HARTENERGY

A SUPPLEMENT TO Oil and Gas Investor

Shale 2024

QUALITY OVER QUANTITY

As US Shale Consolidates, Fewer Players with Bigger Balance Sheets to Dominate the Field

VALUE ADDING
Shale Producers Temper Ambition with Consolidation

MONTNEY MOMENTUM
Canada's Top Shale Plays Plan to Boost Production

CRITICAL MASS
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Shale 2024

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Buckle Up for Shale

Corporate strategy, geopolitics and emerging technologies are reshaping U.S. energy.

One thing you can be sure of is that the oil and gas industry is now, and probably forever will be, steeped in uncertainty.

Our editorial team has drawn on our experiences of covering the industry's top stories for you in 2023 to assess how those events—billions of dollars' worth of consolidation, private equity exits, advances in artificial intelligence, the energy industry's transition and, of course, the calamity of wars—will shape the energy business during the coming 12 months.

The world continues to grapple with the supply and demand mechanics of its reluctant dependence on fossil fuels. And the industry continues to seek ways to maintain its social license in the midst of transformation.

The corporate landscape of U.S. shale has changed and it will continue to do so. Corporate sweeps during the last six months have upended legacy independent producers: Exxon Mobil wrapped a highly acquisitive year with its deal for Pioneer Natural Resources; Chevron took out Hess Corp.; and Occidental Petroleum bought privately held CrownRock to make 2023 the busiest for private equity in years.

These megadeals have primed the sector for a new A&D round in 2024 as buyers will no doubt shed some of the assets accrued to perfect their portfolios.

Haynesville assets in Chevron's pro forma holdings from the PDC Energy closing are likely to be unloaded, along with the Bakken assets included in the Hess deal. Selling off non-core assets will shore up the balance sheet for additional shareholder returns or building up precious assets in Chevron's growing Guyana business.

A variety of analysts, including Ernst & Young, Siemens, Precision Reports and others forecast millions of dollars in annual investment to advance artificial intelligence (AI) applications in the industry, both in terms of efficiency and emissions.

Some companies have been to reluctant to embrace the technology as anything more than a consultant, a kind of advanced spreadsheet or highly gifted librarian—not quite ready to put it in control of sensitive or critical tasks.

Still, AI advocates say it could be more important to the world—especially in the energy sector—than all recent technology combined.

As 2024 unfolds and money is spent, the AI implications will come into clearer view.

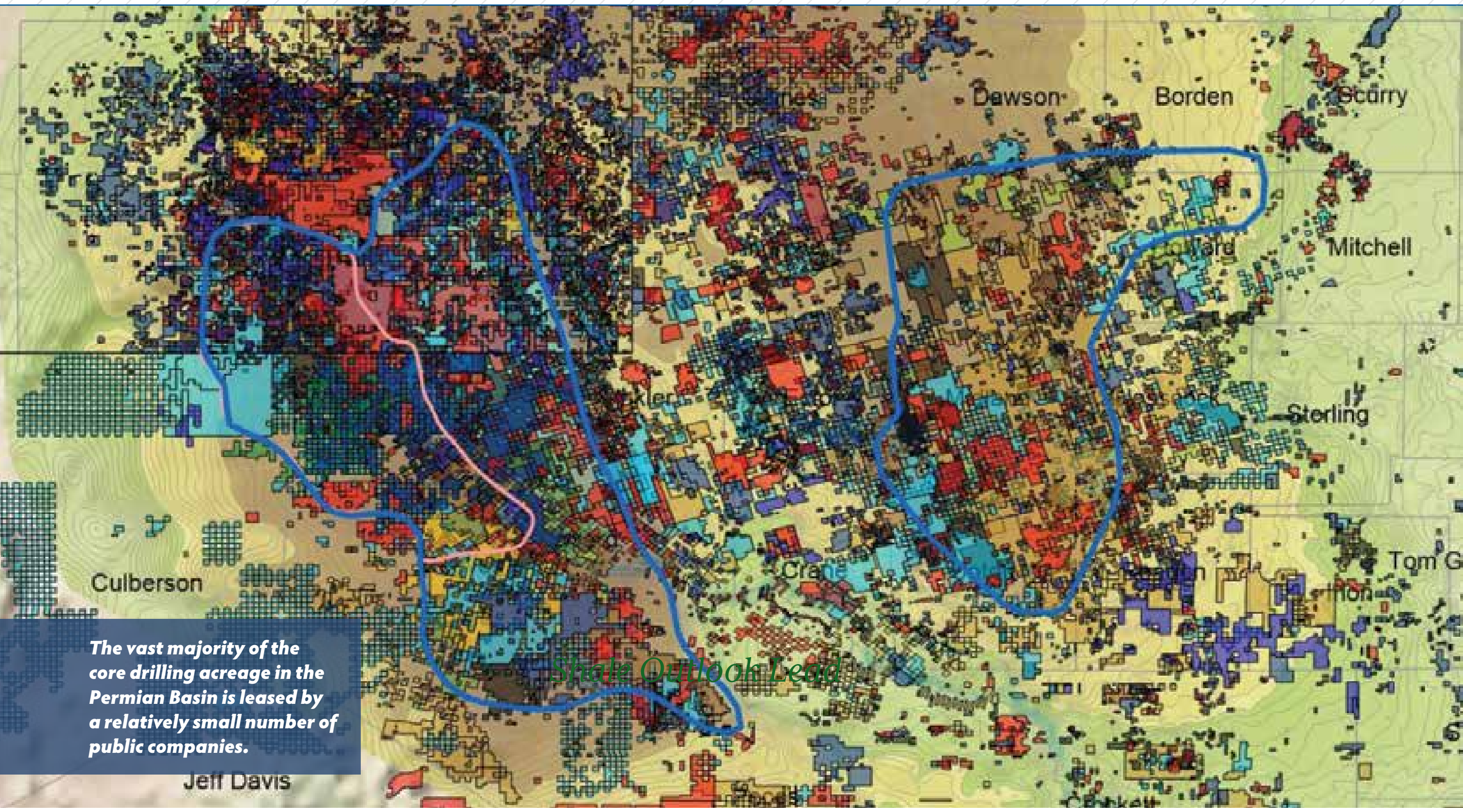
But as the promise of the new and novel takes shape and rebuilds the industry, the oil and gas business remains vulnerable to geopolitical upheaval.

Russia's invasion of Ukraine has shaken world markets and made U.S. deployment of its LNG resources an imperative, but how it plays out remains a big question.

Most companies consider energy security as a measure in most of their decisions, strategic or otherwise. In the U.S. and in allied European nations, energy security is prominent in the speeches of serious politicians and other thought leaders.

Nevertheless, some may still say that the more things change, the more they stay the same. Fitch Ratings expects the industry's sector performance in the year ahead to look much like it did in 2023, with perhaps some strength in mid-cycle levels. OPEC-plus curtailments and slowing U.S. crude production will keep oil prices broadly stable, according to Fitch.

But that's if all goes to plan. Other analysts predict U.S. shale growth inching well above the 5% many companies anticipate; OPEC has proven itself to be unpredictable at times; and war is hell. ■



The vast majority of the core drilling acreage in the Permian Basin is leased by a relatively small number of public companies.

Source: Bernstein, Enverus

M&A Bonanza Can't Stop, Won't Stop

Permian Basin well productivity has trended down. Top-tier drilling locations are scarce. Capital is at a premium. E&Ps need low-cost inventory and scale, and they're willing to pay big bucks to get them.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Civitas Resources was fresh off of a merger deal with three Colorado E&Ps when questions started to pop up about its drilling runway.

The deal among Denver-Julesburg (D-J) Basin producers Bonanza Creek Energy, Extraction Oil & Gas and Crestone Peak had yielded Civitas, the largest pure-play Colorado producer. Chris Doyle had recently been brought in as president and CEO after an executive search.

Civitas had a strong position in the D-J Basin, Doyle told Hart Energy in an exclusive interview. These were high-quality assets with low breakeven costs that could generate strong volumes of free cash flow.

"It was a very successful business model for the first six, nine months of Civitas," Doyle said.

"What we were really trying to do is: How do we take that business model that's focused on shareholder returns, little growth, maximizing free cash flow, and how do we extend the duration of that business model?"

The company needed to find more inventory depth—ideally the same kind of high-quality, low-cost inventory already competing for capital in its D-J Basin drilling plans. But that was going to be a tall task to actually locate and buy in the D-J Basin.

At that point, the D-J was already significantly consolidated, Doyle said. The basin's core was essentially

"I do think there is a recognition from industry that high-quality inventory and access to resource is more precious today than it was a year ago, or certainly a couple years ago."

CHRIS DOYLE, president and CEO, Civitas Resources

already leased up by the likes of Chevron, Occidental, PDC Energy and Civitas itself.

And the basin consolidated even more when Chevron bought PDC for $6.3 billion last year.

"That really limited the opportunities for Civitas to continue to grow and extend our business model within the D-J," Doyle said.

If Civitas couldn't find the high-quality inventory it desired in Colorado, it needed to look somewhere else. So the Colorado pure play turned its attention south to Texas and New Mexico.

Doyle said Civitas knew it needed to enter a new basin—the Permian Basin, America's top oil-producing region—with scale. Instead of dipping its toe into the pool, Civitas cannonballed its way into the Permian with nearly $7 billion in M&A in 2023.

The first pair of deals, announced in June, included Delaware Basin assets from NGP-backed private operators Hibernia Energy III and Tap Rock Resources. Civitas agreed to pay $4.7 billion in a cash-and-stock transaction.

In October, Civitas entered the Midland Basin with a $2.1 billion acquisition of Vencer Energy. Vencer is backed by international energy trader Vitol.

Scale matters in the oil and gas business, Doyle said. Being bigger helps you negotiate more favorable services contracts to lower drilling and completion costs. You can be more efficient with your rigs and frac crews on a larger, more contiguous position. All of those help you lower the breakeven cost of your drilling inventory.

But scale also helps your balance sheet and trading liquidity. Larger companies generally trade at higher multiples than smaller players. And a strong, investment-grade balance sheet can help you access lower costs on bank debt—an important point with elevated interest rates.

Civitas has seen some of the benefits of scale: the company's stock price was up around 20% year over year when the market closed on Dec. 7.

"I do think there is a recognition from industry that high-quality inventory and access to resource is more precious today than it was a year ago, or certainly a couple years ago," Doyle said.

Top 50 U.S. shale public companies

(Average first-half 2023)

Rank	Operator	Boe/d
1	Exxon Mobil	1,167,969
2	Chesapeake Energy	1,130,230
3	EOG Resources	1,103,901
4	EQT Corp.	990,448
5	Occidental Petroleum	977,228
6	ConocoPhillips	970,496
7	Southwestern Energy	926,887
8	Chevron	903,877
9	Devon Energy	809,620
10	Pioneer Natural Resources	801,198
11	Coterra Energy	799,473
12	Antero Resources	540,976
13	Diamondback Energy	491,636
14	Marathon Oil	439,170
15	Permian Resources	391,236
16	Ovintinv	355,588
17	Range Resources	352,079
18	Comstock Resources	343,248
19	BP	301,417
20	CNX Resources	263,056
21	Chord Energy	225,408
22	Crescent Energy	220,905
23	Gulfport Energy	218,957
24	APA Corp.	207,481
25	Civitas Resources	202,492
26	National Fuel Gas	195,655
27	SM Energy	194,141
28	Repsol	187,581
29	Matador Resources	165,966
30	Hess Corp.	154,760
31	Diversified Energy	141,445
32	Vital Energy	141,405
33	Callon Petroleum	126,277
34	California Resources	103,722
35	Exco Resources	103,218
36	Magnolia Oil & Gas	86,205
37	Enerplus	78,822
38	TotalEnergies	70,666
39	Silverbow Resources	70,321
40	Kinder Morgan	69,803
41	Baytex Energy	57,400
42	Amplify Energy	55,508
43	HighPeak Energy	55,304
44	Tellurian	39,685
45	Murphy Oil	32,052
46	Berry Petroleum	28,529
47	Riley Exploration	26,305
48	Ring Energy	23,195
49	Dominion Energy	22,568
50	Equinor	19,264

Source: Enverus

Some well productivity has declined in the Permian Basin, even as average lateral lengths have increased.

Shutterstock

Anatomy of a bonanza

E&Ps have spent years and billions of dollars innovating and trying to organically boost shale productivity. But a new realization is settling across the shale patch: If you want the highest quality drilling inventory, you'll probably have to buy it from someone else.

In our 2023 Shale Outlook, we highlighted efforts by Pioneer Natural Resources—one of the Permian Basin's largest and most adept players—to overcome well productivity declines and a rising gas-to-oil ratio on its Midland Basin position.

These concerns weren't exclusive to Pioneer. Exxon Mobil, Chevron and several other of the basin's top operators were dropping their outlooks for Permian oil and gas volumes because of declining well production, services cost inflation and other headwinds.

E&Ps expressed optimism despite the challenges. Both Chevron and Exxon continued touting plans to push their respective Permian outputs up to at least 1 MMboe/d in the coming years.

Pioneer said it would go back to the drawing board and reshuffle its 2023 drilling portfolio to target wells

Top 10 U.S. shale producers
(By oil production, average first-half 2023)

Rank	Operator	Gross bbl/d
1	EOG Resources	626,454
2	ConocoPhillips	590,931
3	Occidental Petroleum	567,771
4	Pioneer Natural Resources	503,072
5	Exxon Mobil	500,093
6	Chevron	458,355
7	Devon Energy	453,315
8	Diamondback Energy	328,028
9	Marathon Oil	247,982
10	Permian Resources	204,667

Source: Enverus

Top 10 U.S. shale producers
(By gas production, average first-half 2023)

Rank	Operator	Gross bbl/d
1	Chesapeake Energy	6,672,115
2	EQT Corp.	5,888,008
3	Southwestern Energy	5,419,569
4	Exxon Mobil	4,007,100
5	Coterra Energy	3,929,764
6	Antero Resources	3,162,310
7	EOG Resources	2,864,588
8	Chevron	2,673,046
9	Occidental Petroleum	2,456,643
10	ConocoPhillips	2,277,330

that could potentially generate higher returns.

The industry believed it would be able to develop itself out of declining shale productivity, leaning on engineering innovation like the kind that ushered in a historic fracking boom more than a decade ago.

And beyond making development more efficient, there was still plenty of runway for the industry to continue drilling like it had been. In 2022, energy analytics firm Enverus Intelligence Research estimated there were 125,000 remaining undeveloped locations across North America that could break even below a $40/bbl WTI price.

A lot can change in a year.

Drilling and completion costs continued to rise. New well productivity in the Permian appears to have peaked and is declining moderately, and the basin's gas-to-oil ratio continues to climb. The circumstances are even less rosy in more mature shale plays like the Bakken and the Eagle Ford.

Shale wells, by and large, aren't getting all that much better: Average well productivity across U.S. shale appears to have peaked in 2021, according to data analyzed in reports by Bernstein, Enverus and Novi Labs.

The roughly 7,300 horizontal wells that came online during 2021 produced an average of 106,800 bbl/d of oil in their first six months of production, Novi Labs found. Meanwhile, the 3,000 horizontal wells that began production this year—and have been producing for at least six months—averaged 97,700 bbl/d, a decline of 4.2% each year.

Moreover, productivity declined despite average lateral lengths increasing from 9,200 ft in 2021 to 9,800 ft in 2023.

The conundrum is even more pronounced in Lea County, N.M., the heart of the Permian's Delaware Basin and the only Permian county that produced more than 1 MMbbl/d in August 2023.

