fifth-longest lateral in the basin at 20,873 ft.

Franklin Mountain Energy

Denver-based Franklin Mountain Energy has the sixth-longest lateral well in the Permian. Located in Lea County, N.M., the company's Green Light 801H well, which is 20,765 ft long, began producing in August 2023.

Permian Resources

The eponymously named Permian Resources operates the seventh-longest lateral well in the Permian Basin. Located in Eddy County, the 20,503 ft-long Ovation 1318 241H well began production in September 2022.

Pioneer Natural Resources

Pioneer Natural Resources (acquired by Exxon Mobil) had the eighth-longest lateral well in the Permian Basin. The 19,301 ft-long Frank-Sally 11K 111H well, was drilled in Midland County, Texas, by H&P's rig 641.

Are 3-Mile Laterals Worth the Extra Mile?

Every additional foot increases production, but it also increases costs.

PAUL WISEMAN | CONTRIBUTING EDITOR

Almost like tree roots, laterals in unconventional plays have spread farther and farther since the shale revolution began, weaving their way across multiple basins. As drilling and completions technologies have gradually improved, so has the industry's ability to do more with less—constantly lengthening those laterals to reach more production zones with fewer wells.

Drilling longer laterals has an obvious upside, but the process comes with some challenges that are both technological and economic.

Evaluating the Third Mile's Output

The most basic question about adding a third mile to laterals in unconventionals is whether there is enough incremental production to justify the expense of going the extra mile.

Ryan Hill, principal analyst at Enverus, told *E&P* the potential payback must evaluate the productivity of a well and the ultimate forecasted recovery of the well per lateral foot drilled. The decision hinges on whether the extra mile not only produces significantly more, but that production per foot is at least close to that of a nearby 2-mile well.

Ryan Hill

"On that incremental mile, are you gaining or losing productivity per foot relative to that offsetting 2-miler?" he asked.

Hill cited Enverus data showing that the most positive answer involves the long term, specifically in the Permian and in the Bakken.

"You're not getting the same kind of peak rate" on a lateral normalized basis (per foot), he said. "But we're seeing pretty comparable forecasted total recoveries. So, what you'll eventually get out of that well, on a lateral normalized basis, is very close to being in line with 2-mile drills, which is quite reassuring."

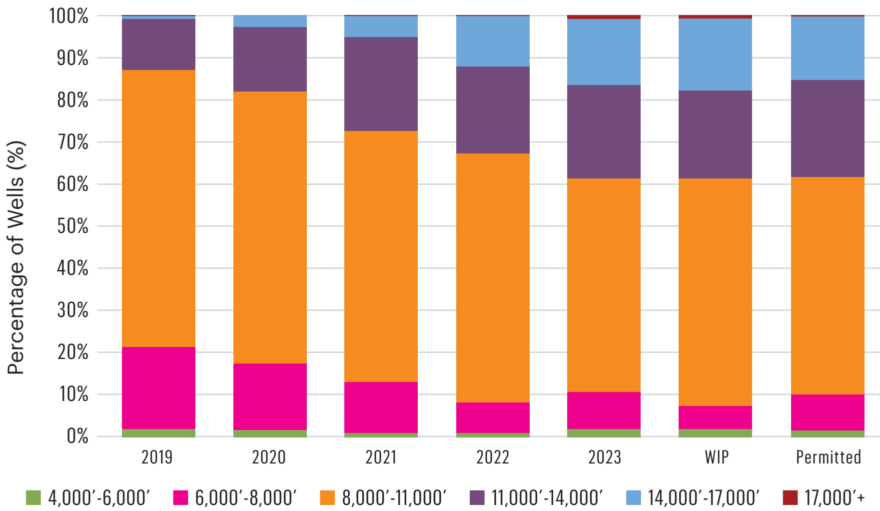
A lower peak rate is balanced by a slower decline curve.

With similar per-foot production, it validates the idea that drilling two 3-mile laterals is indeed more cost-effective than drilling three 2-milers.

"The more you have that capital cost savings, the more it pushes you down the 3-mile road," Hill observed.

This good news only applies to producers that are willing to accept some delayed gratification. Many operators are looking to pay for the well as quickly as possible, therefore pushing for the highest per-foot peak production possible. For those operators, it might make sense to stick with shorter laterals, Hill noted,

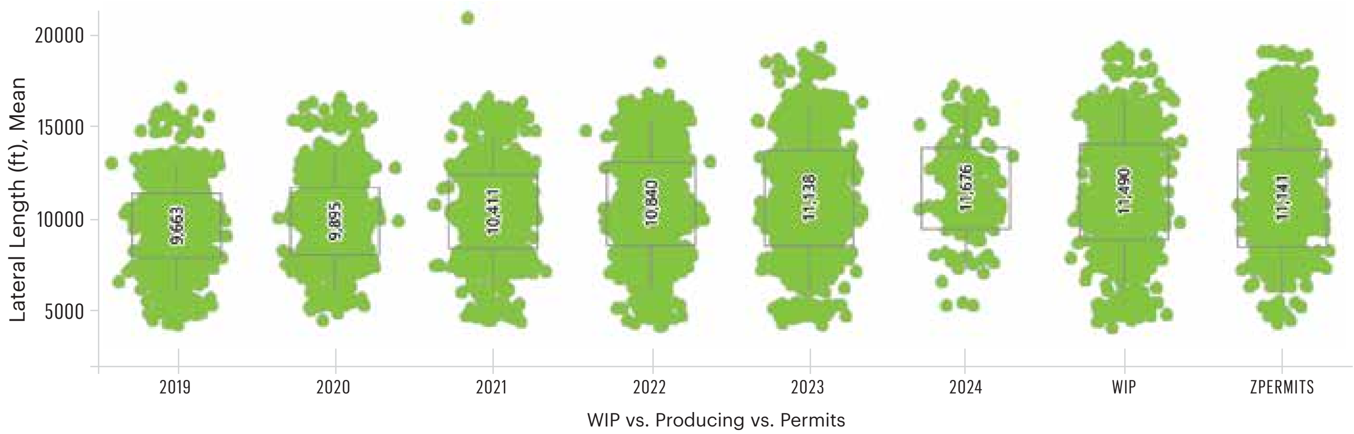
Midland Basin Average Lateral Lengths Over Time



SOURCE: ENVERUS INTELLIGENCE RESEARCH, ENVERUS CORE

Between 2019 and 2023, laterals of 8,000 ft to 11,000 ft (orange) were dominant in the Permian Basin, but those of 11,000 ft to 14,000 ft (purple) and 14,000 ft to 17,000 ft (blue) grew steadily. "WIP" indicates wells in progress (wells currently being drilled, wells drilled and uncompleted, and completed wells). Permits are approved permits that have not spudded.

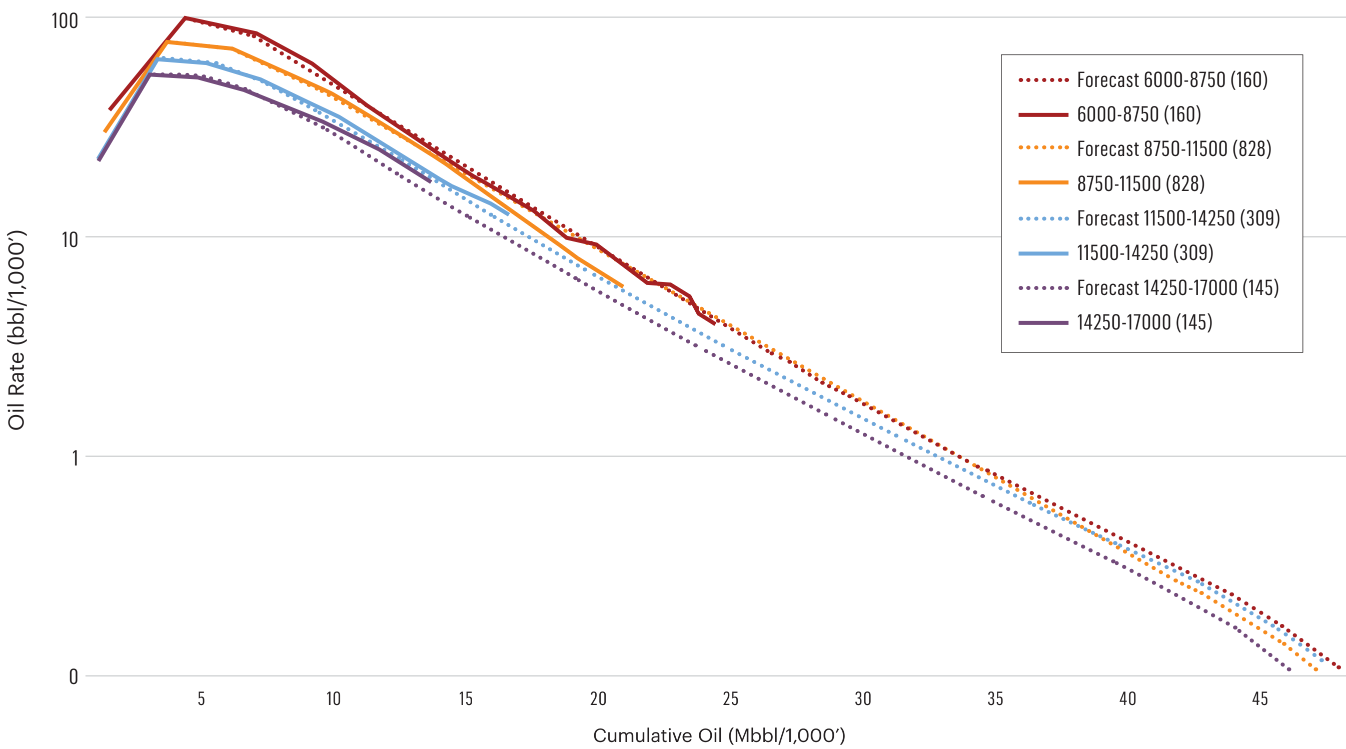
Midland Basin Lateral Length Through Time



SOURCE: ENVERUS INTELLIGENCE RESEARCH, ENVERUS

Each dot represents one well's length (Y axis), sorted by year (X axis). The number in the middle is the mean.

Midland Basin Oil Productivity by Lateral Length



SOURCE: ENVERUS INTELLIGENCE RESEARCH, ENVERUS CORE

Grouping lateral lengths into four buckets, this compares production on the basis of barrels/ thousand ft. The shorter wells of 6,000 ft to 8,750 ft do best, while the longest are at the bottom of the list.

rather than facing higher up-front costs for the long laterals and slightly reduced peak flow.

Still, there are significant savings in entry costs when longer laterals result in fewer wells drilled. Hill says the cost savings can be "around 15%, even 20%, on a per-lateral-foot basis, just by avoiding those multiple vertical holes to access the horizontal."

If three is good, why not go further? Hill says Enverus research has shown that Exxon Mobil has drilled at least a few 4-milers. But lateral length limits are set by technology, including production capabilities and, at least for now, 4 miles is about the far end of those abilities.

The Shape of Things to Come

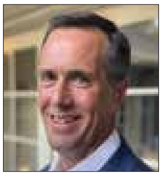
Drilling laterals in a fairly straight line is by far the preferred configuration, Hill noted, but there are several reasons drillers sometimes veer off the straight and narrow. Drilling U-shapes and even Ws—"We call it creative drilling"—is "an opportunity to save capital or even execute otherwise uneconomic drills because they would be too short," he said.

The main reason for creative drilling is lease limitations, he said. A wellbore positioned closer than 2 miles from a lease border limits how far a well can go in that direction. South Texas and the Permian's Delaware Basin are the main areas where this occurs.

Length and shape are also influenced by regulatory pressures, especially in Colorado, in Hill's view. That state has passed laws mandating longer separation between well sites and structures, meaning that operators can be forced to drill farther to engage producing zones.

Completion, Drilling Tech

David Millwee, Patterson-UTI's vice president of drilling performance, told *E&P* the growth in wellbore length has depended on a number of technological advancements, not just on the drilling side. A major factor has been ongoing improvements in hydraulic fracturing techniques made necessary by the tight formations.



David Millwee

"In 1997, a long lateral was 500 ft because that's how far they could reach for completions," he recalled.

As processes expanded over the years, drillers grew their own abilities accordingly. Laterals slowly extended to 2 miles, then 3, and today they are approaching 4 miles in some areas.

"What made you go from a 2-mile lateral to a 3-mile lateral? Well, completions people figured out how to frac that third mile efficiently; so let's go out there and drill it," Millwee said. "Every time we find a technical limit, we identify how to engineer improvements, implement the changes, and continue to move forward."

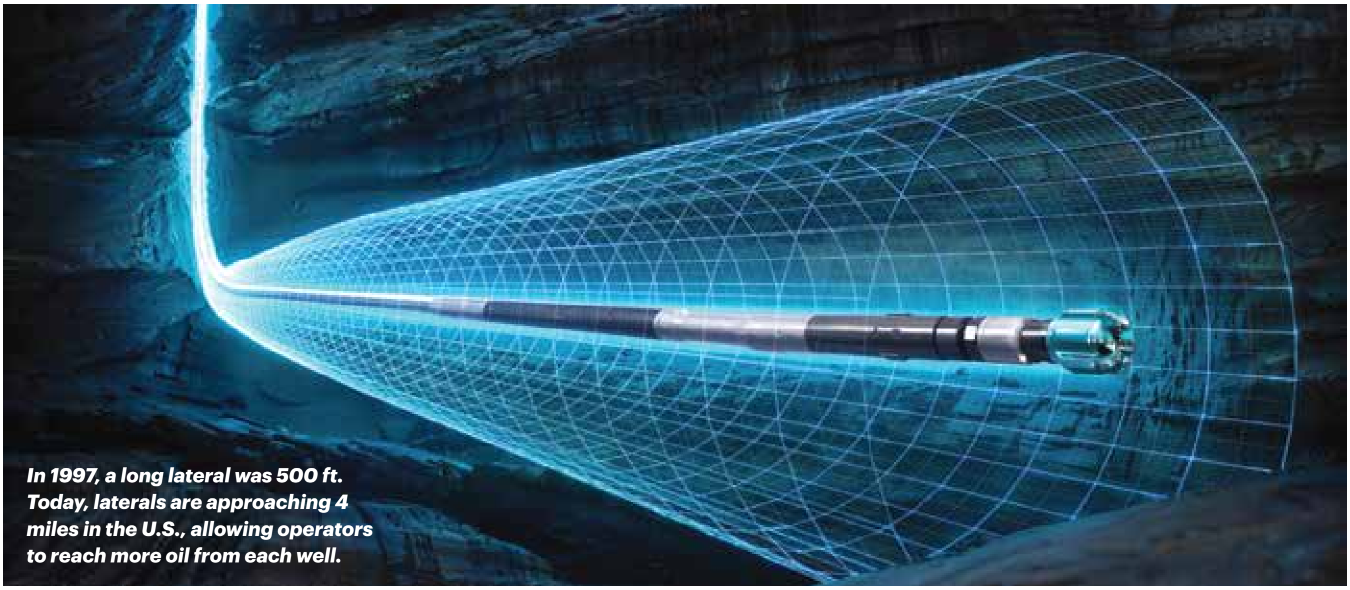
Early improvements involved increasing hydraulic horsepower capability for drilling rigs. That is because increased flowrates and pressures required additional pumping capacity and raising pressure limits to 7,500 psi instead of the industry standard 5,000 psi. Additional torque requirements were next, requiring higher torque drill pipe, upgraded top drives and high-performing mud motors.

Some of the recent progress he sees includes new drill cutters making larger depth of cut, more powerful mud motors coupled with rotary steerables "so you don't have to slide and keep rotating the pipe," enhanced precision in rig control systems, process automation, and more.

All of these can inform decisions about overall lateral well length. Limiting the number of downhole trips is another factor.

Longer laterals require higher pressures in the drilling process—rising to 7,500 psi today, from just 5,000 psi a few years ago.

PATTERSON-UTI



In 1997, a long lateral was 500 ft. Today, laterals are approaching 4 miles in the U.S., allowing operators to reach more oil from each well.

PATTERSON-UTI

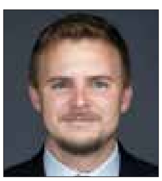
"The fewer times you re-enter the production zone, the better," Millwee said.

The ability to use just one bottomhole assembly (BHA) or minimal BHAs, depending on the play, is crucial. Every time the equipment trips out of a production zone and reenters it, the risk of problems increases.

"If we're drilling a 4-mile lateral and there's a BHA failure at three-and-a-half miles, sometimes they don't drill the extra half-mile," he said.

Tier 2 Acreage

While lateral footage has grown by several factors since the early days of unconventional drilling, the yearly increase is incremental at about 350 ft per year, according to Matt Mayer, senior product manager for TGS Well Data Products.



Matt Mayer

He noted an upward trend with a peak of estimated ultimate recovery (EUR) around 2016 that is slowly coming back down, which TGS has partially attributed to lower-tier acreage or infill drilling with parent-child well interaction.

He sees necessity as a motivating factor behind the move to longer laterals. With most Tier 1 acreage already drilled, this could be a way to get more out of wells drilled in Tier 2 acreage. There is no geological reason for the third mile to be different from the first two in terms of production.

Efficient use of rig time could also factor into the mix.

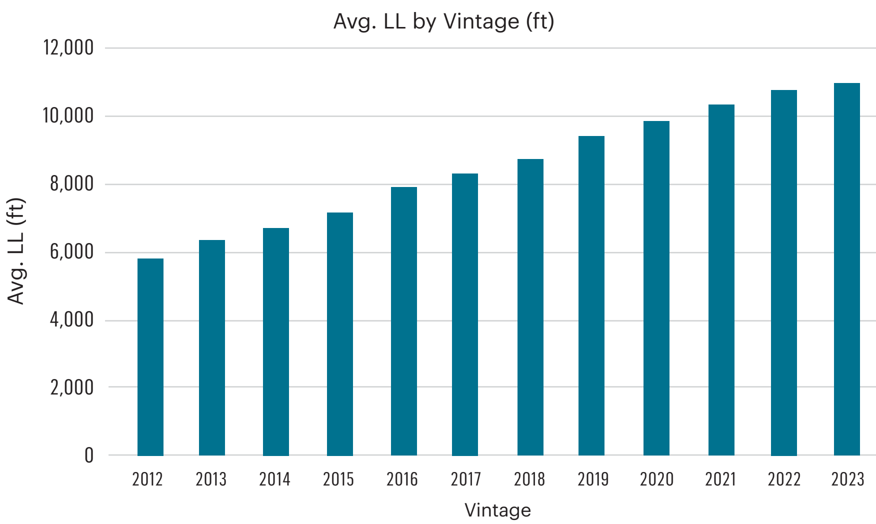
"If you only have (a rig) available for a certain time, it's probably more efficient on a per-foot-of-productive-interval basis to drill longer laterals than it is to drill a lot of shorter ones," Mayer told *E&P*.

One factor de-risking the longer laterals could involve technological improvements in LWD tools, he observed, adding that today's tools are more reliable and more accurate than ever before.

Avoiding Downhole Collisions

With the increase in longer laterals—and laterals as a whole in the crowded

Average Lateral Lengths in the Permian



SOURCE: TGS WELL DATA PRODUCTS

Lateral lengths in the Permian Basin have grown gradually in recent years.

To steer clear of production zones in existing wells, H&P technicians take extremely precise magnetic field inclination and declination measurements with survey instruments to refine the producer's existing in-field referencing magnetic model.

