Oil and Gas Investor

SPECIAL OGI REPORT

Keeping Up with the Haynesville

Producers: Show Us the Money

'CRITICAL' NEED FOR INCENTIVES

Exxon Mobil Seeks Support for Hydrogen

TRADE WAR! OR NOT

Industry Grapples with Tariff Impact

LONE STAR STATE OF MIND

Rockcliff III's Nexus is in Texas

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MARCH 2025

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

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UNDISCLOSED SELLER HAS DIVESTED ASSETS IN THE CENTRAL EAGLE FORD TO Crescent Energy	Crescent Energy SECONDARY OFFERING	EL TORO RESOURCES LLC ASSET DIVESTITURE	MACH NATURAL RESOURCES INITIAL PUBLIC OFFERING	MAMMOTH ENERGY SERVICES INC. ABL REVOLVER & TERM LOAN
Financial Advisor	Underwriter	Financial Advisor	Underwriter	Financial Advisor
UNDISCLOSED	$324 MILLION	$475 MILLION	UNDISCLOSED	$155 MILLION
BLUE WOLF PERFORMANCE SOLUTIONS A PORTFOLIO COMPANY OF Dorilton. HAS BEEN ACQUIRED BY	Atlas Energy Solutions INITIAL PUBLIC OFFERING	PERFORMANCE PROPPANTS HAS AGREED TO BE ACQUIRED BY PROFRAC	RAM Energy LLC ASSET DIVESTITURE	CHEYENNE SENIOR SECURED TERM LOAN
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$1.3 BILLION	UNDISCLOSED	$55 MILLION	$126 MILLION	$307 MILLION
ENPC BUSINESS COMBINATION WITH ROCK TO FORM GRANITE RIDGE	SPONTE RESOURCES ASSET DIVESTITURE	BRIDGER PHOTONICS HAS RECEIVED AN INVESTMENT FROM MADISON VALLEY PARTNERS NEXTfrontier CAPITAL CARICA	EnSight IV Energy Partners, LLC ASSET DIVESTITURE	MURCHISON OIL & GAS, LLC SENIOR SECURED TERM LOAN & PREFERRED EQUITY
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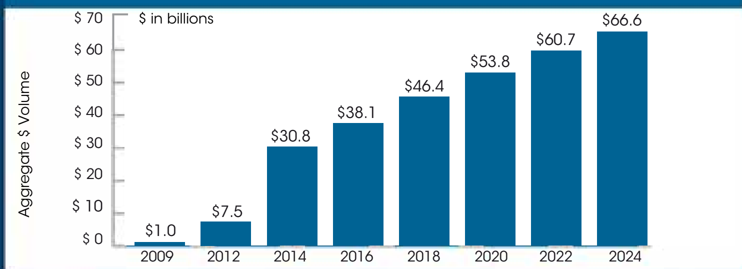
~$300 Million
Average Transaction Size

228
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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Chris Wright

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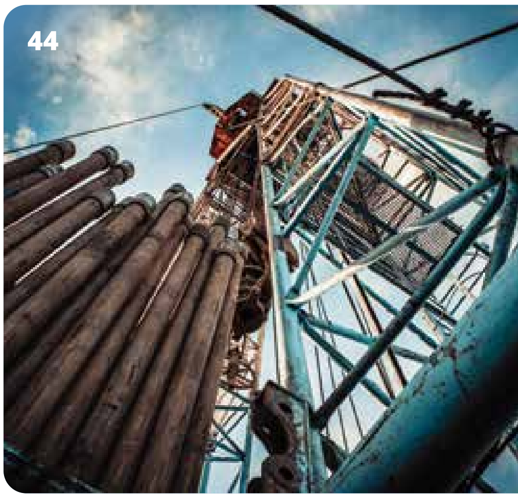

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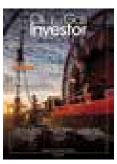

ABOUT THE COVER:
Expand Energy, one of the top Haynesville Shale producers, shared this image of one of their pads in northwestern Louisiana.

Natural Gas Off the Backburner

Commonwealth LNG scores first LNG permit of President Donald Trump's term following the former administration's halt on permitting.

DEON DAUGHERTY
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Apart from questions and concerns surrounding the frenetic pace and nature of change that President Donald Trump is ushering in, his Day One executive order lifting former President Joe Biden's pause on LNG permitting is raising hope for natural gas demand.

Kimmeridge-owned Commonwealth LNG in mid-February won the first permit of Trump's second term. The facility will be located on the Calcasieu River near Cameron, La.

The original plan hatched by Kimmeridge would have the site reach a final investment decision (FID) during first-quarter 2024. That was delayed by the U.S. Department of Energy's order to stop issuing permits pending the outcome of a study on the environmental effects of LNG facilities.

Trump followed through on his campaign pledge to reverse the decision in one of his first actions as president.

New Energy Secretary Chris Wright, the former CEO of Liberty Energy, said the LNG permitting is "one of many steps that [the] DOE will be taking to assure our future as a reliable energy supplier to the world and resume regular order to our regulatory responsibilities over natural gas exports."

When it reaches full capacity, Commonwealth LNG will be able to export the equivalent of 1.2 Bcf/d of natural gas. Commonwealth CEO Farhad Ahrabi said the company now anticipates reaching FID in September, with first LNG production expected in first-quarter 2029.

News of the first permit approval coincided in mid-February with reporting from the U.S. Energy Information Administration (EIA) that natural gas storage withdrawals are routinely hitting the triple digits.

The agency confirmed a 100 Bcf drop in natural gas storage for the week ending Feb. 7, beating the amount anticipated for the third week in a row.

Expectations for the withdrawal averaged about 90 Bcf. Instead, withdrawals stayed in triple digits for the fifth consecutive week, according to the EIA report. Analysts said the heavy withdrawals followed colder-than-expected weather and a growing demand for LNG.

This time last year, the EIA's weekly reports were setting records of a different sentiment. On Feb. 7, 2024, there was more gas in storage than ever before with about 2.545 Tcf in the Lower 48, 181 Bcf above the EIA's five-year average.

But this year, the amount in storage is at 2.297 Tcf—67 Bcf below the five-year average. Analysts at East Daley are forecasting the storage amount will remain lower than the five-year average at least until the summer of 2026.

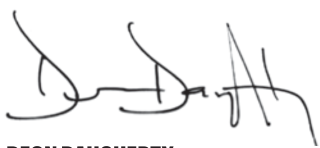
All of which is setting an upside scenario for the natural gas sector in the U.S. If it's natural gas that the people want, the U.S. has it. Continental Resources' Harold Hamm said during the February NAPE Conference in Houston that the U.S. has 100 years of natural gas resources.

And this month, Hart Energy's DUG Gas Conference takes place in Louisiana, home of many Haynesville Shale assets and operators.

This edition of *Oil and Gas Investor* features stories to stoke your excitement for the show and an understanding of the market. Nissa Darbonne, our executive editor-at-large, produced an in-depth analysis of the Haynesville Shale. Chris Mathews, senior editor for shale and A&D, examined western U.S. gas windows. Editorial Director Jordan Blum talked with Dan Brouillette, former energy secretary, about the regulatory changes on the horizon for oil and gas. And I interviewed longtime Haynesville developer Alan Smith, former CEO of Rockcliff I and II, along with Rockcliff III CEO Sheldon Burleson.

If you've not yet registered for DUG Gas, you can sign up for the March 19-20 event in Shreveport ahead of time or on-site. We hope to see you there. OGI

All the best,

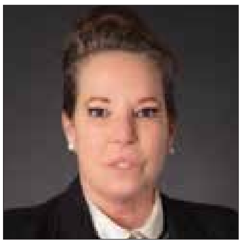


DEON DAUGHERTY
EDITOR-IN-CHIEF

NATURAL GAS

Keeping Up with the Haynesville

Futures are up, but extra Haynesville Bcfs are being kept in the ground for now, while operators wait to see the Henry Hub prices. A more than $3.50 strip is required. As much as $5 is preferred.



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Jim Wicklund, a managing director with energy investment-banking firm PPHB, wrote after a NAPE dinner hosted by Raymond James, "Natural gas was a hot topic."

In particular, "where will the needed natural gas come from, if the drivers of demand require another 20 to 30 Bcf/d?"

The figure includes both incoming growth in U.S. Gulf Coast LNG exports and projected gas-fired power-generation demand by new AI data centers.

The Appalachian Basin has the gas, but Wicklund's dinner mates said more takeaway capacity could take years to come online "even with a cooperative administration."

Thus, the Haynesville will be leaned on–and hard, Wicklund wrote in a note to investors.

But "it would have a difficult time supplying more than an additional 4 to 6 Bcf/d of production," he added.

The Haynesville's shown she has an extra 3 Bcf/d, at least, in her. All-time high Haynesville output was 14.7 Bcf/d in May 2023, according to the U.S. Energy Information Administration (EIA) data.

As operators choked back their capex when futures plummeted a few months later, production tumbled to 11.2 Bcf/d into last October and was 11.7 Bcf/d in January.

Nick Dell'Osso, Expand Energy's president and CEO, agrees the Haynesville can't answer the incoming call by itself, which is nearly 6 Bcf/d more in LNG exports alone by year-end 2026.

"The dynamics of demand internationally are pulling hard on the supply of the U.S.," Dell'Osso said at a Goldman Sachs conference in early January.

Wicklund noted after the NAPE dinner in February that Permian gas could fill the gap. But "there is not a pipe that can deliver natural gas to the east side of Houston and all the [Gulf Coast] LNG facilities to the east."

Kinder Morgan has shown up to answer some of that. To supply Golden Pass LNG at the Texas-Louisiana border, it announced the 216-mile $1.7 billion Trident Intrastate Pipeline in January that will deliver 1.5 Bcf/d of Permian and South Texas gas beginning in early 2027. With expansion, it could grow to 2.8 Bcf/d.

John Abeln, senior gas analyst for research firm RBN Energy, wrote that past difficulty with getting West Texas gas east of Houston has been a "Herculean task" of overcoming urban opposition to rights of way.

Until Trident, that is. The pipe will travel to

"We've had a lot of questions at this conference and leading up to it about, 'Hey, it got cold, so are you going to go faster?' Now the answer to that is 'No, nothing's changed.' … Things are playing out as expected, so nothing's changed for us."

NICK DELL'OSSO, president and CEO, Expand Energy

Drilling at sunrise in the Louisiana Haynesville at a rig operated by Southwestern Energy's Southwestern Drilling Co., now a part of Expand Energy.

Katy, Texas, and then north, around Houston, instead.

Wicklund wrote, "This won't solve the problem alone, but it is a good start."

'Starts with a $5'

As for Wicklund's table mates' thoughts on what gas price would be needed to answer the LNG call, he wrote, "around $5 an Mcf."

Gordon Huddleston, president of 2.5 Bcf/d Haynesville producer Aethon Energy, concurs. "It probably starts with a $5 to bring significant development on," he said at the Goldman Sachs conference.

Bernstein senior research analyst Bob Brackett thinks $5/Mcf gas could actually be on the horizon this year and in 2026, and that's "conservative, in our view," he wrote in a January forecast for "a coming U.S. gas super-cycle."

Strip at the time—and into Feb. 11 as well—was $4.

Brackett cited new gas demand for power-hungry data centers as contributing to his forecast. U.S. utilities' outlook was unchanged after China's DeepSeek announced a low-power-intensity AI model later in January.

While the model remains unproven, investors' consensus in early February was that lower-cost AI will result in more AI use, thus an unchanged forecast for 8 Bcf/d or more of additional U.S. gas demand.

More certain is incoming growth in U.S. LNG exports, which are currently 14.5 Bcf/d.

That will grow another 10 Bcf/d alone by 2030 from projects already underway, Brackett reported.

Net of powering data centers, filling more LNG tankers

"(The Haynesville is) the poster child for a well-located—i.e., near LNG and Henry Hub—and low-cost, earning good returns at $3.50/Mcf and amazing returns above $4.50/Mcf, shale-gas basin."

BOB BRACKETT, senior research analyst, Bernstein

and other factors in Brackett's modeling, U.S. demand "would thus rise to approximately 150 Bcf/d in 2030," he concluded.

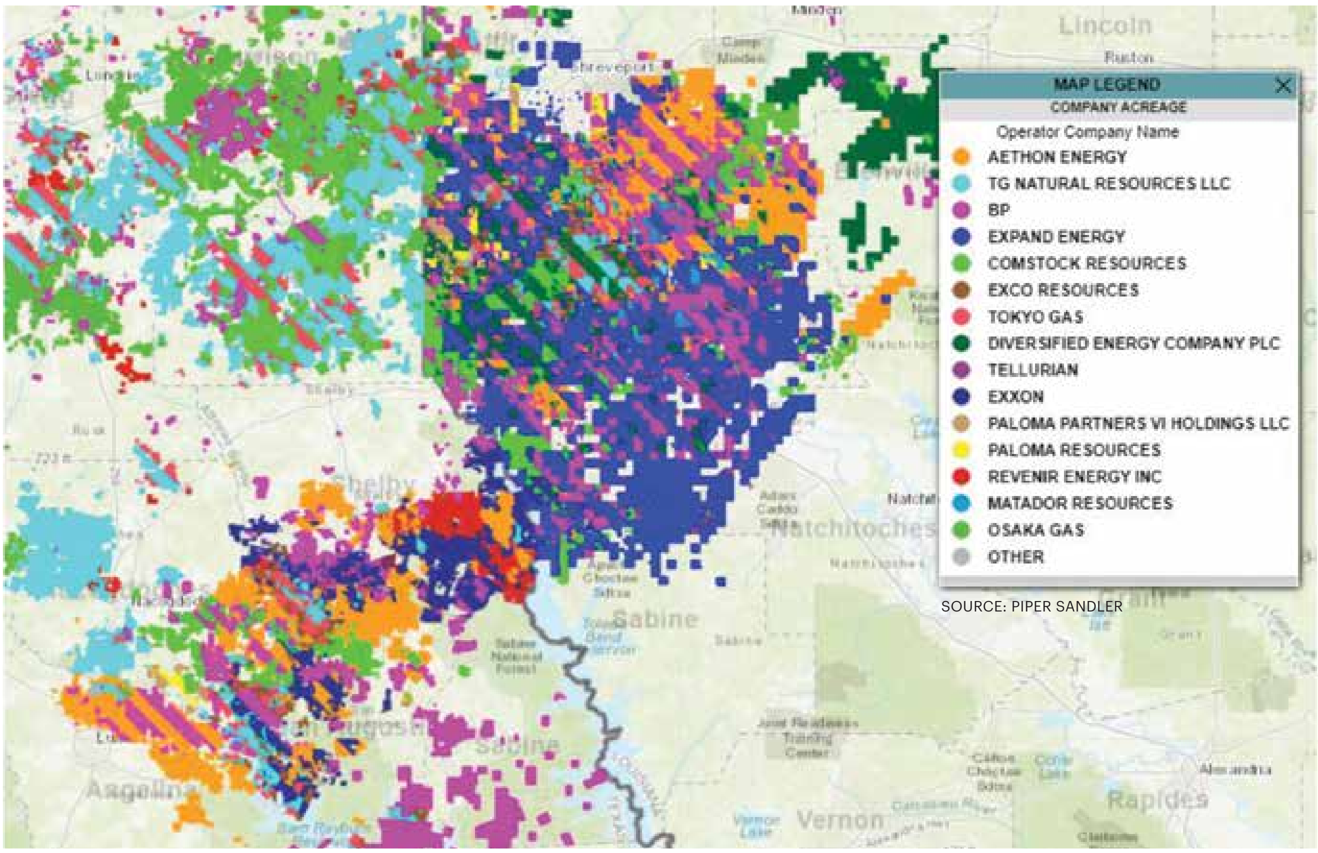
He called the Haynesville "the poster child for a well-located—i.e., near LNG and Henry Hub—and low-cost, earning good returns at $3.50/Mcf and amazing returns above $4.50/Mcf, shale-gas basin."

'Not Surprised'

The money appears to agree as three pipelines are underway to get more Haynesville gas to the Louisiana Gulf Coast.

Williams Cos.' Louisiana Energy Gateway (LEG) is among them. Capacity is 1.8 Bcf/d; in-service is expected in the second half of this year.

Haynesville Operators



SOURCE: PIPER SANDLER

The Tellurian property is now part of Aethon Energy. Tokyo Gas property is part of TG Natural Resources. Osaka Gas property is Sabine Oil & Gas.

The other two are Momentum Midstream's NG3 project that will take 1.7 Bcf/d from the Haynesville to the Louisiana Gulf Coast, expandable to 2.2 Bcf/d, and DT Midstream's LEAP with 1.9 Bcf/d.

Alan Armstrong, Williams president and CEO, said of the three projects in a November earnings call, "I'm not too terribly surprised, if you look at the balance of where gas is going to have to come from and particularly gas that can meet the LNG specs and low nitrogen specs that are going to be required."

With the demand growth Williams and others are seeing, "that's going to have to come from somewhere," Armstrong said.

"And it's starting to mount up pretty big. I'm not too terribly surprised by that, frankly."

Chad Zamarin, Williams executive vice president, corporate strategic development, added, "Even third-party models are showing over 10 Bcf/d of growth out of the Haynesville by the early 2030s to meet LNG demand.

"That's a lot of gas that's going to need to find its way to those LNG markets."

'Not a Huge Incentive'

But Haynesville producers aren't showing up yet. Both Expand's Dell'Osso and Aethon's Huddleston said their Haynesville ramp-up would be cautious.

Like Aethon, Expand produces 2.5 Bcf/d from the Haynesville.

"You're talking about a lot of potential demand coming on, and we know that's going to necessitate higher pricing," Huddleston said. "But until we see that materialize, it's not something we want to get out in front of."

Without significant returns, "there really isn't a huge incentive for us to grow production."

BP is also cautious about adding Haynesville supply, he added. The operator produces 1.4 Bcf/d from the play.

"Even third-party models are showing over 10 Bcf/d of growth out of the Haynesville by the early 2030s to meet LNG demand. That's a lot of gas that's going to need to find its way to those LNG markets."

CHAD ZAMARIN, executive vice president, corporate strategic development, Williams

"They haven't been active in developing" and, when it does step up, "that certainly could provide some additional swing production," he said.

It would probably take nine to 12 months for the Haynesville to significantly ramp. "That means it's going to take longer for the basin to react to pricing."

Aethon would want to see triple-digit returns "because otherwise [capex is] going to be impacting free cash flow, and that's not really our objective."

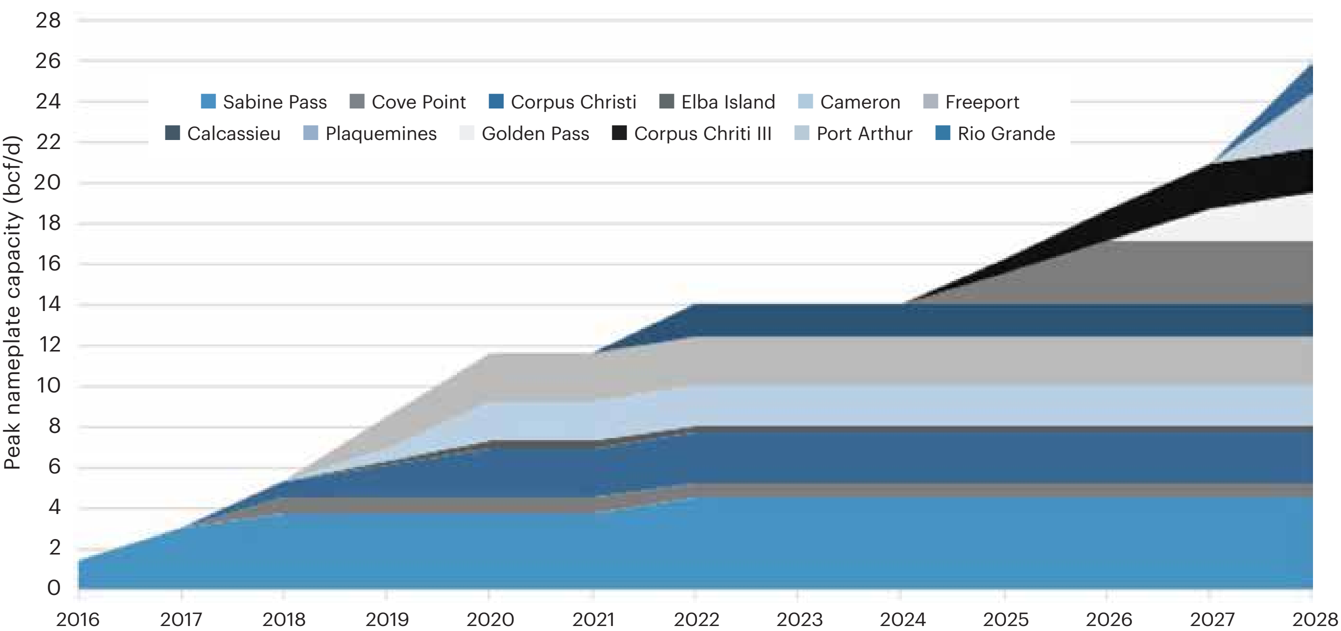
Overall, "$3.50 works pretty well for most participants depending on where that inventory is and what their margins are."

'No, Nothing's Changed'

Dell'Osso said, "We've had a lot of questions at this conference and leading up to it about, 'Hey, it got cold, so are you going to go faster?' Now the answer to that is 'No, nothing's changed.'"

Strong winter demand through January made the first

U.S. LNG Export Projects: Existing and Under Construction



SOURCE: J.P. MORGAN SECURITIES

U.S. LNG exports of about 14 Bcf/d at year-end 2024 will grow to 26 Bcf/d by 2028 from projects under construction, according to Energy Information Administration data.

WELL TRENDS

Piper Sandler ranked Aethon Energy as its No. 4 Haynesville operator in terms of 12-month cumulative gas output with 5.68 Bcf per 9,500 feet of lateral, analyst Mark Lear said in late January.

Following closely was Paloma Natural Gas with 5.54 Bcf per 9,500 feet of lateral.

Expand Energy came in first place with 7.27 Bcf per 9,500 feet, followed by Exco Operating with 6.62 Bcf and GeoSouthern Energy's GEP with 6.53 Bcf.

Exco, which was an early Haynesville explorer, produced 97 MMcf/d from Carthage-Haynesville Field last November in Harrison, Nacogdoches, San Augustine and Shelby counties, Texas, according to RRC data.

Among its newest wells, Gomez SU B-C #1H made 8.3 Bcf its first five months online.

At J.P. Morgan Securities, analyst Arun Jayaram reported the top scorers in his Haynesville review in January on multiple 2024 metrics.

At No. 1 was Comstock Resources, followed by Sabine Oil & Gas and Expand. Placing third through sixth were Trinity Operating, TG Natural Resources and Aethon.

The highest scores were given to those with the greatest productivity per lateral foot on a three-month and six-month basis.

Jayaram noted, though, that the scores do not consider at what cost, since there is inconsistent transparency into this among operators.

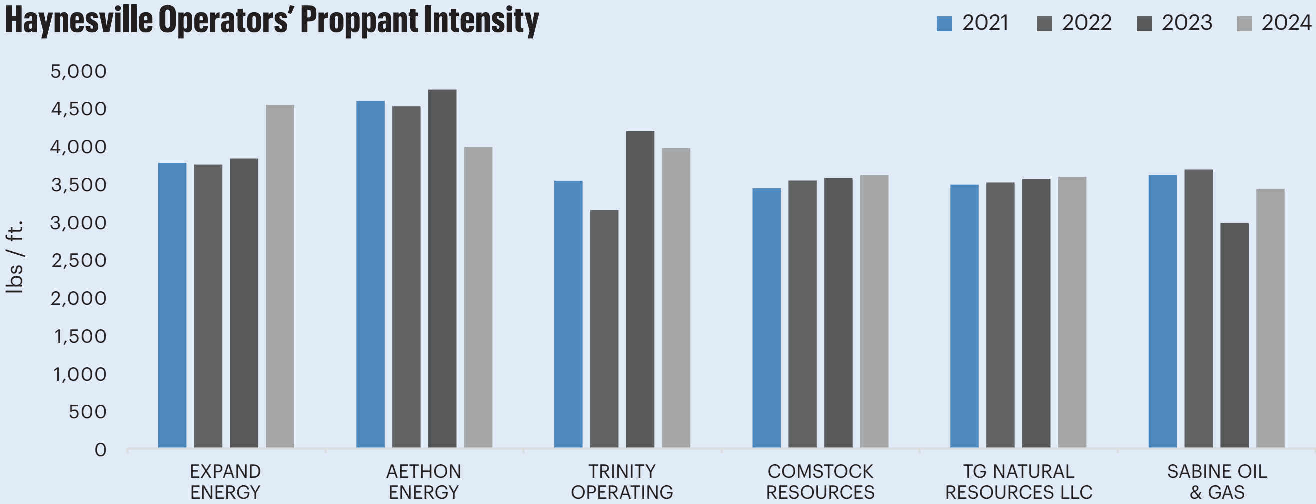
"As such, we acknowledge that low-cost producers can still deliver strong capital efficiency, even if well performance is not in the top quartile, given the importance of completed well costs on overall shale returns," he wrote.

The analysis was of second-half 2023 and first-half 2024 completions in contrast to the prior 12-month period.

Jayaram found wells' first-three-month output declined 13%, but he noted that operators pared their D&C pace in 2024.

Continued on Page 17

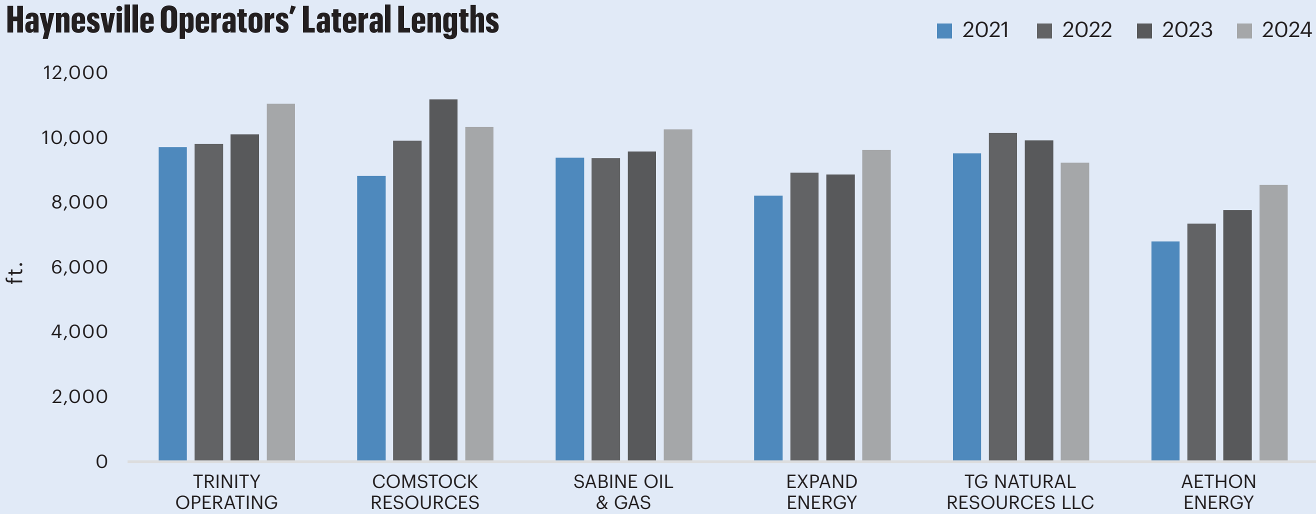
Haynesville Operators' Proppant Intensity



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

Haynesville operators have varied their proppant recipes over the years, with Expand Energy recently increasing intensity while Aethon Energy recently reduced it.

Haynesville Operators' Lateral Lengths



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

Average lateral length in the Haynesville grew slightly in 2024 to 9,697 ft among operators, with Trinity Operating making the longest laterals, followed by Comstock Resources and Sabine Oil & Gas.

significant dent in persistent U.S. oversupply, taking gas in storage to 8% less than at the end of January 2024 and 4.4% less than the five-year average, according to EIA data.

The $4 strip that materialized is what Expand anticipated it would be by this time. "Things are playing out as expected, so nothing's changed for us," Dell'Osso said.

By the end of 2026, the call on gas will be 5.6 Bcf/d more than at year-end 2024, including from Golden Pass LNG, Plaquemines LNG and Corpus Christi Liquefaction's Line 3 (CCL3). The latter two came online in December and were ramping to full capacity when *Oil and Gas Investor (OGI)* went to press.

"And 5.6 Bcf/d is actually quite a bit for us to grow," Dell'Osso said. It will take time "and it's going to be expensive.

"You do need to see some volume growth and I think you are just [beginning to see] prices that might encourage some volume growth."

The breakeven in the Haynesville is probably $3.50, he said.

And the Haynesville is the marginal supplier—that is, the swing supplier—so futures will have to be "materially higher than $3.50" for there to be a significant supply response from the play.

Of course, "there are plenty of wells in the Haynesville that make money at $2.50," Dell'Osso said.

"But if you're going to grow volumes, you're going to need to capture the growth from areas that require a higher price."

Russian Deleted

A colder winter this year in Europe had countries there rushing in early February to keep up as well. France's natural gas tank was 65% empty, Bloomberg reported.

EU-wide, the 4 Tcf of capacity averaged less than 50% full, according to Turkey's Anadolu news agency. Of that 4 Tcf of capacity, 80% of it is in Germany, Italy, the Netherlands, France, Austria and Hungary.

The price for LNG delivered to the Netherlands' TTF for March delivery was $17 on Feb. 10, up from $12 in mid-December and $14.79 in mid-January, according to CME Group.

Meanwhile, Gazprom's contract to deliver gas to Ukraine expired at year-end.

And non-Russian gas demand in Europe is set to grow further after the Baltic States disconnected from Russia's power grid on Feb. 8, drawing electrons from EU members instead and rendering Moscow's Kalingrad Oblast a power-grid island.

"Demand around the world is growing for gas," Bryce Erickson, managing director for business valuation firm Mercer Capital, wrote in January.

Delays in bringing on new LNG supply "kept supply tight, while extreme weather events added to market strains," he added.

That stress is expected to continue until new U.S. and Qatari supply begin to come online after 2025 and into 2030.

LNG Exports

Cheniere Energy counted 20 Bcf/d of global LNG export capacity under construction and potentially coming online this year through 2027, possibly shifting into 2028, the LNG exporter reported at a J.P. Morgan Securities conference in London in November.

Of that, the U.S. will add 10.7 Bcf/d; Qatar, 6.7 Bcf/d; and Canada, 2.7 Bcf/d.

"As an undersupplied natural gas market drives prices above $5 starting this year and continuing to 2030, it provides a unique opportunity for long-term value creation."

BRYCE ERICKSON, managing director, Mercer Capital

J.P. Morgan energy analyst Arun Jayaram estimated in early February that U.S. LNG capacity may be 17.8 Bcf/d in 2026 and 18.5 Bcf/d by year-end 2026, up from 14.5 Bcf/d in January.

The January figure was boosted from 13.5 Bcf/d into December with Venture Global's Plaquemines plant on the Mississippi River and Cheniere Energy's CCL3 both coming online.

Exports may grow to 16.1 Bcf/d in this quarter as the Plaquemines plant reaches full capacity. It has FERC approval of 3.3 Bcf/d.

At CCL3, full capacity from the seven-train expansion will be 1.3 Bcf/d, bringing the plant's total output to more than 3.3 Bcf/d.

Exxon Mobil's long-awaited Golden Pass export plant on the Sabine River has FERC approval to 2.6 Bcf/d.

Mercer Capital's Erickson wrote that, with Plaquemines and CCL3, nominal production capacity in the U.S. will be 15.4 Bcf/d, peaking at 18.7 Bcf/d.

That will grow to 21.2 Bcf/d and a 25.2 Bcf/d peak by 2028 with Golden Pass and two other projects that are underway—Rio Grande LNG at Brownsville, Texas, and Port Arthur LNG near Golden Pass on the Sabine River.

"As an undersupplied natural gas market drives prices above $5 starting this year and continuing to 2030, it provides a unique opportunity for long-term value creation," Erickson concluded.

Aethon at $14 Billion?

Haynesville gas producers' stock prices have soared in the past 12 months, according to market data. Focused on both the Haynesville and Appalachia, Expand's grew from $77.56 to $105.12 through Feb. 10.

Haynesville pureplay Comstock Resources' stock grew from $7.71 to $18.49.

Aethon is rumored to be for sale or IPO with an estimated valuation of $10 billion.

The $10 billion figure, reported by Reuters in mid-November, was outdated in early February, though.

Based on pureplay Comstock's $5.2 billion market cap on Feb. 12 and $3 billion of debt, enterprise value for its 1.45 Bcf/d was $5,655 per flowing Mcf/d.

Meanwhile, fellow pureplay Aethon produces 2.5 Bcf/d, suggesting its enterprise value would be $14 billion at $5,655 per flowing Mcf/d.

Aethon also holds 1,400 miles of gathering and takeaway, covering 85% of its Haynesville production, giving "us a margin uplift that allows us to be a little more comfortable in these lower-price situations," Huddleston said at the Goldman Sachs conference.

A walking rig at a TG Natural Resources pad in Panola County, Texas, where another pad is being prepped in the background.

TG NATURAL RESOURCES

He told *OGI* in late January that, as for a sale or IPO, "we have a lot of different options."

He added, "For several years, we've been looking at what those options are going to be. We have been IPO-ready and continue to be."

According to the Reuters report, Goldman Sachs and Citigroup are Aethon's advisers. Huddleston wasn't asked about whether it was for sale or planning to IPO while in the Q&A in January with Goldman Sachs commodities and securities analysts.

In addition to the Huddleston family, equity owners include RedBird Capital Partners and the Ontario Teachers' Pension Plan.

He told *OGI*, "I think people are starting to realize that gas is going to be a very long-term fuel … for this country and for the world."

Haynesville $/Mcf Comps

Woodside Energy, which recently bought Tellurian and its Driftwood LNG project on the Louisiana coast, isn't interested in buying gas production, too, it told the Wall Street Journal in January.

Before selling its LNG permit and property to Woodside in July, Tellurian sold its Haynesville E&P property to Aethon for $260 million.

The 31,000 net acres averaged 200 MMcf/d net in 2023 from 161 wells, according to Tellurian's annual report, resulting in a deal value of $1,300 per flowing Mcf/d.

Henry Hub was $2.20/Mcf when the deal was signed on May 29, according to EIA archives.

Meanwhile, Haynesville pureplay TG Natural Resources' (TGNR) deal for fellow pureplay Rockcliff Energy that was signed on Dec. 15, 2023, was for $2.7 billion plus $1.7 billion in debt assumption in a $4.4 billion total deal value, averaging roughly $3,650 per flowing Mcf/d net.

Rockcliff's production was 1.3 Bcf/d gross and 1.2 Bcf/d net. Its net leasehold was more than 200,000 acres.

Henry Hub at the time was $2.44/Mcf, according to the EIA archive, having plunged from $3.34 just six weeks earlier.

And the Aethon Buyer is?

TGNR's owner, Japan's Tokyo Gas, is looking for more energy investments in the U.S., but its next investments won't necessarily be more E&P, the parent's president told Bloomberg in January.

Bill Marko, a managing director for Jefferies, said at Hart Energy's A&D Strategies and Opportunities conference in October, "If you're an [LNG] off-taker, you're thinking about, 'How do I lower the cost of supply?' One way to do that is to own the assets."

In addition to Tokyo Gas, he said TotalEnergies has interest in owning more U.S. gas.

Huddleston said at the Goldman Sachs conference that he gets queries from parties with LNG contracts that are "trying to understand, 'Hey, how am I going to supply gas for a 20-year contract? Where am I going to get this gas from for 20 years? And what price?'"

He told *OGI* that Aethon is among few gas producers on the Gulf Coast that is confident it could deliver gas for that long.

"And we're also integrated. We have our own midstream across the bulk of our assets. So, our margins are the highest in North America," he said.

"When you add that all up, there's a lot of different, interesting options for us on ways we can partner and … continue to create additional value."

And Chevron Panola?

Jefferies was the marketer in 2024 of Chevron's leasehold in Panola County, Texas, that remained unsold, according to Railroad Commission of Texas (RRC) files through November 2024.

Jefferies had opened the data room on Feb. 12, 2024. Chevron did not reply to a request for comment by press time.

According to Mercer Capital, a sale of the property was being discussed at Chevron as long ago as November 2023 as a portfolio revision post-merger with Hess Corp. toward raising $15 billion in divestments over five years. The Hess deal was not yet closed at press time.

The Chevron offer last spring was a sale or joint venture of

Expand's first-three-month production averaged 219 Mcf/ft; Comstock's, 177 Mcf/ft; Aethon's, 152 Mcf/ft.

Average lateral length grew slightly to 9,697 ft among operators analyzed.

Proppant averaged 3,593 lbs/ft with Expand, Aethon Energy and Trinity pumping the largest amounts.

In particular, Expand took proppant to nearly 4,500 lbs/ft after holding steady at about 3,500 the prior three years.

Meanwhile, Aethon decreased its load to less than 4,000 after pushing 4,500 lbs/ft the three years prior.

