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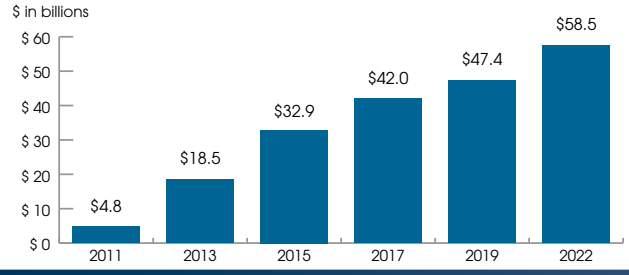
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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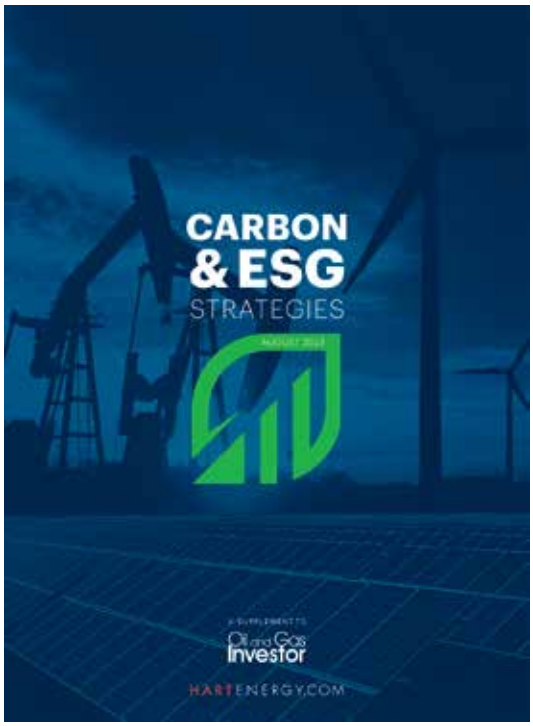

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ABOUT THE COVER: Photographer Tom Fox captures an image of EnLink Midstream CEO Jesse Arenivas in the company's Dallas headquarters in July.


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Carbon Capture and Capitalization: Industry Transforms, Tackles the Transition

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There remains some debate about the verbiage that best describes the dynamic reshaping of the oil and gas industry, but there is little room for doubt that the business of energy is changing.

This edition of *Oil and Gas Investor* features two special supplements: one focused on ESG strategies and one depicting the future of hydraulic fracturing. Much of the content is linked by the various components of a multifaceted goal: the capturing of and capitalization on the capture of carbon emissions.

This year, the U.S. Environmental Protection Agency reported total emissions from the petroleum and natural gas systems sector increased 13% to 312.2 million metric tons of carbon dioxide equivalent (MMt CO_2e) in 2021 from 276.7 MMt CO_2e in 2016. While methane emissions fell 27% to 70.9 MMt CO_2e from 89.8 during the same period, CO_2 emissions jumped more than 29% to 241.2 MMt CO_2e from 186.7 MMt CO_2e.

Carbon capture and storage (CCS) is a likely key to wrangling emissions. And incentives in the Inflation Reduction Act of 2022—such as an increase to the 45Q tax credit, expanded construction deadlines and lower carbon capture thresholds—are luring companies to incorporate CCS into their emission reduction strategies.

The Inflation Reduction Act, which became law in August 2022, is designed to encourage more developers to pursue such projects as significant tax credits and other benefits improve project economics. The 45Q tax credit is $17/metric ton (mt) for sequestered qualified carbon oxide, but the value jumps to $60/mt for storage associated with enhanced oil recovery (EOR), $85/mt for dedicated geologic storage, $130/mt for direct air capture with carbon utilization and up to $180/mt for direct air capture with carbon storage.

The U.S. government in 2021 guided how the business model can work with an updated 45Q policy; and across the U.S. space, carbon capture is gaining momentum and a growing share of corporate spending. Stephen Stokes, global head of CO_2 transport and storage at Wood, told Hart Energy in June that there is a growing industry trend for economies of scale in CCS projects. Occidental Petroleum, BP, Pioneer Natural Resources and many other producers are targeting CCS investment in technology and deal making.

From in-house research and development to acquisitions and asset repurposing, companies such as Exxon Mobil and EnLink Midstream are developing ways to integrate carbon capture into their business models.

In mid-July, Exxon Mobil made a $4.9 billion all-stock deal to buy Denbury Resources. The acquisition gives Exxon the largest owned and operated CO_2 pipeline network in the U.S. with 1,300 miles throughout Louisiana, Texas and Mississippi. Exxon executives said the synergies expected will enable annual emissions reductions of roughly 100 million tons and drive returns.

In an exclusive interview with *Oil and Gas Investor* this month, EnLink CEO Jesse Arenivas lays out how the firm achieved first-mover status among midstream players in the CCS space. Working with BKV Corp. in Texas and Exxon in Louisiana, EnLink is relocating and repurposing certain pipeline assets with proximity to both the emissions and sequestration sites needed. The venture with Exxon has capacity of up to 10 Mt of CO_2 annually.

Still, the International Energy Agency (IEA) estimates that the more than 500 projects in various stages of development throughout the value chain is just enough to meet one-third of what's required to reach global net-zero by 2030.

Gains are happening, but ongoing capital deployment between $400 billion and $500 billion would be needed every year until 2030 to close the net-zero gap, according to IEA. OGI

DEON DAUGHERTY
EDITOR-IN-CHIEF

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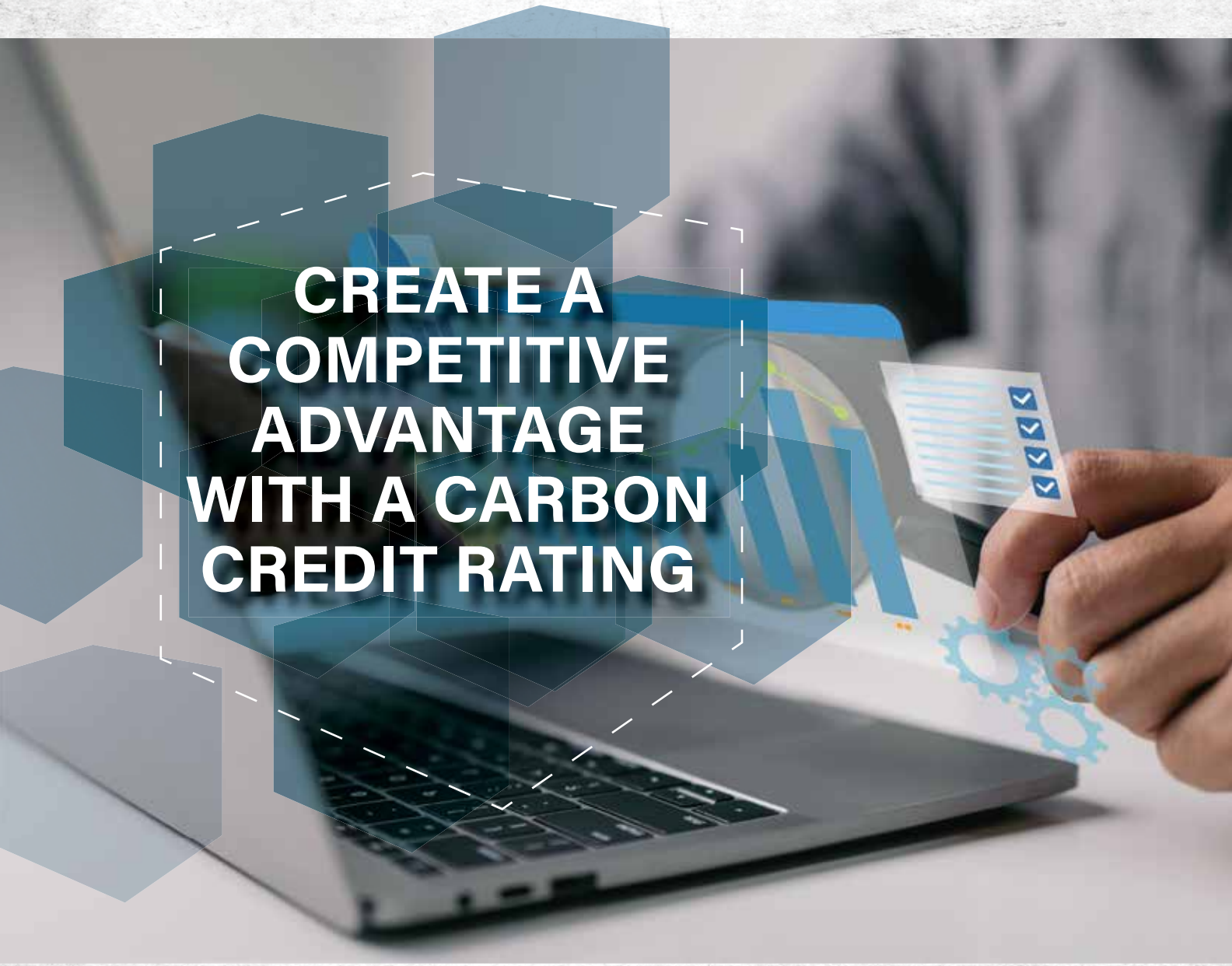

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For LNG, 2023 is the New 2014

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Bear with me, this will only take a second: The market for super-chilled LNG is heating up.

There. It's done. Out of my system. Ah, clichés. If necessity is the mother of invention (cliché), then clichés are the mothers of lame writing (not exactly a cliché but self-evident).

In this instance, though, reaching back for inspiration can be justified. The "heating up" line was deployed ad nauseum in coverage of LNG in 2014 (I should know, I used it enough), and it's starting to look like 2023 is the new 2014.

Three major projects with total capacity of 5.1 Bcf/d are on track for final investment decisions this year, the most since 4.9 Bcf/d in 2014, Reuters has reported. They include Venture Global LNG's Plaquemines facility in Louisiana (1.2 Bcf/d) and Sempra Energy's facility in Port Arthur, Texas (1.8 Bcf/d). NextDecade's Rio Grande project in Brownsville, Texas (2.1 Bcf/d) would be the third.

Then there are the deals signed to move that gas. INEOS Energy Trading will transport 1.4 million tonnes per annum (mpta) of LNG from Sempra's terminal to Germany's Brünsbuttel regasification facility via two brand-spanking-new carriers built by MOL in South Korea. Cheniere locked in a 20-year agreement to sell about 1.8 mtpa to China's ENN Natural Gas. Part of that deal is subject to an FID on the first train of Cheniere's Sabine Pass Liquefaction Expansion Project and stems from China's demand as it shifts away from coal.

Four scenarios

So, let's blast "Happy" by Pharrell Williams and look at the numbers.

Everything hinges on price. If the price of natural gas isn't high enough overseas, it's not worth building the export terminals here. Clearly, the recent slew of deals reveals confidence that price won't be a problem.

The Energy Information Administration (EIA) projects volumes of U.S. LNG on the global market to rise, eventually forcing international prices to drop. The opposite happens domestically—increased exports tighten the U.S. natural gas market and push up prices.

Eventually, the EIA says prices reach an equilibrium at which building new LNG capacity no longer makes economic sense because the spread will evaporate. That will limit LNG exports, which, if demand continues to rise, will push global prices … you get the picture.

The EIA lays out four scenarios for the LNG market in 2050: the reference case from its Annual Energy Outlook; low international gas prices; higher international gas prices; and higher prices combined with faster development of export facilities.

What is interesting about the EIA analysis is that, while LNG exports affect U.S. natural gas prices, it's not by much. Or, at least, not as much as it has been.

In the combination scenario of fast development and high international prices for LNG, exports will come in 77% higher than the base case in 2050. The Henry Hub price of $4.81/MMBtu, however, is only 28% higher.

And consumption will be flat across the board.

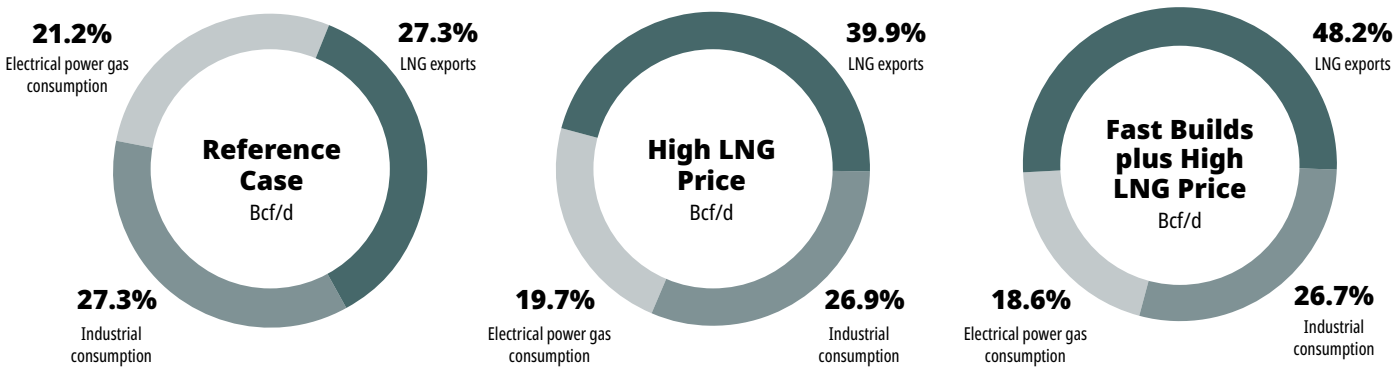
"In total, U.S. natural gas consumption changed only slightly across the cases because decreases in domestic consumption are largely offset by additional natural gas consumption required to support higher levels of LNG production and transmission," the EIA says in its latest report in May.

The upshot in the EIA analysis is that, barring unexpectedly low international prices, LNG exports will become the largest segment of U.S. natural gas consumption beginning in the 2030s. And shipping it to those in Europe and Asia lacking in our bounty will not cause economic hardship domestically.

Makes ya want to dance like it's 2014. OGI

And the Winner is … LNG Exports

In three scenarios, LNG exports become the largest segment of natural gas consumption in 2050.



Source: EIA

To markets, to markets

LNG developers see more natural gas, more terminals, more ships to get their product to international customers.

Source: Hart Energy

Viability of US Offshore Oil and Gas Industry at Risk

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

The U.S. offshore oil and gas program has been facing severe challenges for the past couple of years. In fact, the National Outer Continental Shelf (OCS) Oil and Gas Leasing Program, which has been the backbone of the industry in the U.S., has been delayed by actions and inactions taken by the Biden administration.

In early 2021, the administration decided to "take a pause" on new oil and gas lease sales, including all offshore lease sales, in order to determine their impacts on U.S. climate goals. It canceled three lease sales in 2022, two in the Gulf of Mexico and one in Alaska's Cook Inlet. This resulted in no federal OCS lease sales held in 2022—the first year without a sale since 1958.

Also in 2022, the Interior Department initiated the process to develop a new five-year offshore leasing plan for 2023-2028, raising the specter of additional delayed lease sales given the lengthy reviews required prior to actual leasing. The draft proposed plan that it submitted contained options for between zero and 11 lease sales, with a maximum of 10 in the Gulf of Mexico and one in the Cook Inlet and no lease sales in the Atlantic or Pacific.

To address the risk that offshore oil and gas leasing would be further postponed, provisions were included in the Inflation Reduction Act (IRA) passed by Congress August 2022 that directed the Interior Secretary to hold three offshore lease sales that had previously been scheduled but subsequently canceled by Interior.

In other words, it literally took an act of Congress for federal lease sales to resume. The IRA also linked continued federal offshore wind leasing with continued offshore oil and gas leasing, stipulating that offshore wind leasing not take place unless there are first federal oil and gas lease sales that result in leases being awarded. The measure was part of a compromise with Senate Natural Resources Committee Chairman Joe Manchin (D-W.Va.), who said the administration had been "putting their radical climate agenda ahead of our nation's energy security."

U.S. law directs the Interior Department to issue five-year offshore leasing programs. Contrary to the will of Congress and despite the impact that the war in Ukraine has had on global oil trade, the Interior Department continues to slow-walk the federal leasing process. After significant delays in initiating the five-year plan process, Interior continues to slow-walk the environmental review process, placing the feasibility of any Gulf of Mexico oil and gas lease sales in 2024 in serious doubt, regardless of whether it completes the five-year plan process in 2023 as it has committed to doing.

Other federal actions could jeopardize the future of federal offshore oil and gas leasing, including new administration initiatives to place a value on nature and incorporate it into cost-benefit analysis for all federal regulatory decisions. Known as the "National Strategy to Develop Statistics for Environmental-Economic Decisions," this initiative formally launched in January has been developed under the premise that GDP is no longer an acceptable way to measure the health of the U.S. economy.

More recently, in late June, the White House launched a new effort to develop a "National Strategy for a Sustainable Ocean Economy," which among other things will identify new actions to "advance sustainable management." The effort is part of the administration's commitment to develop a "Sustainable Ocean Plan" for all federal waters as part of the country's recent accession to the High-Level Panel for a Sustainable Ocean Economy.

The U.S. offshore oil and gas program has been the envy of the world since the 1950s. It is both a technological and environmental marvel. According to the National Ocean Industries Association, the Gulf of Mexico has about half the carbon intensity of other onshore areas and the deepwater Gulf of Mexico has the lowest greenhouse gas emissions intensity of all oil producing regions. Similarly, the Obama administration determined that outsourcing Gulf of Mexico production would increase overall greenhouse gas emissions. In other words, hindering future U.S. offshore oil and gas exploration and production may actually impede U.S. greenhouse gas reduction goals.

Actions being taken by the Biden administration, under pressure from anti-fossil energy forces, ignore those facts to the peril of U.S. energy and environmental security. Current executive branch policies are threatening the long-term viability of domestic offshore energy development—which provides 15% of the nation's oil production—increasing uncertainty and the economic viability and investibility of offshore production. Amid these challenges, political and business leaders must use every available lever, including additional potential permitting legislation, to preserve this critical industry. OGI

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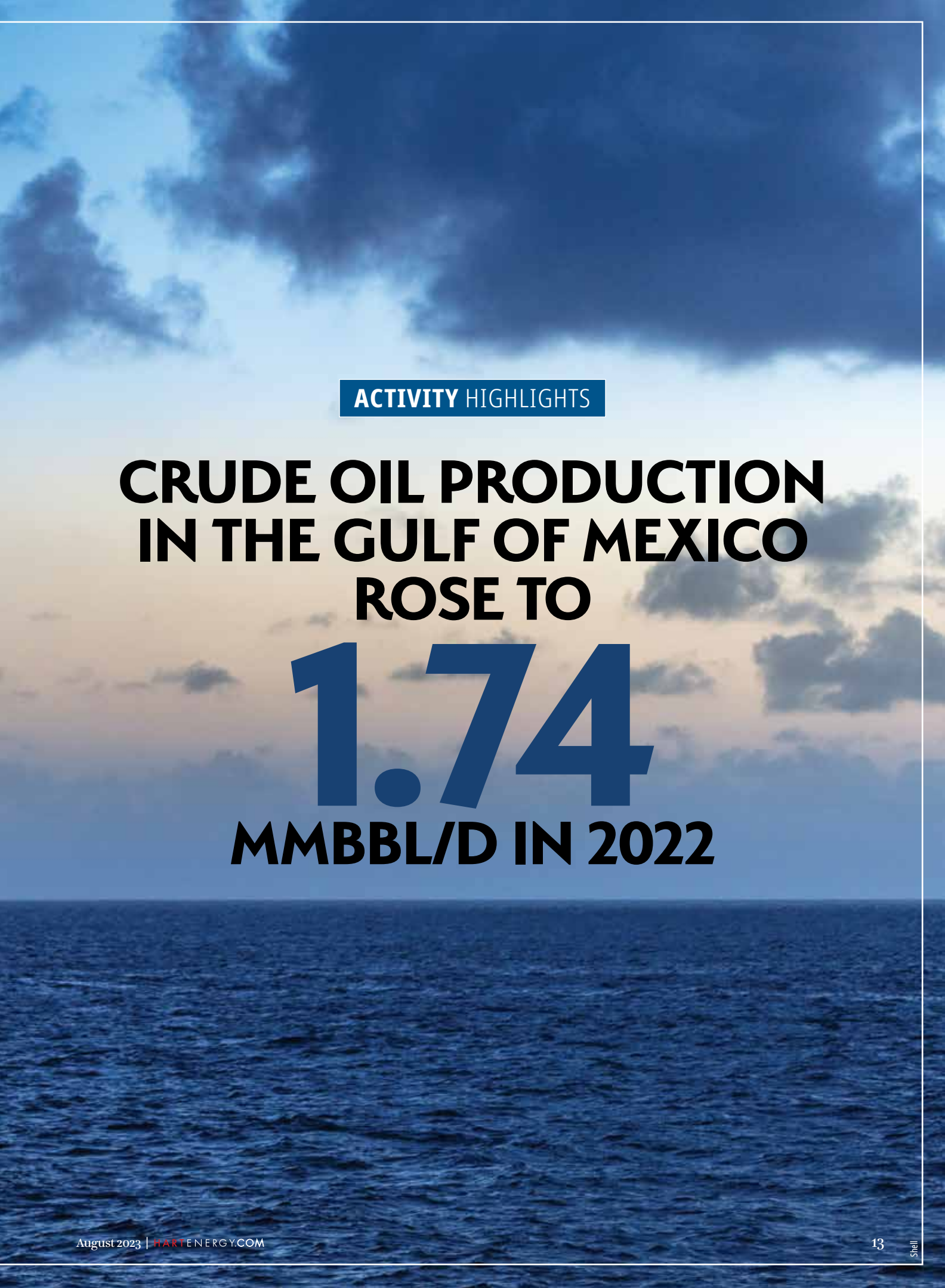
CRUDE OIL PRODUCTION IN THE GULF OF MEXICO ROSE TO 1.74 MMBBL/D IN 2022



Shell

FOCUS ON: GULF OF MEXICO

After a downturn in offshore activity during the pandemic, the Gulf of Mexico is playing a key role in U.S. oil production.

Gulf of Mexico crude output averaged approximately 1.74 MMbbl/d in 2022—up from around 1.71 MMbbl/d in 2021 and 1.67 MMbbl/d in 2020, according to U.S. Energy Information Administration data.

Some of the world's largest oil and gas players are active in the Gulf: Shell has led the pack in oil production, pumping out 98.38 MMbbl during 2022, according to Rextag data.

BP is the second-most active operator in the Gulf of Mexico, where the supermajor saw production of around 55.19 MMbbl for the year.

The Gulf is also home to several active U.S. E&Ps, including Chevron (48.71 MMbbl), Occidental Petroleum (39.35 MMbbl), Murphy Oil (25.26 MMbbl) and Hess Corp. (11.84 MMbbl).

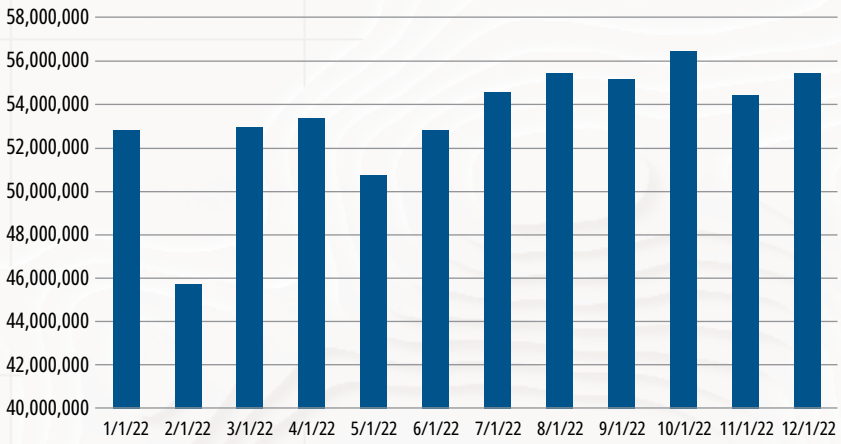
The Gulf of Mexico's most productive region is, by far, the Mississippi Canyon offshore of southeast Louisiana. Operators in the Mississippi Canyon produced more than 152.34 MMbbl of crude during 2022, per Rextag data.

The second-most productive region in the Gulf is the Green Canyon, where production totaled 93.55 MMbbl over the past year.

Gulf of Mexico output is expected to average about 1.84 MMbbl/d in 2023, according to the EIA's latest forecast.

Gulf of Mexico 2022 oil production

(BBL/MONTH)



GoM production by operator (12 months)

Oil Production	BBL
Shell	98,381,257
BP	55,198,563
Chevron	48,714,049
OXY	39,353,962
Murphy	25,264,845
Hess	11,848,747
LLOG Exploration	11,360,046
QuarterNorth Energy	8,723,183
Woodside Energy Group	7,704,664
Talos Energy	4,640,846
Arena Energy	4,333,889
COX Operating	4,157,818
Walter O&G	4,097,726
Cantium	3,499,816
Talos Ert	3,437,843
W&T Offshore	3,154,121
ENI	2,610,019
Riverstone	1,994,984
Hilcorp	1,296,450
Texas Petroleum	1,048,272

GoM production by area (12 months)

Oil Production	BBL
Mississippi Canyon	152,347,131
Green Canyon	93,553,951
Walker Ridge	44,690,969
Alaminos Canyon	15,269,420
Garden Banks	10,040,665
Ewing Bank	8,207,013
Viosca Knoll	3,611,629
Eugene Island South	1,897,244
Bay Marchand	1,775,370
Main Pass	1,718,396
West Delta	1,690,207
Ship Shoal	1,689,408
Main Pass South & East	1,611,280
South Marsh Island South	1,407,939
Eugene Island	1,305,067
South Timbalier	1,272,771
Ship Shoal South	1,244,109
Plaquemines	1,049,103
South Timbalier South	1,023,368
South Marsh Island	804,402

Source: Rextag

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PERMITS

E&Ps are focusing on future drilling prospects in the Permian Basin, according to the latest well permitting data.

Martin and Midland counties, Texas—located in the core of the Midland Basin—took the top two spots for well permitting activity in the past month, according to Rextag data.

Operators are also looking further west in the Permian's prolific Delaware Basin: Reeves and Loving counties, Texas, were also magnets for well permits in the past month.

The intense focus on the Permian Basin makes sense: The Permian is the top oil-producing region in the Lower 48 and is expected to be the primary driver of U.S. output growth for years to come.

Outside of the Permian, E&Ps are also looking north for drilling opportunities in Wyoming's Powder River Basin.

Converse County, Wyo., came in at third on the county leader board with 37 well permits issued. Campbell County, Wyo., saw eight permits issued.

La Salle, Gonzales and Atascosa counties, Texas, in the Eagle Ford Shale also saw permitting activity.

The Lone Star State led the way in total well permits at 377—a 28% increase from 294 permits last month.

Permitted wells by state

State	Well Count
Texas	377
Colorado	66
Wyoming	56
North Dakota	23
Louisiana	11

Permitted wells By operator

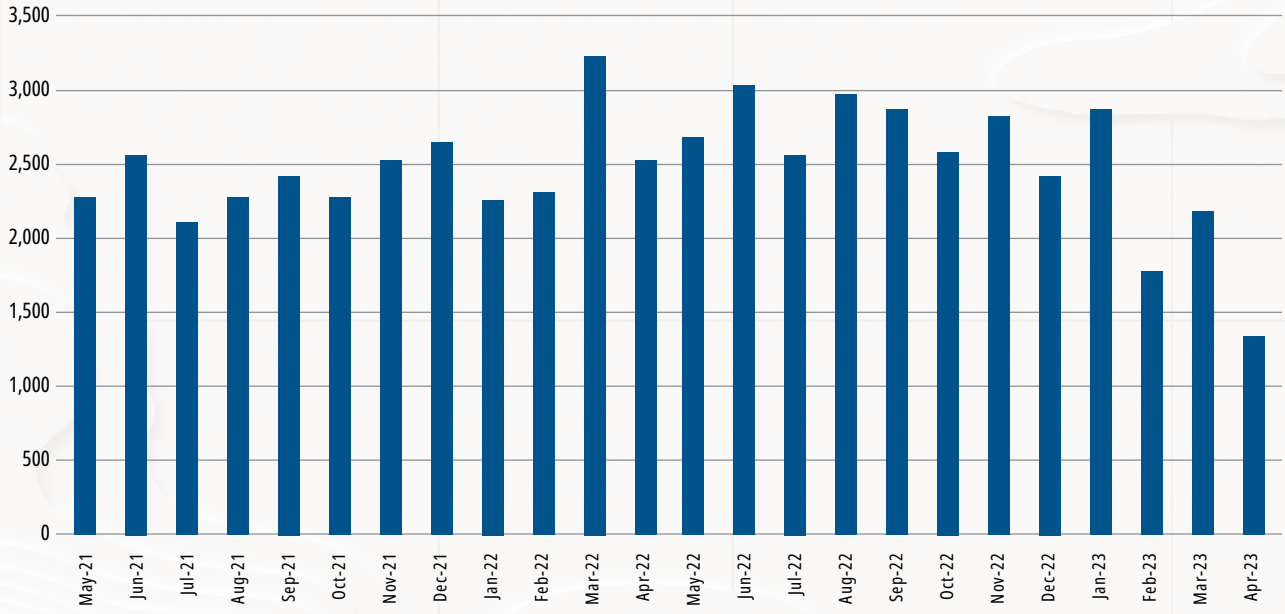
Operator	Well Count
Pioneer Natural Resources	28
PetroLegacy Energy II	27
Verdad Resources	26
EOG Resources	24
Endeavor Energy Resources	21
CrownQuest Operating	17
Pdeh LLC	15
Ovintiv	13
Fundare Resources	13

Permitted wells By county

County	Well Count
Martin, Texas	65
Midland, Texas	44
Converse, Wyo.	37
Reeves, Texas	27
Loving, Texas	21
Reagan, Texas	16
La Salle, Texas	14
Gonzales, Texas	13
Ward, Texas	11
Atascosa, Texas	10
Williams, N.D.	10
Campbell, Wyo.	8
Jackson, Colo.	7

U.S. drilling permits

(May 2021-April 2023)



Source: Rextag

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Analysts: Exxon-Denbury Deal Adds Meaningful CCUS Scale

The $4.9 billion deal gives Exxon Mobil even greater scale in CCUS—a major pillar of its low-carbon strategy.

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While Exxon Mobil's $4.9 billion bid to acquire Denbury Inc. delivers immediate cash flow in the near term, analysts say the deal will better position the U.S. supermajor in carbon capture, utilization and storage (CCUS)—a maturing space where Exxon is planning to pour billions of dollars in the coming years.

"We think the deal makes a ton of sense for [Exxon] as [Denbury's] 1,300 miles of CO_2 pipeline would have been difficult, costly and, most importantly, time consuming for [Exxon] to replicate across the high emitters along the Gulf Coast," analysts at Capital One Securities wrote in a market note on July 13 following the announcement.

CCUS is one of the major pillars in Exxon's Low Carbon Solutions strategy. Exxon, which relocated its corporate headquarters to the Houston region this summer, plans to invest around $17 billion in low-carbon initiatives through 2027.

Around 60% of that spend will contribute to reducing emissions from Exxon's own operations. In an exclusive interview with Hart Energy earlier this year, Exxon Chairman and CEO Darren Woods said the company aims to build out a value chain for it to develop more products with no carbon footprint.

The remaining 40% of Exxon's planned low-carbon spend—about $7 billion—will go toward its Low Carbon Solutions business to aid other customers in reducing emissions.

Exxon has already secured several CO_2 offtake agreements with third-party customers, including steelmaker Nucor Corp., fertilizer maker CF Industries and industrial gas company Linde.

While Exxon has won high-quality offtake agreements, the company did not have any existing CO_2 pipeline infrastructure of its own, analysts at Jeffries wrote.

And, the clock is ticking on obligations for some of its CO_2 offtake deals: Exxon's agreement to transport and permanently store up to 2.2 million metric tons (mtpa) annually of CO_2 from Linde's hydrogen production facility in Beaumont, Texas, is expected to begin in 2025.

"Enter [Denbury], which possesses the only CO_2 pipelines on the U.S. Gulf Coast, headlined by the 16-mtpa Green Pipeline, which runs from Houston to central Louisiana," Jeffries analysts wrote.

Denbury also brings its own sizable pipeline of agreements in hand, including future storage of more than 22 mtpa of CO_2 emissions from existing and proposed industrial plants, the company said in Securities and Exchange Commission filings.

"[Denbury] is still in the early stages with CCUS, and we think it makes industrial sense to be part of a larger organization that can execute and accelerate the timeline,"

—Gabriele Sorbara, ***managing director of equity research, Siebert Williams Shank & Co.***

"[Denbury] is still in the early stages with CCUS, and we think it makes industrial sense to be part of a larger organization that can execute and accelerate the timeline," said Gabriele Sorbara, managing director of equity research at Siebert Williams Shank & Co.

The transaction marks one of the first significant public M&A deals where CCUS assets make up the bulk of the value, said Andrew Dittmar, director at Enverus Intelligence Research.

Denbury's CCUS business is valued at about $2.8 billion, according to Enverus' analysis.

"Holistically, we believe that placing this business into the hands of a mega cap, [investment grade]-rated balance sheet lowers the cost of capital for agreements already signed and is a net positive for carbon sequestration on the Gulf Coast," analysts at KeyBanc wrote.

Exxon is acquiring Denbury in an all-stock deal valued at $89.45 per share based on Exxon's closing price as of July 12, the companies said. Under the terms of the agreement, Denbury shareholders will receive 0.84 shares of Exxon Mobil for each Denbury share.

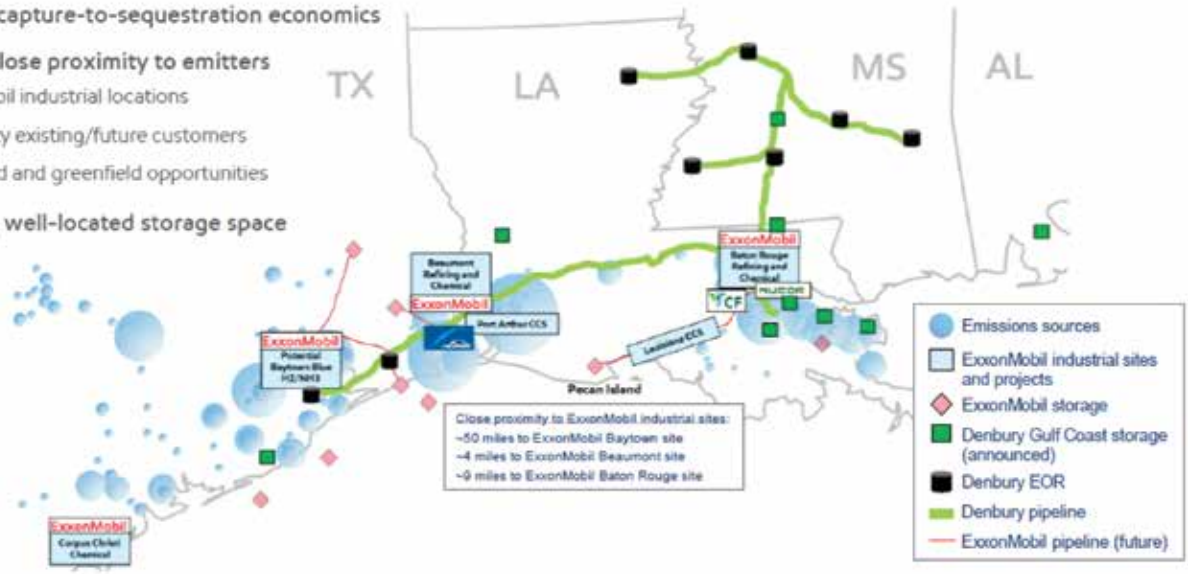
However, for a CCS and an EOR player like Denbury—which has seen its stock trade above $90 per share often in the past year—the pricing of the deal seems soft, KeyBanc said. The firm's extensive conversations with Denbury investors last year suggested they were seeking an

Exxon Mobil relocated its corporate headquarters to the Houston area in July. The acquisition of Denbury puts the supermajor in a better position to execute on its CO_2 offtake obligations.

Daniel Ortiz/Hart Energy

Combination creates strong U.S. Gulf Coast position

- Advantaged capture-to-sequestration economics
- Pipelines in close proximity to emitters
  - ExxonMobil industrial locations
  - Third-party existing/future customers
  - Brownfield and greenfield opportunities
- High-quality, well-located storage space



Exxon Mobil will gain access to Denbury's extensive network of Gulf Coast CCS infrastructure.

Note: all information shown is approximate (e.g. storage / pipeline location) and has potential to change as projects are developed and implemented.
Source: Exxon Mobil

acquisition price well above $100 per share.

KeyBanc said it is "surprised and somewhat underwhelmed by the terms and believe[s] [Denbury] shareholders may have the same view."

Upstream considerations

The real driver of the deal for Exxon is access to Denbury's extensive network of CCUS infrastructure, particularly in the Gulf Coast region, Dittmar said.

But acquiring Denbury and the company's EOR operations does deliver a bit more upstream production to Exxon.

Denbury makes the majority of its money selling crude oil and natural gas. The company generated about $341 million in first-quarter revenue and around 92%, or $314.5 million, came from sales of oil, gas and other products, according to Denbury's latest earnings report.

The company saw average daily sales of around 47,000 boe/d during the first quarter; oil production came in at around 46,000 bbl/d.

Denbury's upstream assets carried a value of around $1.7 billion, according to the Enverus analysis.

"These are low-decline assets that complement [Exxon's] current focus on short-cycle, high-decline shale wells in the Permian, if a very small incremental add for a company with nearly 4 million boe/d of global production," Dittmar said.

Acquiring Denbury's network of EOR assets is expected to provide Exxon immediate cash flow of around $600 million per year. The EOR assets also give Exxon near-term optionality for its CO_2 offtake agreements and the execution of its carbon storage business, the company said in an investor presentation. OGJ

Will Patterson-UTI's M&A Spree Continue?

After Patterson-UTI's merger with NexTier Oilfield Solutions and its acquisition of Ulterra Drilling Technologies, analysts wonder if there are more deals on the way.

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Patterson-UTI Energy and **NexTier Oilfield Solutions** agreed to a combination that will create the largest U.S. shale drilling and completions pure-play company in the energy sector.

The deal, an all-stock merger of near-equals, will result in a new Patterson-UTI with a combined value of $5.4 billion and operations in the Lower 48's most active shale basins. Patterson-UTI shareholders will own a 55% stake in the expanded company.

The combined company will have a fleet of 172 super-spec drilling rigs, 45 active frac fleets (33 NexTier, 12 Patterson-UTI) and directional drilling services.

Its combined 3.3 million hp will make Patterson-UTI the largest North American pressure pumper by capacity, slightly larger than Halliburton, analysts at **Evercore ISI** said in June.

The combined board will include 11 directors—six from Patterson-UTI and five from NexTier.

Patterson-UTI will remain headquartered in Houston after closing, which is expected to occur during the fourth quarter.

Patterson-UTI expects to realize yearly cost savings and operational synergies of around $200 million within 18 months of closing through operations integration, supply chain management and G&A savings.