HELMERICH & PAYNE

Permian Basin—avoiding collisions becomes as much of an issue downhole as it does on oilfield roads.

Andrew Pare

Drilling rig giant Helmerich & Payne sees a way to steer clear of these buried conflicts, Andrew Pare, H&P's Manager of Geophysics and Technology Development, told *E&P*.

Pare is not aware of any cases where 3-mile laterals have actually collided in the Permian due to most companies' awareness of the issue and adoption of strong anti-collision policies. But he listed some ways the extended laterals can still destroy value.

"If survey accuracy is not addressed, then the wells will drain the reservoir with less efficiency but with high certainty. So, that'll be very common if the decrease in survey accuracy is not addressed," he said.

Such laxity could lead to a rise in "frac hits" as laterals grow to 3-mile lengths. "In rare cases, the laterals may collide in dangerous and destructive ways," he said.

Before drilling starts, H&P technicians "take extremely precise magnetic field inclination and declination measurements with survey instruments" to refine the producer's existing in-field referencing magnetic model, which was built with "less-accurate airborne measurements." This is based on the direction of the earth's natural magnetic field in relation to true north.

Pare said many current tracking methods become less accurate as the lateral passes the 2-mile mark, and accurate data is necessary to precisely locate existing production.

Previous locating methods involved sending a gyro downhole, but that means drilling must stop while data is obtained. Plus, the longer the lateral, "the harder it is to push the sensor out into the lateral," he noted.

H&P's system gathers the data before drilling starts to better inform the planning process, he said.

The Long Run

The long and short of the decision leans on the industry's ability to drill and frac efficiently at greater distances from a single well site. Perhaps someday drilling activity will be measured in feet drilled as well as in rig counts to more accurately represent the potential for new production.

The sky may not be the limit for lateral length growth—technology and lease configuration are today's issues—but reports of laterals exceeding 50,000 ft are coming from the Middle East, where national borders are the only geographical restriction. In the interest of managing drilling costs by getting more rock exposure with fewer entry points, laterals will likely grow as far as the machinery and the economics will take them. E&P

Cracking the Fracking Code

Technology, process innovations improve operational efficiencies even as companies scramble for greener fracking solutions.

JAXON CAINES | TECHNOLOGY REPORTER

While not synonymous, fracking and energy go hand in hand, and innovations in hydraulic fracturing technology and processes have directly contributed to the U.S. becoming the global oil and gas powerhouse it is today.

"Fracking and the exploitation of shale in the United States has created unprecedented growth in oil and natural gas production and led to the U.S. being a leader in energy production globally," James West, senior managing director at Evercore, told *E&P*.

Although fracking is paving the way for the U.S. to continue to advance its oil and gas operations, a more efficient and sustainable approach is required to optimize wellbores while also reducing emissions.

"Completions technology through the 2010s was just improving the horizontal completion process with multistage fracturing and the different tools and processes that enabled that," William Ruhle, strategic business manager at Halliburton, told *E&P*. "When I think about the last five or even the last seven years, it's been about making the process at the surface more efficient to get through more work, deliver more materials and do more services in a given day."

Efficiency and optimization have been the name of the game for oil and gas operators for years because there is no use in spending millions of dollars to drill multiple wells if the maximum volume of hydrocarbons cannot be recovered. Concepts that emerged in the manufacturing sector in the '80s and '90s, like continuous improvement and sophisticated supply chain management, have been incorporated into business models and have also spearheaded the widespread industrialization of the industry, ProPetro CFO David Schorlemer told *E&P*.

Service companies in the oil industry were doing good work in harsh conditions in different regions of the world, but the industry reached a point of complacency; they were just "getting the job done," Schorlemer said. The problem with that approach is that simply "getting the job done" is not good enough, particularly in challenging market conditions, and that prompted the industry to take a long, hard look at its business model.

"The full optimization of fracking and completions is going to involve a lot of data analytics and machine learning, which go hand in hand."

JAMES WEST, senior managing director, Evercore

Strategies for Optimization

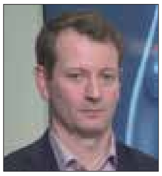
Companies realized they needed to try something different, Schorlemer said, so they began using new processes and technologies.

"It required optimizing and utilizing industrial technologies and equipment for the industrial application," he said.

One significant change has been the migration from daylight-only operations to 24/7 operations. Another is reducing swap times, the time between completing the fracturing stage of a well, sending wireline down and completing and perforating the next zone, and beginning the next frac.

The need to minimize time between stages led to the development of technologies like hydraulically actuated frac manifolds, FHE's RigLock wellhead connector and new approaches to executing fracturing programs, such as zipper fracs and simul-fracs.

The efficiency of zipper fracturing, a multi-well completions technique in which horizontal wells are completed in a back-and-forth fashion, with



"Even if you're running an e-fleet off natural gas, there are enormous savings relative to burning diesel. You're saving on the order of a couple of million dollars a month on diesel."

WILLIAM RUHLE, strategic business manager, Halliburton

Electric fleets, or "e-fleets," generate lower emissions than traditional diesel fleets.

PROPETRO

one well pumping while wireline operations occur on another, has made it a widespread practice, but simul-frac operations, in which two or more parallel horizontal wells are hydraulically fractured at the same time, enable faster swap times.

"It's been nearly 10 years since we brought simul-frac into the market where we simultaneously fractured two wells at once," Ruhle said. "We saw the industry grow steadily over the years doing more and more of that, and today we're even doing trimul-fracs where we're simultaneously pumping down three wells at once."

In a recent trimul-frac job, Halliburton fracked 6,000 ft in one day, or 60% of the well.

Not long ago, Ruhle said, it was only possible to frac two wells over a five- to six-day period. Now, the

The industry is beginning the transition to electric frac fleets.

PROPETRO

industry is beginning to roll out quadral-fracs, or fracking four wells simultaneously.

Companies today are able to build anywhere from 10 to 20 wells on a single pad, Schorlemer said. Operators can be on site for a longer period of time pumping instead of moving from location to location. This reduces mobilization time and replaces it with enough pumping time to increase the amount of footage treated per day, he said.

"We can be fracking on a multi-well pad for not just days, but weeks, and even in some cases months. You're basically converting from a 'day job' mentality to almost that of a mini-manufacturing plant out in the field," Schorlemer said. "Once you can convert it to that mini-manufacturing plant, you can begin to take advantage of all the different processes and technologies that the manufacturing industry has benefited from in decades past."

Improving logistics also has contributed to fracking process improvements. With around-the-clock operations, there are fewer interruptions to the processes of gathering water, frac sand or proppants because they are already onsite.

West said, "I wouldn't say that the technology itself has changed a lot in the last decade. It's been more about better utilization of technologies. Better structuring, better planning and better execution has had the most impact."

For one thing, it is possible to complete "12 or 13 stages per day at this point," he said, "and maybe even higher in some of these highly optimized operations," he continued, noting the significant improvement over one to two stages per day, which was typical a decade ago.

Even though enormous improvements have been made, West believes there is room for improvement. "There are still times when a well might have 30 frac

"Utilizing new technologies that reduce emissions, that improve efficiencies, that reduce truck traffic on the roads, all of those things are in our interests..."

DAVID SCHORLEMER, CFO, ProPetro

stages, but a half or a third of the well doesn't produce. In other words, it's fracked but no oil or gas comes out," West said.

"While we've optimized the top side of the well operation, and we've optimized the drilling of the well," he said, the industry has not figured out how to optimize the fracking process. "Because shale geology doesn't conform to normal geology, it's not consistent. We have been trying to figure out how to make every fracture stage work, and we're not quite there yet."

Another example is advancements in explosives technology. This has led to better penetration during frac operations and less shrapnel left behind in the well, but the technology used in oil and gas operations lags behind the tools used by the U.S. Department of Defense, West said.

The Role of AI

One area of innovation that is flourishing is AI and machine learning in equipment monitoring and predictive maintenance to prevent catastrophic failures. These technologies also help operators and service companies evaluate productivity and aim to solve the issue of making every stage of the fracture "work." Halliburton's Octiv Intelligent Fracturing platform, for example, uses operational data and AI to automatically respond to different events in the well.

"We recently deployed a system across our whole fleet called Octiv, which automates how we run a whole fracturing spread. We've also automated how we run our wireline equipment," Ruhle said. "With the push of a button, you can complete a whole frac job, or you can complete a wireline run and go and perforate a well."

And data analytics and machine learning are playing a more critical role than ever, according to West.

"The full optimization of fracking and completions is going to involve a lot of data analytics and machine learning, which go hand in hand," West said. "We're going to—at some point here—drill, complete, construct wells and start to produce wells autonomously as well. I think it's highly likely that we see an autonomous well drilled in the Permian probably before we see an autonomous taxi in New York City."

Schorlemer cautioned, however, that increased adoption of AI is something that the antiquated technical architecture of the traditional oil field cannot support without massive upgrades.

AI "has required us to completely revamp our technology resources. We have been building out a new team that is focused on understanding the requirements of big data and helping us to understand how we can benefit from AI and machine learning," he said. "We've also been replacing organic disintegrated systems with more enterprise solutions that ... have some of these technologies embedded in them, so it's required us to build a team internally to help us make that transition."

In addition, Schorlemer said ProPetro has been augmenting its internal team with expertise from third parties.

In a recent job, Halliburton fracked 6,000 ft in one day.

HALLIBURTON

Changing Perceptions

Although the industry is using cutting-edge technology and processes that make people safer and streamline operations, public perception of fracking and oil and gas operations remains negative.

This has led companies like ProPetro to think critically about how they and their customers operate and about the impacts of their operations.

Schorlemer said many of ProPetro's completions processes and technologies have been created with the goal of reducing the impact of traffic and emissions and improving site safety.

"We want to be good stewards of the environment that we're operating in, and we believe in the hydrocarbon industry," Schorlemer said. "Utilizing new technologies that reduce emissions, that improve efficiencies, that reduce truck traffic on the roads, all of those things are in our interests, and we're going to continue to look at ways to make sure that we're doing things in the most efficient and environmentally friendly way that we can."

One way the industry is improving environmental stewardship is by reducing emissions with a dual-fuel frac fleet, which is powered by both natural gas and diesel fuel, and shifting to electric fleets or "e-fleets."

"The reason [operators] like the electric systems is that they're cleaner. They are lower emitting. They're more reliable, which means you get more uptime, so they're more efficient operations," Ruhle said. "And the big kicker—the No. 1 driver—is the lower input costs when it comes to fuel. Even if you're running an e-fleet off natural gas, there are enormous savings relative to burning diesel. You're saving on the order of a couple of million dollars a month on diesel."

Halliburton, which first successfully deployed a grid-powered frac fleet in West Texas in 2021, has transitioned 40% of its fleet from conventional diesel-powered fracturing units to electric.

As operators aim to recover as much oil and gas as possible from a well, service companies are innovating on the tech that will help them reach those goals.

"I think the whole industry is up to the challenge," Ruhle said. "There are a lot of technologies that will be coming out that enable that, where we can hook up to the wells on a pad and pump continuously the whole time we're on that pad."

Although significant challenges remain, West, a long-time oil analyst, is optimistic: "Don't bet against the U.S. oilman." E&P

Safety First, Efficiency Follows: Unconventional Completions Go Automated

Automation advances in unconventional completions, streamlining operations.

ADAM DYESS | DIRECTOR OF BUSINESS DEVELOPMENT, HUNTING TITAN

If we look back at the past 15 years, the unconventional completions sector has seen a tremendous growth in daily stage capacity and operation efficiencies, primarily driven by process and product innovations in the plug and perf space, which consists of isolating and stimulating individual zones in the lateral via wireline perforating followed by hydraulic pumping from the surface.

Step-change advancements in techniques have more than doubled capacities to 20+ stages per day in several basins throughout North America. If you were to visit any multi-well pad wellsite, you could see how various technologies have driven efficiencies and safety by eliminating human interactions.

For example, personnel have been completely removed from several hazard zones near the wellhead where pressurized lines and elevated valves pose safety risks. Automated hydraulic wellhead connections not only eliminate humans from red zones, but also provide time savings of over 50% when stabbing onto the well compared to standard man basket operations.

Similarly, automated valve control systems simplify the thousands of individual valve turns involved in each pad completion. This technology allows digital, remote and seamless well-to-well valve control for the frac operations, which increases safety and provides additional time savings on the well completion.

SOURCE: HUNTING ENERGY SERVICES

The Ezi-Latch Hydraulic Wellhead Connector.

Perhaps the greatest impact to plug and perf productivity is the continued enhancement of simul-frac operations, which has revolutionized resource utilization compared to traditional plug and perf methods. Simul-frac aims to eliminate all non-productive time by fracking multiple wells while simultaneously perforating multiple wells so that the completion process for all wells on the pad is continually progressing.

This methodology has led to 50% gains in stage capacity compared to traditional plug and perf techniques. Moreover, the advent of electric pumping units with more reliable and higher horsepower has enabled single fleets to pump multiple wells, further reducing costs and environmental impact. The combination of e-pumping fleets and simul-frac has enabled record U.S. production with decreased drilling activity in recent years.

Advances in Automation

Constraints still exist in the overall plug and perf process that inhibit ideal utilization rates as the industry strives to reach continuous 24-hour pumping. The post-COVID labor force in the services sector has led to stagnant operational efficiencies since 2022. Skilled labor shortages, high turnover and inexperience have generated huge inconsistencies in service operations, which is a recipe for quality issues and down time.

It is imperative that the collective industry—which includes producers, service companies and product companies—address the variabilities inherent to manual processes by advancing automation. Digital tools and automated solutions reduce operating costs in the industry by streamlining processes, enhancing accuracy and optimizing resource allocation.

One key to mitigating the labor issues is automating the preventive maintenance of strained equipment and processes. For frac, the latest e-pumps feature state-of-the-art sensory systems and data acquisition equipped with machine learning capabilities. This technology allows for the predictive maintenance required to reach continuous pumping for the entirety of the well pad completion.

On the perforating side, smart perforating systems feature addressable switch technology that allows top to bottom wireline tool string interrogation, status reports and troubleshooting aid prior to deployment into the well. The most advanced switch system can output the functional condition of each perforating gun's detonator and even the plug setting tool's power charge. This technology has prevented over 60% of suspect initiators from being run in hole, saving hundreds of hours associated with mis-run non-productive time every year.

While previous automation initiatives have focused on the frac side, recent developments have focused on wireline perforating operations. E-pumping units have been paired with electronic winches to create closed-looped automated pump-down systems that substitute the insufficient human reaction times with instantaneous pump and winch controls.

These automated systems use machine learning to optimize pump rates and line speeds during the lateral trip to save time, horsepower and fluids on every stage. The superior response time of the automated pump-down units prevent unintentional pump offs that lead to costly fishing operations.

New perforating technology was recently launched that integrates the software-driven shooting power supply, data acquisition and switch software into a single wireline panel, such that the entire perforating process is automated. Each perforating stage program for the entire pad completion can be uploaded into the system prior to or during trip in hole. Once pumped down to bottom, the wireline technician can simply push a button to start the automated perforating process. The system will check switches, arm guns, calculate winch speed and fire precisely on depth while pulling out of hole, without any manual input from the user.

Since the shooting power supply links with the data acquisition, the panel can automatically log and annotate perforation depths on the log record, which eliminates the manual shot confirmation. This real time shot verification, as well as the other various surface and downhole data channels, are also available to stream to remote monitoring dashboards.

SOURCE: HUNTING ENERGY SERVICES

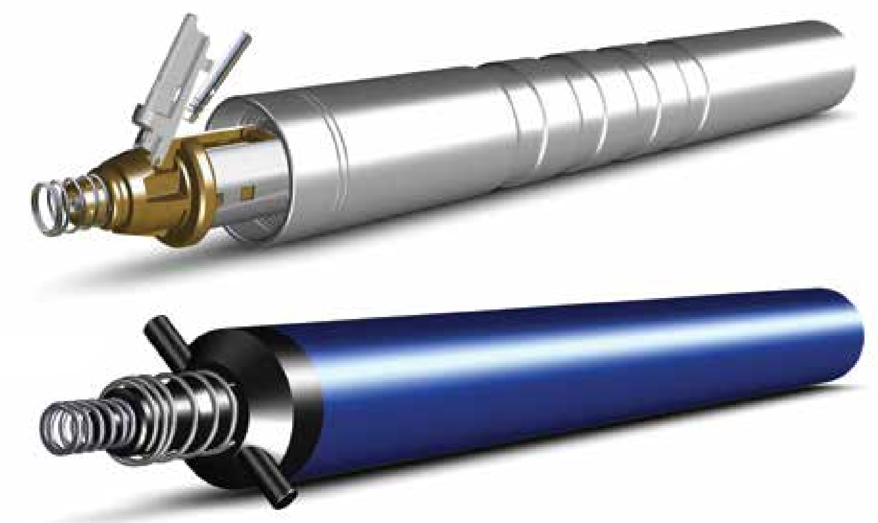
The Perf+ Panel fully automates the entire perforating process.

The perforating panel calculates the ideal winch speed during the perforating process, which can be communicated in real time to existing automated winch controllers, meaning the technician could potentially focus on monitoring all activities rather than manually handling the winch. Over the past year, this technology has eliminated several of the failure modes caused by human error, such as shooting the wrong gun or off-depth perforations, overpowering and damaging downhole electronics and unintentional initiations due to inadvertent power application.

The Path to Full Utilization

As around-the-clock pumping becomes more and more possible with automated technologies, the interdependency of frac and wireline processes becomes more pertinent. It is feasible for the digital valve and wellhead controllers used by frac teams to communicate with the perforating system and winch controller of the wireline unit.

Full plug and perf automation and continuous pumping involves collaboration among several stakeholders, from products providers to service companies. Ideally, compatible controllers will use machine learning to automate all valves, connections, winch, pumps, shooting panel and data acquisition so that all plug and perf processes are seamlessly integrated and run at maximum capacity. E&P



SOURCE: HUNTING ENERGY SERVICES

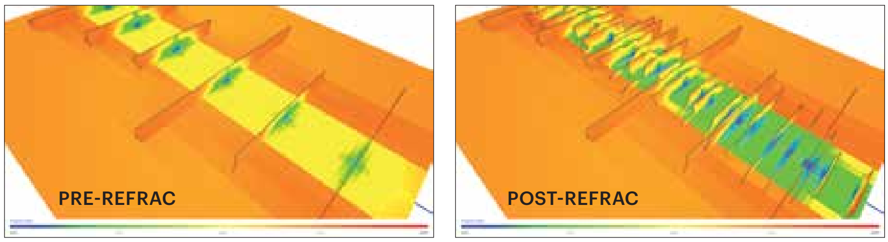
The H-4 Perforating System and PowerSet Recon are embedded with initiator-reading ControlFire switch technology.

Where, When and How to Refrac—Weighing All the Options

Experts examine the strategic considerations in play when deciding how to rejuvenate production from a tired well.

PAUL WISEMAN | CONTRIBUTING EDITOR

They are called re-fracs, re-entries, re-completions and other variations on re-peat terms. Whatever the name, the purpose is the same—to re-enter an existing and declining well to access more rock and pump new life out of it—and it is becoming a much more common practice for operators.



SOURCE: RESFRAC

Images compare a well's fracture area before and after a cemented liner refrac, performed to increase the density of producing fractures near the wellbore. The effective fracture length, or the distance the fracs drain from the reservoir (shown as blue, low-pressure fracture regions), is unchanged before and after the refrac. The increase in productivity post-refrac comes from adding fracture area between existing fractures rather than extending the effective lengths of the existing fractures. The mechanism for a bullhead refrac would be different.