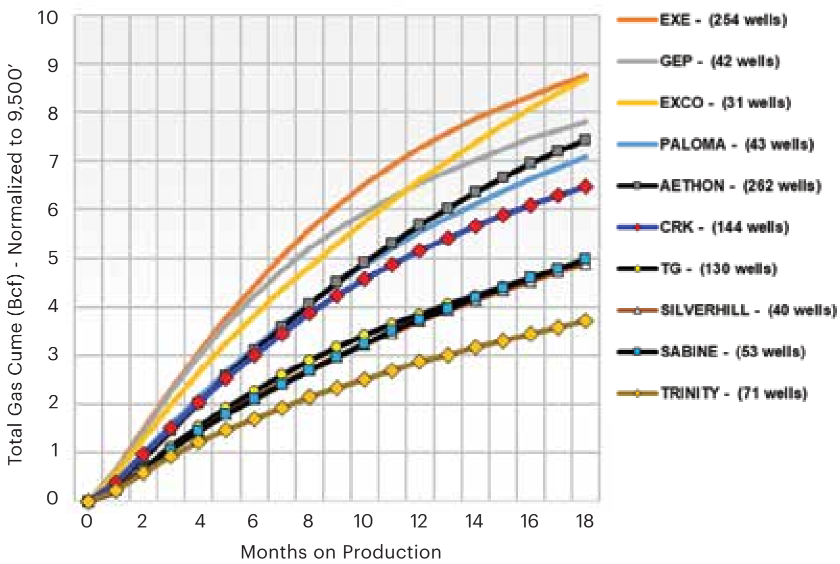
Trinity, which had been low-proppant-loading in comparison, dialed up its recipe to roughly 4,000 pounds in 2023 and kept it up at just under 4,000 in 2024.

Comstock and TGNR held steady at about 3,500 lbs/ft for a fourth year.

Meanwhile, Sabine had drastically reduced its formula in 2023, pumping less than 3,000, but it pushed that back up in 2024 to nearly 3,500 pounds.

Six-Month Gas Ranked Total Gas Cume

(Bcf) - Normalized to 9,500' (2-stream)



SOURCE: PIPER SANDLER, CITING ENVERUS DATA

Expand Energy, Exco Resources and GeoSouthern Energy's GEP have led in first-six-month cumulative production among their Haynesville wells normalized to 9,500 feet in the past three years.

LEG, MOMENTUM, DT

Chevron is in a deal to supply gas to Williams' Louisiana Energy Gateway (LEG) pipeline from 26,000 dedicated acres in Panola County, Texas.

A flyer marketing Chevron's 71,000 net Panola acres in 2024 reported, "Committed future capacity on LEG provides direct access to premium markets, including [Williams'] Transco, industrial markets and LNG export demand."

But Chevron cut D&C spending in the county after signing the deal with Williams in 2023. The 1.8 Bcf/d LEG long-haul pipe was to come online this year but was delayed by a dispute with Energy Transfer.

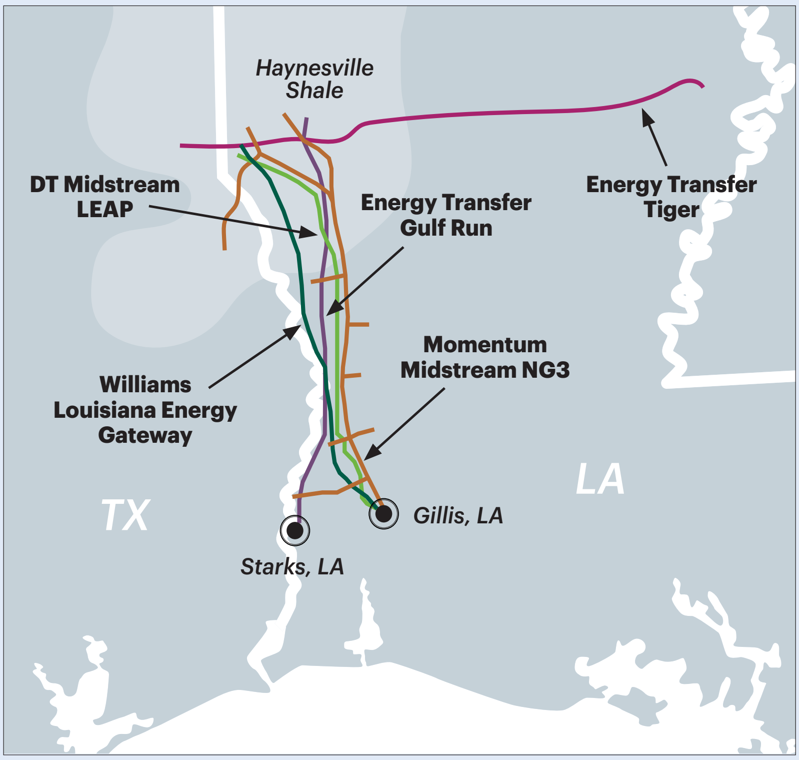
Meanwhile, Momentum Midstream's NG3 gas-gathering project will take 1.7 Bcf/d of Haynesville gas to the Louisiana Gulf Coast, expandable to 2.2 Bcf/d.

The project was to be completed in second-half 2024 but pushed to year-end 2025 while also delayed by an Energy Transfer lawsuit. The anchor commitment is from Expand Energy with an option to own 35%.

Nick Dell'Osso, Expand Energy's president and CEO, said at a Goldman Sachs conference in January, "We're gaining access to the [NG3] Gillis delivery point here over the

Continued on Page 18

Select Haynesville Natural Gas Pipelines



SOURCE: RBN ENERGY

New takeaway projects by Williams Cos., Momentum Midstream and DT Midstream will ship 5.4 Bcf/d of additional Haynesville gas to the Louisiana Gulf Coast.

next year out of Louisiana, which is going to put us directly in contact with the LNG export facilities."

DT Midstream's 1.9 Bcf/d LEAP pipeline project was also sued by Energy Transfer. In all three cases, Energy Transfer said it had exclusive right of way of its Tiger pipeline route. The others' pipes could not cross Tiger's path, the company claimed.

Tiger is a 189-mile east-west route across North Louisiana, noted Alyssa Schabel in an RBN Energy report, and connects with Energy Transfer's south-directed Gulf Run gas pipeline.

Federal courts and FERC rejected ET's claims last summer.

DUCS AND DTILS

After 2026, more LNG supply will be in the global market, particularly from Qatar, so some U.S. export facilities might not be running at capacity, Expand Energy President and CEO Nick Dell'Osso expects.

"I think we likely will have a very tight market until you see Qatar bring on incremental trains, which is probably the end of 2027, beginning of '28 timeframe," he said at a Goldman Sachs conference in January.

Expand wants to time its decision to increase its D&C spend to when the LNG market is flush so it can grow its gas output, rather than keep its D&C spend steady, which has been keeping its production flat.

The math of how much U.S. gas supply is needed will have to be revisited, Dell'Osso said: What does domestic demand look like? And has international demand grown fast enough to absorb all the new LNG?

"I think it's a bit of an unknown as to how long we're going to need that growth and ... is really the biggest thing we're trying to understand," he said.

Expand, as well as Southwestern Energy, which it bought Oct. 1, were DUC'ing (drilled but uncompleted) wells and deferring turning inline (DTIL) others in 2024, totaling 60 DUCs and 80 DTILs by November.

Instead of ramping to the pre-2024 level, Expand plans to use its DTILs and DUCs over time to counter production declines that have come from reduced activity, Dell'Osso said.

"In other words, we can level out our production to a good level in 2025, around 7 Bcf/d. And that cadence and that timing is exactly what we expect to do throughout the year."

NEW IN-BASIN DEMAND

Adjacent to the Haynesville Shale play, two power producers announced new gas-fired fleet expansions in December.

Swepco plans a 450 megawatt plant in Harrison County, Texas, and converting a 1 gigawatt (GW) plant from coal to gas nearby in Morris County. Both are in the Southwest Power Pool, outside Texas' ERCOT grid.

Just east of the Haynesville, Entergy announced three newbuild combined-cycle turbines with a combined capacity of 2.32 GW, with two of these in Richland Parish in North Louisiana.

The plants are to power Meta Platforms' $10 billion data center, its largest to date, in the parish.

Expand Energy, which produces 2.5 Bcf/d of Haynesville gas, sees gas-fired power demand for data centers as higher-margin, since it brings demand closer to the wellhead.

"You reduce the infrastructure needed to deliver the ultimate valuable product, which is the data that you're trying to create," said Nick Dell'Osso, Expand Energy president and CEO.

Transportation cost is less because in-basin demand is a short pipe to the power plant.

"Those opportunities are pretty significant and represent a growth opportunity," Dell'Osso said.

WHEN JEVONS MET DEEPSEEK

J.P. Morgan Securities analysts hit their decks after DeepSeek's news in late January that it had developed a lower-power-intensity AI model.

Revisiting the numbers and models at the firm were its tech, utilities, electrical equipment, multi-industry, energy and other analysts.

The news had "called into question the billions being spent on AI capex—and thus the resulting impact on future growth of natural gas power demand—and weighed on natural gas E&P equities," Arun Jayaram, energy analyst for the firm, wrote.

The results? The DeepSeek news is good news, actually.

Enter the Jevons paradox.

"The lower cost of DeepSeek is likely to be a positive for AI adoption and ultimately more compute will be needed given increased proliferation/demand," Jayaram wrote.

J.P. Morgan hosted a call with an unidentified tech expert, who said there remains some skepticism about DeepSeek's claims.

But "ultimately he believes that this is definitively positive for AI adoption and the world will need more compute as the volume of things like agents will explode with this declining cost curve, which we are just on the cusp of, and that lower pricing has always been key to these advances," Jayaram wrote.

AI has been called the fourth industrial revolution, following mechanization, electrification and digitization.

Google Trends found scant use of "Jevons paradox" on the internet dating back to 2004 until Jan. 27, setting an all-time high shortly after the DeepSeek news. Prior references often were to the decline in the cost of chips, thus the pricetags for computers, phones and other devices.

Gas-weighted producers' stocks were hit initially on Jan. 27 but recovered along with gas futures. "We think that the decline in natural gas stocks was too punitive," Jayaram wrote.

Separately, DeepSeek gave the EU some confidence in late January that it might still compete in the AI race with the U.S. and China after all.

"There has been a feeling in Europe that the AI race is over," DealBook newsletter reported, quoting André Loesekrug-Pietri, president of the Joint European Disruptive Initiative.

"DeepSeek brought a big sense of hope that reshuffling the cards is always possible."

the 71,000 net contiguous Panola County acres, which have been mostly untouched by Chevron for its Haynesville potential.

Jefferies described it in the flyer as "substantial virgin inventory with approximately 300 [potential] operated Haynesville locations."

The acres are 85% operated and 100% HBP, primarily by vertical Cotton Valley wells. Production at the time was 48 MMcf/d net, 86% gas, according to the Jefferies ad. PDP was 120 Bcf net. EURs averaged 1.9 Bcf per 1,000 lateral feet for the handful of horizontal wells.

TGNR was considering buying the property, the Financial Times reported in October. TGNR didn't respond to an *OGI* request for comment by press time.

Craig Jarchow, TGNR's CEO, said at Hart Energy's DUG Gas conference in Shreveport, La., last spring, though, that he was aware the Chevron property was on the market. But TGNR was busy with integrating its Rockcliff acquisition at the time. "We really have our hands full, but generally we look at everything just as a matter of discipline."

By June, Jarchow told Reuters that he was looking for more deals. Tokyo Gas' president similarly said in June that it was looking to buy more U.S. gas property.

Carthage-Haynesville

Carthage-Haynesville Field production in Panola County in November 2024 totaled 35 Bcf or 1.67 Bcf/d, according to RRC records.

Of this, TGNR produced 15.5 Bcf (517 MMcf/d); Sabine Oil & Gas, 7.2 Bcf (240 MMcf/d); R. Lacy Services, 5.4 Bcf (180 MMcf/d); and Comstock, 2.2 Bcf (73 MMcf/d).

TGNR's Panola production includes what it picked up from Rockcliff in December 2023. In the prior month, Rockcliff had produced 21.6 Bcf or 720 MMcf/d from Carthage-Haynesville in Panola, while TGNR produced 2.3 Bcf (77 MMcf/d) that month.

Chevron produced 115 MMcf this past November from Carthage-Haynesville in Panola of its total 877 MMcf from the county, which was primarily 611 MMcf from hundreds of legacy, shallower, vertical Carthage-Cotton Valley wells.

It gained the position in 2000 in its merger with Texaco. Chevron had five Haynesville wells online on the property in November.

Aethon does not operate in Panola County. Instead, it produced 34 Bcf (1.1 Bcf/d) in November from Carthage-Haynesville in San Augustine, Nacogdoches, Angelina and Shelby counties, Texas, according to the RRC.

"That [Panola acreage] is a position that all Haynesville operators are interested in," Mike Winsor, CEO of Paloma Natural Gas, which bought Haynesville operator Goodrich Petroleum in 2021, said at the Hart Energy conference in Shreveport.

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

It's a rare block of property. "It's not very often you can come into an acreage position that is consolidated," Winsor said.

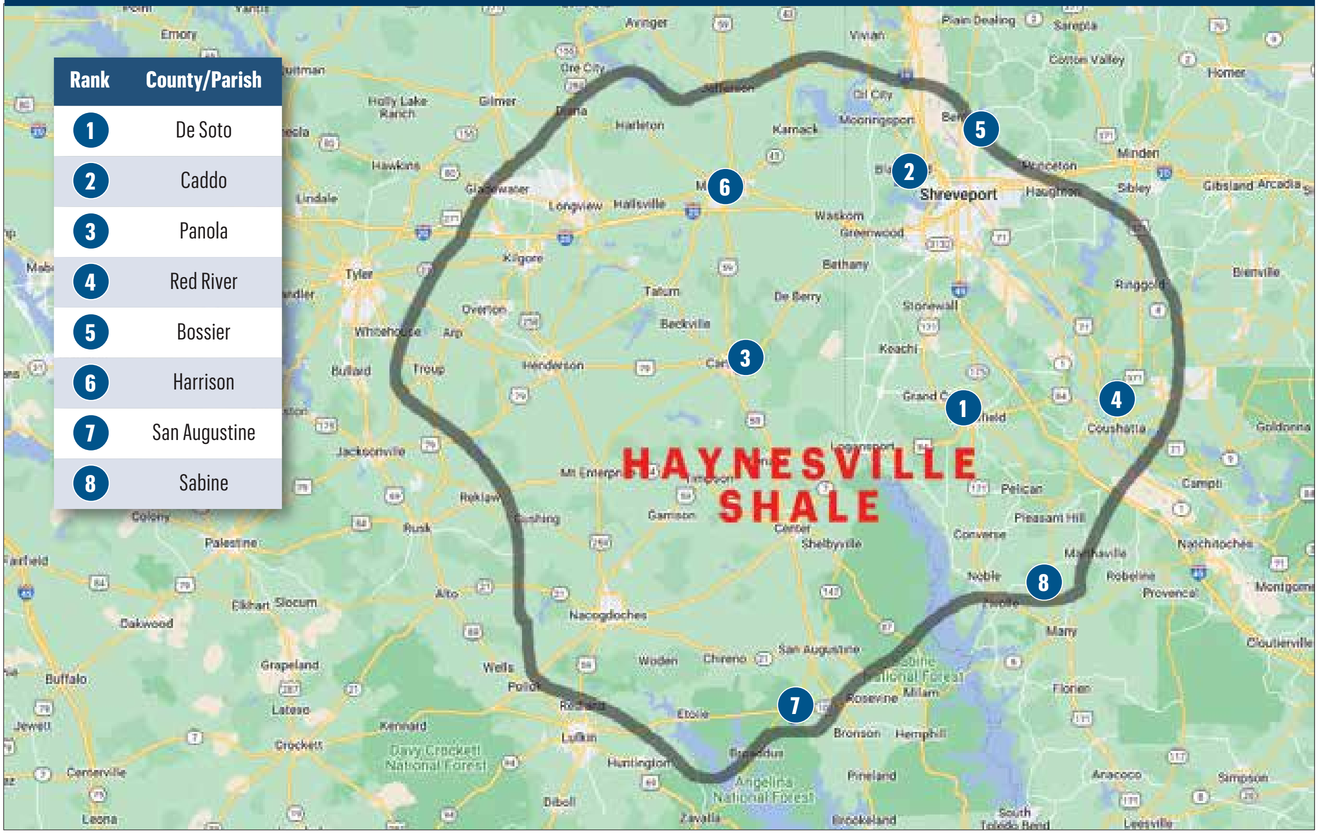
"You can come in with a blank slate. And whatever your well-spacing, whatever your design, there's a huge amount of running room there." OGI

HART ENERGY/TOM FOX

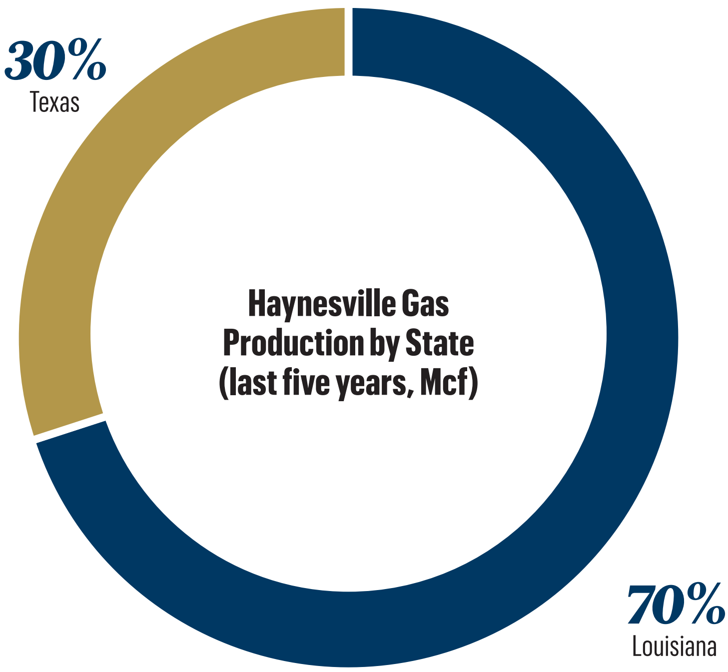
BASIN FOCUS: HAYNESVILLE SHALE

Expand Energy has led all operators in Haynesville gas production over the last five years.

TOP GAS-PRODUCING COUNTIES/PARISHES



Rank	County/Parish
1	De Soto
2	Caddo
3	Panola
4	Red River
5	Bossier
6	Harrison
7	San Augustine
8	Sabine



Leading Haynesville Gas Producers

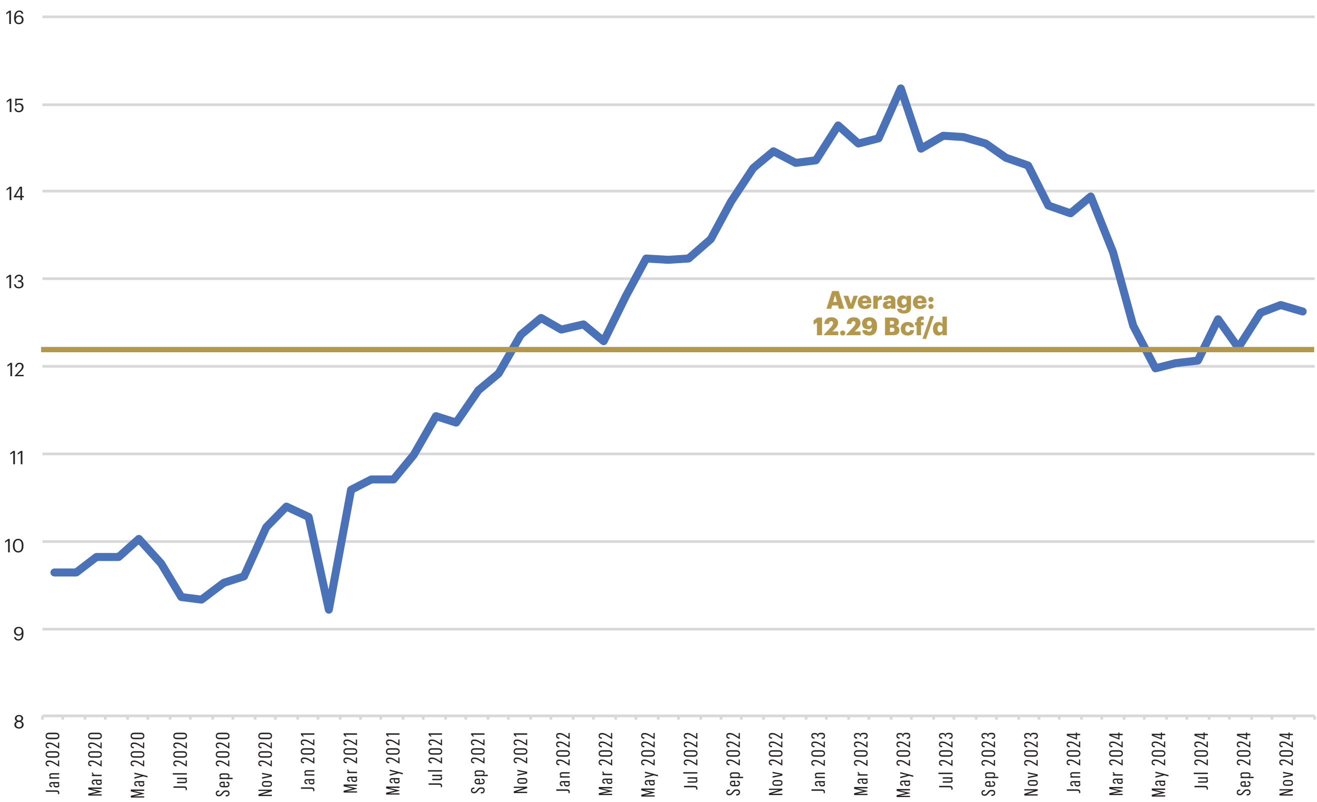
last five years

Operator	Avg. Mcf/month
Expand Energy	6,693,341,837.14
Aethon	3,492,949,733.77
Comstock	3,031,747,867.50
Rockcliff Energy	1,621,698,208.00
BPX Operating	1,012,925,050.75
ExxonMobil	700,675,065.85
Paloma Natural Gas	627,383,806.25
Sabine	598,011,793.00
EXCO	467,800,743.61
ConocoPhillips	301,751,785.49

SOURCE: REXTAG

Haynesville Shale Natural Gas Production

last five years, Bcf/d



SOURCE: ENERGY INFORMATION ADMINISTRATION

THE WALL

Gas demand is rising in the western U.S., and Uinta and Green River producers have ample supply and takeaway capacity.

CHRIS MATHEWS
SENIOR EDITOR, SHALE/A&D
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Sometimes, the value of a hydrocarbon resource play can be as simple as "location, location, location."

Natural gas demand is rising across the western U.S., but there are few avenues to supply the West with the gas it needs.

Western U.S. gas demand is expected to increase from around 13 Bcf/d today to 14 Bcf/d by the end of the decade, according to experts at East Daley Analytics.

Demand is growing across different parts of the West for different reasons. Gas demand within California, a leader in renewable energy deployment, is expected to remain roughly flat by 2030. Meanwhile, gas demand is expected to rise in states like Arizona, fueled by population growth and interest from data center developers.

And gas supply from within the West—around 2.1 Bcf/d from California and New Mexico's San Juan Basin, along with storage reserves—makes up only a fraction of its demand.

So, western states are left to import the difference from Canada, the Permian Basin and the Rocky Mountains. But, with import capacity from Canada and the Permian effectively tapped out, gas producers in the western Rocky Mountains sit at an important crossroads to be a swing supplier to the West during periods of high demand.

Vast gas reserves lie in the eastern Rockies and the Midcontinent. But only so much pipeline capacity exists to carry the gas westward across the Rocky Mountains.

There's a dividing line from east to west along the bottlenecked Colorado Interstate Gas Co. (CIG) pipeline in southwestern Wyoming, running through the heart of the Greater Green River Basin.

"What it's effectively known as is the I-80 corridor constraint," said Kristel Franklin, COO of PureWest Energy, one of the top natural gas producers in Wyoming.

It's become a pretty common concept that bifurcates the area into east versus west, she noted.

"Essentially, you have full pipes entering that constraint point from the east," she said. "Then downstream of the constraint, things open up and there's ample capacity."

PureWest's blocky asset on the Pinedale Anticline formation sits downstream of the CIG bottleneck.

"The way we kind of think about it is that we're west of the wall," Franklin said.

There are efforts to relieve some of the bottleneck across the mountains. Williams is expanding the MountainWest Overthrust Pipeline in Southern Wyoming by an additional 325 MMcf/d. The expansion is expected to be in service by December.

But without large-scale projects to solve the structural shortages of supplying gas demand to the West, it serves to have gas located west of "the wall."

The availability of gas reserves and ample takeaway infrastructure gives greater upside to basins west of the divide, including the Uinta and Green River gas basins, said Ian Heming, natural gas research analyst for East Daley.

Meanwhile, production from gassy basins east of the I-80 constraint—like the Piceance and San Juan basins—is forecasted to decline while Uinta and Green River gas grows.

"On the West Coast, your best opportunities are going to be in the Green River and Uinta Basins," Heming said. "Those will be followed by the Piceance and San Juan."

West of the Wall

Denver-based PureWest Energy is one of the top gas producers in the Greater Green River Basin, where the company has consolidated most of the historic Pinedale Anticline field.

Oil exploration in the Pinedale field dates to 1939, when the California Co.'s Government #1 was drilled in the structure to a depth of 10,002 ft, according to the Wyoming State Geologic Survey. The well delivered no oil shows.

Although there were shows for natural gas, there was no market for it. The well was eventually plugged and abandoned. But significant gas production from the area came online in the early 1980s, spurred also by the prolific Jonah gas field nearby.

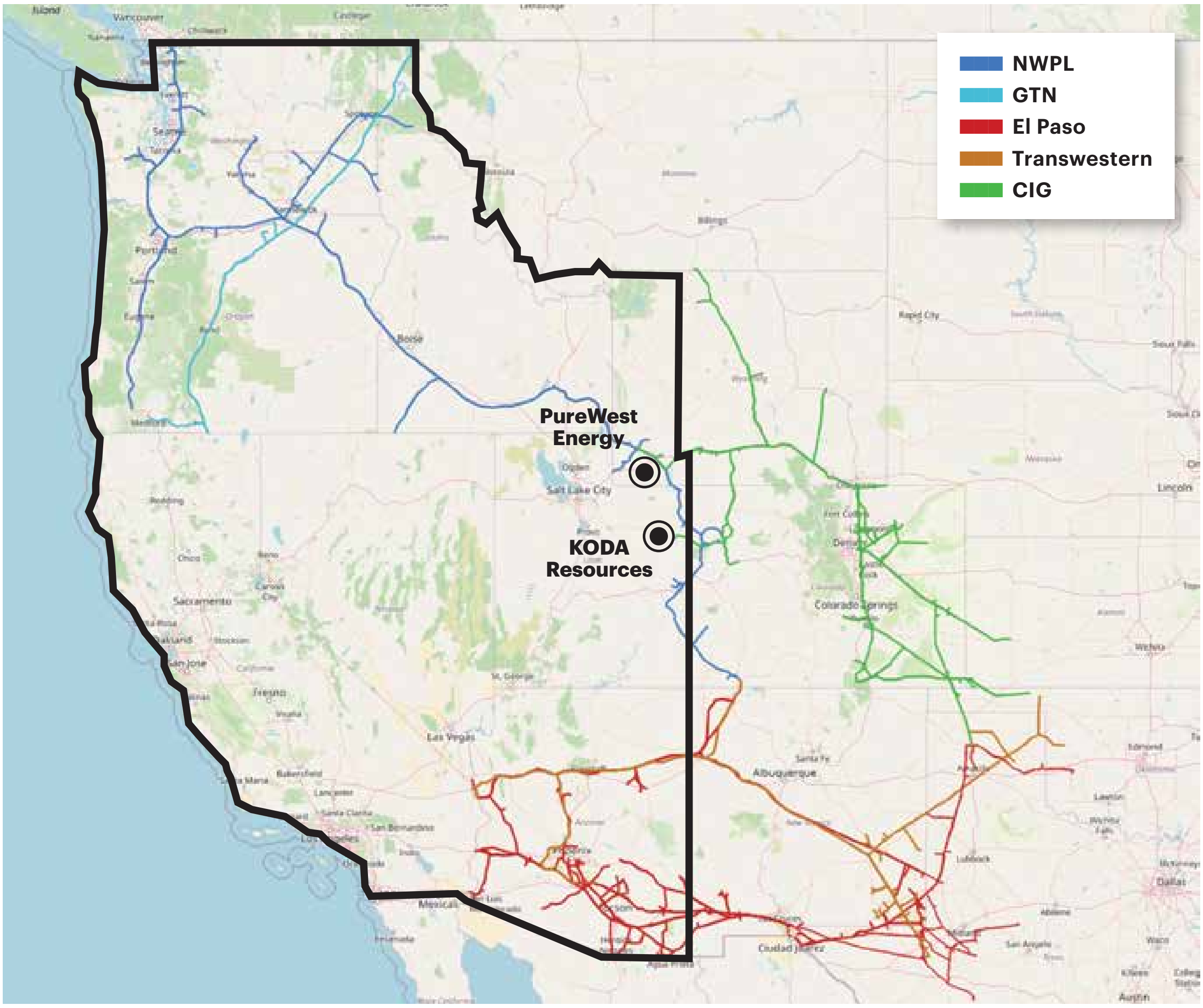
The Mesa 15-8 well, drilled in 1998, was Pinedale's first multistage fracture-stimulated well.

PureWest was born out of the Chapter 11 bankruptcy of Ultra Petroleum, a longtime Wyoming gas producer from the Pinedale and Jonah fields. Ultra emerged from bankruptcy in September 2020.

The surviving entity eventually rebranded as PureWest Energy, which today manages approximately 3,500 wells across the massive Pinedale Anticline formation.

PureWest's current gross operated production is 625 MMcf/d; PureWest's 2025 net production is estimated

Major Gas Import Pipes to Western US



SOURCE: UPLIFT ENERGY STRATEGY, EIA, GENSCAPE AS OF FEBRUARY 2024

The western U.S. receives inbound gas imports from Canada, the Permian Basin, the San Juan Basin and the Rockies. Western Rockies gas is located downstream of pipeline bottlenecks carrying volumes from the eastern Rockies and Midcontinent. PureWest Energy and KODA Resources are leading western Rockies producers.

at around 300 MMcfe/d (95% gas).

PureWest operates around 1,600 of its 3,500 wells on behalf of Wincoram Asset Management.

Wincoram was a part of a family office-led private investor consortium that acquired PureWest for $1.84 billion in cash in 2023. The PW Consortium also included Petro-Hunt, A.G. Hill Partners, Cain Capital, Eaglebine Capital Partners, Fortress Investment Group and HF Capital.

PureWest has been able to extend its drilling inventory by using wider spacing and larger slickwater fracs.

Compared to the company's modern drilling projects, PureWest's legacy wells are spaced together tightly. PureWest manages some older pads with 50 wells spaced between 8 and 20 feet apart.

"They would have mostly 10-acre development but some as tight as 5-acre development," Franklin said.

Legacy Pinedale wells were completed using antiquated gel fracs and "hardly stimulated at all relative to what a modern slickwater frac looks like today."

EURs from the roughly 3,500 legacy vertical Pinedale wells ranged between 2 Bcf to 3 Bcf.

"What we're doing today with modern slickwater fracs is 20 to 30 acres per well of drainage expectation," she said–much wider than legacy designs.

PureWest pumps 10x more fluid than the 3,500 legacy wells drilled across Sublette County over the past four decades.

EURs from 65 of PureWest's modern Pinedale wells have ranged between 6 Bcf and 10 Bcf.

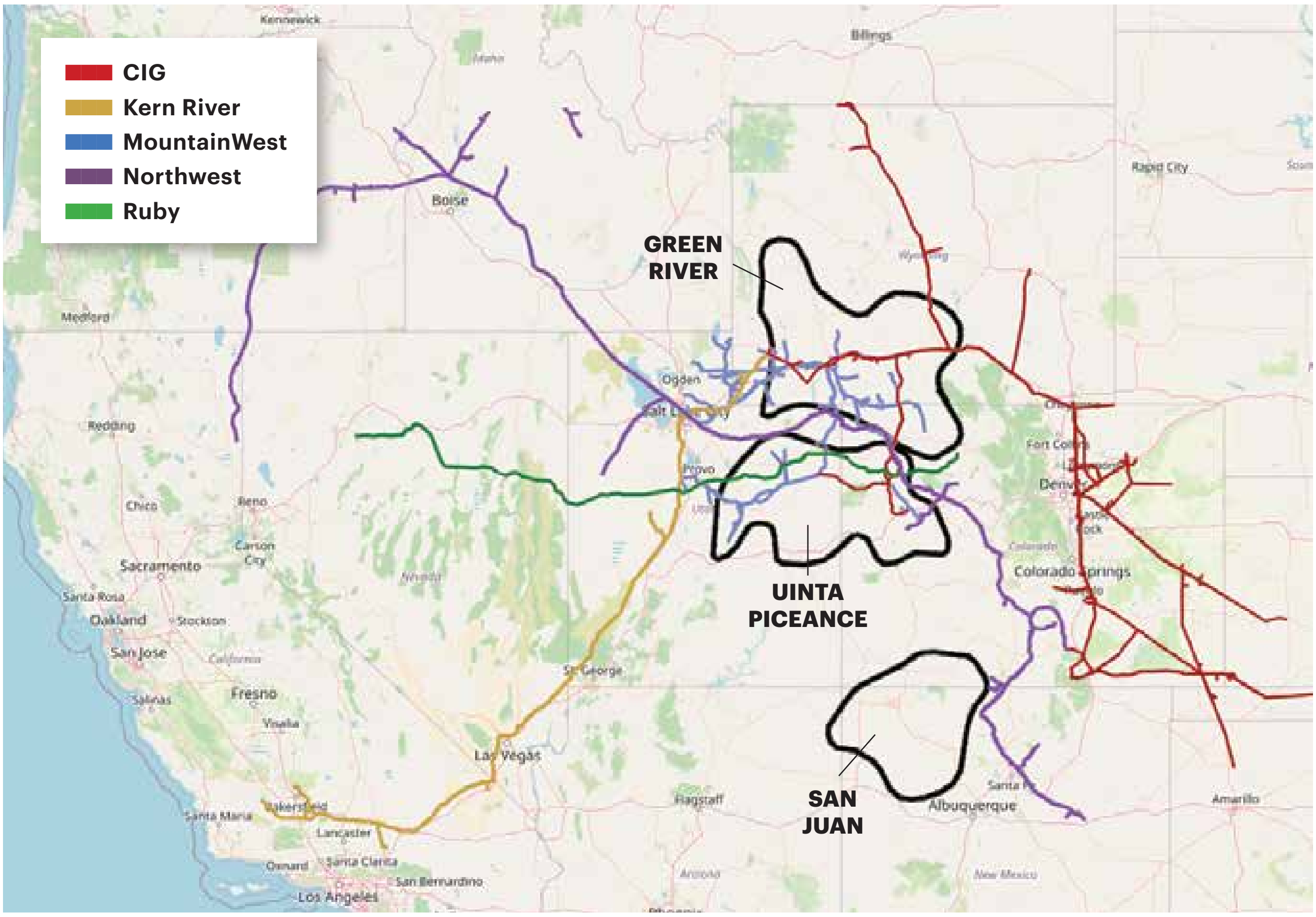
"It's the same wellbore architecture to get there," she said. "Now, we're just doing more with horsepower on completions and it's making this work from an economic standpoint."

Takeaway A-OK

Unlike gas producers east of the I-80 corridor constraint, PureWest enjoys very few takeaway challenges moving its gas to premium West Coast markets.

Production from the Pinedale Anticline is below peak levels seen in the early 2010s, according to Wyoming state

Major Western Natural Gas Pipelines



SOURCE: REXTAG

Major western U.S. gas pipeline systems include CIG, Kern River, MountainWest, Ruby and Northwest Pipeline, according to East Daley Analytics.

data. The Pinedale field and the nearby Jonah field were producing between 2 Bcf/d and 2.5 Bcf/d during those years.

Today, the two prolific fields produce just less than 1 Bcf/d, Franklin said.

So, on a hyperlocal level, PureWest has ample—if not redundant at times—infrastructure for gas gathering, processing and takeaway, she said.

"Generally speaking, (there's) ample takeaway capacity for this entire region. It's highly interconnected," Franklin said. "Gas moves west, but it can also move east. The gas can find a home in any number of directions."

But during periods of inadequate supply, like during winter cold snaps, greater gas volumes flow from the Rockies into the West, according to East Daley Analytics data.

A particularly cold winter from late 2022 to early 2023 saw regional natural gas prices skyrocket across the West.

PUREWEST

A PureWest-operated natural gas pad in the Pinedale field of Sublette County, Wyo.

"It was cold everywhere, but it was especially cold in the West," Franklin said, "and price was going nuts."

Pipeline flows westward from the Rockies averaged about 2.67 Bcf/d during all of 2022—but grew to around 3.37 Bcf/d during the cold snap from November 2022 to January 2023, per East Daley figures.

At that point, gas imports from Canada and the Permian were operating at nearly full transportable capacity.

Permian imports, in fact, were hampered by an August 2021 explosion on the Kinder Morgan El Paso Natural Gas (EPNG) system, one of the main pipelines delivering Permian gas to the West.

Repairs took around 550 MMcf/d to 600 MMcf/d of Permian egress offline until capacity was restored in February 2023, Heming said.

The high commodity prices seen over that extended period reflect the impact of losing half a Bcf/d of supply, and how difficult it was to incentivize additional westward flows to compensate for the EPNG outage, he said.

But it was Rockies gas, with more than 1 Bcf/d of spare transport capacity, that filled the increased demand.