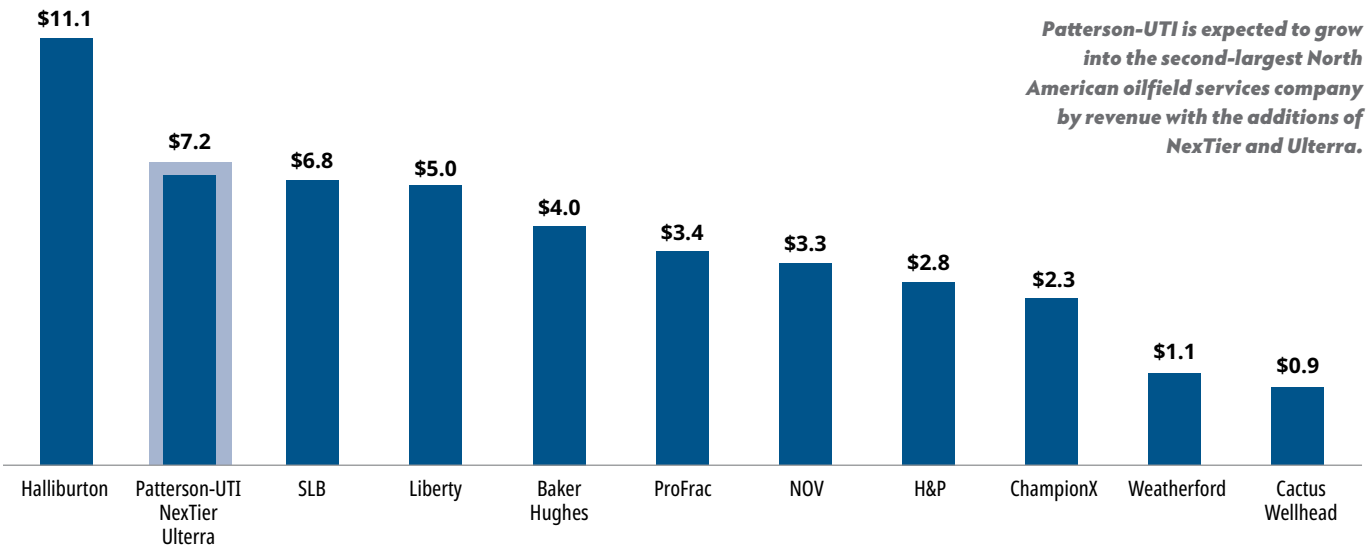
Nearly two-thirds of the expected synergies will come from the combination of the well completions business, management said during a conference call with analysts.

The combined services company aims to distribute at least 50% of free cash flow to shareholders through dividends and share repurchases.

Drilling deeper

Patterson-UTI is also expanding its capabilities in drilling, completions and

North American oilfield services companies by revenue
(In billions)



Patterson-UTI is expected to grow into the second-largest North American oilfield services company by revenue with the additions of NexTier and Ulterra.

Source: PTEN investor presentation

manufacturing with its acquisition of **Ulterra Drilling Technologies**.

Patterson-UTI agreed to pay $370 million in cash and 34.9 million shares of the company's PTEN common stock to acquire Ulterra, a Fort Worth, Texas-based provider of specialized polycrystalline diamond compact drill bits.

Ulterra is already a market leader in North America. The drill bit company owns a leading 30% market share in U.S. land, according to an Evercore ISI analysis.

Despite already owning a leading position in the market, there's still room for Ulterra to grow and enhance its business in the U.S., Patterson-UTI CEO Andy Hendricks said during the call.

"While they are the leading provider of drill bits already, there are a few basins where they may be able to do a little bit more," Hendricks said. "And we've got some good strong customer relationships in some of those places as well with our broad customer base."

But Patterson-UTI also sees a lot of runway for Ulterra to grow its business in markets in the Middle East, Latin America and Asia. That includes growth in both international onshore and offshore markets, Hendricks said.

"I think the international opportunity is probably where you'll see the majority of the growth come from," Patterson-UTI COO James Holcomb said.

"While they are the leading provider of drill bits already, there are a few basins where they may be able to do a little bit more."

—Andy Hendricks, *CEO, Patterson-UTI*

Analysts at **Piper Sandler** had expected Patterson-UTI to be focused more on the integration of NexTier than further diversifying into manufacturing with the Ulterra acquisition.

But the firm believes Patterson-UTI "isn't done acquiring yet and could further broaden its reach to become an even more diversified company focused on drilling and completions."

Civitas Enters Permian with $4.7 Billion Worth of Deals

Denver-based E&P buys two private operators as it extends its drilling runway beyond the D-J Basin.

Civitas Resources is extending its drilling runway outside of the Denver-Julesburg (D-J) Basin with $4.7 billion in Permian M&A.

Civitas' agreements to acquire oil and gas assets in the Midland and Delaware basins will help the company establish a substantial foothold in the Permian Basin, the Lower 48's top oil-producing region.

The Denver-based E&P said in June it is acquiring private Permian operators **Hibernia Energy III** and **Tap Rock Resources** in a cash-and-stock transaction valued at approximately $4.7 billion. Both Hibernia and Tap Rock are backed by private equity firm **NGP Energy Capital Management**.

Not only do the deals help establish a sizable footprint in the Permian, the acquisitions are expected to increase free cash flow per share, leading to debt reduction and continued strong shareholder returns, according to analysts at **Truist Securities**.

"With a pro-forma ~20% FCF yield, strong shareholder returns, solid leverage and notable inventory, [Civitas] should check most investors' boxes, in our view," Truist Securities Managing Director Neal Dingmann wrote in a research note.

Civitas is acquiring a portion of Tap Rock's assets in the northern Delaware Basin, which include around 30,000 net acres and average production of around 59,000 boe/d (52% oil).

Civitas agreed to pay $2.45 billion for the Tap Rock assets, including $1.5 billion in cash and approximately 13.5 million shares of Civitas common stock valued at $950 million.

In the Midland Basin, Civitas agreed to purchase Hibernia's assets for $2.25 billion in cash. The Hibernia transaction includes about 38,000 net acres and average production of around 41,000 boe/d (56% oil).

The deals also add around 800 gross drilling locations to Civitas' inventory.

Rig reductions

Like other E&Ps boosting inventories through M&A, Civitas plans to reduce drilling activity on the acquired assets when the deals close.

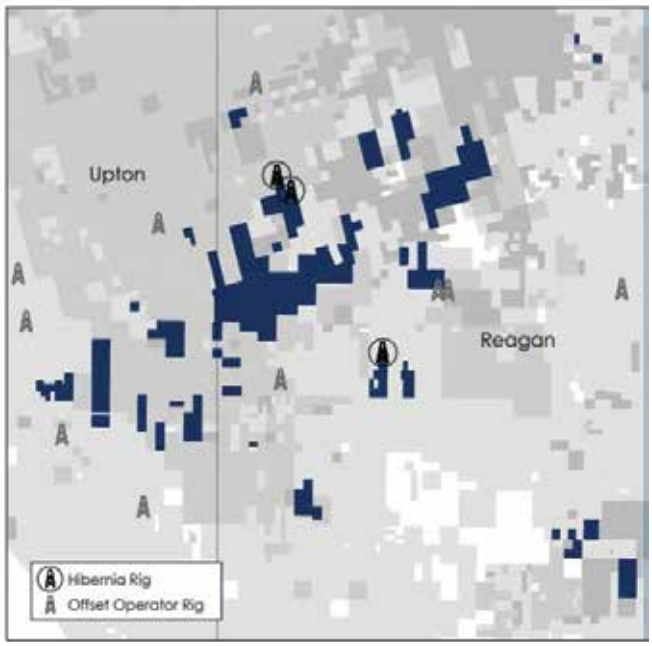
Tap Rock is currently running four rigs on its Delaware acreage position, Civitas President and CEO Chris Doyle said during a conference call with analysts. Civitas plans to reduce activity to a two-rig program in the Delaware, he said.

Hibernia is running a three-rig program on its acreage; Civitas also plans to drop drilling activity by a rig in the Midland Basin.

Those two-rig programs in the Delaware and Midland will complement Civitas' two drilling rigs deployed in the D-J Basin, Doyle said.

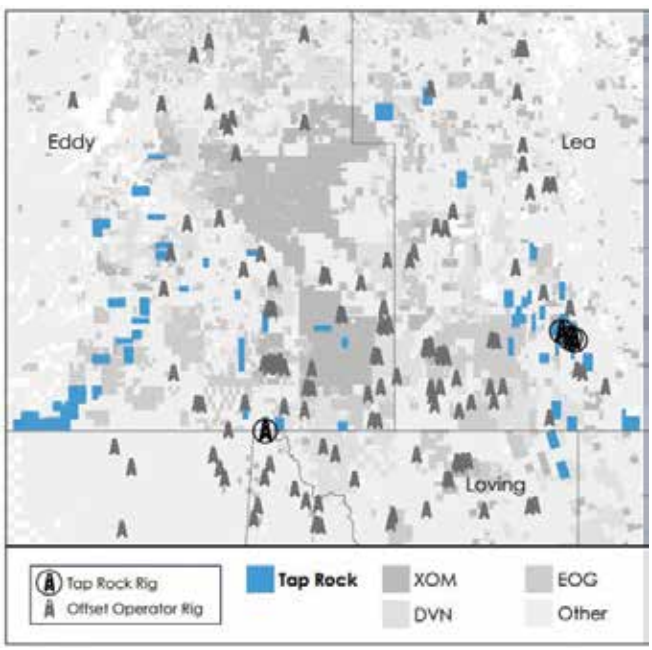
"This gives us tremendous flexibility to drive competition for capital and to optimize capital allocation across those three high-quality positions," he said.

—Chris Mathews, Senior Editor, Shale/A&D



Source: Civitas Resources investor presentation

Hibernia is running three drilling rigs on its Midland Basin acreage.



Source: Civitas Resources investor presentation

Tap Rock is currently running four rigs on its Delaware acreage position.

Hitting the Market Soon: The Entire Federal Helium System

Some have expressed concern should a major industrial gas player scoop up the federal government's legacy assets.

The federal government plans to begin a sales process for the Federal Helium System at Cliffside, outside of Amarillo, Texas.

The federal government has started the process to sell the Federal Helium System, a major supplier of global helium demand.

Helium is often thought of in association with party balloons and zeppelins. But helium, a product recovered from natural gas, is commonly used for defense applications, medical devices such as MRIs, and aerospace technology, among other sectors.

And the Federal Helium System, managed by the Bureau of Land Management (BLM), is an important part of the global helium market. Phil Kornbluth, president of helium consultancy **Kornbluth Helium Consulting**, told Hart Energy the federal system accounts for between 15% and 17% of global helium supply.

But under the direction of Congress, the BLM is required to sunset its management of the helium production and storage system and dispose of the assets—part of a multi-decade effort to reduce government spending and privatize the reserve that has provided refined helium since the 1960s.

The disposal process, being led by the General Services Administration (GSA), began on July 12.

As the sales process ramps up, industry experts and stakeholders have expressed concerns about disruptions to helium supply if the system is eventually transferred to a private owner.

Floating a sale

Many of the assets included in the Federal Helium System package are concentrated in the Cliffside gas field northwest of Amarillo, Texas.

The sales process includes the Bush Dome—a 12,000-acre, natural geologic reservoir that stores federally and privately owned helium.

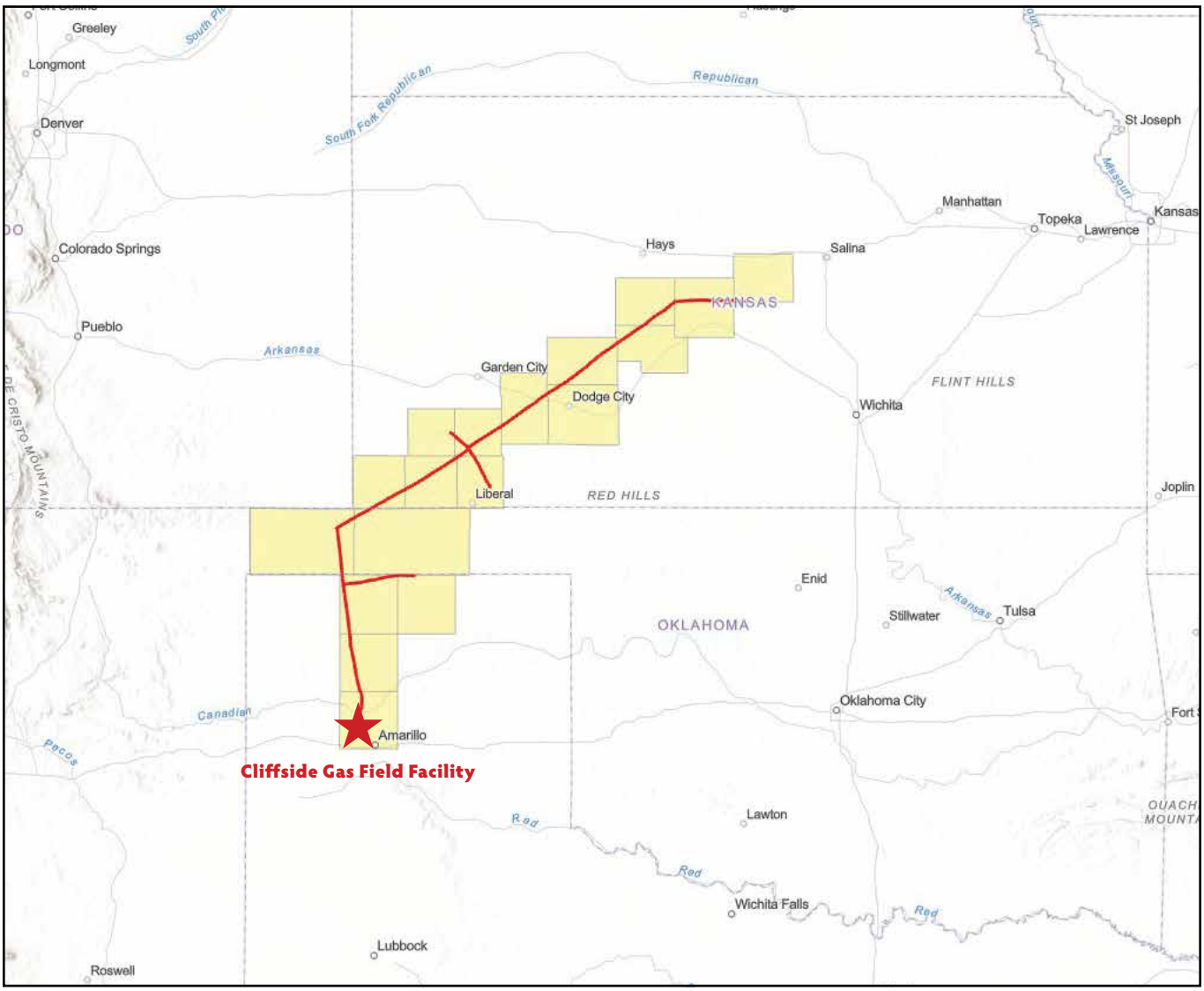
The government is also selling a roughly 425-mile helium pipeline system connected with privately owned helium refineries in Texas, Oklahoma and Kansas.

Included in the GSA sales is the Cliffside Gas Plant, approximately 12 miles northwest of Amarillo; subsurface oil and gas mineral interests; 23 gas-producing wells developed in the 1960s and 1970s; and various federally owned plant equipment, according to the announcement.

Perhaps most notably, the GSA is also marketing around 1.8 Bcf of crude helium.

"The most valuable asset that's up for sale is the crude helium itself," Kornbluth said.

As the industry experiences another prolonged shortage



Source: U.S. General Services Administration

Included in the Federal Helium System assets is a roughly 425-mile helium pipeline that connects to several private helium refineries in Texas, Oklahoma and Kansas.

of helium since early 2022, the helium sector is at the peak of a pricing cycle as future prospects for new global supply come into view.

"[The crude helium] is very valuable at today's market price," he said. "The issue is the deliverability—it's going to take many years to get it out of the ground at the current rates of deliverability."

A buyer would likely pay in the area of $300+ per thousand cubic feet for the crude helium the federal government is marketing, Kornbluth said.

The value of the physical assets in the partially depleted Cliffside field is likely much smaller than the value of the crude helium itself, he said.

Major headaches

GSA said it expects the entire sales process to last between eight and nine months as it engages with industry and stakeholders to efficiently transfer the assets.

But the industrial gas sector has raised concerns about the processes for the privatization of the helium system.

Several major industrial gas players—names like **Air Products**, **Linde PLC** and **Messer Group**—have plants for purifying and refining crude helium connected to the BLM system. And the **Compressed Gas Association**, which represents more than 100 companies in the industrial, medical and food gases space, has laid out several issues it has with the GSA's disposal plan.

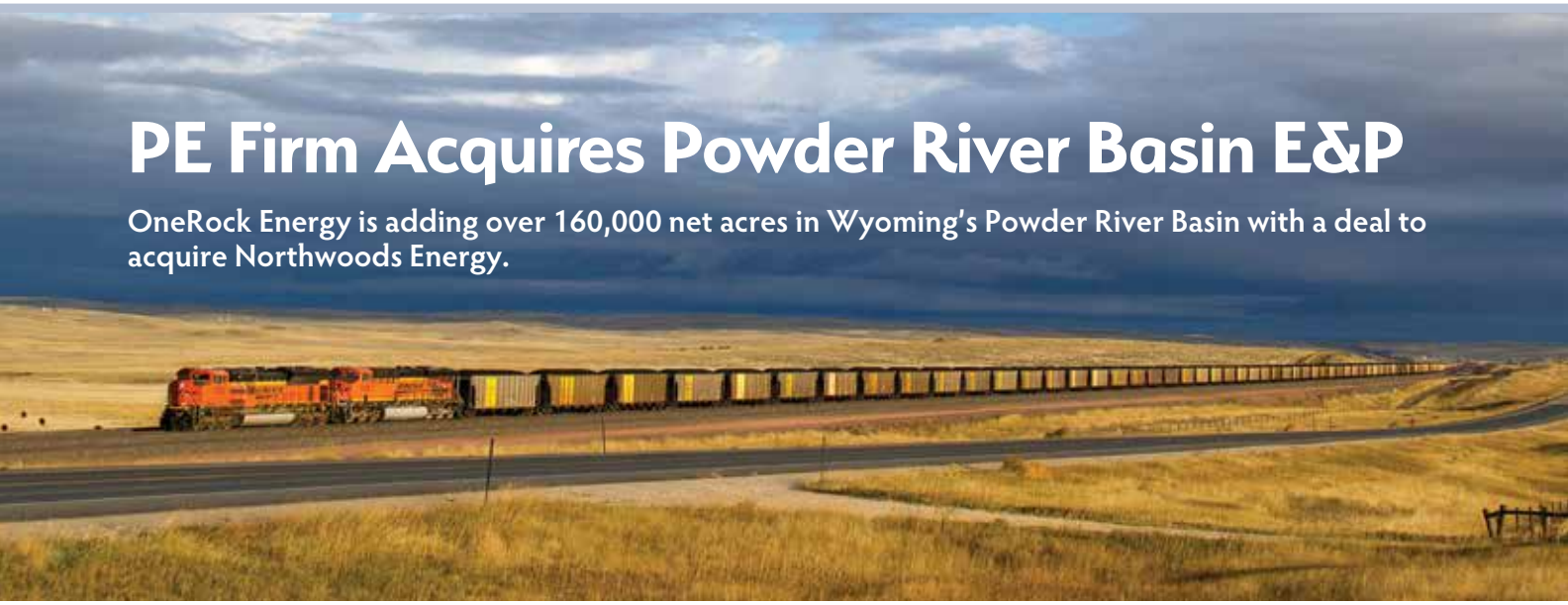
Despite concerns, Kornbluth said there is general interest by the industrial gas sector in acquiring the helium assets marketed by the federal government.

The most natural buyers would likely be the companies with plants connected to the federal helium pipeline, which have invested in continued refining operations and would put the crude helium to use.

—Chris Mathews, Senior Editor, Shale/A&D

PE Firm Acquires Powder River Basin E&P

OneRock Energy is adding over 160,000 net acres in Wyoming's Powder River Basin with a deal to acquire Northwoods Energy.



Shutterstock

Train pulling out of the Power River Basin in Wyoming

Private equity firm **OneRock Energy** is adding a sizable position in the Powder River Basin in its purchase of E&P **Northwoods Energy**.

Houston-based OneRock Energy Holdings agreed to acquire Northwoods Management Co. and certain related entities for an undisclosed sum, the firm announced. Northwoods is backed by investment firm **Apollo Global Management**.

Once closed, the Northwoods acquisition will add more than 160,000 largely contiguous net acres of leaseholds interests spanning Converse, Campbell and Johnson counties, Wyo.

OneRock, which serves as the upstream investment arm of Houston-based energy investment firm **Pan Capital Management**, said the acquired assets include average production of approximately 5,000 boe/d.

Daniel Fan, partner and head of North American E&P investments at Pan Capital Management, said the firm expects to leverage the OneRock platform to acquire more oil and gas assets for future expansion.

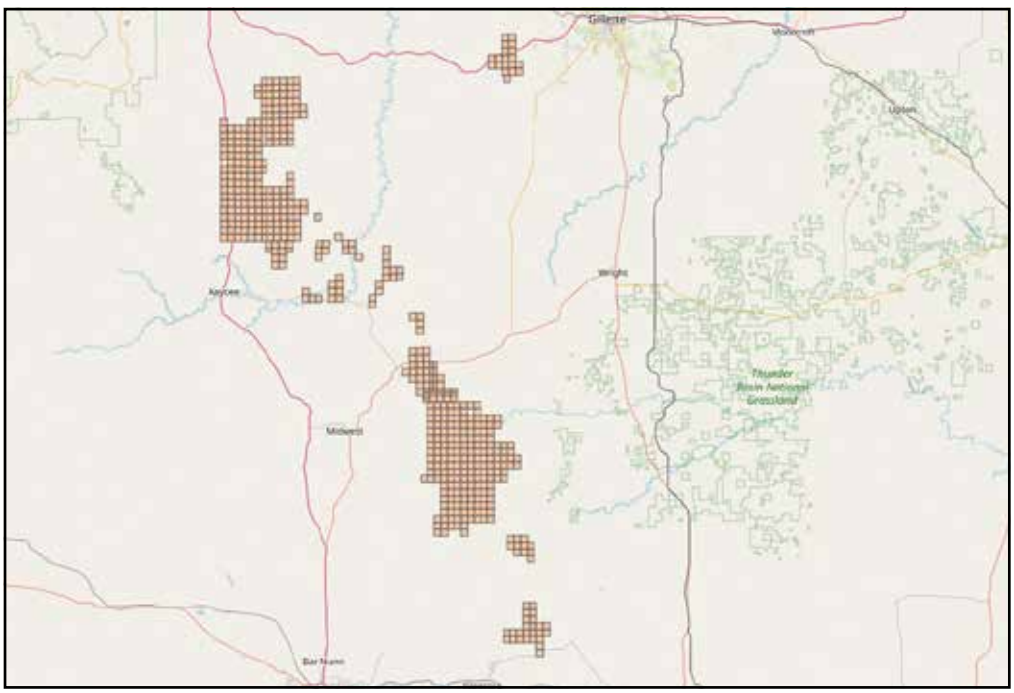
"We consider this acquisition to be a pivotal move for OneRock, solidifying our position with a robust presence in resource-rich unconventional plays," Fan said in the release. "It represents a crucial component of our growth strategy into the E&P business, while concurrently expanding our commodity optionality and seamlessly aligning with Pan Management's overarching investment strategy."

The deal, subject to customary closing conditions, is expected to close during the third quarter.

OneRock was represented by **Willkie Farr & Gallagher LLP** as legal adviser.

With Apollo's financial backing, Northwoods added more than 112,000 acres in the Powder River Basin through a $500 million acquisition from **SM Energy** in 2018. The deal represented around 80% of SM's Powder River acreage at the time.

—Chris Mathews, Senior Editor, Shale/A&D



Source: Rextag

OneRock Energy is adding over 160,000 net acres in Converse, Campbell and Johnson counties, Wyoming, through the acquisition of Northwoods Energy.

Berkshire Hathaway Boosts Stake in Cove Point LNG for $3.3B

Berkshire Hathaway Energy is growing its ownership stake in Cove Point LNG through a $3.3 billion acquisition from Dominion Energy.

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Berkshire Hathaway Energy, controlled by billionaire investor Warren Buffet, has agreed to purchase Dominion's 50% limited partnership stake in Cove Point LNG LP, an LNG export terminal complex in Lusby, Md.

When the deal closes, the acquired interest will be held by Berkshire Hathaway Energy subsidiary **BHE GT&S**, which currently serves as the general partner and operator of Cove Point.

The transaction increases Berkshire's ownership interest in the Cove Point LNG limited partnership to 75%, the company said in July. The remaining 25% limited partnership interest is held by a subsidiary of **Brookfield Infrastructure Partners**.

"We are proud of our operations at Cove Point and are excited for this opportunity to increase our ownership in these world-class facilities," said BHE GT&S President Paul Ruppert. "The Cove Point team will continue to focus on providing safe, affordable and reliable service to its valued customers."

The $3.3 billion deal will be funded with cash on hand, including cash realized from liquidating certain investments, Berkshire said.

In 2020, BHE acquired a 25% stake in the Cove Point LNG limited partnership through a major acquisition from Dominion. The nearly $10 billion transaction also included interstate gas transmission pipelines and gas storage capacity, according to Securities and Exchange Commission filings.

Gibson, Dunn & Crutcher LLP is advising Berkshire Hathaway Energy on the deal.

—Chris Mathews, Senior Editor, Shale/A&D

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Berkshire Hathaway is boosting its stake in Maryland's Cove Point LNG.

UPSTREAM

• **Earthstone Energy** is expanding its position in the northern Delaware Basin with a $1 billion deal to acquire **Novo Oil & Gas**.

Northern Oil & Gas simultaneously announced it will acquire a 33.33% undivided stake in the Novo assets in partnership with Earthstone for an additional $500 million, bringing the transaction value to $1.5 billion.

For Earthstone, the acquisition of Novo Oil & Gas Holdings, a private E&P backed by **EnCap Investments**, will add around 11,300 net acres in Eddy County, N.M, and Culberson County, Texas, to the E&P's footprint, the company said.

Earthstone's Delaware Basin acreage position will grow to approximately 56,000 net acres after the deal closes, which is expected to occur during the third quarter.

The deal caps a first-half 2023 run for EnCap in which it has sold at least $7.5 billion in assets.

Novo's assets include average production of about 38,000 boe/d (37% oil, 66% liquids) from 114 wells, as well as proved reserves of nearly 74 MMboe.

"I am pleased that we are continuing to further our consolidation strategy with today's announcement of the Novo acquisition as we further build our northern Delaware Basin asset base," said Robert J. Anderson, president and CEO of Earthstone, in a press release. "With significant production volumes from the Novo Acquisition, we expect Earthstone's near-term production levels to surpass 135,000 [boe/d]."

• **Baytex Energy** closed its multibillion-dollar acquisition of **Ranger Oil**, expanding the Canadian E&P's footprint and scale in the South Texas Eagle Ford Shale.

Baytex's cash-and-stock acquisition of Eagle Ford pure-play Ranger Oil adds 162,000 net acres and 741 undrilled locations in the crude oil window of the Eagle Ford—complementing the company's existing non-operated position in the Karnes Trough.

The acquisition is expected to contribute to growing overall production from around 88,000 boe/d in the first half of 2023 to between 153,000 and 157,000 boe/d (84% oil and NGL) during the second half of the year, Baytex said.

Total consideration Baytex paid for the acquisition, including assumption of net debt, was about US$2.2 billion (CA$2.9 billion). Ranger shareholders received 7.49 shares of Baytex stock and $13.31 cash for each owned share of Ranger stock under the terms of the deal.

"We are excited to close the Ranger acquisition, which materially increases our scale in the Eagle Ford while building quality operating capability in a premier basin," said Eric T. Greager, president and CEO at Baytex. "We have emerged from this transaction as a well-capitalized and diversified North American exploration and production company with a portfolio of high-quality oil weighted assets in Western Canada and the Eagle Ford shale in Texas."

Baytex plans to spend between $595 million and $635 million on exploration and development activities during the second half of the year after integrating Ranger's Eagle Ford assets.

In conjunction with closing the deal, Baytex also plans to increase its shareholder returns to at least 50% of its free cash flow through share buybacks and a dividend.

• **SM Energy** is expanding its Midland Basin footprint, signing a deal to acquire 20,000 net acres in Dawson and northern Martin counties, Texas, for $93.5 million.

The acquired assets include average net production of 1,250 boe/d, approximately 90% of which is oil, as well as undeveloped acreage.

"Based on extensive geologic data and demonstrated economics from nearby wells, the company expects to target the Dean and Middle Spraberry sand intervals," the company said.

"Upside locations are expected to breakeven at less than $50/bbl oil prices," with the company assuming a 10% discount rate, current capital costs and a $2.50/Mcf natural gas price.

SM Energy also said it acquired an additional 2,800 net acres adjacent to a first-quarter acquisition of 6,300 net acres in the Midland Basin, for a total of 9,100 net acres.

• **Callon Petroleum** closed its previously announced Delaware Basin acquisition of **Percussion Petroleum Operating II** and exited the Eagle Ford in a sale to **Ridgemar Energy Operating**.

Collectively, the A&D was valued at about $1.13 billion.

Callon paid for the Percussion's Delaware assets with a combination of $249 million in cash and approximately 6.3 million shares of Callon common stock.

In the Eagle Ford, Callon received $551 million in cash for its sale to Ridgemar, which is backed by **Carnelian Energy Capital Management**.

"The bolt-on Percussion transaction improves our Delaware inventory depth and also lowers our cost structure," said Joe Gatto, president and CEO of Callon.

Now a Permian Basin pure-play, the E&P also used the two transactions to reduce its debt position and start a shareholder return plan. At closing, Callon's outstanding debt went down by approximately $300 million, with gross debt now at less than $2 billion.

• **Crescent Energy** closed its acquisition of operatorship and incremental working interest in its existing Eagle Ford assets for approximately $600 million cash.

The deal, announced in May, will bolt-on assets in the Eagle Ford Shale from **Mesquite Energy**, which formerly operated as **Sanchez Energy**.

The Mesquite Energy assets are 100% operated and span approximately 75,000 contiguous net acres, primarily located in Dimmit and Webb counties, Texas.

Following closing, Crescent assumed operatorship of its existing western Eagle Ford acreage and plans to maintain a one-rig development program on the asset through the remainder of the year.

For the second half of 2023, the company estimates the acquisition will increase net production by 19,000 boe/d to 21,000 boe/d and capital investments by approximately $45 million to $55 million.

"We continue to execute on our long-term strategy, which includes opportunistically growing our footprint in the Eagle Ford through accretive M&A while maintaining financial strength and enhancing our capital markets presence," Crescent CEO David Rockecharlie said.

• **Vital Energy** is boosting its full-year production and capital spending guidance after closing a deal to acquire Permian Basin E&P **Forge Energy II Delaware**.

Vital payed a $391.6 million cash consideration for 70% of Forge's assets, after closing price adjustments.

Vital acquired Forge's assets in a joint deal with Minnesota-based **Northern Oil & Gas**—Vital, which will operate the Forge assets, acquired 70%, while NOG purchased the remaining 30% for $167.9 million in cash.

The deal adds around 24,000 net acres and another 100 gross drilling locations in Pecos, Reeves and Ward counties, Texas. Acquiring Forge grows Vital's Permian footprint up to around 198,000 net acres.

Vital is raising its oil and gas production outlook after both completing the Forge acquisition and the company outperforming its own production expectations during the first half of the year.

The company anticipates total production to range between 82,000 boe/d and 86,000 boe/d during 2023—up from Vital's original guidance of between 76,000 boe/d and 80,000 boe/d. Crude oil production is expected to range between 40,000 bbl/d and 43,000 bbl/d, up from guidance of 36,300 bbl/d to 39,300 bbl/d.

During the second half of 2023, Vital plans to operate a single drilling rig and bring five wells online on the Delaware Basin acreage acquired from Forge.

• **Ring Energy** entered an agreement to acquire Central Basin Platform assets in the Permian Basin assets for $75 million cash.

Ring said it would buy approximately 3,600 net acres in Ector County, Texas, from **Founders Oil & Gas IV**. The E&P said the assets are similar to those Ring acquired from **Stronghold Energy Operating II** in 2022.

Founders' assets include second-quarter 2023 production that averaged 2,500 net boe/d, 86% oil. Ring said the deal adds "low-risk inventory" including approximately 50 undeveloped drilling locations. Existing infrastructure offers takeaway capacity and opportunities to reduce costs and improve efficiencies.

Ring said the $75 million price tag is approximately 2.3x the assets' next 12 months adjusted EBITDA beginning April 1, 2023.

The assets include 99% working interest and net revenue interest of approximately 87%. Ring said reserves include 9.2 MMboe, 80% oil, "characterized by shallow declines and long lives."

Payment for Founders' assets, subject to customary closing adjustments, will consist of $60 million in cash at closing and a $15 million deferred cash payment due four months after closing.

Paul D. McKinney, Ring's board chairman and CEO, said the assets strategically expand the company's operations in the southern portion of the Central Basin Platform, "allowing us to capture operating cost and G&A synergies associated with a larger core operating area."

• **Riverbend Energy Group** has returned as a buyer in the Williston Basin after exiting from its non-operated position nearly a year ago in a $1.8 billion deal, the company said in June.

Riverbend said it pulled the trigger on a "sizeable non-operated" working interest in the core of the Williston. The acquisition, along with other recent acquisitions, provides a "high-quality, free cash flow positive non-operated asset base" in the Williston and Permian basins, the Houston company said.

The company did not disclose details about the Williston acquisition, but Riverbend said its assets are underpinned by top-tier operators.

The company said the recent transactions mark the "rebuilding" of Riverbend's non-op strategy following its August 2022 divestiture from the Williston.

Riverbend said it continues to manage and grow other active traditional energy strategies, which target operated Midland Basin properties and mineral and royalty interests across leading oil-producing shale plays.

• **Houston Natural Resources Corp.** plans to rebrand after acquiring full ownership of Appalachian Basin E&P **Cunningham Energy**.

Houston Natural Resources (HNRC) acquired a 100% interest in Charleston, W.Va.-based Cunningham Energy by issuing common and preferred stock.

Financial terms of the transaction were not made available, but the deal increases HNRC's net asset value by $3.35/share, based on the current number of outstanding shares.

Assuming Cunningham's current drilling program is completed as proposed, the independently appraised value of the company's leasehold position was $352 million as of year-end 2022, according to HNRC.

In connection with closing the deal, HNRC plans to change its name to Cunningham Natural Resources Corp. CNRC will focus on traditional oil and gas opportunities, as well as opportunities in energy transition materials like copper and lithium.

Cunningham Energy, managed by principal and operating partner Ryan Cunningham, owns oil and gas leasehold interests on 30,000 net acres in West Virginia, according to regulatory filings.

As part of the company's future phase 1 development plan, Cunningham plans to permit, drill and complete 20 horizontal wells in the Big Injun, Weir and Berea sandstone formations to fulfill legacy drilling and lease obligations.

Cunningham identified 68 potential sites for well development on its existing leases, and the E&P plans to expand its leasehold footprint through future acquisitions and leasing.

INTERNATIONAL

• **Neptune Energy**, producer of an average of 135,000 boe/d, is selling all but its German operations to **Eni International** and **Vår Energi**, which is 63% owned by Eni, for an aggregate total of $4.9 billion.

Neptune is retaining only its German operations and selling its Norwegian assets for approximately $2.3 billion to Vår. Eni is scooping up Neptune's remaining operations in the U.K., the Netherlands, North Africa and Asia-Pacific for approximately $2.6 billion.

The transactions are expected to close by the end of first-quarter 2024. The Vår transaction will close immediately prior to the Eni transaction, and the proceeds from the Norway sale will remain with the Neptune Global Business that Eni is purchasing.

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The German operations contribute 17,500 boe/d, or 13%, of Neptune's production. The Neptune-operated Römerberg oil field and the Adorf gas field are both under development there. Neptune, founded in 2015, is owned by **China Investment Corp.** Its funds are advised by **Carlyle Group, CVC Capital Partners** and certain management owners.

"This transaction offers a new and exciting phase for Neptune, with significant growth opportunities supporting energy security and the energy transition, which will benefit from Eni's and Vår Energi's larger scale and available resources," Neptune Executive Chairman Sam Laidlaw said in a press release.

SERVICES

• Oilfield services provider **RPC Inc.** is expanding its cementing business with an acquisition of **Spinnaker Oilwell Services**.

Atlanta-based RPC paid $79.5 million in exchange for 100% of Spinnaker's equity. The purchase price included $77 million in cash, the assumption of $500,000 of capital lease liabilities and a $2 million payoff.

Oklahoma City-based Spinnaker maintains 18 full-service cementing spreads spread across the Permian Basin and the Midcontinent. The company operates two facilities in El Reno, Okla., and in Hobbs, N.M.

"The acquisition of Spinnaker will significantly expand RPC's cementing business from its presence in South Texas to basins in which we currently provide other services," said RPC President and CEO Ben M. Palmer in a news release. "We are impressed with Spinnaker's management team, talented workforce and the quality of its operations, and plan to continue operating under the Spinnaker name."

The majority of RPC's business focuses on services to customers during the completion stage of a well, and more than 85% of the company's revenues are directed toward unconventional completions, according to investor materials.

Arnall Golden Gregory LLP served as legal counsel to RPC in connection with the deal. Spinnaker was represented by **FMI Capital Advisors** as financial adviser, and **Locke Lord LLP** acted as legal counsel.

MIDSTREAM

• **Superior Pipeline** is rebranding after full ownership of the midstream company changed hands.

Superior investor **SP Investor Holdings**—jointly owned by Canadian firm **OPTrust** and Swiss private equity firm **Partners Group**—acquired a 50% ownership stake in Superior from **Unit Corp.** The transaction results in SP Investor owning 100% of Superior.

Unit Corp. entered into an agreement in late February to sell its 50% interest in Superior to SP Investor for $20 million, the company disclosed in regulatory filings.

Tulsa, Okla.-based Superior, operator of pipeline, natural gas gathering and processing assets and gas treating plants in Texas, Appalachia and the Midcontinent, is rebranding to **Superior Midstream** in conjunction with the deal closing.

Superior Pipeline was formed in 1996 with partner Unit Corp., which owned 40% of the company at the time. Unit Corp. later acquired full ownership of Superior, which became a wholly owned midstream subsidiary of Unit.

Unit sold a 50% ownership stake in Superior to SP Investor for $300 million in 2018 as it looked to deploy more capital toward its E&P drilling program.

LNG

• **Venture Global LNG** signed a 20-year purchase and sale agreement (PSA) with Germany's state-owned company **SEFE Securing Energy for Europe GmbH**.

Under the agreement, SEFE's subsidiary **WINGAS GmbH** will acquire 2.25 million tonnes per annum (mtpa) of LNG from Venture Global's third project, **CP2 LNG**, Venture Global LNG said.

With the deal, Venture Global LNG is set to become the largest LNG supplier to Germany, with a combined 4.25 mtpa of 20-year offtake agreements already signed.

"Germany has acted decisively to diversify its energy portfolio, and LNG will be a vital part of that mix as it seeks to strengthen its energy security while at the same time advancing environmental progress," Venture Global LNG CEO Mike Sabel said in the release.

The CP2 LNG terminal will be located on a 546-acre site in Cameron Parish, La. Construction is expected to commence in 2023, according to Venture Global LNG. When completed, the facility will have a nameplate liquefaction capacity of 20 mtpa and a peak capacity of 24 mtpa.

To date, 9.25 mtpa of CP2's nameplate capacity has been sold, and active discussions continue for the remaining capacity. Beyond SEFE, customers signed on for future cargos include **Exxon Mobil**, **Chevron**, **JERA**, **New Fortress Energy**, **INPEX**, **China Gas** and **EnBW**.

Importantly for Europe, and Germany in particular, "approximately one-third of the current offtake agreements are with German buyers, further underscoring the importance of CP2 LNG to Germany's long-term energy security," Venture Global LNG said.