Decisions, Decisions

There are two main types of refracs: bullhead and cemented liner. The first is less directed and therefore less costly. The second is used mainly in older wells with more untouched rock.

Garrett Fowler

Garrett Fowler, COO of modeling company ResFrac, explained that a bullhead refrac does not direct frac fluid.

"You're just kind of hoping that it goes into the right place. We've seen great results, but it's certainly less consistent. Sometimes we call them 'pump and pray,'" he told *E&P*.

By contrast, a cemented liner refrac involves installing a new liner inside the existing casing, which covers all the previous fracs.

"Then you frac it as if it were a new well," Fowler said.

After setting new plugs and perforating, stimulation is pumped into targeted sections of the well, usually many more than were fracked the first time, generating "a much higher likelihood of initiating new fracs" than with a bullhead. The new fracs become the point of re-entry; however, it is important to note that cemented liner refracs cost substantially more than bullhead refracs, and inventory can be limited by the size of the original casing.

Most good targets for the latter procedure are in early frac plays such as the Barnett, Bakken and Eagle Ford, where there is more unfractured rock. Permian fracking developed later, so that play has more fracs per foot, leaving less virgin rock to target with a refrac, according to Fowler.

Companies are considering refracs for several reasons, Fowler said.

"One motivation for refracs would be creating fractures where there were not fractures previously," he said. Another reason could be to protect an existing well when stimulating an adjacent well.

By fracturing the depleted well before fracturing an infill well, "a stress barrier or boundary around that existing well is created, which helps to mitigate, or at least limit, the severity of the interaction between the infill and the existing well," he said. Without that barrier, the child well could rob productivity from the parent.

Additionally, he said this "protective refrac" also can add to the fracture area in the existing well, which is likely older and might have fewer original frac zones, which leaves some rock untapped.

Why is Refracturing Growing?

Fowler credits de-risking of refrac technology for much of the growing interest in revisiting older wells, noting that public information, including a 2022 Department of Energy-funded consortium of operators that gathered diagnostics on refrac procedures through the Hydraulic Fracture Test Sites projects in the Eagle Ford and elsewhere, has helped de-risk the technology.

Boosted by Tech, Economics

Another boost comes from how far the technology has come since its early days. In the Bakken, the birthplace of most modern fracturing, early fracs were few and far between. They were completed with openhole procedures, which limited isolation, "roughly producing one fracture every 300 feet," Fowler said.

Fractures in 2024, on the other hand, involve 15- to 25-ft cluster spacing.

The result is "there are potentially 10-20 times more initiation points per unit of lateral length," he said.

Fowler sees the decreased spacing as an evolution in economics and in tools.

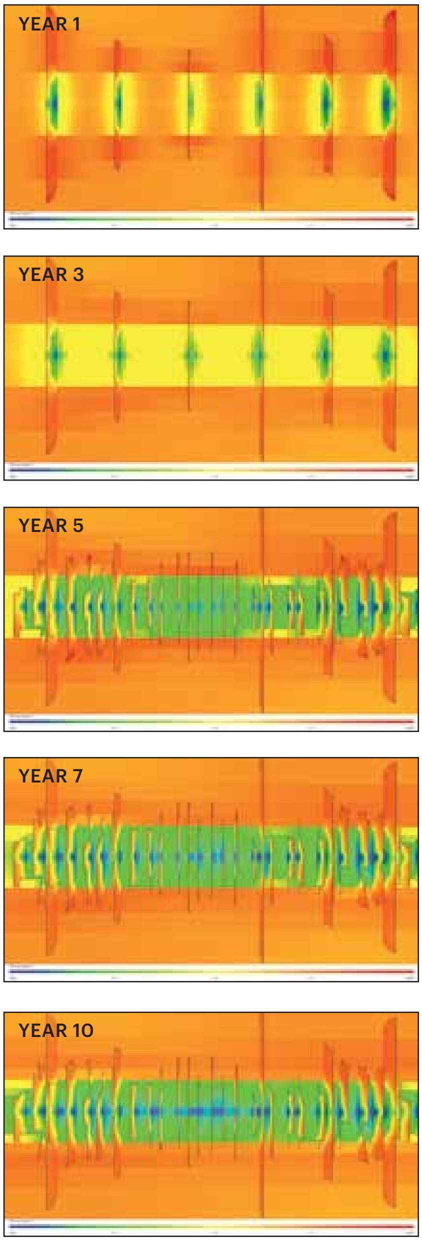
"We've gotten better at strong tools that can withstand higher pressures, and we can isolate more sections downhole, etc. Simultaneously, that evolution of technology has resulted in those technologies becoming much cheaper," he said.

Even so, every additional frac adds dollars to the completion cost. Operators must weigh the financial balance of how much more to invest because there are diminishing returns. "The optimal decision is rarely to have 15-ft cluster spacing with 5,000 pounds per foot of proppant and 70 bbl/ft of fluid, because you may not get the requisite economic return on that investment," Fowler said.

Deciding How to Recomplete

Whether and how to refrac revolves around economics. In short: Will the procedure net enough additional production to boost the bottom line?

For Geoffrey Gullickson, technical adviser for Halliburton, it comes down to "service intensity buckets," which take into account the time and cost of doing a refrac. Deciding among the common refrac approaches, including



SOURCE: RESFRAC

These images show the depletion rates before and after a refrac over a series of years. The refrac occurred after three years.

pipe-in-pipe or casing-in-casing reentries or a bullhead refrac, which would include chemical treatments, is what Gullickson calls "the holistic view of recompletions at large."

Bullheads are more general, involving no relining of the well. "The bullhead is very common in the Bakken-Three Forks system and has started gaining popularity in the [Denver-Julesburg] Basin as well," Gullickson said, adding that the Eagle Ford and Haynesville have also seen this method succeed.

Chemical treatments have been increasing in popularity there, as well, "as they're very low in service intensity and fall under the pale of almost classic production type work," he said.

The more costly pipe-in-pipe method, where a new pipe covers old fracs to create an entirely new frac design, tends to be most effective on wells with large spacing intervals, he said, while bullheads are more appropriate for recent wells with more frac zones.

To put it simply, frac spacing is the key factor in deciding what type of refrac to employ, Gullickson said.

"Those decisions really come down to how much effective white space is left in the reservoir, and the value proposition of that white space against the intervention risks and the financial figures associated with the refrac," he said.

According to Gullickson, some of the breakout successes since 2017 were not due to a macrostatistical approach. Rather, it has been "empirical modeling that has matched the actual physical response of treatments against some of the more service-intensive diagnostic tactics" used, such as fiber optic technologies and radioactive tracers in bullhead refracs to understand how to get better distribution, he said.

Life-of-well Planning

Many refrac candidates are several years old, although some are a decade or more.

"There's a concept of maintenance, almost like an 'early and often' approach with restimulation that has proven incredibly effective in increasing overall asset value and also in estimated recovery," Gullickson said.

This is especially true for Tier 2 wells whose profitability is on the line in terms of production, he noted.

In a well's earliest planning stage, Halliburton now recommends "a life-of-well operations plan" to aid in the long-term production effort, he said. That plan extends to anticipating future refracs as the technology continues to improve.

Sealing Previous Fracs

Most non-bullhead refracs involve cementing and relining the entire well to keep old fracs from absorbing the proppant from the new one. This procedure, while very effective, is costly, especially for wells with long laterals, said Scott Benzie, CTO of Coretrax, a company that has developed a system for using expandable pipe to reline the existing perf clusters, eliminating the need to reline the entire lateral and reducing the time and cost of the operation.

Benzie notes that this system, designed for older wells with few frac clusters, can deliver considerable savings. For a 2,000-ft well with four frac clusters, the system would use about 200 ft of pipe instead of the 2,000 ft required to reline the whole well.

Because it is expandable, the system retains almost all the original pipe's inside diameter (ID), Benzie said.

Retaining the larger ID offers two advantages: First, a traditionally lined refrac can reduce fluid flow rates by up to 50%. This can increase stimulation costs because the smaller wellbore requires more horsepower to restore the flow rates. Second, retaining the larger wellbore accommodates standard downhole tools and frac plugs rather than requiring slimbore equipment, which is more expensive. The expandable pipe also can function in HP/HT environments, providing further cost savings.

Benzie explained that patches can be inserted by wireline, which means the workover rig can stay in place during the procedure, expediting the process.

"With a lot of refracs, you have to rig up and clean out the well using stick pipe or coil. Some operators have seen value using their own personnel to complete these cleanouts," he said.

In such cases, the operator would prep the well before having Coretrax run the patches on wireline to minimize standby and spread rate costs that are typical with refracs.

Refracs do not pertain only to laterals, Benzie said, noting that a number of vertical wells also are being updated.

"There are often multiple target depths and existing perforations in such wells that need to be sealed in order to reach new rock located between the previously fracked stages or to access a newly targeted formation," he said.

He has seen fewer refracs in old vertical wells, especially in the Permian Basin. These vertical refracs often do not require the expense of a rig.

"We've found ID to be of significant importance in legacy vertical assets," Benzie said. "By using wireline patches, we help keep the wellbore ID-friendly for standard artificial lift methods, eliminating the need for pumps to be moved uphole, along with the need for a redesign of production equipment that has previously been optimized to match a standard wellbore configuration."

Patches are an option for new wells, too. If the casing ruptures, sleeves open prematurely, or if the original perforations are placed incorrectly, patches can rescue a well from a major and expensive workover right at the start, Benzie said. E&P

SOURCE: CORETRAX

Expandable straddle patches like Coretrax's ReStore expandable straddle system cover only the fracture area, eliminating the need to re-line the entire wellbore before a refrac.

SOURCE: CORETRAX

Coretrax's ReLine HYD expandable tubular solution provides both short- and long-length isolation solutions with minimal loss of inner diameter, while providing high burst and collapse ratings.

Drowning in Produced Water: E&Ps Seek Economic Ways to Handle Water Surge

Strained disposal limits push beneficial reuse to the forefront for produced water management.

JENNIFER PALLANICH | CONTRIBUTING EDITOR

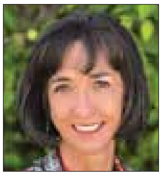
With water production often outpacing oil and gas, E&P companies turn to recycling, disposal and beneficial reuse to handle the water, but each solution has its limitations.

Some regions, such as the Delaware Basin, have a water-oil ratio (WOR) as high as 10 bbl of water per 1 bbl of crude, although an industry average WOR is closer to 4 bbl of water per 1 bbl of crude, XRI Water Vice Chairman John Durand told *E&P*. That means if the Permian Basin is pumping out 5 MMbbl/d of crude, it is accompanied by about 20 MMbbl/d of water.

John Durand

All that water has to go somewhere and, for now, much of it is being sent back into the ground.

And as Laura Capper, principal at EnergyMakers Advisory Group, which consults on water management handling, told *E&P*, "capacity is not keeping up with our produced water growth."



Laura Capper

Capacity in Texas is further strained, she noted, because New Mexico's produced water is brought to Texas for disposal.

The industry is doing an "admirable job" of recycling produced water for use in frac operations, with recycling "becoming a de facto thing," but that still means operators have to find something to do with the rest of the produced water, she said.

A steel pipe drains suspension fluid into a hydraulic dump as part of the process to separate effluents for reuse of water in a closed cycle.

SHUTTERSTOCK

Vast Volumes

Speaking during a Pickering Energy Partners Permian-focused webinar on produced water in April, Kelly Bennett, co-founder and CEO of B3 Insight, said the industry needs solutions that can handle "something in the magnitude of several million barrels a day of water."

Matthias Bloennigen, managing director at Pickering Energy Partners, speaking during the same webinar, expects water-handling costs in the Permian to rise over the coming years.

"If we don't do any reuse, we are going to have too much produced water," he said. "In 2029, if we don't drill enough, we're going to be running out of disposal capacity."

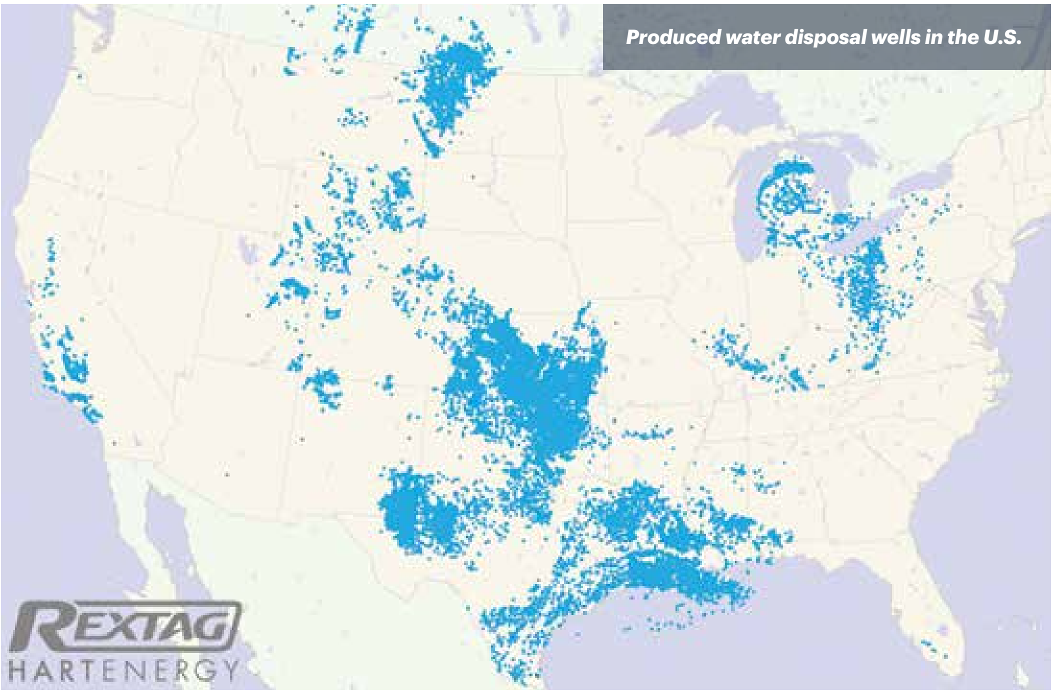
Even if more disposal capacity is drilled, Bloennigen said he expects the Permian market will become tighter. "That's why we especially think that the water-handling costs are going to continue to increase as we have seen over the last few years," he said.

According to Bloennigen, this dynamic has changed how operators are thinking about produced water.

"Water used to be more of an afterthought," considered only after the oil and gas strategy had been developed, he said. "Now water will have to be part of the oil and gas development."

Seismic Events

One of the long-favored solutions for all this produced water has been to store it in disposal wells or reinject it into enhanced oil recovery (EOR) wells to maintain reservoir pressure.



Produced water disposal wells in the U.S.

REXTAG

there may be more of a correlation with under-pressured wells and seismicity than over-pressured wells and seismicity. So, it's really confounding," Capper said.

Some places in Texas with quakes have no nearby disposal wells or very low-pressure wells, while others have a lot of over-pressured wells with no quake activity, she said.

"It's not what people think. It's a trickier science," she said.

But the question remains: What can be done with the water that isn't recycled if it can't go into deep disposal wells?

"In the last year from seismic curtailments, if you will, we've lost almost 1 MMbbl/d of actual injection that we used to be able to stick down wells, and now we're not allowed to. We had to find new homes for that water, either make it go shallow or make it go farther away and go someplace else," she said.

Doing that economically and

After the Railroad Commission (RRC) of Texas concluded that deep injection of produced water is the likely culprit behind recent seismic activity rocking the state, deep disposal wells came under scrutiny. The RRC has limited deep disposal wells in a bid to stave off additional earthquakes, but some question the correlation between these wells and increased regional seismic activity.

"People have a lot of fallacies about pressure and earthquakes," Capper said. "People always think high volumes lead to high pressure, lead to earthquakes."

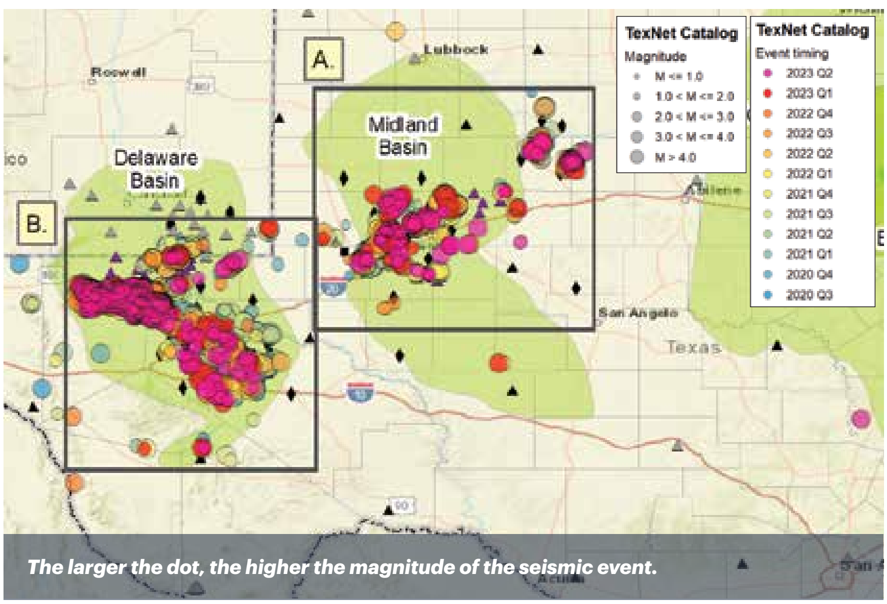
That is not necessarily the case.

"It's far more nuanced. It's different in every region. It's not a direct correlation. It's very fuzzy and indeterminate science. Part of the reason is because we really don't even know where the earthquakes happened with great accuracy. The reported stuff from TexNet (Texas Seismological Network and Seismology Research) could be a mile high or low off of where the actual earthquake happened. So, there's a big error of margin in reporting," Capper said.

A complicating factor, she added, is that parallel operations like production and injection in the same area make it hard to tell what truly affects seismicity.