"This is the tipping point," Heming said. "When gas is really needed over in the West and demand is really high, prices have to increase strongly in order to start pulling that gas from the Midcon out across the Rockies and into the West."

KODA RESOURCES

Cyclone Drilling rigs No. 34 and 41 drill the KODA Resources Painter Pad in Uinta County, Utah.

Uinta Gas (Not Waxy Crude)

Much of the attention on Utah's Uinta Basin has concentrated in the waxy crude oil window, which has attracted over $4.5 billion in M&A activity in less than a year.

Instead of doubling down on the Permian Basin, SM Energy entered the Uinta Basin through a $2.6 billion acquisition of XCL Resources; Northern Oil and Gas (NOG) acquired a non-operated minority interest alongside SM.

Building on that momentum, Ovintiv recently sold its Uinta Basin crude assets to private E&P FourPoint Resources for $2 billion.

Much less attention is being paid to the Uinta's natural gas window to the southeast, where Denver-based KODA Resources has grown into the state's largest producer in relatively quiet fashion.

KODA, backed by Quantum Energy Capital commitments, merged with another Quantum-backed Uinta producer, Middle Fork Energy, in the summer of 2020.

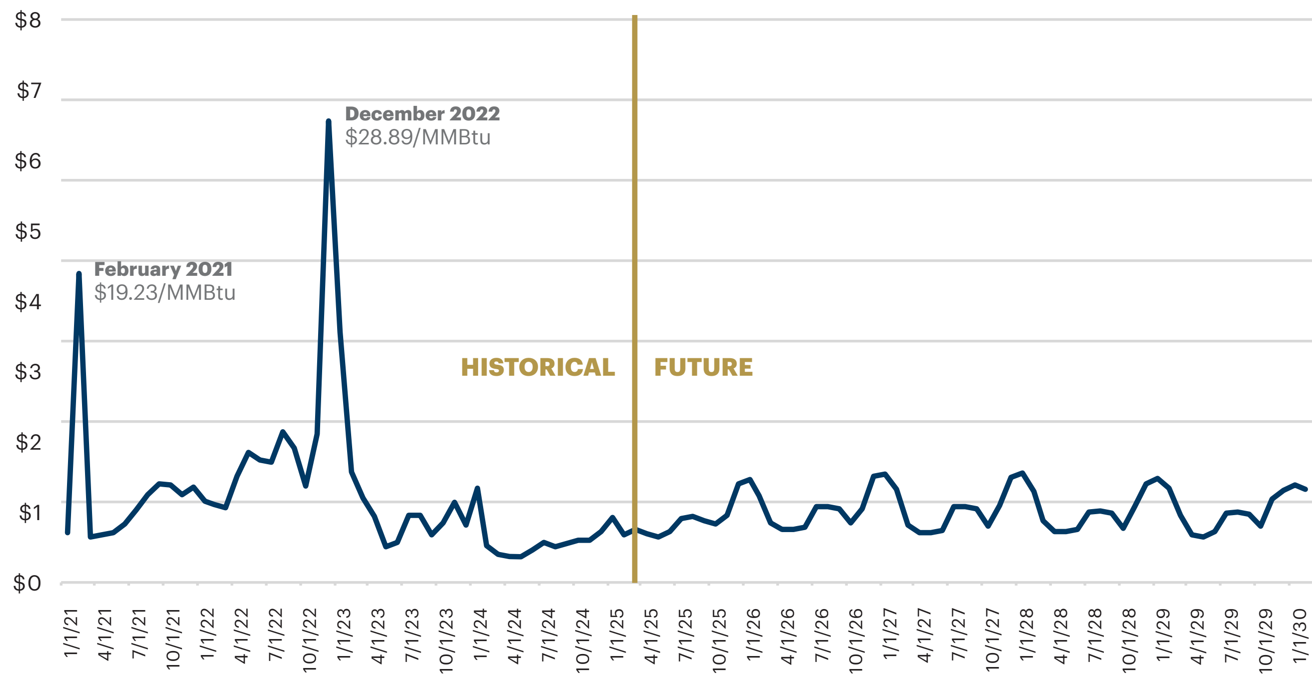
Middle Fork produced approximately 252.66 Bcf of gas from the Uinta Basin–Uintah and Duchesne counties, Utah–from 2020 through 2024, according to a company spokesperson.

Middle Fork produced 85.85 Bcf during 2024, or around 234.5 MMcf/d.

Last year, KODA's Uinta gas empire grew larger through Quantum's $1.8 billion acquisition of Caerus Oil and Gas. Caerus owned Rockies assets in the Uinta Basin and in Colorado's Piceance Basin. KODA received the Uinta assets, while Quantum-backed QB Energy nabbed the Piceance assets.

Caerus Uinta has been Utah's largest gas producer since 2020, churning out approximately 269.26 Bcf through 2024, per Utah state data. Caerus Uinta's 2024 production totaled

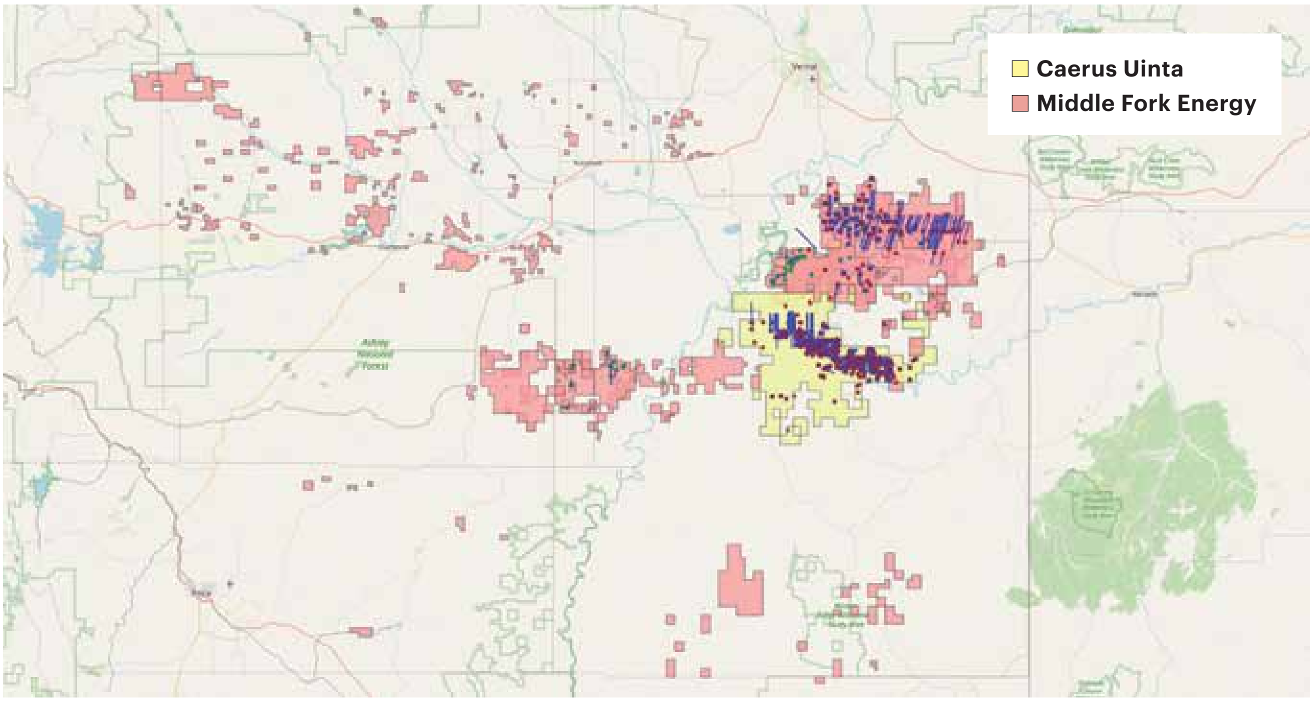
West Coast NatGas Price Spikes



SOURCE: EAST DALEY ANALYTICS

Spot natural gas prices at the Southern California Border (SoCal Border) trading hub was elevated in 2021 and 2022 due to cold weather snaps and an outage on a key gas pipeline from the Permian Basin.

KODA Resources



SOURCE: REXTAG

KODA Resources combined the portfolios of leading Utah gas producers Middle Fork Energy and Caerus Uinta. (Pictured): Horizontal and directional wells operated by Middle Fork and Caerus, per available Rextag data.

51.84 Bcf, or approximately 141.63 MMcf/d.

The Caerus acquisition included approximately 160,000 net Uinta acres and associated gathering and compression midstream assets.

Today, KODA operates most of the natural-gas focused window within Utah. The company also maintains an oily asset in North Dakota's Williston Basin.

With Uinta gas volumes poised to grow, leading midstream companies Williams Cos. and Kinder Morgan are developing a series of projects to manage the increased output.

KODA RESOURCES

Cyclone Drilling rigs No. 34 and 41 drill the KODA Resources Painter Pad in Uinta County, Utah.

And it's not just KODA and its gas-focused peers: The new horizontal wells in the Uinta's waxy crude benches also produce associated gas volumes.

Several Uinta midstream projects are under development or have recently started service, according to East Daley.

Williams' MountainWest Pipeline began service on its 113 MMcf/d Uinta Basin Expansion (UBE) project in third-quarter 2024, adding capacity to Western Midstream's Chipeta processing plant. Williams also closed a binding open season for a second UBE project adding 66 MMcf/d of extra capacity.

In November, Williams opened a non-binding open season for a third expansion that would carry another 250 MMcf/d to the Kern River Pipeline, which flows into southern California.

Kinder Morgan also sees gas volumes growing from the Uinta. Last year, Kinder Morgan signed agreements to move forward with the Altamont Green River Pipeline, a 150 MMcf/d project carrying gas from the Altamont gathering and processing system to the Chipeta plant.

The Altamont system is within the Uinta waxy crude window.

KODA processes gas volumes at both the Chipeta plant and MPLX's nearby Iron Horse processing complex.

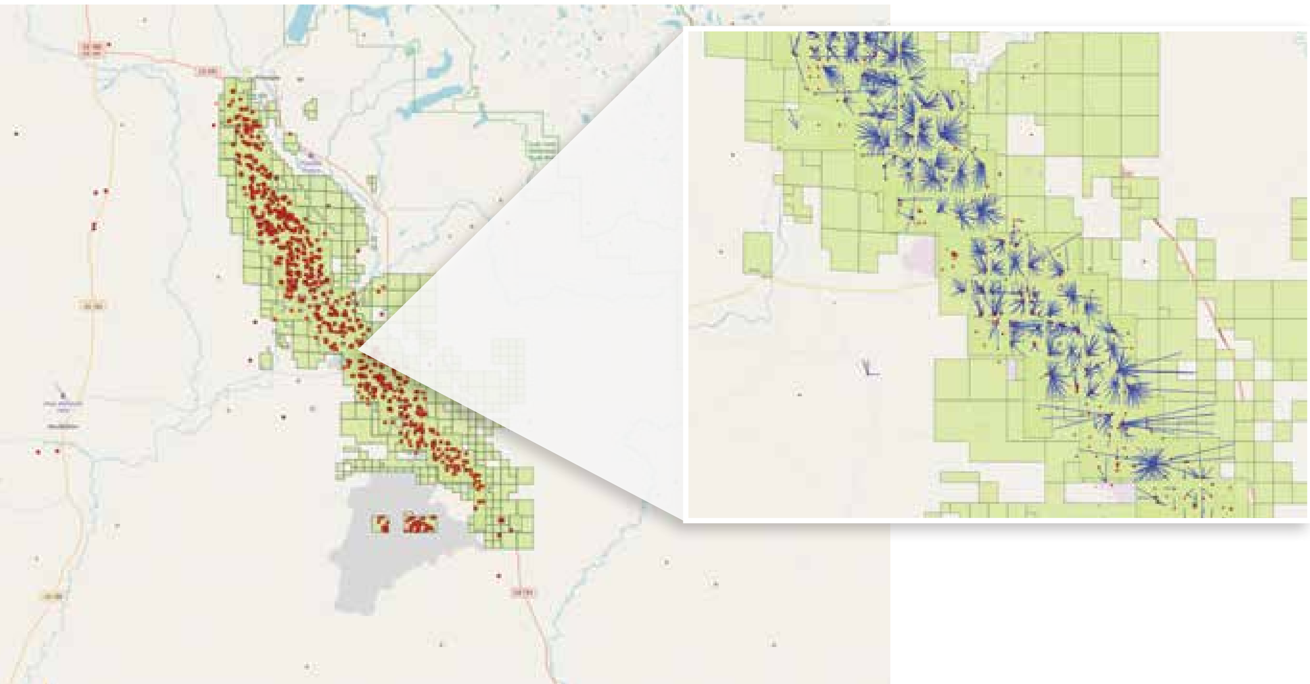
With an enviable position on the western side of the midstream bottleneck, KODA's gas effectively gets priority to flow into the West.

KODA executives declined to be interviewed for this story.

Longer-Term Themes

There are some longer-term themes that could also support increased gas supply from the western Rockies in the future, Franklin said.

PureWest Energy - Pinedale Acreage and Wells



SOURCE: REXTAG

PureWest Energy is a leading Wyoming gas producer. PureWest operates 3,500 wells from the historic Pinedale Anticline formation, part of the Greater Green River Basin. (Pictured): Horizontal and directional wells operated by PureWest Energy.

Planned retirements of existing coal and nuclear power generation assets give tailwinds to western gas demand.

Coal retirements in the West through the end of the decade could require an equivalent 1.2 Bcf/d of gas supply to make up the difference, according to PureWest's analysis.

Renewables will make up some of that difference, Franklin acknowledged. But natural gas will fill some of the gaps, too.

"It's got to come from somewhere as you're taking power supply out of the market," she said.

PUREWEST

Drilling operations for PureWest Energy on the Pinedale Anticline in Sublette County, Wyo.

There are also several new gas-fired power plants and natural gas plant conversions planned across Nevada, Utah, Wyoming and Arizona.

Gas supply to feed LNG feedstocks on the Pacific coast of Mexico also spell upside for western Rockies gas.

Sempra Infrastructure is developing the Energía Costa Azul LNG (ECA LNG) project at the site of a former regasification terminal in Baja California. The project's first phase, currently under construction, includes a single liquefaction train with a nameplate capacity of 3.25 million tons per annum (mtpa).

ECA LNG has signed 20-year sale and purchase agreements (SPAs) with TotalEnergies and Mitsui & Co. Ltd. for the purchase of a combined 2.5 mtpa. The startup of ECA LNG will take additional gas supplies from the western U.S. via exports to Mexico.

AI data centers are another wild card thrown into the mix.

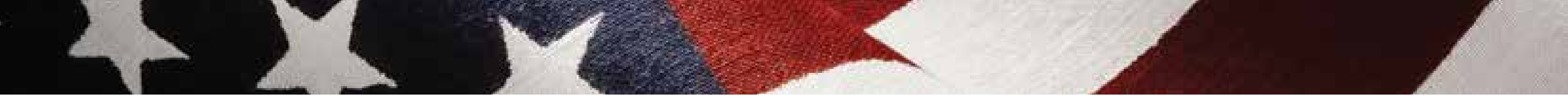
Phoenix is already an established hub for data center development, but experts see Salt Lake City, Utah, and Cheyenne, Wyo., as other emerging hubs for future data center buildouts.

Wyoming already houses eight data centers, Gov. Mark Gordon said in February during the 2025 NAPE conference in Houston. Last year, Facebook and Instagram parent company Meta announced a new $800 million data center project south of Cheyenne.

"It was always interesting to me that Texas was a place that a lot of data centers were going because it's hot, it's humid, it's hard to cool," Gordon said. "Wyoming is not those things, and we rank ninth in natural gas."

He called the opportunity set for Wyoming to attract new data centers could be "a game changer."

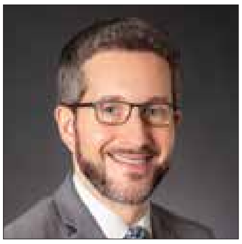
"There's no question that we need to use our resources to be able to power that," he said. OGI



POLICY

The Evolving Federal State of Energy

What happens when the Trump wrecking ball swings into the bureaucratic web of everything that touches oil and gas?



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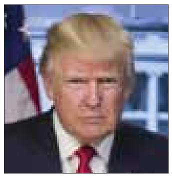
The 2.0 version of the Trump administration has the energy sector exuberant about the White House's immediate declaration of a "national energy emergency" along with an executive order pledge to "unleash American energy."

A more experienced President Donald Trump with a more loyal team surrounding him is wasting little time attacking the nation's federal bureaucracy, but that convoluted web of bureaucracy can work to either streamline or impede the oil and gas industry at various points and under varying leadership.

The domestic oil and gas upstream and midstream sectors are touched by close to 30 federal departments, divisions and councils, as well as at least a dozen congressional committees, not to mention federal and appellate courts.

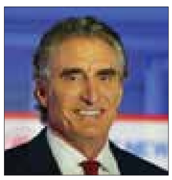
Assigned with untangling the knots are Trump's "dream team"—as dubbed by Harold Hamm, executive chairman of Continental Resources—of Energy Secretary Chris Wright, former CEO of Liberty Energy; Interior Secretary Doug Burgum, former North Dakota governor; and EPA Administrator Lee Zeldin, the former New York congressman. Burgum will oversee Trump's new National Energy Dominance Council.

While the Department of the Interior and the Department of Energy touch the most aspects of oil and gas, there are a bevy of little-known but critical agencies and acronyms to know. Companies operating on federal lands often must work with the Department of Agriculture's U.S. Forest Service, while offshore players deal with the Department of Commerce's National Marine Fisheries Service, among many other agencies.



Donald Trump

Chris Wright



Doug Burgum

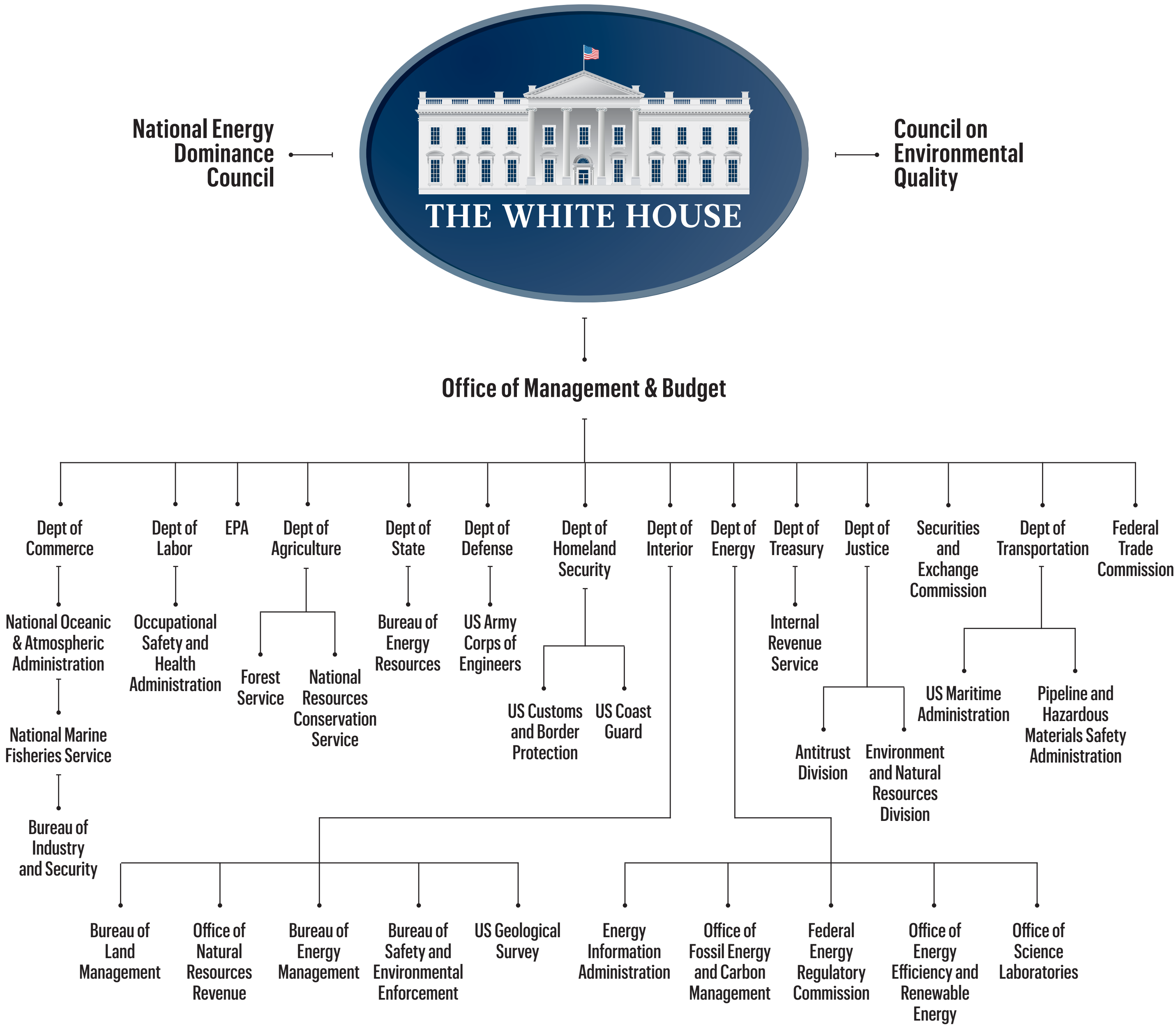
The Interior's Office of Natural Resources Revenue is ONRR, pronounced like "honor," while many, such as the Department of Justice's Environment and Natural Resources Division, or ENRD, lack any fun pronunciations.

Dan Brouillette, Trump's energy secretary from 2019 to 2021, has observed the bureaucratic mishmash from the inside and outside, recently leading Sempra Infrastructure until mid-2023 and then the Edison Electric Institute until late 2024.

"It does get confusing for some industry players, but certainly for the public itself," Brouillette said in an interview with *Oil and Gas Investor*. "We can streamline a lot of processes, in my view."

While bureaucratic nightmare scenarios

All of the Federal Hands in Oil and Gas



SOURCE: OIL AND GAS INVESTOR

certainly can exist, Brouillette does offer praise, in particular, for the energy and interior departments and how they usually balance each other.

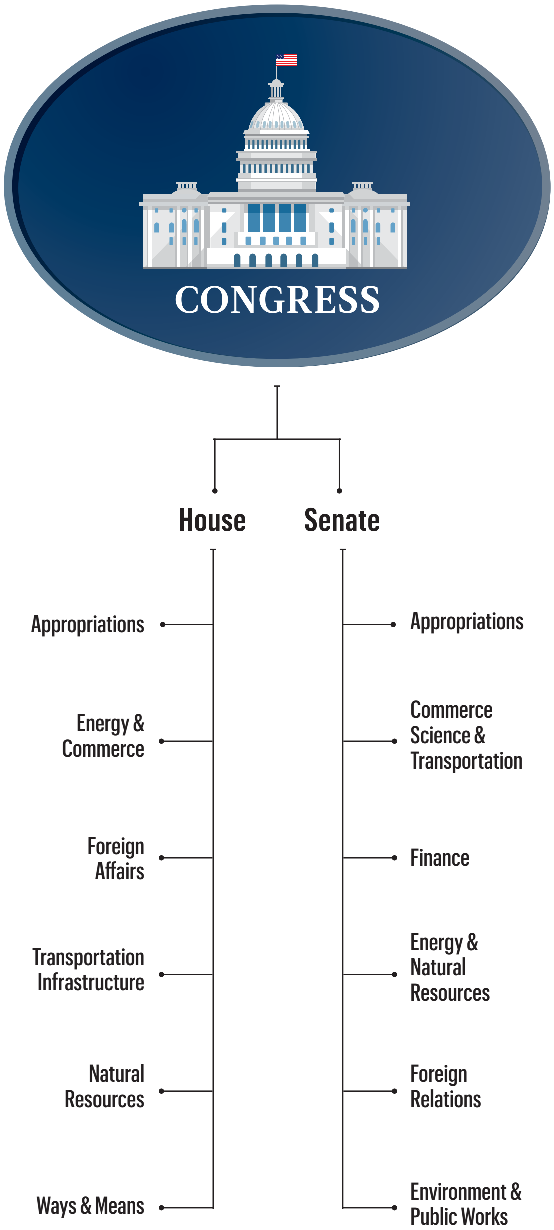
"I think they work fairly well together," Brouillette said. "I mean, I'm sure there are instances when there are disagreements, or you'll have competing interests. But, nonetheless, I think they work well."

What Goes Where and How

Interior's Bureau of Land Management (BLM) and Bureau of Ocean Energy Management (BOEM) handle the onshore and offshore leases, but the Energy Department's scientific research on the shale and deepwater reservoirs plays key roles in the decision-making processes for lease sales, Brouillette said.

The DOE oversees the Office of Fossil Energy and Carbon Management (FECM), the Office of Energy Efficiency and Renewable Energy (EERE) and, most importantly, the Office of Science Laboratories and the 17 national labs, including Los Alamos, Oak Ridge and Sandia.

Early on, Brouillette worked as a pipe welder in his native southern Louisiana, and then he eventually became a congressional staffer, working in the House Energy and Commerce Committee. Under President George W. Bush, Brouillette joined the DOE as assistant secretary for congressional and intergovernmental affairs. In the Trump administration, he became deputy secretary and then secretary after Rick Perry resigned.



The scientists and career staff in DOE, DOI, EPA and the Federal Energy Regulatory Commission (FERC), which is independent but part of DOE, tend to work in cooperation, Brouillette said.

"They have long histories. I think there's a lot of respect amongst the agencies and amongst the senior players in the agencies," he said. "It doesn't mean that they don't disagree from time to time. They absolutely do, but that's what you want in the scientific arena."

While a lot of the staff may work together, the energy companies typically see things differently and more cynically. They often need help navigating the patchwork, said Jack Belcher, principal at Cornerstone Government Affairs.

"The NEPA process is just out of control. In today's world, every agency wants to do an environmental impact statement. You go to FERC, they want to do one; you go to EPA, they want to do one; you go to Interior, they want to do one. In my view, it's redundant, it's bureaucratic and it's expensive. That's one of the reasons why consumers have not enjoyed the benefit of the increased production of oil and gas here in the United States over the last four years."

DAN BROUILLETTE, former U.S. Energy Secretary

"It's like a real web of entities that don't really work well with each other and their priorities are not aligned with yours, usually," Belcher said. "Sometimes you'll need approvals from two or more in order to get whatever it is you need. It gets quite complicated, and things take a long time. It's inherently inefficient.

Jack Belcher

"Federal agencies are set up with jurisdictions. Those jurisdictions are set by the way they were organized by Congress. And Congress has its own fiefdoms, and it likes to control certain things," he continued. "Some of it has to do with turf wars. Over time, they develop their own personalities and quirks and characteristics that you have to understand."

Offshore, companies often must engage with the Department of Defense, the U.S. Coast Guard, the Department of Transportation's U.S. Maritime Administration and the Department of Commerce's National Oceanic and Atmospheric Administration (NOAA).

Onshore, there's also the U.S. Geological Survey, the U.S. Army Corps of Engineers, U.S. Customs and Border Protection, FERC, Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and more.

Everyone has to work with the Department of Labor's Occupational Safety and Health Administration (OSHA) and the EPA's Clean Water Act, Clean Air Act and Endangered Species Act, which has introduced energy companies to the dunes sagebrush lizard, the lesser prairie-chicken, the Rice's whale and many other obscure and endangered species.

A lot of rules, programs and tax credits are going under review under Trump, Belcher said, from the EPA's Methane Emissions Reduction Program (MERP) to credits like 45Q for carbon sequestration and more.

"What's going to happen? We don't know. They're going through this review process. The president doesn't know, and he changes his mind a lot," Belcher said. "We know that. He's not afraid to change his mind. There's an opportunity for industry to provide feedback and make its case. And then there's going to be litigation."

Interpreting Executive Orders and Reforms

Brouillette is most eager to see reforms enacted with National Environmental Policy Act (NEPA) processes to determine if energy projects have significant environmental impacts.

"The NEPA process is just out of control," Brouillette said. "In today's world, every agency wants to do an environmental impact statement. You go to FERC, they want to do one; you go to EPA, they want to do one; you go to Interior, they want to do one. In my view, it's redundant, it's bureaucratic and it's expensive. That's one of the reasons why consumers have not enjoyed the benefit of the increased production of oil and gas here in the United States over the last four years."

He contends the DOE could handle the NEPA reviews for every agency. The nation needs to expedite infrastructure for pipelines, gas-fired power generation, data centers, LNG export hubs and more.

"Pipelines are critical and are sort of the weakest link in the chain right at the moment in the United States. It's not the production elements, but it's actually the infrastructure elements. We know full well how to produce molecules. That's how we've become the largest producer in the world," Brouillette said. "Our challenge today is actually getting the product to market, developing enough pipeline capacity to get the natural gas to the oceans, to get the oil to the markets. That's been our challenge, and that leads back to the permitting challenges that we have here in the United States."

The White House "lost a lot of time" in Trump's first administration learning the ins and outs of government, but now Trump is operating at a "blistering pace," Brouillette said.

"I think there's a world of difference," he said. "The president, when he was elected in 2016, had a wealth of business experience, and he understood very clearly what he was elected to do, but he wasn't quite as comfortable in the governmental space."

Brouillette also sees Trump's declaration of a national energy emergency as "absolutely necessary," especially for encouraging natural gas production and gas-fired power plant construction instead of just wind and solar.

"As we think about the demand coming on with AI data centers, increased industrial loads, we are very dangerously short of electricity generation," he said.

When it comes to Trump, the challenge is often differentiating between what's real and what's rhetoric. The key is interpreting between Trump's "signal versus noise" in his executive orders and language, and where they cross over on everything from energy production to data center construction, said Jamie Webster, non-resident fellow at Columbia University's Center on Global Energy Policy.

"Some of the executive orders look like really clear signals, but many of these are not self-implementing. Some of them are already kind of in the system," Webster said.

An executive order, "Unleashing American Energy," is a clear signal for the industry, but what it will accomplish is less clear. The industry wants high oil and natural gas prices—but not too high—while Trump wants to bring prices down for consumers. And oil and gas producers won't want to produce more in low-price environments.

"The real question is going to be does he ever actually pull the trigger on these [tariffs] in a broad way, or is it used as a cudgel to get other things that would be useful for the administration, which is increased investment?"

JAMIE WEBSTER, non-resident fellow, Columbia University's Center on Global Energy Policy

"I think there's a lot of uncertainty that is out there, and we'll continue to try to figure that out," Webster said. "But, what's pretty clear to me, I think the longer-term trend and focus is going to be on lower prices because that has a lot of positive economic implications for the United States."

What also is clear is the short-lived, Biden-era LNG pause is over, although the timeline for speeding up permitting is murky. And Trump is already pushing for new exploration and production on federal lands and waters, as well as in Alaska, including Alaska LNG in a potential partnership with Japan.

Already, FERC is citing Trump's executive orders to move past judicial hindrances on NextDecade's Rio Grande LNG and Glenfarne Group's Texas LNG projects. So, the orders are clearly not without some teeth.

Even if U.S. production ticks up more slowly under Trump, he can still "declare victory" because volumes still rose, Webster said.

Trump also is moving with orders to ramp up pressure and potentially sanctions on Iran and Venezuela, which ultimately could remove more crude from the markets and increase prices, said Matt Reed, vice president of Foreign Reports. U.S. and Saudi barrels could fill the void.

"Sanctions could mean the difference between a supply surplus or deficit this year," Reed said. "Remember, in his first term, Trump managed to slash Iran and Venezuela's combined exports by over 2 million barrels a day compared to where they stand now."

As such, Trump will lean more on Saudi Arabia and give them the benefit of the doubt, he added.

"There may be disagreements on policy, but the Saudis are going to focus on fundamentals, as usual, and Trump's affinity for them should shield OPEC from any retaliation," Reed said.

Talking Tariffs

The other big uncertainty revolves around Trump's love of threatening and occasionally implementing market-destabilizing tariffs.

He already has set and then delayed major tariffs on Canada and Mexico, while implementing smaller 10% tariffs on China, and then broader ones on foreign aluminum and steel. Trump is more recently focused on planning reciprocal tariffs worldwide, from the European Union to India, which could easily upset global trading networks either in the short term or permanently.

"That is where the tension is," Webster said. Tariffs raise prices, but they also incentivize more manufacturing within the United States.

"The real question is going to be, does he ever actually pull the trigger on these in a broad way, or is it used as a cudgel to get other things that would be useful for the administration, which is increased investment?"

Brouillette acknowledged the constant tariff threats create anxiety and disruption and the last thing that energy project developers want is unnecessary uncertainty.

Yes, tariffs on Canada could raise U.S. fuel prices, he said, but it's not that simple.

"What options do the Canadians have?" Brouillette said. "Well, their primary export market for heavy crude is the United States. It's not easy for them to build another pipeline to get their product to Asia or Europe. They're not likely to do that. What they want to do is to maintain access to the U.S. market. So, what they'll do in that instance is actually to lower prices to maintain access. In that sense, the tariffs are actually born by Canadians, not by Americans."

Webster agreed that Western Canadian Select prices would have to be discounted, but he also sees U.S. pain as inevitable, too, which is why he does not believe Canadian crude will ever fall under tariffs, at least not for long.

"I don't see how this is a long-term strategic option for the United States without significant economic difficulties," Webster said. "So, I don't see that happening on a long-term basis."

And much of this will require some degree of patience to see what actually comes to fruition, Belcher said.

"A lot of this is symbolic. A lot of it is a message, and I think that's very aligned with what Trump likes to do … create a momentum and support," Belcher said. "These executive orders and tariff talks are kind of a first round with more granularity to come."

Maybe the most important longer-term development could be how Trump's new Energy Dominance Council shakes out under Burgum.

"It's a nexus. It's bringing federal agencies together to focus on national energy policy," Belcher said. "That's going to be interesting to see how that group works and if it can work through the rough edges where these departments kind of stick with one another.

"I think it's a really exciting time. There's no doubt about it. You can feel it when you're talking to people. There's a little concern about tariffs, projects, federal money. But, overall, it's the sort of notion that the oil and gas industry is not a bad word anymore. It's a return to government being pro-production." OGI

Lone Star State of Mind

Rockcliff Energy III Executive Chairman Alan Smith and CEO Sheldon Burleson have their Quantum Capital-backed company's Texas-sized ambition focused on the western Haynesville and the Eagle Ford.

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Rockcliff Energy III brings together Alan Smith, a long-time leader in the industry and former CEO of Rockcliff I and II, with former Chesapeake Energy executive Sheldon Burleson. The pair are leading the newly formed E&P with private equity firm Quantum Capital Group, and have their eyes on Texas assets in the Haynesville and Eagle Ford shales. They talked with Deon Daugherty, Oil and Gas Investor *editor-in-chief, about their plans, what they bring to the table and how the emerging political environment under President Donald Trump may impact their company and the industry.*

Q&A

Deon Daugherty: Let's begin with how Rockcliff III came together. Sheldon, you were with Chesapeake for several years. What made this opportunity interesting to you?

Sheldon Burleson: I think there were a couple things. [Alan and I] had worked together in the past on some different boards, and so I've known Alan for a long time, seeing his track record and him being a good mentor and person I could bounce things off through some of those roles.

At Chesapeake, I spent almost 10 years there, running a lot of different business units. But during the last few years I was there, it was really focused on Haynesville and the Eagle Ford. During the tenure in Haynesville, we'd made some acquisitions, our merger with Vine Energy in 2021 and were continuing to look at other operators in the basin. I really saw what Rockcliff was doing and had a lot of interaction with Alan on their development on the Texas side of the basin.

Not only did I know Alan personally, but I also was impressed with what he'd built at Rockcliff, the capability of the team and what they'd done with that asset, taking that position and really growing it into a scaled business. And then, as he said, all those other facets of building a midstream and mineral business. That piqued my interest.

I always had a bit of entrepreneurial bent, even though I'd worked in some large companies. As we divested our Eagle Ford assets, that opened up the opportunity to decide what I wanted to do next. I looked at a few other public opportunities, but the private equity route is the way I'd like to go.

The timing worked out where I started moving down that path and then had some prior interaction with Quantum and had kept in touch with Alan. I felt like this is a great opportunity to come in and work with a successful team and also bring in the background that I had as well in Haynesville and other multiple basins to go look at what's next.

DD: And Alan, what made you interested in changing your role from being the "roll-up-your-sleeves" CEO type to an executive chairman and being more strategic?

Alan Smith: We're always reinventing ourselves a bit and, well, I think it's great to build another business. I've been partnered with Wil VanLoh for a long time at Quantum, and we decided it made a lot of sense for me to move to being executive chairman at Rockcliff and come back to Quantum as a partner–they're a much larger private equity firm now–allowing me to move from, for lack of a better term, being the leader of a business to more of a sage and getting the opportunity to hopefully pour into some other leaders like Sheldon and working closely with some very talented partners over here at Quantum and in the portfolio companies. I think just having done this now for 20 years on the entrepreneurial side of building companies [and] 30 years in leadership, to just

"If there's a runway and it looks like the big LNG projects are getting approved and there's more certainty in those investments, then that creates opportunity for us."

SHELDON BURLESON, CEO, Rockcliff Energy III

"We're inventory builders. We're going to take something that's maybe not quite as valuable in somebody else's portfolio–thus, it's on the market and available–and really put an intense amount of focus and execution on it ... knowing that whatever we build, it needs to be interesting to someone else five years from now."