RENEWABLES & CCUS

• Utility firm **Duke Energy** said it would sell its commercial distributed generation business to private equity firm **ArcLight Capital Partners** in a $364 million deal.

The business includes operating assets of **REC Solar**, which Duke had acquired in 2015, development pipeline and operations and maintenance portfolio, as well as distributed fuel cell projects managed by **Bloom Energy**.

Duke said it expects about $259 million of proceeds from this sale, which the company would use to help incorporate more than 30,000 megawatts of regulated renewable energy into its system by 2035.

Electric utilities in the United States are streamlining their operations to shift away from fossil fuels toward cleaner energy sources, including solar and wind, to meet climate goals.

Duke's peers such as **FirstEnergy** and **NiSource** have also sold stakes in their subsidiaries this year as they seek to invest in cleaner sources of energy.

"The sale of commercial renewables businesses streamlines our portfolio and provides the resources to support our growing regulated territories," said Duke President and CEO Lynn Good.

The deal is expected to close by year-end 2023. OGI

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Hart Energy LIVE is pairing our **Energy Capital Conference and A&D Strategies & Opportunities** together on October 2-3, 2023, at the Statler Hotel in Dallas.

Private equity is coming back to the upstream sector, perhaps with as much as $15 billion raised this year. But that drop in the bucket is dramatically outweighed by the forecasted market supply needed to prevent a short fall of $4.9 trillion by 2030.

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Private Equity Touts E&P Investments, Acknowledges Fundraising Woes

ESG pressures and declining returns in the past have hindered plans by private equity firms such as Quantum Energy Partners to raise billions of dollars.

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Oil and gas private equity executives described the current E&P investment environment as "more favorable than it's ever been," "as attractive as it's ever been" and that it's "never looked so good."

But in interviews with Hart Energy, top-level executives also acknowledged much more work and time is required to assemble funds, with some saying raising funds takes twice as long as it has in previous years.

And private equity is nowhere near raising the funds the industry has said are needed.

"The market is not that efficient. There's a lot of political things that get in the way," said Tomas Ackerman, co-founder and partner of Carnelian Energy Capital in Houston. "Potential returns in the traditional energy asset class do not drive a lot of these investors. Divestment mandates are really influencing a lot of the decision making."

Others cited declining returns and investors' fears of getting clobbered on the downside of another boom-bust cycle. Private equity executives said about one-third of their peers are done with fossil fuels.

That's resulted in portfolio companies getting dramatically fewer equity commitments. Private equity E&P commitments peaked at 128 in 2017. So far in 2023, just eight have been made, according to Enverus. Private equity and venture capital's oil and gas investment peaked at $21.6 billion for the U.S. and Canada in 2017, and is down to just $1.4 billion so far this year, according to S&P Global Market Intelligence.

Some expectations for private equity's haul in 2023 range $15 billion to $25 billion. Whether those funds come to fruition is another story.

"The industry is in a world of hurt because the amount of private equity that used to be available five years ago was probably $100 billion. Today, it's probably less than $15 billion."

—Wil VanLoh, *founder and CEO, Quantum Energy Partners*

EnCap Investments is reported to be raising its first private equity fund in five years. Quantum Energy Partners is, likewise, reported to be nearly halfway toward raising a fund of more than $5.5 billion. In February, Chad Michael, president of Tudor, Pickering, Holt & Co., said private equity was likely raising $15 billion for oil and gas in 2023.

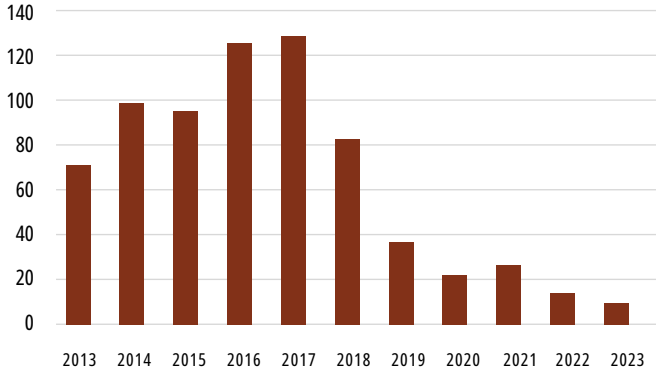
Muhammad F. Laghari, senior managing director at Guggenheim Securities, said during the May SUPER DUG conference that whatever is raised—$15 billion or $25 billion—private equity is clearly busy trying to raise money.

"Pretty much any private equity energy client I have is either raising money or has just raised

"Hedging is a bigger part of the conversation now because acquisitions have a lot more value in the existing production stream, versus historically where a lot more of it was probably in acreage and upside that you can't hedge as effectively."

—**Paul Steen,** ***managing director, First Reserve***

Number of private equity E&P commitments



Source: Enverus

money," Laghari said. "So we do expect quite a few folks to raise money. I think what we've been hearing from them is positive comments from a fundraising perspective. They all admit it's not easy."

Wil VanLoh, founder and CEO of Quantum Energy Partners, said he's seen some improvements raising money, but firms are certainly putting in more time and work than in years past. VanLoh said it once took four to six months to raise a fund; now assembling a fund is taking 15 to 18 months.

"The industry is in a world of hurt because the amount of private equity that used to be available five years ago was probably $100 billion. Today, it's probably less than $15 billion," he said. "Does it need to be $50 or $60 billion? Yeah, it does."

Energy investment remains a tricky proposition, particularly as renewable funds bite into traditional oil and gas private equity.

VanLoh said E&Ps' equity needs are hurting with banks, too. The companies could get 3.5x turns of leverage in recent years, he said, but they cannot get even two turns today. And despite public energy companies having boosted stock buybacks and dividend yields higher than any other sector in the stock market, the sector remains, in many analysts' views, undervalued.

Billy Quinn, founder and managing partner of Pearl Energy Investments, said his Dallas-based private equity firm took 16 months to raise a $705 million energy fund announced in May, despite the fact that he believes he has a great story to tell potential LPs.

"Opportunities and value are driven less by fundamentals than by flow of capital, so whenever you have a business where capital is effectively leaving the business, you're generally identifying better values and better investment opportunities there," Quinn said. "The fundamentals of the day-to-day business and overall price levels never looked so good."

Private equity potential

VanLoh also said there's much to tell potential LPs about E&P investing.

"The supply demand dynamic is more favorable than it's ever been. Multiple valuation on assets is cheaper than it's ever been … and oil and gas is a phenomenal inflation hedge," VanLoh said, adding that oil and gas assets can be bought at all-time low valuation multiples.

VanLoh said potential investors respond to this with concerns about money lost in the last decade, and they need to hear what is different this time.

Ackerman said other investors are held back by overly optimistic views of renewable energy's potential.

"People talk a lot about renewables and electric vehicles, but renewables do not really displace oil demand, they primarily address power demand which oil has a very small share of," he said. "When you look at the use case, about 25% of global oil demand comes from passenger vehicles. The rest is shipping, trucking, aviation and petrochemicals. [These are] very hard sectors to displace with renewables and electrification."

While private equity investors painted a picture of great investment opportunities, Subash Chandra, an energy analyst at Benchmark Co., said he does not see it as such a sure bet.

"It's not a slam dunk. They have to be very careful about how they spend their money. They have to be lucky, and they can't put too much money in the ground. They have to be in the right place and have a Tier 1 resource that someone's going to want," Chandra said, adding that exit multiples are lower than ever, which is why it is now harder to build and flip. Unproved assets on acreage acquired by private equity is worth less now, he said.

'Salivating' at opportunities

Paul Steen, managing director of First Reserve, a private equity firm with offices in Houston and Connecticut, said many buyers want to rely on the assets' cash flows to drive much of the return, and the new realities have made hedging more important.

"Hedging is a bigger part of the conversation now because acquisitions have a lot more value in the existing production stream, versus historically where a lot more of it was probably in acreage and upside that you can't hedge as effectively," Steen said. "We can design a pretty low-risk business plan underpinned by existing production that's well engineered and a robust hedge book that typically goes out five to seven years, effectively de-risking the return of invested capital and providing some continued exposure to the long tail production and commodity price. The industry hasn't really seen asset valuations at these levels historically."

Some family offices are among private equity's new energy investors, and some, like Andrew Bremner, who manages a natural resource portfolio for the Jaco family office in California, said family offices are rushing to meet needs private equity can't.

"It is creating opportunities for family office investors like myself. We're salivating at these opportunities," Bremner said. "I would expect that a lot of the private equity asset managers are very frustrated because there are excellent opportunities to generate outsized returns." OGJ

Energy IPOs May More Than Double by Year-End

Latham & Watkins partner explains why the market has suddenly reappeared.

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So far this year, four energy companies have launched IPOs that share a common thread: international law firm Latham & Watkins advised each.

The firm has served as legal counsel for IPOs in January, February, March and June. First out of the gate: TXO Energy Partners—formerly known as MorningStar Partners—led by Bob Simpson. Next came Israel's Enlight Renewable Energy, then Atlas Energy Solutions, formerly Atlas Sand of Austin, Texas. Finally, in June, Kodiak Gas Services, the Montgomery, Texas-based oilfield service provider, successfully launched an IPO.

In a conversation with Hart Energy Senior Editor Patrick McGee, Ryan Maierson, a Latham & Watkins partner specializing in M&A, capital markets and special purpose acquisition companies (SPAC), discussed the appetite for energy IPOs, the stalled energy IPOs market in recent years and the decline of SPACs.

Maierson said the energy industry could bring as many as six more IPOs to market before the end of the year—more than in the past four years combined.

Q&A

Patrick McGee: We've had four energy IPOs this year. How did Latham and Watkins become the law firm involved in all of them?

Ryan Maierson: First, we are and have been for many years the top IPO law firm more broadly in the U.S. and globally, so I think we have a reputation for being effective counsel on IPOs in general. The second reason is the energy expertise that we bring. We have over 130 lawyers in Houston alone, many of whom are primarily focused on energy and energy transition.

PM: Can you say what the IPO market has been like for energy in the last few years, and how that compares to the current year to date?

RM: The last few years have been extremely challenging for us. We've seen a downtick for IPOs more broadly over the last couple of years, but energy in particular has not seen any significant and sustained IPO activity for several years, and energy IPOs tend to go in waves.

If you look at that 2010-2014 period, there were literally dozens of IPOs of MLPs, energy companies that are publicly traded as partnerships. Then, there was the commodity price crash, and then there was a wave of oilfield services IPOs in 2016 and 2017. The market has been relatively choppy since then. There were two energy IPOs last year, two in 2021, none in 2020 and two in 2019.

Now we're halfway through the year with four U.S. energy IPOs. We're more than double the number of energy IPOs in the last three years. I'm not prepared to say that we are in a new wave, but I would say there are very positive signs of investor interest in energy IPOs in the current market. We've seen the four IPOs already this year, and our backlog is about as significant as we've seen for quite some time.

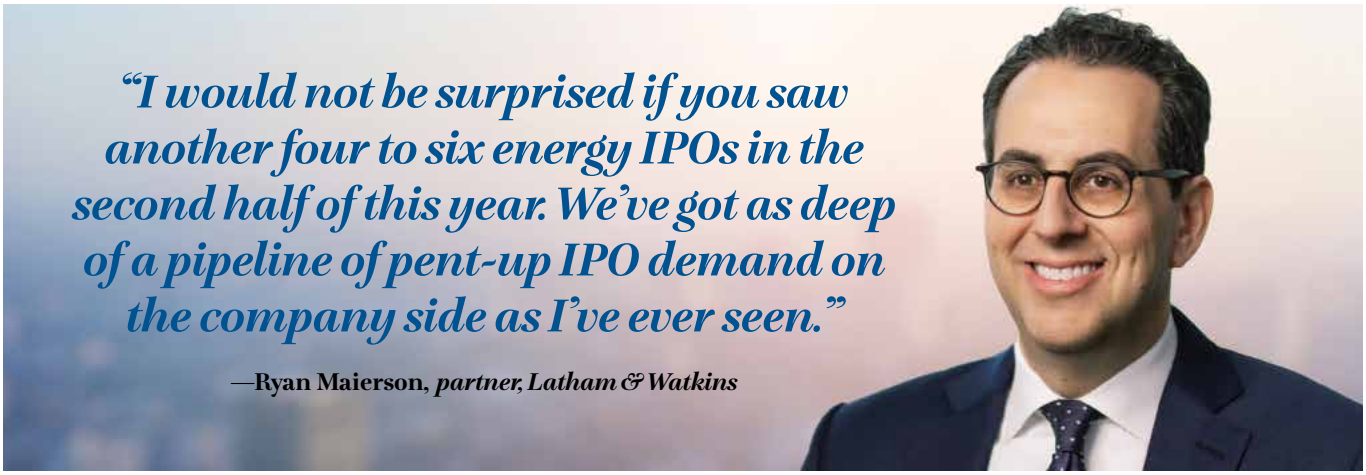
PM: What do you think is spurring the new interest in energy IPOs?

RM: I think it's a few things. One is that the energy transition is upon us. We are moving more rapidly than many expected toward an electrified and decarbonized world. At the same time, there's a recognition that we have a ways to go to get there and that we are still in a fossil fuel-driven economy and we will be for some period of time, and there's a recognition that both those things can coexist. We're not going to flip a switch, metaphorically, and become a carbon-free economy overnight. While we're making tremendous strides in energy transition, there is still a place at the table for traditional natural resources.

If you look at the four energy IPOs this year, you sort of see that story. You see compression and sand, and you see upstream in the form of the TXO IPO. There is a recognition that oil and gas development is still an important part of the economy, but there's also a recognition that there are new things on the horizon.

PM: How do commodity prices affect these IPOs?

RM: It's a great question, and the answer is, it depends. I would say the macro commodity price sentiment is more important than the closing price of WTI on any given day, but, certainly, higher commodity price macro environments make production [more] economically favorable than lower commodity price environments. So, to the extent that we're talking about businesses that are dependent on production



or that have a nexus to production, a sustained and forward-looking prediction of a sustained higher commodity price environment is going to be more favorable. But I think even though there is always volatility built into commodity prices … we're in a fairly favorable commodity price environment, which I think is what's leading to some of the positive sentiment.

PM: Why are these new IPOs being made now?
RM: If you look at the broader U.S. IPO market, while the first half of 2023 was slow, there's definitely a sense that there are more favorable market conditions emerging. Everyone has talked about how well [the food chain] Cava priced and traded as one of the major positive signs over the last some number of months and years. You can't put too much stock in the trading of a single IPO, but I think it's reflective of a fair amount of demand for new products. There are companies that could be very successful when they're public if the demand is there. I think we're now finally seeing both institutional and detailed demand for new equity paper emerging.

That's on the macro side. On the energy side, I think it's the two threads that I described. There's a continuing emphasis on sustainable and clean energy generation and a growing recognition that businesses in that sector can be quite profitable. Secondly, I would say there is also an increasing recognition that oil and gas exploration and development is still an important part of how we keep the lights on…There's obviously pent up demand for IPOs, and there's a recognition that the energy sector–which has been in disfavor for so long–is still a tremendously important part of the economy and needs capital formation in order to be sustained.

PM: What does success look like for the companies engaging in IPOs this year, and are you tempering expectations given the current commodity market?
RM: We are certainly trying to temper expectations for a number of reasons. While we are seeing green shoots, it's still early to be calling IPOs resurgent. We're advising companies to make their preparations if they think that an IPO, and being a public company, is right for them. We're advising them that any IPO will have to be carefully timed in the market and that they should be making backup plans if they need a capital infusion.

When there's this few data points, every IPO is potentially meaningful, everybody's trying to unpack the significance of every single anecdote that goes on in every single IPO. It's been sort of humorous to see how much attention has been paid [to the small number of new IPOs] because we are all trying to figure out which way the wind is blowing in a sort of nascent resurgent IPO market.

PM: Based on conversation with your clients, can you give us a sense of the energy industry's appetite for further IPOs this year?
RM: I would not be surprised if you saw another four to six energy IPOs in the second half of this year. We've got as deep of a pipeline of pent-up IPO demand on the company side as I've ever seen. We've got a sort of mix of those who are opportunistically looking at this year's data points and saying "maybe now is a good time to accelerate" … as well as companies that had shelved IPO plans two years or three years ago who are now thinking that it's time to really step on the gas and hit this market which seems to be somewhat favorable.

PM: What needs to happen to IPOs in the market in general to make them more attractive to investors again?
RM: That's a great question. I'm not sure I have a complete answer but at this point, I would say demand is back or coming back. There's still a lot of price and valuation sensitivity among investors, and so the IPO discount, as we say, is probably greater than we would all like it to be, at least in energy. I think it's going to take some sustained positive performance from recent IPO companies as well as continued acceptance among investors of the role of natural resources for the foreseeable future.

PM: Do you expect SPACs to be a popular mechanism compared to IPOs this year or do you see them declining?
RM: What I see is what I call a tail. There are almost 300 SPACs that went public during the boom times that are still either in search of a target company to take public or have a signed-up deal but have not yet closed it. In the next few months, that tail will effectively run off where the glut of SPAC IPOs from a couple of years ago will have run its course. We've seen a handful of SPAC IPOs this year … I think there have been about 16 in the first half of this year, as opposed to the 300-plus we were seeing per year during the boom.

I think SPACS will continue to play a role in the going public landscape alongside direct listings and alongside traditional IPOs. It remains to be seen what the run rate looks like. Is that 30 companies a year going public SPACs? Is it 70? I think we can be assured it's not going to be 250 a year, at least for the foreseeable future. OGJ

Rystad: Oil, Gas Sector Has All the Money it Needs

Despite the hue and cry over oil and gas investment, experts say E&Ps are meeting demand because of greater efficiency and productivity.

PATRICK McGEE
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Fears of underinvesting in oil and gas are way off the mark, Rystad Energy insists. The consultancy said in a report that efficiency and productivity gains, lower oil production costs and a sharper focus on more mature wells and the highest producing wells are handily making up for a more than 40% drop in global upstream investment since 2014.

Rystad's conclusion is at odds with the prevailing view within the oil and gas industry. Analysts and E&P companies have long said chronic underinvestment could have serious consequences. Hess Corp. CEO John Hess has been outspoken on the lack of capital investment in the sector, which he has said could be one of the "greatest challenges the world has."

But Rystad, a Norwegian energy research company, says they are looking at the numbers wrong.

"We don't think the total oil and gas investment numbers are telling the full story. Efficiency gains, productivity gains and portfolio effects have made the upstream industry much more efficient, and we get much more out of every dollar spent now compared to earlier," Espen Erlingsen, head of upstream research at Rystad, told Hart Energy. "We predict that the current activity level can keep up with demand."

The analysis found that the industry is hitting the same production levels reached during the robust years of 2010 to 2014—but at much lower costs. Rystad analyzed the development of oil prices for different supply segments and found production costs have come down 20% to 30%, resulting in more activity for every dollar spent.

Benchmark Co. energy analyst Subash Chandra is among the few who believe the industry has the capital it needs.

"Everyone's paying down debt. No one's really paying for newly discovered resources," Chandra said. "Oil and gas output is rising in the U.S. despite the fact that producers choked back drilling. Buyers are not paying for unproven resources. Maybe that changes, but there are no signs of that yet. Producers should continue to focus on free cash flow. They can still pursue exploration, there's enough free cash flow for that, but that should be a secondary pursuit."

"Everyone's paying down debt. No one's really paying for newly discovered resources."

—Subash Chandra, ***energy analyst, Benchmark Co.***

The number of new wells drilled worldwide peaked at about 88,000 in 2014 when global upstream investment reached its highest point at nearly $900 billion. The new well count dropped for a few years and then grew steadily from 2016 until the pandemic in 2019, according to Rystad.

Now the world has fewer new wells, but they produce more efficiently. There were about 55,000 new wells in 2022—a decrease of about 35% from 2014. The wells drilled in 2014 have a total production potential of 37 Bbbl of oil over a lifespan of about 30 years.

The wells drilled in 2022 are fewer in number but produce at nearly as great a capacity, Rystad said. The firm estimates they have nearly 32 Bbbl of oil. That productivity is being achieved with only 60% of the capital investment the industry had in 2014, and productivity may reach 35 Bbbl by the end of 2023, according to the analysis.

"It is not sufficient only to look at investments, you also need to understand how we are developing resources," Erlingsen said.

When fewer wells were drilled, the focus on more productive wells sharpened, according to Rystad.

"Our modeling and analysis tell a different story" about the industry's need for capital, Rystad said in a statement with its analysis. "The industry can do the same as before, but at a much lower cost."

In June, the International Energy Agency said that oil demand will slow significantly by 2028, and the U.S. Energy Information Agency forecasts lower global oil production through 2024. OGI

Fears of underinvesting in oil and gas are way off the mark, according to a Rystad Energy report. The consultancy says efficiency and productivity gains, lower oil production costs and a sharper focus on more mature wells and the highest producing wells are handily making up for a more than 40% drop in global upstream investment since 2014.

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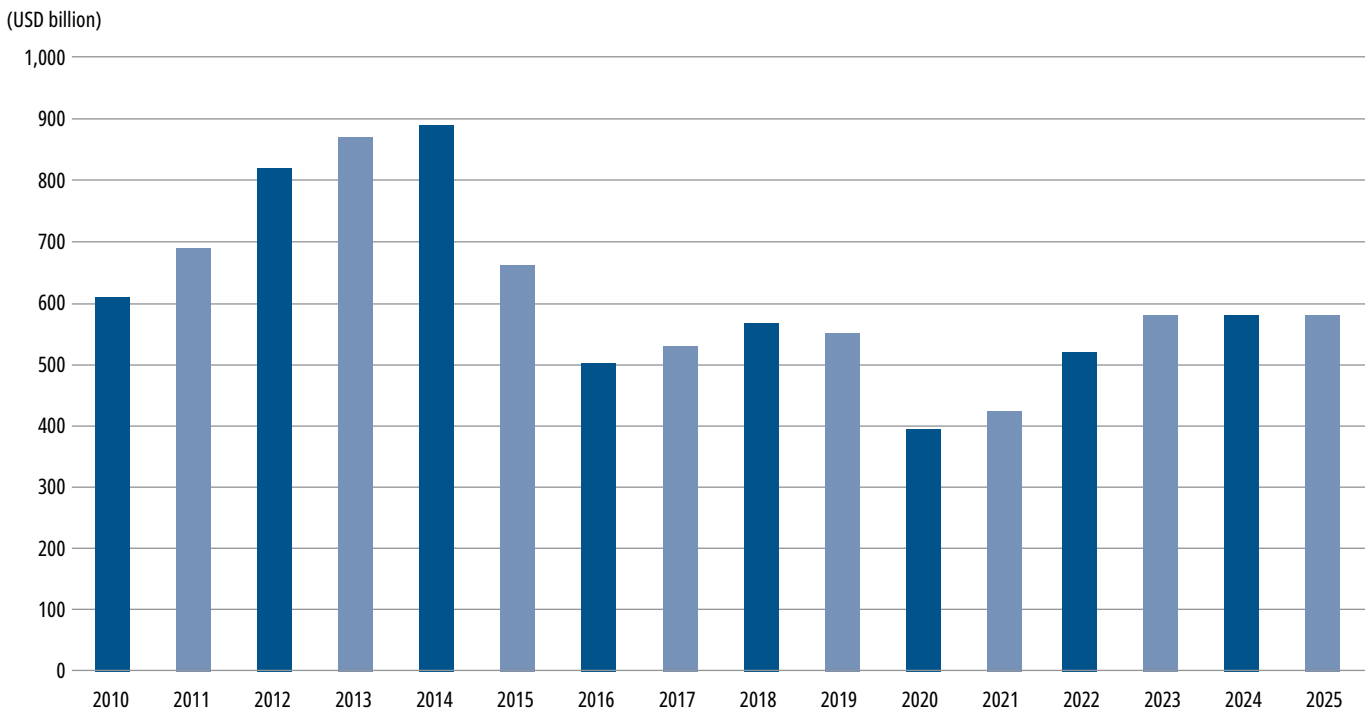
Global Upstream investments



Source: Rystad Energy

Gas Producers Pass Their Stress Test

Nine natural gas companies examined by Fitch Ratings showed resilience to lower prices, but other E&Ps could potentially face debt repayment hardships.

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In another sign of greater capital discipline exercised by E&Ps, Fitch Ratings found resilience among the nine U.S. natural gas producers that the credit rating company submitted to a pricing stress test.

The test found the companies could withstand a multi-year period of lower natural gas and oil prices because they've toughened up with better cost structure, hedging intensity and fund availability under long-term credit facilities. Light hedging was a threat to some companies.

Some companies would face difficulties with debt repayment and others would dip into negative cash flow, the test found.

"There's been a sizable amount of debt repayment across the space," said Fitch Ratings Senior Director Michael Ainge. "There's been this meaningful change in the way that the industry and most of the individual companies within the industry manage themselves and think about capital allocation."

Slava Demchenko, Fitch Ratings' director of natural resources and corporates, shared additional numbers with Hart Energy showing capex among these nine companies went from 127% of cash flow from operations in 2018 to just 48% in 2022.

"They are in much better shape than they were in 2019 when, unexpectedly, the pandemic hit," he said. "This time around, the companies are more prepared. They have lower debt. Most importantly, some of them have quite in-depth hedging programs."

The companies representing the entire U.S. natural gas industry were chosen because natural gas accounts for more than 35% of their production volumes. Companies tested were Antero Resources, Ascent Resources Utica Holdings, Chesapeake Energy, CNX Resources, Comstock Resources, Coterra Energy, EQT Corp., Gulfport Energy and Southwestern Energy.

Gas prices recently nudged up slightly, but long-time lows prompted Fitch to do a stress test of a further price drop.

The companies were tested at average Henry Hub spot prices of $2.25/1,000 cf in 2023-2025.

The testing found Antero, Chesapeake and Comstock would have negative free cash flow if gas prices dropped to $2.25/1,000 cf. They also have the lightest hedging programs among the nine companies, according to Fitch. Fitch's commodity forecast for natural gas prices in 2023 is $2.50/1,000 cf.

"[The nine companies tested] are in much better shape than they were in 2019 when, unexpectedly, the pandemic hit. This time around, the companies are more prepared. They have lower debt. Most importantly, some of them have quite in-depth hedging programs."

—**Slava Demchenko,** ***director of natural resources and corporates, Fitch Ratings***

Comstock has sufficient liquidity, but it could be pinched by a 3.5x leverage maintenance covenant to maintain access to the credit line they have with a syndicate of banks.

Coterra, Gulfport and Ascent came out on top as the most resilient in Fitch's stress test.

Antero, Chesapeake, EQT and Southwestern Energy did not have excessively high leverage, but could exceed their downgrade sensitivities under the stress test, according to Fitch.

Despite the test, the New York- and London-based rating agency said it expects gas prices to rise this year.

Fitch's prediction is based on a number of factors, including a declining number of active drilling rigs, increased LNG gas feeds following the restart of the Freeport LNG plant and increased switching from coal to gas.

Demchenko said gas prices bumped up a bit recently because of high temperatures demanding more energy. OGI

In another sign of greater capital discipline exercised by E&Ps, Fitch Ratings found resilience among the nine U.S. natural gas producers that the credit rating company submitted to a pricing stress test.

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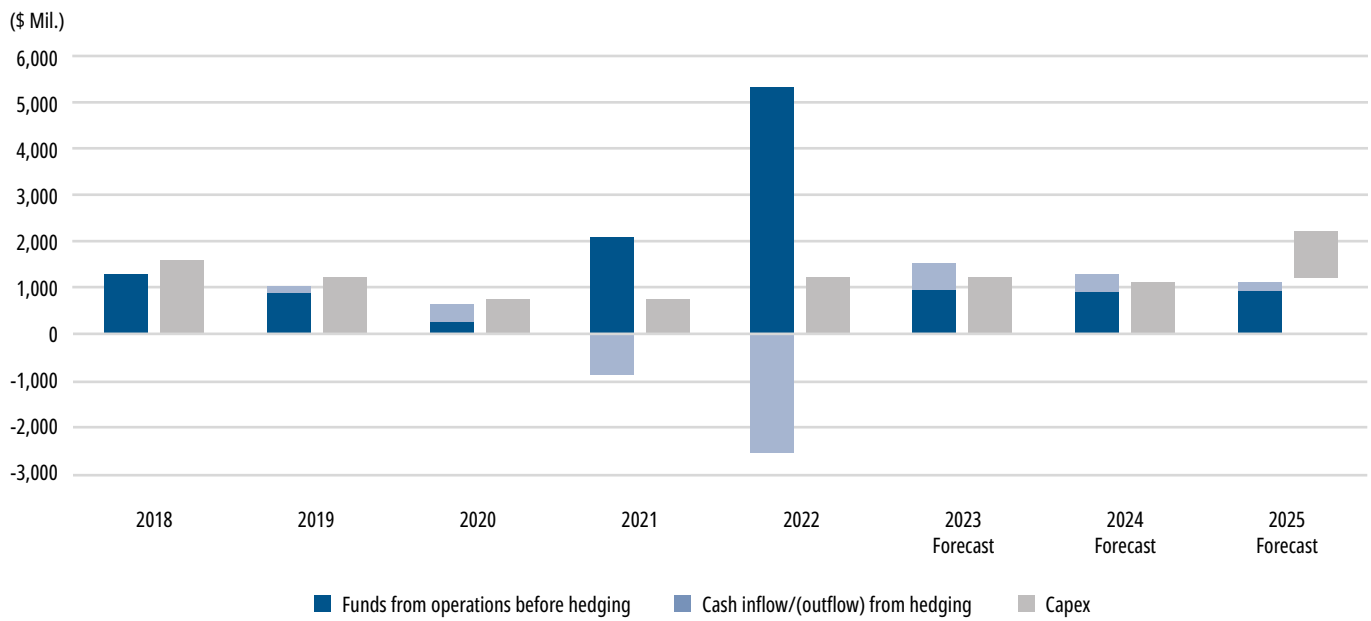
Funds, cash and capex among the nine large U.S. natural gas producers



Source: Fitch Ratings

Paisie: Oil Price to Zig and Zag Up

OPEC+ will remain intent on adjusting supply to align with demand.

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.

The oil market has been stuck in a rut for the last two months with the price of Brent crude bouncing between $70/bbl and $80/bbl. The current price dynamics are the result of ongoing concerns about the global economy, including the two largest economies (the U.S. and China). The concerns about the global economy and the associated oil demand are being reflected by the negative sentiment of the oil traders. At the end of June, the net long positions of traders of WTI fell back to the level last seen on March 21, just prior to the announcement of additional supply cuts on April 2 by OPEC+.

As such, it not surprising that OPEC+ announced on July 3 another round of production cuts, which entail the following:

- Saudi Arabia is extending its voluntary production cut of 1 MMbbl/d through August, with the possibility of further extensions.
- Russia is planning to decrease its crude oil exports by 500,000 bbl/d in August, which is in addition to the reduction of 500,000 bbl/d announced by Russia back in March; however, there is limited evidence that Russia moved forward with this initial reduction.
- Algeria chimed in with an announced cut of 20,000 bbl/d during August, which is in addition to the 48,000 bbl/d cut that Algeria made in April.

These additional cuts align with our view that OPEC+ will remain proactive in adjusting supply to align with demand and to place a floor under oil prices. The cuts also align with our view that oil prices will zig and zag on an upward trend during the second half of the year, with oil demand starting to outstrip supply.

Downside risks

There remain, however, downside risks, in part because of the aforementioned uncertainty associated with the global economy. Another potential risk, though with a lower probability, is the breakdown in the cooperation among OPEC+ members. Saudi Arabia is likely reaching its limit with respect to further production cuts with its current production at around 9 MMbbl/d. While Saudi Arabia has previously reduced its production to 8 MMbbl/d to balance the market, those instances were associated with significant downturns in oil demand.

Another factor that could cause instability would be an agreement between the U.S. and Iran that would allow Iran to increase its exports; however, we think that such an agreement is unlikely. The U.S. is seeking an agreement with Iran that would entail Iran agreeing to not enrich uranium past 60% in exchange for the U.S. not tightening sanctions further on Iran.

The proposed agreement, however, does not include the removal of sanctions on Iran's oil sector. Even if some agreement is reached, the more important development is Iran's growing ties with Russia (which goes beyond the supply of drones) and China. Consequently, Iran appears to be less motivated in dealing with the U.S. because China and Russia provide an alternative to making concessions to the U.S.

Furthermore, Iran has been able to increase its oil exports since the beginning of the Biden administration. Iran's oil production is now back to nearly 3 MMbbl/d and exports are running more than 1.5 MMbbl/d (with China being the main destination), which is the highest since 2018, though still well below the 2.5 MMbbl/d before the U.S. put additional sanctions on Iran.

Flows to Europe

Regardless of the short-term uncertainty, the oil market has proven again its resiliency and flexibility while facing disruptions. A vivid example is the shift in oil flows to Europe that have taken place in response to the sanctions on Russian oil-related exports.

In the Atlantic Basin, the U.S. has increased its exports to Europe from 1.05 MMbbl/d in 2021 to 1.61 MMbbl/d in 2023 (based on our projections for the rest of 2023) with most of the exports being light and sweet in quality. Brazil has also increased its exports to Europe from 160,000 bbl/d in 2021 to 286,000 bbl/d in 2023 with most of the exports being medium and sweet in quality. Other producers, including Saudi Arabia (from 481,000 bbl/d to 878,000 bbl/d) and Iraq (from 666,000 bbl/d to 692,000 bbl/d) have increased their exports to Europe. Concurrently, Russia has shifted its exports toward Asia—namely India and China.

It is because of this flexibility that oil prices have moderated and the impact of the sanctions on Russia has been muted. To ensure the future security of energy supply, the robustness of associated supply chains will need to be explicitly considered in determining the optimal speed of shifting from oil (and natural gas) to alternative sources of energy—including energy to meet the demand associated with the transportation sector. OGI

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THE OGINTERVIEW

Right Place, Right Time, RIGHT SIZE

CEO Jesse Arenivas takes EnLink Midstream to first-mover status with a pipeline of carbon capture and sequestration projects.

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DALLAS—A native of the Permian Basin with two decades of navigating the maze of North American midstream challenges, Jesse Arenivas is now reshaping the space.

Just shy of 20 years at Kinder Morgan, Arenivas in July 2022 took on the top job at EnLink Midstream, where he led a ground-breaking deal with Exxon Mobil in October. EnLink is repurposing half of the firm's existing natural gas pipeline network to deliver CO_2 from the Mississippi River corridor in southeastern Louisiana to Exxon Mobil's 125,000-acre CO_2 storage location under development in Vermilion Parish.

Arenivas learned the ropes of the midstream business and cultivated a niche expertise in CO_2 transportation during his time at Kinder Morgan. As president of both the CO_2 business and energy transition ventures group, he oversaw the workings of the largest transporter of CO_2 in North America, delivering approximately 1.3 Bcf/d for use in enhanced oil recovery projects.

EnLink's transportation service agreement holds an ultimate available reserved capacity of up to 10 million metric tons (MMmt) per year, with initial reserved capacity of 3.2 MMmt/year, beginning early 2025. It's the first agreement of its kind in the U.S.

Arenivas shared his vision for EnLink, the midstream sector and the energy industry with Hart Energy's Deon Daugherty, editor-in-chief of *Oil and Gas Investor*, during a wide-ranging discussion at the firm's downtown Dallas headquarters in July.

THE OGI INTERVIEW

Watch the video interview here:

Q&A

Deon Daugherty: Does the nomenclature of 'energy transition' best describe the dynamics of the current cycle?

Jesse Arenivas: It's more of an energy transformation. The industry is going to utilize multiple products rather than only hydrocarbons. You're going to have bluer, greener products that emerge onto the market. Growth in hydrocarbons will continue for the next three decades, and the consensus is pretty well aligned on that.

We view this as a transformation to include hydrocarbons, hydrogen, and other synthetic fuels, as well as other energy sources, such as wind and solar; the future is transforming into multiple options.

DD: What does that mean for the traditional hydrocarbon space?

JA: I think it's an opportunity. You have the option now to invest in higher quality cash flows—those that are not dependent on commodity prices or drilling activity, and they don't have a decline rate.

It's also an opportunity to decarbonize the industrial sector. Obviously that benefits economic activity in that it facilitates growth in hydrocarbon and industrial uses. EnLink sees the energy transformation as a real opportunity to grow our base business—which today is 90% natural gas and NGLs—to a more diversified portfolio and a higher quality cash flow. It strengthens the company, and it strengthens the industry.

The industry as a whole will have opportunities to invest in capture technology, capture equipment, transportation, sequestration and utilization.

As worldwide demand for cleaner energy continues to grow worldwide, we see the addressable market in the state of Louisiana as actually not just 80 million metric tons, it's 80 million and growing."

—**Jesse Arenivas**, *CEO, EnLink Midstream*

Tom Fox/Hart Energy







EnLink Midstream

EnLink's base business is natural gas and NGL, with a strong presence in the Permian Basin.

The industry should look at this as an opportunity to continue to invest in fossil fuels and develop greener products by utilizing carbon capture. The world's demand for blue products and green products facilitates growth in the industrial sector. It also facilitates growth in the hydrocarbon sector. So overall it is an opportunity to contribute to reduction in greenhouse gas emissions while maintaining our standards of living.

DD: In many ways, EnLink is a first mover as far as midstream companies go in, in handling carbon capture, technologies and integration. What was the impetus behind it? What interested EnLink in taking this risk?

JA: We did a lot of research ahead of it that quickly led us to focusing on Louisiana.

EnLink operates two of the four market systems for gas delivery in Louisiana. We had redundancy in our systems, and we had very large diameter pipe. So that presented the opportunity, and that's where our innovation mindset came forward and we asked, 'Can we move large quantities of CO_2 in our existing pipeline infrastructure?'

Historically, carbon has moved at a super critical dense phase of high-pressure pipelines. After all of the analysis, thorough engineering work, hydraulics studies and metallurgy studies, it became apparent that in short distances with large diameter pipe, you can move large quantities of CO_2 in existing natural gas pipelines. In short, EnLink is sitting in the perfect position due to what I call the 'trifecta': first, there is an existing large concentration of CO_2 emissions in the state of Louisiana—80 million metric tonnes per annum in the industrial Mississippi River corridor; secondly, this overlays existing, underutilized pipeline infrastructure that can be repurposed to move CO_2; and thirdly, there is nearby, high quality geologic sequestration sites. This trifecta provides the opportunity for EnLink to execute on our first mover advantage.

DD: Louisiana has recently filed with the U.S. Environmental Protection Agency for primacy of Class VI injection wells. Would that have any impact on EnLink's plans?

JA: Absolutely. Primacy in Louisiana would remove an uncertainty around regulation and permitting timelines—and that uncertainty is a big one in the decision to go to FID for our customers' projects. We believe Louisiana gaining primacy will accelerate the development of these projects, which is good for the industry, good for the economy, and good for the state which has set its own CO_2 reduction goals.

DD: What would the impact be on the natural gas business in Louisiana when you complete the conversion to CO_2?

JA: EnLink has two of the four natural gas market systems, so that redundancy allows us to continue to service our existing industrial customers with natural gas. We see growth in the natural gas sector continuing, as well as growth in the LNG sector. EnLink is positioned to where we don't have to cannibalize our natural gas business, and we will be able to grow both the industrial and the LNG

"What we're seeing is a return of the generalist interest, at least in seeking a way to participate in energy security and the energy transition, because the sentiment is changing slowly to [recognize] that energy security is paramount."

—**Jesse Arenivas**, *CEO, EnLink Midstream*

Tom Fox/Hart Energy

markets while we capture the CO_2 opportunity.

DD: EnLink has a transportation deal with ExxonMobil. What can you share about those steps and that project and how that's coming along?

JA: We are in the execution phase, which includes permitting.