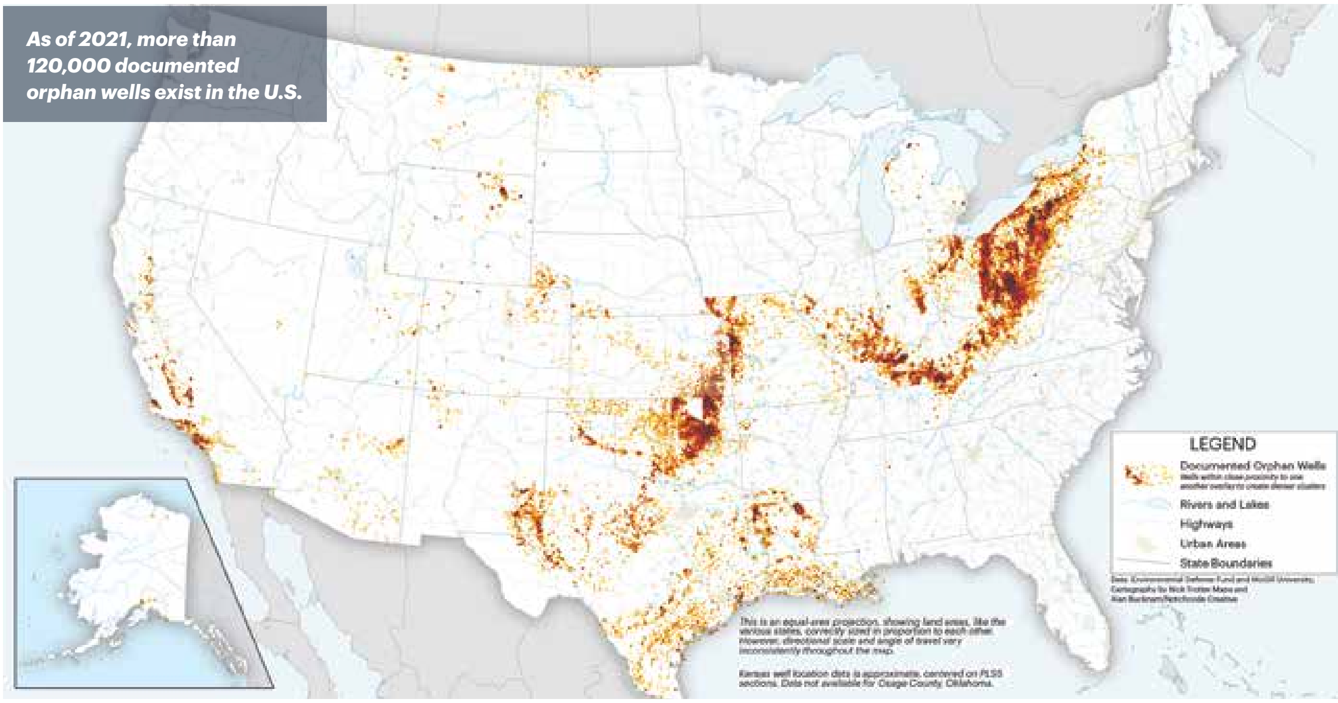
Pressure of the formation is one of the concerns.

"The vast majority of shallow wells are highly over-pressured, while deep [wells] are moderate, and in many cases under-pressured. And actually,



The larger the dot, the higher the magnitude of the seismic event.

TEXNET



As of 2021, more than 120,000 documented orphan wells exist in the U.S.

ENVIRONMENTAL DEFENSE FUND

efficiently is a challenge, especially because alternative shallow disposal wells are not an equal alternative to deep disposal wells.

"They cut us off deep, so we're going shallow," Capper said.

With deeper wells, she said, it is possible to store quite a bit of water, but shallow wells cannot accept the same quantity of water, and they tend to be more over-pressured.

"Most operators think they can put the same amount of water in shallow as deep. I'm like, 'Oh no,'" she said.

The capacity of shallower wells simply does not match the capacity of deep disposal wells because of the formation pressures. With produced water rates increasing, it is problematic that capacity is "pretty much flat" for shallow and EOR wells, Capper said.

Storage capacity aside, shallow disposal wells could lead to problems with orphan wells, she added.

Roughly 125,000 documented orphan wells—those for which no company is financially liable for plugging—exist throughout the country. Many of these orphan wells are thought to have compromised infrastructure.

"The old wells have already rotted out and corroded. They're just a leaky straw waiting to be used as a conduit," she said.

The orphan wells likely weren't designed to handle the increased formation pressure that might result if water disposal in a shallow well drives up the pressure in the formation, making it possible for produced water to migrate into an orphan well. The result, she said, is that the orphan well could become a conduit to pollute groundwater or cause other issues.

"It's really the intersection of legacy, compromised well infrastructure and then modern-day operations," she said.

Beneficial Reuse

Restrictions on deep disposal wells, the limited capacity of shallow disposal wells and concerns that shallow disposal wells could potentially lead to problems with orphan wells leaves operators with a weighty decision to make about what to do with all that produced water.

Durand said, "We're talking about a vast amount of water getting pumped every day, and we are all in agreement as an industry that you've got to limit disposal."

Recycling is one answer, but that still leaves a lot of water to be dealt with. Enter beneficial reuse.

In the near term, beneficial reuse possibilities include industrial use, closed loop and zero liquid discharge applications, mining and dissolution mining, aquifer recharge for future use and agriculture for non-edible crops like cotton, hemp, switchgrass and oil seeds. In the long term, beneficial reuse could include agriculture for consumable crops and for animals as well as water sent to municipal drinking water facilities for further treatment. Durand also sees the possibility for the produced water to be used to help cool large-scale data centers.

Durand said the industry is working on pilot testing beneficial reuse projects.

While beneficial reuse is still in its infancy, "we're fast tracking it as an industry to figure out ways to potentially discharge on the ground, but that's going to take a lot of testing and a lot of commitment from the industry," he said.

According to Durand, XRI will be working alongside its clients to solve this challenge. He said it is critical that the industry reach "the right results to make sure the beneficial reuse becomes a reality sooner than later because there's going to be a direct correlation between limiting the use of disposal water to increasing the use of water for beneficial reuse."

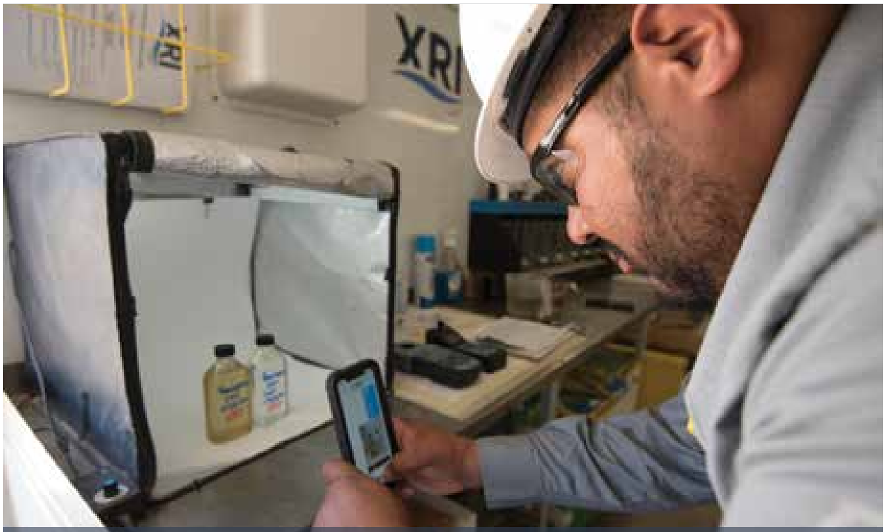
Standards for water treatment for beneficial reuse are in progress, and pilots are showing that the technologies to treat the water work in the field and at scale, Capper said.

"The challenge is these aren't going to be cheap projects. They're going to be tens to hundreds of millions of dollars to implement," she said.

On the other hand, because Texas is also going to be "in a perpetual drought for the rest of its foreseeable future" without sufficient water supply, there is plenty of incentive to find a way to make it work, she said.

Durand sees the possibility of a greener future for Texas.

"West Texas is a massive desert-like area. Imagine us being able to utilize and green up West Texas on a year-round basis with water that before was going downhill and potentially causing issues such as seismic activity," he said. "And then, all of a sudden, hopefully we're talking in a very few short years, a lot less disposal injections and a lot more beneficial reuse." E&P



An XRI laboratory technician documents produced water treated and untreated samples.

XRI WATER

An orphaned well on a farm. Orphan wells are thought to have compromised infrastructure and could become conduits to pollute groundwater if produced water sent into a shallow disposal well migrates into an orphan well.

SHUTTERSTOCK

AI & Generative AI Now Standard in Oil & Gas Solutions

From predictive maintenance to production optimization, AI is ushering in a new era for oil and gas.

JENNIFER PALLANICH | CONTRIBUTING EDITOR

No technologies dominate headlines like AI, generative AI and machine learning (ML) these days.

Now considered "table stakes," or a minimum entry requirement, software vendors are embedding such tech in all manner of oil and gas solutions. AI can evaluate large datasets for patterns better than humans can. It can flag potential equipment failures for repair before damage occurs and can drive automated decision-making to improve oil production. And generative AI, which uses massive datasets to deliver information and answer questions, opens up even more possibilities for the industry.

Of course, implementing AI and generative AI solutions means companies will have to take into consideration the state of existing data and accept the fact that AI will change work in unexpected ways, experts said at recent events in Houston.

Brad Davis, CEO of RIOT SCADA, said during the AI in Oil & Gas conference in April that it's helpful to think of ML as being similar to how humans learn to beat a video game level by incrementally improving as they replay the level. ML requires a huge amount of pristine data, he noted. It can be easy to taint that data, as in the example of Netflix profiles which run on ML.

"This is why my wife won't let me on her Netflix account, because I screw up her algorithm," he said.

Deep learning, he said, handles large-scale pattern recognition and can be useful for things like detecting leaks and flare emissions.

Generative AI Potential

When generative AI is used to enhance SCADA data, or the data related to controlling, monitoring and analyzing industrial equipment and processes, it can improve employee performance across the board, according to a joint Stanford University and MIT study published in 2023.

For example, a person comfortable working with data may have a productivity level of 80% compared to 60% for one who struggles with data and does not care to use a data dashboard, Davis said.

The 2023 study revealed that generative AI boosted by 34% the productivity of employees uncomfortable with data-driven environments to 94% productivity, while generative AI upped the productivity of employees already comfortable working with data from 80% to 91%.

That improvement happens by "taking data outside the realm of data and putting it in the realm of conversation," he said.

In short, generative AI makes it possible to interact with data in a completely different way, Catalina Herrera, field chief development officer at Dataiku, said during the same event.

"We talk to data, ask questions of the data," she said.

Generative AI can be used to increase general productivity and remove dull, menial tasks, Brent

From left, Enass Abo-Hamed of H2GO Power Ltd., Ben Wilson of Amazon Web Services and Jim Chappell of AVEVA during an Agora Studio at CERAWeek.

JENNIFER PALLANICH

Railey, chief data and analytics officer at Chevron Phillips Chemical Company, said during the same event.

He urged companies to be strategic in how they adopt AI and generative AI technologies, not least because AI's success hinges on the quality of the data it uses.

"Generative AI will uncover your data governance problems," he said. "Trying to fix your data quality problems is like boiling the ocean."

Given the importance of data quality, Alina Parast, senior vice president and CIO at ChampionX, said during the same event that no data is brought into the company's enterprise data lake until "it's clean and validated."

Ben T. Wilson, director of products and solutions at Amazon Web Services (AWS), said during CERAWeek by S&P Global that AI loves complexity but the data it uses must be of high quality.

"AI is very much garbage in, garbage out. If you have high-quality data, in other words, accurate data, whether it's IoT (Internet of Things) type data or maintenance data, then you're going to get much better results from your AI," Wilson said.

Although generative AI has massive potential, Wilson cautioned that the tech is still young.

"I don't think I see anything that's mature in generative AI yet. Generative AI is so new, it's been around for 18 months. We can't expect maturity in it," he said.

Despite this fact, Bill Vass, AWS vice president of engineering, who also spoke at CERAWeek, said he sees a future where generative AI is as ubiquitous and helpful as spell check.

And in much the same way that spell check has not put writers out of business, generative AI coding capabilities will not replace software engineers, he said. Amazon CodeWhisperer, for instance, handles the drudgery of writing software code, he said.

As a software engineer, Vass said, "the hard part is figuring out what you want to do. And once you've figured it out, it's busy work to do the coding."

Gino Hernandez, head of digital for ABB Energy Industries, said during CERAWeek that the company is launching a generative AI bot for diagnosing asset failure and repair using natural language.

"You're able to ask the asset, 'When was the last time you failed? When it failed last time, what did you do?' And then most importantly, the operator can ask, 'Well, how do I fix this?'" he said. "And it's a game changer."

Bill Vass, VP of engineering at Amazon Web Services, said during CERAWeek that he sees a future where generative AI is as ubiquitous and helpful as spell check.

CERAWEEK BY S&P GLOBAL

Judson Jacobs of S&P Global, moderator, left, and Gino Hernandez of ABB during an Agora Studio at CERAWeek.

JENNIFER PALLANICH

Gen AI is also expected to boost software engineering productivity by 50%, resulting in cleaner code with better documentation and more cybersecurity, he said.

"We have hundreds of R&D engineers developing our software. If I could unlock 50% more capacity of that organization, that is huge," he said.

Vivek Chidambaram, senior managing director at Accenture Strategy, urged business leaders to become familiar with AI, noting that while Canadian author Malcolm Gladwell popularized the idea that 10,000 hours of practice results in expertise, leaders need far less experience with AI to lead effectively.

"About 1% to 2% of that time is the minimum amount of time that you need to put in as a leader. Otherwise you're simply not in the game. The same sort of thing has to apply to the rest of the organization," he said during CERAWeek.

Chidambaram noted that throughout history, technology has destroyed some jobs and created others and suggested that AI will probably create jobs that at present "we can't comprehend."

Chase Lochmiller, Crusoe Energy Systems co-founder and CEO, is optimistic about AI's effect.

"I definitely view it as more friend than foe. I think there's a lot of talk around AI taking people's jobs, but I'm sort of the opinion that AI can be a catalyst for the greatest job-creating event in the history of humanity," he said during CERAWeek. "When we invented the tractor, it might have taken some farming jobs, but it freed up human capacity to go pursue other interests and higher leverage, more productive things for society."

Capitalism will likely drive AI adoption.

"If you don't adopt fast enough, your competitors will," he said.

And the change is definitely coming.

"We're sort of facing ... a Darwinian event for corporations in terms of the genie's not going back in the bottle. We've broken through this level of productivity gains that people are able to get from AI, and it's at a moment of rapid exponential increase in the development of this technology," Lochmiller said. E&P

From left, Vivek Chidambaram of Accenture Strategy, Chase Lochmiller of Crusoe Energy Systems and Mike Bleadorn of Korn Ferry during a session at CERAWeek.

JENNIFER PALLANICH

Goodbye Manual Control: Vital Energy's Automation Program Boosts Production

Production, ESP efficiency soared when the company automated decisions with AI at the edge.

JENNIFER PALLANICH | CONTRIBUTING EDITOR

Whether it is optimizing production enabled by AI-guided automated decision-making or controlling corrosion inhibitor injection at the edge, digital technology is transforming Vital Energy's potential.

Vital Energy, formerly known as Laredo Petroleum, created a proof of concept in 2020 that would improve production from its wells by combining sensor data with AI and edge computing to automate electrical submersible pump (ESP) operations.

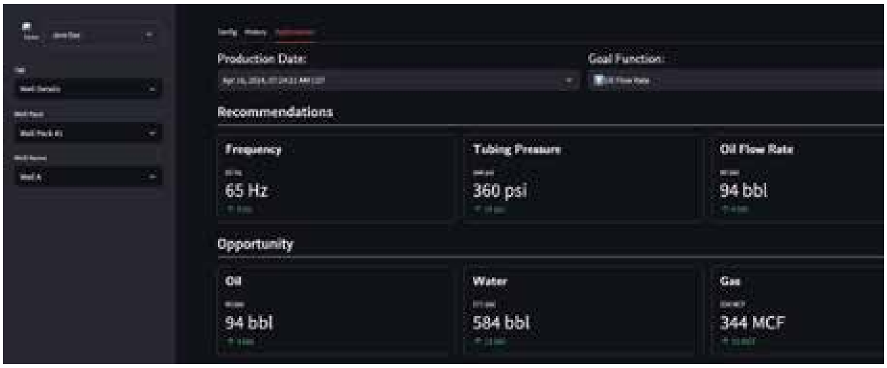
As the company implemented various phases of the Intelligent Well Program, it saw production increase by 400 bbl/month during the ESP optimization proof of concept, by 1,400 bbl/month with the addition of the gas lift optimization proof of concept, by 6,600 bbl/month through the inclusion of physics constraints and the addition of an ESP health monitoring solution and now by 45,000 bbl/month by automating ESP control at the edge.

David Benham

David Benham, director of digital innovation at Vital Energy, told *E&P* that scaling the technology created an exponential production growth curve and helped extend the lives of ESPs as the program was applied to more and more Vital Energy wells.

At first, Vital Energy focused on maximizing oil flow while minimizing disruption events, such as ESP failure.

ESP Optimization > Analytics Portal



SOURCE: VITAL ENERGY

The ESP optimization analytics portal allows Vital Energy petrotechnical experts to see each day's opportunities to improve production. In this case, the recommended adjustment is to keep the pump speed steady while applying minor backpressure on the well to increase oil output by 4 bbl over the next 24 hours.

A Vital Energy field operator uses at a laptop to make in-person ESP adjustments on site.

VITAL ENERGY

The initial phase focused on objective measurements and creating the AI solution to accelerate the speed of decision making.

"You can't exploit any opportunity if you're not looking at it in a timely fashion," Benham said. "Things like outlier detection, multivariate alerting—those are the real beneficial items."

An ESP artificially lifts production from an oil well after it has stopped free flowing. ESPs consist of an electric motor, centrifugal pumps and additional components to protect the motor, handle gas in the fluid stream and provide downhole system performance data. A variable speed drive (VSD) controls the motor either at the surface or remotely. ESPs are typically installed as a first form of artificial lift because they can handle high production rates from deep and deviated wells.

CHAMPIONX

Vital Energy's petrotechnical experts designated set point ranges for ESP pump frequency and tubing pressure and provided feedback about the decisions the system got right and wrong.

"Everything that we designed in this first phase is to capture subject matter expertise so that we can begin to create more sophisticated models in the optimized phase," he said.

For Vital Energy, optimization means focusing on determining which operations are effective and profitable and which are not in terms of goals and the environment.

"We take what's working, and we apply those to the opportunities where they're not working. Sounds really simple, but this is really the transition from unsupervised or simple machine learning to more sophisticated supervised algorithms, where we can get a deeper, more precise answer," Benham said.

And when the petrotechnical experts consistently accept the algorithm's recommendations and the optimized answers are within the company's risk tolerance, Vital Energy begins to automate those decisions through an automated routine, including a computer self-tuning at the edge, and scale by deploying the tech to more wells.

Beyond Proof of Concept

As Benham points out, it is not one and done. Instead, Vital Energy iterates the optimize and automate phases on other factors that could improve a well's profitability. The first focus was on oil flow rate while minimizing disruptions, events and failures.

"We automated that, and now we've circled back to optimize the gas liquid ratio. Then we circled back for low-producing wells to maximize total fluids," he said.

These three optimization capabilities, combined with commercial value, are available to all Vital Energy's current assets, and the company is refining several other optimization factors for testing later this year.

The Intelligent Well Program relies on a lot of tech: AI, algorithms, machine learning, edge computing, the Internet of Things, sensors, the Amazon Web Services cloud and more. All of this comes together in a surveillance portal showing the performance of Vital Energy's roughly 375 ESPs in the ground. A

A variable speed drive (VSD) controls ESPs from the surface or remotely. The downhole equipment consists of an electric motor, centrifugal pumps and additional components to protect the motor, handle gas in the fluid stream and provide downhole system performance data. ESPs, which artificially lift production from an oil well after it has stopped free flowing, are typically installed as a first form of artificial lift because they can handle high production rates from deep and deviated wells.

CHAMPIONX

petrotechnical expert can tune a well's ESP to a specific optimization function in the portal, and the program adjusts ESP operations automatically.

The program has been developed to accommodate 22 of the most common pump sensors.

From its 2020 launch, Benham said the program has behaved like a startup.

"We had to take prudent risks," he added.

Each product would ultimately need to be able to sustain itself, and ideally serve as a building block to more advanced functionality. Eventually, the goal is for fully autonomous operations, he said.

Vital Energy did not create the project on its own—collaboration made the Intelligent Well Program's success possible.

Vital Energy scaled its internal digital team with staffing from software development company SoftServe to create products such as the algorithms and portal.

ChampionX helped Vital Energy understand disruption events, Benham said, noting more than half of Vital Energy's ESPs were manufactured by ChampionX.