ALAN SMITH, executive chairman, Rockcliff Energy III

be able to be in a position to utilize the gifts and talents that I've been blessed with. It was just an opportunity to go into more strategic roles and be able to help and mentor other entrepreneurs as they build and run exciting businesses.

DD: That makes a lot of sense. It's growth, it's evolution of your career. So, gentlemen, is it your intent to continue working in the Haynesville? Or, where do you want to deploy your resources? You both have worked in different areas of the business, but Rockcliff I and II were drilling and development focused. What direction do y'all want to take the company?

AS: Well, I'll maybe hit it high level and then let Sheldon comment on some of the specifics since he's right in the middle of it. When we were starting Rockcliff [III] last summer, the gas macro was a little more bleak than we would've liked. You had low gas prices, a lot of things that you would [question whether] you want to stand up a rig pretty quickly in the Haynesville, and we just didn't think that was a great idea right out of the gate. Sheldon has quite a bit of Eagle Ford experience. A mantra we've had literally since we started doing this back in '03 is, we tend to feel like our expertise is Texas and what touches Texas.

So, I think that the Eagle Ford and the Haynesville would still be at the top of our list. The Eagle Ford has multiple fluid windows, which was attractive, and we got off to a pretty good start there. But that basin is also relatively competitive. And then we got into the back half of '24, and as you know, the gas prices began to firm up. Being in the business, we just had a lot of insight into what's coming in LNG. It was delayed and now you're going to get that first 6 Bcf/d wave coming, which I think [drives] a stronger and more stable gas price.

But now we have also the AI movement and the data center movement that is also going to create more demand. All of a sudden, gas has firmed up pretty dramatically. We've begun to explore the Haynesville. That's not to say we would never go outside of Texas, but it would take a very special situation.

SB: That's spot on, as we really looked early on at focusing on, what's the core capabilities of the team? That naturally led to the Eagle Ford and Haynesville because the team has a lot of background there, and in the past, we had done additional work up in the Delaware Basin, as well. The team looked at those three areas and did some refresh of our technical views. We really continued to drill into opportunities and think about where there's opportunity to get something that's scaled, with more consolidation opportunities, so we've focused a bit more on the Haynesville and East Texas areas again recently. We think there's a lot of opportunity there. I think, on both commodities, oil and gas, there's been underinvestment by the industry with just the focus on free cash flow and the capital discipline expectations.

I think there's opportunities in both commodities, but we feel like the tailwinds and the structural look ahead for gas is strong. I think there's a number of places where there's some sizable positions still available. There's also still areas, especially in East Texas, that are just less developed than what you see on even some of the Louisiana core side in the Haynesville. I think there's opportunity to go and acquire an asset and/or go and build up a position and go deploy capital.

As Alan said, we have looked at some broader opportunities, and I think with a number of the team that's worked in different areas, and then my background working six or seven different basins throughout the U.S. in the past, we have the operating capability and then the technical know-how from reservoir and geoscience to go and really evaluate assets.

We have looked at some things that are both outside of Texas and inside Texas, and that's still something we'll work on, but it would need to be a scaled asset and something that we can really go and take our expertise and apply it.

So, there are those opportunities that may look a little different than Rockcliff was in the past, just because we think there's a market there for some large-scaled assets even beyond that of Texas and in the Haynesville area.

DD: Tell us some more about that. Have you bought assets yet or are you still looking?

SB: We're still looking and still working on core assets. Our goal is to capture the right assets. We look at a lot of different opportunities [because] you really want to make sure that it fits the criteria that you need so that when you make that acquisition, you can go add value to it.

You want to have some locations you can go develop into something that is either attractive today or will be attractive in that three- to five-year timeframe. What's a little different today than in the past is, you're probably looking at a little bit longer window for private equity deployment. We want to find something that ... is either very attractive today or we can go apply our skillset and it'll be what's next. It's an asset that's up next in the dispatch curve for the companies. If we look ahead three to five years, what will be the inventory that will be very attractive for us to consume, develop or for others that want to continue to look for opportunities to grow?

And, I think, the last piece that we look for is multiple ways to win. Our goal as a private operator, and I think also our strength, is having that small nimble team that's got deep experience, where we can add value through operational improvement, D&C (drilled and completed) improvements or really look at providing a low-cost structure to go develop assets.

Those are the main components that go into capturing the right asset.

DD: How will Rockcliff III be different from its predecessors?

AS: Well, I would say it won't intentionally be different, but I think that a lot of it'll depend on the complexion of the asset that we can actually secure [and] that we feel like that we can ultimately create a lot of value with.

What Rockcliff did previously was … it had some underlying PDP (proved developed producing) production, but it also had a significant undeveloped component. I would say that is the mandate for where we're looking for, but sometimes there's something that has more development that we think that we can manage that well, but also have more undeveloped upside that we can hopefully bring to fruition.

I think another thing that we've done well historically that we will also pay a lot of attention to and lean into is actually the marketing of the hydrocarbons that we ultimately get access to. I think that the natural gas markets are complex and that can be an issue or that can be a competitive advantage, and we're always looking for competitive advantages. The subsurface team's capabilities—we drilled over 300 wells, we spent $3.5 billion of capex in Rockcliff II—we want to take a lot of that tuition that we've paid historically and try to turn that into competitive advantages.

SB: I think the market is a little different today than what it was maybe five or seven years ago when Rockcliff II was formed and operating.

There'll be opportunities that have a lot more existing production. There was a time in the early days of the shale revolution that it was more likely to find some land and then you can quickly turn those over. And it may have been smaller pieces or very short exits. Now that the basins are more developed, I think it's going to be a combination of something that has a lot more existing production and still has that runway to develop for the future.

That's one of the areas I think the Rockcliff team has a capability [to do well]. That's something from my past, working large assets with lots of wells, and a key part of that was doing production optimization, workovers, even looking at other opportunities for refracs, et cetera. Those are all things that I think can add a lot of value as well.

AS: One of the things we've always said is, you have to begin with the end in mind. We're inventory builders. We're going to take something that's maybe not quite as valuable in somebody else's portfolio—thus, it's on the market and available—and really put an intense amount of focus and execution on it … knowing that whatever we build, it needs to be interesting to someone else five years from now. We have to put all that into our calculator, so to speak, as we're searching out the opportunity.

But generally speaking, the market will ultimately dictate what we can actually wrestle to the ground. And the good news is, this team has done both the exploitation and the significant development strategies. We've just got to be patient and find the right opportunity.

DD: With all of the consolidation that happened in the upstream space during the last couple of years, it seems like there should be a lot of opportunities for A&D. Is that what you're finding, that there's a lot more to choose from now?

SB: I think with all that consolidation, the thought process is that, as these companies consolidate and build big positions, there'll be things that are further out in their inventory plans, further out in their skyline charts, and so they just may not get to it for a while.

I do think that will create opportunities, and you're starting to see some of that now. It probably took a little bit longer for some of that flywheel to get going—that maybe took a quarter or two longer than what a lot of people thought. We're starting to see that momentum build now and you're seeing deals start to transact that are coming out of the larger companies or that are product of these consolidations. It's happening at a little bit faster pace the last month or two, and we're seeing that's starting to ramp up this year.

I think the other component of it is, with some of the changes in policies, and you think about some of the changes within the political arena, people have confidence that deals will likely go through. There's more positive sentiment around getting LNG capacity approved.

If there's a runway where it looks like the big LNG projects are getting approved and there's more certainty in those investments, then that creates opportunity for us as we like to go buy assets and start to develop the supply, especially on the gas side.

AS: One of the things we've noticed that is a bit unique with where we've been recently, compared to where we've been historically, is the amount of leverage that all the public companies have is significantly lower than it has been historically, where a lot of these larger companies, even after a merger … didn't necessarily have a lot of debt.

You're seeing 1x EBITDA to ~1x EBITDA, even after a merger in some of these situations. And while, as Sheldon described, there will be some asset rationalization, I don't think there's going to be as much as you once thought. And I think companies are beginning to understand that inventory is valuable. It's going to cause us to be a little bit more creative also because there's going to be some things they're going to hold onto in their portfolio.

We have to not only look for acquisitions, but I think we also have to be thoughtful about different structures like joint ventures and farm-outs and things like that.

DD: Do you have a preference for oil or gas or are you resource agnostic?

AS: I think, in a perfect world, having some exposure to both would be optimal. We talk a lot about the margins around oil versus the margins around gas, which is why, generally speaking on a production basis, oil is more valuable currently just because the margins are generally higher, but that causes natural gas assets to price accordingly.

I'd say generally we're agnostic. Our job is to make a great return for our team and our investors. That's really what drives what we do. But I think it's fair to say also that—and you can't ever predict that this will continue to be a constant—natural gas has just had more volatility. That's why we've always been big hedgers. When we make a significant acquisition, we hedge out the production several years and then we'll even hedge out of the gate into the drilling program to some extent. That's how we manage that volatility. But it's not lost on us that the natural gas strategy does create some risk while, at the same time, it creates some opportunity.

Rockcliff III's Alan Smith and Sheldon Burleson are confident of the natural gas outlook in Texas plays.

SHUTTERSTOCK

DD: What might be the impacts of the Trump administration on the energy industry with policy changes, such as permitting and tariffs?

AS: I might take the federal side and then let Sheldon—he is the new chairman of the board of the Texas Oil and Gas Association—share his views on Texas.

From a federal perspective, things are changing rapidly. The LNG [pause] was lifted almost immediately. I think that the carbon tax, that was on its way to being fully implemented, will be repealed or certainly pulled back. I think access will be a focus of the Trump administration. And so, from a federal perspective, with the two gentlemen that are running Interior and the Department of Energy, I think that is going to be a more positive environment for traditional energy and a good environment for all the additions that we need to make the world and the economy run properly.

The places we're looking, generally speaking, don't require a lot of [input from the U.S. Bureau of Land Management] to make it work. We always want to be great stewards of the assets that we buy and that we operate, and so ESG is part of our culture. We created a lot of value at Rockcliff II around biofuel fleets and piping our salt water and managing all our emissions reporting, including trust well certifications. I don't think any of that's going to change just because the administration changed, but a lot of this still resides with the states.

SB: As Alan said, the states are a key part of it. I think one of the reasons you've seen such strength in the U.S. energy industry is because Texas, the southern states and [other states] have been friendly to energy development.

As you get more support on the ability to go and capture carbon and then be able to have the wells and the infrastructure to go do that, I think that's a great opportunity for the industry and the industry has the technical expertise.

[There is] a lot of talk about tariffs and what impact that could have. One that's recently come out is around steel tariffs. There are some potential impacts there on our business, but when you think about how much of a well cost is tubular goods steel, generally 5-7% is a typical percentage for that for those wells.

Even if there is a tariff that increases the price of steel, it may have a 1% or 2% impact on the total well cost. It's a bit of a cost, but I think it's something that can be factored in and we can plan for.

I think the other part of that is just ensuring that you've got the supply chain that doesn't cause disruptions there. We plan out our business, and the industry does a good job of planning ahead so you can manage the supply chain. I think the overall impact from having a more friendly environment and more certainty around the permitting and overall development is a net positive with what we're seeing with the administration's look at energy.

AS: The only other thing I would say is the president is often quoted as saying, "drill, baby, drill." I think the discipline that you've seen in the upstream space is not changing anytime soon. That has been a big focus back to return on capital employed, free cash flow generation, share buybacks, returning cash through dividends and yield to investors. That's what [E&Ps] are being rewarded for. So, I just don't think that is going to change.

While they have lots of different reasons for why you might put a tariff on Mexico, it might be different than why you put a tariff on Canada. But some of those—depending on how those who are being "taxed," for lack of a better word—respond, that could result in a supply hit that could ultimately have the opposite effect of [what] I think Trump would really like, [which is] to see energy prices go down. You could have the opposite effect with these tariffs.

One of the biggest expenses on an oil and gas well is tubular [steel]. If those tariffs are coming on and then your steel automatically increases their price book, that means that our cost structure can go up as a result of that, which means that we need higher prices to make our returns.

I think it's going to take a better part of this year for all that to sort of settle out because it's been fast and furious out of the gate, which in a lot of ways we're really pleased to see.… Anytime you have uncertainty, that can cause people to take a bit of a pause until they feel like they have more certainty around how their investment is going to be treated and what the ramifications to their investment are. So, while there's a lot of positive developments going on, I wouldn't expect to see the capital being spent here in the U.S. to go up dramatically. OGI

Trade War! Or Maybe Not

An energy industry that prefers stability attempts to adjust to the Great Disruptor taking over the White House.

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President Donald Trump began his second term by giving prize after prize to the energy industry:

- Industry executives and friendly faces in cabinet and staff positions.
- Executive orders re-opening areas to exploit and LNG development.

But Trump followed up his opening salvo by engaging in one of his other loves–tariffs.

Citing illegal immigration and fentanyl traffic, Trump had pledged to implement a 25% across-the-board tariffs on Canada and Mexico as soon as he took office on Jan. 20. The plan was delayed, almost implemented a week later, and then delayed until March after both countries made temporary concessions.

Meanwhile, Trump implemented a 10% tariff on all Chinese imports on Feb. 4. China retaliated, putting a duty on U.S. LNG, among other products. Six days later, Trump raised tariffs on aluminum and steel on everyone.

"That's all countries, no matter where it comes from, all countries," Trump said while signing the measures scheduled to take effect on March 4. Now, Trump is considering potential reciprocal tariffs globally.

Whatever their opinion of the president's moves, businesses in the energy sector are in for a bumpy ride.

In U.S. history, the government has generally limited the use of tariffs for economic reasons, to protect an American industry or to punish another country for not playing fair.

The current president sees tariffs as one of his favorite all-purpose tools, meaning an industry heavily focused on international trade is likely to see the issue coming up over and over for the next four years.

Takes on Tariffs

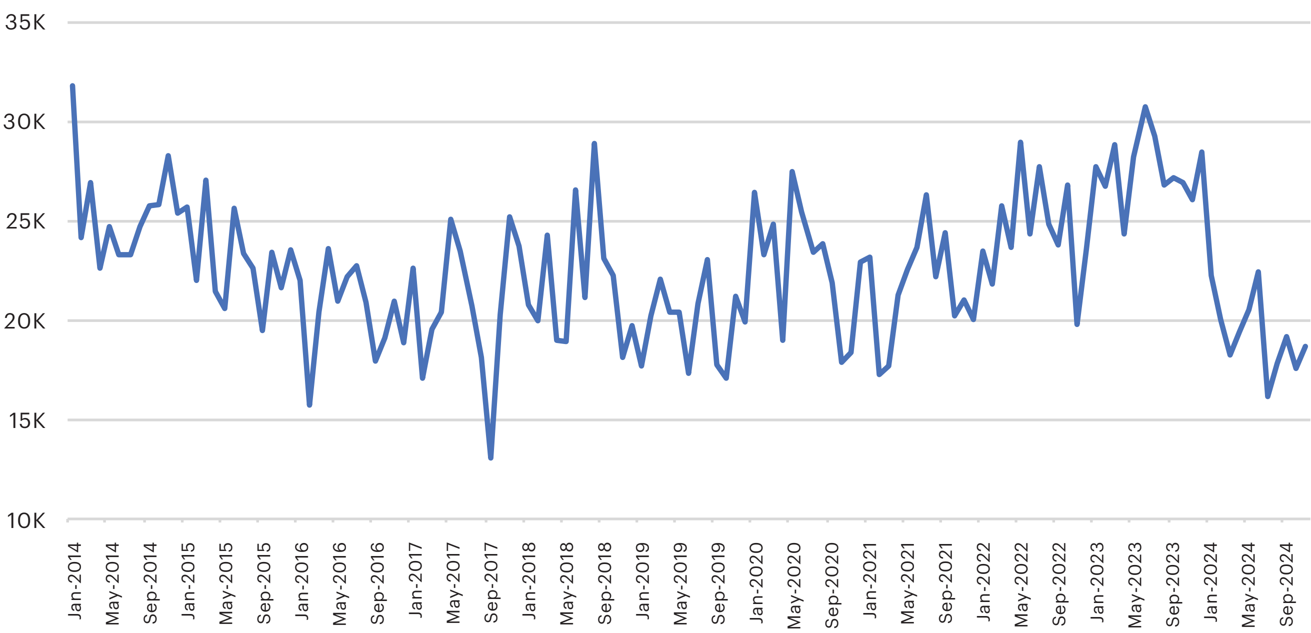
Overall, free trade has been beneficial to the U.S. petrochemical industry, said Anne Bradbury, president and CEO of the American Exploration and Production Council. Bradbury spoke on a panel at NAPE in February.

"We've only been exporting since 2016, and now we are one of the biggest oil exporters; we're the biggest exporter of LNG," she said. "Our products are global commodities."

With Trump in office, the administration's focus will most likely shift away from maintaining or expanding free-trade

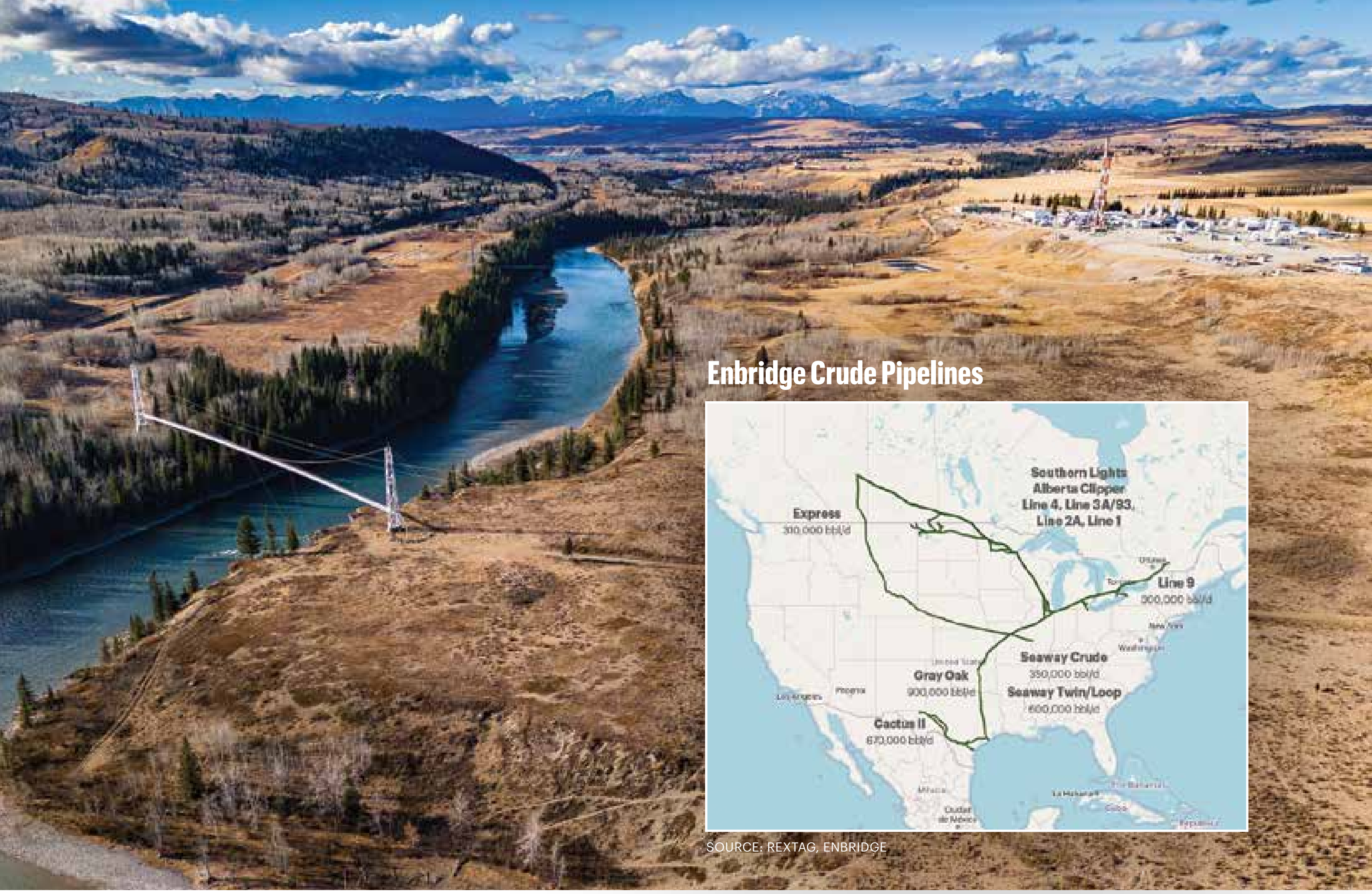
U.S. Crude Imports from Mexico

crude oil and petroleum products, thousands bbl, monthly



SOURCE: ENERGY INFORMATION ADMINISTRATION

Enbridge Crude Pipelines



SOURCE: REXTAG, ENBRIDGE

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Natural gas pipeline crossing over a river near Cochrane Alberta, Canada. The U.S. imported 253.9 Bcf of natural gas via pipeline from Canada in October of 2024 and, in 2023, imported 2.052 Bcf from LNG shipments.

"We have a president who thinks of tariffs as a strategic tool when it comes to international diplomacy, who both threatens to use the tool and uses the tool—both in a targeted manner and in a much more widely applied manner. I think that is something that we are going to see for the next four years."

ANNE BRADBURY, CEO, American Exploration and Production Council

agreements, due to the president's preferred negotiating tactics.

"We have a president who thinks of tariffs as a strategic tool when it comes to international diplomacy, who both threatens to use the tool and uses the tool—both in a targeted manner and in a much more widely applied manner," Bradbury said. "I think that is something that we are going to see for the next four years."

As a negotiator, Trump is loath to refuse any leverage available to him, such as when he set off mini-tempests by refusing to rule out the use of force to reclaim the Panama Canal or buy Greenland. But beyond its usefulness as a diplomatic weapon, the president has claimed that tariffs are simply a positive for an economy.

"To me the most beautiful word in the dictionary is 'tariff,'" Trump said during the campaign.

In interviews since his election, the president has said that tariffs have worked well in the past and, if implemented, would bring in enough foreign revenue to allow the federal government to cut taxes. Tariffs have been one of the issues that Trump has remained steadfast upon since becoming a public figure.

"If you look at President Trump's views on tariffs all the way back, he was talking about tariffs and immigration in the 1980s," said Dan Naatz, COO and executive vice president of the Independent Petroleum Association of America.

"People often ask me, 'What are his core beliefs?' Those are the two. Other things have evolved, other things have changed."

Though, as on other issues, the president has given

Oil tankers are moored at an oil storage terminal in Taicang Port, China. On Feb. 4, in an immediate response to tariffs levied by the Trump administration, the Chinese government placed a 15% tariff on U.S. LNG and coal, plus a 10% tariff on crude.

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conflicting opinions on different days and often in the same press conference.

"Oil is going to have nothing to do with it as far as I'm concerned," Trump said in late January about the potential tariffs on Canada and Mexico. When asked about oil later at the same press conference, the president said his administration "may or may not" place tariffs on oil.

Three Targets

While the negotiating parameters shift, the energy industry is focused on real, large numbers, especially with Canada, Mexico and China.

In 2023, the last full year of data, Canada exported 3.9 MMbbl/d of crude to the U.S.–more than half of all U.S. crude imports–while Mexico exported 733,000 bbl/d, according to the U.S. Energy Information Administration.

Canada and Mexico are the only countries to ship natural gas into the U.S. via pipeline, with Canada making up the lion's share of contributions. The U.S. imported 253.9 Bcf from Canada in October 2024, the last month Energy Information Administration (EIA) statistics are available. Mexico shipped 21 MMcf.

In 2023, Canada supplied the U.S. with 2.052 Bcf from LNG shipments, second only to Trinidad and Tobago, which supplied 11.929 Bcf of natural gas from LNG. (The U.S. leads the world in LNG production but is unable to supply U.S. customers as it has no domestic LNG tanker fleet.)

In early February, both countries threatened to retaliate if the across-the-board 25% tariff was put in place. Canada announced a $155 billion package of tariffs on its own. Mexico vowed to fight the new rule but was not specific.

The two governments did the same when Trump raised the steel and aluminum tariff. Mexico, along with Brazil, delayed its response after the new rate was implemented.

Canadian Prime Minister Justin Trudeaur blasted the move as "entirely unjustified" and said the country would respond swiftly.

Companies in all three countries braced for the impact.

The U.S. would likely "win" a trade war with Canada and Mexico because it has more resources and options available, according to an analysis by RBN Energy.

Mexico has long planned to send more of its oil to its new Bocas refinery and also has more ports available to export its products than Canada.

Canada, with most of its infrastructure built in tandem with the U.S., has fewer options overall.

The majority of imported Canadian crude flows into Midwest refineries, which specialize in handling the heavier, sour and generally cheaper blends that come out of Alberta.

The U.S. would be able to handle a drop in Canadian supply if the Midwest can rapidly replace its usual load of Canadian crude with oil piped in from other regions of the U.S.–without paying a premium.

Regardless, tariffs would be a challenge for most major players in the energy business, as they own assets in both the U.S. and Canada. Exxon Mobil owns three refineries, among other downstream assets in Canada.

Canada-based Enbridge specializes in shipping Canadian crude to the U.S. and owns one of the largest pipeline networks in North America, moving 3 MMbbl/d of crude south on its Mainline System. Enbridge would not pay the tariff because the fees would go toward its shippers. However, the company could potentially feel an impact if producers find other routes for their product.

Enbridge could also feel the results of tariffs at the downstream end of its system. The company owns the Ingleside Energy Center in South Texas, which handles about 25% of U.S. crude exports moving through the Corpus Christi port.

Trump said during an interview with Fox News that Canada and Mexico had not done enough on illegal immigration and drug trafficking to stop him from implementing the across-the-board tariffs he had threatened earlier in the month.

A section of Calgary, Canada-based TC Energy's Sur de Texas – Tuxpan Pipeline, which delivers U.S. natural gas to Mexico. It is not yet clear how Mexico would respond to tariffs imposed by the U.S.

ALLSEAS

Asia's Share

China, involved in trade disputes with Trump going back to his first administration, made no deals after the president's latest moves.

Instead, China immediately moved to implement a response. On Feb. 4, the government made the U.S. energy sector a primary target, putting a 15% tariff on U.S. LNG and coal, plus a 10% tariff on crude.

The government also said it would open an investigation into Google.

"The U.S.'s unilateral tariff increase seriously violates the rules of the World Trade Organization," China's State Council Tariff Commission said in a statement. "It is not only unhelpful in solving its own problems, but also damages normal economic and trade cooperation between China and the U.S."

One analyst said China's response to the tariffs was strategic, aiming to limit damage on both sides while still responding to the president.

According to the EIA, the U.S. exported more than 362 MMbbl of crude to China in 2023, the last full year for which numbers are available. In 2024, however, monthly exports had fallen, never surpassing 30 MMbbl in a 30-day period. In 2023, U.S. exports to China surpassed 30 MMbbl/month four times.

China nevertheless remained the second-largest customer for U.S. crude exports, behind only Mexico.

The Asian giant may be sending a warning with LNG. The U.S. leads the world in LNG exports and currently does not export much to China. In 2023, the U.S. exported 173 Bcf of LNG to China, about 2.3% of its total natural gas exports, according to the EIA.

However, continued forecasts for growing demand in China drive much of the reasoning behind growing investment in U.S. liquefaction facilities. ING predicted in a study that global demand for LNG would increase by as much as 35% by the end of the decade, with Asia dominating the growth.

"China can make all the difference between the global LNG market being tight or more manageable," the study said. China has planned extensively for LNG import growth and currently has 190 Bcm of regasification capacity expected to come online by 2026.

Turbo-Mixed Messages

While blasting out global trade threats, Trump displayed his enigmatic nature in February with another Asian country, Japan.

At a joint press conference with visiting Prime Minister Shigeru Ishiba, the president announced that the U.S. and Japan planned to enter a joint venture to develop an LNG project in Alaska.

"We're talking about the pipeline in Alaska, which is the closest point of major oil and gas to Japan, by far," Trump said.

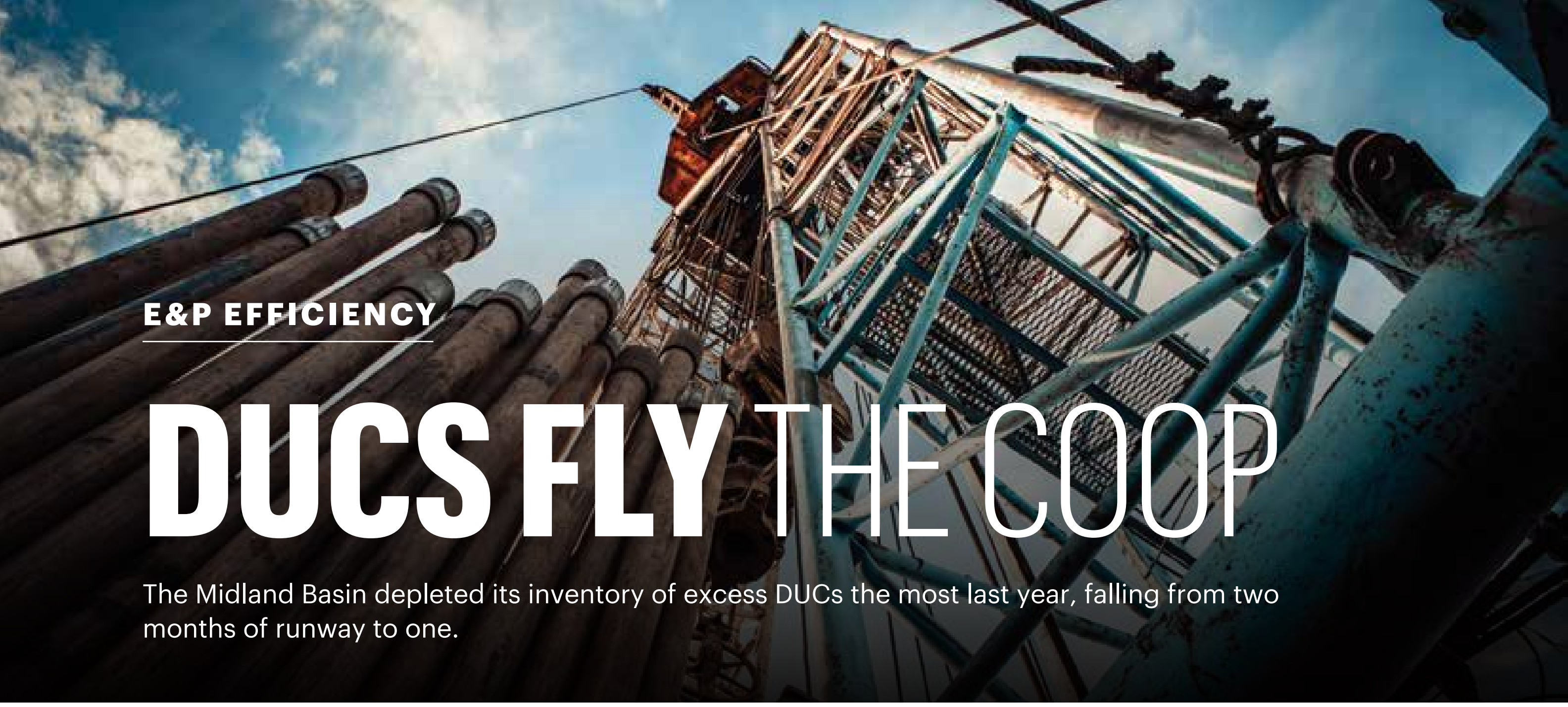
The Alaska Gasoline Development Corporation, which is developing the project, celebrated the announcement, saying in a press release that it welcomed further support and engagement from Japan.

The Japanese were less committed. Ishiba said Japan was interested in more U.S. LNG, along with bioethanol and ammonia. The Japanese Embassy did not respond to requests for comment after the press conference.

Trump the negotiator doesn't mind remaining an unknown factor, and often ends up contradicting himself or switching tactics on a dime. Over the course of February, the White House's stance on tariffs changed so quickly that several news websites established pages that promised hourly updates.

The president has, however, remained consistent in his belief that tariffs can work as an overall economic good, even if the immediate results aren't what his constituents expected.

"WILL THERE BE SOME PAIN? YES, MAYBE (AND MAYBE NOT!)," Trump said in a social media post. "BUT WE WILL MAKE AMERICA GREAT AGAIN, AND IT WILL ALL BE WORTH THE PRICE THAT MUST BE PAID." OGJ



E&P EFFICIENCY

DUCS FLY THE COOP

The Midland Basin depleted its inventory of excess DUCs the most last year, falling from two months of runway to one.

SHUTTERSTOCK

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Some operators are entered 2025 with substantially lower DUCs than last year, creating potential effects on E&Ps' capital efficiency and production, according to a report by Enverus Intelligence Research. Nearly every shale play has seen DUCs fall, in some cases by the hundreds.

Mark Chapman, principal analyst and the report's co-author, said DUCs in the past year fell faster than the decrease in drilling rigs, which indicates the backlog of wells ready for completions has declined.

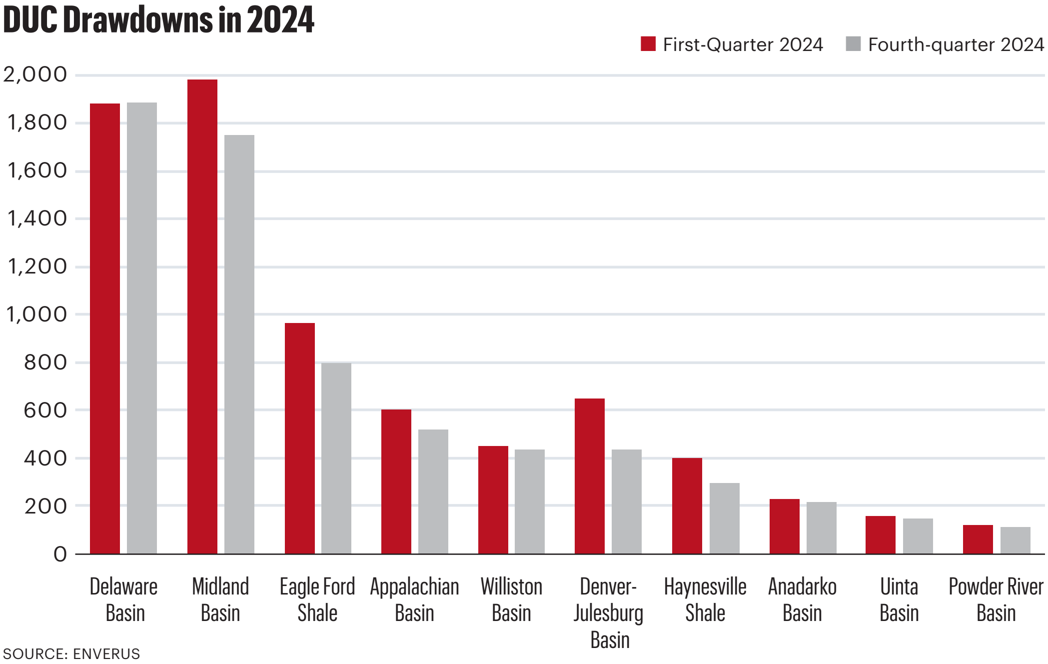
The Midland Basin saw the largest depletion of excess DUCs, with ready to complete inventory falling from two months to one. The Midland saw a drawdown of 233 rigs from the second quarter (2,022) to the fourth quarter (1,743). During the same period, the Denver-Julesburg Basin also saw 186 DUCs completed—a drop from 616 DUCs to 437.

Chapman told *Oil and Gas Investor* that to keep completion activity where it is, more wells will have to be added in the basin.

"I think that we're already starting now to see a response in the rig count in the Midland where it's up 10 rigs so far this year and, actually, it seems like it's at the expense of the Delaware," he said. "So, the Delaware is declining some while the Midland's growing."

A challenge with oilier basins is that the price outlook has been fairly stable and not attractive enough for companies to grow production but not low enough to jeopardize the profitability of Tier 1 areas.

DUC Drawdowns in 2024



SOURCE: ENVERUS

On a corporate basis—not basin specific—operators are maintaining several months of DUC inventories, but most also rapidly complete wells. Exxon Mobil has three to four months' worth of DUCs—the amount of time they could complete wells without additional drilling. Exxon averages roughly 80 completions per month.

BP has a little more than five months of inventory. Midland pureplay Diamondback Energy has five months of inventory and completes about 50 wells per month.

EOG Resources completes "just north of 60, Oxy just north of 60, as well, and Conoco is just north of 60. And then Exxon's the one that's up close to 80, but those are the five that are in the tier of their own," Chapman said.

Among private operators, Chapman said Fasken Oil and Ranch has "a fairly good inventory of DUCs."

The Permian should see a small amount of production growth this year, although "not really large growth like we had in '23 or even last year," Chapman said.

And companies' drilling efficiencies mean the number of rigs running now—about 100 fewer than in 2023—are still able to drill about the same amount of lateral footage, he said, adding that along with fewer rigs there are between 17 and 20 fewer frac crews.

Gassy basins also saw large dips in DUC inventory despite low 2024 commodity prices. The Haynesville Shale saw a drop of 105 DUCs from first-quarter 2024 to the fourth quarter; the Appalachian Basin's drawdown was 83, according to Enverus data. Both have fewer DUCs now than during the low point of inventory post-COVID.

Chapman said one impetus for the report was to examine inventory in anticipation that gas demand will increase this year—largely because of LNG, as well as the cold winter.

"Will the operators be able to respond quickly if gas prices increase during this wintertime in order to meet that demand? Or is that something that they just won't have the capacity to respond quick enough? And any gas growth, will that have to wait until summer or a season when demand is lower if LNG pushes?"