EnLink entered into an agreement to transport an initial volume of 3.2 million metric tonnes per annum with a reserved capacity up to 10 million metric tonnes per annum. We are well on our way with the project, which will be in service in 2025. Those are near-term, real cash flows in this space in less than 24 months from today. We're very excited to be a first mover and are executing on that advantage. We anticipate that, over time, ExxonMobil will fill the 10 million metric tonnes per annum in our contract.

We're also very excited about EnLink's multiple letters of intent with other highly regarded, high-quality credit companies such as ConocoPhillips, Oxy, Shell and Talos, and we're in multiple discussions beyond those. We feel very good about positioning ourselves as the CO_2 transporter of choice in Louisiana. We're not competing with any of these parties—the emitters or the sequesters. We are the transportation solution, so we will facilitate the transportation of CO_2 emissions to be permanently sequestered by one of those parties. We feel very good about being able to capture the lion's share of the CO_2 transportation opportunity in Louisiana.

DD: In an industry that is as capital intensive as energy, does carbon capture have unique financial upside?

JA: Today in Louisiana, our emitter customers are focused on sequestration. Obviously, that's the highest tax credit value due to the IRA. Also from an ESG perspective, the emitters are highly focused on reducing their emissions through permanent sequestration. Industrial facilities, like ammonia and fertilizer facilities, already separate their emissions as part of their existing processes. So then you're just capturing, compressing, transporting and permanently sequestering the carbon. CCS is highly economic today because of that. The market will grow and expand the addressable market with post-combustion CCS, but I think there's still a ways to go to make that economic. On top of that, there are various newer technologies being developed to utilize, rather than permanently sequester CO_2. We're watching those technologies, but it's clear that transportation will still be a big component of the value chain.

DD: Tell us about your CCUS projects in North Texas.

JA: We have two CCUS projects in North Texas. One—with our customer, BKV—will be operational late this year. For EnLink, the project with BKV is a great pilot to see where we can take this technology and this type of project to other areas where we operate.

Both North Texas projects also provide an added benefit of reducing EnLink's own emissions. We're on our way to reaching our 2030 target to reduce our scope 1 CO_2e emissions intensity by 30% over 2020 levels. Overall, it is a value-added proposition for our customers and for our asset base in general.

DD: EnLink's year-end and first-quarter earnings reports showed record-setting profit, and at this point, none of that includes profit from CCS. When you consider future profit growth, how will CCS contribute on top of your base business?

JA: Our base business is 90% natural gas and natural gas liquids, and it's been very, very resilient in the temporarily negative gas macro environment the industry is in. Our largest segment, the Permian Basin, continues to grow exponentially over the last few quarters. Even our Oklahoma segment is going to have double digit growth year-over-year. Our North Texas assets have been very resilient, and in Louisiana, we're seeing in our downstream markets growth in NGLs, propane and others due to the resiliency on the demand side there. We feel very good about growing our base business and that it will grow organically. Longer term, we are bullish on natural gas prices, which will lead to further investment and earnings growth in our basins, not only the Permian, but north Texas and Oklahoma, as well as our downstream business in LNG growth and in industrial demand growth in the Louisiana area.

But as you said, this carbon transportation business will be above and beyond that growth. We believe we can grow our carbon capture business to be about 25% of EnLink's 2023 cash flow. That is very robust growth. We feel like these are very differentiated and higher quality cash flows because they are not dependent on commodity prices, they do not decline, and they are growing.

As worldwide demand for cleaner energy continues to grow worldwide, we see the addressable market in the state of Louisiana as actually not just 80 million metric tons per annum, but 80 million Mtpa and growing. For example, CF Industries and Mitsui recently have announced a $2 billion investment in a blue ammonia facility in Louisiana. We feel very good about the growth we anticipate of our carbon business, especially as a company of our size, as this business will provide highly sought after cash flows and should add tremendous enterprise value to EnLink.

> *"I think the midstream space is going to look different. There are going to be multiple products—there's going to be carbon, there's going to be hydrogen, there's going to be other synthetic fuels—that need to be moved around."*
>
> —**Jesse Arenivas**, *CEO, EnLink Midstream*

DD: Have these CCS projects had any impact on reversing the negative sentiment of generalist investors toward the oil and gas business?

JA: Yes; what we're seeing is a return of the generalist's interest in the space, at least in seeking a way to participate in energy security. The energy transformation sentiment is changing slowly to [recognize] that energy security is paramount. The affordability and the reliability of energy has taken center stage. So the growth in this space is now a lot more conducive for a generalist to be interested in the space.

I think the EnLink investment opportunity is unique because we have this carbon capture opportunity that we're executing on today, which allows a generalist to participate in midstream in a differentiated way that gives them upside in the next several decades of the energy transformation.

DD: How do you view the role of CCS in U.S. energy security and independence?

JA: From an independence perspective, carbon capture and sequestration allows for a reduction in greenhouse gas emissions that are associated with the utilization of oil and gas production. It allows for the growth that is necessary to meet energy demand worldwide, enabling the production of more hydrocarbons without increasing the associated emissions.

We see this as a solution for growth in the oil and gas space, for growth in the industrial space, and ultimately, as a benefit not only to the [physical] environment, but also to the political environment worldwide as we're able to supply our allies with cleaner, more reliable energy, ultimately creating a safer environment worldwide.

DD: Where does the midstream sector fit into the energy security equation?

JA: The midstream space is paramount to energy security, as it provides the ability to get the production to the end user. I believe today is the day for midstream to participate in a big way, both in energy security and in the push for lower greenhouse gas emissions.

Our role as the midstream industry is to facilitate the movement of not only hydrocarbons to a global hydrocarbon demand market, but also to transport carbon to sequestration sites as a way to reduce emissions. There's a dual role for us to play, and EnLink is uniquely situated to do that.

The industry has transformed post-IRA due to economic incentives coupled with motivations to reduce emissions from an ESG perspective. In short, I think all interests are aligned, and midstream will continue to be a vital part of both the energy transformation and energy security for many, many years.

DD: How do you view the future of midstream, if you will? What will it look like in 10 years from now?

JA: As evidenced by our ExxonMobil deal, I think the midstream space is going to look different. Traditionally we moved hydrocarbons, but now there are going to be multiple products—there's going to be carbon, there's going to be hydrogen, there's going to be other synthetic fuels—that need to be moved through midstream.

I think the future of midstream is combining a sustainable set of assets that facilitates both traditional hydrocarbon gathering, processing, transportation and storage with assets that facilitate a CCS business and the transportation of other products.

The future of midstream is one that's going to solve energy demands, facilitate growth in demand, and ultimately play a vital role in getting energy to the world in a way that can sustain our standard of living in the U.S., while helping emerging markets worldwide get more energy, security, reliability and prosperity. And it will do all this while at the same time lowering emissions and reducing environmental impacts through CCS.

DD: How do your peers view CCS as a midstream growth component?

JA: I think the opportunity set for EnLink is unique.

Historically, midstream is a hard business because you've got multiple challenges, from regulatory and permitting to economics.







EnLink Midstream

EnLink's operations in Louisiana include two of the state's four market systems for natural gas delivery.

EnLink is a first mover and has a unique opportunity for two reasons. One is we're the right size of company. To grow a business 25% is extremely rare. On top of that, we're sitting in the trifecta of opportunities. We've got all three of the necessary components to execute and be a first mover. Many midstream companies have developed teams around how to capture these opportunities. But the reality is, you've got to have pipes to move the product, you have to have high concentrations of emissions, and you've got to have nearby sequestration, each of which EnLink has in Louisiana.

For example, in the Midwest, they have a high concentration of emissions, but there's not pipeline infrastructure in place today. There's not nearby geologic sequestration.

There's a lot of complexity around the CCS business. I think the midstream space is highly incented and highly interested to develop carbon transportation deals, but it's finding those opportunities and being able to execute that is the challenge today for most and what sets EnLink apart as a first mover.

DD: Is midstream seizing on the CCS opportunity in terms of investment?

JA: EnLink is definitely the first in the midstream space that's actually investing and has near-term cash flows. The industry has seen multiple announcements of projects that have not gone to FID, and there are no real hard dollars going into the space.

That's the uniqueness of EnLink's agreement with ExxonMobil. Not only do we have a real 25-year contract with the highest credit quality producer in the space, we're actually executing on that. And we have near term line of sight to revenues, which no one else in the space can say today.

DD: How much has EnLink invested?

JA: We're investing $40 million this year and another $160 million over '24 and '25 on the existing ExxonMobil deal. And, we also have four or five projects in discussion. We have strong cash flows. We've got a great balance sheet and free cash flow profile. We believe that we can execute on multiple utilizing our internal cash flow.

DD: Do you anticipate opportunities for growth in the emerging LNG market?

JA: We have longstanding relationships and decades of supplying natural gas as a feedstock to industrial customers in Louisiana. We also are uniquely situated. We have over 4,000 miles of pipe in the state of Louisiana alone and are very well positioned to grow along with the LNG space. Two years ago, 0% of our volumes we're associated with LNG. Today, that's 11%. We anticipate by the end of 2024, that'll be about 25% of our Louisiana natural gas business.

We are very excited about the multiple ways for EnLink to win in Louisiana. We spend a lot of time talking about carbon, but there's also strength in our LNG and our industrial growth prospects. We see growth in both areas. Having multiple systems in the state allows us to participate on both fronts, and we view that as a big growth driver for EnLink in the next few years. OGJ

Hunting Giants

Harold Hamm reflects on his life, career and ongoing plans in his newly released book, "Game Changer: Our 50-Year Mission to Secure American Energy Independence." In a conversation with *Oil and Gas Investor*, he reflects on exploration, shedding the shackles of a public listing, oil politics, the role of American energy and why he wrote the book.

NISSA DARBONNE
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While a junior in high school in the early 1960s, Harold Hamm was asked to write a paper on a career that sounded interesting to him. He picked the oil business, researching and describing in great detail how it worked—from exploration and extraction to refining and transportation.

Until then, the petroleum industry—although it was all around him in Enid, Okla.—wasn't very familiar to him.

What was familiar had been farming with his family at his first home south of Oklahoma City, and picking cotton when in season in Texas, getting paid 2 cents a pound.

As the season began to wane, the family would return home. Hamm and his siblings—he was the youngest of 13 children—would go back to school, catching up on the missed work as best they could.

His earliest years were without electricity, as the bucket trucks and linemen of the Rural Electrification Act had not yet reached the family farm.

His first oil job—after working at a gas station during high school—was cleaning sludge out of oil tanks. He helped grow the boss' three-truck company to 10 trucks, but the owner had "personal challenges" and Hamm quit.

Having a family already—a wife and two small children—he took a refinery job, but felt stifled by timeclock-oriented union work. He wanted to explore.

Starting with a smile and a truck of his own in 1967, he grew his oilfield-services company into a $25 billion E&P, Continental Resources, which he took private again last fall by buying out the remaining percentage of the shares he sold in 2007.

In 1973, living 100 miles from a commercial airport, he obtained a pilot's license and a plane to expedite business travel. And, one year later, he attended [the former] Phillips University in Enid to study geology so he could better understand how to find oil.

The two skills literally helped him "see" rock strata, such as near Inola, Okla. He observed its waffle-like surface features from the air that helped determine what was required to tap the resource matrix from the intersections of these squares.

Q&A

Hamm, 77, still has that initial high school paper, which he titled simply "Oil," along with hundreds of other mementos from his career. He cites excerpts of it in his memoir, "Game Changer: Our 50-Year Mission to Secure America's Energy Independence," published Aug. 1, in which he shares more C.V. details beyond the few-paragraph synopsis that is typically his corporate bio.

The book's forward is written by former Secretary of State Mike Pompeo.

And, yes, Hamm talks about former President Donald Trump too, with whom he "remained friends throughout much of

> ***The problem is, for 60 years we have faced political fumbles that have cost Americans energy security and independence .... Is there a solution? There is. Innovation and technology.***
>
> —**Harold Hamm**, *founder and executive chairman, Continental Resources*

Harold Hamm in his element

Continental Resources

his term," he wrote, but he saw "become more and more distracted" as time went on.

"I get asked a lot about my support for [Trump] running again," he wrote. "Although many of his policies were sound and helped our nation prosper, he simply did not stand with many of those who stood with him.

"My strong belief is there are better qualified candidates …." But not Biden.

Nissa Darbonne, Hart Energy's executive editor-at-large, visited Hamm at his headquarters in late June. During the three-hour conversation, he sent to voicemail three calls from another GOP presidential candidate.

Hamm still looks for unique surface features today from the air, but not as the pilot. The company's board urged him to quit in 2010 when he turned 65. Does he miss the cockpit? Not really, he said. "Now I get to sit in the back and enjoy a drink."

Nissa Darbonne: You've been working on the book for several years. What do you hope readers come away with?

Harold Hamm: No. 1, our goal is to set the record straight and tell it like it is. There have been a jillion myths and untruths unfairly told by disparagers about this industry I love—for their own benefit.

No. 2, I'm someone who sees the glass half-full, and I'm always looking for solutions. I believe people will come away with common sense and real-world solutions to inspire future generations. Perhaps the next little, barefoot country boy will get a big enough good idea to change the world.

ND: Of all the presidents you've met over the years, Ronald Reagan was not on your list.
HH: Yeah. I didn't have the opportunity to meet him. I wish I had. He did some great things and he did some things that were really harmful to our industry.

ND: Like crushing Russia with an oversupply of oil, but crushing the U.S. industry, too, with sub-economic prices?
HH: He broke up the Soviet empire, drove the Soviet

economy into the ground. But it really harmed our industry. It was devastating.

ND: You write that his tack with the U.S. natural gas industry was no better.
HH: He deregulated natural gas, which probably needed to be done, but it should have been done over time—slower and more systematic. He did it all once—dumped all the nation's gas supply on the market at once.

It drove down the price to the point you couldn't invest in it, and it actually wound up causing a shortage in 2000.

But was he a great American? Probably. I don't think any of us ever thought he wasn't. But he was tough on us. About half of the industry didn't make it through the '80s.

ND: In early 1982, you felt like the market had become too overheated, too frothy. You sold your 10 rigs and bought them back just a few years later for 10 cents on the dollar.
HH: I started doing what I like to do best: explore. I looked at all the basins in the country.

I wanted to find oil—and [a] lot of oil. The Williston Basin and Powder River Basin were interesting, but primarily the Williston. I wanted to find some really large fields. I wanted to find some giants.

And, as we say, the rest is history.

ND: You had the idea of testing the Middle Bakken in eastern Montana and brought it to a Dallas operator who declined, but then did it on his own. There are people you name in your book, but you didn't name this person.
HH: I didn't want to throw any bad light on these guys because that's what happens sometimes.

ND: You didn't get to be first in the middle Bakken in eastern Montana, but you had already moved onto figuring it out in North Dakota.
HH: We wound up with almost half of Elm Coulee Field in Richland County, Montana. That's where the Bakken started. Quickly, I jumped over to where the rest of it was—in North Dakota.

ND: The center of the Williston is in western North Dakota, so if using the "you find oil where it's been found before" rule of thumb, it seemed the Bakken—the source rock—would be particularly bountiful there?
HH: It was grassroots geology. You always got a show in the Bakken. But every time you tried it, it didn't do much of anything.

North Dakota had a core library. We went up to Grand Forks, and [the late] Julie LeFever—she was a great geologist—who ran the core library, laid out all the cores they had on the Bakken. I mean, she had a full room of them. The rock looked like this [granite] table. It was so dense that it was just hard to imagine how you could get oil out of it. But all of it had [oil] staining through it. It had very little porosity and very little fracturing. So, it wasn't a fracture play [a play made of tapping oil trapped inside natural fractures].

We came back [to Oklahoma City headquarters] and completed the mapping and decided, "Hell, let's go try it." We leased 350,000 acres. [With test wells,] we were getting a little more precise in where we needed to be, and what we needed to do. Basically, we put together all the acreage we could near the Nesson anticline, and we amassed 1.2 million acres over time.

ND: You decided in 2007 you needed more money.
HH: [The rock] didn't work anything like it did in Montana. It was different. What worked in Montana did not work over here. We kept trying different techniques and finally went to stage treatments. So we had to change everything.

We'd bought a lot of acreage that we needed to be developing, and we had very little capital. We decided we'd take the company public.

ND: You went on to wildcatting new tight-rock plays in Oklahoma and Wyoming. What's been the most obstinate of them all? Was it the Bakken?
HH: I think it was. It took breaking the code in the Bakken in North Dakota. It was an extreme challenge. And a lot of people just didn't believe we could do it.

> *"Yes, you could get gas out of shales. But as far as getting oil molecules out of shale, it's probably the toughest thing we ever did."*
>
> —**Harold Hamm,** ***founder and executive chairman, Continental Resources***

ND: Newcomer generalists in the business miss the fact that producing oil from nearly impermeable rock is a much greater challenge than producing gas from shale, since an oil molecule's so much larger and heavier.
HH: Yes, you could get gas out of shales. But, as far as getting oil molecules out of shale, it's probably the toughest thing we ever did.

ND: As the Eagle Ford and Permian joined in, the U.S. soon didn't have enough refining capacity for all the new light, sweet oil. Oddly, the U.S. had developed a situation of "stranded" oil.
HH: Almost all the refining capacity at that time had [been retrofit for] heavy Canadian crude [after U.S. light, sweet production began to decline in the 1970s]. The U.S. refineries didn't want our oil. Believe it or not, here in the U.S., it had all been modified for heavy sour. That's why lifting the export ban was necessary.

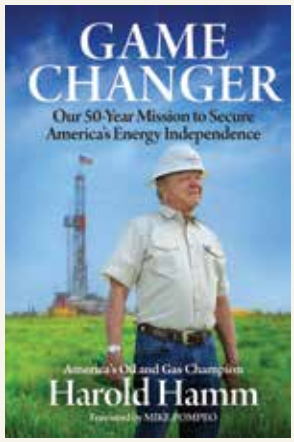
ND: Since you don't have to publicly announce a new play anymore, might Continental get to do more exploring than before?
HH: Oh, yeah. It's going to be better.

ND: Were you having to hold back to keep your ideas tight-holed?
HH: You always did. You didn't want to give secrets away early, but you had to when it became material [to investors]. It's like observing the oil-staining down in the Three Forks and [later on] testing it. When we did, everybody thought it was crazy even thinking about it. But, within a year, everybody was drilling the Three Forks.

ND: You had seen the staining in Three Forks when you looked at the cores for the nature of the overlying Bakken.
HH: Yes. And it was like, "What the hell? How did this get down here?" I can understand, up here [in the Bakken] where you have

HAROLD HAMM'S SECRETS TO SUCCESS

The following are among the truisms that Harold Hamm shares in his book that have guided him on his journey.



BE ALLERGIC TO DEBT

"Of course, there are opportunities for which using other people's money to advance a cause is smart.… In my 50 years, I've seen too many instances when too much debt rendered companies helpless and hopeless. The burden of excessive debt and interest load has crushed many a company—especially in a commodity business where price swings are the norm."

LEAD BY EXAMPLE

"Never expect anyone to do a job you wouldn't do yourself.… For too long, I played too hard. I was not as good an example as I could have been. I regret that. So, I work a little harder every day at being a better example to others."

ADVOCATE FOR YOUR INTERESTS AND YOUR INDUSTRY

"Stand up for what you believe in. Don't expect someone else to carry your load or represent your view.… You can't outsource advocacy."

ACT WITH INTEGRITY

"Never sacrifice integrity and never be silent when others do. Tell the truth even when it hurts. Be transparent and honest to a fault.… Avoid those … who don't have it."

ENJOY WORKING HARD

"… If there isn't fun and fulfillment in your work, it will become a grind and you will grind to a halt."

DECIDE DAILY YOUR "MAIN THING"

"Brush fires and dust storms occur all the time and often obscure the primary mission. Don't get distracted.…"

EXERCISE DAILY AND BE HEALTHY

"Eat the foods that are good for you. Drink in moderation. And please don't smoke unless it's an occasional celebratory cigar."

IT'S NEVER ABOUT THE MONEY

"More than 50 years ago, I left one of the best-paying union jobs with a major oil company to start a one-man, one-truck oilfield-service company. I had what felt like a ton of debt—and what felt like a ton of ambition too.

"… Yes, money is a way to keep score and survive, but it has never been my reason for being. There are better ways to keep score. Maintaining purpose in life, an abundance of close friends and a wonderful family tops the scorecard.…"

BE HAPPY

"It's contagious to all those around you. Stay clear of bad apples. Or make sure they go out with the evening's trash."

PERSEVERE

"… Sometimes meaningful change takes years to accomplish. Never surrender to the naysayers. If it's worth doing, keep trying until you find a way.…"

PICK GOOD FRIENDS AND ASSOCIATES

"Become an expert listener. You will gain in intelligence, wisdom and the ability to grow.…"

IDENTIFY THE "DOERS"

"… Surround yourself with people who want to take the next hill. Nurture the stars. Ditch the asteroids.…"

KEEP IT SIMPLE

"When it comes to making deals, if you can't write the details down on a dinner napkin in plain English, walk away."

HAVE SOME FUN!

"Enjoy the adventure. You only get to play one round."

organics, you're going to have oil show. But there are no organics in Three Forks. Yet, we had oil show. I never forgot that. I just hung onto that for the time being. We started drilling it once we figured out the Bakken.

ND: What might we hear about that you're working on right now?
HH: [Laughs.] Well, it's no secret, really. Powder River is one that we have a big interest in. It's needed somebody that had enough size and scale to consolidate the basin. And we've done a pretty good job of that, putting a huge leasehold together—and big enough that we could add scale to it.

ND: I understand it's gassier in the southern fairway.
HH: Part of it is. It's a big enough and diverse enough basin that you can pick and choose.

ND: And the Powder has lots of formations and benches.
HH: You have so many zones out there in the Powder. It's hard to even put them in a box, you know? It's a stacked pay. I mean, it's just pay after pay after pay.

ND: You're still looking for a new play—but from the cabin—while you're flying?
HH: It's interesting, particularly in the northern Rockies. In Wyoming and a lot of Montana, all of the geology is on top of the ground. You see a lot of it expressed in the surface features. Here in Oklahoma, you don't. Where I saw that waffle-like pattern—the block fracturing—it was over around Inola here in Oklahoma. And once I figured out what that was, then I could treat it. Up until then, it was just a tight formation that you were lucky if you had one good producer.

Well, once we figured out the structure, we could use retarded acid to get into the bigger system. You couldn't go in and get rough with it. If you did, you were out of zone. But using retarded acid and being careful, then you'd get into the bigger block system. And all of a sudden, you were connected.

Made some damn nice wells. If you hadn't seen it on top of the ground, you wouldn't have known it.

ND: What's an area you'd like to get into?
HH: We continue to look for new basins. We don't have any burning desire to go international. You get into all the geopolitics. Pretty soon, it's nationalized and it's taken away. But there are some interesting basins still that have some allure, some of which have been picked over a little bit but no one found anything. That doesn't mean it's not there.

So, we'll continue to pay attention to those. And, they're in the U.S., so we'll keep looking.

ND: Would you ever consider a gas play?
HH: Yes, in the right economic situation. Certainly, the Haynesville is a really great play. It's close to market. And it has a lot of running room. But it has the same supply-demand situation as everything has. It's fairly easy to oversupply the gas market. So, it's precarious.

ND: You had an opportunity to get into the Barnett early on when it was going horizontal in 2002, but passed. You were disinclined even then to do gas.
HH: As a geologist, you learn that there's just a heck of a lot of natural gas. I say it's ubiquitous. It's everywhere. And oil is not; oil is hard to find. And, it's a different animal; it's harder to oversupply oil than gas.

ND: The team probably has a great deal more time to explore these days since Continental's gone private.
HH: We do. Instead of preparing quarterly reports and all that kind of business, we're basically back to looking for oil and how we can better produce and how we can create more profit for the company. Doug [Lawler, president and CEO] and I both estimate the time savings is 20% across the company. A huge amount of time. Our auditor, Grant Thornton, recently reassessed what it takes to audit us and do our work. They cut 20%. It's a game-changer.

> *"I wanted to find oil—and [a] lot of oil. ... I wanted to find some giants. And, as we say, the rest is history."*
>
> —**Harold Hamm,** ***founder and executive chairman, Continental Resources***

ND: Is there a risk that E&Ps' current tack of low- or no-production growth, returning profits to shareholders instead, is stymying U.S. wildcatting and will harm the American energy posture?
HH: I think it could. The publics are all in this drive to make themselves look good quarter-to-quarter, trying to please the market. I'm really glad to exit that scene.

ND: You were going to be invited to be Department of Energy secretary, but declined. Looking at how things went for Rex Tillerson [as secretary of state], did you dodge a bullet?
HH: I felt like there was so much more for me to do outside of government. I could have done a lot there for a while—a couple years—that would've made a big difference. But it would've been temporary. And it would have shut down what I was doing from a company perspective. I'd have had to put everything in a trust.

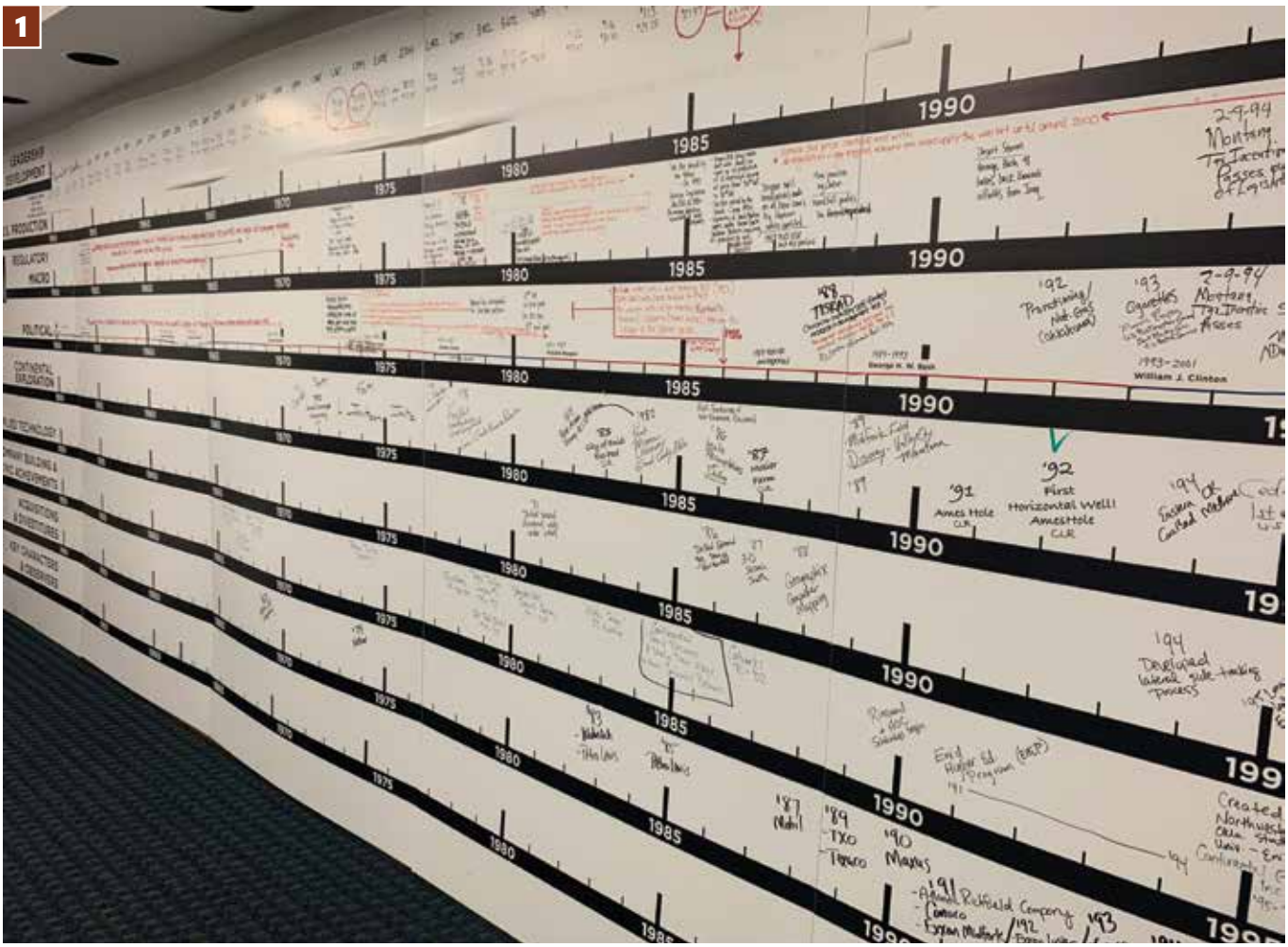
It takes you out of the picture. I wasn't ready to be taken out of the picture.

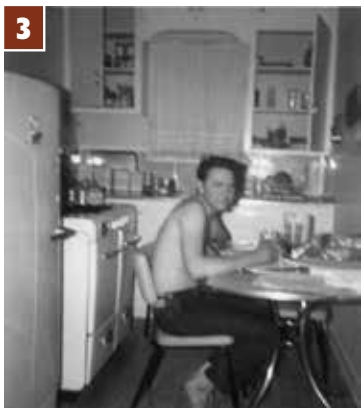
ND: You're affecting the U.S. energy narrative in other ways instead?
HH: You know, the Hamm Institute for American Energy that was set up here at Oklahoma State University can really do a lot to change the narrative of American energy back to what it should be. I look forward to doing that.

Whenever I set out on any task or mission, there are three things I ask myself, going back to when I was a young man: Is there a problem? Is there a solution? And what is the best solution?

The problem is, for 60 years we have faced political fumbles that have cost Americans energy security and independence. And they told us we were running out of oil.

Is there a solution? There is. Innovation and technology. After a lifetime of work, it revealed itself as horizontal drilling, which changed everything. I'm eager for people to read the book to understand the history, the importance





Continental Resources

1. The timeline of Harold Hamm's career is on display at the memento room in Continental Resources' headquarters in Oklahoma City. 2. Portrait of an oilfield legend as a very young man. 3. Hamm in the early days of building an oil company. 4. Hamm poses for a selfie with students at the University of North Dakota Harold Hamm School of Geology & Geological Engineering.

of it, and to inspire the next generation of technologists and explorationists and give hope to Americans along the way.

ND: Could a 1981 happen to the U.S. industry again—an event or series of events that mean U.S. producers don't fully begin thriving again for 20 or more years?
HH: Back then, you had several situations. One was a huge over-capacity from OPEC that's not there today. Back then, you had an estimated over-capacity of as much as a third of the market.

It's all different [today]. And, even with natural gas [today], supply-demand is pretty nip and tuck. It's pretty well balanced.

ND: You wanted to emphasize the value of U.S. energy independence in your book.
HH: That was the real story that we had to tell: Energy independence gives us peace in the world. That's the whole theme of the book. You don't have to kowtow to anybody. You [don't] have to kowtow to someone who's inhumane [like Vladimir Putin]. You don't have to deal with them [for] energy. OGJ

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EQUIPMENT REFRESH, RETIREMENT SUGGEST TIGHT FRAC MARKET ..... HFT 1
Tier 4 dynamic gas blending and e-frac systems deliver fuel savings to capital discipline-conscious E&Ps.

SHALE DEVELOPMENT ENTERS A NEW ERA ..... HFT 4
Digitization, electrification and refined chemistry shape the future of hydraulic fracturing.

EXTENSIVE TOOLS FOR FRAC DATA COLLECTION AND ANALYSIS FUEL BREAKTHROUGHS ..... HFT 10
Frac design, refrac liner testing and a waterless frac gun are among deep diagnostics in the queue.

GoM'S LOWER TERTIARY DRIVES PROPPANT FRACKING OFFSHORE..... HFT 14
Whether the reservoir is a sandstone or carbonate, completing an offshore well is high-stakes and logistics-intensive, but technologies have helped drive down emissions associated with offshore hydraulic fracturing.

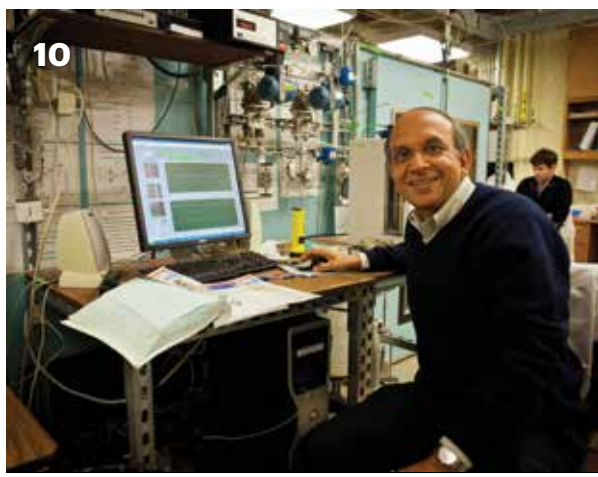
CLEAN THE FRAC UP ..... HFT 18
In an effort to boost sustainability, service providers are making conscious choices to use less diesel fuel.

TAKE YOUR PICK OF PROPPANTS ..... HFT 20
Advances in proppant technology give the hydraulic fracturing space the best of all worlds.

INNOVATIONS CONTINUE TO PUSH THE LIMITS OF EFFICIENCY ..... HFT 22
Next-generation fleets are poised to take center stage.

REMOTE COMPLETIONS COULD BE WAVE OF THE FUTURE ..... HFT 26
Technology, trust and a track record could vault completions activities into remote workflows.

ENCORE OF THE OIL PATCH ..... HFT 28
Underutilized to this point, refracking wells has proved itself effective in boosting oil recovery.



Equipment Refresh, Retirement Suggest Tight Frac Market

Tier 4 dynamic gas blending and e-frac systems deliver fuel savings to capital discipline-conscious E&Ps.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Hydraulic fracturing companies are pursuing next-gen technologies and approaches like continuous pumping and remote fracturing to drop fuel costs and trim well drilling and completion time frames for their E&P customers.

Pressure on E&P companies for capital discipline, dividends and share buybacks translates into pressure on hydraulic fracturing companies through demand for faster, less-costly operations, Luke Smith, an analyst at Westwood Global Energy Group, told Hart Energy.

"A big driver for pressure pumpers, as far as adoption of technology and efficiency, is really coming from their clients, from the E&Ps, who are under pressure to return value to their shareholders," he said.

The E&P capital discipline narrative will likely be strong for the remainder of the year, and a lot of the efficiencies from the pumping companies will revolve around reducing costs for their clients, especially on the fuel consumption side, he said. Next-generation equipment like Tier 4 dynamic gas blending (DGB) engines and e-fracs can provide significant fuel savings compared to hydraulic fracturing units that run on diesel.

"Next-generation technology is really rolling out on a consistent basis," he said.

Much of this new technology involves replacing existing older-generation crews rather than increasing horsepower capacity. He also expects retirement of horsepower through the NexTier-Patterson UTI merger of near-equals. That combination will turn the resulting company into one of the leading pressure pumpers in terms of capacity, Smith said.

Halliburton has over 2.9 million hydraulic horsepower (hhp) capacity across the U.S. while the newly merged company will have about 2.6 million hhp capacity. He said the retirement of older units in the new company will likely drive up utilization and tighten the market further.

"That puts upward pressure on pricing," Smith said.

The NexTier-Patterson UTI combination raises the question of what might happen to the small hydraulic fracturing companies, especially as E&Ps continue their focus on capital discipline.

"They're not completely left out. There's Tier 4 DGB that they can invest in that doesn't require nearly the investment as an e-frac crew," he said.

"Overall, a lot of the E&Ps tend to like the things that reduce the amount of time."

LUKE SMITH, ANALYST, WESTWOOD GLOBAL ENERGY GROUP

Cannibalized for parts

The retirement of older units is not new. In 2020, Smith said he knew of companies idling half of their fleet with no intention of redeploying those units. Instead, they were cannibalizing them for parts, he said.

That resulted in a drop in horsepower in 2020 and 2021, but the industry has started building up capacity again, he noted. In first-quarter 2022, overall horsepower capacity was 14.3 million hhp. A year later, in first-quarter 2023, that number had grown to 15.2 million hhp capacity. In first-quarter 2024, that number is expected to reach 15.7 million hhp.

With Tier 4 DGB engines and e-frac units filling out fleets, Smith said, another factor for pressure pumpers to consider is being efficient with their time and equipment.

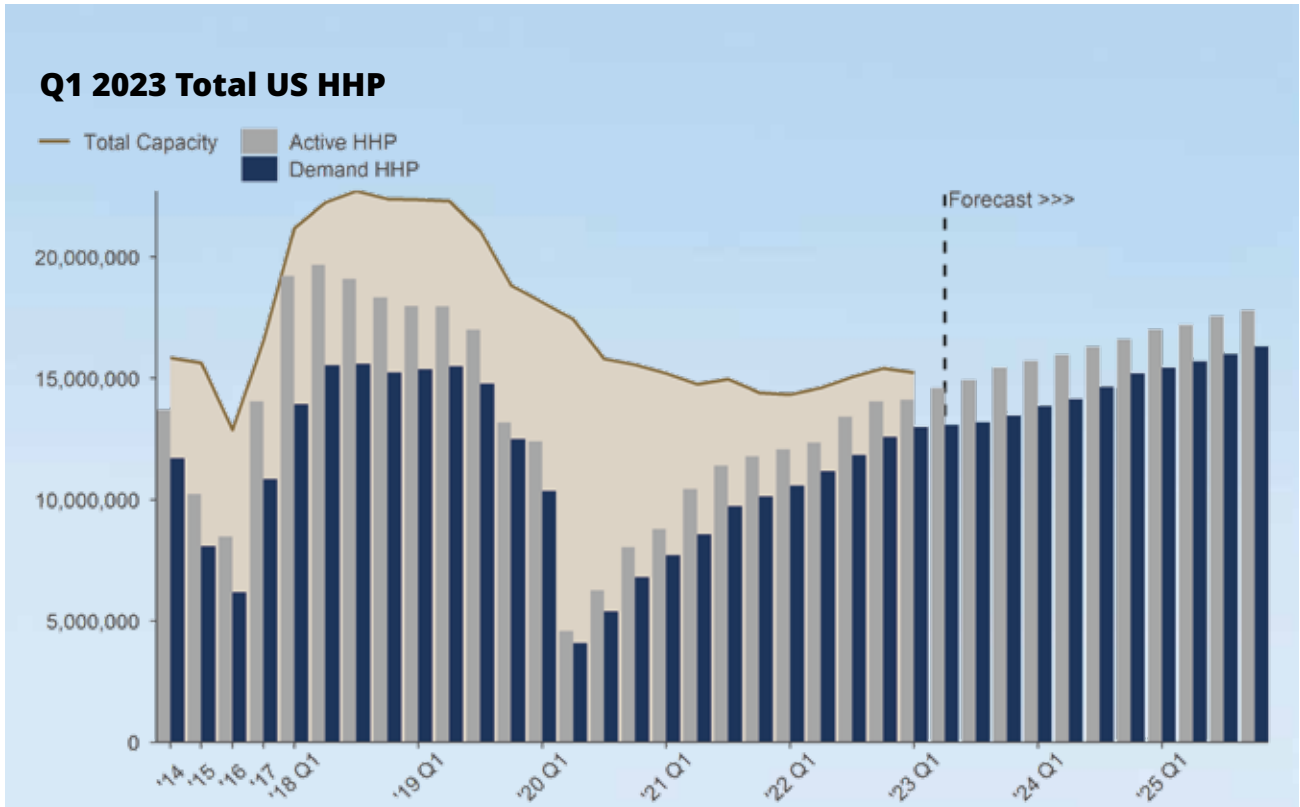
"Overall, a lot of the E&Ps tend to like the things that reduce the amount of time," Smith said. "What we've seen from some of the E&Ps is, they like on the earnings calls to mention how many extra days of production they're getting per quarter."