Not only has the program generated more barrels for Vital Energy, it improved ESP uptime by about 4% in 2023 over 2022 levels, even though there was a 138% year-over-year increase in the number of ESP systems in use. In 2022, 42.7% of ESP units experienced a failure, compared to 29.6% in 2023, according to the company. The mean time to failure increased from 220 days in 2022 to 328 days in 2023.

Change Management

Transforming ESP decision-making took buy-in from leadership as well as the departments affected by the change. For that reason, Benham said, goals had to be fully aligned.

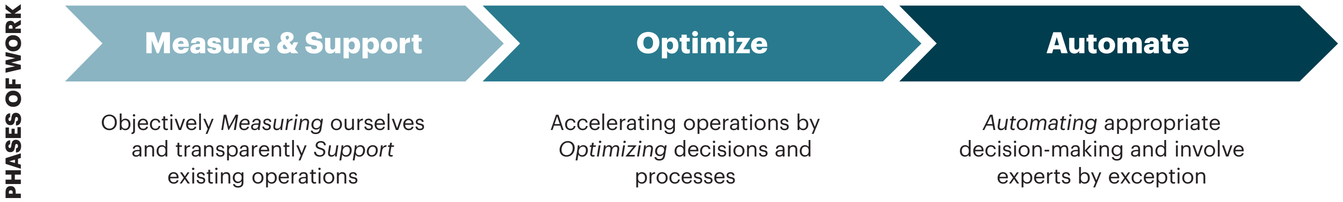
The program's algorithm also had to balance a physics-based approach with an AI-based approach.

"Oil and gas loves their physics. It's what people are taught in school, but there's a lot of missed opportunity if you don't augment that with AI and analytics," he said.

But getting that buy-in was a bit harder than Vital Energy CTO Brandon Brown expected.

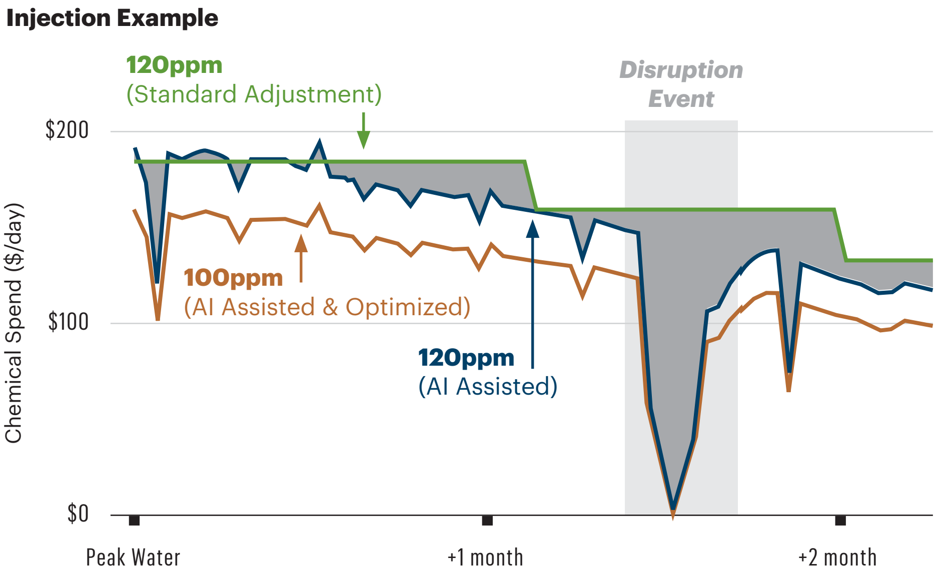
"You would think this would be really easy stuff to implement. Everybody would be excited for it.

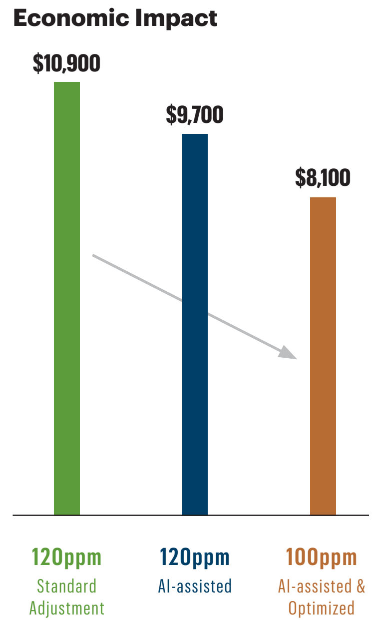
Intelligent Well > What Does it Look Like



In the first phase of Vital Energy's Intelligent Well Program, the objective was to measure and support existing operations. In Phase 2, the goal was to accelerate operations by optimizing decisions and processes. Phase 3 automated decision making.

Chemical Tank Optimization > Standard Example





SOURCE: VITAL ENERGY

The Chemical Tank program is the first edge compute solution Vital Energy realized as a company. Through the program, Vital Energy auto-adjusted the injection of corrosion inhibitor at the wellhead. The first step adjusted the chemical injection rate in real time and handled outlier water readings, making it possible to capture the upside from dialing injection down during low production times and ramping up for corrosion protection during higher production moments. The next evolution of the algorithm allowed reducing the dosage to the supplier's recommended concentrations and adding intelligence to account for the concentration differences during slowdowns and ramp-ups so the concentration is always near the vendor's specifications.

Brandon Brown

Well, they're not necessarily excited for it," he said.

Senior leadership was keen on the opportunity to boost production but petrotechnical experts did not blindly accept the technology.

"There's a necessary process to engage people and gain their support on this path. Unlike in their private lives, where they might unknowingly accept AI in various applications, here, they don't just take it at face value," he said.

Benham said he underestimated the amount of time and money the company would have to spend on change management.

He said the most successful projects were those with the digital team working directly with the people who would be affected by a change.

"We have data scientists that are out every other week in the field riding with lease operators, techs, foremen, supers, sitting in the office with engineers, going to training seminars to speak their speak, to learn the way that they walk every day of their day-to-day. And that's the biggest difference between a successful project and an unsuccessful project," he said.

Giving ownership also helped. For example, petrotechnical experts were able to set real-world parameters for

ESP operations.

Looking back, Brown said he might change how the project team approached launching the Intelligent Well Program.

"We should have started better explaining the why," he said. "And if I had to do it all over again, I would send every single production engineer we have to an AI or machine learning/AI course. The ones that have taken the time to educate themselves truly understand the benefit and fully embrace it."

On the other hand, he said, now that the Intelligent Well Program and a couple other AI-based efforts have shown success, iterating on similar projects should reach productivity more quickly.

"The next project becomes a little bit easier because we have talked about it, we have seen results, and people start to understand it a little bit better," Brown said.

Data-driven Decisions

Vital Energy's Chemical Tank Optimization Program was the company's first AI solution to become fully autonomous with an edge control device, and it is saving the company money every month on corrosion inhibition.

According to Benham, as of March 2021, every new Vital Energy well is equipped with a fully autonomous corrosion inhibitor solution. From the very outset, it has paid dividends, he said.

"One of the most neglected areas in the upstream industry is dispensing chemicals, particularly as a well comes off of peak production," Benham said.

Traditionally, the amount of corrosion inhibitor a well will receive is set for "the worst day of the month," or the most the well will need in a month, and that rate is revisited and adjusted every 30 days, he explained.

"If the well goes down or if the water fluctuates for some reason, people are not auto-adjusting those chemical injection rates," which results in over-injection of those chemicals, he said. "We built a solution that adjusts as water adjusts."

The AI solution at the edge automatically regulates the amount of corrosion inhibitor dispensed into each well based on the current water flow and whether the well is actually producing. In the past, Benham said, if a well went offline for any reason, it was common to continue dispensing chemicals, but the edge controller automatically drops the injection rate to zero when a well is offline to prevent unnecessary injection of chemicals.

According to Benham, average savings amounted to about 11% initially per month per well in the well's first two years due to real-time injection adjustments. The savings increased even more, he said, as Vital Energy tuned the amount of chemicals injected in each well. In total, each month the AI-automated chemical injection optimization solution is saving Vital Energy about 18% on continuously dispensed chemicals per well in the first two years of the well's life, he said. The savings does decrease as the production decreases, he added.

"From a change management cycle, everybody knows it's expensive, everybody knows it's neglected, and they can see how it works. They feel good about it," Benham said.

Brown said the corrosion inhibitor program was like a gateway project that made later AI-related efforts go a bit more smoothly.

"This is the one that got them to open up a little bit to how AI could possibly help them with their jobs," he said.

Digital Wellspring

Generative AI figures into Vital Energy's 2024 tech roadmap.

"What does that mean for us? It's access to knowledge, faster," Benham said, from documentation access to procedures and automation.

Brown said, "As a technologist, what I've been using in my personal life for years is now actually being asked for at work. And oh, it's so much fun."

AI opportunities in oil and gas are "almost limitless," he added. "Vital plans to take advantage of those opportunities that are yet to be discovered." And one of the biggest opportunities an oil and gas producer faces comes from digital transformation or revamping the business' business operations using digital technologies. Digital transformation starts with good data.

"You've got to have some data that you're confident about, and it's accurate, and that confidence needs to span multiple departments, not just one department," Brown said, explaining that people often have data that works in their silo but not in another department's silo.

Given the importance of quality data, Benham said Vital Energy considers data at the outset of every project.

Brown said, "In a perfect world, it would've been great to go get all your data fixed and then go do these projects, but that's never going to happen anywhere."

Vital Energy knew it had solid production data, which made a project like the Intelligent Well Program a logical starting spot.

"From a production standpoint, the data lift was relatively mild. The overall data lift for the entire company is huge, and that's a multi-year journey," he said.

The goal is to be a fully data-driven company, he said, noting many companies that say they are data driven are in actuality only working off of a small percentage of the data available.

"How do you become a data-driven company with all of your data? That's the transformation that has to take place. And one of the most effective ways to do that is by leveraging cloud technologies and machine learning," Brown said. E&P

How Generative AI Liberates Data to Streamline Decisions

When combined with industrial data management, it can allow processes to be more effective and scalable.

JASON SCHERN | FIELD CTO, COGNITE

McKinsey & Co. dubbed 2023 generative AI's breakout year, and rightfully so. There was seemingly no industry that wasn't touched by this technology in some way. But as much as we've looked to AI to solve challenges at the personal, community and global levels, we've not yet fully tapped into the technology to solve one of the most pressing and important challenges of our time: the energy transition.

The International Energy Agency reported that global emissions hit an all-time high last year, and while we already have many of the necessary tools available to support a safe, secure and reliable energy source, the challenge lies in the implementation. We need energy providers' processes to be more efficient and automated, which is where generative AI fits in.

One of generative AI's primary functions is analyzing vast amounts of complex data and turning it into new and original content. At its core, it's a way to provide the right insights to the right people at the right time.

But to deliver on its full capabilities, organizations need to first liberate data that's typically locked in different systems and applications, leaving it largely useless. Once the data is more easily accessible, it can be connected to create a meaningful and holistic view that accurately represents an organization's industrial reality. This industrial knowledge graph is what then provides the necessary context to the large language model and operationalizes the data, arming the company with the information

Cognite Data Fusion is an Industrial DataOps platform that enables industrial data and domain users to collaborate quickly and safely to develop, deploy and scale digital solutions.

COGNITE

and context it needs to make better decisions.

One example of this is Cosmo Oil, the third-largest oil refiner in Japan. A few years ago, the company was struggling to hire qualified engineers. The team attributed this to the decline in the working-age population as the birth rate decreased in Japan, as well as the reputational challenge oil and gas was facing amid growing calls for emissions reduction that made it difficult to recruit.

As the team at Cosmo Oil searched for a way to operate a refinery with fewer engineers, its initial focus was on figuring out how engineers conducted their tasks to see where productivity could be maximized and how operations could be consolidated across multiple sites.

This research found that approximately 70%-80% of an engineer's job involved data collection. This crucial data—which included operational data, maintenance data, equipment inspection records, asset performance management tool data, piping and instrumentation diagrams, and data sheets for various components—was scattered across multiple sources and formats. The data was siloed, and the team was wasting time and resources trying to track it down.

To address this, Cosmo Oil turned to Cognite Data Fusion, an Industrial DataOps platform that could take all the previously unusable data, including unstructured data, and consolidate and connect it using AI for automated data contextualization. From there, the technology extracted data patterns in a flexible knowledge graph that represented the organization's operations digitally. This allowed Cosmo Oil's engineers to access data on all refineries quickly and easily, simplifying data-driven plant operations and increasing their overall efficiencies.

Aker BP, one of Europe's largest independent oil and gas operators, and Siemens, a technology company, faced a similar data problem. Aker BP had granted Siemens access to the field data of its Ivar Aasen onshore team and was looking to improve condition monitoring of the Ivar Aasen asset. But the Siemens team often found the data it needed to address the problem was locked in inaccessible systems, hindering their visibility into important information like work orders, work permits and document systems.

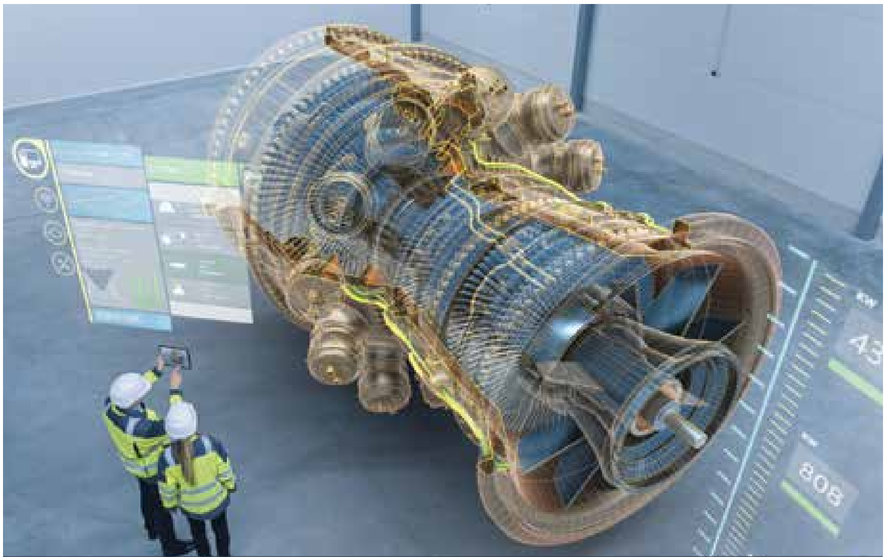
Rather than continuing to operate with fragmented and limited insight, Siemens turned to Cognite Data Fusion, which was already in operation across Aker BP's assets. The ability to read data through a single platform and access live and historical data, regardless of original source or format, via a single point of entry, saved hundreds of hours and enabled Aker BP to increase efficiency, bring down the cost of equipment failure and deploy the right crew and tools when maintenance was needed.

SLB, an oilfield services company, saw an opportunity in the use of AI and the liberation of data to solve cross-industry global problems, like the rising cost of operations and the need to reduce carbon emissions. Digital technologies are central to solving these issues and data is central to the operation of these technologies. To help upstream players manage data complexity and make smart decisions around where to apply optimization, SLB partnered with Cognite to integrate the company's Enterprise Data Solution for subsurface with Cognite Data Fusion.

With the current partnership, users of SLB's subsurface Enterprise Data Solution can integrate data from reservoirs, wells and facilities into a single platform, make it accessible and use embedded AI to identify opportunities for optimization and ways to innovate at scale.

The system can help companies look beyond solving existing problems and build a foundation to solve emerging use cases.

Across all of these examples, what we see is that industrial data management, in combination with the predictive capabilities of generative AI, can play a fundamental role in streamlining intense data processes to be more effective and scalable. As we look to create a safe, secure and sustainable energy future, energy providers' abilities to fully harness technology to create efficient and automated processes will be paramount. If 2023 was generative AI's breakout year, 2024 is the year of putting it to work. E&P



Many oil and gas operators find that their data is locked away in inaccessible systems, hindering visibility into critical information.

COGNITE

Cognite Data Fusion can unlock trapped data, empowering energy providers to automate processes and accelerate the energy transition.

COGNITE

Code Cracked?

The U.S. is poised for a geothermal boom using existing oil and gas technology. Does the industry have what it needs to scale?

VELDA ADDISON | SENIOR EDITOR, ENERGY TRANSITION

To say the geothermal industry is heating up in the U.S. might be an understatement.

Once shunned by potential investors due to project failures, poor planning and other investment risks, geothermal company leaders and others in the energy sector are turning the situation around.

And they are using techniques from oil and gas company playbooks. Think horizontal drilling and multi-well pads. Oilfield service companies are unearthing new ways to use their products, such as insulated tubing, to minimize heat loss and maximize energy as fluids in geothermal wells move from the subsurface to the surface.

Experts say the technology is there, though tweaks may be needed.

"It's a common misconception that all this innovation needs to happen in order to bring geothermal power to market. But … we have all of the technology we need," Sarah Jewett, vice president of strategy for Fervo Energy, told *E&P*. "We have a pretty massive and robust customer set. So, the only thing we have to do is build the projects and deliver to the market."

Still, roadblocks remain on the path to commercial scale. Although upfront costs are falling, they remain high. Capital constraints and financing concern some. Plus, geothermal is no exception to the federal permitting and grid interconnection woes the entire energy industry faces.

Hot Reservoirs

Geothermal energy harnesses heat

FERVO ENERGY

Fervo Energy drilled one vertical well and six horizontals at its 400-MW Cape Station project in Utah, drilling wells faster than it achieved with Project Red.

SAGE GEOSYSTEMS

A scale rendering of the Sage Geosystems 3-MW energy storage system.

below ground using wells drilled into hot reservoirs. Conventional geothermal does not require much engineering to capture heat because it's closer to the surface, with naturally-occurring fractures and fluid, such as in volcanic areas.

Next-generation geothermal energy, however, uses existing oil and gas technologies to harness heat and unlock geothermal energy from anywhere. With an enhanced geothermal system, fluid is circulated in a pair of wells connected by fractures created in hot reservoirs. Closed-loop geothermal systems, also referred to as advanced geothermal systems, circulate fluids through closed wellbore loops in the subsurface. The heat extracted can be used to heat or cool homes and buildings via direct use heat or generate electricity with higher temperature geothermal resources.

In addition to supplying a renewable energy source, geothermal power plants provide baseload power—meaning they consistently produce electricity—regardless of weather conditions. The renewable energy source can be used to store energy underground, and the footprint required is relatively small compared to solar and wind sources of renewable energy.

"It's a common misconception that all this innovation needs to happen in order to bring geothermal power to market. But ... we have all of the technology we need."

SARAH JEWETT, vice president of strategy, Fervo Energy

It has the potential to replace or at least reduce the number of coal- and gas-fired power plants with renewable energy.

"Next-generation geothermal power is poised to become a key contributor to a secure domestic decarbonized power sector in the United States. This is an industry that is ready to grow to large scale," said Charles Gertler, a senior advisor for the U.S. Department of Energy (DOE) Loan Programs Office and a lead co-author of the "Pathways to Commercial Liftoff: Next-Generation Geothermal Power" report.

"There is a set of emerging technology that is just coming online that vastly expands the total resource available for geothermal power generation," he said on a webinar discussing the report earlier this year. "The sector overall has really significant and unique starting advantages."

This includes the oil and gas industry, which has been pumping both dollars and technical knowhow into geothermal.

The O&G Effect

Oil and geothermal drillers have loads in common. Geothermal developers, like wildcatters, hunt for heat. They carry out site assessments using sensors and other geological aids and evaluate reservoirs. Downhole tools, pumps and turbines are also part of the process as are hydraulic fracturing tools and injection pumps for EGS. So, it may not be too surprising to see oil and geothermal drillers working together to bolster geothermal.