A few gas producers bucked the industry trend and managed to increase their DUC inventory by more than one month since last year.

Expand Energy has highlighted in its earnings that it has a healthy backlog of DUCs, which from a capital perspective should lead to improved efficiency this year.

"They drilled and completed a number of wells in the Haynesville and a few in Appalachia and just deferred production," Chapman said. "That is all sunk cost in '24. It's going to have very little cost to bring it online and produce it in '25. So, that should improve Expand's capital efficiency in '25."

Likewise, Range Resources added DUC inventory in 2024 and should be able to capitalize on it this year.

Chapman said he was surprised how many deferred completions remain in the Haynesville, particularly with Expand.

"That's not a common thing you do, is sink all the cash in to drill and frac the well without producing it," he said. "They should benefit from [that] as prices have increased for gas so far this winter."

Other operators have significantly reduced their DUC counts.

"EQT is one of them in Appalachia that's going to have to increase drilling if they want to respond just because their DUC count's fairly low," Chapman said.

However, because of efficiencies, on a per-foot basins the overall cost to drill and frac laterals is actually going to go down, he said.

"We still think there's pressure on pressure pumping and in drilling," he said. "That's going to drive prices down a little bit further throughout the year."

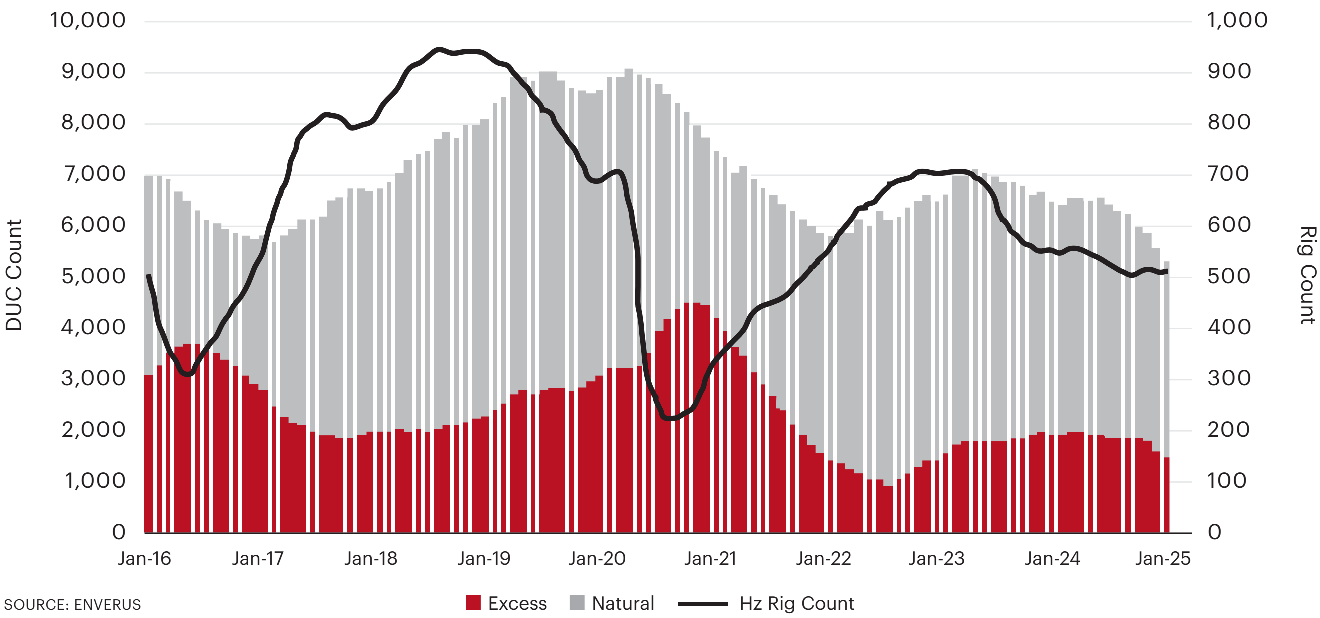
In-demand super-spec and e-fleet rigs will see more stable prices than diesel rigs, but "at the same time, we still anticipate a 5% improvement on efficiencies for those overall."

"But when you talk about a whole well, we do think that laterals are getting longer. A larger percentage of laterals are 3-mile laterals versus 2 miles," Chapman said.

Total well costs are going to be more dependent on how long operators drill.

For rig rates and pressure pumpers, price and efficiency gains could result in "somewhere like 5%, 8% cheaper per foot for them to drill these." OGI

DUC Inventory Levels in the U.S.



SOURCE: ENVERUS

EXPAND CFO: LNG, NOT AI, WILL DRIVE DEMAND

Exports will account for at least 75% of growth, while data centers' needs will be more muted, he says.

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Producers are gassed up about growing natural gas demand to fuel data centers, with Appalachia, the Permian Basin and the Haynesville fighting for a piece of the AI pie.

But it's LNG, not AI, that underpins Expand Energy's outlook for natural gas demand growth.

"Just to be clear, in our view at least 75% of the natural gas demand growth is going to come from LNG," Expand Energy CFO Mohit Singh said at the 2025 NAPE Summit in Houston.

Around 5.6 Bcf/d of incremental gas demand is coming online within the next 12 months to fuel three new LNG projects on the Gulf Coast.

Venture Global's Plaquemines plant is currently pulling around 1.3 Bcf/d after coming online in late 2024. The Plaquemines project on the Mississippi River south of New Orleans has Federal Energy Regulatory Commission (FERC) approval to export 3.3 Bcf/d.

Cheniere Energy's expansion at Corpus Christi, Texas, began liquefaction in December. Full capacity from the seven-train expansion will be 1.3 Bcf/d, bringing the plant's total output to more than 3.3 Bcf/d.

Exxon Mobil's long-awaited Golden Pass LNG plant is also expected to come online within the next 12 months. Golden Pass LNG has FERC approval for 2.6 Bcf/d.

LNG projects represent "durable demand" within Expand Energy's massive gas portfolio, Singh said. Chesapeake Energy and Southwestern Energy merged last year to form Expand, the nation's largest pure-play gas producer.

"When LNG is taking that gas off the grid, that's doing it every day, every week, every month, every year," he said. "That's durable through cycles, over decades."

Looking at LNG plants that have reached final investment decisions (FID) and pre-FID projects, it's "easy" to estimate that U.S. production will rise to 120 Bcf/d to 130 Bcf/d, Singh said.

U.S. total dry natural gas production averaged 103.1 Bcf/d in 2024, according to U.S. Energy Information Administration data.

> *"When LNG is taking that gas off the grid, that's doing it every day, every week, every month, every year. That's durable through cycles, over decades."*
>
> **MOHIT SINGH,**
> CFO, Expand Energy

AI 'Wild Card'

If LNG delivers durability to natural gas demand, AI and data centers insert volatility.

Producers and stakeholders along the gas value chain are frothing at the mouth with excitement for new gas demand to fuel energy-hungry data centers.

Hyperscalers such as Google, Meta, Microsoft and Amazon are competing in an "adapt or die" AI landscape and looking for reliable power. Some are looking at restarting shuttered nuclear plants, including the Three Mile Island plant in Pennsylvania.

But producers still think natural gas will make up a considerable amount of the power stack to fuel AI's growth.

Supermajors Exxon and Chevron are each having conversations with tech customers about building gas-fired power generation for specific data center projects.

But future gas-demand forecasts for data centers and AI vary widely. Gas demand could increase by 10 Bcf/d by 2030 due to AI, according to Wells Fargo projections. That is a 28% increase over the roughly 35 Bcf/d currently consumed for U.S. electricity generation.

Appalachian gas giant EQT Corp. has told

New Gulf Coast LNG Projects

SOURCE: REXTAG

investors that AI fervor could result in as much as 18 Bcf/d in incremental demand by the end of the decade.

Expand has heard forecasts ranging from 2 Bcf/d all the way up to 20 Bcf/d of incremental gas demand, Singh said.

But that was all before DeepSeek.

Tech and power markets are still scrambling after the launch of an energy-efficient AI chatbot by Chinese firm DeepSeek, raising questions about just how much power AI really needs to succeed.

The back-and-forth movement in AI-demand scenarios will be “noisy” in the coming years, Singh said.

“I think we’ll land around an incremental 5 Bcf/d of natural gas demand from data centers,” he said.

‘Gas-On-Gas Competition’

Producers are clinging to the “demand growth” light at the end of the tunnel.

And with demand growth spurred by LNG exports, data centers and the overall electrification trend, utility buyers are worrying about their ability to buy all the gas they need.

“We are sensing a lot of fear among end-buyers about gas-on-gas competition, because where is that next molecule going to go?” Singh said.

Will gas be hoovered up by the next massive LNG export facility to come online?

Will gas go toward another power-hungry data center for Meta or Microsoft?

Could industrial buyers on the utility grid face shortages, impacting operations and productivity?

And never mind those everyday citizens using more and more electricity to power their EVs and devices.

But valid questions also remain about where all the gas is going to come from.

The top gas-producing regions in the U.S.—Appalachia (35.3 Bcf/d in 2024, per EIA figures), the Permian Basin (24.8 Bcf/d) and the Haynesville (15 Bcf/d)—each have their own challenges to getting gas to market.

Appalachia’s Marcellus and Utica shales hold the lowest-cost gas reserves to drill. But pipeline takeaway constraints strand considerable volumes within the basin, to the ire of producers and mineral rights owners.

Tim Pawul, president of the Minerals & Royalties Authority, said mineral and royalty owners in Appalachia are excited about the prospect of in-basin gas demand fueled by new data center projects.

Associated gas production in the Permian is a byproduct and cost of doing business to drill for oil. The Permian is churning out more associated gas each year, but takeaway capacity is limited. Midstream companies are racing to add new gas pipeline projects. Others, such as the 2.5-Bcf/d Matterhorn Express, have already come online, though Matterhorn quickly filled up.

The Haynesville is in a goldilocks position to be the swing producer for LNG supply, with ample takeaway capacity and proximity to the Gulf Coast. But Haynesville gas is deep and expensive to drill, and high-quality Tier 1 inventory is depleting in the play’s core.

Higher Henry Hub gas prices are needed to spur future Haynesville development, experts say.

“Obviously it’ll be volatile,” Singh said. “But, on average, we think [gas] prices naturally are going to go up because there’s more competition and there’s more demand.” OGI

Needed: ‘Manhattan Project’ Focus on US Energy

Quantum Capital Group’s Wil VanLoh says energy security demands an “all of the above” strategy.

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The energy industry is transitioning, but the shift is more about the global economy, supply and demand, and recognizing that natural resources and capital are finite, said Wil VanLoh, founder and CEO of Quantum Capital Group.

Action is needed now to preserve U.S. energy security and dominance, and an “all of the above” strategy is critical, VanLoh said during a keynote speech at NAPE.

“As an industry we need to understand, and hopefully as a country we can come together on this, we need to adopt an ‘all of the above’ strategy. If we really want to maintain energy dominance and energy security, we generally need a Manhattan Project’s intensity and focus like we had when we developed the atomic bomb in World War II,” he said.

To achieve the dual goals of maintaining energy dominance and energy security in the U.S., four steps–or rather, giant leaps–need to happen.

From the outset, investment in oil and gas must meaningfully increase to boost resource production and infrastructure building.

“It’s abundant, it’s affordable, it’s reliable, it’s here in America and we’ve got to invest as a country,” he said. However, he added, “We’ve got to have policy that supports this. We’ve got to have capital markets to support this.”

Next, the U.S. needs to upgrade and expand the grid, which means supporting all forms of power, including gas, wind and solar.

“Look, our grid is ancient. It is falling apart. It’s pathetic,” VanLoh said. “It’s vulnerable to cyberattack and it just doesn’t work. It’s not going to be able to carry the electrons [required] as we continue to move to more electricity and less forms of other power. We’ve got to build new grids to get the power from where it’s developed [to] where it’s used in the natural gas space.”

The third step is to shore up the nation’s supply chain to produce the critical minerals needed for electric vehicles and the energy transition.

China has a massive head start, he said.

“I don’t actually know if we can ever catch [up with China], but we [should] at least be able supply it for ourselves. They will be the OPEC for the next 50 years on that,” he said. “We need to make sure we have our own abilities here.”

“Look, our grid is ancient. It is falling apart. It’s pathetic. It’s vulnerable to cyberattack and it just doesn’t work. It’s not going to be able to carry the electrons [required] as we continue to move to more electricity and less forms of other power.”

WIL VANLOH, founder and CEO, Quantum Capital Group

The fourth step? The U.S. needs to go nuclear.

“We need to accelerate the role that nuclear plays in the mix. It’s a shame that nuclear, when Three Mile Island happened, just took such a hit from American public opinion,” he said. “It’s really the answer. I mean, candidly, nuclear, it’s the only form of clean energy that’s 24/7, 365 days a year.

“There’s no other energy [like] that today.”

The government needs to fast-track reactor designs and cut regulatory red tape to move the projects forward and make the projects less expensive, he said. The cost of building similar facilities in South Korea or China is one-third of that in the U.S.–a factor that policy can change, VanLoh said. But it could still take years to bring the projects online.

A combination of these steps for an “all of the above” strategy will take time, commitment and investment, he said.

“But on all of these things, we’ve got to start today,” he said. OGI

Execs: Sluggish Pace of Gas Projects Threatens Growth

Infrastructure needs to catch up to allow U.S. producers to meet global demand, says Liberty CEO Gusek.

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Natural gas is the most likely fuel for future global energy needs, but the world is behind the curve in building the infrastructure needed to transport and use it, a panel of executives and experts said at the 2025 NAPE Energy Business Conference in Houston.

"As we think about growth in global energy demand, we have a real opportunity to be a meaningful player in that," said Ron Gusek, who succeeded Energy Secretary Chris Wright as CEO of Liberty Energy.

"We've been slow to get infrastructure built to the coast and support energy exports from here to around the globe, so I do think that is the most meaningful thing that will be coming in the next little while."

Gusek and fellow NAPE panelists discussed the many potential changes coming to the energy industry, including the possibility of nuclear power playing a more prominent role in the U.S. But the talk repeatedly returned to governments taking a more encouraging stance toward infrastructure projects that balance environmental and cost concerns.


Josh Viets

Josh Viets, Expand Energy's COO, said the industry faces a "trilemma" of balancing cost, reliability and lower carbon emissions–with the focus increasingly on reliability.

"If you look out into parts of the country like California that have struggled with blackouts over the last decade-plus, because you have a … grid that's unreliable and often causing problems such as we've seen with fires and whatnot, society just won't accept that," Viets said.

"That's why we've seen, in recent times, society moving in a direction that starts to favor reliability, and I think that's why we feel so strongly that natural gas will play such a critical role in the energy mix moving on into the next several decades."

Gusek said analysts have found that during the past 12 years, the world's energy use grew from 500 exajoules to 620 exajoules. Natural gas supplied 40% of the extra load, with oil supplying 24%. Coal was third.

"Wind, solar, nuclear was way, way down there, unfortunately, but I don't think that changes," he said, noting that demand is expected to grow to 800 exajoules by 2050.

The problem many countries now face is that they have backed themselves into a corner, cutting emissions to the point where development is stymied, Viets said.

The Expand executive discussed a recent investor trip the company took to Europe. In Ireland, the national government has forbidden the construction of new AI data centers to conserve the power supply, he said.

In Germany, Volkswagen has considered shutting down factories because the cost of power was too high to make the plants profitable. The cost of electricity in Germany is about three to four times higher than U.S. prices.

Gusek said Germany's struggle to provide electricity is illustrative. The country has a capacity of 200 gigawatts, more than twice the typical daily demand. However, the system is hampered because the majority of the power is provided by intermittent wind and solar sources. Often, supply threatens to fall below demand.

"It's driving industry out of there and ultimately pushing it elsewhere, arguably to the places where energy generation is done less efficiently," Gusek said. "So, it's probably actually driving energy use up globally along with the emissions footprint."

The panelists said they expect the Trump administration to be able to clear away some of the red tape faced by U.S. interstate transport and LNG export projects. Tara Righetti, the Occidental Chair in Energy and Environmental Policies at the University of Wyoming, said the federal government should think beyond its current policies, and also consider what states are doing.

"Every state has different policies and processes, and we're having a hard time building these things that are on a national scale because they're getting held up," she said. "There needs to be some kind of centralized backstop process to make sure that projects that are really critical to energy security and reliability can get built in a reasonable amount of time." OGI

Antero, Gas Markets on Winning Streaks

Appalachian producer's stock price jump 90% YoY as the outlook for U.S. natural gas improves.

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As the U.S. natural gas price market improves, investors are hot on gas-weighted stocks—Antero Resources, in particular.

Analysts say Denver-based Antero is one of the best producers poised to take advantage of improving natural gas and NGL prices this year and into 2026.

Investors have been snapping up shares for Antero and its gassy peers at a rapid clip over the past year. Despite dismally low Henry Hub prices, gas-weighted stocks have generally outperformed oily names over that span.

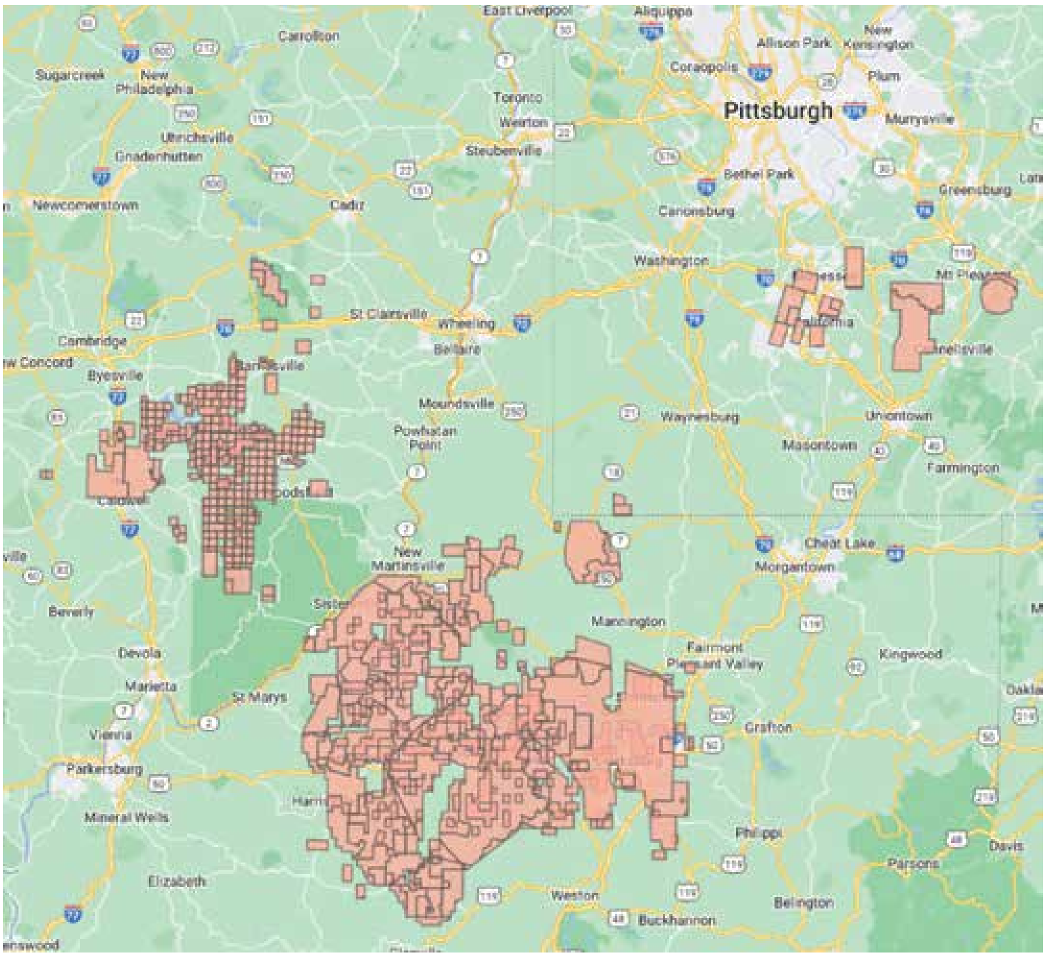
Shares for Antero Resources are up nearly 90% year-over-year, based on AR's closing price of $40.15 per share on Feb. 13. The shares easily outpaced the S&P 500 index by about 22% and the S&P's upstream-heavy XOP index by about 2.7% over the past year.

Antero's current market cap of $12.5 billion values the company above Ovintiv's $11.5 billion, Permian Resources at $11.4 billion and Apache parent APA Corp. at $8.6 billion.

Other U.S. gas producers have also outpaced oily peers in the public markets.

Shares for Haynesville shale E&P Comstock Resources are up around 155% over the past year. Dallas Cowboys owner Jerry Jones now holds over 71% of Comstock's outstanding

Antero Resources Appalachia Acreage



SOURCE: REXTAG

common stock. Analysts question whether Jones could be making a run at taking Comstock private in a similar fashion to Harold Hamm's buyout of Continental Resources in 2022.

Comstock and Antero are the two companies with the most torque to improving natural gas prices right now, Siebert Williams Shank & Co. Managing Director Gabriele Sorbara told *Oil and Gas Investor*.

Stock prices for other gassy names have grown in the past year, including EQT Corp. (62%), Expand Energy (39%), CNX Resources (57%), Gulfport Energy (44%) and Range Resources (35%).

Antero held 521,000 net acres of gas, NGL and oil properties, primarily in Ohio and West Virginia, as of year-end 2024, regulatory filings show.

LNG, NGL Upside

Antero is bullish on rising demand for its Appalachia gas volumes to feed U.S. LNG exports.

The company's net production averaged 3.4 Bcfe/d in 2024, a 1% increase over 2023 levels, Antero told investors in its fourth-quarter earnings call. Natural gas output averaged 2.2 Bcf/d in 2024.

Antero's firm transportation portfolio sends 75% of its gas production into the Gulf Coast LNG corridor.

The startup of new LNG export facilities on the Gulf Coast should result in higher premium price realizations to NYMEX in the coming years, CFO Michael Kennedy said.

Venture Global's Plaquemines plant—on the Mississippi River south of New Orleans—is currently pulling around 1.5 Bcf/d after exporting its first cargo in late December.

Justin Fowler, Antero's senior vice president for natural gas marketing, said Plaquemines' ramp up has been faster than market expectations.

"Looking at the TGP 500-L basis—which is the basis hub with the most current exposure to Plaquemines—the quicker-than-anticipated ramp-up of the facility has already lifted summer 2025 pricing by $0.10/ MMBtu, compared to the strip pricing before the startup," Fowler said.

For context: Every $0.25/Mcf improvement in natural gas strip pricing adds around $220 million to Antero's incremental cash flow, Kennedy said during the call.

Gas producers are bullish on prices as more LNG exports tick online. Cheniere Energy's expansion at Corpus Christi, Texas, began liquefaction in December. Full capacity from the seven-train expansion will be 1.3 Bcf/d, bringing the plant's total output to more than 3.3 Bcf/d.

And Exxon Mobil's long-awaited Golden Pass LNG plant is also expected to come online within the next 12 months. Golden Pass LNG has FERC approval for 2.6 Bcf/d. Both projects "are expected to significantly increase the call on natural gas along the LNG corridor," Fowler said.

NGL are also a big part of Antero's growth outlook. Antero's liquids production averaged 209,000 bbl/d in 2024—an 8% increase year-over-year.

Last year, Antero realized a $1.41/bbl premium over Mont Belvieu prices, the best C3+ differentials in the company's history, said Dave Cannelongo, senior vice president of liquids marketing.

Fourth-quarter realizations came in at a $3.09/bbl premium over Mont Belvieu.

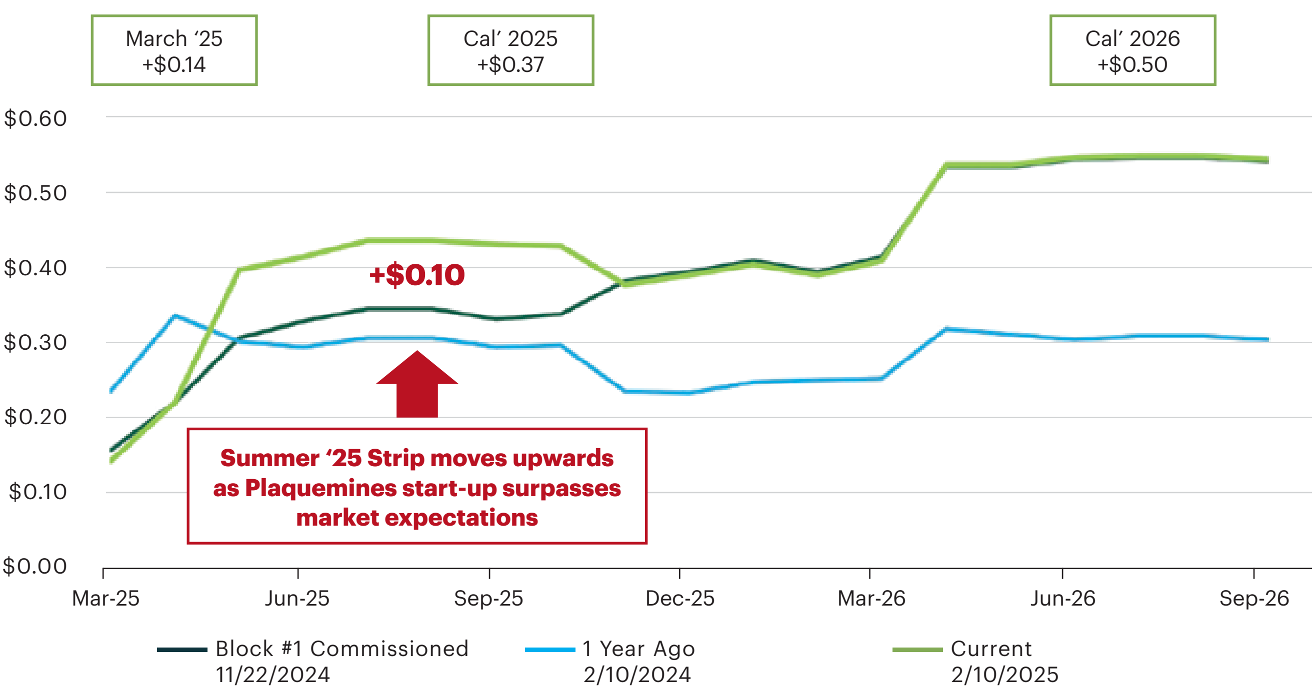
Antero still expects to see high annual NGL export premiums this year.

"Those premiums, coupled with our domestic marketing efforts, are allowing us to set our guidance for 2025 at levels even higher than 2024's record year, resulting in a range for our C3+ NGLs of $1.50 to $2.50 per barrel premium to Mont Belvieu prices," Cannelongo said.

Every $5/bbl improvement in NGL pricing adds another $200 million to Antero's cash flow bucket. OGI

TGP 500-L Differential to NYMEX Henry Hub

$/MMBtu



SOURCE: ANTERO RESOURCES

Kissler: Is it Time to Worry About Crude Prices?

Oil trends will hinge on China's economy, plans to refill the SPR and how tariff threats play out.

DENNIS KISSLER
BOK FINANCIAL SECURITIES

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

Although U.S. crude production fell from its record high of 13.436 MMbbl/d in October to 13.314 MMbbl/d in November, that latest figure is still high. At the same time, President Donald Trump is calling on OPEC to increase production, which could easily push crude prices lower into the second quarter, as supply would likely then outpace demand.

Just how low could prices go—or will they fall at all? The answer depends on a confluence of factors, as supply is just one part of the equation.

Economic Slowdown Still a Risk

For instance, another fear haunting crude is the stubborn 10-year Treasury yield currently hovering just over 4.5%. If 10-year yields drift north of 5%, it would very likely create the economic slowdown that most economists once predicted but have now reneged on.

Although the U.S. stock market highs that investors have enjoyed make it easy to ignore this possibility, keep in mind that the last two years of the S&P 500 posting returns north of 23% each year are not sustainable. That's especially true given that a handful of stocks known as the "Magnificent 7" anchored these gains, rather than performance being spread out within the index.

And then there's China to consider. The Chinese economy struggled throughout 2024 despite government stimulus to try to jumpstart growth.

As China is still the "manufacturer of the world"—and thus the second-largest oil consumer—continued economic slowdown in China would negatively impact global oil demand. Along these lines, if we add declining demand from China to the other factors, it's easy to justify the view that crude prices may decline.

At the same time, the prospect of more Chinese economic stimulus, combined with potential sanctions on Iranian and Russian oil, have been encouraging hedge fund investors to increase their bullish positioning on U.S. crude.

Although these bets may at first seem to support the view that higher U.S. crude prices are to come, it's also important to keep in mind that they place the market in a vulnerable position. In other words, there could be a significant price drop in the market if traders who previously bet on the price going up are now forced to sell due to a sudden downturn, causing further selling pressure and accelerating the price decline.

Effects of Trump Policies Remain to Be Seen

Many speculated that Trump taking office would impact the energy industry. In just the first few weeks of his term, he announced policies and plans that could indeed impact crude prices. Most directly, he said he plans to refill the U.S. Strategic Petroleum Reserve (SPR) "right to the top and export American energy all over the world."

This plan to refill the SPR—and do it quickly—could create a buying floor for crude, and purchases could step up very quickly if the price of WTI falls significantly.

Furthermore, the Trump administration's policies on tariffs could be both a positive for crude prices and a negative, depending on who bears the brunt. Tariffs on imports from oil-producing countries would likely restrict supply, driving prices higher. Meanwhile, tariffs on imports from countries with heavy demand for crude, such as the tariff on Chinese goods, could easily slow those countries' economies, creating less demand.

Initially, U.S. gas prices rose on the news that the U.S. was imposing tariffs on Canada, Mexico and China, but then fell again on Feb. 3 after the tariffs on Mexican and Canadian goods were paused. Around 25% of the crude that comes into the U.S. is from Canada and Mexico.

How other countries respond to these tariffs is also a question mark. Immediately after Trump made the announcement, Canada responded by putting 25% tariffs on some American goods, such as alcohol and perfume, but Trump pivoted and delayed the tariffs for 30 days so Canada paused theirs as well.

And so, what's ahead? Well, looking from a longer-term technical outlook, the trends have been retracing lower for WTI crude futures. The longer-term weekly chart, which sets moving averages below both the 100 and the 200 period, is possibly trending back toward the $65/bbl area.

While the trend is lower, keep in mind that the fundamentals of supply and demand draw the charts, and the fundamental outlook is definitely a moving target in each coming week as the Trump administration settles in further. OGI

Viper-Diamondback $4.5B Dropdown Raises Expectations

Analysts anticipate more $500 million deals by public mineral and royalty companies in 2025.

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Diamondback Energy's $4.45 billion dropdown in mineral and royalty interests to its subsidiary Viper Energy is large enough to move the needle for both firms.

The transaction, announced at the end of January, will accelerate Diamondback's debt reduction and boost its exposure to Viper's "differentiated growth profile and market-leading minerals position," Diamondback Chairman and CEO Travis Stice said.

Diamondback will exchange certain mineral and royalty interests for $1 billion in cash and approximately 69.6 million units of Viper's operating subsidiary.

Based on the $49.55 per share 30-trading day average sales price of Viper's common stock, the drop-down transaction is valued at $4.45 billion.

Viper plans to fund the cash portion of the deal through cash on hand, borrowings under its credit facility and proceeds from one or more capital markets transactions.

"This [drop-down] transaction with Viper is a major milestone in the continued synergy capture and execution of corporate development objectives related to the Endeavor transaction," Stice said.

Diamondback is working to deleverage after a massive $26 billion acquisition of private Midland Basin producer Endeavor Energy Resources. The Endeavor acquisition closed in September.

The company is expected to end 2025 with around $8.8 billion in net debt, or a 0.8x leverage ratio.

Diamondback management had been clear in messaging its aim to execute the drop-down transaction early in 2025, said KeyBanc Capital Market analysts Tim Rezvan and Jonathan Mardini in late January.

"Our December upgrade walked through a theoretical structure for a $4.5B drop," the analysts said. "We did this work to assess management's claim that a drop could be structured to send cash up to parent Diamondback, while also managing Viper's leverage profile. We found that it was feasible, given the parameters management set."

In the analysts' "theoretical exercise," a dropdown to Viper would funnel about $1.8 billion in cash to Diamondback, along with Viper shares.

"Paying down $1.8B of debt would lower [Diamondback's] YE25 leverage to 0.6x and should accrete more value to the equity," the analyst said.

The valuation is based on limited detail of the minerals package: It generated $499 million in EBITDA in 2023.

"We believe the limited disclosure from Diamondback on this minerals package, both before and after closing the Endeavor merger, is intentional," the analysts' report said.

One impetus may be a flattish price for Viper shares and a fourth-quarter 2024 pullback in Diamondback shares, they said. Viper's last deal was a $915 million acquisition of Midland Basin mineral and royalty interests from Tumbleweed Royalty IV. Tumbleweed was founded in 2014 by Cody Campbell and John Sellers, the co-executives behind Permian E&P Double Eagle Energy.

Several other large minerals packages may also break free in 2025, the analysts said.

"We expect 2025 will be a year when several large minerals packages find their way into the hands of public minerals companies," they said.

While 2024 proved to be a quiet year on the M&A front for most minerals companies under KeyBanc's coverage, Viper was the only major acquirer. Overall, Viper did deals with Tumbleweed and its affiliates totaling about $1.1 billion.

"We expect to see transactions for multiple large minerals packages in/above the $500 [million] range get announced in 2025," they said. "Recent discussions with industry participants highlighted multiple packages currently on the market. We believe Kimbell [Royalty Partner's] ability to win the bid for a $231 [million] Midland Basin minerals package may reflect conservatism by other industry participants who remain focused on larger deals."

Kimbell's successful equity issuance this January and Viper's successful equity issuance last September show the marketplace is ready and willing to support companies making logically priced acquisitions, they said.

"We view Sitio [Royalties] as the most likely acquirer in 2025 (ex-Viper dropdown), and we believe that the 'scale begets scale' thesis we have for growth-oriented coverage companies suggests that Kimbell may look to transact again in 2025, given its history

SHUTTERSTOCK

of being aggressive when market opportunities present themselves," the analysts said.

Moritas Minerals

In early February, Viper entered into a definitive purchase agreement to buy mineral and royalty interests from Morita Ranches Minerals in a cash-and-equity deal valued at about $330 million.

Viper will acquire interests in approximately 1,691 net royalty acres located in Howard County, Texas, in the Midland Bason from Morita in what it called the "Quinn Ranch Acquisition," according to a filing with the U.S. Securities and Exchange Commission.

David Deckelbaum, managing director at TD Cowen, told *Oil and Gas Investor* that the Diamondback dropdown to Viper is essentially a form of capital structure arbitrage. He compared it to deals in the past by MLPs designed to unlock value.

"MLPs traded 12x, your upstream company trades at 5x, so you drop down all your midstream assets to the MLP" to get a multiple better than the core business.

However, he said the current environment has made such deals outsized as the scales of the companies involved has become so vast.

"A drop-down should not be a $5 billion transaction," he said.

Deckelbaum said that assuming the announced 32,000 boe/d (about 56% crude) and a $70/bbl WTI price deck, "we calculate roughly $520 [million] of 25E EBITDA translating to an 8.5x multiple on the deal vs our current 25E FANG EV/EBITDA multiple of 5.5x."

"Viper also notes future upside with FANG completing 300-325 gross locations on the acquired acreage at an estimate 6% NRI, which is expected to drive FANG-operated production from an average of 11 MBD in 2025 to 14 MBD in 2026."

The deal also gives Diamondback, which will receive $1 billion in cash from Viper, some cushion ahead of potential share sales related to its $26 billion acquisition of private Midland Basin producer Endeavor Energy Resources, which closed in September.

"While the issued shares give FANG plenty of flexibility to lean into insider sales when necessary, the deal also serves as a cash buffer ahead of any potential share sales related to the Endeavor acquisition," Deckelbaum wrote. "Recall, over 13.2 [million] shares ($2.3bn) issued for the Endeavor acquisition were sold in September 2024. As a result of the sale, related shareholders entered into a 170-day lock-up period, opening a window for the next potential sale beginning in March."

Viper said that at closing of the Quinn Ranch acquisition, its guidance for the first quarter is average oil production of 30,000 bbl/d to 31,000 bbl/d (54,000 boe/d to 56,000 boe/d).

Provided the Diamondback dropdown closes by the second quarter, Viper's average daily production will range between 47,000 bbl/d and 49,000 bbl/d (85,000 boe/d and 88,000 boe/d).

At the midpoint of guidance, Viper's daily oil production will be 61% higher than the company's fourth-quarter 2024 oil volumes, the company said.

Viper will acquire the Morita interests in exchange for $211 million in cash and approximately 2.3 million units. Based on the $49.55 per share 30-trading day average sales price of Viper's common stock, the units are worth $118.9 million.

Viper will fund the cash portion of the deal through a combination of cash on hand and borrowings under the company's credit facility. The transaction is expected to close in first-quarter 2025, subject to customary closing conditions.

Truist Securities analyst Neal Dingmann said the Morita acquisition adds "even more core inventory."

Combined with the Diamondback dropdown, "While we view the deals as positive given the appropriate value for significant core assets, our price target [for Viper] declines to $68 from $78 due to more equity and slightly lower production than we had estimated," Dingmann said. OGI

Prairie to Buy Bayswater's D-J Assets for $600MM

Bayswater will retain assets in Colorado and the northern Midland Basin.