Well productivity in Lea County dropped by 16% over two years, despite a small increase in average lateral lengths.

Headwinds like rising drilling costs and declining productivity caused Enverus to recently reduce its previous estimates from 125,000 to around 75,000 remaining Tier 1 drilling locations, at a sub-$45/bbl WTI price, across North America.

At current activity levels, it represents just about six years of remaining top-tier drilling inventory across the continent.

And that top-tier inventory isn't easy to find. The vast majority of the remaining Tier 1 drilling locations throughout all benches of the Midland and Delaware basins—approximately 80%—are held by a small number of public companies with a market cap of more than $30 billion, according to Wood Mackenzie research.

U.S. rig count by top 50 operators
(Average first-half 2023)

Rank	Operator	US Rigs Running
1	EOG Resources	27
2	Occidental Petroleum	26
3	ConocoPhillips	25
4	Devon Energy	21
5	Pioneer Natural Resources	20
6	Exxon Mobil	19
7	Chevron	18
8	Diamondback Energy	15
9	Marathon Oil	11
10	Permian Resources	11
11	BP	11
12	Chesapeake Energy	10
13	Coterra Energy	10
14	Ovintiv	8
15	Southwestern Energy	7
16	Matador Resources	7
17	Comstock Resources	6
18	APA Corp.	6
19	SM Energy	6
20	EQT Corp.	5
21	Chord Energy	4
22	Hess Corp.	4
23	Callon Petroleum	4
24	Antero Resources	3
25	CNX Resources	3
26	Gulfport Energy	3
27	Vital Energy	3
28	Enerplus	3
29	Range Resources	2
30	Crescent Energy	2
31	National Fuel Gas	2
32	Repsol	2
33	Exco Resources	2
34	Magnolia Oil & Gas	2
35	Silverbow Resources	2
36	Baytex Energy	2
37	HighPeak Energy	2
38	Ring Energy	2
39	Dominion Energy	2
40	Civitas Resources	1
41	Kinder Morgan	1
42	Tellurian	1
43	Riley Exploration	1
44	Diversified Energy	0
45	California Resources	0
46	TotalEnergies	0
47	Amplify Energy	0
48	Murphy Oil	0
49	Berry Petroleum	0
50	Equinor	0

Source: Enverus

Untapped potential

Civitas isn't alone in its U.S. shale aspirations. E&Ps big and small are spending billions to acquire undeveloped drilling inventory capable of generating returns even if oil prices slump below $40/bbl.

In a transaction that might have been considered unthinkable a year or so ago, Exxon inked an agreement to acquire Pioneer Natural Resources in an eye-popping $60 billion deal, excluding the assumption of Pioneer's net debt.

The megadeal adds Pioneer's more than 850,000 net acres in the core of the Midland Basin to Exxon's existing 570,000 net Permian acres. At closing, Exxon's Permian production will more than double to 1.3 Mboe/d, based on 2023 volumes; Permian output will grow to 2 Mboe/d by 2027, up from Exxon's previous goal of 1 Mboe/d the company laid out before inking the Pioneer deal.

In another large-scale Permian deal, Occidental Petroleum agreed to scoop up private E&P CrownRock for $12 billion.

CrownRock holds one of the most coveted acreage positions among private Permian E&Ps. Occidental's acquisition includes 94,000 net acres of stacked pay assets and a runway of 1,700 undeveloped drilling locations across the core of the Midland Basin.

Smaller players are also spending billions to add Permian runway: Permian Resources added runway in the Delaware and Midland basins through its $4.5 billion acquisition of Earthstone Energy.

Ovintiv acquired three EnCap Investments-backed portfolio companies for $4.275 billion to bolster its footprint in the Midland Basin. EnCap also sold Delaware Basin E&P Advance Energy Partners to Matador Resources for $1.6 billion last year.

Vital Energy's desire to boost the oil weighting of its portfolio fueled nearly $2 billion in Permian M&A in 2022.

But public E&Ps are also looking for quality drilling runway outside of the Permian.

Chevron's acquisition of Hess Corp. delivers the California supermajor some incremental onshore production from Hess's large footprint in the Bakken Shale.

But Chevron's $60 billion megadeal was mostly about getting into the action offshore Guyana, the world's latest and most prolific oil discovery.

Those massive deals tighten an already tight market for quality M&A.

"Exxon and Chevron effectively took two of the best assets that were available for purchase off the board," said Fernando Valle, senior oil and gas equity analyst at Bloomberg Intelligence.

"There isn't another Pioneer out there," he said. "There isn't another Guyana out there for sale."

A new era?

The U.S. shale patch looks a lot different today than it did when horizontal drilling and fracking advances first unlocked tight oil and gas.

"There's certainly a tacit understanding moving forward for the next 10, 20, 30 years that the industry has a lifetime, both geological- and demand-wise. And it's really about being in the driver's seat to be a competitive force in the long term."

MATTHEW BERNSTEIN, senior shale analyst, Rystad Energy

Droves of privately held independents were among the early pioneers in unconventional resource plays like the Eagle Ford, the Bakken and, more recently, the Permian.

As these basins matured over time, it's become more difficult for the small players to compete with the scale and engineering prowess of the majors and super-independents.

As a result, there are fewer small independents out there. The most successful private players with attractive assets have been acquired and integrated into larger E&Ps.

Many of the less fortunate wildcatters restructured or liquidated their assets through bankruptcy during periods of low commodity prices like the 2014 global oil glut, the Saudi Arabia-Russia price war and the COVID-19 pandemic.

Emerging from the pandemic, the survivors of the great shale reckoning have worked to attract capital back into the sector by spending within their means and pushing oodles of cash back to shareholders.

Matthew Bernstein, senior shale analyst at Rystad Energy, colloquially refers to this period of capital discipline by the shale industry as "Shale 3.0"—a period in contrast to the early innovations of the fracking industry and the drill-at-any-cost boom the sector saw in the years that followed.

Bernstein said U.S. shale could be entering a fourth era defined by the largest players absorbing even larger swathes of tight oil inventory into their portfolios.

Experts expect the deluge of shale M&A to continue in 2024. With fewer attractive private E&Ps left to buy, Bernstein thinks the market could see more mergers between public players in the future.

"There's certainly a tacit understanding moving forward for the next 10, 20, 30 years that the industry has a lifetime, both geological- and demand-wise," Bernstein said. "And it's really about being in the driver's seat to be a competitive force in the long term." ■

Drilling rigs operating in west Texas.

Shutterstock

Scarcity Fuels Record Year for M&A in Permian

The big have grown bigger and the Tier 1 acreage even pricier in the U.S.' hottest oil basin.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Inventory scarcity is fueling a historic wave of consolidation across the Permian Basin as U.S. shale enters a new phase of maturation.

Activity across the Permian Basin, America's hottest oil play, took a major hit during the COVID-19 pandemic. Operators slashed rigs and frac crews, and shut in production; the industry worked through a wave of restructurings as oil prices collapsed.

But today, the Permian is back. E&Ps have ramped up their drilling cadence over the past three years—working hard to spend within their means and return as much cash back to shareholders as possible.

The strategic importance of the Permian Basin cannot be understated: The Permian was expected to account for more than 5.98 MMbbl/d of crude oil production in December—or roughly 62% of total Lower 48 oil output, according to the Energy Information Administration.

The Permian's prolific resource output continues to attract investment from among the world's largest oil and gas companies, like supermajors Exxon Mobil and Chevron.

Top Permian public producers
(Average first-half 2023)

Rank	Operator	Boe/d	Bbl/d	Mcf/d	Well Count	US Rigs (Nov 19)
1	Exxon Mobil	1,167,969	500,093	4,007,100	17,103	19
2	EOG Resources	1,103,901	626,454	2,864,588	9,285	27
3	Occidental Petroleum	977,228	567,771	2,456,643	16,051	26
4	ConocoPhillips	970,496	590,931	2,277,330	8,066	25
5	Devon Energy	809,620	453,315	2,137,760	6,023	21
6	Pioneer Natural Resources	801,198	503,072	1,788,724	6,555	20
7	Diamondback Energy	491,636	328,028	981,631	4,863	15
8	Permian Resources	391,236	204,667	1,119,399	2,356	11
9	Ovintinv	355,588	197,923	945,960	3,843	8
10	APA Corp.	207,481	82,715	748,551	6,749	6

Source: Enverus

Source: Hart Energy

And with the Permian anticipated to drive U.S. oil production growth for the foreseeable future, E&Ps are spending big bucks to give themselves a bigger piece of the pie.

The problem is, there isn't that much more of the Permian pie to go around.

Hunting for inventory

The highest quality acreage inventory in the Permian with the lowest drilling costs—often referred to as core or Tier 1 inventory—is scarce.

About 80% of the remaining Tier 1 drilling locations throughout the entire basin, including all benches of the Midland and Delaware basins, are held by a small number of companies with a market cap of over $30 billion, according to data from Wood Mackenzie.

That inventory scarcity is driving up prices for acreage and production in the Permian. Acquiring between 500 and 1,000 Tier 1 drilling locations in the Permian could fetch a price tag anywhere between $3 billion and $10 billion.

With acquisition targets dwindling and investors demanding greater scale and inventory runway, E&Ps are pumping historic amounts of cash into Permian Basin deals.

Total transaction value in Permian assets eclipsed $100 billion during 2023, said Wood Mac. The previous record was $65 billion in 2019.

The $60 billion megamerger between Exxon Mobil and Pioneer Natural Resources, announced in October, will reshape the future of the Permian Basin.

Exxon expects its Permian production to grow to approximately 1.3 MMboe/d after closing the Pioneer deal, positioning it atop the Permian producer leaderboard.

By 2027, Exxon aims to boost its total Permian output to 2 MMboe/d—up from its previous goal of 1 MMboe/d before acquiring Pioneer.

Roughly 45% of Exxon's global upstream volumes will come from U.S. production after closing the Pioneer acquisition.

Occidental Petroleum is also digging deeper into the Permian: The company inked a $12 billion deal to acquire CrownRock, one of the most attractive remaining private E&Ps in the basin.

The acquisition of CrownRock, a joint venture between CrownQuest Operating and private equity firm Lime Rock Partners, includes more than 94,000 net acres of 1,700 undeveloped drilling locations in the core of the Midland Basin.

"This most recent deal will create the sixth soon-to-be 1 MMboe/d U.S. [Lower 48] producer, with others including Chevron, EOG, Exxon Mobil, EQT and ConocoPhillips," said Robert Clarke, vice president of upstream research at Wood Mac.

"And in the Permian specifically, Oxy will become a top three producer behind the majors, pumping more oil and gas pro-forma than Pioneer did at the time of its sale announcement," he said.

The Permian has also seen a deluge of smaller transactions as public E&Ps work to shore up their balance sheets and inventory portfolios.

Civitas Resources allocated nearly $7 billion to jump into the Permian with scale during 2023. The company entered both the Midland and Delaware basins with a pair of deals with private E&Ps NGP-backed Tap Rock Resources and Hibernia Energy III.

Citivas followed with a $2.1 billion acquisition of Vitol-backed Midland Basin E&P Vencer Energy in October.

"Given what has happened with commodity prices—we've seen a significant run-up last year and now some softness as the market's digesting global macro issues—it underscores again the importance of having high-quality, low-breakeven inventory," Chris Doyle, president and CEO of Civitas, told Hart Energy.

62%
Permian's share of Lower 48 oil production

In a rarer public-public transaction, Permian Resources spent $4.5 billion to acquire Earthstone Energy, adding core Delaware inventory and production in the Midland.

Ovintiv spent $4.275 billion acquiring three private Midland E&Ps backed by EnCap Investments.

"If you're a company with a more limited scale in the basin, there's less both long-term opportunity and current valuation upside that comes as a result of that," said Matthew Bernstein, senior shale analyst at Rystad Energy.

Companies unable to afford premium Tier 1 inventory are moving out into fringier areas of the Permian or targeting less developed zones deeper underground. But these Tier 2 or Tier 3 opportunities require more money to drill and exploit than core Tier 1 locations.

"We have a way to get more oil out of the ground," said Fernando Valle, senior oil and gas equity analyst at Bloomberg Intelligence. "It's a matter of whether it's worthwhile and how that cost can come down over the next five to 10 years."

$100B+
Permian transaction value in 2023

Buying bonanza

E&Ps in the Permian still need inventory, so experts think the trend of consolidation will continue in 2024. But the number of attractive and somewhat affordable acquisition targets is shrinking as options are plucked off the market.

Endeavor Energy Partners holds a coveted position in the core of the Midland Basin. A Fitch Ratings report from November disclosed that the privately held E&P is producing 331,000 boe/d, up 25% from 2022 levels.

But Endeavor wouldn't be cheap to acquire: Analysts suggest that its current market valuation could be in the neighborhood of $30 billion. That's a whopping asking price that few oil companies, outside of the majors, could afford to pay.

There's also Tyler, Texas-based E&P Mewbourne Oil, one of the Permian's top private producers and among the most active drillers in the Delaware.

In an exclusive interview with Hart Energy last summer, Mewbourne President and CEO Ken Waits insisted that the company wasn't for sale.

"[Endeavor's and Mewbourne's] strategies may be a bit more different in terms of willingness and timing of wanting to sell," Bernstein said.

Fort Worth-based Double Eagle has been one of the largest independent purchasers of oil and gas leasehold interests in the Permian.

Double Eagle IV, formed in 2022, is growing a position mainly in the Midland Basin but has also scooped up interests on the Delaware side.

There are several other private equity-backed E&Ps developing footprints in the Permian, but many of the most attractive options were bought up last year. The runway for public-private deals might be shorter in 2024 than it was in 2023.

"As opposed to X private equity firm bundled together three operating companies and sold them for $1 billion to X midsize E&P, I think it's going to be a bit more of those public names to watch, for sure," Bernstein said.

The gas glut

E&Ps buy Permian acreage to drill for crude oil volumes, but Permian wells are producing more natural gas over time as the oily basin develops and matures.

Associated gas volumes—the natural gas output associated with drilling new oil wells—continue to rise across the Permian.

Permian associated gas output was expected to hit a record 24.85 Bcf/d during December, according to the EIA's most recent forecast.

Energy intelligence firm East Daley Analytics reported that natural gas flow out of the Permian Basin hit record volumes during November 2023.

Companies are pouring a lot of money into getting more associated gas and NGL out of the Permian and into demand centers.

East Daley found that 60% of the midstream capex budgets across the Lower 48 are being spent in the Permian Basin; 49% of that total is being spent on Permian NGL takeaway capacity, excluding gathering and processing investment. ■

Hart Energy

The World Calls Out for US LNG. Is Haynesville the Answer?

Booming production and proximity to Gulf Coast export terminals weigh in the play's favor.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Nations around the globe are increasingly demanding secure supply of U.S. LNG. Gulf Coast LNG developers are tapping Haynesville gas to answer the call.

The sprawling Haynesville Shale, which stretches from northwestern Louisiana into eastern Texas, has boomed into a hub of U.S. natural gas production since the play was pioneered by Chesapeake Energy and Petrohawk Energy in 2008.

Natural gas volumes from the Haynesville were expected to average 16.43 Bcf/d during December 2023, according to the U.S. Energy Information Administration (EIA). Only Appalachia (35.76 Bcf/d) and the Permian Basin (24.86 Bcf/d) are more prodigious than the Haynesville in shale gas output.