And as a result, pressure pumpers are doing things like continuous pumping and remote fracking to increase efficiency in operations.

"We're getting reports from E&Ps that they're seeing 24 hours, 36 hours of continuous pumping," he said, noting traditional crews might pump between 19 and 21 hours per day. "That's a big increase in efficiency."

Another efficiency gain in hydraulic fracturing comes from remote fracking, which is happening in the Permian Basin, he said.

"You have a pad corridor, and you can essentially frac



Source: Westwood Global Energy Group

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three of the pads with one crew remaining on a single pad," he said. "That way you do not have to break down the crew and then rig it up two times in order to frac all three pads."

Looking forward, Smith said leading pressure pumpers will need to be ready to meet demands associated with deeper targets.

"[E&Ps are] going after some of the gassier targets in the Permian, and that's in anticipation of LNG export capacity expansions that'll be coming online next year," he said.

Challenges associated with deeper targets may mean more wear on the equipment and the need to pump more proppant, which means larger crews and more hydraulic horsepower, along with access to sand and water infrastructure.

"For the leading edge pressure pumpers, it's about paying attention to those kinds of challenges," he said. ■

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Shale Development Enters a New Era

Digitization, electrification and refined chemistry shape the future of hydraulic fracturing.

JUDY MURRAY, CONTRIBUTING EDITOR

Today's unconventional oil and gas developments bear scant resemblance to those of a decade ago, and experts designing new technologies say things will look even more different in the next few years.

That's because the focus of operators has shifted from maximizing production to maximizing shareholder distribution and reducing debt, said Ryan Duman, Wood Mackenzie's director of upstream research.

"That has shifted the focus to technologies that improve efficiency," he told Hart Energy.

Part of the reason stems from operators acquiring step-out acreage and adding to their inventories between 2016 and 2019.

"Now, they need to find the most efficient way to harvest what they already have, and that means doing more with less," Duman said.

For many companies, that has meant exploring ways to leverage automation software and AI to streamline operations.

"Using data captured in real time, 24/7, provides a clearer picture of operations, which leads to better decision-making," Duman said.

Operators are using operational data to fine-tune processes and are applying advanced analytics to real-time data, monitoring the performance of tools and equipment, and decreasing downtime through predictive maintenance.

"The market demand for ESG reporting is another driver that has made operators more bullish for technology like electric equipment, on-site gas turbines to generate electricity, no-bleed pneumatics and lower-emitting kits," he said, noting that reducing the environmental footprint of operations and improving economics are sometimes competing priorities.

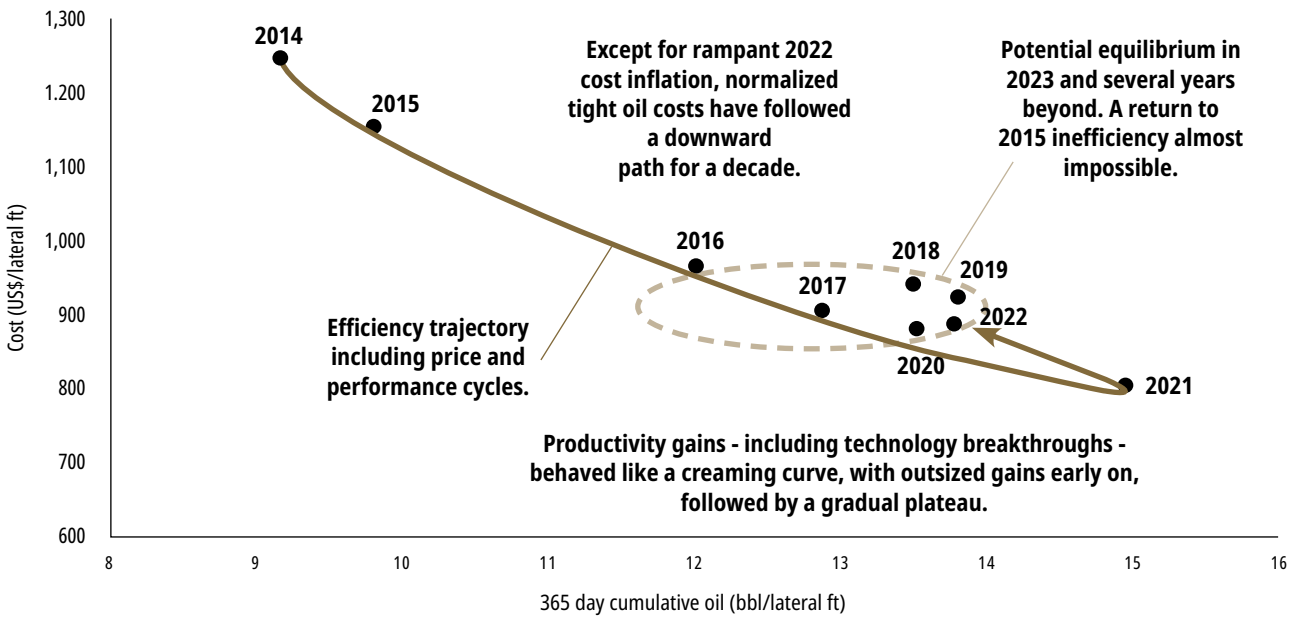
Despite the challenges, Duman said the industry overall has embraced ESG, and companies are making changes that allow them to market themselves attractively to investors.

"They are reducing methane and flaring, and the cost of the technologies that are helping them achieve those goals is more than offset with incremental revenue gains," he said.

Wood Mackenzie will continue to watch refracturing and enhanced oil recovery (EOR) technologies, which Duman believes are ripe for greater innovation.

"Because of the potential benefits associated with 45Q credits, there is going to be a push for CCUS [carbon capture, utilization and sequestration] development as well," he said. "This tends to make sense from a core compe-

Normalized costs versus oil well performance



Source: Wood Mackenzie

tency standpoint because companies can leverage in-house knowledge."

Electrification, alternative fuels and the value of automation

To Sam Sledge, CEO of ProPetro, the most dramatic change in the past couple of years is the transition from diesel to mostly natural gas as a primary fuel source.

"The transition away from diesel has been going on for three years, but right now, there is a massive recapitalization from a hard asset and financial standpoint going on in our space, and it might be one of the biggest changes at the well site," said Sledge, whose hydraulic fracturing company is 100% focused on the Permian Basin.

The primary reason for the transition is pure economics, he said.

"It is much less expensive to burn a molecule of natural gas than a molecule of diesel," Sledge said. That economic inducement is aligned with the environmental objective of lowering emissions. "If we want to talk about environmental sustainability, I think it is strongest when it runs parallel with economic incentives. We live in a free-market, capitalist country, and the goal of a company is to make money, but our goal as citizens and members of a community is to take care of the place where we live."

ProPetro

The Caterpillar engines used by ProPetro in the Permian Basin use dual-fuel engines that reduce emissions by burning diesel and natural gas at the same time.

The result?

"We are pushing harder and faster to the future, especially from an equipment standpoint," Sledge said. "The main part of that story is electrified equipment, which is mechanically simpler with fewer moving parts, allowing it to be operated

precisely and accurately."

ProPetro planned to deploy its first electric fleet in early summer 2023, but the company already employs dual-fuel engines—technology pioneered by Caterpillar that enables the engine to burn diesel and natural gas at the same time.

"We think this is a bridge to more electrification," Sledge said. "This is possibly the only application in the world that consumes diesel and gas simultaneously."

Sledge expects many more innovations going forward.

"We are on a continuum, and we don't know where the end of the continuum is. There are so many smart people n the oil and gas sector that I think you're going to see a lot of amazing things happen over the next 10 to 20 years," he said.

Displacing diesel

Leen Weijers, Liberty Energy's vice president of engineering, shares Sledge's sentiments about economics continuing to drive innovation.

"Every company wants to add efficiencies to produce each barrel of oil more economically," said Weijers.

One of the ways Liberty is going about achieving that is by inventing and manufacturing operational equipment such as the Scorpion sand delivery system and the Mantis screwless sand delivery system, which moves sand directly into the blender tub.

"This equipment has enabled us to effectively pump local wet sand, which can be purchased at a lower cost than sand traditionally used for hydraulic fracturing operations," he said.

The company also is developing ways to manage fuel consumption and equipment performance. For example, the company's new digiFrac fleets enable diesel replacement with natural gas or CNG, both of which are much less expensive per energy unit.

"As we roll out digiFrac equipment, we now regularly break daily records for diesel displacement in the basins where we operate," Weijers said.

The company also has made moves to address the vulnerabilities associated with gas-only equipment by taking ownership of the natural gas/CNG delivery system through Liberty Power Innovations (LPI) to provide a reliable source of field gas (through mobile gas processing) or CNG to power its lower-emission solutions.

Underpinning the digiFrac and digiPrime fully electric frac system technology are Rolls-Royce gas reciprocating engines, which, according to Weijers, have the best thermal efficiencies of any engine available.

"Measuring performance in terms of hydraulic horsepower hours (hhp-hr) pumped for 70% daily pump efficiencies, gas reciprocating engines have about 45% lower emissions than Tier 4 diesel and are three times as clean as gas turbines," he said.

It's critical to improve operations incrementally, so Liberty focuses on putting new technologies to work as soon as it is practical.

"We are always looking for ways to cut emissions, reduce our footprint, minimize noise and curtail the number of trips to the work site to be a better neighbor in the areas where we work," Weijers said.

Liberty Energy

Liberty Energy's digiFrac pumps enable precise rate control and produce significantly lower emissions than Tier 4 diesel and gas turbine engines.

Liberty Energy is among the companies that have developed software that uses field data to increase efficiencies and ultimately improve the bottom line. Weijers described his company as "laser focused on reducing the barrel cost of production."

Liberty achieves this, in part, by leveraging its FracTrends database and performing statistical economics analysis using Fraconomics and fit-for-purpose calibrated modeling tools.

"We are helping to focus our industry on cost-effective ways to provide ever larger and denser fracture networks and to evaluate trade-offs, for example, between well density and fracture treatment size," he said.

Results over the last decade demonstrate that the company has helped lower well costs by 50% and enhanced well productivity to reduce the cost per barrel of oil produced by as much as 75%, Weijers said.

Electrifying the wellsite

Innovators at Halliburton are likewise well down the path of deploying electric fracturing equipment. By providing the same horsepower at the wellsite with half as much equipment, these innovations allow a company to reduce its carbon footprint, as well make strides in efficiency and reliability.

"We see about 30% faster transition times, which leads to more pumping hours," William Ruhle, Halliburton's strategic business manager, told Hart Energy. "That gives us 11% more hp-hr pumped per month than diesel, which is about equivalent to completing an extra seven wells per year per crew."

Removing the need for diesel has saved up to $2.5 million per month in diesel costs for zipper crews and reduces emissions by approximately 30%, Ruhle said. While there is a cost for electricity to run the equipment, it is considerably less

Halliburton

Halliburton's Zeus electric fracturing system can achieve up to 5,000 HHP per pumping unit without downtime during stage transitions.

Universal Pressure Pumping

Universal executes a frac job in the Utica shale.

than the cost of diesel.

On a project for Diamondback Energy in the Permian Basin, a Halliburton simul-frac crew achieved exceptional results using the company's Zeus electric fracturing system, which Ruhle said can achieve up to 5,000 hhp per pumping unit without downtime during stage transitions.

"By combining simul-frac operations with electric, Diamondback has realized completions savings of $50 a foot," he said.

Electrification is driving down costs and reducing emissions, but operators need to capture more efficiency gains, and that has led to expanded use of subsurface monitoring and using operational data gathered to optimize recovery.

"Digitization is embedded in everything we do and build; ML (machine learning) and AI aren't discrete solutions, they are embedded in processes and solutions," Ruhle said.

One example is the company's Octiv intelligent fracturing platform, which fully automates the fracturing process from a single system.

"Within that platform, we use technology such as AI and ML to predict equipment failures, identify anomalies, see how operations are running and respond automatically," he said. "Octiv automates up to 90% of the decisions made to control our surface equipment, and that leads to better reliability and consistency."

In North America, the system has completed thousands of stages using full-spread automation, controlling the fracturing process and executing condition-based protections that help prevent downtime across operations.

Capitalizing on data analysis and specialized chemistry

James Segars, director of solutions engineering at Universal Pressure Pumping, said his company is delivering value by analyzing data to optimize perforation efficiency.

"A huge amount of effort has gone into analyzing fracture geometry with regard to perforation design in the past few years," he said, noting that complex analysis goes far beyond simply creating the longest possible fracture. "We are targeting a high degree of recovery within the near-wellbore section to make the most of the wellbore spacing plan. From our standpoint, that is making the output more predictable, and that creates a positive impact on the economics of the program."

The company's solutions engineering team uses data to help operators with predictive analysis.

"We use output from laboratory testing to generate a hydraulics model to estimate pipe friction, which allows us to set expectations for surface treatment conditions. Ultimately, we can solve for the expected hydraulic horsepower hours and can generate a high-level assessment for cost and ESG consideration through fuel savings," he said.

Engineers also compare the predicted pressure to the actual pressure in end-of-stage variance reporting and examine the data to determine when there is a difference, and then share the findings with the operator to evaluate opportunities for improvement.

"We also know proppant delivery on a stage basis is critical to recovery as is controlling the volume of fluid we're injecting. In addition to managing differential pressure, we are looking at the volume of proppant used and identifying stages in which more or less fluid was pumped than expected. Many inefficiencies are rooted in variances between what was designed and what was delivered," Segars said. "Operators spend a lot of time and effort developing the fracture sequence, and they know what works best for their reservoir. Our job is to help them deploy that in a predictable and consistent manner."

Universal also is investing in developing tailored chemistries to help resolve challenges that routinely surface in the field. One of these is increased friction resulting from the use of higher salinity brines in place of fresh water, particularly in parts of New Mexico and Texas.

"Chemical technology is being improved upon daily to allow the use of as much brine as possible and to ensure produced

water is reusable," said Joe Pinkhouse, Universal's chemistry domain champion.

Water is a valuable resource and is scarce in some areas where there is widespread drilling. Increasing the amount of fresh water that can be reused cuts down on water usage as well as treatment and disposal costs, he said.

The industry is trying to figure out whether the use of produced water is beneficial to the reservoirs, Pinkhouse said.

"Historically, the view overwhelmingly has been negative, but new research shows that the produced water—as long as it is used appropriately—has the ability to enhance the performance of the reservoir and perhaps eliminate some of the chemical needs."

Making headway with these initiatives depends on changing the perception of chemicals as commodities rather than specialty materials and assuming, for example, that one clay stabilizer is the same as another.

"That's simply not true," he said. "There is a lot of time and energy that goes into developing the chemistries, and we work with operators to ensure they are looking at data and comparing the products in a meaningful way."

Pioneering technology and the art of oilfield economics

Software advances continue to improve field operations and ResFrac, a company that provides computational subsurface modeling, is taking software to the next level.

COO Garrett Fowler explained how the solutions his company has developed address the issues that have arisen from erroneously applying "factory mode" development to oil and gas operations.

"Wells interact. Rock is variable. And there are nuances that differentiate individual wells and locations, so applying a single well design across a range of wells does not produce consistent results," he said.

What is known about the subsurface continues to expand.

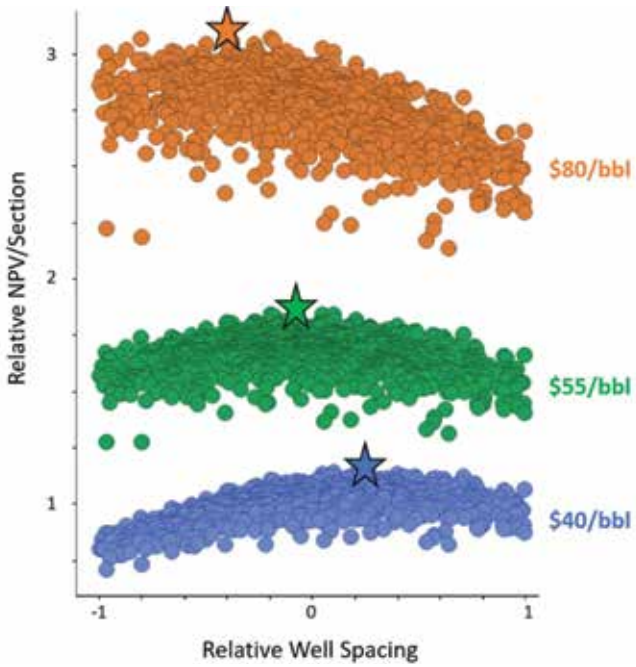
"Diagnostics today give us the ability to see into subsurface an order of magnitude better than 10 years ago," he said. "And applying first principles physics will unlock even better understanding."

Multiple things happen in the subsurface simultaneously, but the traditional methodology for subsurface modeling has been to segment activities and use separate pieces of software to calculate them independently from one another. Fowler said this is why modeling software has struggled to produce a truly cohesive picture of the subsurface.

"It is computationally and mathematically challenging to model all of the variables in one self-consistent, coherent set of equations where everything happens at once, but it is possible," he said.

ResFrac initiates this process with building a "why" model using first principle physics.

"Once we have a model that accurately describes how things are acting in the rock, we apply algorithms that use data analytical techniques," Fowler said. "Optimization algorithms run a variety of hypothetical simulations—moving a well 50 feet deeper, for example, or using twice as much fluid—to determine the best next step in the development process."



Source: ResFrac

Technology is allowing operators to build highly predictive models that enable prescriptive frac design and field planning. This image shows how NPV increases as the oil price goes up and that progressively closer well-spacings with higher commodity pricing delivers optimal NPV.

Fowler contends that this approach makes it possible to see the interaction of oil price and well spacing.

"The ideal distance between the existing wellbore and new wellbore depends on oil price because if you look at an internal rate of return, or net present value analysis, or other financial metrics, the degree of interference you tolerate is tied to the amount of revenue you can expect per barrel of oil," he said.

He believes the future of the industry is in prescriptive design that derives from enhanced understanding of the subsurface, where it is now possible to observe what is happening and explain why.

"The industry is mature enough to layer surface engineering, subsurface engineering and financial engineering to get a clearer picture of what should be done in a given situation," he said.

Building a computation framework for understanding these systems is crucial to establishing a foundation for extrapolating beyond hydrocarbons and examining how resources are extracted generally.

"That could lead to enabling extraction of other resources such as geothermal heat or exploiting the open pore space in the subsurface for carbon sequestration," Fowler said. "It becomes a matter of looking at what resources exist and what expertise we have as an industry to extract those resources." ■

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Extensive Tools for Frac Data Collection and Analysis Fuel Breakthroughs

Frac design, refrac liner testing and a waterless frac gun are among deep diagnostics in the queue.

PAUL WISEMAN, CONTRIBUTING EDITOR

With current shale well fracturing and production procedures stranding the vast majority of the well's oil, industry and academia are focusing extensive efforts to improve the process. Today's array of sensors and other data gathering devices are flooding researchers with rich troves of data that can help them improve frac procedures.

Among those with research advancements are petroleum departments at the University of Texas, Oklahoma State University, Colorado School of Mines and the University of Houston.

Tapered frac design

For the last decade, Mukul Sharma and associates at the Petroleum and Geosystems Engineering department at the University of Texas at Austin have researched the presence and the effects of induced, unpropped fractures in shale wells. In verifying their presence and identifying their causes, the goal has been to make a way to design frac clusters that properly engage the formation to maximize production. Sharma occupies the W.A. "Tex" Moncrief Jr. Centennial Endowed Chair in petroleum engineering at the university.

The result is a software package called Multifrac-3D, which models the process of hydraulic fracturing and flowback. The program tells frac designers how to get uniform fractures to drain more of the reservoir. This modeling has improved production by an estimated 30%-40% over fracs done without it, Sharma said.

As hydraulic fracturing of horizontal shale wells ramped up around 2010, limited knowledge of how frac networks propagated gave producers uneven production results across a field. Sharma showed that fracking didn't just create planar fractures. Often, fractures too small to receive proppant are created.

Sharma's team presented five pieces of evidence to demonstrate that this was happening in a 2015 SPE paper entitled "The Role of Induced, Un-Propped (IU) Fractures in Oil and Gas Wells." The five elements were: micro-seismic data, production history matching, tracer data, pressure communication between wells and calculations on the fate of the injected fracturing fluids.

"We've recently been studying what controls the geometry of the hydraulic fracture network in a naturally fractured reservoir," Sharma told Hart Energy. "The well completion, the number and clusters and the number of perforations in each cluster, as well as the pumping schedule, are things that we can control and have a major impact on the geometry of the fracture network. Of course, the natural fracture network and the heterogeneity in the reservoir have a big influence as well."

They observed that a geometric cluster design, in which all clusters contain the same number of perforations, often creates heel-dominated fractures. This can result in a loss of production from the other fractures. Adding more perforations to the toe, referred to as tapered completions, can provide more uniform proppant and fluid distribution.

Sharma's research provides a quantitative method to design the perforation clusters to provide the most uniform proppant and fluid placement in all clusters. The software has been extensively used in many applications, such as the growth of hydraulic fractures in naturally fractured rocks, geothermal wells and interference between parent-child wells.

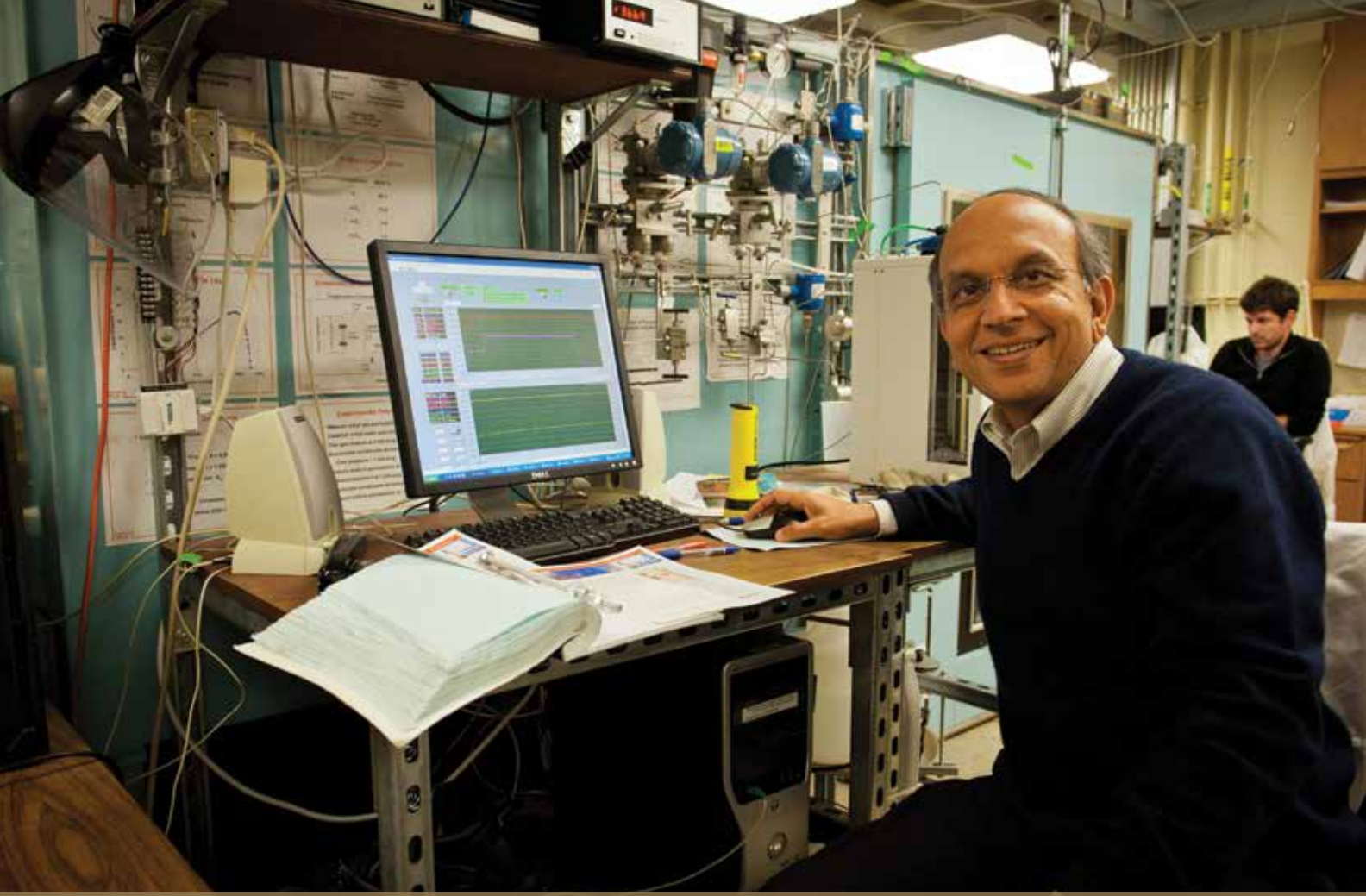
He said this software has been tested in several wells with success and stressed that the team continues to learn from field results to make further updates as needed.

Frac count and spacing optimization

Shale wells are notoriously stingy with their oil. To learn how to release more of that resource, petroleum engineering program professors at Oklahoma State University (OSU) use AI and machine learning (ML) in analyzing surface drilling and core test data to improve frac methods.

Early results show the potential to increase production by up to 50% over existing frac methods.

A U.S. Department of Energy (DOE) grant includes Continental Resources, which is the principal partner in the project; Lawrence Berkeley National Laboratory; the Oklahoma Geological Survey; and the University of Pittsburgh. They are nearing the end of the four-year, $19.9 million DOE project, with cost sharing from Continental Resources, aimed at evaluating shale formations in the Caney Shale, a potential petroleum resource in southwestern Oklahoma.



Mukul Sharma and his Petroleum and Geosystems Engineering team at the University of Texas at Austin have developed software known as Multifrac-3D, which models the process of hydraulic fracturing and flowback.

University of Texas at Austin

Geir Hareland, a professor and Continental Resources Chair in petroleum engineering at OSU, described the work as a field laboratory site.

Geir Hareland

"The objective was to core through this formation and do a variety of core testing and modeling, and to fracture one horizontal well about two miles long," he told Hart Energy.

The OSU frac team also includes Hunjoo Lee, assistant professor in the School of Chemical Engineering; Mohammed Al Dushaishi, Ward Fellow and an assistant professor in the petroleum engineering department; and other researchers.

During the process, they gathered extensive downhole data, analyzing each frac zone for rock hardness, ductility and other geomechanical properties. The research principles were then applied toward analyzing and improving frac designs in a variety of shale formations.

Three types of software were used for data analysis: Calgary, Alberta-based Rocsol Technologies' D-WOB (Downhole Weight on Bit), which uses surface measurements and wellbore friction drag models to calculate the downhole WOB on horizontal intervals; D-ROCK, also from Rocsol, which cost-effectively uses inverted Rate of Penetration (ROP) models and core correlations to create a detailed geomechanical and reservoir property log; and Halliburton's GOHFER frac modeling software.

Unsurprisingly, they learned that maximizing exposure to the producing zone boosted production. But the specific mechanics were less obvious. More fracs, closer together, over longer laterals and concentrating on the hardest and most brittle rock were the keys.

They also made new discoveries on staging parent-child wells, using something Hareland called "wine-racking." Alternating wells geared to produce higher and lower in the formation creates a kind of well cross-section waveform, he said, keeping larger distances between the wells and production from overlapping.

With about 18 months of production data in hand from the Caney horizontal well, the researchers have seen actual production match their pre-simulated model production in the formation.

Refracturing could also benefit from this research, said Hareland, because fracs done 10 years ago had fewer stages, but they were larger and spaced further apart. But shale's low permeability limits its oil's abil-

Colorado School of Mines

One refracturing method involves lining the existing casing before setting off the frac charges. But when the frac is done, the liner must maintain its position so the new fracs in the pipe line up with the fracs in the liner. These sections of old casing show the liner protruding out, at bottom right, from refractured sections ready for testing, in an operation overseen by the Colorado School of Mines.

ity to flow, so fracturing more stages with smaller fracs exposes the well to more production.

Keeping casing liners in place

As producers and investors look for more production, they also look for ways to lower costs and boost cash flow. To make that work, many producers look to refracturing wells that were first fractured in the early days of the shale revolution. Multistage wells are particular targets, as producers hope to reach producing zones that were missed or inadequately stimulated the first time.

One refrac method involves inserting an expandable casing liner into the existing casing. After sliding the liner into place, the installer expands the liner to fit by pulling a tool along its length. The liner's purpose is to keep the new frac from taking the path of least resistance through existing fissures without creating new ones. From there, the producer is starting anew because at that point, it is essentially a brand new well that has not been perforated, said Jennifer Miskimins, F.H. Mick Merelli/Cimarex Energy Distinguished Department Head Chair at the Colorado School of Mines. She is also the founder and current director of the Fracturing, Acidizing, Stimulation Technology (FAST) Consortium.

Jennifer Miskimins

Civitas Resources, an E&P operating in Colorado's Denver-Julesburg Basin, was using this kind of liner made by Mohawk, but wanted to be sure it performed as advertised, Miskimins said.

After installing the liner, the new frac would involve creating half-inch-diameter fracs using "piston-like forces, which could potentially move the liner that's sealed inside the casing," she said. If those forces shifted the liner by a half inch or more, that would cover up the corresponding fracture in the original casing, "destroying your refracking potential."

So Civitas asked the school to conduct as close to a real-world test as possible in order to find out.

At the school's Edgar Mine Testing Facility in Idaho Springs, Colo., the research team prepared both anchored and unanchored patch components in a pipe. One type of each was perforated with a full-size perforating gun, three shots in each section.

According to a paper published by the team, "Both the anchored and unanchored, perforated and unperforated, patch/casing sections were then push/pull-tested to determine friction factors and the impacts of the perforating on the patch/casing interface. These results were then incorporated into finite element method (FEM) modeling to determine the ability of the full-size, field-deployed patch to remain stationary and the impact such would have on perforation alignment during treatment conditions."

FEM modeling is a common method of mathematically solving engineering and math modeling equations.

The push/pull testing involved a lab machine that applied 50,000 psi of pressure to the lining, many times more than the normal frac pressures, Miskimins said.

As a result, "The takeaway was that these liners don't move," she told Hart Energy.

Formation structure analysis

The volume of water used in fracturing has surpassed 1 MMgal/well in tight shales, leading researchers to investigate alternative methods that don't require water. Pulsed power plasma stimulation (PPPS), which is already common for rock removal in mining operations, is gaining interest among academics. Researchers are seeking private funding to expand these efforts into oil and gas, especially in tight reservoirs and shale plays.

Mohamed Y. Soliman

But for the University of Houston's (UH) Mohamed Y. Soliman, a particular subset of the method shows great

At the University of Texas at Austin, researchers in the Petroleum and Geosystems Engineering department are testing how a geometric cluster design, in which all clusters contain the same number of perforations, works in a naturally fractured reservoir.

University of Texas at Austin

potential for analysis as well as for fracturing. As PPPS fractures the rock, it also emits an electromagnetic field in a process called electromagnetic wave propagation (EWP). Soliman, chairman of the Petroleum Engineering Department, was awarded the Society of Petroleum Engineers SPE Legends of Hydraulic Fracturing Award in spring 2023.

He and his UH team believe that tracking the EWP field's behavior as it navigates the rock could much more deeply and accurately analyze the character of the fracture and formation than current methods do. With that in mind, they want to design "a field tool that may be used for waterless stimulation for well format/fracture diagnostics and underground imaging," according to a paper Soliman published with colleagues at sciencedirect.com in November 2022.

Soliman compared PPPS to releasing the power of two double-A batteries all at once into an area of the formation.

"You have two capacitors, each of which stores 10 kilojoules (kj) of electricity. That's a small amount of energy when you release the energy slowly, as in a flashlight," he wrote. "But here, we are discharging those capacitors in 5-6 milliseconds."

By hitting the rock so hard, "It fractures the rock. When you do that, you also create an electromagnetic field that produces a shock wave, or EWP, which propagates through the rock," according to his research.

First step

The first step in testing their hypothesis involved creating a small physical model with which to compare actual results against computer models. If proven sufficiently accurate, the testing could be expanded into a field-scale trial.

Their lab test samples were concrete cylinders 9 inches in diameter and 12 inches long, with a bore tube down the center. Into those samples they discharged the 10 kj current and monitored its results. Soliman said, "We measured the electromagnetic field the shock wave produced, and we matched that experimentally and numerically."

Soliman and his team say their results validated the procedure and justified large-scale field research, for which they are currently seeking funding. They concluded that creating a PPPS-based stimulation tool would indeed be a cost-effective alternative to "current low-accuracy microseismic applications." ■

GoM's Lower Tertiary Drives Proppant Fracking Offshore

Whether the reservoir is a sandstone or carbonate, completing an offshore well is high-stakes and logistics-intensive, but technologies have helped drive down emissions associated with offshore hydraulic fracturing.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Proppants, the sandy heroes of the shale revolution, are rising in demand for offshore wells, particularly in the Gulf of Mexico's (GoM) Lower Tertiary Wilcox Trend.

The Lower Tertiary's reservoirs are sandstone, not the more common offshore carbonate reservoirs that require acid fracturing to maintain permeability. And the play is steadily gaining the attention of offshore operators.

Alexander Pirogov, senior fracturing engineer with Baker Hughes' global production enhancement product line team, said one of the chief trends he's observed is that offshore operators are increasingly starting to produce wells tapping the Lower Tertiary.

"They're going after these tighter, deeper, hotter formations, versus the old, established, maybe slightly shallower, unconsolidated formations they have been going after for decades," Pirogov told Hart Energy. "That means that we are shifting to a more complicated, more complex type of completion."

Because these tend to be larger jobs, he added, the offshore logistics become more complicated. That makes it more important than ever to plan from the perspective of fracturing, not just production.

"Previous wells would be drilled for production predominantly, and maybe have some sort of sand-control process in place," he said. "But now they're planning for a fracturing job targeting these lower permeability type of reservoirs."

That signals a shift to operators pre-planning wells with stimulation in mind, compared to past operations in which they largely only anticipated production, he said.

And they also are keeping in mind the potential for later workovers, he added.

Lower Tertiary formations require more exposure to the reservoirs, said Marty Usie, pressure pumping North America offshore service delivery technical manager at Baker Hughes. The longer fracture length requires more proppant and fluids, he said, but operators have to contend with higher pressure and temperatures in these formations.

"We're going to specialized fluid systems, specifically tailored with additives that address their reservoir needs, including surfactants and potential scale-inhibiting type of products during the completion," Usie said. "We're using high-end proppants, not sand, to maintain the fractures."

In one Lower Tertiary well in the Keathley Canyon area of the Gulf of Mexico, Pirogov said, Baker Hughes's *M/V Blue Tarpon* pumped 4.4 million pounds (MMlb) of KryptoSphere HD 25 proppant into a well to cover five stacked zones. This set a GoM record for the most proppant pumped into a single well.

"It's like a Formula One race. You know, you have that one shot, and you don't want to miss it."

PAUL HOSEIN, DIRECTOR OF STIMULATION AND RESERVOIR PERFORMANCE, SLB

In a second Keathley Canyon area well, the *M/V Blue Tarpon* pumped a GoM record amount of that same proppant—almost 1.1 MMlb—into a single zone of a three-zone well.

Usie said these types of jobs require much more logistics planning, including using multiple vessels to carry all the proppants and supplies.

Completing a multi-zone well in a single trip or multiple trips depends on how much proppant a vessel can carry. For multi-zone wells completed in a single trip, Usie noted, "You don't have the luxury of coming back into the dock."

"Usually, there's alternative supply vessels and in some cases, multiple stimulation vessels required to support the project and having to reload on location."

Fewer trips, fewer emissions

As Paul Hosein, SLB's director of stimulation and reservoir performance, pointed out, offshore is a high-stakes area.

Never have expenditures, carbon impact and emissions profiles mattered more, he said.

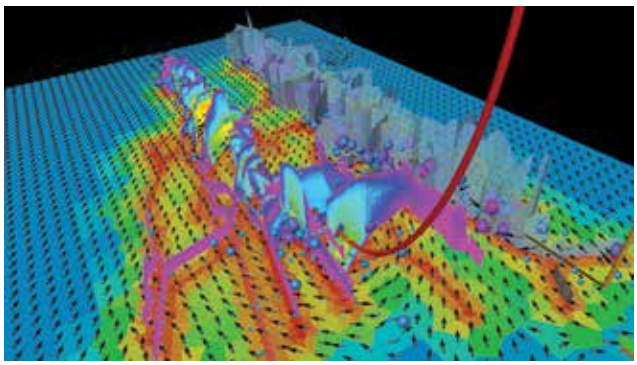
"You need to get it right the first time," he said. "The cost of failure is so high. On top of that, you generally don't want to go back to the well when you're finished."

Because offshore wells are increasingly deeper and more complex, that can mean more complicated completions requiring more materials—along with the right personnel and equipment—at the right time, Hosein said.

"From a fracture design perspective, typically you need

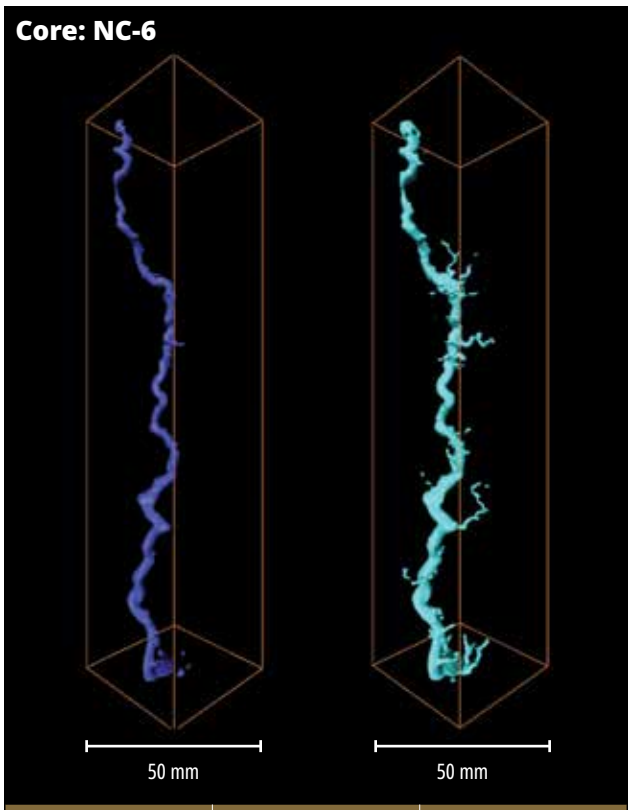
Baker Hughes

Baker Hughes' new Blue Orca stimulation vessel can carry 2.5 million lbm (1,134 tonnes) of sand or equivalent proppant, allowing it to perform multiple fracturing treatments without having to return to port to resupply.



SLB

SLB's Kinetix stimulation-to-production software has workflows that optimize hydraulic fracturing and acidizing in any reservoir and well environment.



Fully Dissolved (Vol. %)	Partially Dissolved (Vol. %)	Total Affected Material (Vol. %)
0.98	0.77	1.75

Source: Halliburton

* Volume % calculated from a cropped volume

X-ray processed images of treated cores for plain 15% HCl acid (left) and X-Tend (right, at 15% HCl acid) with flow rate at 1, 3, 5 and 8 mL/minute, showing X-Tend allows deeper penetration of live acid into the formation.

to get deep reservoir penetration during fracturing," he said. "In general terms, the longer you get the fracture half-length, the better chances you have with long-term sustained production."

Getting such a fracture right requires a good design up front, he said.

"It's like a Formula 1 race. You know you have that one shot, and you don't want to miss it," Hosein said.