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Prairie Operating has entered into a definitive purchase and sale agreement to acquire certain Denver-Julesburg (D-J) Basin assets from privately held Bayswater Exploration & Production in a cash-and-stock deal valued at $602.75 million.

The deal expands Prairie's D-J Basin footprint, while Bayswater will continue to develop some assets in the basin and keep its holdings in the Permian Basin, the companies reported in early February.

"This acquisition delivers compelling strategic and financial advantages and reflects our disciplined, but opportunistic approach to rapidly expand our footprint in the D-J Basin," said Edward Kovalik, chairman and CEO of Prairie. "Not only will the addition of these high-quality assets be immediately accretive, but they will also accelerate our development plans, enhance operational efficiencies and drive sustainable, long-term value creation for our shareholders."

Edward Kovalik

Gary Hanna

Prairie President Gary Hanna said the acquisition represents a "transformative milestone" for the company by expanding its footprint and production in oil-rich D-J Basin assets.

"Upon closing, we will be well-positioned to deliver significant organic production growth in 2025 and beyond," he said.

Prairie said the Bayswater acquisition will add about an average 26,000 boe/d (69% liquids) in net production across ~24,000 net acres in Weld County, Colo. The transaction will increase the company's operational scale in the D-J to about 54,000 net acres, including about 600 highly economic drilling locations with about 10 years of drilling inventory.

Bayswater said the sale includes 300 producing, horizontal wells on 30 pads. The company gave a slightly lower production estimate of 25,000 boe/d. Bayswater said the deal also includes nine DUC horizontal wells and an operated saltwater disposal system.

Following the transaction, Bayswater will retain and operate 70 horizontal wells in the D-J, producing approximately 18,000 boe/d. The company will run one active rig on its remaining Colorado position.

Bayswater will also continue to hold 50,000 acres in Texas' northern Midland Basin, which the company is actively developing. Bayswater's Midland position includes 140 horizontal wells producing approximately 20,000 boe/d. The company's assets there include a large saltwater disposal system. Bayswater affiliate Tejon Treating and Carbon Solutions provides a gas gathering and treating business in the Midland Basin.

Prairie's deal values Bayswater's proved developed producing (PDP) reserves at PV-20 with a purchase price of $23,500 per net flowing barrel of oil equivalent, Prairie said. The company said it will leverage existing infrastructure to drive operational efficiencies and reduce development costs proforma for the transaction.

Prairie will fund the transaction with cash and up to 5.2 million shares of its common stock. The cash portion will be funded through a combination of cash on hand and borrowings under the company's credit facility. The company said it has received commitments to expand its borrowing base to $475 million at the closing of the acquisition. Prairie will also apply proceeds from one or more capital markets transactions, subject to market conditions and other factors.

The company expects a leverage ratio of ~1.0x at closing.

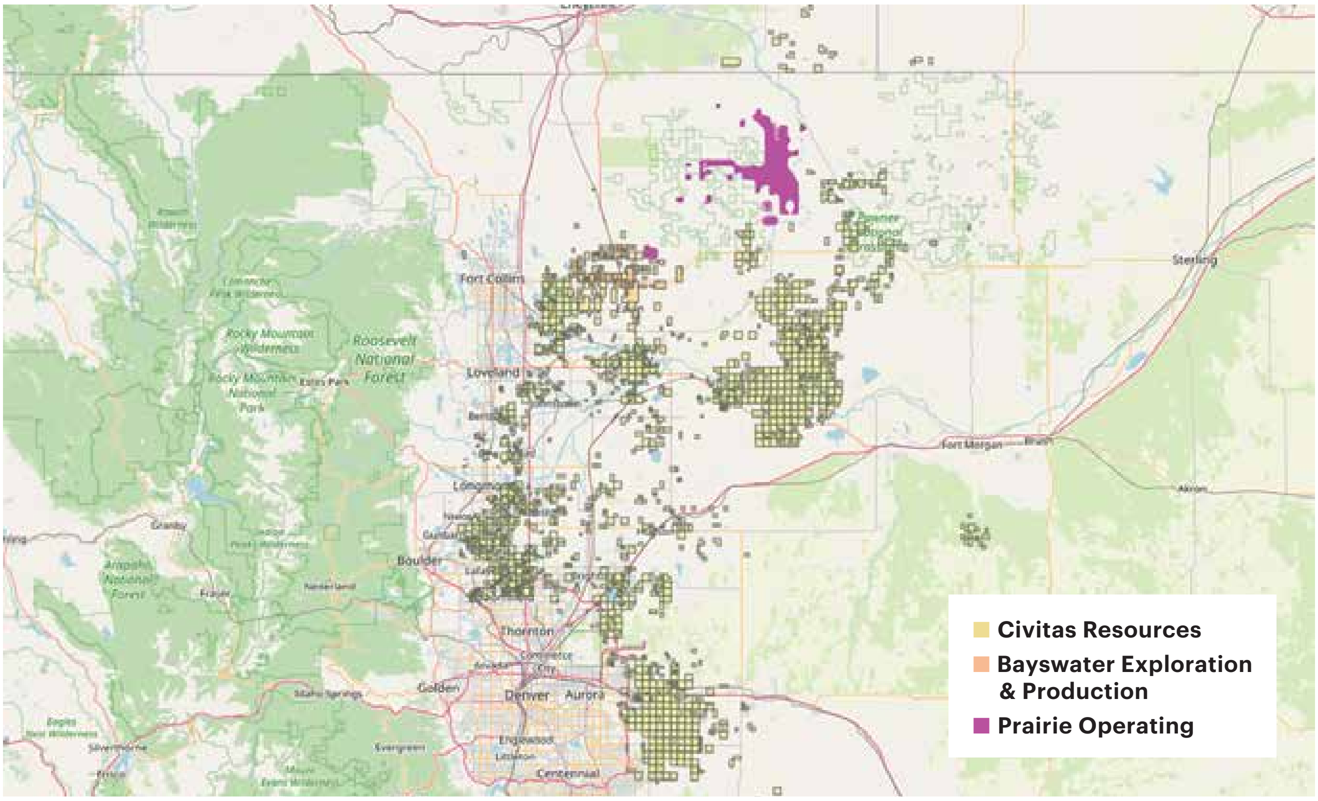
26K
boe/d in net production

24K
net acres

52 MM
shares of stock

$6.44
price of Praire stock following the deal

D-J Acreage Overlap



SOURCE: ENVERUS, TD COWEN

The deal between Prairie Operating and Bayswater could have wider implications for Civitas, who is reportedly weighing a sale of its D-J assets.

Following the transaction announcement, Prairie's share price fell about 25% to $6.44 per share in mid-day trading on Feb. 7.

Bayswater has been an operator in the D-J Basin since 2009, and the agreement with Prairie represents the culmination of years of work by the company's team, said Steve Struna, president and CEO.

Steve Struna

"We are proud of the high-quality asset we have built, our reputation as a responsible operator, and the positive impact we have had in surrounding Weld County communities," he said.

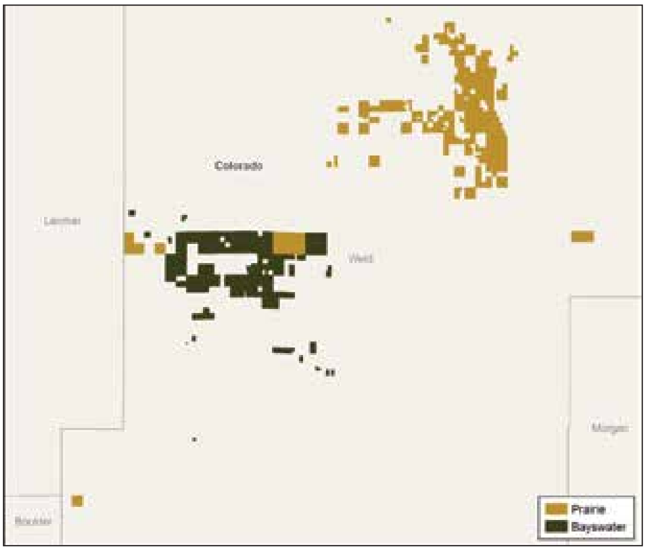
The company remains committed to operating in the D-J Basin and "rebuilding our Colorado footprint with newly raised capital and continuing to responsibly produce Colorado oil and natural gas—the cleanest energy molecules on the planet," Struna said.

Prairie expected to close the Bayswater deal within weeks of the announcement, with an effective date of Dec. 1, 2024. The Davis Graham firm served as Bayswater's legal adviser for the transaction.

Implications for Civitas?

The deal's metrics could also have implications for Civitas Resources, should the company pursue a D-J Basin divestiture. Civitas began as a D-J pureplay, but during the last two years, the firm has spent billions of

Prairie Operating, Acquired Bayswater Acreage



	Prairie	Bayswater	Pro Forma
Daily Production (mboepd)	2	26	**28**
Net Acres	~30,000 [1]	~24,000	**~54,000 [1]**
Locations (gross op. locs.)	517 [2]	69 [2]	**586**

SOURCE: ENVERUS, TD COWEN
1) INCLUDES ~7,000 NET ACRES CONTRACTED BUT YET TO CLOSE.
2) INCLUDING PDNP.

Prairie Operating's acquired Bayswater acreage substantially increases the company's oil-weighted production, expands the company's footprint and inventory life, significantly increases free cash flow, and realizes meaningful infrastructure synergies.

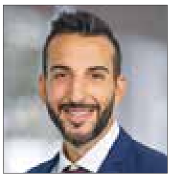
dollars acquiring acreage in the Permian Basin.

Civitas is reportedly weighing a sale of its assets in the D-J with an asking price of $4 billion. The Denver-based E&P has retained a financial adviser to assess buyer interest in the assets.

Civitas didn't respond to *Oil and Gas Investor's* requests for comment.

Civitas is reportedly open to selling all or only portions of its D-J Basin portfolio. Production from Civitas' D-J Basin assets averaged around 160,000 boe/d (70,674 bbl/d oil) during third-quarter 2024.

Given regulatory concerns within Colorado and the relatively short inventory life of Civitas' D-J assets, a PDP-only deal "makes sense in our view," TD Cowen analyst Gabe Daoud Jr. said in January.



Gabe Daoud Jr.

Taking the proceeds from a D-J Basin exit, Civitas could try to acquire Double Eagle IV—one of the most coveted private E&Ps remaining in the Permian's Midland Basin.

Acquiring Double Eagle IV would make sense for Civitas, given the companies' overlapping acreage in the Midland Basin, Daoud said.

But buying Double Eagle would have risks, including a high price and only around 424 drilling locations, according to TD Cowen estimates.

Analysts had previously questioned whether Ovintiv, which has been more Permian-focused lately, might make a run at acquiring Double Eagle. But Ovintiv ultimately turned its attention north to its legacy roots in Canada, acquiring Montney Shale assets from Paramount Resources for US$2.38 billion (CA$3.33 billion) in cash.

Daoud said Prairie's deal for the Bayswater assets screens at an implied ~1.6x transaction multiple. Based on Prairie paying $23,500 per flowing boe metric, Civitas 155,000 boe/d suggests a $3.6 billion value for the company's D-J production.

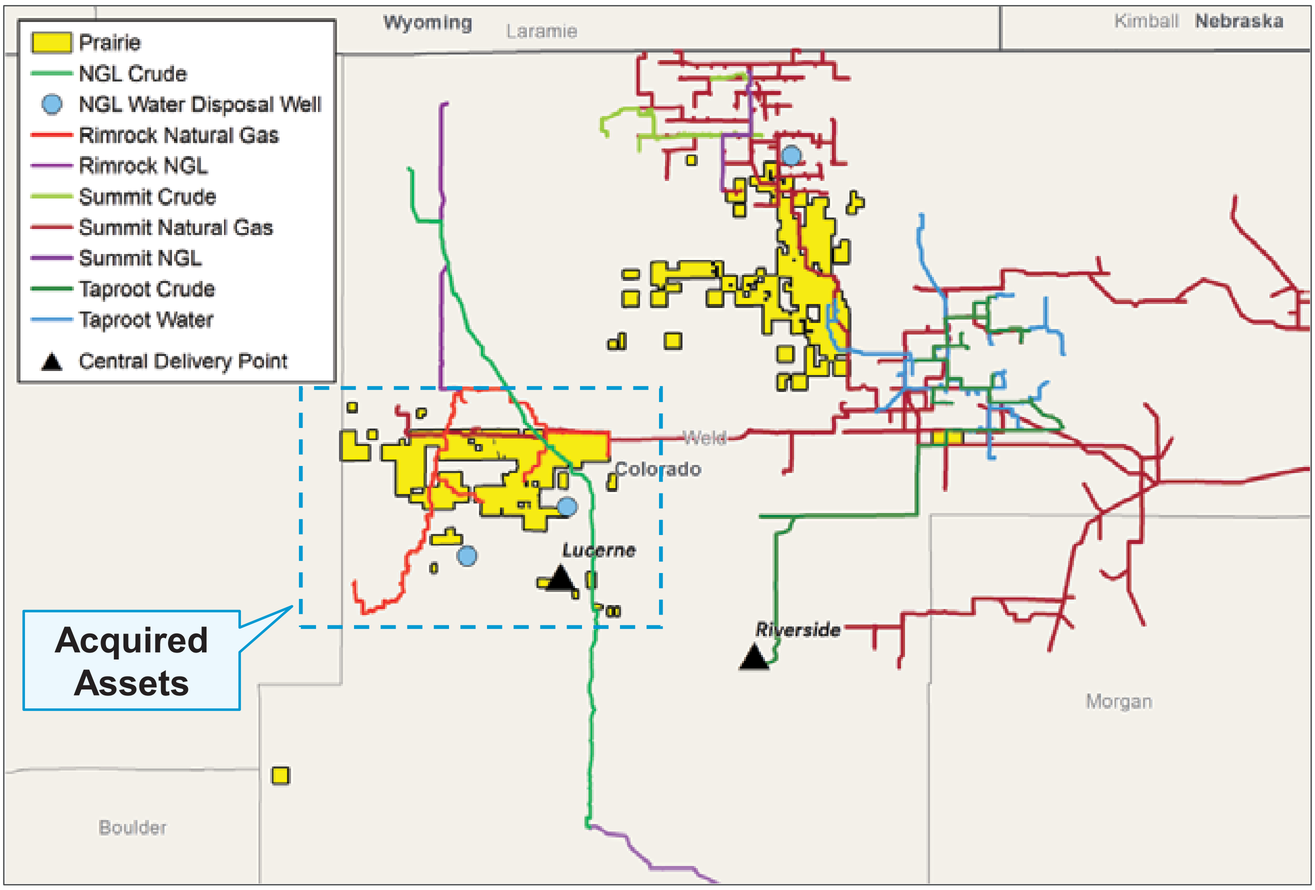
Daoud said that the $4 billion Civitas seeks screens light relative to its estimates for Civitas' net asset value.

In an early February report, Daoud said the deal appears to be strictly PDP, with little to no value placed on undeveloped areas due to regulatory concerns and a short inventory life. The $4 billion price implies 2.2x EBITDA on Cowen's 2025 D-J-only estimate of $1.75 billion, or about 23% free cash flow yield, given the estimate of about $900 million.

That compares to Civitas' multiple of about 2.4x and a about 23% free cash flow yield.

"Thus, a D-J sale would be largely neutral to valuation," he said. "Overall, we carry ~555 MMBoe of [Civitas] D-J resource potential at ~$2.6Bn in our NAV, which combined with PDP value of ~$4Bn would imply ~$6Bn+ for total asset value, but again we'd note it's unlikely a buyer would be willing to ascribe value to undeveloped locations."

Prairie Operating Expanded Footprint



SOURCE: PRAIRIE OPERATING

Prairie Operating's acquired Bayswater acreage expands the company's footprint and access to midstream takeaway, including agreements with NGL Energy Partners, Taproot Energy Partners, Rimrock Energy Partners and Summit Midstream.

MIDSTREAM

Renegade Infrastructure Primed to Build and/or Buy

CEO Drew Ward says the company is currently “basin agnostic” and wielding a capital commitment from PE firm Energy Spectrum Partners.

SANDY SEGRIST
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Renegade Infrastructure CEO Drew Ward said he would prefer to stay on the natural gas side of the business.

SHUTTERSTOCK

Roughly six months after selling the assets of Pinnacle Midstream II for $550 million, the executives behind the deal are paring down the potential opportunities for their latest venture, Renegade Infrastructure.

Renegade recently secured an inaugural equity capital investment from private equity firm Energy Spectrum Partners, which was also a primary investor in Pinnacle Midstream II.

Drew Ward and Jason Tanous led the Permian Basin-focused Pinnacle firm, and they are in charge at Renegade, too. Ward is CEO and Tanous is again in the role of CFO.

The team is considering several greenfield projects, as well as M&A, Ward said.

But for now, the company is “basin agnostic” about where to develop. Renegade wants to find a niche where infrastructure development is needed by a larger company that also has immediate priorities elsewhere.

Pinnacle benefited from the upstream consolidation trend as companies grew larger and needed infrastructure. Pinnacle Midstream’s original anchor customer was Double Eagle, which sold to Pioneer Natural Resources, which sold to Exxon Mobil. The Exxon acquisition was a “bullish sign” for Pinnacle because the supermajor is known for drilling, and thus increased the value of the midstream assets, said Ben Davis, managing partner at Energy Spectrum.

The company’s path could potentially follow the same pattern as Pinnacle II, a Midland Basin platform co-led by Ward. Phillips 66 bought the firm in July for $550 million. Ward was also part of Pinnacle Midstream I’s western Delaware Basin midstream portfolio, which was sold in 2018 to EagleClaw Midstream.

“We really are trying to be opportunistic acquirers of existing assets and go in and try to find the operational efficiencies in those assets, and grow them commercially,” Ward told *Oil and Gas Investor*. “There’s a handful of those assets that exist within larger, consolidated companies that some would consider capital starved—not because of their location, but because those big companies have a better return profile somewhere else.”

Ward said he was open to any sector of the midstream business but would prefer to stay on the natural gas side.

“We’ve done gas assets, we’ve done crude assets,” he said. “I think our first preference would be to stay in the gassy side of the business—that includes gathering, compression and processing. Not that we will not look at other assets, but I’m a firm believer in the gas business.”

Ward said he was also taking into account the Trump administration’s interest in loosening regulations that should help the natural gas industry’s development. On his first day in

"We're waiting for some sort of catalyst, or volatility in the marketplace that allows us to insert ourselves into the system with venture capital or private equity, whatever you want to call it. But you can't do that if you don't have the powder lined up and sitting on the sidelines with you."

DREW WARD, CEO, Renegade Infrastructure

office, President Donald Trump issued an executive order allowing the resumption of processing export permit applications for new LNG projects.

The Biden administration had "paused" awarding permits for new LNG facilities in early 2024 to allow for the study of the environmental effects of the export plants on nearby communities and climate change.

"[Allowing export facility permits] affects everything upline of the LNG facility," he said. "It affects the pipeline, the infrastructure, the drilling, the pricing mechanisms. So, we're definitely keen on following that very closely and trying to insert ourselves into that value chain."

The U.S. became the largest LNG exporter in 2023, surpassing Qatar and Australia. In December 2023, some 8.6 million metric tons departed U.S. terminals, according to Rapidan Energy Group.

U.S. LNG production is expected to more than double before 2028, from requiring just over 11 Bcf/d in 2023 to 24.4 Bcf/d, if projects currently under construction begin operations as planned, according to the U.S. Energy Information Administration. Newly opened plants in Corpus Christi, Texas and Plaquemines, La., are on track to provide a significant increase this year as operations ramp up.

Renegade on Familiar Path

Renewing the relationship with Energy Spectrum was key for Renegade's plans. Each party's familiarity with the other aids in the rapid decision-making necessary when the right prospect becomes available.

"We're waiting for some sort of catalyst, or volatility in the marketplace that allows us to insert ourselves into the system with venture capital or private equity, whatever you want to call it," Ward said. "But you can't do that if you don't have the powder lined up and sitting on the sidelines with you."

Energy Spectrum Managing Partner Mike Mayon said Ward and Tanous set the foundation for a great management team.

"The team's creativity and solutions-oriented approach are differentiators, and we believe Renegade can continue to build on the strong track record of its management team," he said. "We are grateful for this partnership and look forward to the journey ahead." OGI

Segrist: Permit Reform Rumbles

The White House has called for changes to a heavily criticized system, but new rules require a lot more work.

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The U.S. is the world's top LNG exporter and can move natural gas to just about any place on the planet—it just can't get enough to Massachusetts.

"In Massachusetts, they import LNG," said Josh Viets, COO of Expand Energy, the nation's largest producer of natural gas.

Massachusetts accounts for about 87% of the nation's LNG imports, usually bringing in cargos from Trinidad and Tobago on the spot market, according to the U.S. Energy Information Administration.

"And yet several hundred miles to the south, we're producing around 5 Bcf/d of natural gas," said Viets, who spoke on a panel at NAPE.

Thanks to the Jones Act, the U.S. is unable to ship LNG to Massachusetts. However, the cheaper option, sending natural gas to the northeast via pipeline, isn't an option either, thanks to the red tape that any company faces when attempting such a project.

The libertarian Cato Institute called Massachusetts' LNG import terminal "the poster child for irrational energy permitting in the United States."

Permitting regulations guided by the National Environmental Policy Act (NEPA) from 1970 have evolved into a system heavily criticized in the energy industry for causing delays and legal costs through interminable hearings and bureaucratic delays that add years to the construction process.

In his executive order, "Unleashing American Energy," President Donald Trump spent an entire section directing the federal government's administrative departments to streamline the permitting process.

Bloomberg News reported it as the latest attempt by a "U.S. president to address longstanding, bipartisan complaints over the lengthy waits for proposed projects to clear environmental reviews and secure federal authorizations." The problem, according to analysts, is that the executive order is just an initial step.

The laws covering the permitting process go back decades, and the primary regulations that involve government permitting can only be changed by Congress.

"We would love to have a pipe that would go from Pennsylvania into Massachusetts," Viets said. "If that happened, if we were able to get the right regulation in place, the right judicial system in place that allowed demand to be created there … we would have the ability to grow into that."

"There are a lot of other industries that would like to see permitting reform. It will continue to be discussed. I'm hopeful that we could put something into some sort of reconciliation package. We're going to have to see."

MALLORI MILLER, vice president of government relations, Independent Petroleum Association of America

Congressional Moves

The last Congress considered permitting reform. The measure, sponsored by Sen. Joe Manchin (I-W.Va) and Sen. John Barrasso (R-Wyo.), advanced out of committee with a bipartisan 15-4 vote.

Manchin and Barrasso introduced the Energy Permitting Reform Act in July 2024, the most serious attempt in the 118th Congress at changing the current system among the more than two dozen reform bills submitted.

Manchin and Barrasso's bill argued for streamlining judicial review, one of the biggest delaying factors in the permitting process. The allowable time to file challenges was to be shortened from six years to 150 days. For LNG projects, the Federal Energy Regulatory Commission would have only 90 days to approve or deny a project after the applicant submitted the final environmental review.

"The bill almost made it across the finish line," said Mallori Miller, vice president of government relations for the Independent Petroleum Association of America. Miller discussed the topic during a forum at NAPE.

"There was a lot of talk in December, and we were very supportive. It didn't fix every problem, but it was tailored to the committee's jurisdiction."

The House GOP leadership refused to take up the act before finishing the session, and both Houses of Congress blamed each other.

Everett LNG, located in Everett, Mass., has a storage of of 3.4 Bcf. Due to domestic LNG shipment limitations as a result of the Jones Act, Massachusetts now accounts for 87% of the nation's LNG imports despite its proximity to domestic natural gas hotspots.

CONSTELLATION ENERGY

"Our initial application [for SPOT] was 13,000 pages. I thought that was ridiculous, but by the time we completed the process, our final submission was over 30,000 pages. We addressed over 80,000 comments over two comment periods, predominantly from NGOs."

JIM TEAGUE, Co-CEO, Enterprise Products Partners

"By taking permitting off the table for this Congress, Speaker (Mike) Johnson and House Republican Leadership have done a disservice to the incoming Trump Administration, which has been focused on strengthening our energy security and will now be forced to operate with their hands tied behind their backs when trying to issue permits for all of the types of energy and infrastructure projects our country needs," Manchin said.

Johnson said that Democrats had delayed negotiations until the end of the term and that the next Republican-controlled Congress would be able to pass a more amenable bill.

"There are a lot of other industries that would like to see permitting reform," Miller said, adding that passage of a bill will more than likely still require bipartisan support.

"It will continue to be discussed. I'm hopeful that we could put something into some sort of reconciliation package. We're going to have to see."

Poster Children

The term "poster child" was mentioned more than once when industry insiders discussed projects that encountered difficulty with the federal government's permitting rules.

"I believe that SPOT should be the poster child for the need for permit reform," said Enterprise Products Partners Co-CEO Jim Teague.

Enterprise's ambitious SPOT (Sea Port Oil Terminal) project's permitting took so long that one of its anchor customers backed out. According to analysts, the project's original projected cost increased from $1.85 billion to about $3 billion.

"It took over five years to get the SPOT license, including almost four years to get the record of decision and a year and a half to get the license to construct," Teague said during Enterprise's fourth-quarter earnings call.

"Our initial application was 13,000 pages. I thought that was ridiculous, but by the time we completed the process, our final submission was over 30,000 pages. We addressed over 80,000 comments over two comment periods, predominantly from NGOs."

One NGO comment was 60 pages long. Teague said his favorite comment was from a person who wanted to know how the company was planning to mow the right of way for the onshore facilities.

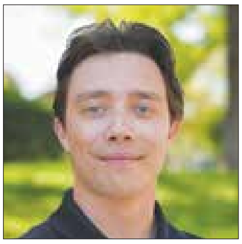
"She was concerned that field mice would be protected from hawks."

Meanwhile, the time for the latest Congress to pass permitting reform is short, Miller said. If the midterm elections follow historical patterns, the Republicans' slim majorities vanish.

"I'm not a pessimistic person," she said. "However, I will say traditionally the midterms swing in the opposite direction of the presidency. If the GOP Congress wants to get things done, they have a very finite amount of time to do it, and, really, it's right now." OGJ

East Daley: Midstream Investors Drawn to Southeast

Competition for gas supply will heat up with demand from data centers and new LNG projects.



ZACH KRAUSE
EAST DALEY ANALYTICS

OREN PILANT
EAST DALEY ANALYTICS

Zach Krause and Oren Pilant are energy analysts at East Daley Analytics.

Midstream investors are pouring billions into new pipeline expansions to meet natural gas demand growth in the Southeast. The region has many advantages, including big interest from developers of data centers, that could fuel the next expansion cycle for the natural gas industry.

Kinder Morgan, Williams Cos., Energy Transfer and Boardwalk Pipeline Partners are all planning pipeline projects to bring more gas to the Southeast. Taken together, these expansions would draw supply from basins across the U.S., including the Marcellus and Utica shales in Appalachia, the Haynesville on the Gulf Coast, the Anadarko Basin in the Midcontinent and potentially even the Permian Basin in West Texas.

Both Kinder Morgan and Boardwalk have advanced competing projects to a final investment decision (FID), bringing the new market opportunity into focus. Boardwalk on Dec. 11, 2024, announced it would move forward with its Kosci Junction project for 1.16 Bcf/d of capacity, while KMI made FID a week later on the Mississippi Crossing project.

Boardwalk's Kosci Junction will extend east from the existing Greenville Lateral on the Texas Gas Transmission system. The new 36-inch pipeline is designed to travel 80 miles to Clarke County, Miss., to an interconnect with the Southern Natural Gas system, and an additional 18-mile segment will deliver gas into the Gulf South system near Destin Pipeline.

The Kosci Junction project is anchored by a 20-year agreement for 600 MMcf/d, and Boardwalk said negotiations are underway to market the remaining capacity, potentially up to 1.58 Bcf/d. Boardwalk expects to enter the FERC pre-filing process in the first quarter and is targeting the start of service on the expansion in the first half of 2029.

Meanwhile, Kinder Morgan subsidiary Tennessee Gas Pipeline is moving forward with the Mississippi Crossing project at an estimated $1.6 billion capital cost. The project includes new pipeline between Greenville, Miss., and Choctaw County, Ala., where Compressor Station 85 of the Transcontinental Gas Pipe Line (Transco) sets the price for much of the Southeast market.

On the company's fourth-quarter earnings call, Kinder Morgan said it has secured binding agreements for 1.8 Bcf/d of capacity for Mississippi Crossing. The company plans to build out the project with 2.1 Bcf/d of capacity and is targeting startup in November 2028.

Energy Transfer is pursuing a third expansion, the South Mississippi project, that competes along a similar eastbound route as the Boardwalk and KMI projects. Subsidiary Energy Transfer Interstate Holdings held a non-binding open season in October to take gas from the Carthage and Perryville hubs in East Texas and northeastern Louisiana further into the Southeast, including Florida Gas Transmission's Zone 3 as a primary delivery point.

The South Mississippi project is a brown/greenfield hybrid and includes a mix of new large-diameter pipes and compression facilities, as well as leases and possible expansions on existing pipes. The project is currently scoped for 1 Bcf/d but is potentially expandable to 2 Bcf/d.

Williams, KMI Team Up to Deliver Gas South on Transco

Meanwhile, Kinder Morgan and Williams are coordinating projects to bring gas supply south from Appalachia on the Transco system to meet growing demand.

Kinder Morgan's South System Expansion 4 (SSE4) will expand the Sonat system in Georgia and Alabama, adding up to 1.3 Bcf/d of capacity. KMI estimates a $3 billion project cost with an in-service in late 2028.

SSE4 will deliver additional flows on Transco from WMB's Southeast Supply Enhancement (SSE). The project will expand Transco's southbound capacity by ~1.6 Bcf/d, with 1.3 Bcf/d of the capacity offered from Station 165 in southern Virginia to Station 85 at the Alabama-Mississippi border. The Transco expansion creates more southbound egress from the Northeast, and SSE4 will help deliver that gas to end-markets in Alabama and Georgia.

The Southeast market is proving fertile ground for Transco expansions. The pipeline placed the Southside Reliability Enhancement (SRE) project into full service on Dec. 30, 2024. SRE expands capacity in southeastern Virginia by 423 MMcf/d on Transco's South Virginia Lateral. Local utility Piedmont Natural Gas has contracted for the expansion.

Data Centers, Utilities Drive Demand Growth

Midstream investors are chasing a market with strong prospects for growth. Populations in the Southeast are growing rapidly, and a friendly business climate is attracting new industries. These factors are fueling growth in energy demand, especially for electricity. The region historically has leaned heavily on coal to generate power, but utilities like Southern Company and Georgia Power are shuttering older coal plants to meet long-term goals for net-zero carbon emissions.

Data centers to power AI are another big driver of demand. East Daley Analytics tracks these data center projects across the U.S., and the Southeast has been a particular draw for developers. In Virginia, for example, we are tracking over 22,000 megawatts (MW) of planned generation capacity to meet load growth for data centers, and over 5,000 MW of generation to power data centers in Georgia.

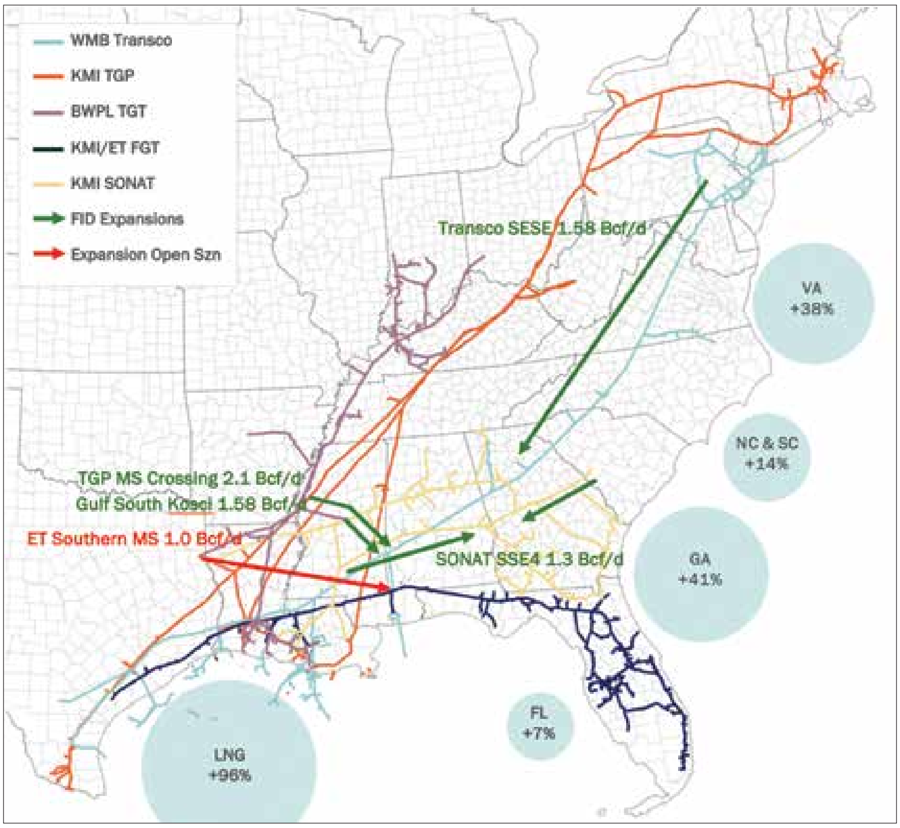
Natural gas won't fuel all this new electricity demand, but the market opportunity is significant, and investors are stepping in to fill the gap. For example, Chevron announced in January that it will partner with Engine No. 1 and GE Vernova to build up to 4 gigawatts of scalable gas-fired generation to power AI. The JV plans to build co-located power plants at data centers and will target customers in the Southeast, Midwest and West regions.

East Daley sees a target-rich environment for the midstream sector. Projects like Kinder Morgan's SSE4 and Transco's SSE are expected to charge rates at least 200% higher than current firm transport tariffs for similar routes to the Southeast. We estimate a rate of about $1.50/Mcf on the SSE4 expansion and about $0.86/Mcf on SESE and build multiples of 4-5x. The high rates and low multiples are a bullish signal for new investments.

East Daley also expects more competition for gas supply as new LNG projects start on the Gulf Coast. Venture Global's Plaquemines LNG in southeastern Louisiana in particular will raise the bar by creating more demand in the eastern Gulf Coast market. We expect gas at points like Transco Station 85 to trade at a premium in the near term until new pipelines are built, particularly when the Plaquemines Phase 2 project comes online in fourth-quarter 2026.

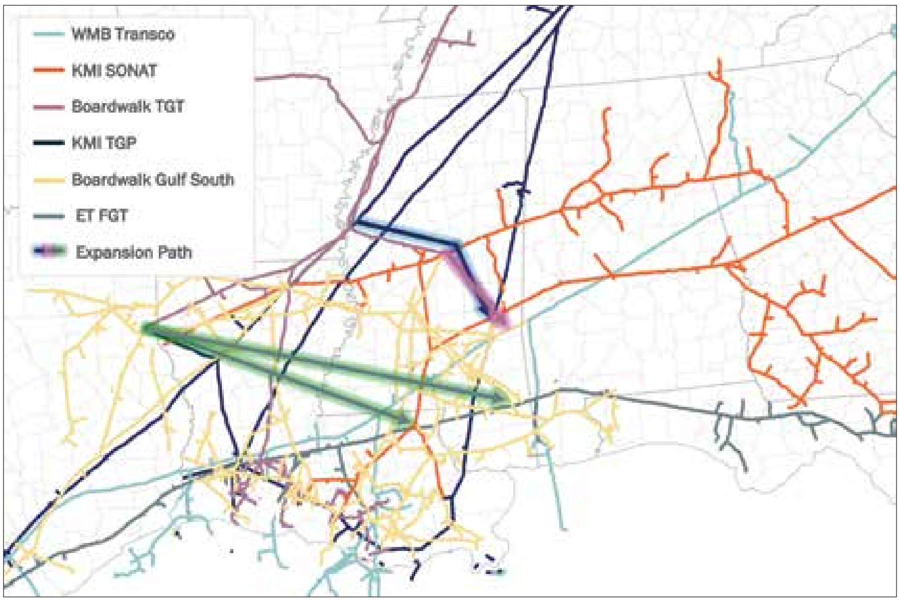
While midstream projects will not be online soon enough to mitigate price volatility in the region, these expansions will play an important role balancing long-term domestic and LNG demand growth. OGI

Southeast Pipeline Projects and Estimated Utility Gas Demand Growth (in Bubbles)



SOURCE: EAST DALEY ANALYTICS

Gas Pipeline Projects Targeting the US Southeast



SOURCE: EAST DALEY ANALYTICS

In Colorado, the Regulatory Noose Tightens

More stringent rules on everything from drilling and orphan wells to emissions is raising the cost of fossil fuel production in the state.

ANDREW PRATT
CONTRIBUTING EDITOR

Colorado regulators, supported by a progressive Democratic governor and state legislature, are steadily tightening regulations on E&P companies to address voter concerns about pollution and the safety of drilling projects close to population centers.

The methodical ratcheting up of state regulation, begun after passage of a watershed law in 2019, is raising compliance costs and sparking consolidation as some large players diversify by buying oil assets in other states or seek economies of scale to deal with higher expenses, industry representatives and financial analysts say.

The proximity of rapidly growing and politically progressive Denver to Colorado's most prolific oil and gas play has been a key driver of industry regulation, say regulators, industry representatives and environmentalists.

Its westward growth constrained by the Northern Front Range of the Rocky Mountains, the Mile High City has sprawled eastward on land atop the Denver-Julesburg (D-J) Basin, where oil has been produced since drillers sank the region's first well in 1901.