The Haynesville is home to several of the nation's top public gas producers, including Chesapeake Energy, Southwestern Energy and Comstock Resources. Privately held E&Ps Aethon Energy and Rockcliff Energy II are also producing significant gas volumes from Louisiana and East Texas.

The past few years have been extremely volatile for the natural gas sector.

After Russia's invasion of Ukraine, Henry Hub natural gas

Top Gulf Coast public producers
(Average 1H 2023)

Rank	Operator	Boe/d	Bbl/d	Mcf/d	Well Count	US Rigs (Nov 19)
1	Marathon Oil	439,170	247,982	1,147,085	4,382	11
2	Comstock Resources	343,248	146	2,058,594	1,509	6
3	BP	301,417	61,934	1,436,881	1,636	11
4	Crescent Energy	220,905	98,303	735,549	8,602	2
5	Diversified Energy	141,445	5,905	813,183	6,772	0
6	Exco Resources	103,218	16,864	518,120	977	2
7	Magnolia Oil & Gas	86,205	39,174	282,169	1,403	2
8	Silverbow Resources	70,321	13,791	339,174	793	2
9	Baytex Energy	57,400	45,469	71,580	1,002	2
10	Tellurian	39,685	-	238,108	39	1

Source: Enverus

Source: Hart Energy

prices rose above $9/MMBtu in August 2022—their highest levels since the 2008 Great Recession, per EIA figures.

Producers chased the high prices and raked in big profits. Once again, high prices proved to be the cure for high prices.

Instead of the structural market shortages seen during 2022, today the market is glutted with natural gas.

Henry Hub spot prices are expected to average around $2.80/MMBtu this winter, the EIA reported in its latest Short-Term Energy Outlook. That's down over 60 cents from the November forecast.

"The downward revision reflects both a warmer-than-average start to the winter, which has reduced demand for space heating in the residential and commercial sectors, and high natural gas production," the EIA said.

U.S. natural gas inventories will end the winter 22% above the five-year average at over 2 Tcf in storage.

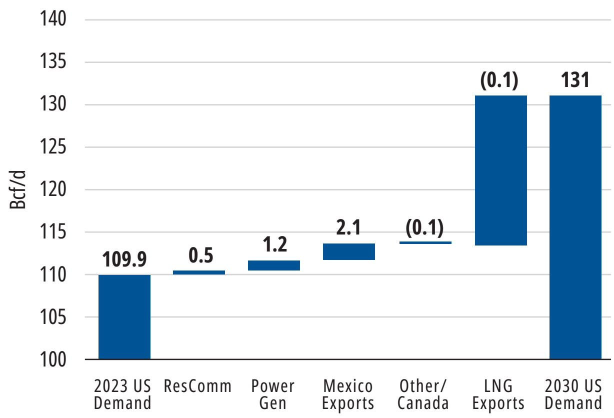
The liquefaction gravy train

Instead of raking in big profits, gas E&Ps have had to hedge production and lick their wounds amid the collapse in prices.

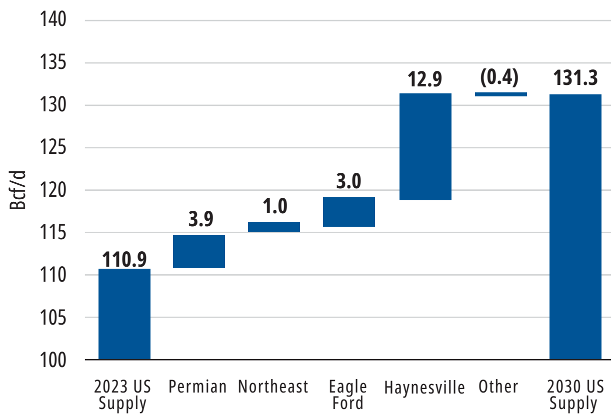
But all eyes have fixated on the proverbial light at the end of the tunnel: Hockey stick-like demand growth from U.S. LNG export facilities in the coming years.

Gas demand for U.S. LNG exports is expected to grow by 17.4 Bcf/d between 2023 and 2030, said Justin Carlson,

East Daley U.S. demand forecast



East Daley U.S. supply forecast

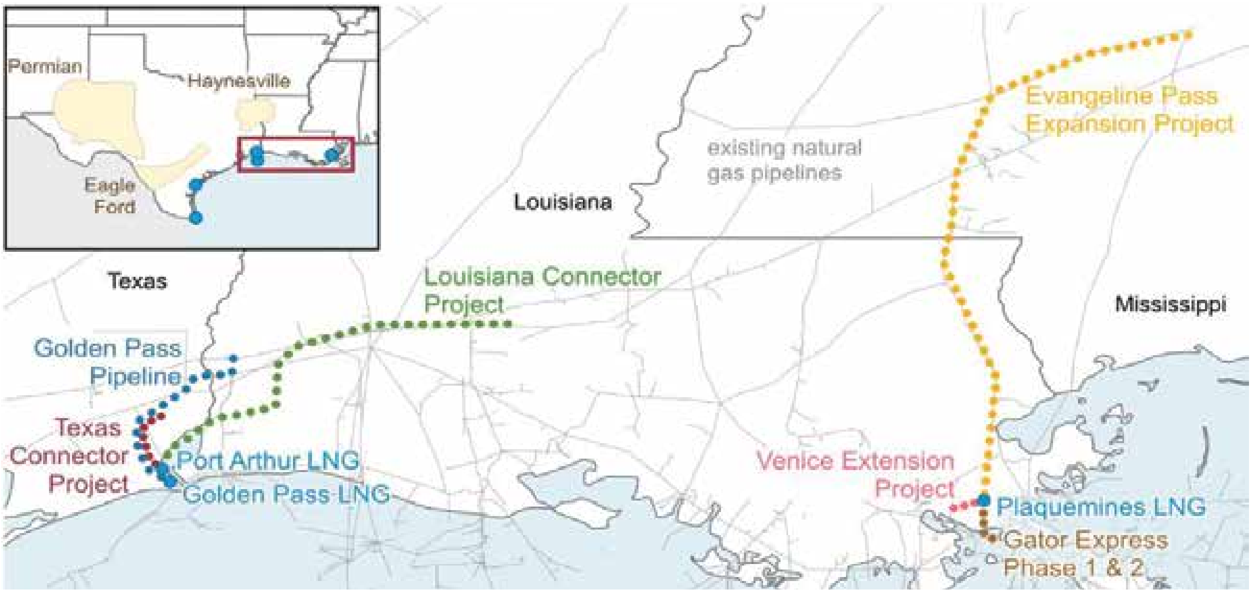


Source: East Daley Analytics

co-founder and chief commercial officer at East Daley Analytics; LNG will make up more than one-fifth of total U.S. gas demand by that time—far outweighing projected gas demand growth for residential consumption, power generation or pipeline exports to Mexico.

It's a huge amount of demand growth in a relatively short

Pipelines to Golden Pass LNG, Port Arthur L.NG, and Plaquemines LNG as of December 2023



Source: EIA

About 13.5 Bcf/d of gas pipeline capacity to feed Gulf Coast LNG projects is currently under construction.

amount of time. For context, the EIA said U.S. LNG exports averaged 11.81 Bcf/d during 2023.

And questions linger about whether U.S. gas supply, hampered in some regions by regulatory red tape, can meet the growing demand.

"What's sustainable and where is all this gas going to come from?" asked Alan Smith, co-founder, president and CEO of Haynesville-focused E&P Rockcliff Energy, at Hart Energy's America's Natural Gas Conference in September.

Due to the basin's close proximity to several Gulf Coast projects under construction, the Haynesville's shale gas will be tapped by the LNG industry in a big way.

Of the roughly 20 Bcf/d of total U.S. gas demand growth through 2030, approximately 13 Bcf/d is expected to come from Haynesville output, says East Daley.

The Haynesville's nearness to LNG export facilities is its saving grace, because a lot of the most cost-competitive gas production is located in other parts of the U.S. The Haynesville is a deep play. Equipment to drill wells has to be able to withstand extremely high temperatures. These factors all translate into higher drilling costs.

The cheapest gas production, by and large, is coming out of Appalachia plays like the Marcellus Shale.

But getting greater volumes of Appalachia gas across state borders to the Gulf Coast is easier said than done. The Mountain Valley Pipeline recently required an act of Congress to move forward.

Associated gas output from Permian Basin oil wells is also cheaper than Haynesville gas. But the Permian, historically a play for crude oil, is dealing with gas takeaway constraints of its own.

The good news for the industry is that more than 20 Bcf/d of new pipeline capacity to feed LNG export projects is under construction, partly completed or approved, according to the EIA. Around 13.5 Bcf/d is currently under construction.

Five new LNG export terminals—Plaquemines LNG, Golden Pass LNG, Port Arthur LNG, Corpus Christi LNG Stage III and Rio Grande LNG—have one or more pipelines under development.

Gas M&A outlook

The U.S. shale patch has seen a lot of activity for oil-weighted M&A. The Permian Basin has been the epicenter of upstream deal activity; recent megadeals include Exxon Mobil's $60 billion acquisition of Pioneer Natural Resources and Occidental Petroleum's $12 billion acquisition of private E&P CrownRock.

Extreme natural gas price volatility has chilled the market for gas-weighted transactions. But experts anticipate a narrowing of the spread between buyer and seller as demand, and prices, increase in the coming years.

In a rare gas deal last summer, a consortium led by family office investment groups took ownership of Wyoming gas producer PureWest Energy in a $1.84 billion cash deal.

Rumors are also swirling that Chesapeake could merge with Southwestern to create a premier public natural gas E&P. Both companies already have large positions in the Haynesville and in the Marcellus.

Combined, Chesapeake and Southwestern would have a production of around 8 Bcfe/d—positioning the combined firm ahead of EQT, the nation's current largest gas producer, analysts say. ■

Vaca Muerta Offers Argentina Game Changing Options

Argentina's Vaca Muerta Shale is the most prospective outside the U.S., and represents an opportunity to convert the South American country into a major exporter of oil, piped-gas and LNG.

PIETRO DONATELLO PITTS | INTERNATIONAL MANAGING EDITOR

Argentina's famed Vaca Muerta ("dead cow") Shale is arguably the most prospective play outside the U.S., representing a game-changing opportunity to convert the country into a major exporter of oil, piped-gas and LNG to South America and world markets.

In recent years, production gains in Argentina have been impressive, driven primarily by higher production from the Vaca Muerta in Argentina's Neuquén Basin. Further gains hold the potential to drastically change the country's energy matrix and help it achieve energy self-sufficiency. That's if Argentina can overcome the numerous above-ground headwinds linked to economics, finance and infrastructure, all tied to political uncertainties.

Whether newly elected President Javier Milei, an economist with two masters on the topic, can change any of that remains to be seen.

Developments related to the Vaca Muerta have been massive. Without production contributions from the formation, Argentina's oil production would be about half of what it is and gas production would be about one-third of what it is, Argentina's Neuquén Province Energy Minister Alejandro Rodrigo Monteiro told Hart Energy in late November.

Monteiro said that without development of the Vaca Muerta, Argentina would have paid over $20 billion to import hydrocarbons and energy in 2023.

"In other words, the country would have serious energy supply problems, in addition to problems related to reserves in Argentina's Central Bank," Monteiro said. "So, the Vaca Muerta's development can be seen through all the energy that we stop importing, and also in the volume of energy that we can export and the dollars that this generates for the country."

Production from the Vaca Muerta could surpass 1 MMbbl/d by 2030 under a moderate growth scenario compared to around 323,000 bbl/d foreseeable in 2023, according to extrapolated production data through July from the government of the Neuquén Province. Through July, the Vaca Muerta contributed around 51% of Argentina's total oil production profile and around

"The country would have serious energy supply problems, in addition to problems related to reserves in Argentina's Central Bank. So, the Vaca Muerta's development can be seen through all the energy that we stop importing, and also in the volume of energy that we can export and the dollars that this generates for the country."

RODRIGO MONTEIRO, energy minister, Argentina's Neuquén Province

Technically recoverable shale resources

Country	Gas (Tcf)	% of Totals	Oil (Bbbls)	% of Totals
Argentina	**802**	**41%**	**27**	**37%**
Bolivia	36	2%	1	1%
Brazil	245	12%	5	7%
Chile	48	2%	2	3%
Colombia	55	3%	7	9%
Mexico	545	28%	13	18%
Paraguay	75	4%	4	5%
Uruguay	2	0%	1	1%
Venezuela	167	8%	13	18%
TOTALS	**1,975**	**100%**	**73**	**100%**

Source: EIA/U.S. Geological Survey (USGS), June 2013 study, which excluded Guyana.

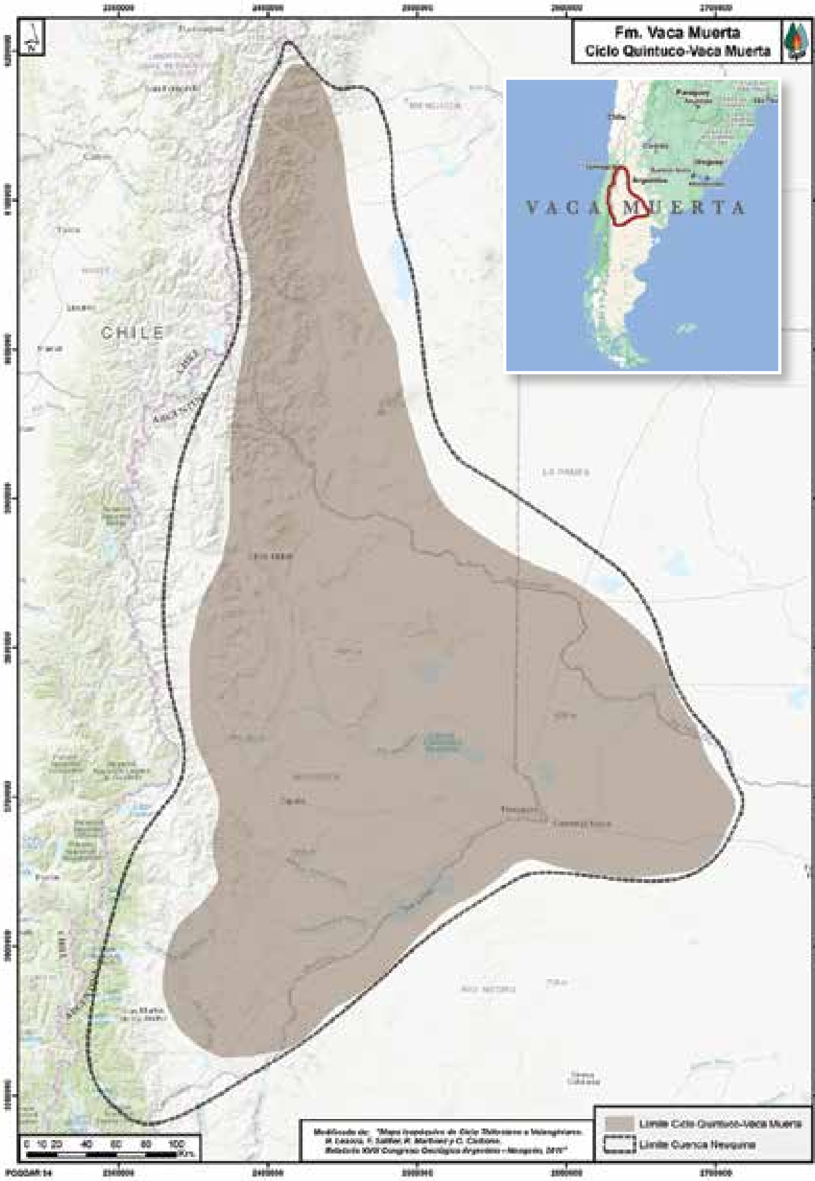
65% of its total gas production, according to provincial data.