SLB's Kinetix software makes it possible to plan the hydraulic fracture program based on mechanical properties of the reservoir using various fracture models. For acid fracturing, it allows simulation of frac fluids reactivity with the reservoir.

The software helps model offshore hydraulic fractures around the globe, including for some wells targeting a sandstone reservoir West of Shetland.

"By being able to accurately simulate with the reservoir data, the interaction of the fracture with the reservoir, and get it correctly placed, we've actually enabled this operator to change the economics of the whole operation," Hosein said.

SLB was involved from the beginning, he said, and is now helping the operator with the second and third phases of the development.

Hosein noted that operators are concentrating on lowering their carbon footprint at every step of the well-construction process.

When working offshore, minimizing the amount of materials needed can minimize the number of vessel trips required to transport the materials, which drops costs and improves the emissions profile.

An offshore frac job may require more than 2,000 bbl of water. These operations typically used fresh water.

"That's hard to do," he said.

SLB's UltraMARINE seawater-base fracturing fluid solves that logistics challenge by making it possible to use seawater, instead of shipping in fresh water.

"You actually can pull seawater on the fly," Hosein said. "You can continuously mix from the ocean and mix it with your proppant."

As a result, operators do not worry about carting freshwater from shore, which burns a lot of fuel and generates a lot of emissions, he said.

"If you can actually use seawater for hydraulic fracturing, it

Source: Hart Energy

really does reduce your emissions impact," he said. "The largest part of the emissions of an offshore fracture job is not the job itself. It's the logistics of moving all the materials."

While proppant fracturing is growing offshore, it is still used less frequently than acid, which is a type of hydraulic fracturing that uses reactive fluids, Hosein said. This is because the types of rock typically stimulated offshore are more frequently carbonates than sandstones.

Opening up carbonates

Julio Vasquez, product manager for Halliburton's production solutions and production enhancement product service lines, said reactive fluids are typically intended for carbonate formations. For carbonates, HCl-based treatments are applied for matrix acidizing and acid fracturing, and reactive fluids eat away at—or etch away—the rock to create larger pathways for hydrocarbons to flow through back to the wellbore.

A little over 18 months ago, Halliburton commercialized X-Tend acid stimulation service, a low-viscosity, delayed-acting acid, for matrix and acid frac of carbonate formations offshore to allow deeper penetration of the live acid into the formation.

"It is very easy to prepare, and we can mix it on the fly or batch mix it," Vasquez said.

Since commercialization, X-Tend has been used on about 100 jobs globally, he said. It is used in carbonate formations up to 350 F, but can be taken to higher temperatures. Using X-Tend, he said, has resulted in oil production increases of between 2,000 bbl/d and 3,000 bbl/d.

World of water

Offshore water handling is particularly challenging, Vasquez said.

"Produced water has to be disposed of or reinjected back into the formation," he said. "You have a lot of restrictions with surface facilities handling water production."

WaterWeb, a technology Halliburton commercialized over a decade ago, selectively reduces permeability to water with minimal impact to hydrocarbon production, which means there is no need for mechanical isolation, he said.

However, while the WaterWeb polymer initially worked well in sandstone formations, it did not perform as well in calcite-rich formations, he said. Following some research and chemistry modification, he said, the product now works in both sandstone and carbonate formations.

In one carbonate application offshore Mexico, the water cut—the ratio of water produced compared to the total volume of liquids produced in a well—was 36%. After Halliburton pumped 370 bbl of WaterWeb into the well, the water cut dropped to 4% while oil production increased by 600 bbl/d, Halliburton said.

In a sandstone application producing from a multi-layered reservoir, water cut was reduced from 80% to 60%, and oil production increased by 300 bbl/d after deployment of WaterWeb.

While produced water is something that needs to be handled, water is needed for some operations. Halliburton's SeaQuest service makes it possible to use seawater instead of freshwater for fracture fluid or frac-packing operations.

"We don't have to go back to the port to get more freshwater," Vasquez said. "We're saving a lot of non-productive time, a lot of CO_2 emissions as well, while providing an optimum frac fluid rheology." ■

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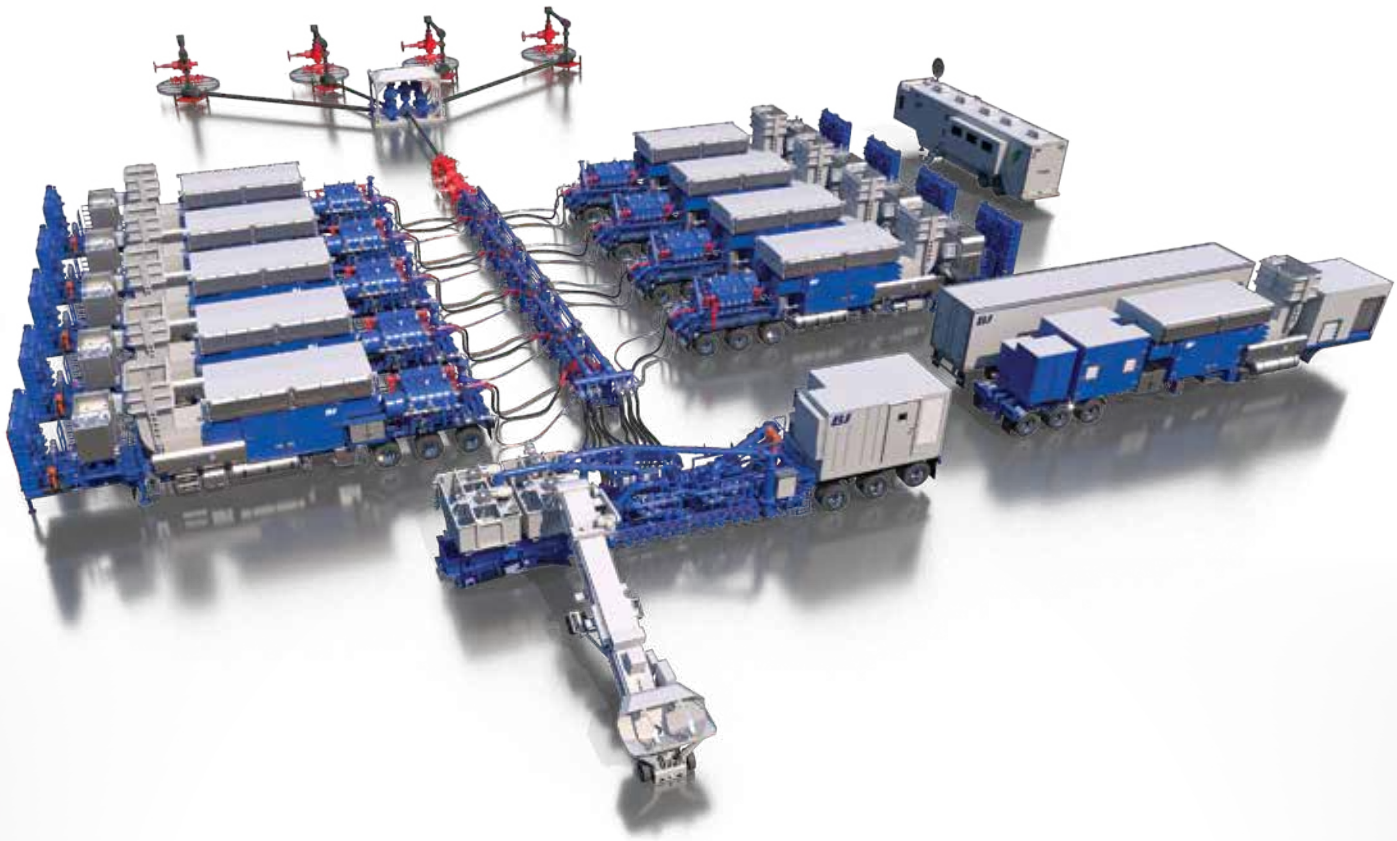

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Clean the Frac Up

In an effort to boost sustainability, service providers are making conscious choices to use less diesel fuel.

JAXON CAINES, TECHNOLOGY REPORTER

The road to net zero can start at the wellhead, where technological advances are enabling a shift to natural gas for fueling hydraulic fracturing equipment—and cutting CO_2 emissions.

"Today, most frac pumps run on diesel. It's kind of the standard, but has a lot of CO_2 intensity," Kurt Harpold, strategic business manager for Halliburton, told Hart Energy. "So, one of the ways you can mitigate that or try to reduce your emissions is to burn more natural gas. You can burn more natural gas in a dual-fuel application where you're blending natural gas with diesel."

Halliburton has these capabilities with its Tier 4 dual-fuel systems. The system costs more, but offers an emissions profile 35% less than dual-fuel Tier 2 fuel systems. The dual-fuel systems pair easily with the company's Q10 X Fracture Pump, a positive displacement pump that takes low pressure water and creates high pressure water needed to fracture rock, he said.

Another way to reduce emissions is to "burn more natural gas in an electric application where you use natural gas to generate electricity for either turbines or gas [reciprocating] engines," Harpold said.

Halliburton's Zeus electric fracturing system allows pumping at higher rates while also lowering emissions profiles of the wellsite. The power-agnostic Zeus system offers a frac pump with no need for a diesel engine or transmission, allowing it to be more efficient on location, Christopher Atchley, product manager for Halliburton told Hart Energy.

Christopher Atchley

"The difference between what you see in a Zeus pump and what you have with the diesel pump, is that your diesel pump is going to be about 2,000 hydraulic horsepower, where the Zeus pump is 5,000 hydraulic horsepower," he said. "We can actually operate [Zeus] at 5,000 hydraulic horsepower, which we feel gives us an advantage in the market. It's more advanced than what we see with some of our competition."

The Zeus pump comes paired with Halliburton's newly designed large-bore, dual-manifold trailer that can deliver up to 230 bbl/min. Since it does not require diesel for fuel, its footprint is also 34% less than that of conventional frac fleets and is easier to maintain because there is no chance of a leak.

"When you think about what operators really want, the old adage is, 'cheaper, better, faster, pick two,' right? It's hard to have all three. Well, with our electric solution, operators want to lower the cost, they want greater performance and they want lower emissions. And electric is the answer," Harpold said.

"When you think about what operators really want, the old adage is, 'cheaper, better, faster, pick two,' right? It's hard to have all three. Well, with our electric solution, operators want to lower the cost, they want greater performance and they want lower emissions. And electric is the answer."

KURT HARPOLD, STRATEGIC BUSINESS MANAGER, HALLIBURTON

E is for economics

Another cheaper, better, faster solution for hydraulic fracturing comes from Texas-based Catalyst Energy Services.

"One thing I do say about ESG in general is that it's missing an 'E.' And the first 'E' needs to be economics," Seth Moore, Catalyst Energy Services co-founder, COO and executive vice president, told Hart Energy. "People want an economic solution. They care about ESG, they've told the world that they care about ESG and this industry cares about ESG. But when you make the first 'E' economics and you're talking up to $18 million a year in savings, who wouldn't do that? Why would you not want to have this ESG solution that also produces real value for the system?"

Catalyst Energy Services' VortexPrime is designed to

The VortexPrime is an easily transportable, military-grade, natural gas-powered direct drive turbine

Catalyst Energy Services

provide both. It is a compact, military-grade, natural gas-powered direct drive turbine. Each unit is easily transportable, self-contained and has its own turbine, drive train and pump. The fleet only requires six to eight pumps as opposed to a traditional frac fleet that might need 20 pumps.

Since VortexPrime requires no outside power source and has its own frac control software, the unit is able to go to location, rig in to the well via a manifold system, rig in water and fluid from the blender, and rig in fuel. From there the team runs a cable to the data van and completes the job.

"We frac by wire, kind of to steal the phrase 'fly by wire' from the air aviation industry," Moore said. "Everything we do is sensor controlled... you're dealing with this pretty impressive mechanical device, but it's all controlled electronically."

The fleet's control system was automated with operators in mind, Moore said. It has safety systems engineered into the technology to ensure that the system will not crash, including "pressure limiters, rate limiters, kick-outs and numerous vibration sensors."

While VortexPrime's invention was spurred by Catalyst Energy Services' desire to shrink some of the technology used for fracking, it also came with the added benefit of reduced emissions. The fleet is in the 95th percentile of waste stream reduction and Moore estimates that there is a 40% reduction in CO_2 emissions when compared to a Tier 4 system. In a recent project, the fleet was able to save 658 metric tonnes of CO_2 emissions.

"One thing I do say about ESG in general is that it's missing an 'E.' And the first 'E' needs to be economics."

SETH MOORE, CO-FOUNDER, COO, AND EXECUTIVE VICE PRESIDENT, CATALYST ENERGY SERVICES

"If you could look at all the things you would want out of a frac unit or a frac fleet, VortexPrime checks all the boxes," said Moore.

Both Halliburton and Catalyst Energy Services have fully deployed their fracking technologies with the intent of bringing net zero goals within reach.

"I think that we'll continue to see that grow and we're to a point now where it's not just a cartoon in some LinkedIn post," Atchley said. "We're doing this on location every day." ■

Take Your Pick of Proppants

Advances in proppant technology give the hydraulic fracturing space the best of all worlds.

JAXON CAINES, TECHNOLOGY REPORTER

There might not be an industry that utilizes the "more than one way to skin a cat" adage better than oil and gas, especially when it comes to the proppants used to fracture reservoirs.

However, some ways are better—and cheaper—than others. Take the three proppants used in hydraulic fracturing: ceramics, resin-coated and natural sands.

Zigurds Vitols

"Ceramics are very good, but they cost 10 times greater than what we buy our natural sand for," Zigurds Vitols, president and CEO of Select Sands, told Hart Energy. "And when you measure the performance against the cost, we think that we have a more economical product to offer."

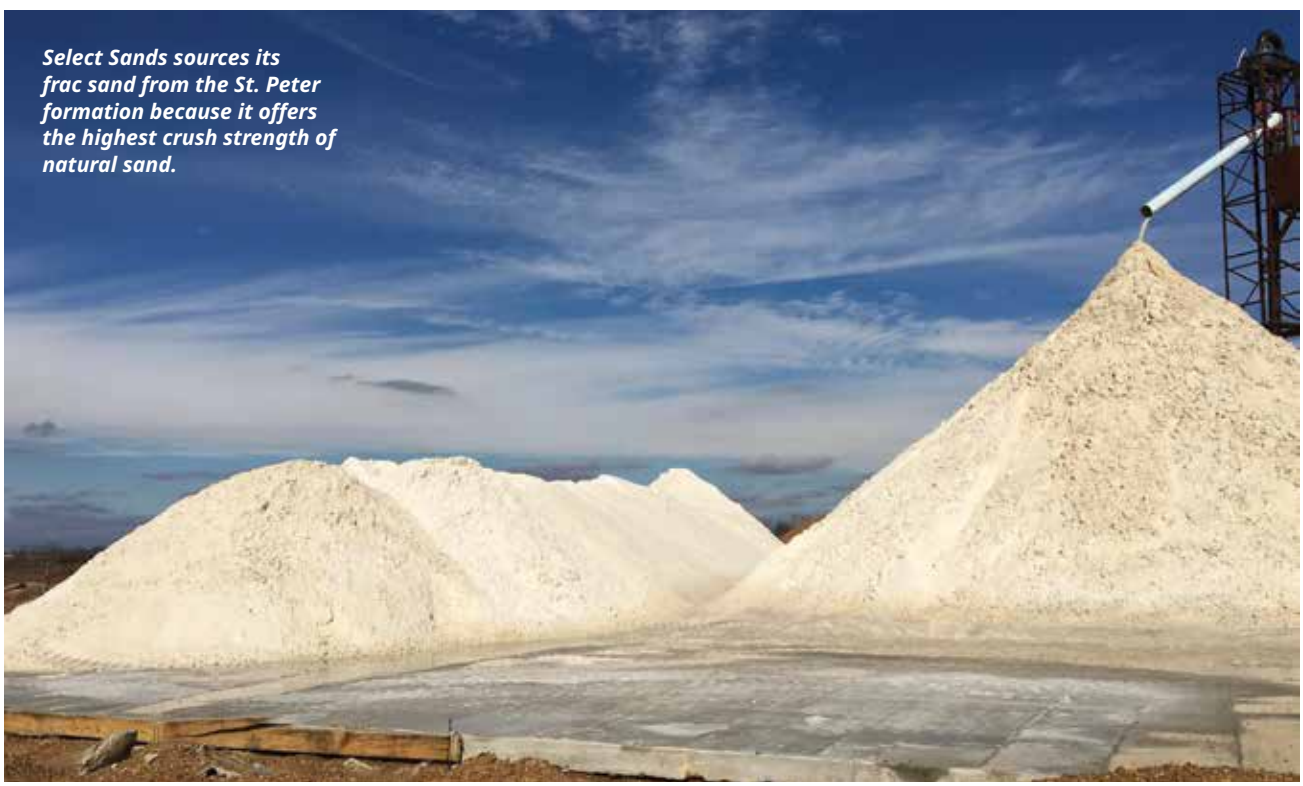
Select Sands is a Texas-based sand provider that mines northern white sand from the St. Peter formation, a sprawling sandstone formation that stretches north to south from Minnesota to Arkansas, and east to west from Illinois to Nebraska and South Dakota. This sand is the highest quality as defined by API and has the "highest crush strength you can get in natural sand," Vitols said. The sand is hard and spherical with little turbidity, making it the right specification to maximize recovery in a well, he said.

Turbidity is a measure of suspended particles, so a lower-turbidity sand is cleaner and has less dirt and silt attached to each particle.

The St. Peter formation is more conducive to fracking jobs in Colorado, Texas and Louisiana than the high turbidity in-basin sands, Vitols said. The in-basin sands are weaker and less spherical, preventing oil from moving easily. But there have been a number of advancements in chemicals and friction reducers that allow oil producers to still use in-basin sands, he said.

Unfortunately, in-basin sands still deteriorate quicker than white sands, which means engineers have to innovate.

"When [in-basin sands] aren't as successful, the completion engineer will design a frac where some of the frac stages are with the white sand and some of the stages—where it's less critical—use in-basin sand," Vitols said. "So, we're seeing some frac stages being done with our sand and



Select Sands sources its frac sand from the St. Peter formation because it offers the highest crush strength of natural sand.

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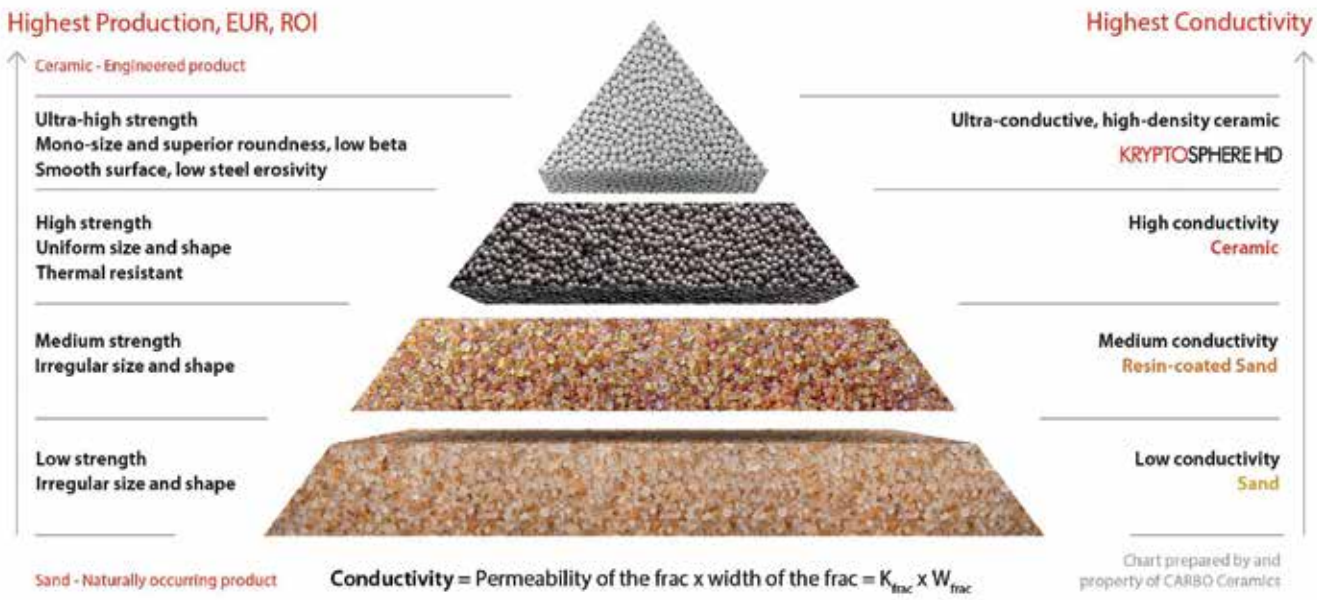
Pinnacle of proppant



CARBO Ceramics

some in-basin sand in the same well. We're seeing some wells that exclusively use white sand, and some that don't use any white sand. So, there is a mix, but if you want to get extraction of your petroleum out of the frac, you use white sand."

Decisions, decisions

Decisions around proppant are some of the most important producers make when fracking a well.

"Your choice in proppant is really what's going to dictate the long-term performance of the well," Josh Leasure, director of sales at CARBO, told Hart Energy. "If you're going to create a long-term well, ceramic proppant is your answer."

CARBO offers a wide variety of ceramic and resin-coated proppants. Among those products is the KRYPTOSPHERE, which Leasure calls "the pinnacle of proppant."

"The manufacturing process is what dictates how good [our] products are," he said. "We pride ourselves on the manufacturing process and how we're able to get rid of the weak points within those proppant grains."

Each proppant under CARBO's KRYPTO umbrella (KRYPTOSPHERE, KRYPTOAIR and others) is ultra-conductive and suitable for high closure stress environments. Each grain is the same shape and size, maximizing the flow of production through the fracs. Each offering from CARBO can also be modified to fit the specific needs of producers. Even the non-KRYPTO options have a higher thermal stability and conductivity than natural sands being used.

"We're not only providing the strength and the particle distribution the industry usually wants from the proppants. We add value to each grain and that value can be tailored to the issues or problems [operators] have," Max Nikolaev, senior vice president of sales at CARBO told Hart Energy. "So, if you are running the assets that have scale issues, we can address that. If you need tracers, we can address that. If you have issues with the flowback, we can address that and many, many, many other problems."

"If you're going to create a long-term well, ceramic proppant is your answer."

JOSH LEASURE, DIRECTOR OF SALES, CARBO

Ceramic proppants, such as the products CARBO creates, are mainly used for offshore fracking due to their expensive, yet highly effective nature. Because the volume of proppants is limited by how much will fit on a ship, producers want to get the most bang for their buck, said Brett Wilson, R&D manager at CARBO.

While natural frac sand is slightly less effective in its ability to maximize the flow of production from a fracked well, it is widely used onshore, as it is typically much easier to acquire than most ceramics. Natural sands are also cheaper than ceramics, allowing for more sand to be used when fracking a well. ■

Innovations Continue to Push the Limits of Efficiency

Next-generation fleets are poised to take center stage.

JUSTIN MAYORGA, RYSTAD ENERGY

Now well into the second half of 2023, the importance of hydraulic fracturing completion efficiencies remains the focal point for many service companies and operators, as both continue to be impacted by higher associated costs brought on by inflationary and activity-driven effects in 2022.

Against this backdrop, with many basins in the U.S. Lower 48 reaching maturity, some operators lacking premium acreage are now striving to enhance their strategies to overcome observed production degradation. Engineers in the U.S. shale industry have been motivated to explore operational improvements as a result of being confronted with both issues in a low commodity price environment. By doing so, operators are constantly pushing boundaries higher as lateral lengths and frac intensities continue to increase.

But it doesn't stop there—operators are now finding new means of further lowering their proppant and fuel cost with the adoption of next-generation fleets that are high in demand. We'll discuss these topics in depth while providing basin level examples.

Despite growing calls for energy transition, Rystad Energy firmly believes that U.S. shale production remains a crucial player in meeting global demand for hydrocarbons.

We'll first investigate completion efficiencies and analyze improvements brought on by the first half of 2023. As service pricing continues to be elevated, frac efficiencies remain a key method to offset some of these increases.

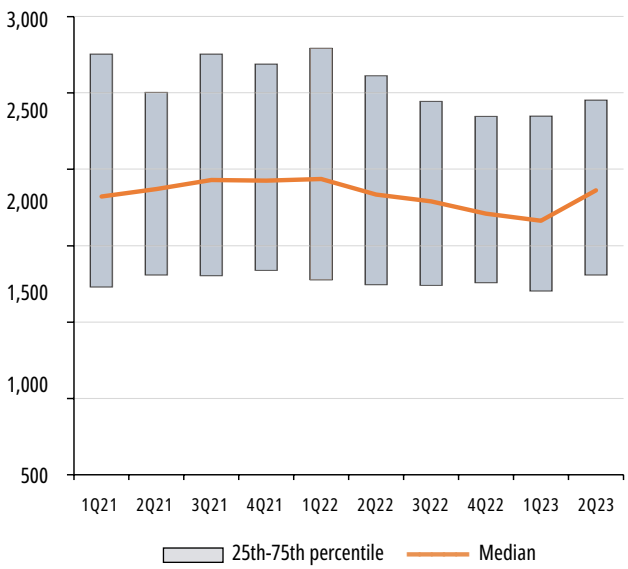
From an aggregated standpoint, stimulated lateral feet per day have decreased since first-quarter 2022 after hitting a high in fourth-quarter 2021. This seems counterintuitive to the story of increasing efficiencies, and this is why it's important to analyze other associated metrics to paint the full picture.

Lateral feet per day have been trending down; however, proppant pumped per day has continued to increase since first-quarter 2022. This essentially means that, despite completing wells at a slightly slower pace, operators have been able to displace larger amounts of proppant, which has resulted in an increase of 9% in proppant pumped per day compared to the prior year. Trends like this are observed in nearly every basin, where the Delaware Basin and Eagle Ford lead all others as proppant intensities continue to trend up despite being somewhat static for several quarters.

Because of this, the U.S. average proppant per well has continued to tick up as lateral lengths extend in various regions.

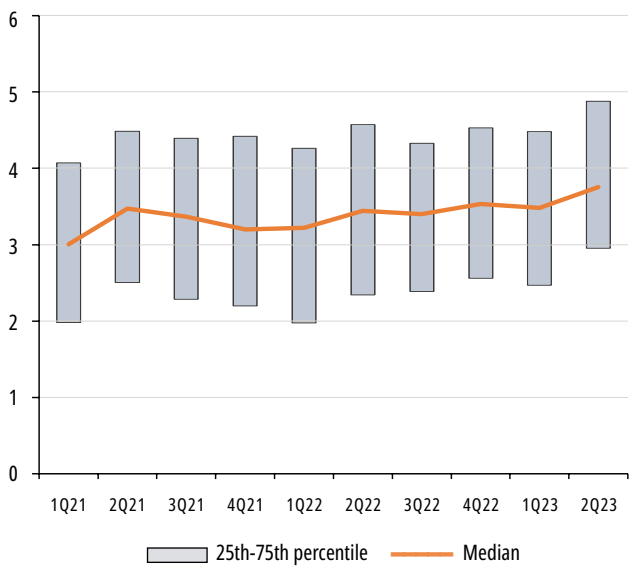
U.S. land hydraulic fracturing completion speed

Lateral feet stimulated per day



U.S. land hydraulic proppant consumption speed

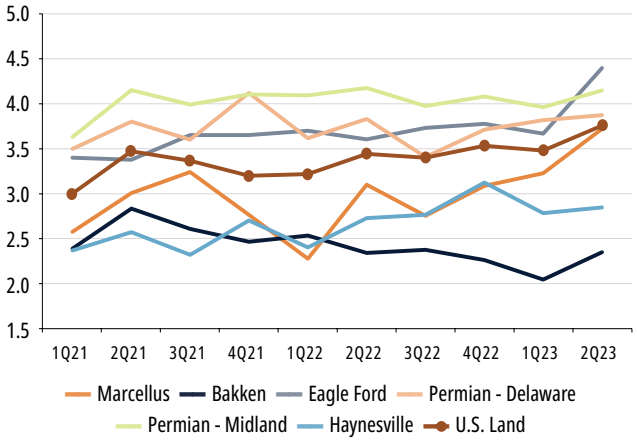
Million pounds proppant pumped per day



All Charts Source: Rystad Energy ShaleWellCube, Rystad Energy research and analysis

Hydraulic proppant consumption speed by basin

Million pounds proppant pumped per day



For example, the average proppant mass per well within the Midland Basin has increased close to 24 million pounds per well, which was as low as 22 million pounds a year prior.

A handful of factors have allowed these types of gains, including, but not limited to, the reduction in time between well swaps, better maintenance programs and newer equipment. However, the main factor remains the adoption of simul-frac (also known as a double barrel and super zippers) activity. Many operators have been able to achieve superior metrics with this type of completion style.

Simul-frac refers to stimulating multiple wells at once with a single frac spread. For example, if you have a four-well pad, instead of fracturing one well while the wireline is perforating another, simul-fracturing will stimulate two wells while two wireline crews perforate another two. Some operators have taken this a step further and are now attempting to stimulate three wells at once, pushing the boundaries for completion speeds.

To date, Rystad Energy's data is suggesting 2023 simul-fracturing has led to an increase of approximately 84% compared to traditional zipper fracturing operations. It comes as no surprise that the Permian Basin is the key region where simul-fracturing operation adoption is the largest; however, operators in other basins have also engaged in this activity in 2023, including in the Eagle Ford and Denver-Julesburg Basin. It is important to note that this technique will not work for all. The primary users of logistical support and execution for large-scale projects are predominantly the larger public operators. To date, Rystad Energy estimates the adoption of simul-frac remains around 11% of all wells stimulated in second-quarter 2023.

It's becoming rather evident which operators are performing these types of operations when analyzing the top peer group within each basin. For example, taking the leading peer group based on the number of wells completed in 2023 within the Midland Basin, it's quite obvious that Pioneer Natural Resources and Ovintiv lead the pack; both are heavily engaged in these types of operations. These two operators have pushed over 6 million pounds or 3,000 short tons of proppant per day.

Among the peer group, consisting of both public majors and private operators, none have reached a daily production level of 5 million pounds or 2,500 short tons of proppant. At this rate, both Ovintiv and Pioneer, due to their heavy simul-frac activity, are seeing at least a 20% uplift compared to others within the peer group.

The Delaware Basin yields similar results with the top operators who heavily conduct these types of operations, such as EOG Resources and Occidental Petroleum, who remain the leaders in these metrics. This is important again because it comes down to cost and increasing the rate of return per well. During this period of high service pricing, despite premiums for additional horsepower for these types of operations, there's a notable amount of cost savings, depending on the contract agreed upon.

Simul-frac, however, is not the only indicator of how efficiencies have been increasing as traditional zipper frac operations continue to improve. This is tied to fleet size. Pressure pumpers continue to iterate that fleet size is increasing year over year, which is true to some extent. With extra pumps at hand, not only can faster rates be achieved, but redundancy for pump maintenance can also be increased.

This trend has not gone unnoticed by Rystad Energy's satellite detection, which has observed a slow increase in signal intensity. Since the pad coordinates are known, using satellites to detect hydraulic fracturing activity allows for accurate near real-time indications of when a crew arrives on location, thus eliminating reporting lag associated with frac focus filings.

Rystad Energy currently views the average fleet size to be around 55,000-60,000 hydraulic horsepower (hhp), depending on the location and the customer needs. Of course, this varies from basin to basin and the type of completion.

When it comes to technology, equipment continues to be the main advancement on the hydraulic fracturing front. Next-generation equipment or natural gas-capable fleets provide a strong value proposition as fuel displacement remains one of the most effective methods of well cost savings. In terms of emissions, these fleets have a positive impact as they use a cleaner fuel source.

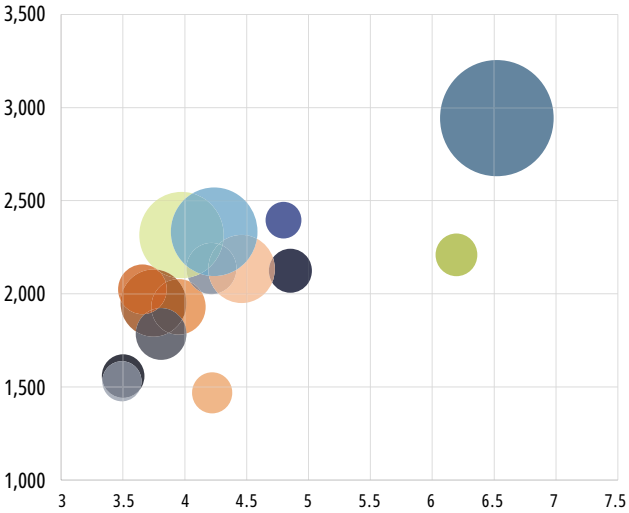
This leads to a reduction in their overall emission profile compared to conventional diesel fleets, provided they are optimized. The adoption of electric fleets remains high, with companies like Evolution Well Services leading the way alongside established oil field giants like Halliburton and ProFrac.

This trend is particularly evident as pure electric providers continue to show confidence in the sector. These electric pumps provide a cleaner method of performing stimulation operations and leave a smaller footprint due to the increased hhp associated with these pumps. A standard electric configuration holds approximately 5,000-7,000 hhp compared to 2,500 hhp on a legacy diesel pump.

Electric pumps boast more horsepower than legacy diesel equipment, but they also have the ability to burn field gas, eliminating the need for CNG, further reducing fuel cost for

Midland operator peer group efficiency metrics*

Feet per day (Y-axis) versus million pounds of proppant pumped per day (X-axis)



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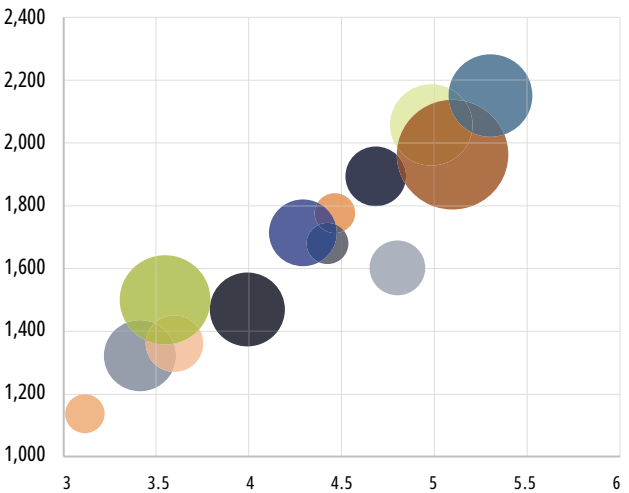
Diamondback Energy · Endeavor Energy Resources · Exxon Mobil
Hibernia Resources · Highpeak Energy · Occidental Petroleum · Ovintiv
Pioneer Natural Resources · SM Energy · Surge Energy · Vital Energy

*Bubble size indicate number of wells and including only wells from January 2022 to YTD.

Delaware operator peer group efficiency metrics*

Feet per day (Y-axis) versus million pounds of proppant pumped per day (X-axis)



Callon Petroleum · Chevron · Conoco Phillips · Coterra Energy
Devon Energy · Diamondback Energy · EOG Resources · Exxon Mobil
Franklin Mountain Energy · Matador Resources · Mewbourne Oil Company
Occidental Petroleum · Patriot Resources · Permian Resources
Tap Rock Resources

*Bubble size indicate number of wells and including only wells from January 2022 to YTD.

the end user. There are still various configurations on the electric power generation side, with some pressure pumpers opting for an agnostic approach. This typically involves a large modular turbine (34 MW) or natural gas reciprocal generator (genset); gensets are becoming more popular due to their reliability and ease of maintenance.

Other solutions have also been developed, including 100% natural gas fleet types that will be rolled out through 2023. Once such example is Liberty's DigiPrime fleet. While this remains in the early phases of deployment, the configuration eliminates the need for an offset power generation solution. It does this by having a natural gas engine mounted directly on the pump, packaging an all-in-one solution.

Rystad Energy currently refers to this type of pump as a mechanical direct drive. If this is successful, this could be a major disruptor in the next-generation fleet sector as it reduces the overall cost by eliminating offset power generation, which is a heavy barrier to entry for many. For example, a larger modular turbine could cost more thanthan $20 million per unit, while gensets could be as high as $10 million. BJ Energy Solutions has had its version of turbine direct drive units for some time now, which have been successful in harsh pumping environments such as the Haynesville.

While the U.S. shale patch continues to be dominated by diesel fleets, this is likely to shift toward natural gas fleets in the near future. Not only are newbuilds continuing to roll out the 100% natural gas side, but Tier 4 dynamic gas blending (DGB) or dual-fuel (DF) upgrades remain at a strong pace, with Caterpillar as a leader in the conversion sector. These types of pump configurations can achieve up to 85% diesel displacement if optimized. Several reports suggest that the accuracy rate in field conditions is around 60%.

Nonetheless, Caterpillar is continuously working on developing updates to enhance its performance. Because of the lower capital cost to upgrade, nearly every premier pressure pumper has now upgraded or has plans to upgrade legacy diesel fleets to be DGB or DF capable, with players such as NexTier leading others in this type of adoption. Due to both fleet types, Rystad Energy continues to estimate that natural gas fleets will soon take the market share by the end of 2023.

In the U.S. shale space, companies are still prioritizing cost reduction and speed when it comes to materials used for stimulations through 2023. While there hasn't been much change in this regard, the adoption of wet sand is becoming increasingly popular, particularly within the Permian Basin.

It's worth noting that even minimal conductivity is better than no conductivity at all. Because of this, operators are now sourcing proppant near their pads by constructing mobile mini-mines, which have been adopted throughout the Permian and Eagle Ford, led by Hi-Crush. Again, it is important to note that these are wet sand mines, or rather damp sand since the water content remains at approximately 5%.

The U.S. shale industry has continued to prove that it is willing to adapt quickly and do what is needed to improve its overall operations. Every year, we observe more and more innovations as the industry continues to shift and evolve, whether due to inflationary effects or the push toward ESG. As the industry continues to evolve, Rystad Energy will continue to monitor and benchmark as the fight for the top position continues to be an ongoing competition between operators and service companies alike. ■

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Remote Completions Could Be Wave of the Future

Technology, trust and a track record could vault completions activities into remote workflows.

JENNIFER PALLANICH, SENIOR EDITOR, TECHNOLOGY

Are remote operations the future of hydraulic fracturing?

Operations like drilling wells and piloting ROVs can be done remotely, which suggests that completion activities could be, as well. The technology exists—or is close to ready—but it takes some trust, as well.

"I think a really big deal in the industry coming up is going to be these remote operating centers," ShearFRAC COO Tom Johnston told Hart Energy.

A geosteering expert can remotely monitor or operate multiple simultaneous well-drilling operations while directional drillers can also handle multiple wells, said Johnston, who has a geosteering background. It would just take a few people present on the drill site to keep an eye on things and handle maintenance of equipment.

"Then you go to the completion squad, and they're all just sitting out there, still doing it [in person]. That doesn't need to be," he said. "If we can do drilling remotely, we can do completing remotely, no problem at all."

On-site and off-site

One of the technologies necessary for remote operations—whether for drilling or completions—is automation. And AI is increasingly playing a role in automation.

ShearFRAC's FracBRAIN completions visualization platform takes pressure, proppant concentration, fluid and chemical rate measurements to calculate the simulated fracture surface area. Changes to rate and proppant change the fracture intensity and number of fractures in the reservoir, which influence completion effectiveness.

Johnston said FracBRAIN can help completions teams mitigate problems such as screening out, or restricted flow, as well as make incremental improvements on subsequent completions. FracBRAIN uses AI to accomplish this.