Service company Baker Hughes has been in the geothermal business for about 40 years, providing services that include geothermal well construction, reservoir subsurface and feasibility analysis, and turbine technology for geothermal power generation. Part of its current efforts focus on closed-loop systems as part of the Wells2Watts consortium.

With partners California Resources Corp., Chesapeake Energy, Continental Resources and Inpex Corp., Baker Hughes looks to retrofit decommissioned oil and gas wells and use existing infrastructure to create closed-loop geothermal wells.

Geothermal startup GreenFire Energy's GreenLoop technology and Vallourec's Vacuum Insulated Tubing solutions are among the technologies that have been tested, but there also are plans to test EGS technologies in the lab.

The consortium's data-driven approach has already led to insights on how to optimize the working fluids and maximize heat transfer in different situations and with varying flow rates, according to Ajit Menon, vice president of geothermal for Baker Hughes.

"There's a whole list of things that we can test," Menon said, referring to working fluids, robust technology for harsh environments and materials that improve heat efficiency. But not every well is suitable to produce geothermal energy, he said, noting that finding the right environment with enough heat requires a great deal of mapping work.

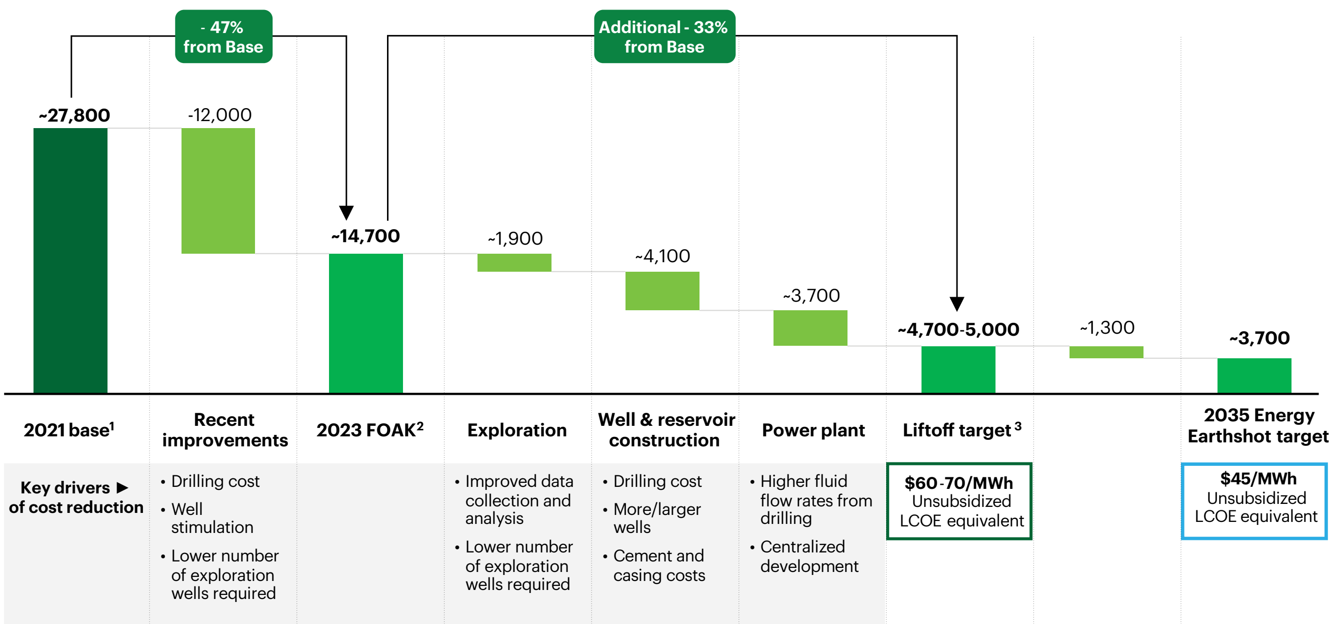
"We see a lot of opportunity here, especially in these new frontiers where you have to look at the optimization of your injection and production system to minimize fluid loss and optimize heat extraction," Menon said. "You have to look at the power you're generating and what's happening on the subsurface all as one system together at the same time."

The consortium aims to move from the lab to the field in 2024.

> "You have to look at the power you're generating and what's happening on the subsurface all as one system together at the same time."
>
> **AJIT MENON,** vice president of geothermal, Baker Hughes

Potential Reduction in National Average Overnight Capital Costs for Enhanced Geothermal Systems

($/kW)



SOURCE: U.S. DEPARTMENT OF ENERGY'S PATHWAYS TO COMMERCIAL LIFTOFF: NEXT-GENERATION GEOTHERMAL POWER
NOTES: 1. NRELATB 2021 BASE CASE 2. NRELATB ADVANCED CASE 3.2030 TARGET BASED ON TRAJECTORY TO DOE ENERGY EARTHSHOT 2035 TARGET.

Cost reduction waterfall for EGS.

Customizing Technology

Base technologies are available for geothermal to scale in the U.S., but tools from the oil and gas toolkit must be customized for geothermal, Menon added. Subsurface and power systems should be optimized as one.

"We're in well construction [and] subsurface, but we're also in power generation. We see a lot of opportunity here, especially in these new frontiers where you have to look at the optimization of your injection and production system to minimize fluid loss and optimize heat extraction," Menon said.

There's also an eye toward speed, which decreases expenses in harsh environments, he added.

"You need to be able to manage that cost effectively. So, it's really adapting technology we have today, and not just technology but processes—bringing tried and true processes that have been developed over the years to scale the oil and gas industry into geothermal," he said.

> "Even though the U.S. has the largest amount of geothermal generation in the world, it's still less than 1% of our utility grid generation."
>
> **CINDY TAFF,** CEO, Sage Geosystems

Sage Geosystems CEO Cindy Taff agrees.

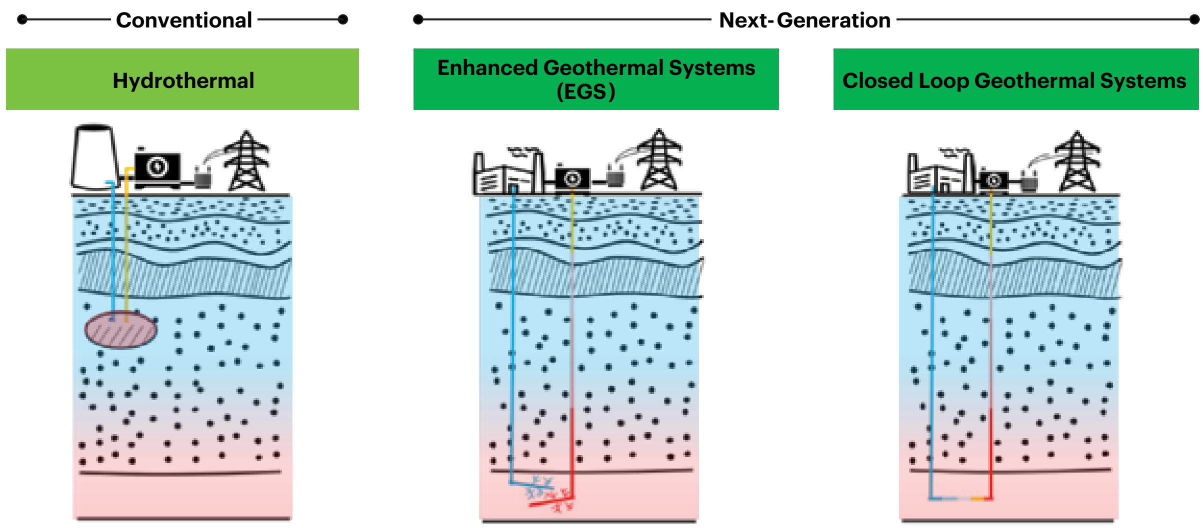
Houston-based Sage gained prominence after it reentered one of Shell's old gas exploration wells in Starr County, Texas, and proved during testing in 2021 and 2023 that it could successfully generate energy.

Its technology involves pumping large volumes of water into an artificial reservoir created by a fracture to harvest heat from hot dry rock. Pressure causes it to balloon open and hold the water under pressure. When electricity is needed, the water is brought back to the surface, where a turbine converts the heat to electricity.

"We operate fracturing like a balloon. We want low permeability, and we also want to avoid any kind of natural faults and fractures," said Taff, a former vice president of unconventional wells and logistics for Shell. "Oil and gas is actually looking for just the opposite. They're wanting the high permeability, and they're wanting those natural faults and fractures, which tend to bring the hydrocarbons to the wells."

When it comes to repurposing old oil and gas wells, Taff said geothermal wells need a diameter that is about double that of oil wells. Plus, one never knows what might be encountered when reentering an old well.

Pathways to Commercial Liftoff: Next-Generation Geothermal Power



Hydrothermal
- Fluids circulate openly through naturally occurring fractures
- Limited estimated total resource (~40 GW)
- ~4 GW on the grid today

Enhanced Geothermal Systems (EGS)
- Fluids circulate openly within a well pair connected by fractures engineered with hydraulic fracturing & horizontal drilling
- Large estimated total resource (5+ TW all next-generation geothermal)
- Scales through modular deployment of many well pairs

Closed Loop Geothermal Systems
- Fluids circulate through a long series of closed wellbore loops permeating the subsurface
- Large estimated total resource (5+ TW all next-generation geothermal)
- Scales through modular deployment and increasing wellbore lengths

SOURCE: U.S. DEPARTMENT OF ENERGY'S PATHWAYS TO COMMERCIAL LIFTOFF: NEXT-GENERATION GEOTHERMAL POWER

Geothermal technology overview across conventional (left) and next-generation (right) designs.

"When we reentered our test well in Starr County, we spent probably an extra $1 million fixing the well to bring the integrity up to snuff," she said. "You'd be better off drilling a new well and having a brand-new wellbore."

Being able to turn the heat into electricity cost-effectively and at commercial scale is the task at hand for geothermal energy developers today.

"In Sage's view, the challenge is now the thermodynamics and geomechanics challenges of basically getting the heat out of the rock, getting it to the surface," to cost-effectively turn heat into electricity, Taff said. "We're looking at both the well design and the power plant design. We think both of them are crucial."

Sage aims to commission the world's first commercial-scale geopressured geothermal system by the end of 2024 in Texas. It has also worked with the Southwest Research Institute in San Antonio to build a supercritical CO_2 turbine designed for 22,000 rpm. A load test was scheduled for late April with ambitions to demonstrate that the turbine can produce more electricity per unit heat extracted from the ground than turbines being used in geothermal today.

"Even though the U.S. has the largest amount of geothermal generation in the world, it's still less than 1% of our utility grid generation. And it all is represented by, again, conventional geothermal ... steam close to the surface of the Earth," near volcanoes or the Ring of Fire, Taff said.

That's not even 5% of the world's geothermal resources. Using today's oil and gas equipment, next-gen geothermal could unlock geothermal resources at about 150 C for about 35% to 40% of the U.S., she said.

About 15 to 20 years from now, "if we can literally crack the code on making [geothermal] commercially viable, I think geothermal is going to represent 20 to 25% of the utility grid," Taff added.

Scaling geothermal will not happen without success in EGS and AGS. The sector is already seeing improvements in the rate of penetration and drilling learning curves happening with first movers in the space, Menon said.

The DOE-sponsored Utah Frontier Observatory for Research in Geothermal Energy (FORGE) project is an international field laboratory managed by the Energy & Geoscience Institute at the University of Utah. Its work, including with Fervo, has enabled improvements in costs, well stimulation and drilling times—all areas that have challenged geothermal's growth in the past.

Driving Down Costs

Fervo Energy, which counts Devon Energy and Helmerich & Payne among its investors, reduced drilling time during its Cape Station drilling campaign by 70% compared to its Project Red drilling campaign in 2022, using modern oil and gas drilling equipment. These included polycrystalline diamond compact drill bits and mud coolers.

In a six-well drilling program, costs for the first four wells dropped by about 50%, from $9.4 million to $4.8 million per well. The campaign, which included one vertical well, reached depths as great as 14,000 ft amid high temperatures.

Fervo Energy CEO Tim Latimer said the company reduced its year-over-year drilling time through high-temperature hot rock granite from 70 days to 20 days.

The learning curve and productivity gains unlocked shale oil and gas production in the U.S., making it the world's largest oil and gas producer, he said during CERAWeek by S&P Global.

"I think we're well on our way to definitively proving that same trend is going to occur in the geothermal sector," he said.

The company is constructing a 400-MW utility-scale geothermal project in Beaver County, Utah. The first phase is set to come online near the end of 2026 with the second phase expected online in 2028.

"It's in full go mode right now. We're doing subsurface development. We're doing the procurement for the power facility and building it," Fervo's Jewett said.

Speaking during a webinar about the geothermal liftoff report, DOE's Gertler said drilling times have consistently improved, and those improvements have translated into significant cost reductions.

"There are some reports from geothermal startups recently that show early deployments demonstrating a 300% increase in drilling rate, and in the process, cutting costs in half. ... All of these advancements taken together can be seen in recent cost reductions and on projections of costs for geothermal technologies," Gertler said.

The DOE's Enhanced Geothermal Shot initiative aims to slash the cost of enhanced geothermal systems by 90% to $45 per megawatt hour (MWh) by 2035. The improvements, driven mainly by well stimulation and improved flow rates, show the EGS target is aggressive but achievable, he said.

The liftoff target corresponds to a levelized cost—or the lifetime costs—of energy of $60/MWh to $70/MWh, without help from government subsidies.

"If you look at the market demand side, what you're seeing ... is that firm clean power in the United States is clearing at $100 a MWh. When you go internationally, it's often a much bigger multiplier than that," Latimer said. "So, it's already something that's quite cost competitive ... geothermal is already winning that cost discussion."

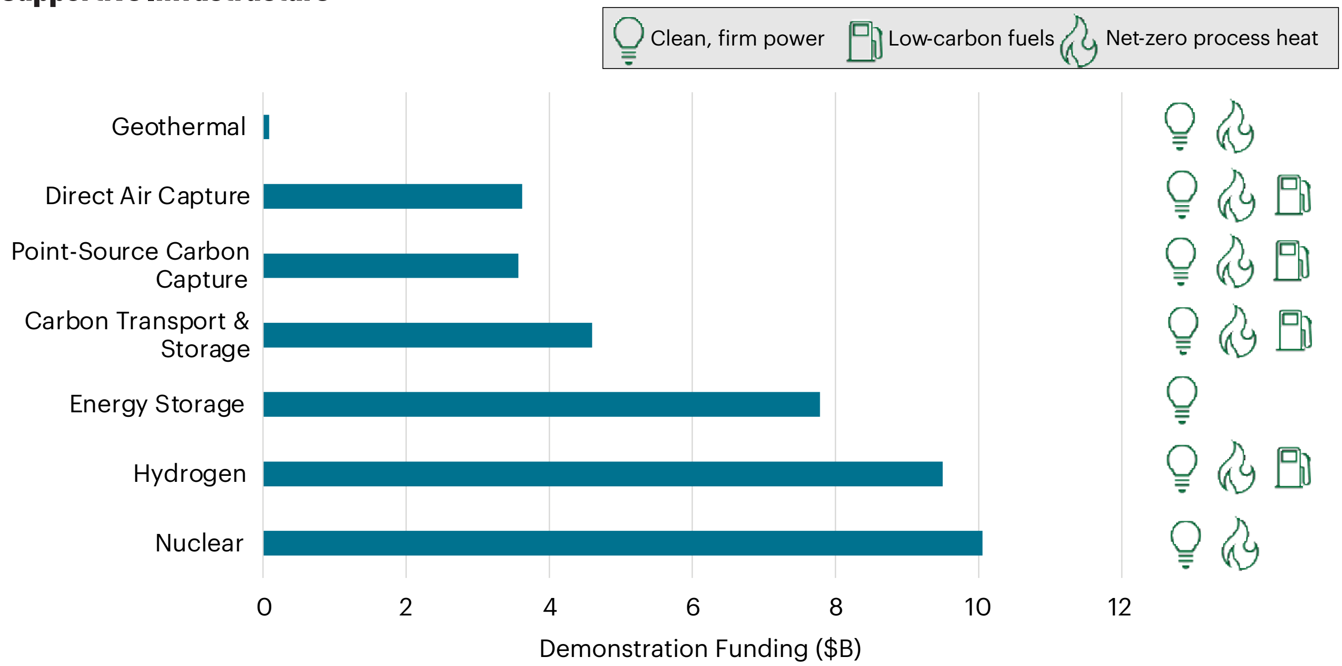
In the past, the geothermal energy industry had never seen real cost efficiencies based on scale, Jewett said. Geographical constraints have prevented companies from drilling multiple wells, carrying out repetitive operations and leveraging economies of scale to reduce costs through learning, she said.

"We're trying to basically upend that," she added.

Drilling is a prime example.

It is difficult to achieve any

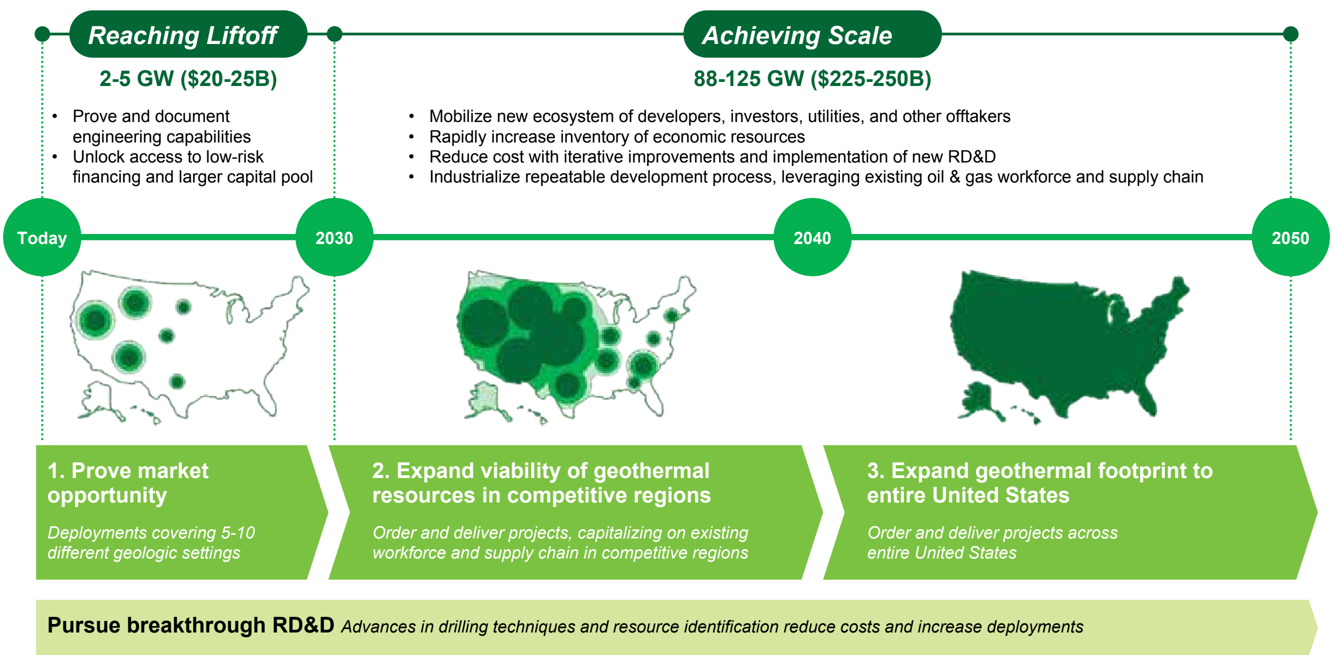
Funding Allocated for Large-Scale Demonstrations, Manufacturing and Supply Chains, and Supportive Infrastructure



SOURCE: U.S. DEPARTMENT OF ENERGY'S PATHWAYS TO COMMERCIAL LIFTOFF: NEXT-GENERATION GEOTHERMAL POWER

Comparison in government funding availability for large demonstrations, manufacturing and supply chains, and supportive infrastructure across key clean energy technologies

Pathway to Commercial Liftoff and Scale for Next-Generation Geothermal Power



SOURCE: U.S. DEPARTMENT OF ENERGY'S PATHWAYS TO COMMERCIAL LIFTOFF: NEXT-GENERATION GEOTHERMAL POWER

Pathway to commercial liftoff and scale. Green dots on maps correspond to representative potential geothermal footprint in terms of power use.

meaningful learning by drilling only six to 10 wells. Applying a manufacturing mindset from a subsurface development perspective can lead to meaningful change.