The forecasted rise in Vaca Muerta production is only possible if takeaway capacity and rig availability don't limit growth, said Alexandre Ramos-Peon, Rystad Energy's vice president of shale research, in a May 2023 report. If production rises, it could lift Vaca Muerta's profile and position the formation as a leading source of shale production, comparable to the Bakken or Eagle Ford developments.

Reaching a threshold of 1 MMbbl/d would pull Argentina out of its more than a decade-long production slump, reducing its reliance on imports to become a key regional and global oil market player, he said.

"In this scenario, we assume new wells that start production from now onwards have the same performance per foot as the average completed and put-on-production (POP) in 2021-2022; oil production from gas wells is negligible; capital re-investment is assured until 2030; linear growth in POP activity in 2023 and onwards," Ramos-Peon said. "For the operators, we assumed that they adopt two-mile laterals gradually within the next three years. Finally, we considered no downturns in the oil industry, global pandemics, significant macroeconomic changes or political unrest in Argentina until 2030."

Argenitina's Vaca Muerta Shale



Source: Argentine Geological Association

Changing Southern Cone dynamics

The U.S. Energy Information Administration (EIA) estimates Argentina had around 13.6 Tcf of proved gas reserves at the end of 2020, enough to last 10.1 years. Argentina also had around 2.5 Bbbl of proved oil reserves, enough to last 11.3 years.

The relatively short-lived oil and gas reserves are already a lingering energy security threat, and Argentina continues to rely heavily on imported LNG during its winter months to fulfill domestic demand. Argentine officials are hyper-focused on developing the Vaca Muerta, especially after Russia's invasion of Ukraine in early 2022 as both Europe and Asia seek secure sources of LNG to offset energy declines from Russia.

The dynamics of trading gas in South America, especially among the Southern Cone countries—Argentina, Bolivia and Brazil—is undergoing a dramatic change. Bolivia's production is declining while production is ramping up in Argentina's Vaca Muerta formation, offshore Brazil in the pre-salt formation and in the Equatorial margin, Rystad Energy analyst Gabriela Sanches and senior analyst Vinicius Romano wrote in late November in a gas report focused on South America.

"Brazil, Argentina and Bolivia are currently interconnected by a network of gas pipelines which help manage supply and demand balances between the three countries. Argentina and Brazil's promising new gas resources could see a rejigging of this relationship in the coming years," Sanches and Romano wrote. "However, the success of these plans depends on construction of

Technically recoverable shale resources by basin and formation

Basin	Formation	Gas (Tcf)	Oil (Bbbls)
Neuquén	Los Molles	275	4
	Vaca Muerta	308	16
	Total	583	20
San Jorge	Aguada Bandera	51	0
	Pozo D-129	35	1
	Total	86	1
Austral-Magallanes	L. Inoceramus-Magnas Verdes	129	7
Parana	Ponta Grossa	3	0
TOTALS		802	27

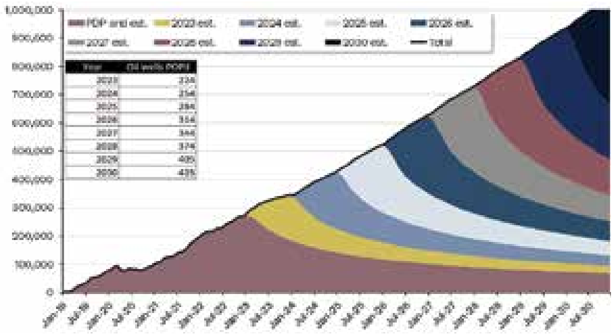
Source: EIA/U.S. Geological Survey (USGS), June 2013 study, which excluded Guyana.

Argentina oil and gas production
(Neuquén Basin)

	2013 A	2021 A	2022 A	2023 E
Oil (bbl/d)	107,130	202,764	277,380	322,858
Gas (MMcf/d)	1,753	2,548	2,967	3,010

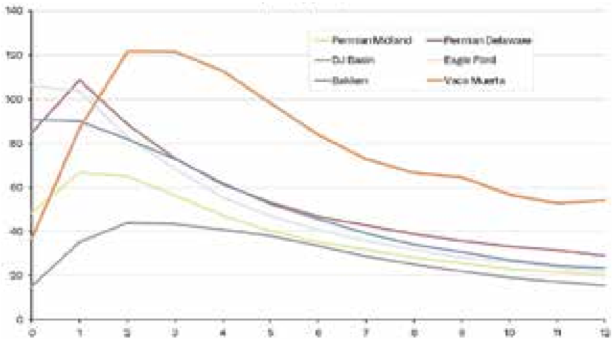
Source: Government of Neuquén Province
Note 1: Figures for 2023 are from a straight extrapolation from data through July.

Vaca Muerta production growth scenario
(Bbl/d)



Source: Rystad Energy's Shale Solution, May 2023

Performance of Vaca Muerta vs. US shale*
(Bbl/d per 1,000 ft lateral)



Source: Rystad Energy's Shale Solution, May 2023 *Only horizontal wells put on production in 2021-2022

critical gas transportation infrastructure in the years ahead, which could either see the region flooded with gas or choked by bottlenecks."

In Argentina, gas is shipped on three different routes from the Neuquén to the Buenos Aires region where key demand centers are situated. In addition to gas pipelines already in place, the country recently inaugurated the first stage of the Nestor Kirchner pipeline.

"By 2025, gas imports from Bolivia are expected to cease as part of the Argentine government's plan to increase domestic gas production and become self-sufficient in gas supply, while also exploring export opportunities," Sanches and Romano said.

Argentina's state-owned YPF SA and its Malaysian counterpart Petronas continue to eye an LNG plant on Argentina's Atlantic Coast that would source Vaca Muerta gas and have a combined capacity of 25 million tonnes per annum (mtpa).

Monterio said he couldn't envision a greenfield LNG project before 2030 but said an intermediate-stage floating LNG project had potential to see cargoes as early as 2026 or 2027.

Argentina ranks No. 2 in the world in technically recoverable shale gas resources, according to the most recent study published by the EIA about 10 years ago. Argentina has technically recoverable shale gas resources of 802 Tcf, positioning the country only behind China, which has an estimated 1,115 Tcf. Argentina ranks fourth worldwide in shale oil resources, according to the EIA.

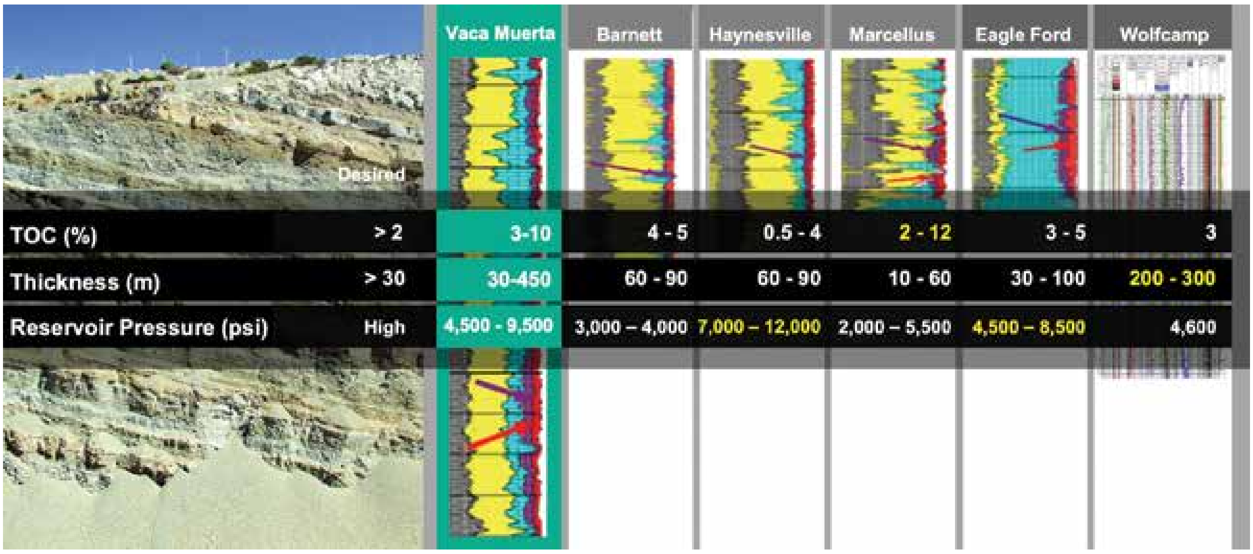
The Vaca Muerta, in Argentina's Neuquén Basin, holds technically recoverable shale gas resources of 308 Tcf. Of that total, 194 Tcf is dry gas, 91 Tcf is wet gas and 23 Tcf is associated gas, according to the EIA. These volumes put the Vaca Muerta on par with the Permian Basin, according to shale basin data published by Rystad.

Argentina is believed to have 27 Bbbls of technically recoverable shale oil resources. Approximately 60%, or 16.2 Bbbl, are located in the Vaca Muerta—2.6 Bbbl of condensate and 13.6 Bbbl of volatile/black oil, according to the EIA. But Argentina is primarily concentrating its Vaca Muerta efforts to supply piped-gas exports and eventually LNG, even as oil exports continue on the uptick.

The Vaca Muerta—which crosses four Argentine provinces: Neuquén, Río Negro, La Pampa and Mendoza—is the main drilling formation targeted by companies. The formation holds 53% of the Neuquén Basin's gas resources and 38% of Argentina's gas resources.

The other major formation in Neuquén is the Los Molles, which is on the radar of companies and investors alike, but not a primary drilling focus. Neuquén has good production potential in the marine-deposited Los Molles and the Vaca Muerta shales.

Vaca Muerta statistics



	Desired	Vaca Muerta	Barnett	Haynesville	Marcellus	Eagle Ford	Wolfcamp
TOC (%)	> 2	3-10	4 - 5	0.5 - 4	2 - 12	3 - 5	3
Thickness (m)	> 30	30-450	60 - 90	60 - 90	10 - 60	30 - 100	200 - 300
Reservoir Pressure (psi)	High	4,500 - 9,500	3,000 – 4,000	7,000 – 12,000	2,000 – 5,500	4,500 – 8,500	4,600

Source: Argentine Geologic Association

"The success of these plans depends on construction of critical gas transportation infrastructure in the years ahead, which could either see the region flooded with gas or choked by bottlenecks."

GABRIELA SANCHES AND VINICIUS ROMANO, Rystad Energy

Argentina has four main sedimentary basins. The other three include:

- Golfo San Jorge, which contains mostly non-marine lacustrine shale source rocks of Jurassic to Cretaceous age;
- Austral Basin, also known as the Magallanes Basin in Chile, which contains marine-deposited black shale in the Lower Cretaceous, considered a major source rock in the basin; and
- Paraná, although more extensive in Brazil and Paraguay, a small area with Devonian black shale potential is located in Argentina.

Vaca Muerta: Geology 101

The Vaca Muerta formation in the Neuquén Basin was found when American Charles Edwin Weaver (1880-1958), doctor in geology and paleontology, noticed the cropping throughout the Vaca Muerta mountain range. The Vaca Muerta is comprised of sedimentites, called bituminous marls due to their high content of organic matter, according to the government of the Neuquén Province.

Under current plans, the Vaca Muerta is now an important part of Argentina's economic development.

The Neuquén Basin is located in west-central Argentina and contains Late Triassic to Early Cenozoic strata deposited in a back-arc tectonic setting, according to the EIA. The basin is bordered on the west by the Andes Mountain range, on the east by the Colorado Basin and on the southeast by the North Patagonian Massif. The sedimentary sequence exceeds 22,000 ft in thickness, comprising carbonate, evaporite, and marine siliclastic rocks. Compared with the thrusted western part of the basin, the central Neuquén is deep and structurally less deformed.

The two primary shale formations in the Neuquén Basin are the Vaca Muerta and Los Molles.

Vaca Muerta: The Late Jurassic to Early Cretaceous (Tithonian-Berriasian) shale is considered the primary source rocks for conventional oil production in the basin. The formation is comprised of finely-stratified black and dark grey shale, as well as lithographic lime-mudstone totaling 200 ft-1,700 ft thick. Organic-rich marine shale was deposited in a reduced oxygen environment and contains Type II kerogen. While the Vaca Muerta is somewhat thinner than Los Molles, its shale is of a higher total organic carbon and is more widespread across the basin.

Los Molles: The Middle Jurassic (Toarcian-Aalenian) shale is considered an important source rock for conventional oil and gas deposits. On average, the prospective shale in the formation is found at depths between 8,000 ft and 14,500 ft, with maximum depth surpassing 16,000 ft in the center of the basin. ■

Production from Canada's Montney and Duvernay Gains Momentum

The dust has settled on acquisitions, and the leading players have publicized five-year plans that demonstrate a commitment to increasing production from Canada's premier shale plays.

JUDY MURRAY | CONTRIBUTING EDITOR

Natural Resources Canada describes the Montney and Duvernay shales as primarily natural gas and NGL plays, with relatively small oil production. The Montney, in British Columbia and Alberta, and the Duvernay, in Alberta, are the two prominent geological formations comprising the Western Canadian Sedimentary Basin.

The Montney Shale's natural gas resources are estimated to be among the largest in the world, and production numbers continue to rise. From 2010 to 2022, natural gas production in the Montney grew to 8.06 Bcf/d from approximately 0.82 Bcf/d. Over that same period, production from the Duvernay grew to approximately 0.58 Bcf/d.

As of 2022, natural gas from the Montney and Duvernay regions represented 50% of Canada's total natural gas production. Natural Resources Canada says that, according to all scenarios in the Canada Energy Regulator's latest "Canada's Energy Future 2023" report, the area is expected to contribute more than 60% of domestic gas production by 2030.

Favorable financials

Mark Sadeghian

Mark Sadeghian, senior director for North American energy at Fitch Ratings, said that although natural gas production is an important factor in assessing the outlook for Canada's shale developments, condensate is the key to the economics in the core of the play because of its value as a diluent used to blend Western Canadian Select, one of North America's largest heavy crude oil streams.

"There is a symbiosis between local condensate production and oil sands bitumen production," he said.

Locally produced diluent economics are attractive because they compete with higher priced imports from the U.S., Sadeghian said, noting that higher oil sands production potentially increases demand for condensate from the Duvernay and Montney. "We don't anticipate dramatic production growth anytime soon, but there is certainly room to grow with recent pipeline expansions, including the pending TMX [Trans Mountain Expansion] pipeline," he said.

Rextag

Regional natural gas pricing, which historically has been under stress due to system constraints, may also be set to improve.

"We think there will be some system improvements and some tightening balances coming from LNG—both south of the border and in Canada," he explained. "When Canada LNG comes onstream, that will be supplied through regional Canadian gas, and that should help balances. Also, there is a fair amount of new LNG export capacity coming up on the Gulf Coast, which could tighten up balances regionally through interconnects."

"As always," he said, "weather is still a dominant factor when it comes to gas pricing, so we will want to see what

Crescent Point Energy added a second rig to its production operations in the Kaybob Duvernay Shale in 2023.