For an initial well on the pad, ShearFRAC's team will make sure the relevant data from FracBRAIN is available to experts in an on-site data van (which can currently handle an average of four wells at a time), as well as to off-site experts.

"We stay there three, four, five days for the initial pad and a couple of days for every pad beyond that," Johnston said.

That helps train the on-site team "to make sure they understand what they're looking at, what they need from us," he added.

ShearFRAC

"I think it's really powerful for us to be able to sit back and track those wells from somewhere else. It's much more efficient."

TOM JOHNSTON, COO, SHEARFRAC

Beyond that, "there's the feedback loop, and then it's all remote," he said.

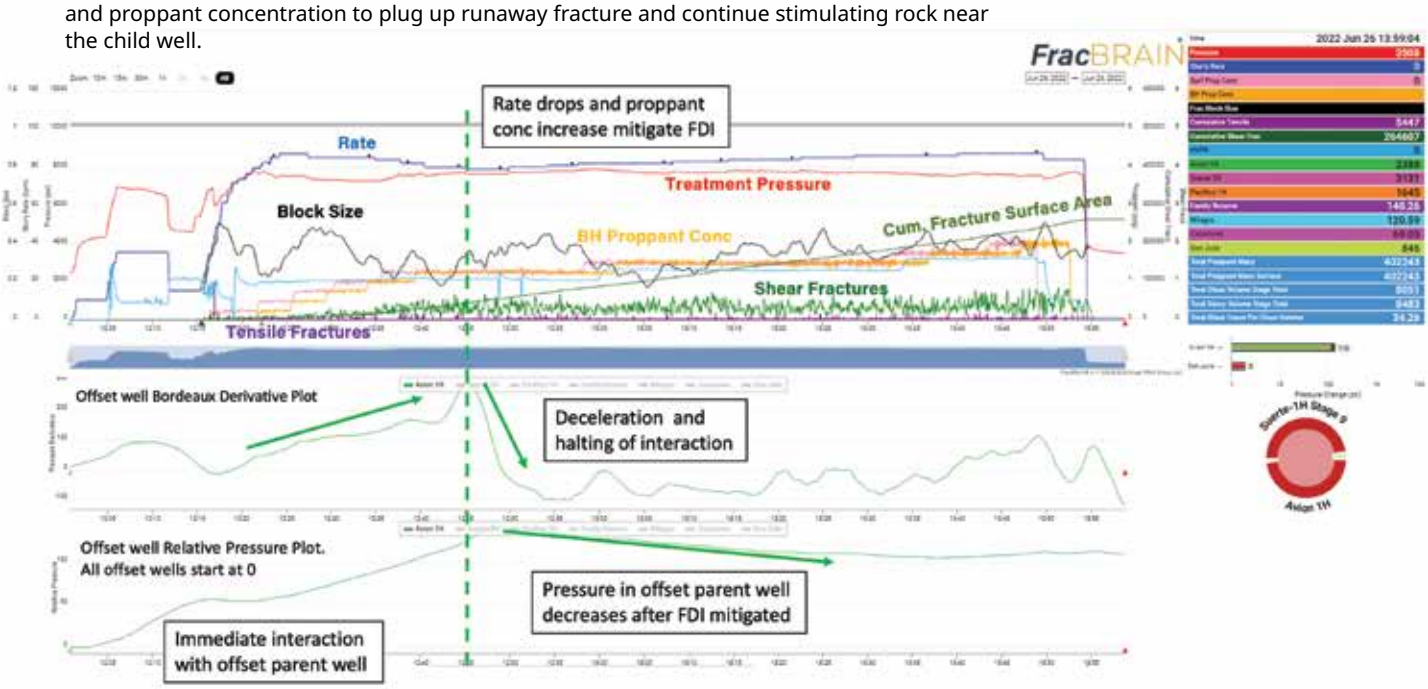
In Canadian completion applications, pump operators have access to the platform on site and consultants use it to work remotely with the pump operators, Johnston said. The approach creates "more efficiency per person so they can work several databases," he added.

Frac information is transmitted to the cloud, sometimes by Starlink, the broadband Internet linked by satellites operated by SpaceX.

"We need the internet. That's the computing power piece," he said. "Not only are we able to work on location with the people there, but because the display piece of our system is super lightweight, it'll grab the data from there, shoot it to the cloud, AWS [Amazon Web Services] will calculate everything, shoot it back to our website"

FracBRAIN and frac-driven interactions

Frac-driven interactions (FDIs) continue to occur instantly; however we learn to change rate and proppant concentration to plug up runaway fracture and continue stimulating rock near the child well.



Source: ShearFRAC

with about three seconds of delay. "That allows you to sit here and track and you're only three seconds behind what's going on location in those Texas wells. It's pretty awesome."

'Grow the grass'

Johnston said the company has calibrated measurements—which he said look like green grass on the FracBRAIN interface—using tracer data, microseismic and fiber optics with production data.

"If you're able to grow the grass higher, your wells are better," he said. "We've got a lot of evidence showing that the measurement is real, super non-invasive, super cheap. And then we get the production data at the end, as well. We're proving that whatever is happening here is correlating to production opportunity."

And while monitoring fracking operations, Sheari—FracBRAIN's AI assistant is a riff on Apple's AI assistant Siri—can recommend changes based on data in the pressure pattern, Johnston said.

But in the future, that could be automated. For example, Sheari's recommendation to increase the rate by 1 bbl/minute pings in the data van and a local expert checks operating values and figures out where that extra 1 bbl/minute will come from.

"There's no reason why it should have to go from a computer to him, from him to the screen to change it. Those pumps are already really smart," he said. "So, rather than the pump operator having to do it nowadays, they can just say one barrel and it will automatically balance them."

Trust issues

That kind of automation is possible, Johnston said. But the track record and trust aren't there yet.

"We need a little bit more experience" to ensure there are no safety issues, he said.

With automation, the consultant doesn't have to worry about risk mitigation and administration details. Instead, Johnston said, the consultant could focus on "just making that well as good as it could possibly be."

And that capability is close, he said. Some code has to be written, but that's the easy part, he added. The harder part is trust.

"It's the same conversation we're having around Tesla and automatic driving, right?" he asked. The hesitation relates to when things go wrong. "What happens, that one incident where that car is automatically driving, and someone's sleeping behind the wheel and runs over a dog. Whose fault is it? Tesla's fault? Is it the driver's fault? The dog's fault? That's the problem."

And Johnston believes the future with remote completions is close.

"I think it's really powerful for us to be able to sit back and track those wells from somewhere else. It's much more efficient," he said. "We're in conversations with the biggest company on how to make that work." ■

Encore of the Oil Patch

Underutilized to this point, refracking wells has proved itself effective in boosting oil recovery.

JAXON CAINES, TECHNOLOGY REPORTER

The goal of the oil and gas industry is to extract oil from the ground, transport and store it, and distribute it to the masses for consumption. This has been the status quo since the 1800s, yet it appears that many companies are leaving too much oil in the ground, and in turn money, on the table.

"We see a big discrepancy between the potential for refracs, with 36,000 wide coastal spacing candidates in the U.S. right now, and yet there's only a handful of refracs," Bob Barba, partner at Triple R Energy Partners, said during Hart Energy's Super DUG event. "Out of the 100 operators in Eagle Ford, 90% have not done refracs. And out of all the operators in the Permian, about 0%, as far as we can tell, have done it."

Despite the reluctance of many in the industry, Barba views refracs as the "real deal," specifically in the Eagle Ford play. And while companies might shy away from refracking basins as a result of operating in chalk or more brittle rock, that doesn't need to be a worry.

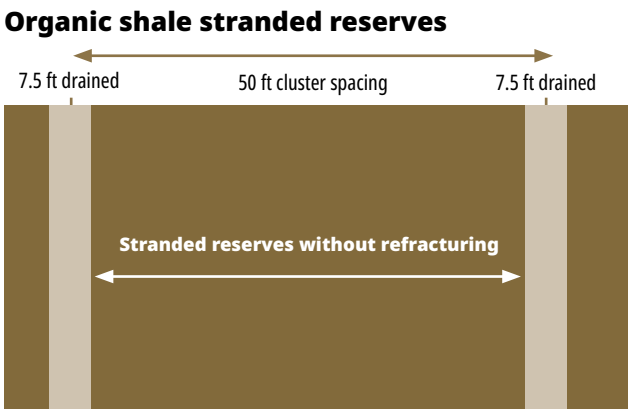
"As far as what I've seen, there hasn't been any reservoirs that haven't responded to [refracking]," said James Segars, vice president for solutions engineering at Universal Pressure Pumping. Segars has experience operating refracs in both shale and chalk basins, such as the Niobrara. He continued, "Obviously, some of them respond differently to the intensity of the fracture... but I would say at least from the overarching scenario, most [basins] should respond favorably."

However, just because most basins should respond favorably doesn't mean all of them will. And there are other concerns as well, including cost. Development costs are typically lower on newly drilled areas than they are on refracked reservoirs, Mark Pearson, president and CEO of Liberty Resources, told the audience.

"Go back three years ago, we were pretty happy if we're pumping 12 hours a day. Now we've got to be pumping 20 hours a day to really set benchmarks. Those efficiencies have really decreased the overall development cost of the place that we're currently in. I guess from my mind, it's kind of the balance between deployed capital," he said. "Do you go for the [somewhat] sure thing with the new D&C or do you look at the refrac opportunity?"

But despite his wariness around refracking, Pearson admits that it will likely soon become the norm. "I think as drilling inventory depletes, refrac is ultimately going to have to be where we go," he said.

One way to mitigate some of the concerns around refracking, Barba said, is to adopt a process called "protective refracking," which restores pore pressure in the parent well.



Source: Bob Barba

Refracking aims to extract reserves left behind following traditional fracking operations and production.

"There's huge potential for refraction and you'll see [refracs] work really well," Barba said. "We've got enough wells to know they work, and yet they're the most underutilized technology.

"Basically, it's a normal refrac, but what it does is restore the original core pressure in the parent well and gives you enough stress cage. That's why you want to do it at the same time, you don't want to do it a month before. You want to have that pressure there in real time so you've got that wall."

According to Barba, the biggest problem with unprotected child wells is the size of their depletion zones. Depletion zones are typically around 350 feet wide, but fracs can reach 1,000 feet. Walls in basins like the Eagle Ford are only three or four feet apart and "as soon as it sees that depleted zone, it's going to stop growing on the distal side" which is where the lost reserves are, Barba said.

To boost the perception of refracking throughout the industry, perhaps it just needs a rebrand. Pearson believes the term "recomplete" is more fitting of the newer, more refined process of recompleting a well, as opposed to the refracking of yesteryear, where oil and gas companies would "bullhead into the well using a chemical diverter and hope it was going to work."

Regardless, refracking has huge capability to change the energy industry, the more it's adopted. ■

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ENERGY SECTOR EVOLVES AS SUSTAINABILITY DRIVE RAMPS UP ..... **C&ESG 2**
Despite challenges such as maintaining social licenses to operate and permitting reform, companies are pushing forward with carbon management and ESG strategies.

2023 ESG AWARDS..... **C&ESG 4**
12 companies are recognized for advancements made in sustainable operation, local community engagement and positive workplace culture.

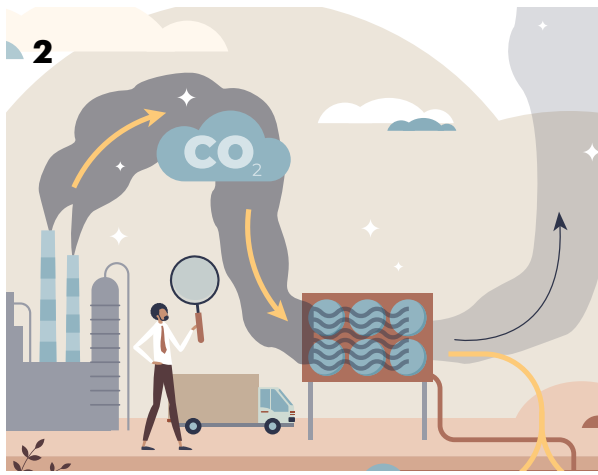
HONEYWELL PICKS UP THE PACE ON CCS ..... **C&ESG 11**
The company's carbon capture and storage technology was selected for Exxon Mobil's blue hydrogen and CCS project in Baytown, Texas.

TALOS ENERGY MAKES LANDFALL TO TACKLE CCS PROJECTS ..... **C&ESG 14**
Low-carbon strategy executive Robin Fielder explains how different pieces—engineering, stakeholder engagement, funding—come together.

CRESCENT BEGINS TO SHINE BRIGHT AFTER RAPID, BUT QUIET, GROWTH..... **C&ESG 18**
CEO Jerry Ashcroft is guiding the offshore pipeline player toward carbon-neutral status by year-end.

THE INTERSECTION OF CORPORATE SUSTAINABILITY AND ENVIRONMENTAL JUSTICE ..... **C&ESG 21**
Wade Foster and Krista Mcintyre of Stoel Rives LLP explain the importance of weaving meaningful objectives into ESG-driven business decision.

WOOD'S DEVIL IN THE DETAILS WITH CCS ..... **C&ESG 23**
Transporting huge volumes of CO_2, tracking impurities in the system and managing carbon systems in varied geographies—Wood's experts on how they plan to make the complicated process work.



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Energy Sector Evolves as Sustainability Drive Ramps Up

Despite challenges such as maintaining social licenses to operate and permitting reform, companies are pushing forward with carbon management and ESG strategies.

VELDA ADDISON, SENIOR EDITOR, ENERGY TRANSITION

As sustainability gets woven into the ESG layers of companies' strategies, the face of energy is changing.

The latest energy transition sees the world moving toward lower-carbon energy sources in an effort to reduce global greenhouse gas emissions and slow global warming. While some are embracing an "all-of-the-above" energy policy, others are focused exclusively on ramping up renewable energy and integrating clean energy into grids. Energy security remains essential.

Regardless of the percentage of fossil fuels in the future energy mix, reducing emissions has become a necessity in all forms of energy production. And ESG is no longer an option when it comes to meeting the world's energy needs, with investors rewarding companies that succeed in creating value without compromising environmental stewardship and safety.

Though many agree that reducing emissions is a must, challenges remain.

Anti-ESG movements have made their presence known. Some environmental groupss and others oppose not only infrastructure for fossil fuel-related projects, but renewable energy projects, as well. Permitting is a lingering concern.

Incorporating ESG strategy—whether it's choosing the right technology, building trust with communities or setting clear practices on accountability and transparency—into overall company ecosystems also remains a work in progress.

Still, companies are making headway and keeping sights on sustainability targets as ESG roadmaps take shape, technologies emerge and federal incentives are offered.

Permian Basin producer Pioneer Natural Resources, which acquired Parsley Energy in 2021, for example, is targeting zero routine flaring by 2030 as it electrifies field operations and works to reduce freshwater use in completions operations.

"Pioneer understands that we have an important role to play in the global challenge to mitigate climate change, and we take that role seriously," CEO Scott Sheffield wrote in the company's latest sustainability report. "Pioneer's board and executive leadership team acknowledge the global threats posed by climate change due to increasing GHG emissions and the resulting impact on rising global temperatures."

Sustainability is also engrained in the culture of Danos, a family-owned and managed oilfield service provider. When it comes to accountability in governance, safety is among its areas of focus. In 2022, Danos employees logged more than 7.7 million man-hours worked with a total recordable incident rate of 0.13, compared to the Gulf of Mexico industry average of 0.58.

"As a company, we're all about protecting investments—both professional and personal," Danos says on its website. "So, we go to great lengths to create an environment of safety and minimized risk and overall well-being for our most valuable assets: our employees."

Energy technology company Baker Hughes is also among

the sustainability leaders, having been recognized for its work in ESG performance; diversity, equity and inclusion; and innovation. The company's sustainability strategy is centered on people, the planet and principles that include a "culture of transparency and integrity—doing the right thing beyond compliance."

"We have been transforming our solutions portfolio by expanding our low-carbon technology portfolio and prioritizing emissions abatement considerations in our corporate strategy," Baker Hughes said in its 2022 Corporate Sustainability Report. "Our strategy is not only focused on financial and operational excellence. It is also heavily focused on sustainability leadership to enable us to deliver on our promises."

Pioneer, Danos and Baker Hughes are among the companies recognized by Hart Energy for their achievements this year. Others include Archrock, Aris Water Solutions, ChampionX, Crestwood Equity Partners, Honeywell, Integrity BioChem, Kodiak Gas Services, MOL Group, MPLX, PureWest, Sentinel Peak Resources, Talos Energy and XRI Holdings.

Companies across the world are stepping up carbon management efforts, including carbon capture and storage projects.

"The main headline is there has been five solid years of growth in the project pipeline starting in 2017. Today we count 37 commercial CCS facilities that are operating, 20 in construction and more than 200 in development," Christina Staib, global finance sector lead for the Global CCS Institute, said in June during a conference in Houston. "The total CO_2 capture capacity of CCS projects currently in development is more than 300 million tons per annum."

"Pioneer understands that we have an important role to play in the global challenge to mitigate climate change, and we take that role seriously."

Scott Sheffield, CEO, Pioneer Natural Resources

The estimates exclude transport and storage-only facilities.

Growth has been driven by a strong response from the private sector and governments' expectations to meaningfully act on climate change, she said.

Having business models that incorporate sustainability, embracing breakthrough and other technologies, and strengthening relationships with people will be essential to meeting the world's growing energy needs amid the threat of continued global warming. In this supplement, companies will share how they are doing that. ■

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ESG AWARDS

Environmental, social and governance (ESG) matters remain a critical—and sometimes, controversial—touchstone for companies across the supply chain as the energy transition cycle transforms the industry.

Hart Energy's annual ESG Awards highlight the findings of data analysis firm Clear Rating in its effort to categorize and quantify individual business efforts to improve ESG performance. These awards recognize advancements made in sustainable operation, local community engagement and positive workplace culture.

Clear Rating analyzed dozens of nominations and applied a weighted methodology to score nominated companies. In this assessment, more easily quantifiable environmental improvements were weighted the heaviest. The ratings still placed critical scoring metrics on social advancement, including community support and workforce sentiment, and on governance matters, such as board diversity. The final weighted score represents an average of the three ratings.

PUBLIC PRODUCER

PIONEER NATURAL RESOURCES

Pioneer Natural Resources

Final Score: 90

Pioneer Natural Resources' CEO Scott Sheffield was one of the highest profile executives to call on the industry to reduce flaring in its operations. Calling flaring a "black eye" as much as five years ago, Sheffield has continued calls on industry colleagues to improve their environmental standards. Pioneer, a Permian Basin pure play, prioritizes emissions reductions, freshwater use and diminishing its physical footprint on the land.

E – Pioneer has committed to reduce methane emissions through facility design, operations and leak-management protocols. Flaring is less than 2% of Pioneer's produced natural gas, one of the lowest rates in the Permian, and the company has eliminated routine flaring.
Category Score: 90

S – The firm strives to protect the environment from damage, as well as the lives of its employees and community members who live near its operations from injury and health risks.
Category Score: 90

Hart Energy

Pioneer, a Permian Basin pure play, prioritizes emissions reductions, freshwater use and diminishing its physical footprint on the land.

G – The board of directors is 23% racially diverse and 31% of its membership is female. Pioneer's board was among the first U.S. producers to report annually on sustainability and climate risk, which is now common among public operators around the world. The board also has realigned its executive compensation calculations with ESG performance measurements.
Category Score: 90

Talos Energy

Final Score: 88.75

One of the leading independent operators in the Gulf of Mexico, Talos Energy strives to create and maintain a culture of ESG awareness with initiatives that foster corporate responsibility in daily operations.

E – Talos has demonstrated commitment to protecting the diverse ocean and coastal environments in which it operates. Through its safety and environmental management system, Talos actively monitors its operations to minimize impacts and ensure full compliance with applicable industry standards and regulations. Current environmental initiatives include a 30% reduction in greenhouse gas (GHG) emissions intensity by 2025 from baseline 2018 levels.
Category Score: 90

S – Talos was named one of Houston Chronicle's Top Workplaces in Houston for eight consecutive years. In June 2021, the company raised approximately $70,000 through employee and company matching contributions to a local Houston children's charity, Kid's Meals.
Category Score: 85

Talos Energy Inc

The Bayou Bend CCS project was the first offshore lease in the U.S. dedicated to CO_2 sequestration.

G – The company has increased female representation on its board of directors to 30%. It has also increased its ESG-related performance metrics to account for 20% of management's annual incentive plan.
Category Score: 85

PRIVATE PRODUCER

PureWest Energy

Final Score: 90.25

PureWest, a natural gas producer in the Rockies, incorporates its ESG principles into daily operations through voluntary initiatives to self-monitor and decrease GHG emissions, as well as through support of community volunteering programs. The company, which recently was acquired by a private investor group largely led by family offices, has cultivated a positive, productive and inclusive work environment and was honored with a Denver Business Journal "Best Place to Work" award in the 2023 Large Company category.

E – PureWest worked closely with Project Canary and TrustWell to certify all of its wells as "Responsibly Sourced" by year-end 2022. A rigorous internal auditing program was established to evaluate leak detection and repair (LDAR) findings and conduct facility evaluations. PureWest voluntarily removed thousands of pneumatic pumps to replace them with solar-powered devices, and removed all of its high-bleed pneumatic devices. The company also deployed stationary methane detection monitors at select sites.
Category Score: 90

PureWest

PureWest is implementing new technology to help replace energy-intensive operations, including solar heat trace pumps and well automation, which allows the company to remove pneumatic devices—eliminating those operational emissions as well as the potential for fugitives.

S – PureWest's charitable giving policy focuses on providing for basic human needs, such as food, shelter, healthcare and education. The company matches employee donations to more than 60 organizations.
Category Score: 85

G - PureWest seeks to encourage healthy debate and embrace the diversity of its workforce. The company says it fosters a workplace that encourages and rewards initiative, and provides authority to make decisions within areas of accountability. It empowers employees to adhere to the corporate commitment to operate responsibly and continuously improve the bottom line.
Category Score: 95

Sentinel Peak Resources

Final Score: 90

Sentinel Peak Resources is focused on the acquisition, development and exploration of oil and gas resources, primarily in California. The firm concentrates on operational excellence, serving as a steward of the environment and investing in its people and communities.

E – The company set a target of achieving carbon neutrality by 2030 through improved efficiencies, adoption of alternative energy sources and utilization of new technologies. Sentinel has improved its methane management with a five-tank vapor recovery system that reduced CO_2 emissions from crude oil storage tanks by 93%. In addition to GHG reduction, Sentinel minimized freshwater use, sourcing over 95% of its water from non-potable sources, including produced water from its own wells.
Category Score: 90

S – Sentinel supports multiple community youth programs, such as mentorship programs in local high schools, and a program to support emancipated young people develop skills required to obtain field or administrative work. The company supports the Los Angeles community by converting some non-operating sites into affordable housing and other socioeconomic needs.
Category Score: 90

Sentinel Peak Resources

Sentinel Peak Resources' oil and gas operation in the McKittrick oil field is located among the foothills of Western Kern County, Calif.

G – Sentinel's regulatory compliance has allowed it to succeed despite the headwinds oil and gas companies face in California. The company adopted the California Air Resources Board reporting standards for GHG emissions, an LDAR program, groundwater monitoring, oil spill prevention and other programs. Sentinel employs a third-party whistleblower reporting service, Lighthouse Service, to ensure a safe space for employees to report concerns, and it says it is committed to adopting cybersecurity protocols to ensure system and source integrity.
Category Score: 90

PUBLIC SERVICES

Baker Hughes

Final Score: 92

The oilfield services giant demonstrates ESG leadership in its goal setting, its sustainability performance and its investments in new products and services. As an energy technology company, Baker Hughes is committed to not only improving its own ESG performance, but also helping customers meet their ESG challenges and opportunities in support of the energy transition.

E – In 2022, Baker Hughes reduced its Scope 1 and 2 CO_2 emissions 28% from the 2019 baseline, with 10 Scope 3 emissions categories reported with limited assurance. The company recycled 57,666 metric tons of waste and sourced 26% of its electricity from zero-emissions sources.
Category Score: 95

S – Baker Hughes pledged $2 million in strategic grants through the Baker Hughes Foundation in support of the UN Sustainable Development Goals in 2022. The company gave $925,000 to support diversity and inclusion programs, as well as education and opportunity initiatives. It donated $417,000 to support health, safety and wellness, and disaster relief. And it gave $650,000 to support environmental programs.
Category Score: 80

Baker Hughes

Baker Hughes's Massa, Italy, facility is part of the company's efforts to run more operations on renewable energies.

G – Last year, 53,846 Baker Hughes employees had completed annual code of conduct training, including training on ethics, compliance and anti-corruption; 99% of the company's governance body members had received anti-corruption training; and 100% of enterprise security personnel, including full-time and embedded contractors, were trained in human rights policies.
Category Score: 85

ChampionX

Final Score: 90

ChampionX is a global leader in upstream and midstream oilfield technology solutions, chemistry programs and services, drilling technology, artificial lift and automation technologies for the oil and gas industry. It defines its overarching corporate purpose as improving lives, and has built a sustainability culture from the ground up.

E – ChampionX says it embedded sustainability into its culture and promoted more sustainable operations internally. It launched an internal carbon footprint calculator, which enables employees to calculate the manufacturing carbon footprint associated with transporting products from facilities to customer assets. In many cases, the calculator has shown the positive impact the company's products have on reducing customers' carbon emissions in the field.
Category Score: 90

S – ChampionX supports nine resource groups with the voluntary participation of over 1,000 employees. The goal is to create a workplace culture that cultivates a sense of belonging and allows for more purposeful alignment with the principles of the company. ChampionX also launched

ChampionX

ChampionX chemical solutions and services provide chemistry, technology, engineering support and onsite expertise to improve outcomes for upstream and midstream oil and gas operations.

SEED (Sustainable Energy Empowers Development), a program that connects employees with opportunities to personally support environmental programs.
Category Score: 90

G – In support of their goal of continuous improvement and to strengthen the inclusivity of the company, ChampionX established an enterprise-wide Diversity and Inclusion Council, chaired by ChampionX CEO Soma Somasundaram. The council is made up of senior leaders from a cross-section of the company's business, including a rotating set of employee resource group leaders.
Category Score: 90

PRIVATE SERVICES

Danos

Final Score: 93.75

A family-owned oilfield service company, Danos views its commitment to ESG principles as fundamental to its success. The company is a founding member of the National Ocean Industries Association's (NOIA) ESG network, which shares and develops best practices across the offshore energy industry.

E – Danos works with wetland conservation groups, and is involved in a projects building artificial reefs–nicknamed Cajun coral–using 3-D printing that will help regrow coral beds, as well as protect against coastal erosion in Louisiana. Danos utilizes engine-calibration software to reduce its fleet's fuel consumption and cut its CO_2 emissions by 1,178 total metric tons a year.
Category Score: 95

S – The Danos Foundation has given over 1 million to 120 organizations and more than 350 employees in need since it launched in 2017. Danos partners with several technical and community colleges that offer degrees supporting

Danos

Danos works with partner Natrx in Louisiana's marsh to offload Cajun Coral, a restoration model that uses digital tools to work with mother nature to protect coastlines.

the industry, and the company has a robust on-the-job training program.
Category Score: 90

G – Danos' fabrication facility is fully certified to International Organization for Standardization quality management system standards and conducts rotating internal process audits to ensure compliance. The company is a multiyear winner of the NOIA Culture of Safety award for establishing an institutional safety culture through behavior-based safety programs and innovation.
Category Score: 90

Integrity BioChem

Final Score: 93.25

Integrity Bio-Chemicals appointed its first director of sustainability in fall 2021 and touts breakthroughs in sustainability initiatives throughout the organization, committing itself to sustainable natural product solutions for the full product lifecycle.

E – Integrity BioChem's bio-based, 4x-concentrated surfactants reduce combustion engine footprint by 75%.
Category Score: 95

S – A small company, Integrity BioChem boasts that, at its core, it is a technology company. The company strives for employee safety, reporting zero lost-time incidents in 2022.
Category Score: 85

G – Integrity BioChem made an executive commitment to ESG with the creation of a new role, director of sustainability. Laura Kuri Benavides took on this charge to implement and document the company's sustainability processes. She also provides guidance on emerging sustainability technologies.
Category Score: 90

Integrity BioChem

Integrity BioChem manufactures biopolymer products.

PUBLIC MIDSTREAM

Archrock

Final Score: 94.5

Houston-based Archrock's mission is to "Power a Cleaner America." The natural gas compression services provider's 1,000-plus employees are spread across 21 states.

E – Archrock reduced its Scope 1 and 2 carbon intensity by 11% in 2021 compared to 2020 levels. Scope 3 emissions in 2021 were 37% below 2017 levels. In 2022, Archrock acquired a 25% equity position in Ecotec, a company that provides methane emissions monitoring, leak detection and environmental compliance. Archrock is working to connect Ecotec's proven technology with its U.S. natural gas compression infrastructure and customer support network.
Category Score: 95

S – The Archrock Cares organization supports volunteer activities with organizations, such as the Houston Food Bank. In 2022, Archrock added a diversity and inclusion metric to its short-term incentive program, increasing the company's percentage of employees that self-identify as members of underrepresented groups.
Category Score: 90

Archrock

Houston-based Archrock's mission is to "Power a Cleaner America."

G – Archrock's majority independent and annually elected board of directors drive a focus on long-term sustainability and governance standards throughout the organization. Of the annually elected Archrock board of directors, three of the seven independent board members are either female or ethnically diverse, including audit and governance committees led by female board members. In 2022, Archrock increased the weight of safety and sustainability within its short-term incentive plan to 20%.
Category Score: 95

Crestwood Equity Partners

Final Score: 93.25

Crestwood Equity Partners made significant strides on its second three-year sustainability strategy, initiated in January 2022, including deliverables achieved through its comprehensive carbon management plan.

E – While the company's GHG emissions increased in 2022 due to the acquisitions of new gathering, compression and processing assets, Crestwood achieved a 5% reduction in its methane emissions intensity rate from 2021 levels and a 58% reduction since 2018. The company also made advancements on its continuous, methane-monitoring pilot and installed devices on 13% of its assets in 2022, enhancing its approach to methane detection.
Category Score: 95

S – In 2022, Crestwood donated $1.5 million to the communities it operates in, and Crestwood employees volunteered over 2,800 hours.
Category Score: 85

Crestwood Equity Partners

Crestwood remains committed to seeking ways to enhance its emissions monitoring.

G – Crestwood continues to increase its female leadership representation and was included in the 2023 Bloomberg Gender-Equality Index for the third consecutive year. Crestwood continues to make significant progress in advancing its approach to corporate governance in alignment with best practices, enhancing disclosures in its annual proxy statement and maintaining a board composition of 89% independent directors, reflecting diverse perspectives and ensuring robust decision-making.
Category Score: 90

Aris Water Solutions

Final Score: 89.25

Aris Water Solutions, a leading developer and operator of critical water infrastructure assets in the Midland and Delaware basins, has committed to exceeding the high standards set by its customers, global regulators and the global investment community. This enables customers to exceed their own water, safety and community commitments and focus on their core businesses.

E – Aris recycled 4.6 billion gallons of water in 2022 to offset groundwater withdrawals, reduce wastewater disposal and cut carbon emissions. Aris led the formation of the largest joint industry beneficial reuse project, working with three major operators to develop, pilot and demonstrate desalination and polishing treatment technologies that aim to facilitate safe beneficial reuse of treated water outside of the oil industry. Also, Aris was able to reduce fresh and groundwater consumption by up to 90% in certain instances.
Category Score: 90

Aris Water Solutions

Aris Water Solutions is a leading developer and operator of critical water infrastructure assets in the Midland and Delaware basins.

S – Aris supports local communities by giving to and volunteering with first responders and local charities.
Category Score: 90

G – The company is committed to ensuring a diverse and inclusive culture, with over 50% minority and female representation, including at senior leadership and executive levels. Aris has an independent governance with a diverse board, including 33% gender and minority representation.
Category Score: 85

PRIVATE MIDSTREAM

XRI Holdings

Final Score: 88.75

XRI was founded in 2013 on the tenets of conservation of water resources, environmental sustainability, employee health and safety and corporate stewardship. XRI's mission is to provide the industry with an environmentally sustainable alternative to groundwater use for hydraulic fracturing operations.

E – The independent water midstream company's operations avoid the emitting of 225,000 metric tons of CO_2 per year, save over 400 million barrels of freshwater aquifers per year, and prevent reinjection of over 270 million barrels of wastewater.
Category Score: 90

S – XRI engages with the community it serves through volunteering and participating in economic development.
Category Score: 85

XRI Holdings

XRI has committed to a corporate culture and code of conduct ensuring the highest level of business ethics, including anti-bribery and corruption standards, stakeholder rights and social justice practices, as well as governance of sustainability initiatives.

G – XRI has committed to a corporate culture and code of conduct ensuring the highest level of business ethics, including anti-bribery and corruption standards, stakeholder rights and social justice practices, as well as governance of sustainability initiatives.
Category Score: 85

Honeywell Picks Up the Pace on CCS

The company's carbon capture and storage technology was selected for Exxon Mobil's blue hydrogen and CCS project in Baytown, Texas.

VELDA ADDISON, SENIOR EDITOR, ENERGY TRANSITION

Carbon capture technologies in the U.S. date back to the 1970s when they were used to remove CO_2 from gas streams, improving the value of natural gas, and for enhanced oil recovery in the Permian Basin.

Times are changing.

Though carbon capture is still used to help boost oil production today, focus is shifting to storing captured carbon as the world aims to reduce greenhouse gas emissions.

"Instead of trying to meet a natural gas product spec, we're identifying other CO_2-rich sources and trying to remove the CO_2 to make sure it never gets into the atmosphere," Jeff Guenther, project development director of carbon capture and blue hydrogen for Honeywell, told Hart Energy. "The U.S. is a leader in this space, given ample storage capacity and some CO_2 pipeline infrastructure in place along the U.S. Gulf Coast."

Hart Energy spoke with Guenther about carbon capture and storage technologies, which the International Energy Agency said are required to reach net-zero emissions targets. He called the state of affairs for CCS in the U.S. "quite good" with strong interest in developing carbon capture projects in other parts of the world, including Europe, as society and corporations get serious about reducing emissions.

Exxon Mobil selected Honeywell technology to capture CO_2 from a new blue hydrogen plant at its Baytown, Texas, complex. The project will have a capacity to store up 10 million metric tons of CO_2 per year.

Data from the Global CCS Institute show the number of CCS projects grew 44% through September 2022 compared to a year earlier, with North America leading the world in CCS development. However, more large-scale deployment is needed to hit net-zero emissions goals.

This interview was edited for length and clarity.

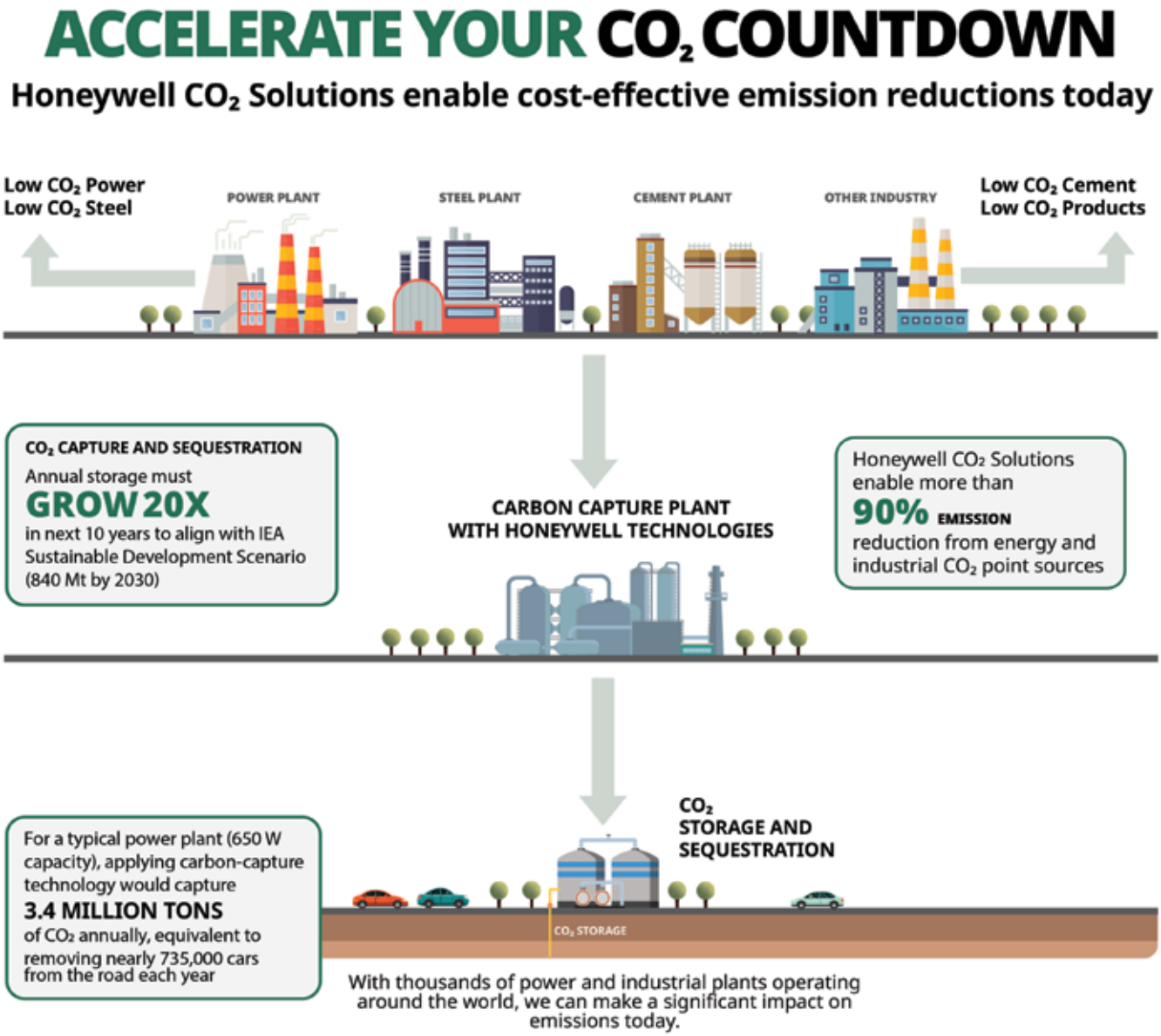
Q&A

Velda Addison: Do you consider carbon capture underutilized globally? How do you see that changing, given the drive to lower emissions and net-zero initiatives?

Jeff Guenther: The key with carbon capture and a lot of these projects is there does need to be some supportive policy for projects to go forward. With the passage of the Inflation Reduction Act, the U.S. has very clear policy in place that gives project developers in the U.S. confidence. Europe also has pretty clear policy. Outside of that, there are many more question marks. I would agree it's an underutilized tool, and it's because policy in other regions are sort of lagging behind Europe and the U.S. in terms of clarity and magnitude of how they would support a project. ... It is moving, but just at a slightly slower pace because they're waiting [for] clarity on the policy side. It is underutilized from that standpoint, but there seems to be global vision that it is a strong opportunity to reduce emissions, especially in sectors that have limited options to continue to operate while lowering their CO_2 footprint.

VA: In the energy industry, we often hear that CCS is expensive. What makes it expensive?

JG: Expensive is a relative term here, right? Everything needs to be compared to the impact of climate change, which is expensive in its own right if we don't do anything. So why is it expensive? There's a lot of CO_2 being emitted into the atmosphere. So, when you're talking about large-scale projects, there's a large capital investment to capture that much CO_2. Power plants are easily emitting over a million tons of CO_2 per year, in many cases over 3 million tons of CO_2 per year. That's



Source: Honeywell

a lot of gas to be able to process and a lot of CO_2 to handle.