"We are drilling not six or 10 wells, but we're drilling a 100 wells. So, we're basically able to apply the learnings of every single well to the wells thereafter," Jewett said.

"We know that we can get to 400 degrees .... What we don't know we can do is complete or really construct that well in a way that has longevity."

TERRA ROGERS, program director for superhot rock energy, Clean Air Task Force

Going Deeper, Hotter

Drilling advances could make harnessing more energy from superhot rock possible.

Speaking during the same CERAWeek panel with Fervo's Latimer, Terra Rogers, program director for superhot rock energy at the Clean Air Task Force (CATF), said it is focused on moving geothermal into temperatures of 400 C or higher.

CATF rolled out maps this year that show how deep drillers must go to make this possible. Its modeling tool showed 63 terawatts of clean power could be generated by harnessing just 1% of superhot rock belowground. Most drillers are not tapping into superhot rock, which is typically found in the U.S. at depths below 8 miles (12.5 km), a point at which existing rig capacity may be maxed out in terms of strength and stress.

"We know that we can get to 400 degrees .... What we don't know we can do is complete or really construct that well in a way that has longevity," Rogers said. "That is also a very important part in the research ingredients. ... I have heard service providers say 7 km without blinking an eye."

Eavor, which specializes in closed-loop geothermal technology, is developing technologies to go deeper and hotter.

"We're working on it, but we're not going to talk about it," Eavor Technologies CEO John Redfern said during the same panel. "Like I say, deeper, hotter, faster, cheaper. That's our mantra. And, those [technologies] will be unveiled as they come along ... 7 to 9 km is sort of the limit [now]."

The company aims to deliver first power to the grid later this year, Redfern said.

The Calgary, Alberta-based company also joined the Alberta government and other stakeholders to develop the Alberta Drilling Accelerator (ADA), a "technology-agnostic, market-driven geothermal test site."

The first-of-its-kind site in Canada will be available for use by any geothermal company pursuing novel drilling techniques and technology development, according to a news release. The ADA also aims to help the province keep pace with other government-supported geothermal test sites, such as Utah FORGE, the Continental Deep Drilling Program in Germany, the Deep Drilling Project in Iceland and China's geothermal drilling program.

Lifting Off, Achieving Scale

The DOE says the U.S. is positioned to produce up to 5 gigawatts (GW) of the clean energy power source across a handful of states. But it will take between $20 billion and $25 billion in investments to reach that power threshold by 2030. Producing 88 to 125 GW across more states by 2050 could require as much as another $250 billion.

Capacity could surpass 300 GW across the country, however, if hydrogen and direct air capture become difficult to commercialize and lead to more geothermal development, according to Michael O'Connor, lead co-author of the geothermal liftoff report and strategist for DOE's Office of Clean Energy Demonstrations. O'Connor and Gertler discussed the potential for next-generation geothermal power and the department's pathways to commercial liftoff report during a webinar earlier this year.

Key enablers for geothermal liftoff as detailed in the report include reducing costs to $60/MWh to $70/MWh, carrying out at least 30+ megawatt-scale demonstration projects to prove consistency and lower technology risk, locking in high-value offtake agreements with utilities or off-grid demand sources such as data centers that support new projects, and selecting sites and developing projects with communities.

"At the DOE-run Utah FORGE site, seismicity monitors are actually on display at the public library. So, community members can transparently see the impacts of drilling and drilling activities in their community in real time," O'Conner said.

The pathway to liftoff includes demonstrating geothermal in five to 10 separate geologic settings to reduce risk and verify resource availability, according to the report. This corresponds to more than 100 developments, comprising overall deployment of 2 GW to 5 GW at a cost of $20 billion to $25 billion. Even more is required to achieve scale, defined as between 88 GW and 125 GW.

"To reach scale by 2050, next-generation geothermal will require an additional $225 to $250 billion in investment, driven by a new ecosystem of developers, investors, utilities, and other offtakers, and leveraging existing workforces and supply chains," according to the DOE.

FERVO ENERGY

Houston-based Fervo Energy set record power and flow rates in 2023 at its Project Red enhanced geothermal project, confirming the commercial viability of its drilling technology.

The biggest roadblock for growing geothermal may be convincing people to finance projects, according to Jewett. For Fervo, "it doesn't take a ton of convincing once they lift up the hood and they see that these are good infrastructure-type return projects with long lifetimes," she added. "We are a company that is not like geothermal companies of yore where we're going to sort of drill all over the place and then come up empty. I think we're a company that plans very well and plans to execute." When investors see that, "they become convinced pretty easily."

When the discussion turned to funding during the CERAWeek session panel, Latimer and Redfern pointed out how their companies have been successful in raising venture capital dollars to pursue projects.

Chevron and Fervo received grants from the DOE for geothermal projects funded by the Bipartisan Infrastructure Bill.

"It's good there's funding there and enough to … put some points on the board and show some wins for our sector," Latimer said.

On the flip side, a chart in the liftoff report compares how much funding geothermal received compared to other technologies.

"I couldn't see the bar on the bar chart," Redfern said, noting that despite that fact, funding will not hold back geothermal.

"As we prove up our different projects, there's going to be a wall of money that wants to invest," he said. "What's going to hold us back is a physical limit of how fast we can scale up ourselves … because it just takes time to get people organized. It takes time to get rid of bottlenecks on the drilling rig side. There's a whole bunch of physical limitations to how quickly you can grow."

Rogers said tech partners are the unsung part of the geothermal's story.

"Google and Microsoft have done an excellent job of pulling aside the green curtains and acknowledging that demand and supply need to align, especially in this space, and trying to match low-carbon expectations and the stress that these hyper-sized datacenters put on grids," she said. "So as there is an awakening to the idea that they are a big part of the buying chain, I wouldn't be surprised if we see some vertical integration. But in any case, they certainly are a strong source of funds. We don't do one without the other." E&P

Seeing is Believing: Fiber Optics for CO_2 Storage Monitoring

Fiber optic systems can offer CO_2 plume insights in CCS applications.

SKANDAR GANDI | GLOBAL SEGMENT LEAD FOR CCS, WEATHERFORD
STEVE MATHIAS | GLOBAL ADVISOR FOR RESERVOIR MONITORING, WEATHERFORD

Reducing the carbon footprint worldwide requires continuous, long-term reservoir monitoring information to ensure captured carbon remains in place in underground storage.

Robust and innovative fiber optic solutions are needed to support the development of storage-asset surveillance for carbon capture and storage (CCS) operations.

The Measurement Monitoring and Verification (MMV) program is an essential part in the CO_2 storage life cycle, including early-stage site characterization, permit application, field development, injection monitoring compliance and post-injection storage monitoring. MMV deliverables are being embedded as part of the CCS operational process to demonstrate containment and conformance of CO_2 being injected and sequestered in the reservoir permanently. With over 30 years of experience developing and installing fiber optic sensing systems, Weatherford recognizes the potential this technology has to meet some of the monitoring requirements specified in the MMV program.

Effective CO_2 plume monitoring in injection wells is one of the key objectives in the MMV framework for upcoming CCS projects in the United States and around the world.

Distributed acoustic sensing (DAS) methodology, enabled through an optical cable as the sensor for both passive and active seismic monitoring, has opened new possibilities of design to incorporate fiber optic systems as a permanent seismic sensor in the architecture of the well.

The challenge for operators is overcoming the reluctance to transition from conventional methods of measurement to more innovative fiber optic measurement solutions that effectively meet the measurement-parameter thresholds.

Fiber Optic Deployment

There are several reasons fiber optic cable might need to be cemented behind casing, but fundamentally, it is done to enhance coupling to the formation, ensuring optimal measurement sensitivity. The fiber-optic cable should be installed, and preferably cemented, close to the sealing caprock position to promptly detect any microseismic activity or out-of-zone injection.

For thorough monitoring of plume saturation and migration, it's essential to cement the fiber optic cable behind casing directly across the injection zone. Although embedding the fiber optic cable in cement during installation provides the most precise

The gun assemblies are oriented so their perforation ports are pointed away from the optical cable, thereby preventing cable or gauge damage before cementing in place.

WEATHERFORD

results and superior imaging quality, acceptable measurement outcomes can still be achieved if it's deployed through tubing instead. When the reservoir section is intended to be cased and perforated, it becomes essential to mitigate the risk of potential cable damage during the perforation operation in this area.

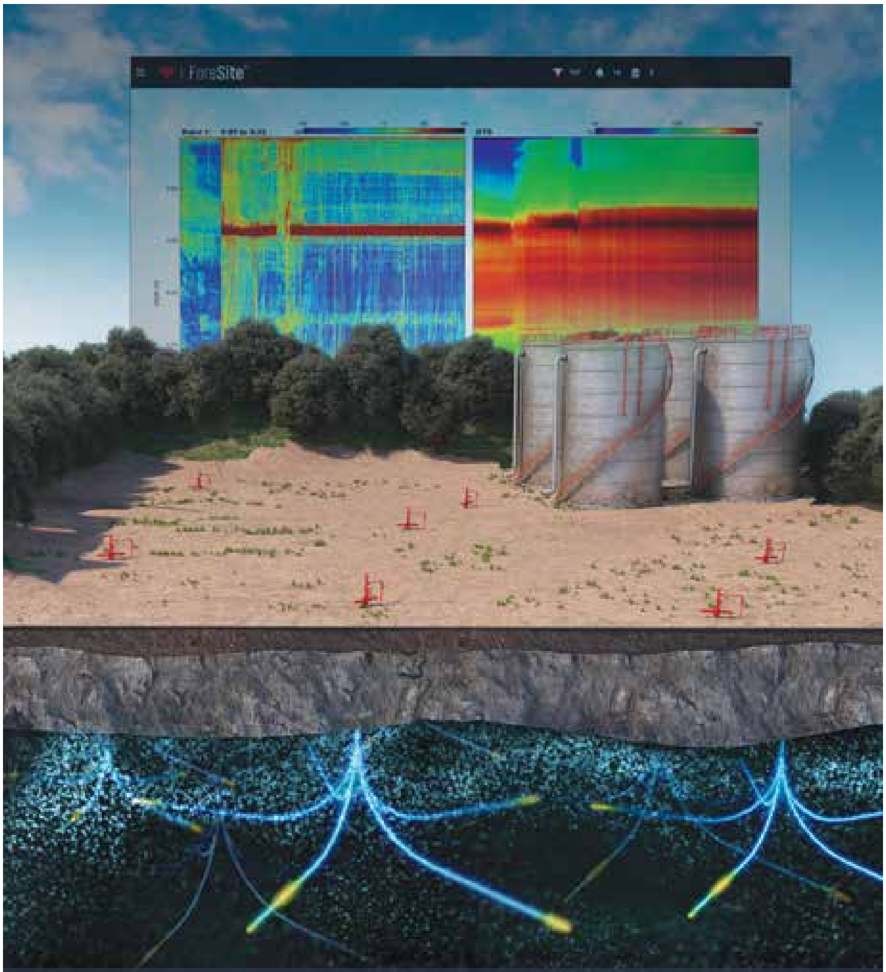
In this scenario, Weatherford leverages the experience from system deployment in well environments for in-zone monitoring in oil and gas, and unconventional applications. Here, the fiber optic system is deployed in cemented annuli, and casing perforation is performed in the same vicinity as production through a method called oriented perforation.

During casing runs, optical cable is lowered to the desired depth using a specialized clamp system positioned over the area of interest, after which cementing is carried out. The clamp system is pre-installed to enable indication of the cable azimuth position inside the casing.

In the perforation stage, a wireline-deployed gun string is run in conjunction with an orientation tool to identify the clamp system behind the casing. This allows the predetermined charge direction string to be pointed away and perforated safely without risking damage to optical cables or gauges.

The additional data stream—gained through deploying a fixed sensor while still obtaining data from distributed measurement—is an added value for the operator.

The use of a single optical cable system allows for the installation of pressure and temperature sensors at the injection depth, enabling real-time monitoring of CO_2 injection. This setup ensures that the injection rate and pressure remain within the frac gradient of the cap rock seal, a level of precision that was previously achievable only with tubing-conveyed options. Installing optical gauges in this environment is ideal because the transducer's low mass enables it to withstand the high G loads typically experienced in the localized area of perforating gun discharge.



Using fiber optic systems to measure and monitor CO_2 provides real-time distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) data insights into underground carbon storage, transforming carbon sequestration monitoring and management.

WEATHERFORD

Technology Deployment

Weatherford has performed the oriented perforation process in the U.S., Middle East and Asia. The deployment of this technology application worldwide has showcased the benefits of adopting a fiber optic system.

The optical system offers the advantage of improvements, enhancements or the addition of new sensing options post-installation. Operators have been able to go back to a 23-year-old optical-sensor system and still obtain data. By leveraging advancements in acoustic sensing processing and interpretation, Weatherford was able to extract additional insights by connecting a different surface instrument to the downhole optical pathway, a surface-instrument solution that was not available at the time of deployment over two decades ago.

Deploying a system that allows scope-of-improvement in data insights is crucial for CCS wells due to the longevity of the application and surveillance requirements in these reservoirs. E&P

Accelerating Adoption

Policy push meets industry pull, positioning CCUS for takeoff.

KATIE ZIMMERMAN | DECARBONIZATION DIRECTOR AMERICAS, WOOD
DAVID BAHR | TECHNICAL DIRECTOR DECARBONIZATION, WOOD

As decarbonization policy continues to evolve on a global scale, carbon capture, utilization and storage (CCUS) adoption is gaining momentum. Endorsed by many prominent trade bodies as a necessary catalyst for unlocking decarbonization at scale, CCUS offers a pathway for industries that previously would have found it hard to decarbonize, such as cement, glass, and pulp and paper.

With the increase of the 45Q tax credit for carbon capture projects through the Inflation Reduction Act (IRA) of 2022, coupled with the funding in the Bipartisan Infrastructure Legislation (BIL), the U.S. government is signaling a shift in focus from research and development, to scale and commercialization of carbon capture technologies. Companies in the U.S. can potentially access government grants to build carbon capture projects, as well as incentives to operate them.

To successfully deploy carbon capture at scale, projects must consider the carbon capture itself, in addition to the transport and final destination of the CO_2. Installing a new CO_2 pipeline and planning for sequestration and/or end-use is an expensive effort for just one company to undertake.

A more cost-effective approach is for groups of emitters to partner on transportation and storage projects for mutual benefit, a practice now commonly referred to as a "hub" or "cluster." Hubs are increasing in popularity in the U.S. and beyond and are recognized as a viable model for advancing industrial decarbonization projects. Well-known examples include the U.K.'s East Coast Cluster, Canada's Pathways Alliance and Houston's HyVelocity hydrogen hub, which includes a significant carbon capture component; however, these projects are still being developed and have not yet delivered emissions reductions.

With most carbon capture projects still in the FEED and pre-FEED phases, early engagement with experts is essential. Without a clear understanding of which carbon capture technology will work best or a clear plan to transport, store or use the CO_2, CCUS will not reach the commercial status it needs to maintain momentum.

CCUS in Action

Providing the world with clean, affordable, secure energy and materials will require us to balance the investment of capital and technology between existing facilities and greenfield developments. The reality is, we do not yet have commercially viable routes to produce all the commodities we rely on today without the use of fossil fuels as a key feedstock. But CCUS could offer us a practical way to address this issue.

With billions of dollars in grants from the U.S. Department of Energy's Office of Clean Energy Demonstrations (OCED) and increased tax incentives from 45Q, Wood is moving forward with projects focused on accelerating the commercial deployment of CCUS technologies at scale. Solutions such as direct air capture (DAC) hubs, carbon capture for industrial decarbonization and hard-to-abate sectors, and CO_2 pipelines are advancing at an accelerating pace, indicating carbon capture's growing appeal.

Despite the increased interest in CCUS, as of 2023, only 40 commercial facilities were operational in industrial processes, fuel transformation and power generation; that's a small share of the 500 projects in the pipeline. The Energy Transitions Commission (ETC) has estimated that by 2050, the world will need to capture and either use or store 7-10 gigatons per year of CO_2, a huge jump from today's 46 mtpa. The current pace of deployment for carbon capture technology falls short of allowing us to meet this goal, meaning serious action must be taken to ramp up CCUS if we are to reach sufficient capacity in the coming decades.

Barriers to Scaling Up

The scale and deployment of CCUS poses technical, commercial and policy challenges. Understanding the basics of carbon capture technology is fundamental. Typically, when companies decide to decarbonize, they must select a licensor's technology from a pool of many options. Not all emissions are the same. The range of concentrations and contaminants can vary widely in industry. It is critical that stakeholders understand the carbon capture technology's capabilities and operating parameters to ensure it will meet their decarbonization needs.

CARBON ENGINEERING

Rendering of the planned Carbon Engineering and 1PointFive direct air capture (DAC) facility in Ector County, Texas. Once completed, the facility is expected to be the largest DAC facility in the world and is scheduled to be in commercial operation by mid-2025.

For some of these industries, the most well-proven technology for post-combustion CO_2 capture, an amine system, is a significantly different type of unit to the existing processes on the site. Similarly, the project development process may also be unfamiliar. Many producers in the commodities industries are accustomed to an off-the-shelf approach to buying units or system components. However, carbon capture units, especially amine-based ones, are typically bespoke designs that need to go through the pre-FEED and FEED development steps. This enables operators to optimize the system while minimizing investment and operating costs. It also stops existing operations and the surrounding environment from being seriously impacted during the carbon capture system's implementation.

Historically, project economics have been a "make or break" factor for carbon capture projects, as well. For example, in 2017, Petra Nova began capturing CO_2 at a Texas power plant and transported the CO_2 by pipeline for enhanced oil recovery (EOR) in a nearby oil field. The project originally cost around $1 billion to build. When the price of oil plummeted in 2020, the carbon capture unit was turned off because the increased oil production no longer produced enough profit to justify running the CO_2 capture operation. The carbon capture unit restarted in 2023, but the lesson on the importance of CCUS project economics remains.

Ensuring projects are technically and economically sound is imperative if carbon capture technology is to achieve its full potential. This is why operators and manufacturers are encouraged to engage specialist decarbonization and technical advisers from the onset.

Beyond this, policy momentum must continue to accelerate to fully unlock the potential of CCUS to advance the energy transition. We have already made exceptional policy progress in the U.S., but replicating this on a global scale is far more difficult. Creating standard forms of carbon accounting for the global supply chain will be key for driving further engagement with CCUS solutions. A clearer understanding of the emissions associated with the production of a particular product can enable countries to implement policy to further their own objectives.