Crescent Point Energy

Historical and projected natural gas production from the Montney and Duvernay shales

	Production	2010	2022*	2030 (CER CM**)	2030 (CER CNZ***)
Montney	Natural Gas	0.82 Bcf/d	8.06 Bcf/d	10.66 Bcf/d	10.70 Bcf/d
Duvernay	Natural Gas	0.00001 Bcf/d	0.58 Bcf/d	0.60 Bcf/d	0.61 Bcf/d
Canada Total	**Natural Gas**	**14.58 Bcf/d**	**17.29 Bcf/d**	**17.69 Bcf/d**	**17.67 Bcf/d**

Source: Canada Energy Regulator

*Estimated 2022 data **Canada Energy Regulator's Canada's Energy Future 2023 Report's Current Measures Scenario. ***Canada Energy Regulator's Canada's Energy Future 2023 Report's Canada Net-Zero Scenario.

things look like on the ground when we get there."

Developing the Duvernay

While financial analysts take a wait-and-see approach, forward-looking producers are laying plans for expansion. Calgary-based Crescent Point Energy, Canada's seventh-largest E&P company and the largest acreage holder in the Kaybob Duvernay Shale, is optimistic about the region's potential. Over the last few years, the company has transformed its portfolio and added to its positions in these reservoirs to enable consistent production growth from its Alberta Montney and Kaybob Duvernay shale acreage.

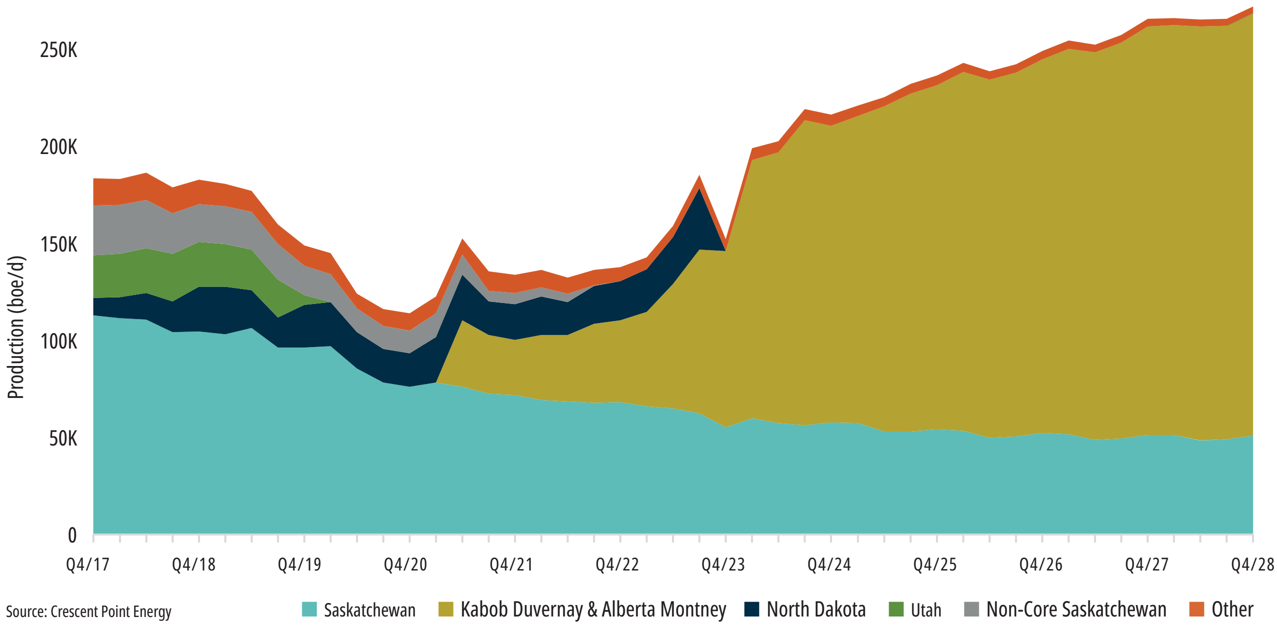
Crescent Point Energy COO Ryan Gritzfeldt said the characteristics of these plays give the company top-tier economics, and the quick payback periods of less than a year at current pricing make the economics exceptionally strong.

Ryan Gritzfeldt

The company has assessed the Duvernay and Alberta Montney and found them both attractive. "The Montney offers multiple benches that contribute to significant resource in place, and because the Duvernay is over-pressured, it yields significant initial production rates and enables considerable reserves recovery," Gritzfeldt told Hart Energy.

"What attracted us to this region is the liquids weighting,"

Historic and expected production



Source: Crescent Point Energy

Crescent Point Energy has consistently added production from its Montney and Duvernay assets and expects continued growth through 2028.

he explained. “We wanted to target the condensate- and liquids-rich window of the Kaybob Duvernay and the volatile oil window in the Alberta Montney.”

When his company acquired its first Kaybob Duvernay acreage in 2021, the asset was producing only 30,000 boe/d.

“We knew when we studied the reservoir, we could enhance results and lower costs,” he said. “When we did that, we started adding to our position in the play in late 2022 and early 2023 and now have 500 premium drilling locations in the Kaybob Duvernay.” The company’s 2024 production forecast from the Duvernay is 50,000 boe/d.

Crescent Point also targeted the volatile oil window of the Alberta Montney for acquisitions, entering the play in spring 2023. Production was about 38,000 boe/d, Gritzfeldt said, “but we knew the quality of those assets was outstanding.”

With that acreage and recently acquired assets of Hammerhead Resources, the company is now the dominant player in the Alberta Montney volatile oil window with 350,000 net acres (close to 550 net sections), giving it 1,400 premium drilling locations at conservative spacing. Total production from the company’s Montney wells is expected to hit 95,000 boe/d in 2024.

“We refer to the Montney and Duvernay as ‘short-cycle’ assets—assets that have high initial production, quick payouts, and very strong rates of return, but come with some decline,” he said. Crescent Point has combined these with its “long-cycle” assets in Saskatchewan, which are waterflood and polymer-flood assets that have low decline and high netback, and generate long-term free cash flow.

“Over the past three years or so, we have pivoted the portfolio of the company,” he said. “Now, with the premium short-cycle shale assets combined with long-cycle assets, we have a balanced, resilient portfolio that can deliver sustainability and growth for years to come with more than 20 years of premium drilling inventory.”

Gritzfeldt said these two sets of shale assets will attract about 80% of corporate capital in 2024 and will constitute approximately 70% of 2024 corporate production.

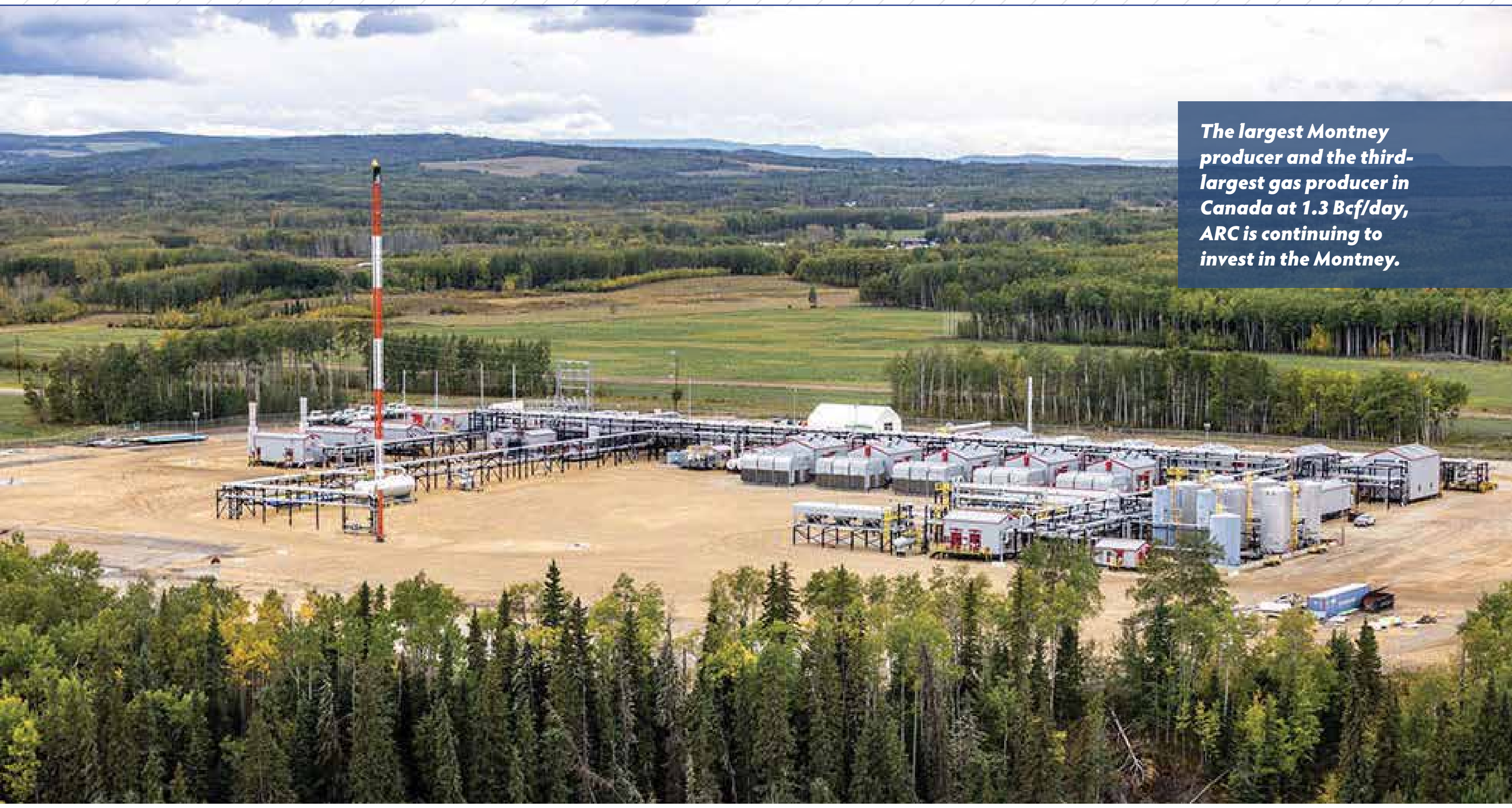
“So, 140,000 boe/d of our 204,000 boe/d in 2024 will be from the Duvernay and Montney,” he said. “This grows about 50% to almost 210,000 boe/d, about 80% of corporate production by 2028, according to the company’s five-year plan.”

Maximizing the Montney

While Crescent Point is combining assets in the two plays in its portfolio, 100% of the production from ARC Resources comes from its Montney acreage. The largest Montney producer and the third-largest gas producer in Canada at 1.3 Bcf/d, ARC is continuing to invest in the Montney and is convinced that it holds the key for consistently increasing production.

In a June 2023 presentation to investors, President and CEO Terry Anderson described the company’s position in simple terms. “We are a pure-play Montney producer for a reason.

“The Montney is one of the most profitable and one of the largest resource plays in North America. We know the Montney better than anyone ... and that is a strategic advantage.”



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

"We know the Montney better than anyone ... and that is a strategic advantage."

TERRY ANDERSON, CEO, ARC Resources

A decade ago, ARC leadership transitioned away from what Anderson called "old conventional assets" to "the new world-class Montney resource play." ARC drilled the first Montney horizontal well in 2005 and, with it, kicked off its Montney boom. The company began acquiring large swaths in sweet spots, rounding out its position with the Kakwa acquisition, the final piece of the puzzle, two years ago. Now, ARC holds more than 1 million acres of high-quality Montney resource.

Anderson pointed out that, in 2014, ARC produced 110,000 boe/d from 5,700 well bores (60% gas and 40% liquids) and that today, the company produces 350,000 boe/d from 1,700 well bores with the same 60:40 split. Now, he said, the company is poised to pursue new business opportunities like LNG and deliver even greater value to shareholders.

The company's five-year plan is a disciplined program that balances capital allocation in phased development with a three-year cadence between development projects. For example, Attachie Phase 1, the leading development opportunity within the company's portfolio, will be fully onstream in 2025, followed by Phase 2 in 2028. According to Anderson, free cash flow per share is expected to triple from about $1.60 in 2024 to $4.80 in 2028.

"Our asset portfolio has the potential to easily grow to 500,000 boe/d and remain flat for decades," he said. "We are very fortunate to be in a position to not have to worry about inventory duration or asset quality."

ARC also is working to link to end-markets at the lowest possible cost through a diversified transportation portfolio with natural gas connectivity to Malin, Ore., in the northwest U.S., Chicago in the Midwest, Dawn in southern Ontario, and Henry Hub on the Gulf Coast. An agreement with Cheniere Energy, signed in November 2023, commits ARC to supplying 140,000 MMBtu/d of natural gas to Texas for a term of 15 years with commercial operations of the first train of the Sabine Pass Stage 5 Expansion Project, anticipated in 2029. This will allow ARC to export gas to Europe. Plans are in place for 25% of production to move eventually into international markets.

This is significant, Anderson said, because the world needs more Canadian natural gas to address energy security, affordability and reliability, and to help lower global emissions.

"We need to do more as a country," he said. "This is an important part of our business." ■

More M&A for E&Ps

Industry experts expect E&Ps to stick with tried and true capital discipline with lighter hedging and more credit financing.

PATRICK MCGEE | SENIOR EDITOR, FINANCE

Two sides of the same coin are expected in E&P finance in 2024—ambition balanced with responsibility. Ambition is expected in the form of more consolidation, and responsibility is expected in continued capital discipline with companies staving off temptations to drill more.

Possible changes on the horizon such as tweaks to hedging and more reliance on credit are seen as slight adjustments to a financing model that's been working for E&Ps.

"I am extremely bullish [on] publicly listed energy companies," BlackRock's head of public energy equities, Will Su, said at a recent energy finance conference at Rice University. "If you look at the S&P 500, the energy sector produces more than 10% of its net income, and its current weighting is less than 5%."

He said E&Ps' strategy to provide growth in the form of capital return to investors has clearly worked.

"When you value a company, it's not just growth in revenues, because you can always go out and buy another company. It's always about appreciation, it's always about growth in the per share value to the shareholder," he said. "I think that's why these companies are really in the sweet spot here."

'Win the day'

Nitin Kumar, an energy analyst at Mizuho, told Hart Energy that E&Ps' protectiveness of their strong balance sheets was shown in Exxon Mobil's and Chevron's decisions to make major acquisitions as all-stock transactions in late 2023.

Nitin Kumar

"They don't want to spend a bunch of cash, increase their balance sheet and then have to worry about downside," he said.

Josh Martin, a managing director at Pickering Energy Partners, told Hart Energy that E&Ps' financial game plan for 2024 should largely be what it was for 2023 because

FIVE FINANCE ISSUES TO WATCH IN 2024

While consolidation has everyone's attention, analysts, attorneys and investment bankers will also have their eye on five other issues in 2024.

1 After three very active years in lucrative private equity E&P exits, private equity monetization of E&P assets is expected to slow in 2024.

"There's just not the opportunity set to go after because of the volume of deals we've seen over the last three years," said Andrew Dittmar, senior vice president at Enverus Intelligence Research. "What you're going to see, I think, is a pretty rapid roll-up of the remaining smaller core Permian positions, but most of those are going to have less than 100 net remaining locations and are going to be smaller-size deals that what we saw in the last few years."

EnergyNet CEO and President Chris Atherton also said he expects far fewer exits by private equity.

"They're reloading right now, but it's not like there's another wave [of exits] coming.... The queue of companies isn't as plentiful," he said. "The private equity overhang might be over."

2 Behind closed doors, attorneys will hustle to take advantage of a 1940s federal law that is expected to exempt oil and gas funds from coming Security and Exchange Commission regulations and transparency requirements for private equity and hedge funds.