Residents of Denver and its suburbs decry air pollution exacerbated by drilling and production activities, and grass-root groups emboldened by state laws authorizing local regulation of the industry have successfully blocked the location of oil and gas infrastructure near suburban homes and businesses.

Lynn Granger

"We've seen the Denver metro area development and housing development that have gone up very close to operations that existed or were planned to be developed by our industry," said Lynn Granger, the new president and CEO of the Colorado Oil and Gas Association (COGA). "The closer you are to humans' [dwellings], the more difficult it is to operate in an industrial setting."

Donald Trump's 2024 victory is unlikely to change Coloradoans' attitudes toward oil and gas exploration, despite his vow to eliminate regulations governing E&P. Colorado hasn't gone for a Republican presidential candidate since the 2000 election, and its politics are solidly progressive.

While concerns about oil industry safety and pollution span decades in Colorado, two high-profile accidents and the growing strength of the state's progressive Democrats eroded industry support and helped bring the passage of landmark legislation, Senate Bill 181 (SB-181), in 2019.

The law, a long-sought and hard-won victory for state environmentalists, rewrote the rulebook for Colorado oil and gas production and paved the way for increased regulation, Granger said. The change was so dramatic that regulators have taken years to ramp up, and some are still in the early stages of developing rules, Granger said.

"I believe they were overwhelmed" by the scope of the law's requirements, Granger said.

SB-181 granted local governments broad authority to regulate industry activities. It also changed the mission of the agency set up to regulate oil and gas operations, then known as the Colorado Oil and Gas Conservation Commission.

The regulator's old mission was promoting economic growth. The current mission is to "regulate in a manner that protects public health, safety, welfare, the environment and wildlife resources." In 2023, the Legislature added authority to regulate carbon capture and geothermal operations in the state and changed the agency's name to the Colorado Energy and Carbon Management Commission.

SB-181 included requirements for more than a dozen sets of rulemaking processes that are taking years to complete and "unfortunately what has happened since passage of SB-181 is additional pieces of legislation that continue to require additional rulemakings," Granger said.

Anti-Fracking Sentiment

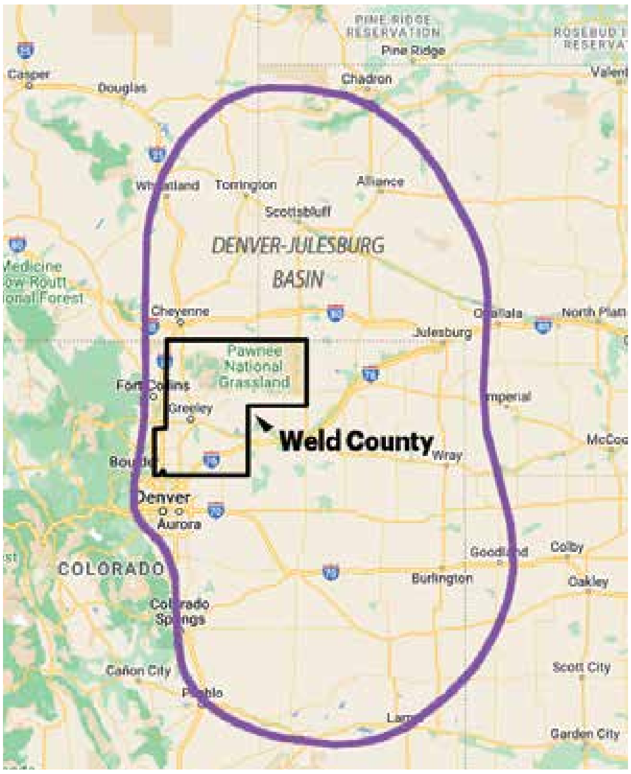
Debate of SB-181 came as two deadly and highly publicized 2017 incidents involving oil and gas production in Weld County were still at the forefront of voters' minds.

In April 2017, a home in Firestone, north of Denver, exploded, killing two people and severely burning two others. The National Transportation Safety Board (NTSB) ruled that the explosion was caused by natural gas that leaked in from a pipe connected to a non-producing well nearby. The abandoned well was in a field operated by Anadarko Petroleum.

In the Rocky Mountain State, the regulatory bar for oil and gas producers keeps getting higher.

SHUTTERSTOCK

Denver-Julesburg Basin



SOURCE: REXTAG

The small-diameter pipe appeared to have been damaged during the building of the home in 2015. NTSB investigators determined that the pipe had not been properly abandoned and that local authorities approved construction near the wells without first obtaining complete maps from Anadarko of gathering system pipelines from nearby wells. Anadarko paid an undisclosed settlement to the families of the victims.

In May 2017, one worker died and three more were injured when an oil tank exploded in Mead, near Firestone. Anadarko, which Occidental Petroleum bought in 2019, also was one of the companies cited by federal regulators in that incident.

SB-181's backing of local oil and gas regulation has emboldened communities that say they fear such accidents and mishaps near their homes.

In May 2023, Boulder County announced that it had won a five-year battle to prevent Extraction Oil & Gas, now a unit of Denver-based Civitas Resources, from undertaking a 32-well development called "Blue Paintbrush" that would have drilled horizontally from Weld County to Boulder County gas deposits.

Drilling-friendly Weld County had approved the project, as had state regulators. Boulder County, in contrast, has been a hotbed of anti-fracking sentiment and refused to authorize the plan.

More recently, the Energy and Carbon Management Commission in November blocked a request by Civitas' Extraction Oil & Gas unit to drill under Erie, a growing suburb of Denver that has bucked pro-industry advocates in Weld County and opposed nearby oil and gas operations. The 26-well operation was known as the Draco pad.

Increased regulatory scrutiny has both killed projects and raised drilling costs for approved projects. The annual costs to oil companies of complying with state E&P regulations put into place between 2018 and 2023 totaled about $590 million a year, COGA estimated in 2024.

As the regulatory process ramped up after the passage of SB-181, producers had to devote resources to keeping up and complying with new requirements, Granger said. Some smaller, older companies had to hire staff to manage regulatory matters for the first time, she said.

More costs are being added regularly as regulators tighten emission rules and seek revenue sources for projects that will reduce pollution and demand for fossil fuels. In December 2024, the Colorado Air Quality Control Commission approved rules that would, for the first time, require emissions reductions for midstream oil and gas operations. The projected cost to the sector is $86 million a year.

'Colorado Oil Wars'

Production expenses have risen enough that it is affecting profitability goals, especially at smaller companies, Granger said. That's led some players to scale back or eliminate Colorado operations, either through the sale of assets to better financed and large competitors or a shutdown of production activities, she said.

Bigger producers are responding by diversifying into the Permian Basin or other oil and gas fields, said Vince Piazza, senior equity analyst covering energy companies for Bloomberg Intelligence. Civitas is trying to sell $4 billion of D-J holdings and may pick up Permian Basin assets, he said.

"Senior players in the (D-J) region have looked across to the Permian Basin, and I think that clearly indicates where they think the best opportunities will be," Piazza said.

Prairie Operating, which already operates in the D-J Basin, is acquiring more assets from privately-held Bayswater Exploration & Production in a $602.75 million transaction, the companies said in February. Bayswater said it plans to keep its Permian holdings while maintaining a smaller footprint in the D-J.

Though Colorado industry lobbyists have successfully opposed many measures proposed by environmentalists and urban interests at both the regulatory and legislative levels, the trend toward tighter oversight remains, and the politics are both aggressive and ongoing.

Democrats took undisputed control of state government for the first time since 1936 with the election of Jared Polis as governor and the expansion of majorities in both houses of the Colorado General Assembly in 2018.

In addition to the governor, the other four statewide elected officials (attorney general, treasurer, lieutenant governor and secretary of state) were Democrats after the 2018 election. Legal and regulatory power in Denver, the state capital, is expected to remain solidly in Democratic hands for at least the next three years.

During 2024's "Colorado Oil Wars," both energy and environmentalist factions used the threat of direct-to-voters ballot initiatives to pressure their opponents into compromise, including an environmentalist proposal to place a ban on fracking by 2030 on the ballot.

Another environmentalist initiative would have held oil and gas companies strictly liable for environmental damage they caused, and created a private right of action to seek enforcement of environmental rules.

Democratic legislators also introduced bills aimed at reducing Denver's high ozone levels by pausing oil and gas drilling in summer months, setting caps on miles driven in gasoline-powered cars and increasing pollution fines directed in part at energy facilities such as refineries.

Ozone formation from pollution in the Denver area is unacceptably high, especially in the summer, the Environmental Protection Agency (EPA) says. The mountains trap pollutants that summer heat turns into ozone. Denver ranks sixth among U.S. cities for ozone levels and is regularly out of compliance, the EPA says.

Willing to Compromise

At the same time Democrats were pushing for tighter air quality rules in the General Assembly, the oil industry backed voter initiatives for November that would have blocked state government bans on home usage of natural gas in favor of electric appliances and on gasoline-power lawnmowers, and other equipment powered directly by fossil fuels.

Saying he wanted to avoid the risks of voters approving ballot initiatives that hindered good government, Polis announced a "Grand Compromise" among environmentalists and oil industry supporters.

In a statement, Polis said representatives on both sides agreed to drop their ballot initiatives and reached agreement on legislation that would fund the capping of orphan wells, reduce oil-industry nitrogen oxide emission standards by 50% by 2030, and have oil and gas companies pay an estimated $136 million a year in fees, 80% of which would be earmarked to fund mass transit projects championed by the governor.

Polis is trying to expand both passenger rail and bus service along the Rocky Mountains' Front Range in central Colorado.

In addition, both sides agreed to hold off on new legislation governing fracking and other oil and gas production activities until 2028. Polis' office said the region's biggest producers such as Occidental, Civitas and Chevron were party to the agreement, as were major environmental groups.

"The deal is, no new legislative restrictions on the industry until the next election cycle in 2028," said Gabriele Sorbara, managing director and senior equity analyst at Siebert Williams Shank & Co. "That should allow E&P companies to permit their wells and go about their business a little more smoothly."

Gabriele Sorbara

The compromise won't stop regulatory efforts already underway. For example, the Legislature created the Colorado Produced Water Consortium in 2023 to come up with rules aimed at reducing the use of fresh water in fracking operations and reuse water that is generated by oil and gas production. Rules are now up for comment and discussion with approval possible early in 2025.

Much of the water now used for fracking is injected back into deep wells rather than cleaned up and recycled, said Hope Dalton, director of the Produced Water Consortium.

Like all efforts at rules governing the use of water in arid Colorado, regulation of recoverable water is complex, the number of interested parties is large and conflicts are almost inevitable, Dalton said.

The 31 members of the consortium represent state and federal agencies, research institutions, environmental groups, industry, local governments, environmental justice groups and disproportionately impacted communities.

"At the first meeting, there was no love lost between everybody, but now they really respect each other and they want to come to a solution that meets Colorado's needs," Dalton said.

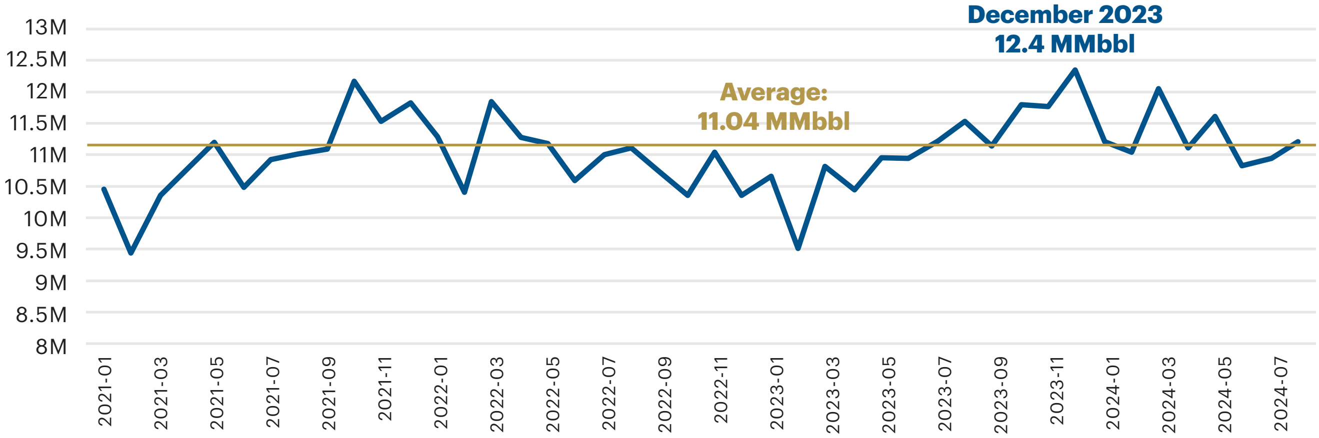
The initial proposal is to implement the rules starting in 2026 by setting the requirements at the current levels of 4% of recoverable water being recycled. By 2038, oil drillers would have to invest in technology and infrastructure that would raise the amount of water recycled to 38%.

A $50 Billion Business

In another regulatory move that raised drillers' expenses, the Colorado Orphan Wells Mitigation Enterprise (OWME) Board

Weld County Oil Production

monthly, bbl



SOURCE: REXTAG

is charging oil companies an annual fee of $115 per well to fund the plugging of so-called abandoned wells in Colorado. The fee takes effect in April. Colorado also has increased its bonding requirements for drillers to help pay to cap wells.

Environmentalists decry the state's orphan well efforts as woefully inadequate, given that Colorado has more than 48,000 unplugged oil and gas wells that will cost billions of dollars to cap and clean up, according to Carbon Tracker, which calls itself an "independent financial think tank" that focuses on the energy transition.

Oil production has peaked in Colorado and many small companies are tapping marginal wells that don't provide enough returns to pay for plugging when their production runs out, said Dwayne Purvis, who wrote a report on Colorado's unplugged wells for Carbon Tracker.

"Renaissance and ongoing development is concentrated in a portion of only one of the basins in the state," the D-J Basin, Purvis said in a statement. "Attempts to redevelop other areas with modern drilling and fracturing technology did not succeed, and wells from the western slope to the eastern plains have continued their decline."

Polis and Democrats in the Legislature realize they can't immediately shut down the state's E&P industry, political and financial analysts say.

Though energy production doesn't rank high as a generator of GDP in Colorado's highly diversified economy, it does generate $50 billion in economic activity and, directly or indirectly, is responsible for creation of 300,000 jobs in Colorado, says analyst Piazza of Bloomberg Intelligence. Interest in the D-J is far from over, he said.

"In general, it seems that some capital that is being redirected elsewhere," Piazza said. "That doesn't mean that the area will be forgotten. There is a lot at stake. [The D-J] will soldier on."

Weld County Secession?

Empowerment of local government in permitting under SB-181 can benefit oil producers in areas where drilling is welcomed, Piazza said.

"The most important oil region in the state of Colorado is rural Weld County," Piazza said. "As long as you have some power at the county seat level, you have a degree of control."

Hydraulic well-fracturing has made largely rural Weld County the epicenter of Colorado oil production. More than 80% of Colorado's oil production and more than one-third of its gas output in recent years comes from that one county, according to U.S. Energy Information Administration figures released in May 2024.

Counties like Weld used to be the typical areas of operation for Colorado E&Ps, Granger said. In the past, oil drilling was conducted away from urban areas and "many people didn't even realize that Colorado was an oil producing state because much of our operations were rural," Granger said.

U.S. Census data show that Weld County's population climbed 42% to more than 359,000 people from 2010 to 2023 as drillers helped make Colorado the fourth-biggest oil producer among the 50 states.

Still, the hot, arid county's population density of 83 people per square mile is one quarter of the density one hour away in the Denver metropolitan area.

While grassroots efforts near Denver aim to combat climate change, Weld County activists have made the news several times over the last two decades by calling for voter initiatives that would allow the county to secede from Colorado because of its policies governing agriculture and oil and gas production.

The last effort in 2021 was a push to make the county part of Wyoming, which activists said is more drilling- and agriculture-friendly than Colorado. Secession efforts have failed, so far, though the last effort was not rejected outright by Wyoming's governor.

Meanwhile, the Denver metropolitan area, already home to roughly half of Colorado's population, continues to expand its financial and political influence, U.S. Census figures show. The area regularly ranks among the fastest growing in the United States.

New, younger residents coming to Denver for jobs in finance, health care and information technology have been more progressive and less comfortable with the oil industry than those in rural Colorado counties and western states, polls show.

Accordingly, Polis has instituted policies designed to reduce pollution and climate change, like the "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" currently touted on his official website.

Because of the "Grand Compromise," the oil industry is hoping for no surprise legislation until the General Assembly ends its session in May, Granger said. That doesn't mean the trend toward tighter regulation is over. OGI

Belcher: Texas Considers Funding for Abandoned Wells, Emissions Reduction

With uncertainly surrounding federal aid, the state is exploring its own incentive system.

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The Trump administration's massive efforts to review existing government programs and spending to increase efficiency and reduce waste have created uncertainty over whether loans, grants and tax incentives that were established by the Biden administration through the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) will continue. Amid the uncertainty, the State of Texas is exploring its own mechanisms for incentivizing orphan well plugging and remediation, and methane emissions reduction.

State Rep. Brooks Landgraf (R-Odessa) has introduced two bills that would provide more state money to plug and mitigate abandoned wells and to reduce methane emissions. The bills, House Joint Resolution 47 and House Bill 188, would set aside 2% of the taxes currently collected from the state severance tax on oil and gas production to fund a Texas Severance Tax Revenue and Oil and Natural Gas (STRONG) Defense Fund. The fund would be applied to address orphan well and methane mitigation and other issues like teacher shortages, law enforcement and infrastructure challenges that exist in parts of the state with the most oil and gas production.

Landgraf notes that 80% of the revenues generated from severance taxes come from 32 oil producing counties, many of which are in the Permian Basin. He argues that these counties need reinvestment for the contributions that they make to the state.

Severance taxes in Texas in Fiscal Year 2022 totaled $10.83 billion, the most ever collected. Those revenues are currently distributed to the state's savings account, known as the "rainy day fund," which totals $21 billion.

There are currently 140,000 abandoned wells in the U.S., including more than 9,000 in Texas. The State of Texas defines orphan wells as non-compliant wells that have been inactive for a minimum of 12 months.

While the average well typically costs about $30,000 to plug, an increasing number of Texas wells are leaking contaminated water that needs to be remediated, which increases the cost per well to remediate. The Railroad Commission of Texas has asked the state to provide an additional $100 million in funds to address the issue. If Landgraf's legislation were enacted, the Texas STRONG fund could pay for that mitigation.

Texas producers are also facing a host of new federal regulations regarding methane emissions. The EPA Methane Rule, which was implemented last year, requires producers to have leak detection and repair programs, and another rule requires emissions calculations and applies a methane waste emission fee. Meanwhile, the European Union (EU) has implemented a requirement that all gas imports into Europe be subject to emissions monitoring, reporting and verification.

While the Trump administration will likely overturn the methane fee and the methane rule is being litigated (Texas is a plaintiff), producers are nonetheless facing increasing pressure to reduce methane emissions and are already making great strides in doing so. For instance, the Texas Methane & Flaring Coalition reports that Permian Basin producers reduced methane emissions by more than 76% from 2011 to 2021, a period in which production increased more than 345%.

New technologies, such as those provided by GHGSat, whose satellites and aircraft detect, monitor and measure methane emissions from oil and gas assets such as gas plants and compressor stations, are available to address methane emissions. These innovations can help producers and midstream companies identify and mitigate methane emissions on a greater scale, allowing them to comply with regulations and help meet EU import requirements.

In addition to plugging abandoned wells, funds provided by Landgraf's STRONG Defense Fund could also be used to utilize advanced technologies to detect and mitigate methane emissions.

Programs on Hold

The federal government created programs to fund methane emissions detection and mitigation and orphan well reclamation that could be applied to states and organizations.

The IIJA released $4.707 billion for orphan well site plugging, remediation, and restoration. This includes $250 million for a federal program, $4.275 billion for a state program in support of improvements to plugging standards and procedures, and $150 million for a tribal program. The federal program allows federal agencies to spend the money on plugging, inventory, site remediation, methane emissions measurement and tracking, and water contamination measurement and tracking.

To date, Texas has received grants totaling $105 million, which have been used to mitigate 737 wells, or roughly 10% of the state's estimated orphan wells. Through a state-funded program, Texas has provided $63 million to plug 2,766 wells in 2023 and 2024.

The IRA created the Methane Emissions Reduction Program (MERP) through which the Department of Energy (DOE) and Environmental Protection Agency (EPA) provide financial and technical assistance to states and organizations to reduce methane emissions. Through MERP, the federal government issued an $850 million funding opportunity announcement "to help small oil and natural gas operators reduce methane emissions and transition to available and innovative methane emissions reduction technologies, while also supporting partnerships that improve emissions measurement and provide accurate, transparent data to impacted communities."

It also provided $350 million in formula funding to 14 eligible states to reduce methane emissions and utilize advanced methane reduction technologies to assist well owners and operators to reduce emissions from low producing conventional wells on federal lands. Texas was awarded $134 million in MERP funding for marginal conventional wells.

Additional federal funding could be available for methane emissions detection and mitigation and orphan well plugging should the Trump administration decide to continue those programs. In the meantime, the Texas Legislature is poised to consider its own solutions by adopting Landgraf's bills establishing a STRONG Defense Fund, a move that could enable Texas to control its own destiny. OGI

"While the Trump administration will likely overturn the methane fee and the methane rule is being litigated (Texas is a plaintiff), producers are nonetheless facing increasing pressure to reduce methane emissions and are already making great strides in doing so."

Could EPA's GHG Rule for Power Plants Give CCS A Boost?

Economics and policy are impacting the pace of carbon capture and storage project growth in the U.S. but some companies are pressing ahead.

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The spotlight is shining on the power potential of abundant natural gas resources in the U.S. as domestic manufacturers and data centers, among others, crave more electricity.

Standing up more natural gas-fired power plants could help meet growing demand, while lowering global greenhouse gas (GHG) emissions by further reducing reliance on coal. Power providers have an opportunity to go even further in shrinking carbon footprints by adding carbon capture and sequestration (CCS) components to their plans.

The U.S. Environmental Protection Agency's (EPA) GHG rule, issued last year during former President Joe Biden's administration, requires new baseload natural gas-fired power plants to install CCS technology capable of capturing 90% of CO_2 emissions by 2032, or run below a 40% capacity factor. Coal plants that plan to operate beyond 2038 are also required to utilize CCS by 2032.

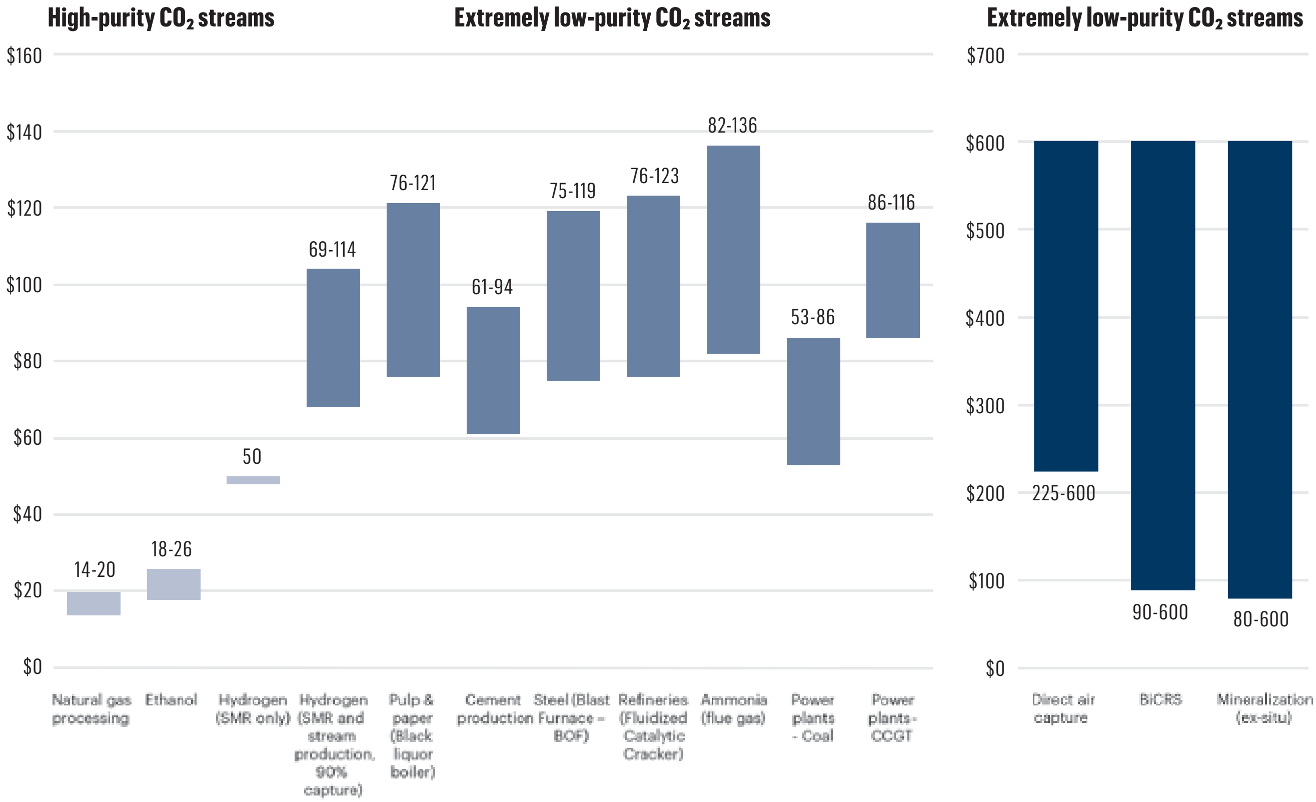
The rule's impact on the CCS project outlook in the U.S. could mark a meaningful shift for the sector. With amine and other technology proven in power and other industrial applications plus the 45Q carbon sequestration tax credit on their side, CCS and midstream companies are positioning themselves to take on projects.

However, the road ahead may be bumpy. The threat of regulations being overturned, opposition from some utilities and the cost of post-combustion capture projects are among the challenges to giving CCS a boost in the U.S.

"From the coal side of things, we anticipate

Carbon Capture Costs

$/tonne of CO_2



SOURCE: DEPARTMENT OF ENERGY

SHUTTERSTOCK

A rule by the U.S. Environmental Protection Agency requires natural gas fired power plants to significantly lower their emissions including by capturing and storing CO_2.

"Our projects are very focused on one emitter with one site. We're not building big hubs right now."

CHARLES FRIDGE, chairman and CEO, Verde CO2

the [rule's] impact to the CCS market to be minimal. Based on the age of existing infrastructure, the move towards natural gas and the cost of retrofitting facilities with capture technology, it is likely most plants choose to retire or convert the plant rather than going with CCS," Brendan Cooke, vice president of CCUS for Rystad Energy, told *Oil and Gas Investor (OGI)* in an email. "On the natural gas side of things, the impact would be much larger but will depend on how new plants are structured and whether they are planning to provide baseload support with a large capacity factor or act as peakers."

The EPA says its Regulatory Impact Analysis projects reductions of 1.38 billion metric tons of CO_2 systemwide through 2047 with the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants

Cooke said the rule could have quite a large impact on the CCS project outlook in the U.S.

"Currently, the power sector is the largest source emissions addressable by CCS and making up 61% of emission sources addressable by CCS in the U.S., with 30% coming from coal and 31% from gas," he said. "So, the potential for CCS in the power sector is really large."

Chasing Power

That is what Verde CO2 Chairman and CEO Charles Fridge is banking on. The Houston-based company, a private full-scale CCS developer, shifted its focus to the power generation sector.

"First and foremost, natural gas power generation is the most reliable form of power. We root for solar and onshore wind, but the wind doesn't always blow and the sun doesn't always shine," Fridge told *OGI*. "To really make a difference in the environment, we felt like the most volumes that we could capture long term is [from] natural gas power generation."

However, it is considered more difficult and more expensive to capture emissions from flue gas at gas-fired power plants due to low concentrations and purity of CO_2.

Some companies have shied away from post-combustion capture projects because of the costs. Federal incentives such as the 45Q tax credit for CCS offer up to $85/tonne; however, that is not enough to make CCS projects economic for big emitters, many say.

"And because the expense with current technologies is relatively high, it's marginally economic unless you can find just the right plant," Fridge said.

Goldilocks conditions include being a newer plant with a long lifespan, which enables money spent to be amortized over the project's life; having favorable geography near the sequestration site; and having enough space for capture equipment such as contact towers near exhaust stacks.

"Your sequestration site needs to be close to your capture so you don't have to incur the significant expense of building brand new pipelines for long distances," Fridge said. "So, most all of our projects are very focused on one emitter with one site. We're not building big hubs right now because we are a private company."

Power generation flue gas is similar, whether it is in located in Texas or Wyoming, and requires the same type of conditioning, Fridge said. He added that amine solvent capture technology has been around for a long time, is proven, effective and used at natural gas processing plants in oil fields.

Some companies are developing separation technologies involving membranes and looping cycles.

"We're rooting for a lot of these new, cheaper technologies and there's some great pilot programs out there," Fridge said. "But there's nothing that we can, frankly, finance around."

Power Moves

Despite the challenges, some companies in the power sector are still pursuing projects to lower emissions.

Calpine Carbon Capture is developing a capture project designed to capture 95% or more CO_2 emissions from turbines and auxiliary boilers at the Baytown Energy Center, a combined heat and power generation facility in Texas. The project, which received funding from the U.S. Department of Energy, will capture and store about 2 million metric tons of CO_2 emissions, according to the company's website.

In Louisiana, Entergy is working with Crescent Midstream on a $1 billion-plus project. The Houston-based midstream company was tapped to build an integrated CCS project at Entergy's 994-megawatt Lake Charles Power Station. The project, which includes a 30-mile pipeline, is designed to capture up to 3 million tonnes of CO_2 per year and is expected to be fully operational by 2029.

They are among the projects moving forward, but economics is preventing a surge in projects.

"Currently this cost is sitting in a range that, after accounting for any required transportation and storage costs, it is difficult to operate for less than the $85 per tonne offered by 45Q," Cooke said. "That being said, power sector mandates have the potential to force further development regardless of economics. However, we aren't seeing the impact of this in the market at this time."

A group of companies, municipal and state authorities and cooperatives asked the Trump administration to review the regulations enacted during the Biden administration. In a Jan. 15, 2025, letter to Lee Zeldin, who now heads the EPA, the group said the regulations–specifically the new GHG rule and coal combustion residual rules–burden the power sector without tangible benefits.

"Any new gas-fired power plants that will operate at greater than 40% of their capacity factor (i.e., the plant generates an amount of electricity that is more than 40% of what the plant was designed to generate) must install by 2032 CCS that captures 90% of the plant's GHG emissions," the letter states. "Because 90% CCS is infeasible and could not be put in place by 2032 even if it were feasible, the GHG Rule effectively forces any new gas-fired power plants to operate at less than 40% of their capabilities, thereby imposing unnecessary and wasteful costs on electric utilities (and the public) by requiring the construction of at least twice as many units to meet electric demand."

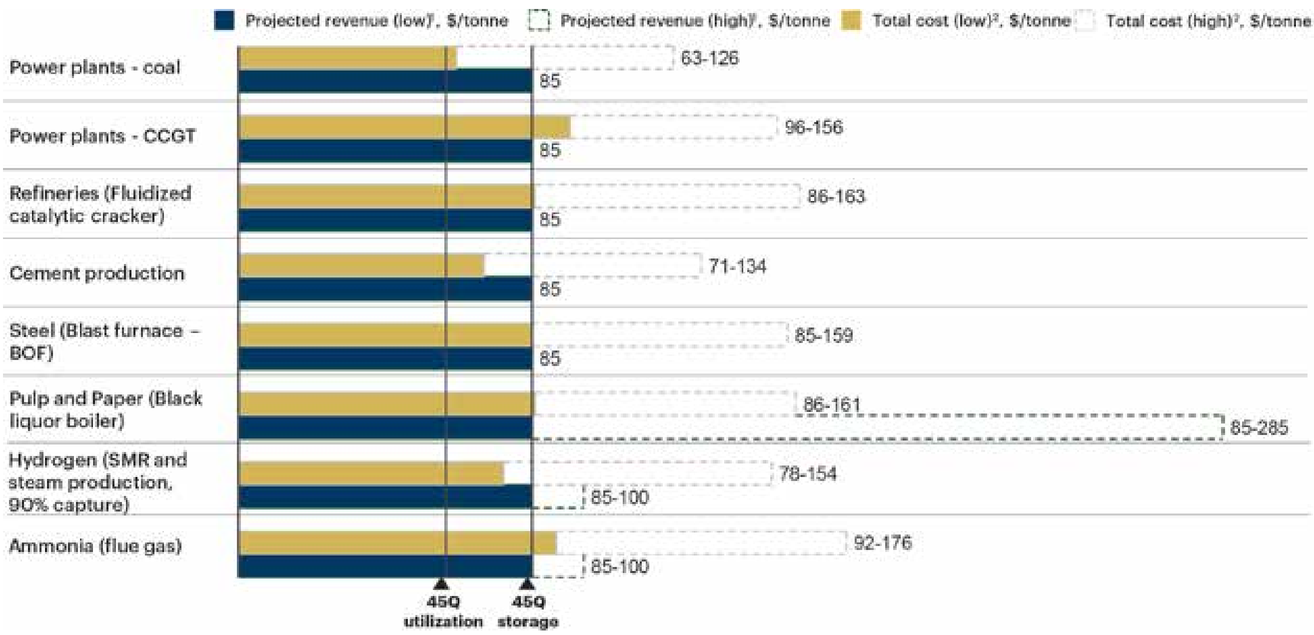
Executives from Duke Energy and Talen Energy were among the signers. The EPA's rule prompted several lawsuits.

Looking Ahead

Cooke also pointed out the timeline is tight given the scale of needed infrastructure during the next seven years. Moreover, Trump has said he plans to undo these regulations, Cooke said.

"The path to repeal is more complex than with other EPA rules he undid in his last term, as the rule for

Costs and Potential Revenues for CCUS Point Source Retrofits in Higher Cost-of-Capture Applications



SOURCE: DEPARTMENT OF ENERGY
1) REVENUE INCLUDES 45Q FOR ALL INDUSTRIES, WITH A VALUE OF $60-85/TONNE. PULP AND PAPER INCLUDES POTENTIAL VCM REVENUE. HYDROGEN REVENUE INCLUDES PTC, ESTIMATED TO BE ~$100/TONNE. 2) INDUSTRIAL APPLICATIONS FROM EFI FOUNDATION, "TURNING CCS PROJECTS IN HEAVY INDUSTRY & POWER INTO BLUE CHIP FINANCIAL INVESTMENTS" COAL AND CCT POWER PLANT RETROFIT COST OF CAPTURE FIGURES DERIVED FROM NETL REVISION 4A FOSSIL BASELINE STUDY RETROFIT CASES ADJUSTED TO 2022 DOLLARS AND WITH 12-YEAR AMORTIZATION-RANGE REPRESENTS FOAK WITH HIGH RETROFIT FACTOR (HIGH FIGURE) TO NOAK WITH LOW RETROFIT FACTOR (LOW FIGURE). TRANSPORT (GCCSI, 2019) AND STORAGE (BNEF, 2022) RANGE FROM $10-40/TONNE

existing coal power plants and new gas-fired turbines was finalized ahead of the Congressional Review Act (CRA) 60-day lookback period," Cooke said. "However, with a Republican-appointed head of the EPA, it is certainly still possible."

Retrofits to existing gas power generation are also unlikely to progress, he added.

Fridge said he doesn't think anyone knows what will happen with the regulations. He referred to executive orders unveiled during the early days of Trump's return to office and some, including a funding freeze, that were blocked in the courts.

"I think there's a lot of trepidation or pause right now with the investing world, which I understand," he said. "But I think everything that has been telegraphed by the Trump administration is that they're pro-fossil fuels, which is a good thing.… If we can capture CO_2, there's zero reason not to do it as long as there are government incentives, which 45Q gives us, and we hope that the voluntary credit markets will continue to improve."

There is no question that CCS technology works, according to Fridge.

"I don't think you can argue with a straight face that we can't effectively capture. The question is, 'Is it cost effective?'" he said. "And with the government incentives that have been out there for a while, that are out there, we certainly believe that it is effective."

Verde CO2 has entered agreements with companies in the power sector, Fridge said, but he couldn't share information about the projects due to confidentiality provisions. "We have several million tons of CO_2 under contract of existing power generation, and we are moving forward with our FEL (front-end loading) Level 3 FEED study, which will lower the cone of uncertainty as to what the actual costs are going to be."

The pipeline of U.S. commercial capture projects tracked by Rystad have about a combined 385 mtpa of capture capacity by 2035. When factoring in risks, the firm put the number at roughly 225 mtpa.

"This takes into account the risk of delays or cancellations to projects that would push their operational date out past what had been communicated by project developers thus far," Cooke said. "In terms of scale, this represents a ~9x growth compared to the capacity of active projects today of roughly 25 mtpa."

The types of CCS projects likely to see the most near-term growth are natural gas processing, ethanol, and blue hydrogen and ammonia, according to Rystad. The reason: project economics.

"The project types, especially gas processing and ethanol, have low costs of capture, which, when combined with the additional costs of transportation and sequestration, still offer a line of sight to revenue generation under the current programs," Cooke said. "Hydrogen and ammonia also have the added potential benefit of capitalizing on blue premiums for low-carbon fuels compared to traditional products. There has been little realization of these blue premiums as of yet; however, they contribute to the business case for CCS in that sector."