SHUTTERSTOCK

The Carbon Engineering Innovation Center in Squamish, British Columbia, is the world's largest dedicated direct air capture research and development facility.

The EU's Carbon Border Adjustment Mechanism (CBAM) is a brilliant example of bringing this into practice. By putting a price on the carbon emitted during the production of goods entering the EU, it encourages cleaner industrial production in non-EU countries. Policies such as CBAM help move the needle on decarbonization projects worldwide. We have seen projects in the U.S. pivot their strategies to optimize U.S. tax incentives as well as CBAM.

Pulling this type of targeted carbon policy to the global market will be no easy feat, but the benefits associated with doing so will be instrumental in scaling and commercializing technology that will make inroads toward reducing our global carbon footprint.

Learning from Successes

As with any technical advancement, we must continue to learn from what has come before us. As U.K. cluster projects approach final investment decisions (FID) and we continue to scale-up DAC and hydrogen hubs in the U.S., there's optimism for accelerated growth in CCUS deployment.

The hope is that as technology develops and deploys, the overall cost of decarbonization solutions will be reduced. Part of what we will learn from successful projects is how to make carbon capture work economically. The projects we are doing to advance CCUS with the U.K. clusters and North American hubs are prime examples of success stories that can be replicated across the globe.

Net Zero Teesside (NZT) Power is a prime example of this. In partnership with the Northern Endurance Partnership, NZT Power aims to be one of the world's first commercial scale gas-fired power stations with carbon capture. The scheme could generate up to 860 megawatts of flexible, dispatchable, low-carbon power equivalent to the average electricity requirements of around 1.3 million U.K. homes. Wood has been engaged to support from an integrated project management standpoint for this pioneering carbon capture project. Onboarding a host of experienced and knowledgeable industry partners will be key to ensuring the sustainability of this project and facilitating industrywide learnings for years to come.

RM VM/WIKIMEDIA

Aerial photo of W.A. Parish Generating Station in Fort Bend County, Texas. Petra Nova was designed as a post-combustion carbon capture treatment system to reduce atmospheric exhaust emissions from the power plant.

About 97% of Canada's proven oil reserves are from oil sands, so decarbonizing oil sands production is vital. In addition to carbon capture at the oil sands, the transport of CO_2 is critical to the success of the decarbonization effort. Wood is designing the CO_2 pipeline system to transport CO_2 captured by Canada's six largest oil sands producers. Determining the correct CO_2 pipeline specification can greatly impact the viability of pipeline networks that will cover hundreds of miles and need to operate safely and reliably for decades to come.

Similar to the projects in the U.K. and Canada, Wood is working on hub projects along the U.S. Gulf Coast to capture CO_2 from multiple industrial emitters across multiple sectors. Ensuring that the pipeline system will operate as intended with varying compositions and contaminants at different flow rates requires a lot of engineering. Understanding the varying permitting requirements along pipeline routes adds additional complexity as well.

Maintaining Momentum

Industrial decarbonization requires collaboration and problem-solving across multiple sectors and disciplines. Technical, economic and policy aspects of projects will have to align to deploy commercial solutions at scale. Lessons learned from both successful and failed projects and initiatives will be instrumental as we continue to decarbonize industry globally.

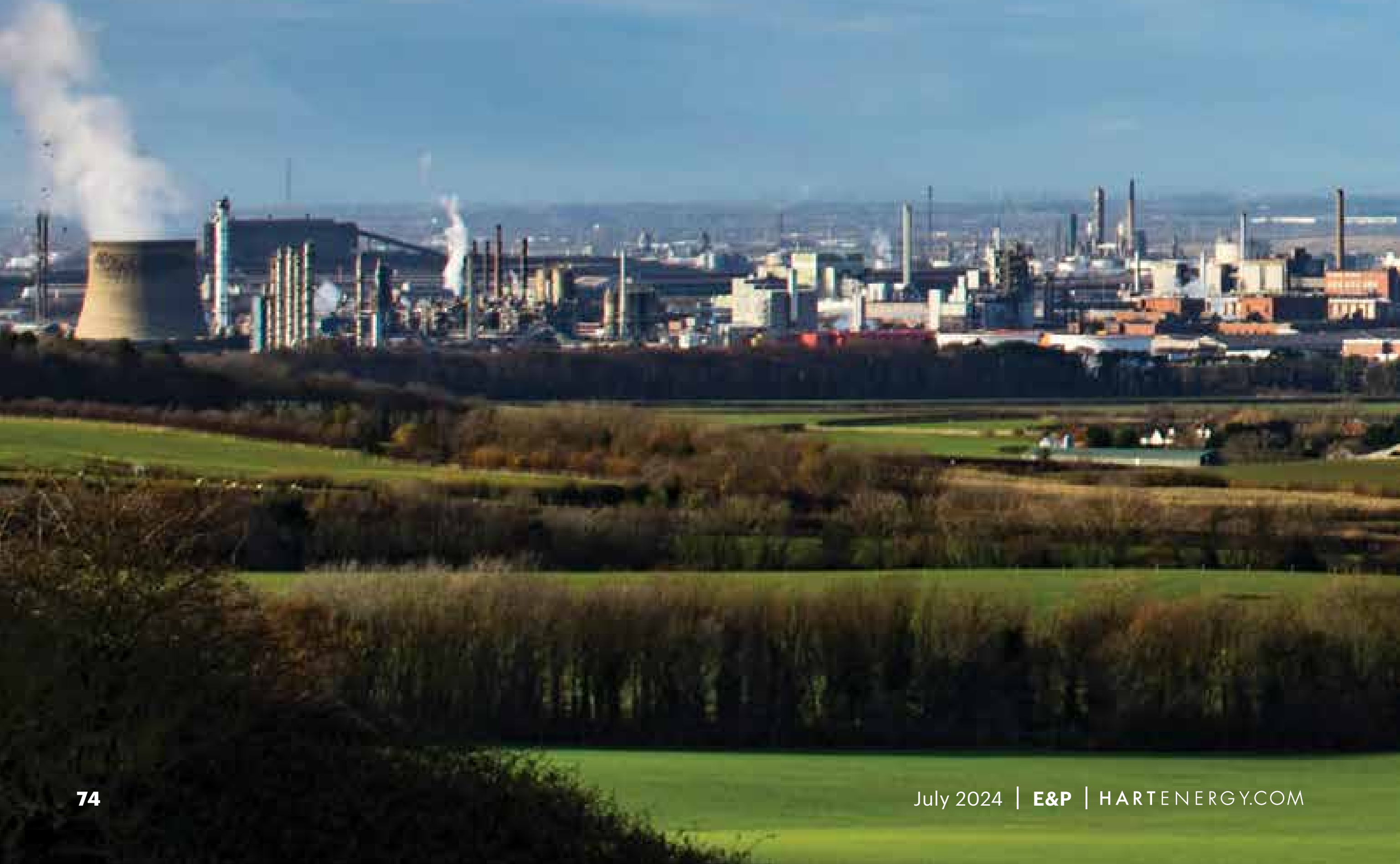
CCUS is on an upward trajectory. As one of the leading technologies for enabling large-scale decarbonization, it is important that we do everything in our power to safeguard this trend.

While government incentives have had a positive effect on the uptick in project development, incentives alone will not ensure sustainability. Engaging the market on the role of CCUS, the different variations and how to effectively design CO_2 transport systems will be essential to ensuring its adoption and longevity. In our experience, there isn't a "one size fits all" approach to CCUS. What determines success is designing a decarbonization strategy that is specific to a company's carbon reduction goals and asset portfolios. E&P

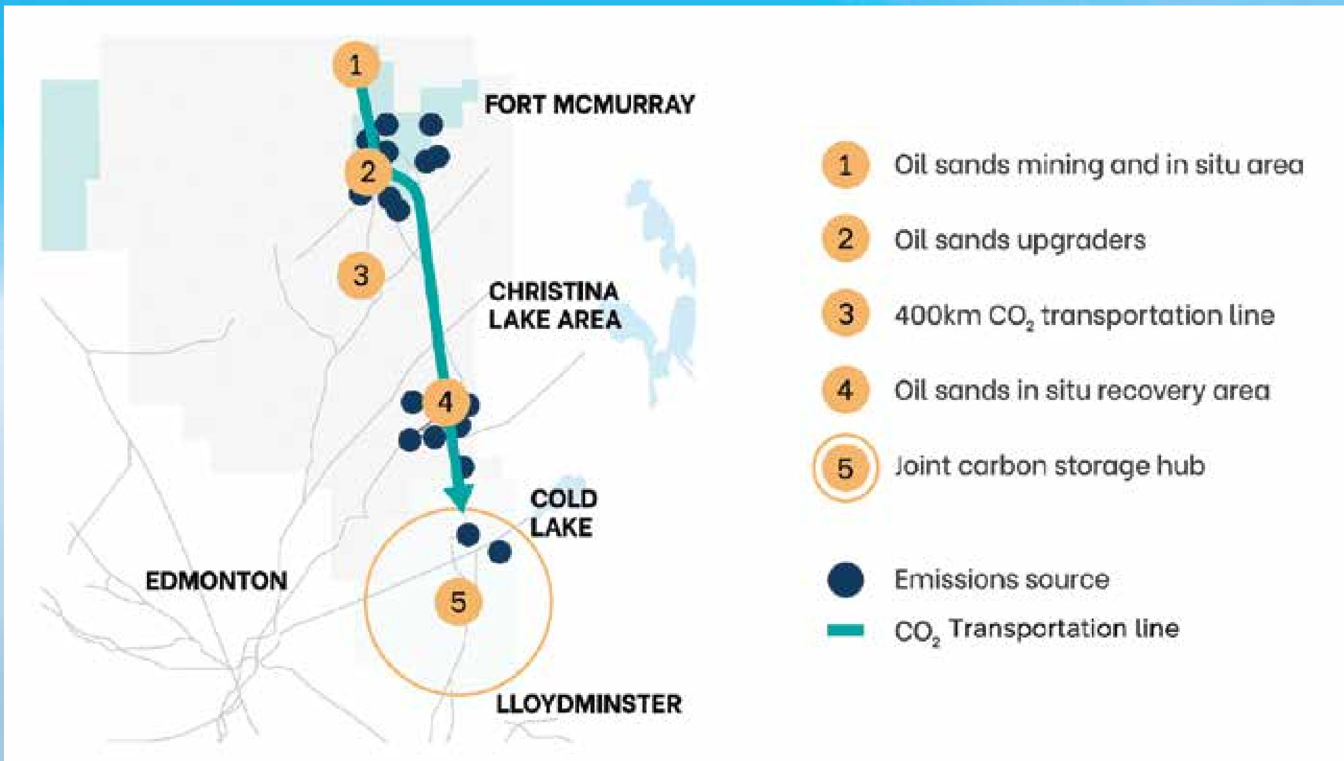
East Coast Cluster Carbon Capture Hub Overview

SOURCE: EAST COAST CLUSTER

The East Coast Cluster, enabled by the Northern Endurance Partnership among BP, Equinor and TotalEnergies, will transport CO_2 from emitters across the Humber and Teesside to secure offshore storage in the Endurance aquifer in the Southern North Sea.



Oil Sands Pathway's Carbon Capture Network



SOURCE: OIL SANDS PATHWAYS

Oil Sands Pathways' carbon capture network includes capturing CO_2 at several emission sources near a transportation line, with eventual permanent storage at a hub east of Edmonton, Canada.

Industrial park in Teesside, U.K. Net Zero Teesside, a part of the East Coast Cluster, is designed to be a fully integrated gas-fired power and carbon capture project and is key for plans to make Teesside the U.K.'s first decarbonized industrial cluster.

SHUTTERSTOCK

Prioritizing Energy Needs and Environmental Responsibility

API is committed to balancing energy security with sustainability in a changing world.

ANCHAL LIDDAR | SENIOR VICE PRESIDENT OF GLOBAL INDUSTRY SERVICES, API

The natural gas and oil industry stands at a crossroads of two compelling global imperatives: promote energy security to meet the world's increasing demand for reliable energy; and protect the environment by addressing climate change concerns. While some might frame these in partisan tones, focusing on one-sided agendas, at API, we recognize these issues are connected and as such, must be pursued concurrently. Both present very real and exigent needs.

For instance, the global population is rising, energy demand is increasing and geopolitical conflicts are escalating. These factors make energy security a critical concern, as it is fundamental to national security, economic growth and myriad societal factors. At the same time, environmental concerns are growing, and we recognize our role in addressing them, especially those related to climate action.

Our approach has been to implement innovative strategies and practices that address both considerations, a dual focus that we pursue through the development and application of rigorous standards.

API's Climate Action Framework aims to accelerate technological innovation and advance cleaner fuels.

API

The Dual Imperative

We accomplish that by publishing world-class standards that provide detailed industry guidelines addressing safety, sustainability, environmental protection and security. For more than a century, our 800+ consensus-developed standards have been the foundation of industry operations around the world, a legacy of excellence whose focus has continually evolved to meet the needs and expectations of industry and the public.

This includes a significant focus on improving environmental performance and reducing greenhouse gas (GHG) emissions, for which we have published nearly 100 standards. In the past three years alone, we have published nearly 60 standards directly contributing to reductions in GHG emissions, targeting flaring and leaks from extraction, manufacturing and transport, all of which help to mitigate risks related to climate change.

Recently, API members codified their commitment to environmental stewardship with the launch of API Energy Excellence program, where members commit to applying 13 core elements to safeguard employees, the environment and the communities where they operate. Commitment to the program provides assurance to continuous improvement across all segments of the industry, from drilling and extraction to transport and refining.

The results of these and other efforts have been profound. Between 2005 and 2023, the United States reduced CO_2 emissions more than any other country in the world, made possible by the increased use of natural gas, according to testimony presented to the House Committee on Energy and Commerce last year. This is a testament to our dual commitment to secure the world's energy supply responsibly while enhancing environmental protection, applying globally recognized standards that are continuously improved and enhanced.

Innovative Initiatives

A foundation for this transformation is API's Climate Action Framework, which is API's roadmap to address the dual energy and climate challenges,

Members of API's Energy Excellence program commit to applying 13 core elements to safeguard employees, the environment and the communities where they operate.

API

including accelerating technological innovation and advancing cleaner fuels. These are accomplished in part through the development of API standards, which are instrumental to facilitating the commercialization of new technologies, including hydrogen and carbon capture.

For instance, API 1509, Engine Oil Licensing and Certification System, 22nd edition, helps ensure that engine components work optimally. It helps improve fuel economy and maintains a vehicle's environmental and pollution controls by keeping a vehicle's emissions control systems optimized. API 521, Pressure-relieving and Depressuring Systems, and API 537, Flare Details for Petroleum, Petrochemical and Natural Gas Industries, provide guidance for flare design requirements, helping to reduce flaring and lower CO_2 emissions by improving flare efficiency.

LNG has become a viable energy source predicated on security and reduced emissions, as it allows countries to diversify their energy sources to reduce their dependence on a single supplier. After Russia reduced its flow of natural gas to European nations allied with Ukraine, the United States stepped in, increasing LNG exports by 141% from 2021 to 2022.

While ensuring energy security is critical, so, too, is environmental responsibility. And for LNG, the science is clear: Using natural gas instead of coal significantly reduces emissions, including air pollutants and CO_2. It's not just about meeting needs; it's about doing so responsibly while continuously working to improve environmental performance.

API's approach includes a focus on both processes and products. Advanced engine oils, carbon capture technologies and hydrogen are major contributors in lowering emissions. Additionally, cross-industry partnerships with technical experts, environmental groups and other stakeholders have led to important knowledge sharing on cleaner technologies and information that helps drive both new and revised standards.

Through innovation and the application of established scientific principles, API is shaping a future where both energy security and environmental stewardship are achievable.

Back to the Future

As the world confronts the dual challenges of securing reliable energy and protecting the environment, API is demonstrating how collaboration, innovation and a commitment to sustainability can produce progress that's both significant and relevant.

While the challenge is complex and ongoing, a balanced approach offers the most practical and effective path forward, meeting the world's growing energy demands while achieving meaningful environmental goals. E&P

SEATRIUM, SHELL STANDARDIZING PRODUCTION UNITS

SHELL

Seatrium and Shell will draw on their experiences from the deepwater Vito production semisubmersible in Mississippi Canyon Block 939, among others, to standardize floating production systems.

In April, Seatrium Ltd. signed a non-binding memorandum of understanding (MOU) with Shell Global Solutions International to explore and strengthen collaboration opportunities in floating production systems by leveraging both parties' engineering capabilities and technologies.

The MOU focuses on driving project standardization and replication, and promoting best practices in the design and construction of floating production systems. Seatrium and Shell will use technologies and experience from previous collaborations on projects such as the Sparta, Vito and Whale developments in the U.S. Gulf of Mexico to mature their replication efforts.

SHEARWATER, MONDAIC FWI COLLABORATION

Marine seismic acquisition company Shearwater Geoservices Holding and 3D-imaging service provider Mondaic AG have entered a strategic collaboration to develop and use full-waveform inversion (FWI) solutions to enhance high-resolution subsurface imaging and optimize seismic acquisition surveys, Shearwater said in April.

As part of the agreement, Shearwater has acquired an equity stake in Mondaic along with exclusive and perpetual rights for the use and further development of subsurface applications for Mondaic's wavefield simulation and inversion codes.

FWI seismic data processing technology improves visualization of subsurface structures, enhances reservoir understanding and helps with planning and executing more efficient surveys.

The technology also is expected to play a role in characterizing and monitoring subsurface carbon storage sites and site surveys for wind farms.

SLB INTRODUCES TWO ARTIFICIAL LIFT SYSTEMS

The Reda Agile electric submersible pump (ESP) system and the rodless Reda PowerEdge electric submersible progressing cavity pump (ESPCP) system are the two newest additions to SLB's artificial lift system family.

The two systems enable continuous operation over a range of production conditions, Ernesto Cuadros, artificial lift business line director at SLB, said in an April press release. The systems connect to digital services for continuous live surveillance and real-time optimization, technologies that enable faster installation and production, with lower power consumption, operating costs and CO_2 emissions.

The PowerEdge ESPCP system provides a more energy-efficient, rodless alternative for low-flow production rates in mature conventional and unconventional wells, SLB said. Using a single PowerEdge ESPCP system for the remaining life of the well as an alternative to rod lift installation in unconventional wells can reduce workovers and production deferments, SLB said.

The Agile ESP system provides operational flexibility, improving economics and efficiency while reducing the cost of operation, SLB said, noting that the ESP system has the widest operating range in the industry, which eliminates the need for frequent ESP changes as production varies.

HALLIBURTON LAUNCHES NEW DIVERTER

Halliburton has added the SuperFill II diverter to its SuperFill surge reduction equipment portfolio.

The SuperFill II diverter redirects fluid flow to minimize frictional pressure loss through the length of the landing string and help maximize casing running speed. The operating glass seat provides an open internal flow path with no restrictions once the diverter is closed.

Because its glass ball seat leaves no debris after activation, there are no inside diameter restrictions that limit use with additional downhole tools, the service company said in an April press release.

According to Matt Lang, Halliburton's vice president for cementing, the SuperFill II diverter is compatible with the industry's liner and subsurface release plug systems. The versatility of this feature helps increase efficiency throughout the entire operation, from running casing to total depth, to the release of the cementing wiper plugs, to the installation of the liner, he said. E&P

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.