Haynes Boone partner Vicki Odette

"(E&Ps) don't want to spend a bunch of cash, increase their balance sheet and then have to worry about downside."

NITIN KUMAR, energy analyst, Mizuho

Josh Martin

it worked. He expressed doubts about CEOs' assurances in recent earnings calls that they are not looking at consolidation deals.

"I just don't think a company can say, 'We're not going to do something' because things change," Martin said. "There are obviously fewer companies than there were 12 months ago or 24 months ago—but there's still some things to be done."

Experts dove into great detail about consolidation at the Rice conference, suggesting they believe more acquisitions are coming.

Jonathan Cox, global co-head of energy investment banking at J.P. Morgan, said while higher commodity prices tend to suppress M&A activity, higher interest rates and inflation make M&A easier because there's more pressure on costs.

Alexander Burpee, senior managing director at Guggenheim Partners, said E&Ps need to compare their project level IRR to their cost of capital when evaluating deals.

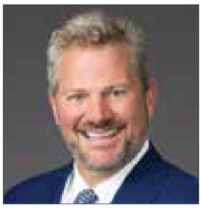
"If the project level IRR is greater than your cost of capital, then you can do that deal," he said. "The lower your cost of capital, the greater your ability to beat out the competition in some of these competitive processes. We have seen a lot of processes recently that have had worse competition, and those with advantaged cost of capital can win the day."

ConocoPhillips vice president and treasurer Konnie Haynes-Welsh said reducing costs is still one of the main drivers of consolidation.

"Some of the reason consolidation is necessary is to get the G&A out, take the best ideas and really make sure that those are being consolidated," she said.

Give credit where banking is through

Holt Foster, co-Leader of Sidley Austin's Global Energy Practice Team, told Hart Energy more consolidations could significantly increase financing activity in the oil and gas sector. If this occurred, he said it would further impact an already rapidly changing banking landscape in the oil and gas sector. Many banks have left the space, and many of the remaining regional banks have reached their desired oil and gas lending allocations. That, Foster said, coupled with a potential real estate crash, has many banks even less inclined to issue more debt. That capital void could be enough to lure some of the larger banks back to the E&P space.



Holt Foster

"Recently, I've seen some large global banks such as J.P. Morgan start dipping their toe back in the oil and gas financing space, but you're also seeing increased activity in the space from alternative credit sources such as credit funds and family offices," Foster said.

Michael Bodino

At Hart Energy's Executive Oil Conference in November, Michael Bodino, managing director of energy investment banking at Texas Capital, told attendees that smaller banks

said her law firm is seeing some uptick in oil and gas investment interest, partly because of the protections offered in the 1940 Investment Company Act.

3 Energy stocks did well in 2023, and some expect more energy IPOs in 2024.

"Coming on the heels of five energy IPOs so far in 2023, the pipeline of energy and energy-transition IPOs is building at the healthiest rate we've seen in a few years," said Ryan Maierson, a partner at Latham & Watkins, a law firm active in IPO work. "Potential IPO candidates run the gamut from traditional upstream to oilfield service companies to renewable energy and distributed energy providers."

Sonu Johl, managing director and co-head of E&P Investment Banking at Raymond James, said that after a few years of skepticism around small- and mid-cap energy IPOs, attitudes are starting to change.

"IPOs are back," he said. "There's a lot of institutional demand looking to play in upstream energy."

4 With small- and mid-cap E&Ps facing sizable maturity walls for their high-yield bond debt, investment bankers expect these companies to seek high-yield refinancing in late 2024.

Jay Salitza, managing director of oil and gas investment banking at KeyBanc Capital Markets, said $3.8 billion in high yield bond debt held by small- and mid-cap E&Ps is don't want to be part of large syndicates, so credit is showing up to fill the capital need.

"Things are changing. What we see in the market is this rapid expansion of the private credit markets," he said. "Private credit has really come in and created solutions for a lot of these companies."

Bodino said $250 million senior note offerings were once commonplace, but now banks require a $500 million minimum for such offerings. Many banks are too small for this—and private credit is stepping in to make up for it, he said.

Nimesh Bhakta, head of investments for the Americas for the Swiss energy trader Vitol, said Vitol recently moved into the private credit space to meet some of the capital need.

"We are stepping into that space, especially in this higher-rate environment," he told Hart Energy. "The risk-adjusted return profile is simply too attractive to ignore."

Drill, barely, drill

The U.S. Energy Information Agency predicts Brent crude oil prices will rise to an average of $93/bbl in 2024, but there is just barely interest in new drilling.

Virendra Chauhan

In a recent survey by the law firm Haynes Boone, 7% of reserve base loan lenders expressed great interest in new drilling.

Virendra Chauhan, head of upstream at the British energy research company, Energy Aspects, said inflation and E&Ps' focus on maximizing recovery rates has E&Ps drilling slower. Martin said only increases in strip pricing would get E&Ps to drill significantly more.

Hedge, a smidge less

An analysis from Capital One Securities shows that E&Ps will ease up on hedging in 2024, but just slightly. Chauhan said this is a sign of the strong shape E&P balance sheets are in; there's less need for caution. PPHB Managing Director Jim Wicklund told Hart Energy that hedging is easing because of expected increases in commodity prices.

Jim Wicklund

"No one wants to hedge out all of next year at $72 [a barrel] and then have the consensus prediction actually come true and all the prices be higher," he said.

Kumar said lighter hedging shows how the industry—and investors—have changed.

"If you employ too much hedging, you're only going to lock in cash flows. You're taking the upside away from investors, which is not where investors' minds are today," Kumar said.

Go with the free cash flow

With some small changes in credit and hedging, experts are nearly all of the opinion that E&Ps will stay away from heavy capex spending to keep their hefty free cash flows supportive of capital return to investors.

"The energy industry struggled to deliver returns to shareholders in the decade between 2010 and 2020. That record has been corrected, but operators will be keen to keep the momentum up in order to keep long-only type investors," Chauhan said. "Producers that are confident in their long-term inventory will continue to de-lever their balance sheets, which should allow them to ratchet up the proportion of free cash flow that they can return directly to shareholders."

Martin said, "The most important message we keep hearing here is just keep focusing on shareholder returns, and the market will come to us eventually." ■

FIVE FINANCE ISSUES TO WATCH IN 2024 (CONTINUED)

set to mature in 2024, and that will skyrocket in the two years after that; $7 billion of this debt is set to mature in 2025 and $16 billion is set to mature in 2026.

"I think the senior bond market is going to be very active in 2024 for E&P companies," Salitza said, adding that they will be helped by healthy balance sheets and further incentivized to seek refinancing if the Federal Reserve Bank cuts interest rates.

5 A blue state legislature might shake things up with a Fossil Fuel Divestment Act in California that would mandate that state pension funds withdraw from oil and gas funds. The bill may have a hearing in July and, unsurprisingly, it is unpopular in the E&P community.

Dan Romito, a partner at Pickering Energy Partners focusing on ESG strategy and implementation, said an abrupt withdrawal from oil and gas isn't feasible with such a high demand for fossil fuels.

"Ironically, California imports about 55% of its crude oil from Russia, Ecuador, Saudi Arabia and Iraq," Romito said. "If emissions were really that important to the state, they would reduce that degree of foreign reliance and tone down the virtue signaling. Divestment only means that a stakeholder loses their seat at the table, weakening future decarbonization efforts over the long term." ■

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OPPORTUNE

Super-EOR Performance

Shale Ingenuity and Titan Oil Recovery's chemical EOR methods, while different, provide a sustainable way to produce more oil in mature basins.

JAXON CAINES | TECHNOLOGY REPORTER

The reservoir wells of the shale revolution that once gushed like geysers are beginning to run dry.

"Since [the shale revolution], there's been about 100,000 horizontal shale wells drilled and put in production, [increasing] our production by about 6 million barrels a day," Robert Downey, CEO of Shale Ingenuity, told Hart Energy. "But today, about a third of those wells are now producing less than 10 barrels a day because they come on like gangbusters and then they have a really steep decline. Pretty much all the wells were drilled prior to 2015 are [almost] depleted."

Robert Downey

According to a Texas Bureau of Economic Geology study, the estimated typical oil recovery is about 6% of the oil in place, or as Downey explains, "You drill this horizontal well, spend $7 million on it and produce for 10 years. And by the time the well is pretty much producing nothing, you've recovered a whopping 6% of the oil."

The Williston and Permian basins and the Eagle Ford Shale hold a combined 3.1 trillion barrels of oil. A 6% recovery at full development leaves 2.9 trillion barrels of oil in place, which is 77 times the proved reserves of the United States. Getting that remaining 94% of oil is the challenge for oil and gas companies today.

SuperEOR is Shale Ingenuity's solution to the shale wells running dry. The SuperEOR process is similar to huff and puff injection, as it involves injecting a solvent into the reservoir, which expands into a gas and drives the oil out of the rock. However, the solvent has a specific composition, making this process more sustainable than other EOR methods. That's because the solvent is able to be recovered from the rock and reused multiple times.

"It's much different than if you just injected natural gas or CO_2 [into the well], because with natural gas or CO_2, you have to get the bottom of pressure up to 3,000 or 4,000 psi to get those gases to go into solution. Our solvent goes into solution at 700 psi," Downey said. "Once you inject it, it forces all this oil through the pores. It expands to a gas and it flows up the wellbore and you recover it on the surface, condense it back into a liquid state, store it on location and then reinject it."

"We've got blending set up in the U.S., Canada, U.K., Holland, Dubai and Singapore. So, we can service the entire world already from our mark."

MIKE CARROLL, vice president of technology, Titan Oil Recovery

When using SuperEOR for a core test, over 90% of the oil was able to be recovered out of the core, said Downey. The recovery process is also quick and efficient, as only five to 10 days of solvent injection can lead to between 10 and 20 days of flowback.

"If you were injecting gas, you'd be injecting for one month to two months and then flowing back for three or four months, but our cycles are fast and the recovery is much greater. So, instead of getting maybe 10% to 40% more oil, we can get 300% to 500% more oil," Downey said.

Another sustainable EOR solution is actually an OOR, or Organic Oil Recovery, solution.

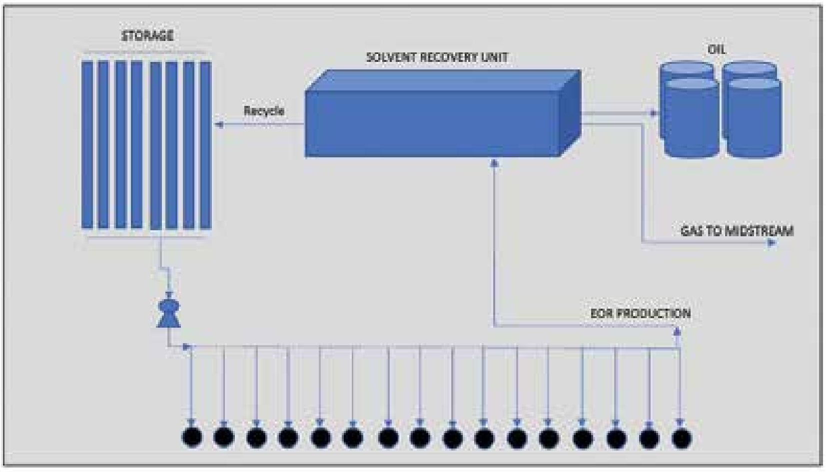
California-based Titan Oil Recovery uses a specialized EOR process that takes advantage of indigenous microbes that have adapted to the environment over millions of years in order to extract oil from mature reservoirs.

Kenneth Gerbino

Titan activates the biology and ecology of oil reservoirs by working with specific species of microbes that can physically deform oil, turning them into micro oil droplets. This allows the trapped oil in reservoirs to escape and be recovered. The technology has a low carbon footprint and can also reduce hydrogen sulfide production in oil fields.

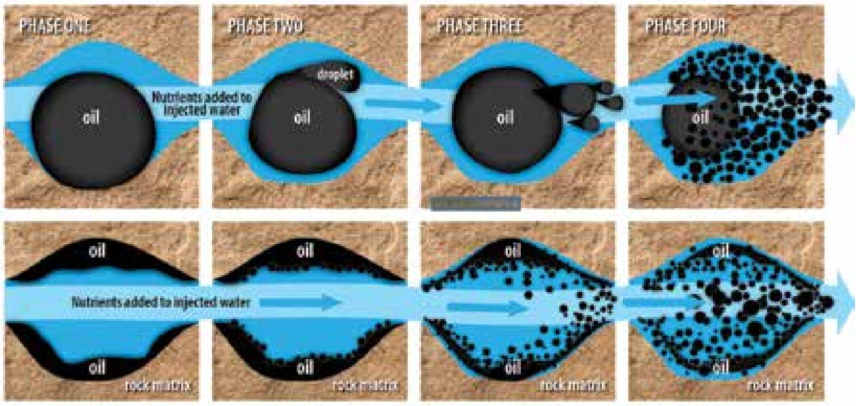
"We do an analysis in our lab and find out which species down [in the reservoir] we can work with," Kenneth Gerbino,

SuperEOR project process schematic



Source: Shale Ingenuity

The SuperEOR package includes solvent storage bullets, solvent recovery unit, triplex pump, controls and SCADA.



Source: Titan Oil Recovery

Titan Oil Recovery's Organic Oil Recovery breaks down oil in order to release it from pores in the reservoir.

CEO of Titan Oil Recovery told Hart Energy. "There are certain species that eat our food and we can change their living habits. Instead of wanting to be next to the water and the rock in the oil reservoir, the sandstone or the carbonates, they now want to be next to oil."

The "food" Gerbino refers to is a complex formula of organic and biodegradable nutrients that is tailor-made for every field. The food causes the targeted microbes to multiply and induces the targeted microbes to become oleophilic (affinity for oils) and attach themselves to oil droplets.

The microbes also become hydrophobic (not wanting to be near water); they move away from the water and rock interface where they have always been and surround the oil, Gerbino said. They then physically deform the oil, creating micro oil droplets.

"They don't eat the oil," Gerbino said. "They just surround it and they break it down. And now, for the first time, you have these micro oil droplets in a reservoir that can now escape from the tight spaces down there."

The Titan process works both onshore and offshore and is able to provide a high return on investment, because the initial investment is next to nothing, the company said. A peer-reviewed SPE paper by Husky Energy in Canada found that the cost of the recovery process was $6 per incremental barrel. Recent results in projects in both the Middle East and North Sea have returned over 1,000% ROI to customers, the company said.

"What's real important with our technology is that there's zero capex ... we're not putting in and installing equipment or building things. We have the potential to move quicker than any other technology in the market to market," said Mike Carroll, vice president of technology for Titan Oil Recovery. "We've got blending set up in the U.S., Canada, U.K., Holland, Dubai and Singapore. So, we can service the entire world already from our mark."

Titan Oil Recovery has been in 63 oil fields on five continents with 350 well applications, including 275 injection well applications, and has delivered an average increase in production of over 90%, the company said. The SuperEOR process has been used in the Bakken Shale and the Utica Shale, as well as in other NDA-protected projects, and has recovered at least 20% more oil than traditional methods of EOR, the company said. The industry has been slow to embrace these less expensive EOR methods, tending to rely more on traditional drilling and completion methods.

"Everyone does the same thing. You drill, you frack, you produce, you drill, you frack, you produce. And that's pretty much the entire focus.... Our industry has kind of gotten away from enhanced oil recovery.... EOR only accounts for about 1.5% of all production worldwide," Downey said. "We've kind of gotten fat, dumb and happy as an industry drilling these shale wells and haven't needed to do EOR. But as we're starting to drill out our acreage and our wells are getting pretty mature and depleted, we're going to have to start thinking about EOR."