Exxon CEO Darren Woods: Hydrogen Incentives 'Critical' for Now

The supermajor's leader says the end goal for energy policy should be a system in which no fuel source remains dependent on government subsidies.

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Policy uncertainty may be clouding new energies pathways in the U.S., but some energy powerhouses appear to still have a line of sight to lower-carbon solutions while acknowledging headwinds.

During quarterly earnings calls, Exxon Mobil and Chevron executives addressed continued pursuits of carbon capture and storage (CCS) and hydrogen. Both are considered key components of ambitions to shrink global greenhouse gas emissions, though the pace of development for projects' customers varies. Some projects are more heavily reliant on government support than others to strengthen economics.

The Trump administration has taken bold steps to undo parts of clean energy legislation that ushered in billions of dollars in loans, tax incentives and other financial benefits to spur development of domestic lower carbon energy resources. The move comes as traditional oil and gas companies add to their energy offerings, aiming to meet demand for lower carbon, affordable and reliable energy.

Exxon Mobil CEO Darren Woods addressed what he called the right policy framework for a successful energy future.

"Through 2030, roughly 90% of our planned capex is allocated to established, fully-functioning markets for energy and products that require no policy support," Woods said. "Only about 10% is earmarked for nascent, lower-emissions markets where market forces have yet to fully take hold. The case in point is our Baytown low-carbon hydrogen project."

Exxon plans to produce up to 1 Bcf/d of hydrogen—using natural gas as feedstock from its Permian Basin operations—for the Baytown project. Eyeing startup in 2029, the company has said it anticipates taking a final investment decision on the project in 2025. The project, however, depends on Exxon securing tax incentives under Section 45V of the Inflation Reduction Act (IRA) to be economically viable.

Chevron Hydrogen Progress

Used today mainly for industrial processes such as petroleum refining and fertilizer, hydrogen is produced primarily via steam methane reforming. But efforts are underway to add CCS components to production methods or use renewable energy. With the cleanest production method, companies could qualify for a tax credit of up to $3 per kilogram of hydrogen produced.

"We believe these incentives are critical to establishing a fully market-based future where hydrogen competes head-to-head with traditional fuels. But the end goal is clear: a system where no energy source remains dependent on government subsidies," Woods said.

He added that government policy should set carbon intensity standards on products.

"We believe this is the best way to engage the collective efforts of industry and leverage competitive market forces," he said. "To drive further innovation and reduce the most emissions at the lowest cost, policies must remain technology agnostic. Governments should not pick winners and losers. Intensity standards establish a level playing field and have a strong precedent."

Aside from policy support, customers signing offtake agreements are needed, he added.

Chevron and partner Mitsubishi Power are moving closer to starting up the Advanced Clean Energy Storage project in Delta, Utah, later this year, according to Chevron CEO Mike Wirth.

Mitsubishi sealed an offtake agreement with Intermountain Power Agency (IPA) for the hydrogen storage project, known as ACES Delta, before Chevron became a majority owner in the project. ACES Delta predates the IRA.

"The project is one of the world's largest hydrogen storage projects and will have over 200 megawatts of electrolyzer capacity," he said.

ACES Delta, the beneficiary of a $504.4 million loan guarantee from the U.S. Department of Energy's Loan

EXXON MOBIL

Exxon Mobil plans to produce up to 1 Bcf/d of hydrogen for its Baytown, Texas, project. The supermajor will use natural gas as feedstock from its Permian Basin operations.

Programs Office, will will use renewable energy to produce 100 metric tonnes per day of hydrogen to be stored in two gigantic 4.5 MMbbl salt caverns. The project will provide long-duration energy storage to be dispatched as needed to the grid as part of IPA's Intermountain Power Project.

CVX, XOM Move CCS Forward

Moves are also being made on the CCS front.

The Chevron-operated "Bayou Bend is working towards a FEED decision for the offshore project, and we're also developing plans to capture and store CO_2 from our Pascagoula refinery," Wirth said.

Located in Southeast Texas, the Bayou Bend CCS project is comprised of the offshore Bayou Bend East and the onshore Bayou Bend West. Chevron's Pascagoula refinery is in Mississippi.

Like hydrogen, lining up offtake contracts is essential to advancing projects. Also, as with hydrogen, costs have been flagged as a customer concern, particularly from those who need more expensive post-combustion capture. The low CO_2 concentration in flue gas requires more energy for separation, making the process more difficult and expensive, compared to pre-combustion capture.

Despite challenges associated with scaling up CCS, Exxon Mobil continues to make strides with its carbon capture business following its acquisition of Denbury in 2023.

"We're the only company in the world today with an end-to-end system capable of capturing, transporting and storing carbon emissions. At 6.7 million tons per year, we've contracted more CO_2 for transport and storage than any other company by far," Woods said. "We're also well-positioned to meet surging demand from data centers for low-carbon power, and on a timetable that alternatives such as nuclear simply can't match."

Exxon Mobil has said its Low Carbon Solutions business, which includes hydrogen, CCS and lithium, could bring in about \$2 billion in earnings growth through 2030.

"Obviously, that'll come as we pick up momentum and start to implement the projects that we've been talking about," said Kathy Mikells, senior vice president and CFO for Exxon. OGI

Carbon Management

Infinium, Summit Carbon Solutions Join Forces to Advance Efuels

Summit Carbon Solutions entered an arrangement with electrofuels (eFuels) producer Infinium for a supply of up to 670,000 metric tons of CO_2 annually at a proposed eFuels facility in North Dakota or South Dakota.

The proposed facility would open more market opportunities for U.S. ethanol producers and farmers in the Midwest, Summit said in a news release.

Made by combining captured CO_2 with green hydrogen, eFuels are used in the aviation, shipping and heavy transport sectors.

"CO_2 is a commodity with growing value, and Infinium's eFuels technology is an important piece of the puzzle," said Summit Carbon Solutions CEO Lee Blank. "By providing a reliable CO_2 supply, we're helping unlock opportunities that support domestic energy production and economic growth."

Energy Storage

PotlatchDeltic Enters Lithium, Bromine Lease Agreement in Arkansas

Real estate investment trust PotlatchDeltic executed a lease agreement that gives Tetra Brine Leaseco exclusive rights to carry out brine exploration and production on land in Arkansas' lithium-rich Smackover Formation.

The agreement covers about 900 surface acres in Lafayette County, according to a news release.

"We view the lease with Tetra as a great first step in demonstrating the lithium potential from our brine deposits," said PotlatchDeltic CEO Eric Cremers. "We estimate we have 5,000-7,000 acres with lithium-bearing opportunities that are located within the higher-grade area in the Smackover Formation, where billions in future lithium-related investments have been announced."

Several companies are working to develop lithium resources in the Smackover region. Though the formation spans from Texas to Florida, Arkansas has been a hotbed of activity. Lithium resources in Smackover brines of southern Arkansas could be between 5.1 MMtonnes and 19 MMtonnes, according to machine-learning estimates released in 2024 by the U.S. Geological Survey.

For the Tetra lease, PotlatchDeltic said it anticipates an initial five-year term for planning, engineering and construction before potential production begins. The lease provides for payments for the duration of the lease as well as future production payments for bromine and royalty payments for the profitable extraction of lithium, the release states.

Cremers said PotlatchDeltic is in talks with other parties about leases. PotlatchDeltic said it owns 2.1 million acres of timberlands in Alabama, Arkansas, Georgia, Idaho, Louisiana, Mississippi and South Carolina.

Standard Lithium, Equinor Unveil New Name for JV

Standard Lithium and Equinor named their JV targeting lithium as Smackover Lithium, according to a news release.

SOURCE: STANDARD LITHIUM

The Smackover Formation stretches from Texas to Florida.

The JV company is developing direct lithium extraction (DLE) projects in Arkansas and East Texas. Its Southwest Arkansas project is expected to become one of the world's first commercial-scale DLE facilities, Standard said in the release.

"Smackover Lithium is a natural fit for the joint venture given the Smackover Formation's prolific resource and our joint venture's commitment to adding to the incredible legacy of American energy production from this region," Standard Lithium CEO David Park said.

DLE involves extracting lithium directly from brine using technologies and processes such as adsorption, resin or membranes. The method is considered more environmentally friendly compared with other methods such as hard rock mining and solar evaporation brine extraction with ponds, as it requires less land, is faster and consumes less water. Lithium is a primary component in electric vehicle batteries and other energy storage systems.

Equinor and Standard formed the Smackover-focused JV in May 2024.

Geothermal

Sage Geothermal, ABB Form Energy Storage, Power Partnership

Sage Geothermal, which inked a deal in 2024 to provide geothermal power to tech giant Meta, has partnered on a preliminary basis with ABB to develop low-carbon energy

SAGE GEOSYSTEMS/ABB

Sage Geosystems' Geopressured Geothermal System energy storage facility.

storage and power generation, according to a news release.

As part of the memorandum of understanding, ABB said it will support Sage's agreement with Meta for the project east of the Rocky Mountains. ABB's work scope will include investigating how its automation, electrification and digital technology can be deployed at geothermal sites to maximize energy efficiency and reliability.

ABB said it could also develop solutions for Sage's energy storage technology. As explained in the news release, Sage's Geopressured Geothermal Systems technology pumps fluid at pressure into a manmade subsurface reservoir. The stored water is then heated and released back to the surface using pressure or mechanical energy. From there, the water moves through heat exchangers and turbines to generate electricity.

"We are focused on scaling our proprietary Geopressured Geothermal Systems (GGS) technology and our partnership with ABB will advance the widespread deployment of next-generation geothermal," said Sage Geosystems CEO Cindy Taff. "Unlike traditional renewable energy sources, geothermal solutions, including energy storage and baseload power generation, can provide an on-demand source of clean energy that is available 24 hours a day, 365 days a year."

Sage agreed in 2024 to deliver up to 150 megawatts (MW) of geothermal energy to Meta to help meet growing data center electricity needs. The project's first phase is expected to be operational by 2027, the release stated.

SLB, DEEP Earth Energy Team Up to Boost Geothermal in Canada

DEEP EARTH ENERGY PRODUCTION CORP.

DEEP Earth Energy Production Corp. is targeting full commissioning of the first phase of its next-generation geothermal project in Canada by 2026.

DEEP Earth Energy Production (DEEP) brought in SLB as a partner to help advance a next-generation geothermal development project in Canada, according to a news release.

Located in southeastern Saskatchewan, the project aims to initially produce up to 30 MW of emissions-free, baseload power. Plans are to use oil and gas techniques such as horizontal drilling and production enhancement technologies, leaning on SLB's geothermal, integrated well construction and drilling technology expertise.

SLB will provide engineering design and integrated well construction services for the first two phases of the project. The work includes development of two production and two injection wells in Phase 1 and up to 18 wells in Phase 2.

"This collaboration with DEEP reflects our commitment to broadening the adoption of geothermal by reducing project risk and accelerating the time to first power," said Irlan Amir, vice president of renewables and energy efficiency at SLB. "The project's innovative engineering design and integrated asset development model brings together developers, technology providers and infrastructure partners to open new frontiers for geothermal power generation in Canada and beyond."

DEEP is targeting full commissioning of the project's first phase by 2026.

Hydrogen

Puget Sound Energy, Modern Hydrogen Form Partnership

Washington utility Puget Sound Energy (PSE) teamed up with Modern Hydrogen to advance adoption of decarbonization technologies such as Modern's distributed methane pyrolysis technology, according to a news release.

The two companies signed a memorandum of understanding to collaborate on "supporting commercial and industrial customer decarbonization objectives, market analysis, and the technical and economic evaluation of Modern Hydrogen's technology as a decarbonized energy solution in customer-specific applications," PSE said.

Modern Hydrogen's technologies remove carbon from natural gas at the meter for commercial and industrial operations, enabling utilities to decarbonize, the company said. The agreement took shape as Washington takes steps to meet clean energy targets.

"Our partnership with Modern Hydrogen is a significant step towards achieving this vision, as their technology has the potential to help our largest gas customers accelerate their decarbonization programs and reduce their greenhouse gas emissions," PSE Vice President of Energy Strategy and Planning Josh Jacobs said.

Washington's clean energy goals include having an electricity supply free of greenhouse-gas emissions by 2045.

Plug Power Launches Spot Pricing for Green Hydrogen

Plug Power introduced a spot pricing program for liquid green hydrogen, marking an industry first, the company said.

The program gives buyers an opportunity to buy liquid green hydrogen from Plug's production plants on-demand and without long-term take-or-pay agreements, the company said.

"By adapting to market demands in real-time, we are not only enhancing the accessibility and affordability of green hydrogen but also accelerating its adoption across various sectors," Plug Power CEO Andy Marsh said.

S&P Global Platts will publish a price on Thursdays for the following week based on Plug's supply and demand at the current time, according to a press release. If customers want to purchase hydrogen at the published price, Plug will execute a transaction agreement to accept a customer tanker at one of its plants for a fill.

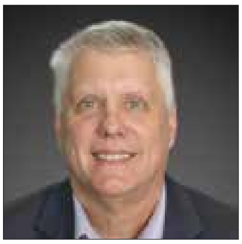
To participate, customers are required to have a spot agreement with the company. Plug said it has already entered such agreements with several industry players, including one of the largest industrial gas companies. The company was not named.

"Looking forward, the ripple effects of this innovative pricing model could redefine supply dynamics and cost structures across the entire green hydrogen ecosystem," Plug said.

The company currently produces about 45 tons per day of liquid hydrogen from its facilities in Woodbine, Ga., Charleston, Tenn., and St. Gabriel, La. OGI

Saving Methane, Saving Money

Startups are finding ways to curb methane emissions while increasing efficiency–and profits.



RICHARD STUBBE
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The methane emissions business is picking up steam as startups introduce solutions to keep the gas in the pipes and out of the atmosphere.

Companies including Envana Software Solutions, ZENRG Services and LongPath Technologies are getting not only awards from the U.S. Department of Energy (DOE) but also private investments. They're deploying lasers, AI and new equipment to detect leaks more quickly and capture gas that might otherwise have escaped in routine operations.

Many of the businesses received grants from the DOE resulting from the 2022 Inflation Reduction Act, which created the federal Methane Emissions Reduction Program. The program provided $1.36 billion in financial and technical assistance through multiple funding opportunities; it also established a waste emissions charge (WEC) for methane.

The WEC's future is uncertain, as Republican lawmakers in both the House and Senate have introduced bills to kill it. It applies to petroleum and natural gas facilities that emit more than 25,000 metric tons (mt) of CO_2-e per year, charging them $900/mt for reported methane emissions in 2024, then $1,200 in 2025 and $1,500 for 2026 and beyond.

For the moment, the incentive exists. Even without it, the industry has been making progress for some time. S&P Global Commodity Insights estimated that methane emissions from the Permian Basin declined 26% in 2023 from 2022.

Companies big and small are moving to keep the product from escaping. After all, it's inventory, the price of natural gas is trending upward and demand is expected to keep rising.

Here are some of the new players.

ZENRG Services

ZENRG Services, based in Houston, deploys mobile units to job sites to enable the safe and emissions-free transfer of gas or liquids from operations into pipelines. The company has secured Series A funding to support its expansion plans from a team including the private firm EIC Rose Rock, Chevron Technology Ventures and BP Energy Partners.

"We're able to keep all the customers' material, whether it be gas or liquids, in that system that the customer owns by compressing it under high pressure," said CEO Joe Chandler,

ZENRG SERVICES

ZENRG Services deploys mobile units to job sites to enable the safe and emissions-free transfer of gas or liquids from operations into pipelines.

formerly the CEO of Yellowjacket Oilfield Services. "The technology that we use hasn't been readily available in the market before, and now we are using it in several different ways."

Sam Edwards, ZENRG's co-founder and COO, said ZENRG formed in late 2021 with two applications in mind. That number grew rapidly.

"We probably have north of 25 applications" at work in upstream, midstream, downstream, chemicals and utilities, he said. "Once they understand the concept is as easy as moving product from one area or one vessel or pipeline or other containment that is under pressure into another area that's able to receive it, that's when the client's minds will start to work and the brainstorm will begin to occur."

David Clouse, managing director of EIC Rose Rock, said his firm picked ZENRG out of more than 100 companies in the emissions-reduction space because the solution is economically beneficial.

"It's not dependent on government mandates or whether the Trump administration guts all of the emissions regulations and mandates and potential fees," he said.

Envana Software Solutions

Envana detects methane emissions by applying AI to data from existing sensors. It was awarded a $4.2 million grant from the DOE to advance its AI methane detection solution.

Envana gleans information from Supervisory Control and Data Acquisition (SCADA) systems, said Khaled Hashem, senior product manager for Envana. Most oil and gas operations have SCADA on site already.

"These are your flow sensors and your temperature sensors," Hashem said. "Every single oil and gas site, almost without exception, has invested in those. Even the smaller sites will have at least a sensor, and large sites have thousands of sensors."

Envana's software can combine the data from those sensors with other available data, then apply AI's pattern recognition to detect methane.

That information helps operators in three ways, Hashem said. It delivers actionable data, sets off alarms when necessary and allows companies to automate to avoid leaks before they happen.

Envana started as a joint venture between Halliburton and the private equity firm Siguler Guff, said Roxana Nielsen, vice president of products and previously Halliburton's director of stewardship and sustainability reporting. "It was my responsibility to do things like our annual sustainability report," Nielsen said. "It was pretty clear that there were some gaps in how oil and gas companies could do this more efficiently." Halliburton's commercial software division was also looking at the space, and eventually Envana was spun off.

Pioneer Energy

PIONEER ENERGY

Pioneer Energy's emission control treatment technology processes wellhead fluid in a closed system that processes crude, resulting in zero routine flaring with no need for atmospheric storage tanks.

Pioneer's technology can deliver efficiency gains in two ways: emissions reduction and increased crude yield right at the well pad.

The technology processes wellhead fluid, replacing traditional infrastructure such as phase separators. This closed system completely processes the crude, resulting in zero routine flaring with no need for atmospheric storage tanks. Pioneer, based in Lakewood, Colo., says it can boost a well's crude yield by 5% to 10%.

With traditional systems, "anyplace you have a connection point, a flange, a valve, you've got the potential for fugitive emissions," said Joseph Palaia, vice president of business development. "We can replace all of that with refining technology that we've miniaturized and automated. We build in a factory environment, with a minimum amount of field labor required to install it and operate it. And it's 100% electric."

Longpath Technologies

The company uses an array of devices and mirrors to create a laser-beam fence around drill pads and other facilities. The system recently received conditional approval for use in New Mexico.

The system works because light changes when it passes through methane, said Caroline Alden, co-founder and chief scientist at Longpath, based in Boulder, Colo.

LONGPATH TECHNOLOGIES

LongPath Technologies provides an emissions network that continuously monitors methane emissions across oil and gas supply chains in real time. Its technology features towers equipped with laser transceivers that send out laser beams to detect emissions.

"When you send that laser beam that we've created that's very specifically tuned to methane's vibrational and rotational properties, and then we bounce the light back off that mirror, we can see essentially where the methane fingerprint has been imposed on that light," she said.

Mounting the Longpath system means companies can reduce regular in-person inspections, which saves a lot of mileage in an area as vast as the Permian.

Kuva Systems

Kuva Systems was awarded a $5 million contract from the DOE to support its remote emissions investigation system across 175 oil and gas sites in the U.S.

The system provides root causes of emissions directly to field staff, said Kuva CEO Stefan Bokaemper, allowing the operators to integrate monitoring into their workflow without hiring extra staff.

Xplorobot

XPLOROBOT

Field inspector using the Xplorobot Laser Gas Imager to detect methane emissions.

Xplorobot's Laser Gas Imager is a handheld mobile detection device that has been approved as an alternative test method for methane inspections. The company says it can detect emissions as small as 1 gram per hour and requires only three hours of training to use.

Highwood Emissions Management

Highwood Emissions Management's new Emissions Intelligence Platform is designed to streamline methane emissions accounting and reporting for the oil and gas industry.

The company said EIP builds auditable, consistent and framework-compliant methane inventories that comply with global methane initiatives and regulations like OGMP 2.0, EU import requirements, MiQ and Veritas. OGI

Hirs: America Confronts Sovereign Risk

The risk to U.S. oil and gas production comes from within, and a recession looms on the horizon.

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The U.S. oil and gas industry understands sovereign risk, or political risk. As the industry proved up reserves and production across the world, regimes often found it easy to renege on their development agreements. OPEC was founded in 1960. In ensuing years, member nations took back control of their oil and gas fields. Actions against global oil companies by Russia, Venezuela, Mexico, Canada, Colombia and several African nations have run the gamut from outright expropriation to increasing taxes on production.

But now the risk to U.S. domestic oil and gas production, as well to as the greater U.S. economy, comes from within.

The Trump administration has doubled down on its support of U.S. oil and gas, but despite that, the oil patch is facing a double whammy–the latest 25% tariffs on imported steel will raise costs, and the administration's pressuring of Saudi Arabia to increase production could lower revenues.

That doesn't count the possibility of a looming recession. Higher costs for steel will raise the cost of pipelines needed to connect producing regions to consumers and LNG exporters. If the promised mass deportations of undocumented immigrants reach the Permian Basin, the cost of labor also will increase. Even if domestic and foreign banks are abandoning net zero redlining, Wall Street will not be forthcoming with new capital for any industry facing the prospect of higher costs and lower revenues.

It is not just the oil patch facing political difficulty. The announced rollbacks of federal incentives and subsidies for wind, solar and batteries will delay installations that many states now require to meet peak electricity demand–especially Texas.

In his first term, President Donald Trump withdrew from the Trans-Pacific Partnership and imposed 25% tariffs on China. China's response was to devalue its currency to counteract the impact of tariffs and to cut imports of U.S. farm products. The Trump administration and Congress paid out $23 billion to compensate farmers for their lost markets.

Trump has temporarily suspended his proposed 25% tariffs on most goods imported from Mexico and Canada (dropping to 10% on imports of Canadian oil). This unilateral threat to suspend the United States-Mexico-Canada Agreement, negotiated during the first Trump administration, is tied to his demand that Mexico and Canada do more to eliminate unauthorized border crossings and the devastating cross-border trade in fentanyl, which contributed to more than 80,000 drug overdose deaths in the U.S. in 2024.

If the nations do not reach agreement and Trump goes ahead with the punitive tariffs, both Mexico and Canada have promised retaliatory measures that will drive up the costs to U.S. consumers for everything from beer to electricity.

The secondary impact on U.S. capital markets may be more severe. Many domestic companies began to prepare for tariffs in fourth-quarter 2024 by rearranging supply chains and prepositioning inventories in the U.S. These additional costs will manifest themselves in lower-than-expected earnings for 2024, pressuring stock prices downward. This will be the least significant impact of the new protectionist tariffs.

While the U.S. does run a trade deficit in goods and services, the domestic economy benefits because U.S. dollars paid out to trading partners come back as foreign direct investment and in dollar purchases of stocks and bonds at home and abroad. This continuing source of investment capital has helped lower domestic interest rates and kept the U.S. stock market at record levels.

The catalyst for the most recent bear market was Russia's invasion of Ukraine. Since then, the S&P 500 index is up more than 2,500 points without a significant correction. Losing any portion of this circular reinvestment back into the U.S. capital markets will knock the legs out from under the stock markets. We will all be poorer.

The Trump administration's plans to reduce domestic federal spending on entitlements programs, direct aid, research and federal staffing will increase unemployment. State and federal workforce aid programs will be strained.

To sum it up, until the benefits of the administration's new policy directions can be seen, a recession is on the horizon for the U.S. and our trading partners. The U.S. oil and gas industry will suffer in a recession and prolonged trade war. The resilience of all Americans will be tested, and the jockeying for the 2026 midterm elections has already begun. OGI

Paisie: Impact of Tariffs, Sanctions and 'Drill, Baby, Drill'

The U.S. has the advantage with tariffs on Canada, but sanctions and pleas for increased oil supply are unlikely to be effective.

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

Much of the news so far this year has been dominated by external factors that can affect the oil market. These factors include the imposition of tariffs, the expansion of sanctions and calls for increased oil supply.

This month, we look at each of these factors and the expected implications.

Tariffs

Early in February, President Donald Trump imposed a 25% tariff on goods from Mexico and Canada, and 10% on energy, including oil. While these tariffs were quickly withdrawn, at the time of this writing, the withdrawal was temporary, and the tariffs could be reimposed in 30 days.

The U.S. is the major destination for Canadian crude exports (more than 90% of Canada's total crude oil exports) with the U.S. importing around 4 MMbbl/d from Canada, which represents around 60% of total U.S. crude imports. (The U.S. also exports around 4 MMbbl/d, so, on a net basis, the U.S. imports about 2.5 MMbbl/d).

Last year, Canada completed a new pipeline to move crude oil to the West Coast–the TMX pipeline with capacity of 590,000 bbl/d–and to complement the Trans Mountain pipeline with a capacity of 300,000 bbl/d. Since July 2024, the West Coast has averaged 444,000 bbl/d of crude imports from Canada, which is an increase from 308,00 bbl/d during the first half of 2024.

While the U.S. is dependent on crude oil from Canada, it is also true that Canada is dependent on the U.S. as a market for its crude exports. Logistically, Canada has, in practical terms, nowhere else to go with its crude oil exports. Additionally, since a substantial portion of Canadian crude oil is heavy (around 21° API), there are only a selected number of refineries with the capabilities to process Canadian crude outside of the U.S.

Because of quality attributes and logistical challenges, Canadian heavy crude is priced at a significant discount compared to U.S. crude (Western Canadian Select is priced about $14.50/bbl less than WTI). With consideration of these factors, while the tariffs would add some friction, we do not think that the tariffs would have any material impact on Canadian oil production nor exports to the U.S.

Sanctions

In January, before leaving office, President Joe Biden imposed additional sanctions on Russia's military capabilities and energy sector. The energy-related sanctions encompass more than 200 entities and individuals, including Gazprom Neft and Surgutneftegas, as well as traders, oil service providers and government officials.

Besides sanctions on Russia, Trump has stated that he will impose sanctions on Iranian oil exports with the goal of reducing Iran's oil exports by 500,000 to 750,000 bbl/d from its current level of around 1.6 MMbbl/d, of which, around 90% of the exports are going to China. There could also be a return of tighter sanctions on Venezuela oil exports, which exported around 775,000 bbl/d in 2024, the highest level since 2019.

We still have doubts with respect to the lasting effectiveness of the sanctions for several reasons. While a couple hundred Russian tankers have been sanctioned, Russia's shadow fleet is thought to be around 800 tankers, and Russia can augment this fleet by purchasing additional older tankers. Russia can also increase the utilization of ship-to-ship transfers and other maneuvers to reduce transparency.

Iranian crude exports are closely linked to China and are done with the use of Chinese currency and non-Western shipping services. While one-third of Venezuelan exports go to the U.S., the remaining two-thirds go to China.

Calls for Increased Oil Supply

At the World Economic Forum, Trump called for OPEC to lower oil prices by increasing production. We do not expect that his statements will have much influence on the strategy of the members of OPEC+. Instead, we expect that OPEC+ will remain cautious with respect to increasing supply while assessing the strength of oil demand growth and the impact of energy policies of the Trump administration.

OPEC+ will need to balance these factors with the need to maintain cooperation among their members–including with those members pushing for more production–notably UAE and Iraq.

Trump also issued executive orders that are supportive of the U.S. oil and gas sector. We do not think that the related push for additional supply will have much influence on the strategy of U.S. shale producers, which are focused on maximizing returns and free cash flow generation–and not production growth. OGI

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

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EVENT	DATE	CITY	VENUE	CONTACT
2025				
SGA 2025 Spring Gas Conference	March 3-5	Charlotte, N.C.	Charlotte Convention Center	southerngas.org
SPE/IADC International Drilling Conference and Exhibition	March 4-6	Stavanger, Norway	Forum Expo	drillingconference.org
CERAWeek	March 10-14	Houston	Hilton Americas-Houston	ceraweek.com
DUG Gas Conference & Expo	**March 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**hartenergy.com/events**
SPE/ICoTA Well Intervention Conference & Exhibition	March 25-26	The Woodlands, Texas	The Woodlands Waterway Marriott Hotel & Convention Center	spe-events.org
AI in Oil & Gas Conference	April 8-9	Houston	Hyatt Regency Houston West	aioilandgas.energyconferencenetwork.com
Energy Workforce & Technology Council Annual Meeting	April 9-10	Frisco, Texas	The Westin Dallas Stonebriar Golf Resort	energyworkforce.org
World Oilman's Mineral & Royalty Conference	April 14-15	Houston	Post Oak Hotel	mineralconference.com
SPE Improved Oil Recovery Conference	April 23-25	Tulsa, Okla.	River Spirit Casino and Resort	speior.org
Offshore Technology Conference	May 5-8	Houston	NRG Park	2025.otcnet.org
Canada Gas Exhibition & Conference	May 6-8	Vancouver, Canada	Vancouver Convention Center	canadagalng.com
SUPER DUG Conference & Expo	**May 14-15**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**hartenergy.com/events**
World Hydrogen 2025 Summit & Exhibition	May 20-22	Rotterdam, Netherlands	Rotterdam Ahoy	world-hydrogen-summit.com
SGA Energy Symposium	May 22	Houston	TBD	southerngas.org
Energy Capital Conference	**June 4**	**Houston**	**The Post Oak at Uptown Houston**	**hartenergy.com/events**
URTeC	June 9-11	Houston	George R. Brown Conv. Ctr.	urtec.org/2025
IADC World Drilling Conference & Exhibition	June 10-11	Amsterdam	Beurs van Berlage	iadc.org
Global Energy Show Canada	June 10-12	Calgary, Canada	BMO Centre at Stampede Park	globalenergyshow.com
Reuters Data Driven Oil & Gas 2025	June 24-25	Houston	TBD	events.reutersevents.com
2025 Operations Conference	July 22-25	Austin, Texas	TBD	southerngas.org
IMAGE	Aug. 25-28	Houston	George R. Brown Conv. Ctr.	imageevent.org
DUG Appalachia Conference	**Aug. 27**	**Pittsburgh**	**David L. Lawrence Conv. Ctr.**	**hartenergy.com/events**
Gastech Exhibition & Conference	Sept. 9-12	Milan	Fiera Milano	gastechevent.com
A&D Strategies & Opportunities Conference	**Sept. 11**	**Dallas**	**The Thompson Hotel**	**hartenergy.com/events**
DUG Permian Conference & Expo	**Oct. 15-16**	**Midland, Texas**	**Midland County Horseshoe**	**hartenergy.com/events**
SPE ATCE	Oct. 20-22	Houston	George R. Brown Conv. Ctr.	atce.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

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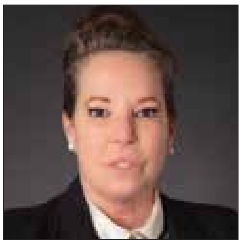
How DeepSeek Made Jevons Trend Again

As tech and energy investors began scrambling to revise stock valuations after the news broke, Microsoft Corp.'s CEO called it before markets open: "Jevons paradox strikes again!"



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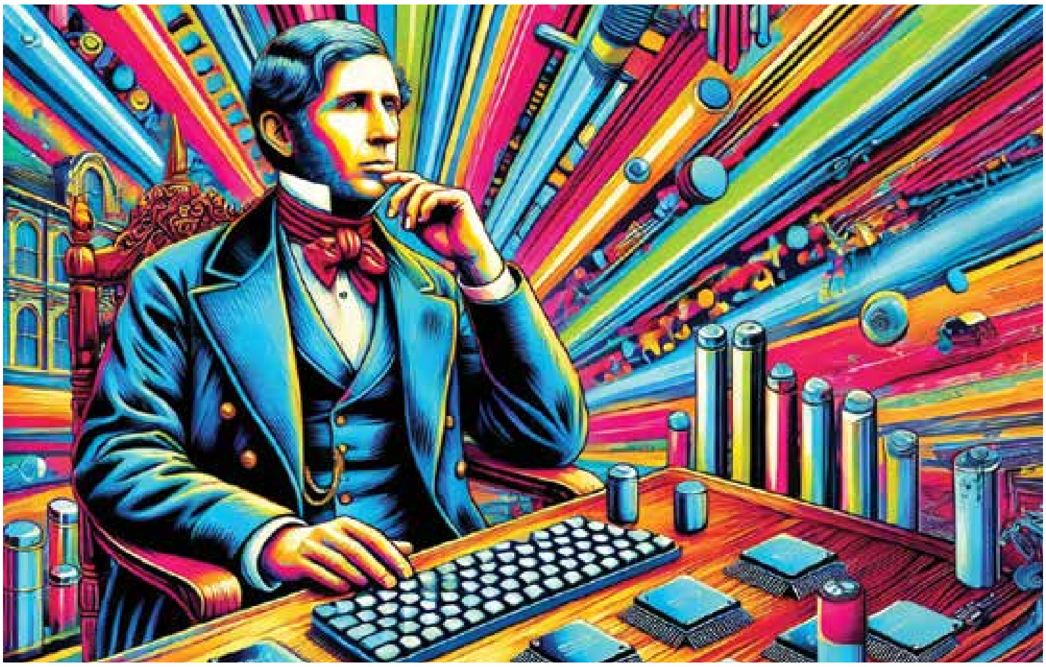

OPENAI DALL-E

Jevons paradox is trending, schooling social media posters in economic theory, particularly "marginal utility theory."

"Jevons" had not been popular since the early aughts, according to a Google Trends scrape of internet use of the word since 2003.

And relatively speaking, it wasn't so hot back at the turn of the century either, when Jevons was used to explain why the decline in chip prices and rise in compute power rapidly accelerated growth in digitization rather than diminish it.

In short, we just can't get enough of it.

A home may have had one or two digital devices in 2003. Today, it could have dozens.

The week after DeepSeek roiled capital markets and sent analysts to revisit their modeling of chip and energy demand, "Jevons" scored 100 in use relative to any past all-time high, which was recorded in 2004 and demoted on Jan. 27 from 100 to 33.

Pre-DeepSeek week, the score was 3.

"Jevons paradox getting its moment in the sun," wrote a Bluesky poster.

Note: The DeepSeek news is not yet confirmed to be a breakthrough. OpenAI is investigating whether DeepSeek didn't "learn" what it knows by self-training. Rather, the investigation is of whether its knowledge is "distilled" from OpenAI.

This is different than simply using the OpenAI model, which it did, but it is open source and is allowed with a condition that prohibits distillation.

Also, there are doubts about how few chips DeepSeek used. Not many chips are needed in AI training in comparison with the knowledge quality and processing intensity it needs when anyone is using the AI–the "inference."

And there are other unresolved concerns, such as whether to interact with China-based AI.

Andrew Munoz, COO of AI-enabled E&P asset valuation firm 4Cast, said at NAPE in February, "I'm not advocating using that model, by the way, because user beware: It's not sourced from the U.S."

In my inbox of energy research reports, there were 12 notes containing "Jevons" between 2013 and the week before DeepSeek's news. In three weeks following, "Jevons" appeared in 10.

The theory was minted in 1865 by economist William Stanley Jevons, who determined that technological advances in energy efficiency–in his research's case, with burning coal–would result in more demand, not less.

Since the Coal Age, it's been proven correct for oil, natural gas, electricity and other commodities, including chips and data storage.

Microsoft Corp. CEO Satya Nadella jump-started trending Jevons, posting on X the Wikipedia link to "Jevons paradox" the evening before the world woke to the DeepSeek news.

"Jevons paradox strikes again!" he wrote. "As AI gets more efficient and accessible, we will see its use skyrocket, turning it into a commodity we just can't get enough of."

Amazon celebrated DeepSeek's news, too. CEO Andy Jassy was asked in an earnings call how it affected cost, uptake acceleration and returns on Amazon investments.

Jassy replied, "Sometimes people make the assumptions that, if you're able to decrease the cost of any type of technology component–in this case, we're really talking about inference–that somehow it's going to lead to less total spend in technology.

"And we have never seen that to be the case."

When Amazon Web Services was launched in 2006, storage cost 15 cents a gigabyte; computing, 10 cents an hour.

Clients could spend less on their in-house infrastructure. But what AWS has seen is that users "will then get excited about what else they could build that they always thought was cost-prohibitive before," Jassy said.

"And they usually end up spending a lot more in total on technology once you make the per-unit cost less," he said.

In AI, the cost of inference is declining and "going to be very positive for customers and for our business."

Gokul Hariharan, tech analyst for J.P. Morgan Securities, wrote, "Even before DeepSeek R1's introduction, AI inference costs have been dropping at 85% to 90% per year."

As a result, there has been an explosion in AI use that didn't exist or was too costly for wider consumption.

Meanwhile, declining costs for training AI models likely won't result in lower spend.

"On the contrary, we believe they are likely to trigger bigger budgets, as more innovations are typically made possible within a shorter timeframe," Hariharan wrote.

What does this mean to previous models for power demand for AI?

Arun Jayaram, the firm's E&P analyst, reported no change: 60 GW of additional U.S. power demand by 2028 versus the 2022 level.

Meta Platforms' plan to spend $65 billion on AI this year is unchanged, it reported. Microsoft's plans are for $80 billion and unchanged.

Meta's chief AI scientist Yann LeCun posted on Threads, "Major misunderstanding about AI infrastructure investments: Much of those billions are going into infrastructure for 'inference,' not training.

"Running AI assistant services for billions of people requires a lot of compute. Once you put video understanding, reasoning, large-scale memory and other capabilities in AI systems, inference costs are going to increase.

"The only real question is whether users will be willing to pay enough–directly or not–to justify the capex and opex.

"So, the [stock] market reactions to DeepSeek are woefully unjustified." OGI

Oil and Gas Investor

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