Currently, Shale Ingenuity works to install and operate projects for clients or license out their SuperEOR patent for a cost. Titan Oil Recovery, who has already worked with four of the top companies in oil and gas and has a partnership with Hunting Plc, looks to find a service company to buy them out.

Despite the industry being slow to adopt these new methods of EOR, both CEOs believe a watershed moment is soon to arrive in the oil and gas industry. ■

Reuse, Recycle, Recover Revenue

Effectively managing produced water can mitigate environmental challenges and even result in revenue streams.

JAXON CAINES | TECHNOLOGY REPORTER

Water's role as the largest byproduct of oil and gas production has become increasingly problematic.

"If you can't handle the produced water or if you can't manage it and it gets out of hand, then it will impact your operations as it will impact energy production," Devesh Mittal, vice president and general manager at Aquatech Energy Services, told Hart Energy. "So, while it is a byproduct, it can be a sort of hindrance if you're not able to manage it."

Produced water comes out of the well along with crude oil when a reservoir is being produced. It can contain both soluble and non-soluble oil and organics, suspended solids, dissolved solids and other chemicals used in the production process. Operators are required by law to manage that waste.

Traditionally, produced water has been injected into underground disposal wells. However, the capacity of these injection wells is limited and the increased use of disposal wells has, in some instances, been linked to seismic activity such as earthquakes. This has led to stricter regulations on the use and development of disposal wells.

Mitigating the impact

That's where companies like Aquatech come in.

"We are working to reduce the impact of the increasing volumes of produced water. We'll recover and purify that and then treat that recovered water to make it suitable for a variety of applications, tailored to a customer's specific needs," Mittal said.

Aquatech's go-to solution is reuse and recycling. For produced water to be reused, the chemicals and organics from the formation must be removed. For water with a high level of total dissolved solids (TDS), Aquatech employs clarifiers and evaporators to use at or near the wellpad. In Oman, Aquatech has one of the largest evaporator systems for produced water, Mittal said, treating about 300,000 bbl/d.

"In certain instances, depending on the TDS of the produced water, it can be recovered using membrane systems such as our Osmotically Assisted Reverse Osmosis (OARO)," Mittal said.

Reverse osmosis is a popular method for water purification in the industry due to its low energy consumption. During the process, seawater or brackish water is forced through a semipermeable membrane, leaving salt and other contaminants on the pressurized side of the membrane while pure water is allowed to pass through.

"The quantity of produced water is increasing and so we have to work to find innovative ways to supplement our current ways of dealing with produced water to provide long-term sustainability."

DEVESH MITTAL, vice president and general manager, Aquatech Energy Services

Aquatech uses a variety of membrane-based solutions, most notably its Advanced Recovery Reverse Osmosis (ARRO) process. ARRO uses modular configuration and automation technology to reduce operator intervention and achieve water recovery rates of over 95%, which is 20% better than traditional reverse osmosis solutions, according to Aquatech.

In addition to ARRO, Aquatech's High Efficiency Reverse Osmosis (HERO) system places reverse osmosis membranes in a high pH environment, causing them to remain in a "continuous cleaning mode." This prevents contaminants from collecting in the pores of a filtration membrane and restricting water flow.

Once rid of the various contaminants in the water, the produced water is available for reuse in applications such as EOR or even irrigation of crops if the water is pure enough.

Adding lithium extraction

Aquatech is also stepping into water reuse in lithium production.

Most produced water has only a small concentration of lithium, but since the amount of produced water from traditional oil and gas operations is significant, a reasonable amount of lithium can be gathered from

Aquatech Energy Services

HERO's "continuous cleaning mode" prevents contaminants from collecting in the pores of the filtration membrane.

Aquatech Energy Services

ARRO is able to achieve water recovery rates 20% better than traditional reverse osmosis solutions, Aquatech says.

the process. Lithium, used in batteries, opens up a completely new pathway for Aquatech customers to generate revenue from water.

"Finding ways to extract lithium out of produced water is a way to reduce the cost of managing this water," said Mittal. "Right now, it's a waste, but if you can convert it into a critical mineral source and you can recover revenue out of it, then it might offset some of the overall water management costs."

The company has succeeded in the oil and gas industry for more than 40 years because of its ability to scale treatment solutions, Mittal said. Now it's working on scalability for lithium production.

"The quantity of produced water is increasing, so we have to work to find innovative ways to supplement our current ways of dealing with produced water to provide long-term sustainability," Mittal said. "That's where we are putting our minds and money." ■

Lithium Rush

Traditional oil and wastewater players join chemical manufacturers and North American lithium pure-play companies to lift production of the critical material.

VELDA ADDISON | SENIOR EDITOR, ENERGY TRANSITION

Traditional oil and gas players looking to tap into another potential revenue stream as the world goes greener are turning to lithium in the U.S., relying on drilling and other expertise to enter new markets.

The lightweight metal is a key ingredient for rechargeable batteries used to power items such as laptops, cell phones and—most notable for the energy transition—energy storage and electric vehicles (EVs).

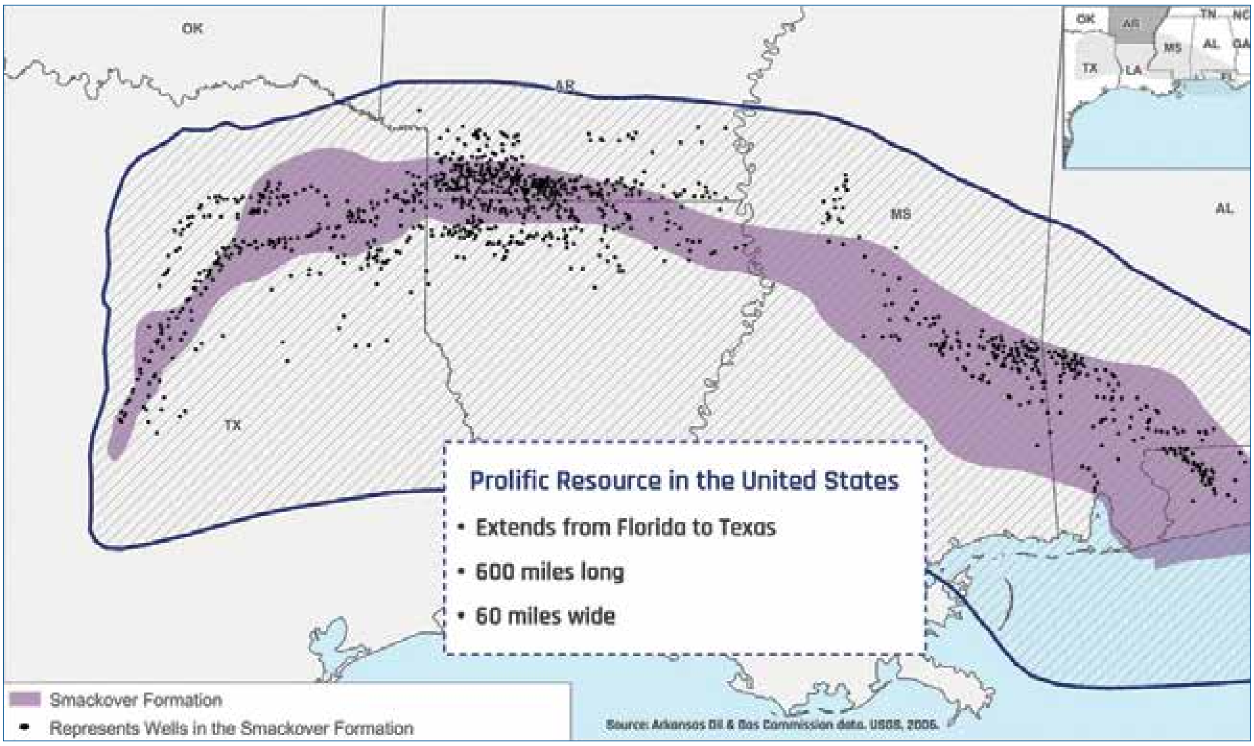
Given President Joe Biden's goal of having 50% of all new vehicle sales be electric by 2030, a power sector free of carbon pollution by 2035 and other emissions reductions objectives, U.S. demand for lithium batteries is expected to increase by nearly six times by 2030, according to an industry report from Li-Bridge, a public-private partnership coordinated by the Argonne National Laboratory. In the U.S. alone, the market for lithium battery cells is forecast to hit $55 billion per year by 2030.

Exxon Mobil has jumped into this market in the Smackover region of Arkansas.

"We're excited about the opportunity and really excited to deploy our skills and capabilities in this new area," Patrick Howarth, lithium global business manager for Exxon Mobil Low Carbon Solutions, told Hart Energy. "We think we've got a pretty unique set of capabilities across this value chain."

Lithium resources, including in the Smackover Formation that spans from Texas to Florida, could be ripe for development.

The U.S. has identified an estimated 12 million tons of lithium resources in the nation from continental, geothermal and oilfield brines as well as claystone and igneous rock, according to the U.S. Geological Survey. The nation is home to only one lithium mine, but efforts are underway to boost domestic supplies of critical materials and manufacturing capacity.



Source: Standard Lithium

Aerial view of solar power and battery storage units in the desert.

Shutterstock

"We see DLE as being very advantageous from an environmental footprint perspective."

PATRICK HOWARTH, lithium global business manager, Exxon Mobil Low Carbon Solutions

The Smackover Formation in Arkansas was known for its oil production, but the bromine-rich region has attracted companies to brine due to its high concentration of lithium. Brines from wells in southwestern Arkansas' Columbia County contain as much as 445 parts per million lithium, according to Arkansas' Office of the State Geologist.

Growing interest

Exxon Mobil entered the region to begin drilling in 2023, joining Albemarle, the world's largest lithium producer, and Canada-based Standard Lithium, which has two projects in southern Arkansas near the Louisiana state line.

The supermajor plans to lean on its conventional oil and gas expertise, drilling about 10,000 ft underground to access lithium-rich saltwater. It will then use a process called direct lithium extraction (DLE)—also used by Standard and Albemarle—to separate lithium from the saltwater, which will be reinjected to the reservoir. The extracted lithium will be converted onsite into battery-grade material, the company said.

The method produces fewer emissions and requires less land than the traditional method of extracting lithium via hard rock mining. It also doesn't require as much land as lithium brine extraction in evaporation ponds, where brine sits for several months or years as the sun evaporates most of the liquid content, ultimately leaving behind lithium and other metals. The brine, with its higher concentration of lithium, is then pumped to a facility for processing.

"The world has two different sources of lithium today. It's either hard rock or from brine. Most of the brine is shallow brine within Latin America, and they use evaporation as the main mechanism to concentrate up the lithium and remove impurities," Howarth said.

"Within Arkansas, we don't feel that there's an

"I think there is a world of endless possibilities" in extracting battery materials from brine.

REAGAN MARBLE, partner, Jackson Walker

opportunity for evaporation there. And frankly, we see DLE as being very advantageous from an environmental footprint perspective," he added. "So, significant benefits from a land use or water use perspective but then also substantially lower carbon intensity versus hard rock mining."

Exxon Mobil aims to begin lithium production in 2027. Standard Lithium is targeting first production of battery-quality lithium carbonate in 2026 at its Phase 1A Project at LANXESS Corp.'s South Plant near El Dorado, Ark.

The year 2023 saw increased activity in the lithium brine space. Companies such as Standard Lithium, for example, unveiled positive feasibility studies and strong project economics—an after-tax NPV of $550 million and IRR of 24%, assuming an 8% discount and long-term price of $30,000/ton for battery-quality lithium carbonate for its Phase 1A project in Arkansas.

While Arkansas may be considered an emerging epicenter for potential lithium brine development and Nevada is the hotbed of lithium brine activity in the U.S., Texas is also in play. Standard Lithium reported in October 2023 that it delivered the highest-ever North American lithium brine grade at 806 mg/L in East Texas.

Oil and gas companies along with water midstream companies are showing interest in pursuing lithium in northeast Texas, according to Reagan Marble, a partner with the Jackson Walker law firm.

Legal uncertainty lingers

Newcomers looking to get in on the action should consider a few things beforehand. Topping that list is who owns the lithium, Marble said.

"Unfortunately, in Texas, we don't have a clear answer to who owns lithium. We do know that brine is a part of the surface estate and, more particularly, the groundwater in the state is owned by the surface owner," Marble said. A legal case touches on the issue but the case mainly focuses on extracting salt—defined as a mineral in Texas—for commercial use. It has left some companies interested in entering lithium extraction in Texas wondering whether to pursue leases from surface owners or mineral owners.

"There are a lot of issues that pop up on your due diligence checklist as you're trying to figure out which one to go after," Marble said. "And to be candid, I don't think we are going to see quite the land grab that Texas could be experiencing at the moment until we have a legislative solution to who owns the lithium.... [The issue] came too late during our extended legislative sessions to really address it, and I don't think it's going to be addressed until 2025."

In Arkansas, such issues are resolved because the state has a well-established brine production industry that has been around since the 1950s. Lithium extraction is regulated under Arkansas's Brine Production Act and the state's Brine Production Regulatory Program.

With case law unclear in Texas, Marble advises oil and gas operators with active leases not to just go out and start exploring for lithium on those leases.

"There's not a ton of case law [in Texas] on how you look at the ordinary and natural meaning of the term mineral. And quite frankly, until there is a legislative solution, there surely won't be a legal solution in court interpreting whether lithium is in the ordinary natural meaning of the word mineral or falls under the surface destruction test," Marble said. "We just don't know."

However, he added companies could avoid the ownership issue by pursuing what is known as fee owners, or those who own both the surface and the minerals.

Still, lithium development in Texas "will surely be stunted until we solve this issue," he said.

Extracting lithium from produced water that comes from the wellbore during oil and gas production is another area that could attract interest from operators looking to find value in oil and gas waste. Areas that come to mind for Marble include parts of the Haynesville Shale in the East Texas area.

"I think the fight eventually will be if that produced water starts to be processed through direct lithium extraction, whether that was a right that an operator has under an oil and gas lease," Marble said. "I find it hard to believe that when the legislature put together the oil and gas waste statute and included produced water, that they meant to give companies the windfall of lithium one day."

Legal issues aside, the future appears promising for lithium extraction from brine. While lithium is "kind of the lowest hanging fruit" for electricity and battery storage, brine could help source other emerging battery technologies.

Marble compared brine to natural gas. Oil producers at times viewed natural gas as a waste product until Henry Hub natural gas spot prices shot up to $6/Mcf.

"You may see that in some of these brine production leases one day, maybe where they are going after

Lithium-ion batteries are produced for EVs.

Shutterstock

lithium, then someone cracks the sodium ion technology wide open and all of a sudden people are buying salt from the brine," Marble said. "I think there is a world of endless possibilities."

Another route

In the Marcellus Shale, Eureka Resources has been receiving wastewater from natural gas companies, extracting minerals from it and generating clean water, Eureka Resources Chief Commercial Officer and CFO Chris Frantz told Hart Energy. The company was formed in 2008 with a business model of grabbing the sodium chloride and treating the rest of the wastewater.

According to Eureka's website, the company's products include pure water, salt, calcium chloride, oil and methanol. Processes used include an exclusive mechanical vapor recompression distiller evaporation technology, which is used to separate particles from the water, resulting in distilled water. Vacuum crystallization, a method that evaporates water from minerals, is used to extract minerals from purified brine. It's the same technology used by salt producers, the company said.

Eureka's focus has turned to lithium in recent years. Working with technology partners and academics, Frantz said the company learned a lot about its brine and the DLE process.

"We also learned that that's [DLE] not the right solution for us because it's a slow process. What we want to do is we want to scale up to high volumes and get lots of lithium quickly," he said.

The DLE process is difficult when working with complicated brine containing many different types of metals, such as in the Marcellus. While the DLE approach plucks out lithium and leaves everything else, Eureka takes the opposite approach and uses methods similar to those it has carried out for years to remove metals from wastewater, Frantz explained. The most prevalent salt is removed, followed by the next and the next until lithium is the end product.

"It took us two and a half years to figure that out," he said.

Working with partner SEP Salt & Evaporation Plants at a pilot plant in Europe, Eureka celebrated a milestone in 2023: the successful extraction of 97% pure lithium carbonate from oil and natural gas brine from production activities. The recovery rate was up to 90%, the company announced in July 2023.

"We made actual lithium carbonate that meets a technical grade specification at the moment suitable for battery manufacturers," Frantz said.

Currently, the company is raising funds to expand its existing facilities in Pennsylvania to add lithium to its list of products from wastewater.

"Based on our current volumes, we're projecting about 500 metric tons per year of lithium carbonate," he said. "We're also simultaneously working with a partner in the oil and gas space for a brand-new facility in another part of the state that would be about 10 times the size of what we currently have."

A third-party investor is already working on locations in other basins where the technology can be used, Frantz added. ■

Turn Down Service: Autonomous Devices' Detection Evolves

Autonomous inflow control devices have evolved from a simple on-off switch to reservoir management tools.

JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

When the goal is to get as much oil or gas out of the ground as possible, controlling the flow of hydrocarbons—and other fluids—is critical. Knowing which fluid is which is part of the challenge.

Inflow control devices (ICDs) are typically installed as part of a completion. Advances from the mid-to-late 2000s made it possible for the device to autonomously shut off the flow when an interval was producing unwanted water or gas to maximize oil production.

"The original AICDs (autonomous inflow control devices) were just kind of on-off tools" that restricted production from an unwanted water or gas producing zone or were used to balance production across the horizontal well, John O'Hara, Halliburton's global business development manager for advanced completions, told Hart Energy.

When water was produced, the AICDs restricted total production or shut off the individual zone. Much like how intelligent completions went from intervention avoidance or to open, or shut off, AICDs have advanced from their original designs, he said.

"They've become more reservoir management tools than just on-off or intervention avoidance technologies," he said. "Now AICDs have more capability in allowing wanted oil production while restricting only unwanted fluids."

AICD technology was originally developed by Equinor—then known as Statoil—and used widely across the Norwegian Continental Shelf (NCS) with well-documented use in the Troll Field.

Detecting viscosity changes

Halliburton is working to develop advanced AICDs that apply to a wider range of wells, he said.

Halliburton's viscosity-based AICD technology detects viscosity changes to differentiate oil from water and gas. Still, that's not effective when oil and gas or water have the same or similar viscosity, he said.

A newer autonomous inflow control device technology detects different densities in the well fluids and restricts the flow of undesired fluids, he said.

"We have those reservoirs where the oil is very similar to water (density). We can still shut off that water and maximize that oil production," he said.

While detecting viscosity is fairly straightforward, O'Hara said the biggest hurdle in developing a density-based AICD came down to orienting it in the well to account for gravity. In essence, he said, Halliburton developed a mechanical centrifugal switch.

"It creates artificial gravity that then identifies the difference in buoyancy forces," he said. "By doing that, it allows us to close off a valve, basically, or shut off flow when it's water and have it reopened if it becomes oil again."

Part of what Halliburton worked out is how to create the centrifugal force for the artificial gravity in a small tool that could be packaged, sent downhole and then operate reliably over the life of the well, O'Hara said. There were, he added, some unique engineering challenges around the mechanical switch, which Haliburton calls the "fluid selector."

"It allows us to prevent a water-producing interval from dominating the overall production in the well," O'Hara said. "One of the big advantages of that is we leave water in place rather than handling water at the surface."

In early testing, he said, an unexpected outcome of the new density-based AICD is that it performed equally well in producing gas while still restricting water versus traditional oil producing wells.

That'll help meet a gap in the market, he said, because one of the limitations of existing AICD technology across all vendors has been a device that shuts off water in gas wells.

Halliburton's density-based tool, slated for field testing with a large Middle East operator in the first quarter, is intended for mature fields with high water cuts or unwanted gas. Following the Middle East trial, additional

> *"Now AICDs have more capability in allowing wanted oil production while restricting only unwanted fluids."*
>
> **JOHN O'HARA,** global business development manager for advanced completions, Halliburton

deployments are planned on the NCS as well as in South America and Asia-Pacific, he said.

Uptick in use

AICD deployment is simple, whether it's viscosity-based or density-based, he said. The AICD integrates with perforated pipe or screens as part of the completion.

"We don't have any control lines from the surface, we don't have anything we need to connect to actuate the balance. Again, they're autonomous," he said.

Typically, one density-based AICD would be placed per screen joint.

"It allows you to truly compartmentalize over long horizontals," making it possible to shut off where the water zone happens to be while still allowing for maximum production in the other producing oil intervals, O'Hara said.

In multi-phase flow, the AICD responds to a defined water cut, but it still allows a small amount of flow to proceed, he said.

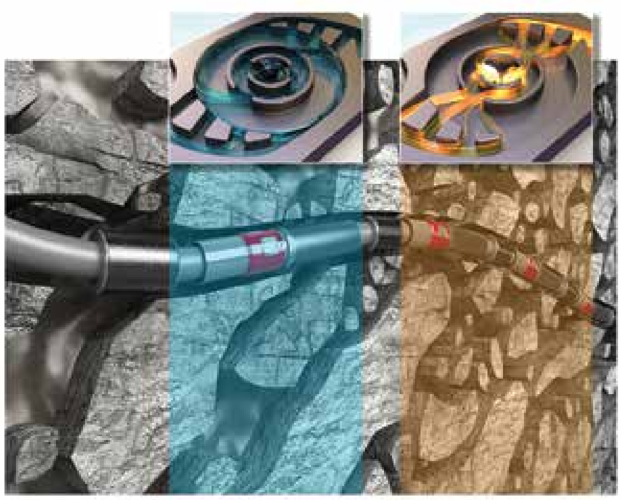
Halliburton's current density-based AICD is a 3.5-inch tool; a 5.5-inch tool is planned. Together, those tools will be able to serve lower flow rate, mature fields like those in the Middle East, along with higher flow rate NCS applications, he said.

The service company has also been working to merge the viscosity-based and density-based AICDs with gravel pack and intelligent completions technologies, O'Hara said.

While AICDs can be retrofitted, he said they are most typically installed as part of the original completion design.

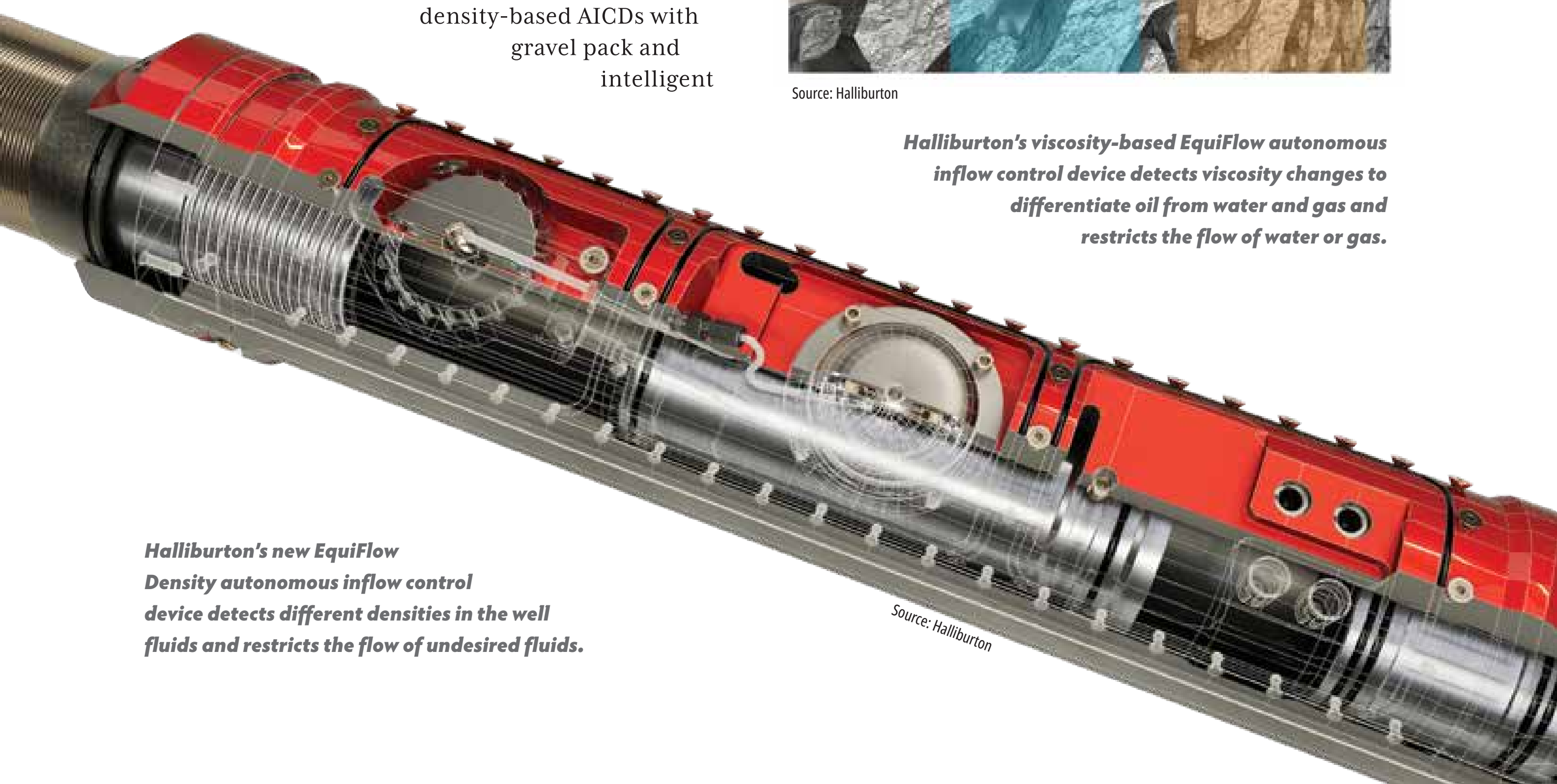
O'Hara said he has seen an uptick in industry use of AICDs.

"Your overall recovery rate is very important, so what we see is, with that need to squeeze every drop out of existing reservoirs or existing fields, technologies like AICDs become critical because as that field ages, it does produce more water," he said. "We're being challenged to squeeze more oil out of rock. This is very much an enabling technology that still has a cost advantage in that it doesn't have complex infrastructure tied to it." ■



Source: Halliburton

Halliburton's viscosity-based EquiFlow autonomous inflow control device detects viscosity changes to differentiate oil from water and gas and restricts the flow of water or gas.



Halliburton's new EquiFlow Density autonomous inflow control device detects different densities in the well fluids and restricts the flow of undesired fluids.

Sibal: Pockets of Growth Balance Fears of Slowdown

SUNIL SIBAL | MANAGING DIRECTOR, SEAPORT GLOBAL

U.S. midstream and energy infrastructure sector entered 2024 on a very interesting note. It was with a mixed fundamental outlook as U.S. and global economies prepare for the potential of a slowdown which could temper energy demand.

Hydrocarbon demand could also experience a loss in market share in overall energy demand growth as renewable fuels gain more traction. This view is offset by a solid oil price backdrop, which should continue to support drilling activity, healthy midstream industry state and some pockets of growth.

The pockets of midstream growth include:

Gas processing in the Permian Basin. The top six public processors that Seaport Global estimates account for close to two-thirds of the total processing capacity in the basin have announced plans to increase capacity by more than 12% in 2024 and about 5% in 2025. Additional project announcements may further push the 2025 number.

This growth is supported by growing crude production in the basin as well as growing Gas to Oil Ratio (GOR) as wells in the basin age. The U.S. Energy Information Administration (EIA) estimates that GOR for production in the Permian has risen by more than 25% over the last five years, matching the crude production growth in the basin and essentially compounding the need for gas processing capacity to support growing crude production.

Gas takeaway capacity in the Permian has been bottlenecked. The fourth-quarter expansion of the Permian Highway (PHP) and Whistler gas pipelines adds a combined 1.05 bcf/d of egress capacity. Additionally, the expected completion of the 2.5 bcf/d Matterhorn pipeline in third-quarter 2024 is expected to provide capacity to move the residue gas from the processing plants to the end-markets.

Similarly, NGL takeaway pipelines from the region are expected to see capacity increases of more than 1.5 MMbbl/d over the next couple of years. This should support good utilization of these processing facilities by providing downstream connectivity to products coming out of the new processing plants.

LNG liquefaction capacity—a continuing growth story. U.S. LNG nameplate capacity reached about 90 mtpa at year-end 2022 following start-up of Venture Global's Calcasieu Pass facility. Average gas flows to LNG plants in 2023 totaled about 13 bcf/d versus 11.8 bcf/d in 2022 and 10.7 bcf/d the previous year, recording a second consecutive year of 10% growth.

Looking forward, we expect U.S. LNG exports to enjoy significant growth based on the facilities already under construction. We estimate total liquefaction capacity of about 75 mtpa currently under construction in the U.S. This includes about 45 mtpa through three projects which can be viewed as in the advance stages of construction and expected to see majority of capacity available by year-end 2025:

- Exxon Mobil's Golden Pass: 16 mtpa;
- Cheniere Energy's Corpus Christi Phase 3: 10 mtpa; and
- Venture Global's Plaquemines facility: 20 mtpa.

We could thus see a U.S. LNG liquefaction capacity expansion of close to 50% through these three projects, providing a major boost to U.S. natural gas demand.

Russia's invasion of Ukraine in 2022, and the subsequent explosion of the Nord Stream gas pipeline that alone had the capacity to provide piped gas from Russia to Europe to the tune of about 75 mtpa of LNG equivalent, has increased the call on U.S. LNG. This provided an impetus to new projects supported by European customers which, in turn, has supported another 28 mtpa of U.S. LNG liquefaction capacity that took FID in 2023. Those projects are:

- Sempra's Port Arthur Phase 1: 11 mtpa; and
- NextDecade's Rio Grande Phase 1: 17 mtpa

These projects would boost capacity in the 2027-2028 time frame. Additional projects under advance consideration include Sempra's Cameron Phase 2, Tellurian's Driftwood, GlenFarne's Texas and Magnolia LNG, among others and could further add to the visibility of growth pipelines.

Regulatory clarity could drive gas infrastructure. The Fiscal Responsibility Act of 2023 included a timely and unified federal review of energy infrastructure projects. This review includes completion within one year of an environmental assessment report and two years for environmental impact statements when needed for projects.

The act had special provisions for the long-delayed Mountain Valley Pipeline (MVP), providing a pathway for its completion that is now expected in the first quarter. The Williams Cos. is looking at gas infrastructure downstream of its Transco compressor station in Virginia, where MVP terminates. This regulatory certainty, coupled with recent cost escalation and setbacks in offshore wind development, could prompt more infrastructure projects in the region. ■