Once you make the investment to capture it, you also need some type of infrastructure available, most likely via pipeline, to move the CO_2 to a suitable sequestration site. To answer your question, when the challenge is big, the solution is equally big.

VA: How is Honeywell working to make CCS more efficient for the industry, given that some projects don't end up not capturing as much CO_2 as originally planned. What are some of the key technologies to help improve cost and efficiency of these types of projects?

JG: At Honeywell, we have a full portfolio of technology solutions that we can use to capture carbon in both pre-combustion and post combustion applications. Pre-combustion applications are characterized as high CO_2 concentration process streams. Typically, in hydrogen production or in natural gas processing, these types of streams are available. They might have 40 to 60% CO_2 and they offer a positive opportunity to capture that CO_2 at a low cost on a dollar per ton basis. To contrast that with post combustion carbon capture, where we have a fossil fuel that's being combusted in a fired heater, turbine or boiler, and we're capturing the CO_2 in the post combustion gas or the resulting flue gas from that process. That's the much larger market opportunity in the world but it's more challenging to treat because it's characterized by lower CO_2 concentrations, which mean capturing that CO_2 becomes a higher cost on a dollar per ton basis.

We use solvents, absorbents, membranes and fractionation technology for these applications. We can deploy those independently or in hybrid schemes. … On the post combustion side, we have advanced solvent carbon capture technol-

ogy that offers some unique advantages in the marketplace. Our solvent has a very high mass transfer rate, allowing the absorption equipment to be smaller than previous first-generation solvents on the market. It also is very stable, meaning that we can operate our process at a higher temperature and pressure, which means we can produce the CO_2 at a higher pressure than other solvents on the market. That's really important because when you're talking about large quantities of CO_2, a million tonnes of CO_2 per year or more, that CO_2 needs to be compressed to very high-pressure levels—typically around 2,000 pounds per square inch—to be transported and stored. When we're able to produce the CO_2 at a higher pressure, it can actually significantly reduce the costs for compressing it before it is transported and stored, typically in the range of 30 to 40%, both in terms of the initial capex of that compression and in the annual operating expenses.

VA: You mentioned solvents, absorbents and fractionation technology. Is there any one technology that Honeywell is seeing more demand for, or is it all of the above?

JG: Two are really standing out. In the pre-combustion space, particularly when in large scale hydrogen production, we're getting a lot of positive feedback on our CO_2 fractionation technology because of the low cost of capture it enables, the possibility to integrate within the hydrogen production process to drive to very low carbon intensities, and to produce the CO_2 directly as a liquid product. On the post-combustion side, the proven technology in the market is solvent based. So, we're seeing many customers who are focused on evaluating solvents today to treat their post combustion flue gases.

VA: What specific technologies do you plan to use for the Exxon's blue hydrogen project?

JG: We are providing the hydrogen purification equipment called a Honeywell UOP polybed PSA unit. We're providing the dehydration unit, which is a Honeywell UOP Molsiv unit, a CO_2 fractionation unit, and a hydrogen membrane unit. Essentially how that process works is there is hydrogen-rich syngas that's produced by the auto thermal reforming (ATR) unit. Our hydrogen PSA unit will process that gas and separate out a high purity hydrogen product stream. It will also then reject the other components in a tail gas stream, including the CO_2, which will be dehydrated and compressed and head to our CO_2 fractionation column, where the CO_2 will be separated and produced as a high purity CO_2 liquid. From the top of that CO_2 fractionation column, we then can send the gas to a PSA and a membrane unit to further recover hydrogen as a product source. The rejected gas from that stream will be recycled back to the ATR so that any unconverted methane or carbon monoxide will continue to recycle in the unit so that it will be converted to CO_2 and captured by our technology. This results in a very low carbon intensity hydrogen product.

So in summary, if you picture our offering as one large box, the gas is going to come in and be separated into three streams: a high purity H_2 product; a high purity liquid CO_2 product; and a hydrocarbon free fuel stream with the remainder being recycled within the system. All of the CO_2 that leaves the system is essentially captured for storage. That's the unique and exciting aspect of that project. We can drive to slow carbon intensities of hydrogen production, providing an opportunity for hydrogen to become a fuel substitute and a high value commodity.

"I would agree [CCS is] an underutilized tool, and it's because policy in other regions are sort of lagging behind Europe and the U.S. in terms of clarity and magnitude of how they would support a project."

JEFF GUENTHER, PROJECT DEVELOPMENT DIRECTOR, CARBON CAPTURE AND BLUE HYDROGEN, HONEYWELL

VA: Are you finding that more companies are focused on sequestering CO_2 instead of utilizing it? How can captured carbon be used?

JG: Most companies that we're talking to are focused on sequestration, especially in the U.S., because we have a suitable geological environment to enable that. Additionally, in the U.S., there are different incentive levels available. The U.S. offers a tax credit of $85 per tonne for CO_2 that is permanently stored and $60 per ton of use for enhanced oil recovery. Most of our customers are looking to permanently store it in the ground. Most climate and market models take the assumption that the majority of CO_2 that's going to be captured is going to be permanently stored because one, that is the surefire way to prevent it from making its way eventually into the atmosphere and two, the amount of CO_2 that we need to abate is just so large that market outlets don't really exist for it today in the quantities that people are planning to capture.

With that said, CO_2 can be used in the beverage and food preservation markets. We're also seeing some interest from customers about using CO_2 as a feedstock for fuels. We recently announced our e-fining process technology that can convert CO_2 and green hydrogen into methanol and eventually into sustainable aviation fuel. So, we continue to look into different ways to utilize CO_2 as a fuel as well as different pathways to produce other chemicals needed by our society. But the near-term focus for most of our customers, especially at the quantities required to make a significant impact on their emissions, is to store the CO_2 permanently. ■

Talos Energy Makes Landfall to Tackle CCS Projects

Low-carbon strategy executive Robin Fielder explains how different pieces—engineering, stakeholder engagement, funding—come together.

JORDAN BLUM, EDITORIAL DIRECTOR

Roughly two years ago, Gulf of Mexico producer Talos Energy took a strategic leap of faith and started picking up acreage both onshore and off with the mindset of injecting—not extracting—carbon.

And, thus, were born a slew of developing carbon capture and storage (CCS) projects: the flagship Bayou Bend CCS offshore of Port Arthur, Texas; River Bend CCS in Louisiana; Coastal Bend CCS near Corpus Christi, Texas; and a point-source project with Freeport LNG in Texas.

As potential pioneers in offshore CCS with Bayou Bend, Talos and partner Carbonvert found themselves in the enviable position of being approached by Chevron to join the team, said Robin Fielder, Talos' executive vice president for its low carbon strategy and the chief sustainability officer.

Chevron came onboard last year as a 50% project owner and, in March, the expanded team added to Bayou Bend's 40,000 offshore acres with 100,000 onshore acres between Houston and Port Arthur.

Fielder sat down with Hart Energy for an exclusive interview on CCS topics.

JORDAN BLUM: I don't think there's been a whole lot of public focus on the extra acreage on the east side of the Houston Ship Channel. Most of the emphasis is on offshore and the Chevron partnership.

ROBIN FIELDER: Yeah. It was the expansion of Bayou Bend, but with it they became operators. So we had two operators.

JB: I was interested in—separate from the Chevron component—delving into the expansion itself. Could I get you to elaborate on just how important, how big a deal it is with the proximity to the ship channel and everything?

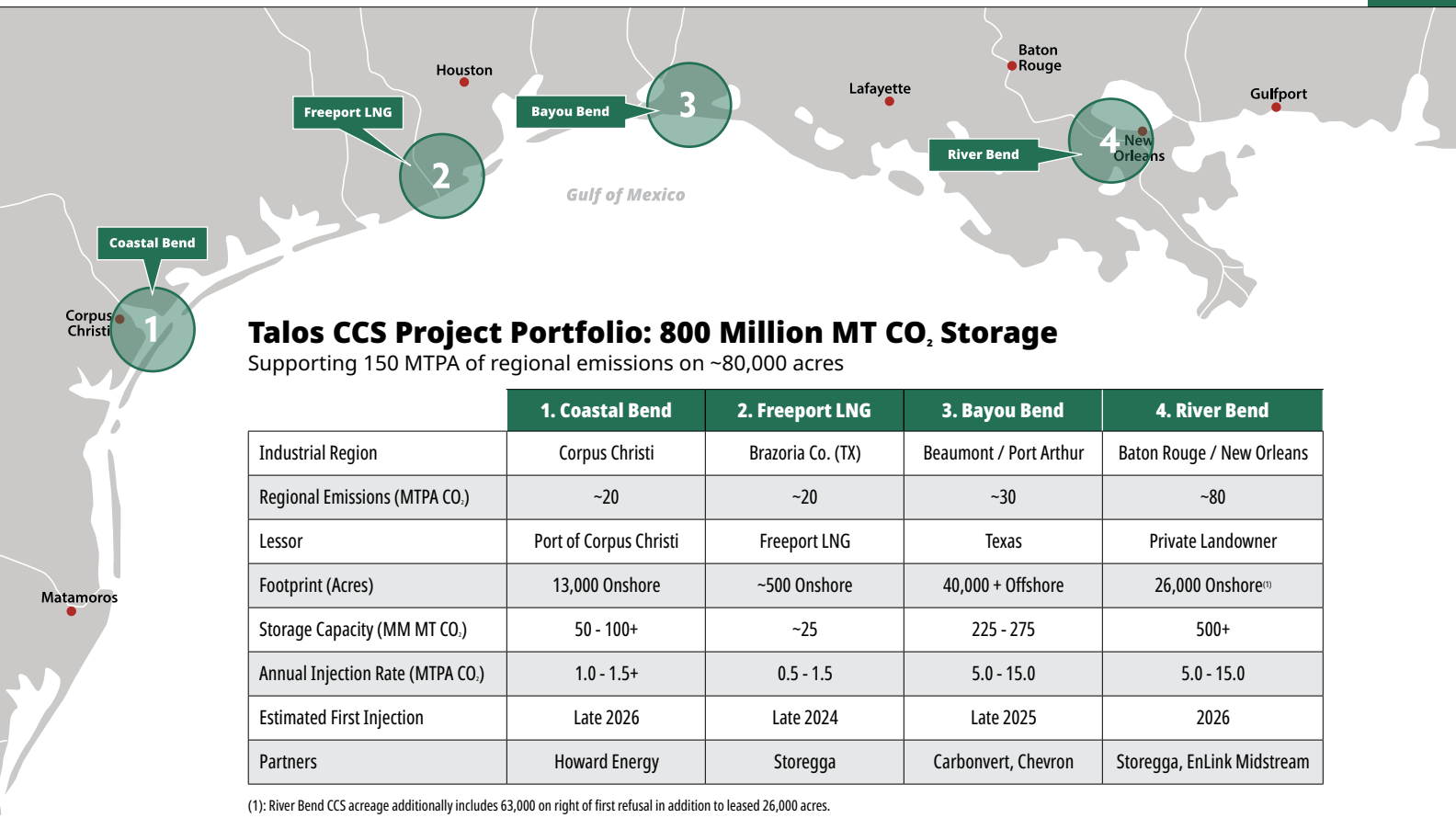
RF: It's a great expansion. It unlocked a whole second industrial region for us. So now, we're in that onshore acreage that crosses Chambers and Jefferson counties. It's right there on the eastern side where you've got Beaumont, Mont Belvieu. So, a lot of power, a lot of fractionation and a lot of industrials. And a large storage site is needed to address that market. We could have taken it to offshore, but it would've been on much farther transport and and higher costs. So, it would've been harder to be competitive there. Now that we've got the onshore, we can address both markets. But, also, we see at some point we can connect both stores up via pipe and have that flexibility if we need to swing volumes, for instance. We have some built-in redundancy because our customer base really wants to see that.

JB: Was there any legacy ownership of the onshore acreage before the Chevron deal?

RF: It came in through our joint venture, so our joint venture decided to go and purchase that. Chevron was the lead on a lot of that, but we, as Talos, were working with them on that as well.

JB: Would you take me though the next steps from here? Bayou Bend is the biggest project, obviously, but you're moving multiple levers at the same time. So, take me through how you see the timeline from here. I know nothing is set in stone.

RF: Each project has its own project manager, subsurface team. So, you've got a lot of parallel processes in each project. You're working through emitter agreements, commercial negotiations. We're talking with the insurance market and what that can look like. We're talking with the EPCs (engineering, procurement and construction)—sometimes it's ourselves—on doing the actual pre-FEED or FEED studies to get the more detailed cost estimates and full designs where you've got all the P&IDs (piping and instrumentation diagrams) and everything mapped out for what the location modifications need to be, where the pipe is going to go in the ground, where the right-of-way would be. So, it's really getting all that detailed process engineering and process work done while we're building a stakeholder engagement plan and engaging. You've got all these parallel pieces and then, oh yes, there's the funding piece. So, we're keeping the door open for each of these projects to have project-level funding or financing if you've got the contracts that are long



Talos CCS Project Portfolio: 800 Million MT CO_2 Storage

Supporting 150 MTPA of regional emissions on ~80,000 acres

	1. Coastal Bend	2. Freeport LNG	3. Bayou Bend	4. River Bend
Industrial Region	Corpus Christi	Brazoria Co. (TX)	Beaumont / Port Arthur	Baton Rouge / New Orleans
Regional Emissions (MTPA CO_2)	~20	~20	~30	~80
Lessor	Port of Corpus Christi	Freeport LNG	Texas	Private Landowner
Footprint (Acres)	13,000 Onshore	~500 Onshore	40,000 + Offshore	26,000 Onshore(1)
Storage Capacity (MM MT CO_2)	50 - 100+	~25	225 - 275	500+
Annual Injection Rate (MTPA CO_2)	1.0 - 1.5+	0.5 - 1.5	5.0 - 15.0	5.0 - 15.0
Estimated First Injection	Late 2026	Late 2024	Late 2025	2026
Partners	Howard Energy	Storegga	Carbonvert, Chevron	Storegga, EnLink Midstream

(1): River Bend CCS acreage additionally includes 63,000 on right of first refusal in addition to leased 26,000 acres.
Source: Talos Energy

"This whole energy transition subsector is about partnering and collaboration. There's not one single company that's best suited to do all the different pieces. So, you have to work and think across the value chain."

ROBIN FIELDER, EXECUTIVE VICE PRESIDENT OF LOW CARBON STRATEGY, CHIEF SUSTAINABIITY OFFICER, TALOS ENERGY

term and underwritten by investment grade counterparties. That's exactly what sets itself up for project-type lending.

So, we kind of keep that end in mind as we're negotiating these agreements to make sure that that's an option. The stakeholder piece is important. It's sort of early and often. One of the nice things, for instance, in partnering with the Port of Corpus Christi is they are a huge stakeholder for that region. They were able to introduce us to all of the local mayors and commissioners, and start making those introductions before we even announced we were thinking about a project last year. It was good just to have the early dialogue so no one gets surprised by a press release that we're going to go explore carbon management or CCS projects. So, when we signed the lease this year, there were no surprises.

People want to just understand what it is you're trying to do, and to let them know before they hear it in the news. Part of it's just getting the buy-in, and it's just the best way to do business. We've got folks that have worked in or even grew up or lived in these various regions. It's just approaching it with that stakeholder mindset that we're a community partner, we're a neighbor. But it's very important and part of the EPA process, frankly. If you're going to seek any Department of Energy funding, they certainly want to see your thoughts around environmental justice and what does your community engagement programs look like.

JB: Will you compare and contrast the onshore versus offshore CCS and how a lot of the things are the same, but what factors are different as well?

RF: In general, when you're drilling wells onshore, it's a little bit cheaper when you're thinking about the rigs. The availability is fairly good to drill a somewhat shallow onshore well, and you can lay a pipeline fairly easily in the states like Texas and Louisiana. Offshore is a little bit more expensive when you're thinking about the rig rates. The luxury of onshore is, when you get a nice big contiguous piece of leasehold that's not shopped up by a lot of private landowners. You've got a single landowner from the pore space through the minerals. So, you've got that luxury of working with one counterparty, building your stakeholder plan, building all of that permitting. But that's harder to find.

For offshore, we meet with the GLO (Texas General Land Office) every six months and update them on the proj-

ect. It's one entity. And you're farther away from potential communities where you have trucks driving in someone's neighborhood. We're all offshore. So, you're kind of away from that when it comes to some of the nuisance things. So, there's a plus and minus to both. We think we'll need both to be successful across the U.S. portfolio. We think there's a luxury in both. Today, the California Low Carbon Fuel Standard (emissions trading mechanism) requires an onshore solution. I think one day that could be expanded to offshore. But it comes down to cost and having a single contiguous landowner where you can put together an onshore position, but there's usually a lot of parties involved.

JB: Are you looking anywhere beyond the Gulf Coast?
RF: We've also looked very briefly at a few international projects. But what's really turned was the (U.S.) Inflation Reduction Act last year. A lot of the focus is now back on doing projects here in the States because of the incentives and the Department of Energy's willingness to fund some of these projects or lend against it through the (DOE) Loans Programs Office. The real excitement is here and the Gulf Coast has some of the best geology. So, it makes sense that that's where the focus continues to lie.

The Gulf Coast has some of the best geology for storage. You've got conventional rock. It's got really good porosity, really good permeability in these very contiguous, continuous sandstone reservoirs that are filled with water. Contrast that to shale: very low permeability and porosity, very tight formations. The (offshore) reservoirs are large. You have a lot of storage capacity, which means ability to scale these projects.

JB: I know the devil is in the details a bit. The insurance component is an obvious part. But, can you talk about why that is so critical and potentially tricky dealing with the Class VI CCS wells?
RF: Part of it is for the EPA permit. Some of it's just … large investment-grade industrial counterparties … want some assurances that if they're going to do a large investment, particularly on the capture side, they want to make sure they can get access to that tax credit. In order to have the credit, the IRS has a clawback period. For three years, you've got to ensure the CO_2 is still being permanently sequestered. They're not going to give you a credit for something that obviously didn't work. And so, we have to show and demonstrate through our monitor, reporting and verification (MRV) plan both to the EPA and the IRS that the CO_2 is still being stored in this reservoir. But then we also need to have assurances in place if something changes. And so, that's where you can have insurance products. I'd say it's still fairly immature as far as how those are developing with the market, but all the major insurance providers are working on various products right now.

JB: It almost seems like we're in a little bit of the wild, wild west for carbon capture where everybody's trying to get a piece of the funding. Talos is more advanced, so that's different. But is there a concern about some bad actors potentially giving CCS a bad name down the line?
RF: I think early on, some folks tried to compare the CCS game to the shale revolution. There were a lot of independents and private equity, in particular, going out [and] leasing up acreage, trying to develop a project and flip it. I don't think that's going to be successful long-term because of the long-term liabilities to the assurances that are required here. Your customers are, in most cases, large industrials that make a product day in and day out. They just need to know that this waste product is being taken care of. While there are a few smaller guys trying to get started and they've submitted some permits, I would bet that they're not all going to be at the same rigor that we're expecting to put together with our partners. So, I don't know how successful they'll be over the long term. Will they be able to monetize some of that acreage? Perhaps somebody can bolt on some of that, but I don't think they're going to be making it to FID [final investment decision] unless they have the right counterparty or balance sheet partner that will be willing to take that on.

JB: You're doing stratigraphic test wells. How important is it economically to have those multitask so the test wells can eventually become the CCS injection wells?
RF: So, you can reuse it? That is important. We drill these stratigraphic test wells that are data acquisition wells. We have that mindset where we're trying to have them as keeper wellbores where you can convert them to be either the injector wellbore of the future or a monitoring wellbore. And so, as we're choosing our location to drill those test wells, it's important to have that broader picture and development plan in mind. You could have kind of a throwaway well as you sometimes do in deepwater exploration, but it's not the most economic version. So, we'd like to keep it. What that does mean though is, up front, we're looking for some of the specialty metallurgy and anticorrosive pipe to run in some of these. That way, when we come back, it can handle the CO_2 in the future.

JB: Can you kind of summarize the Talos CCS strategy?
RF: This whole energy transition subsector is about partnering and collaboration. There's not one single company that's best suited to do all the different pieces. You have to work and think across the value chain. We're not a technology developer, so we need to work with the technology providers. We can be a liaison to those different EPCs or capture tech developers. I think that's the key. It's about collaborating with your stakeholders, all the government bodies. These are big infrastructure projects, so they have a lot of moving pieces and parts. And a lot of thought needs to go into all these parallel processes. So, you just have to have a lot of good collaboration. That's why sometimes it makes sense to bring in your major partner (Chevron) and lean on some of those great resources. ■

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Crescent Begins to Shine Bright After Rapid, But Quiet, Growth

CEO Jerry Ashcroft is guiding the offshore pipeline player toward carbon-neutral status by year-end.

JORDAN BLUM, EDITORIAL DIRECTOR

Despite its origins dating back nearly two decades, Crescent Midstream only entered the public spotlight less than a year ago when it began touting offshore carbon capture and storage (CCS) projects and aggressive net-zero goals for a fossil fuel company.

An offshore Gulf of Mexico and Louisiana pipeline player, Crescent is rapidly growing since its 2021 emergence from parent Crimson Midstream, which was sold along with its California pipeline assets to the CorEnergy Infrastructure Trust.

Crimson founder John Grier, who started the company in 2005, joined CorEnergy and then-veteran midstream executive Jerry Ashcroft eventually took over what is now an independent Crescent.

By the end of 2021, private equity player Carlyle Group, which first invested in Crimson in 2019, took majority ownership of Crescent just as Crescent was quickly, but quietly, growing.

Crescent acquired the Grand Isle Gathering System as part of the CorEnergy deal, and then Crescent scooped up a large minority stake in the big, Genesis Energy-operated Cameron Highway Oil Pipeline System, called CHOPS, in the Gulf.

At the time, Genesis cited the sale of the 36% stake for $418 million to an "undisclosed buyer." CHOPS primarily delivers crude from the Green Canyon area offshore Louisiana to Texas refinery hubs.

As of late 2022, Crescent was partnered with Spanish energy giant Repsol and offshore producer Cox Operating to develop a CCS hub in the Gulf of Mexico within Cox's existing leasehold.

Cox filed for bankruptcy protection in May, but Crescent contends the filing will not impact the offshore project.

The plan is for Crescent to build a 110-mile CO_2 pipeline from refining and petrochemical plants in Geismar, La., to the coastline in Grand Isle, utilizing existing Crescent pipeline rights of way.

The U.S. Department of Energy selected the project in May—providing $8.4 million in federal funding—to help demonstrate the feasibility of offshore CCS in the Gulf. The project is expected to have a capacity of 300 million metric tons (MMmt) of CO_2.

The DOE is supporting the project, officially known as the Louisiana Offshore CO_2 Hub Repurposing Infrastructure to Decrease Greenhouse Emissions—intentionally creating the "Project Lochridge" acronym—through its CarbonSAFE program.

In March, Crescent teamed up with the Well Done Foundation for carbon credits to help sponsor its work for orphaned oil well plugging and site restoration in Louisiana.

Now, the aim is for Crescent to become the first known carbon-neutral midstream company by the end of 2023 with carbon credits, while factoring in only Scope I and 2 emissions.

Ashcroft is the former CEO of EQT Midstream–now Equitrans Midstream–who left to head up the Carlyle-backed Lone Star Ports projects. Then he moved over to Crescent.

Ashcroft sat down with Hart Energy for an exclusive Q&A on his company's growth and goals.

Q&A

JORDAN BLUM: I know Crescent dates back to 2005, but you just got the Carlyle backing a few years ago. How has the growth rapidly sped up in the last few of years?

JERRY ASHCROFT: It really started out with John Grier, our founder and chairman. John saw an opportunity in the market, like many of the MLPs did, to buy assets from the integrated oils. So John bought midstream assets both in California and in the Gulf of Mexico, and kept building and growing upon that. And then, there came a time to look for other shareholders to continue that growth engine. And that's when Carlyle came in, in 2019. And so we've really had rapid growth, especially over the last three years. We've tripled our size, and it's come both through organic growth in the Gulf of Mexico where we decided to focus, and it's come from acquisitions.

JB: Can you talk about some of the acquisitions? I feel

Hart Energy

like they haven't been really publicized that much.

JA: You're right. So, we made a decision to sell our California assets to a REIT [real estate investment trust] called Cor. And with that we received the Grand Isle Gathering System, which is a crude oil pipeline system on the shelf, which was really complementary to the other assets we had. Plus, it fed into our main transmission line that we call Bonefish that runs from Empire to St. James [in Louisiana]. So that was kind of a bolt-on acquisition that we did. And then we also bought a 36% interest in CHOPS, which is the Genesis-owned deepwater pipeline, which really fit our strategy of trying to get farther into the Gulf.

That's a great team with Genesis. We've really enjoyed working with them and watching the growth of that system.

JB: It's just a matter of time before the Gulf of Mexico hits new production records, it seems.

JA: I think you're absolutely right. I think that's kind of where that energy transition piece connects with the Gulf of Mexico. It's such a low-carbon intensity to bring oil from offshore to onshore just because of how it's done compared to the Permian, for example. A lot more carbon intensity goes into pulling a barrel out of the Permian versus what it takes in the Gulf. That kind of goes into where we are in 2023. We're going to be carbon neutral. I think we're the first one in the midstream sector that can say that. We really drove our numbers down by looking at how we can run more efficient pumps and motors. How can we do vapor recovery? And then, finally, for that last part, we've bought offsets from the Well Done Foundation.

JB: Can you elaborate on that offset process?

JA: Basically, we were looking for ways to buy carbon credits in our own backyard. We talked with Ducks Unlimited and they've got a number of projects going on, and we've done work with them in the past. But a lot of times those credits were further out in the future. The Well Done Foundation is plugging old abandoned wells that have methane releases. We were able to convince them to come to Louisiana and do that. It's really a great fit for us that we can continue to be a steward of our environment there in Louisiana.

JB: So the objective is to be—by year-end—the first carbon-neutral midstream company?

JA: That's correct. Yeah, I'm really excited about it.

JB: As a private company, why is it so important to have that carbon-neutral and ESG focus?

JA: We kind of look at it from our own strategy of being a safe, reliable, compliant business. We look at this as, "we're going beyond compliance." Sometimes that comes in the form of the charity that we do, but in this case, it was for us to actually be better stewards of the environment, too. I will say that what we have seen is, we're more welcomed as a partner when it comes to getting insurance for our facilities and our pipelines. We're more welcomed as a partner when we go to banks to get debt. But I don't know whether there's a real dollar value that I could point to.

JB: Is there more of a business case longer-term with that focus?

JA: Absolutely. I just think that it's where society is going in general, right? I think we see it all the time, whether it's your own electricity bill at home and they're saying, "Well, would you like green energy?" Or whether it's recycling programs in neighborhoods. So, when we look at our own business what we can do to lower the carbon intensity, it's just the right thing.

JB: In that vein, can you talk about everything you're doing with the carbon capture focus?

JA: We've got so much momentum with what we're doing. We've got a management team and personnel with the capabilities to run safe and reliable pipelines. And we also have the strategic footprint. You've got a lot of emitters from Louisiana all along the Mississippi River. So, we're making that natural industrial logic link between the emitter and the sink. We think we really have a first-mover advantage because we already have a license to operate pipelines there in Louisiana.

JB: Apart from you and the Chevron-Talos Energy partnership, you don't hear a lot about offshore CCS yet.

JA: There's a great consortium called Carbon-Zero that we support. You've got Cox [Operating], and Repsol was brought in. They've got a lot of downhole knowledge from the geology standpoint, and Europe has really been a leader in decarbonization. Plus, we're linked up with LSU and Southern University and the University of Texas to develop this plan, and we're lucky to receive funding from the DOE CarbonSAFE [Initiative] grant plan.

JB: I know it's relatively early goings, but how do you see the timeline playing out?

JA: That's a great question. We've been working with the DOE hand-in-hand saying this would be great to have as a pilot project. I think a lot of the emitters are looking to hit goals at that 2030 stage. I think that some of the earlier projects may come in as soon as 2027. I'm thinking that you see this surge of projects between 2027 and 2030.

Cox already has the oil and gas extraction leases. The conversation with the DOE is using those for sequestration, especially since you've already got the surety bonds and legal documents done. It makes sense to me.

But we're really the one linking the emitter to the sink. When you're looking to move 2 million mt a year to offshore, you're most likely going to build new pipelines. We have the synergy of the personnel and the rights of way. So, we've got the corridors that we're able to repurpose for CO_2 pipelines.

JB: Are you seeing a lot of customer interest?

JA: I think it's really been very collaborative. When you talk to the refineries, the petchems, the power plants, it's something that's on everyone's radar screen. So, it's pretty open door coming in to talk about your project and how it may fit. I think once there's a better structure on what that permitting looks like offshore, I think that it would take off then.

JB: And can you elaborate on just how important some of the recent federal legislation has been the last couple years?

JA: The IRA [U.S. Inflation Reduction Act] was really a positive for pushing these projects forward. The $85 [per MT of CO_2] for 45Q has allowed a lot of projects that just weren't going to be able to make it economically, now to be in play. And so, now it's kind of taking those appraisals stages into better-defined stages to understand how much will the technology cost, the pipeline cost and the sequestration cost.

JB: So what are the next steps at this point?

JA: The next steps on CCS are, we'll continue to work with DOE on the CarbonSAFE study with them. We're getting a better feel for the geology, and also spending more time creating the least-disruptive right of way for the pipeline to go offshore. And then, finally coming to an agreement with an emitter for how many tonnes a year they plan to capture. And, what do those connection agreements look like?

JB: How does Crescent's growth strategy look overall?

JA: We've really had this hyper-growth mode, which we're excited about from the organic growth and the acquisitions. We want to really take that same momentum into energy transition. I think there's a couple of ways for us to do that. One is our becoming carbon neutral. I think that bodes well for us when we're seeking partners in CCS. And that's really the part two of it. We feel as though that we've got the capabilities to run CO_2 pipelines and the personnel to do that and the resources in Louisiana. We are blessed enough with the strategic footprint that actually already connects the emitters to the offshore sink. We're already in that corridor, except we're kind of reversing the flow a little bit. This is a new product that we'll be needing to safely transport.

JB: Can I get you to compare and contrast the benefits of CCS offshore versus onshore?

JA: I think the benefit onshore is that there's already a permitting process. The EPA has done a really good job in their technical reviews on being thoughtful to that. But you're more limited from a spacing standpoint, right? You've got a lot more things to take into consideration. I think offshore ends up being kind of that longer-term opportunity just because of the amount of geography that you have out there, and the lack of encumbrances that are out there on continuing to grow those saline beds for sequestration. But there isn't a process yet on how to do that offshore. So, I think that's kind of where you are. I really see onshore as possibly being step one, and offshore being step two, and that being really the growth for the Gulf Coast. If you're in the Dakotas, it may be a different point of view. ■

Foster, McIntyre: The Intersection of Corporate Sustainability and Environmental Justice

WADE FOSTER AND KRISTA MCINTYRE, STOEL RIVES LLP

Corporate sustainability, meaning the ability of a business to manage risks and opportunities to promote long-term enterprise durability and value creation, is manifesting in many organizations through ESG commitments. The guiding principles of ESG are rooted in the United Nations Global Compact (2000) and subsequent report, "Who Cares Wins" (2004). Both encourage ESG-focused leaders to create a continuous improvement cycle that places measurable goals at the center of corporate decision-making and action to mitigate enterprise risks and emphasize enterprise opportunities.

As detailed by the International Financial Reporting Standards Foundation's SASB Standards, which "guide the disclosure of financially material sustainability information by companies and their investors," relevant environment factors within the oil and gas sector may include greenhouse gas emissions, wastewater management or ecological impacts. Relevant social factors focus on human rights and community relations. Relevant governance factors may address business ethics, regulatory compliance and incident management. At the convergence of the ESG categories lies Environmental Justice (EJ) and the role of businesses in improving the lived experiences of fence-line communities.

Environmental justice

The term "environmental justice" emerged during the civil rights movement of the 1960s, when the Rev. Dr. Martin Luther King Jr. brought attention to environmental injustices borne by predominately black garbage workers at a Memphis, Tenn., sanitation facility. Later, a national study by the United Church of Christ's Commission for Racial Justice, "Toxic Wastes and Race in the United States," (1987) found a positive correlation between subjects' race and their proximity to hazardous waste sites.

Overburdened communities are not only in black and brown or urban neighborhoods. EJ is defined by the U.S. Environmental Protection Agency (EPA) as the "fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies."

Persistent gaps among communities with different lived experiences and varying access to meaningful involvement in environmental processes are the focus of recent reemphases on EJ across federal and state government. EJ is no longer only a subject of activism and academia. EJ is at the forefront of minds in the White House, state legislatures and even boardrooms.

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A display in the National Civil Rights Museum in Memphis, Tenn., commemorates the 1968 sanitation workers strike. The term "environmental justice" emerged from the civil rights movement and this strike, in particular.

Unpacking the definitions of "environmental," "justice" and "community" reveals meanings that are broader and more complex than generally understood. EJ touches nearly all aspects of society: pollution, food security, energy, disaster relief, housing access, internet access, tribal sovereignty, urban planning, socioeconomic growth, political representation, transportation, education, climate change and resiliency. EJ targets every facet of the lived experience and an individual's ability to enjoy a safe, healthy community and to access opportunity, as Seema Kakade, a law professor at the University of Maryland, wrote in her article, "Defining environmental justice communities," in the American Bar Association's "Trends" newsletter.

Tools for identifying overburdened communities include EPA's ECHO database and EJSCREEN, the Climate and Environmental Justice Screening Tool (CJEST), and the U.S. Census. No tool is perfect or complete. Additional data on health outcomes, education levels, access to healthy food and the Internet, plus language proficiency can supplement these tools and help identify EJ communities.

It's just good business

Companies are implementing EJ strategies that yield real benefits to communities and support ESG objectives. Robert Har-

ris, vice president of environmental affairs at Pacific Gas and Electric wrote that implementing environmental and social justice strategies can improve long-term business durability. In his article, "Environmental Justice is Good Business," in the American Bar Association's "Human Rights Magazine," Harris said that stakeholders, including shareholders, employees, supply (or value) chain partners, customers and community members are increasingly demanding that companies be good corporate citizens. Ahead of regulatory mandates, businesses are confronting pressure to articulate corporate sustainability principles and execute on them. Social impact assessments that include EJ evaluations are also emerging in transaction due diligence, influencing commercial dynamics.

Companies that support EJ initiatives can manifest real opportunities. In today's tight labor market, for example, nearby communities represent a potential local pool of employees that can contribute to operating innovations that reduce impacts on the surrounding area. Implementing effective strategies that improve lives within nearby communities can reinforce ESG goals, leading to diversity in a company's workforce and durable community-driven innovation.

Instead, many fence-line communities are experiencing barriers to economic advancement. Neglecting investment in disproportionately impacted communities deters growth of economic power, diminishes community welfare and slows advancement of the next generation of contributors, consumers and leaders. Ignoring environmental and social impacts on underserved communities perpetuates an unvirtuous cycle in which poor health outcomes, poverty and societal conditions repeat for generations—a cycle that is very much inconsistent with corporate sustainability.

Conclusion

As government and stakeholders urge business to narrow the disparities among communities in America, commitments to EJ can cultivate stakeholder support and fuel value creation. Weaving meaningful EJ objectives into ESG-driven business decision making will also better position a company for success when regulatory and policy changes inevitably emerge. Focusing on EJ complements ESG objectives, aligning environmental impacts, social equity and governance with community-centric investments and metrics to enhance corporate sustainability. ■

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Wood's Devil in the Details with CCS

Transporting huge volumes of CO_2, tracking impurities in the system and managing carbon systems in varied geographies—Wood's experts on how they plan to make the complicated process work.

JORDAN BLUM, EDITORIAL DIRECTOR

In a Hart Energy exclusive, Editorial Director Jordan Blum sat down with Stephen Stokes and Dale Erickson of Wood to delve into the intricate details of carbon capture projects, and how they are approaching those technical challenges as the industry scales up.

Jordan Blum: We're talking about carbon capture projects, all the money that's going into it, but the devil's in the details. So, what are the biggest technical challenges with pumping all of this CO_2 into the ground that we're talking about?

Stephen Stokes, global head of CO_2 transport and storage, Wood: There is a growing industry trend right now for economies of scale for [carbon, capture and storage] projects. And that is where multiple emitters—so power plants and manned factories, industrial users—need a home for their CO_2 emissions. And they're looking at sending that CO_2 to common infrastructure, so, a common transport pipeline. Each of those emitters is going to have a cocktail, essentially, of different impurities. Now, we control that somewhat with a specification on the pipeline and say, "Can you please reduce your impurity levels?" But at the end of the day, we're going to have a very different composition daily and with different sources of CO_2 entering the system. So, over time, we'll have a different set of components in the system, and that causes us a big challenge in CO_2 transportation.

Dale Erickson, intelligent operations technology development lead, Wood: Just think of the volume. In other words, people that drive through Pasadena [Texas], that corridor, see all those plants and just picture all those plants going into one pipeline, all those emissions. It's going to be a huge amount of emissions going into one pipeline and the mix of impurities is really going to be the interesting thing because these impurities may interact with one another.

JB: And how do digital solutions factor into all these wellbore integrity concerns? I think we're talking about a lot of thermodynamic modeling much more as well?

SS: Digital application of thermodynamic models is, we see, critical to support operations and their quests to protect integrity of their assets. What Wood is trying to do in that area is empower the operator with much more information than just physical instrumentation [by] feeding in pressure and temperature and flow into an algorithm, essentially a digital twin, which then tells them much more in terms of the conditions in the system, how those impurities are affecting the fluid that's in the system, and how that might give concerns in terms of phase split in the system, in terms of low temperatures, in terms of corrosion, and ultimately, in terms of protecting their asset.

DE: Yeah, because one of the things that's going to be potentially possible is even blending these things. It may be like a rail line that you stop some for a little while until you have something better to blend with it. It's going to be very complicated, this whole thing of tracking the impurities in the pipeline network.

And in some ways, it's possible, if you have bad impurities, they may not even let them in. There's going to be this whole business that's going to develop of what we call, basically, nominations. Just like you have [with] gas, there's going to be potentially trading and everything else that you may get charged more if you have the bad gas. So, there's a whole industry that will develop on this.

JB: You were talking about lots of flow management issues, concerns about mixing gas and liquids within the reservoirs. You were even talking about factoring in wind, rainfall. Can you elaborate a little bit just on all the different dynamics at play?

SS: The ultimate answer there is, it's complicated. It's a complex system, but it's not new. These systems that we're talking about here—digital applications to support operations in the

"CCS is complicated, as I've mentioned, and I would say in some ways more complicated than conventional hydrocarbon projects. And what we need to do as an industry is collaborate and also reduce hard basis of design between disciplines."

STEPHEN STOKES, GLOBAL HEAD OF CO_2 TRANSPORT AND STORAGE, WOOD

"Your whole project floats on your worst well, and so you need to get that balance right. Because if you don't do it right, well, some power plant may not build the storage CO_2."

DALE ERICKSON, INTELLIGENT OPERATIONS TECHNOLOGY DEVELOPMENT LEAD, WOOD

conventional hydrocarbon industry—[are] a common practice.

With CO_2, it gets more complicated. The complex system becomes even more complicated because we have what we like to call a very narrow phase envelope. What that means is we need to rely on numerically stable and accurate simulations to tell us what phase we have in the system. Do we have gas CO_2, do we have dense phase CO_2, liquid CO_2, or do we have a combination? And if we have that combination, then we have to understand what the implications are. We can get not really slugging, like we would refer to in the conventional hydrocarbon space, [but] more intermittent flow. It causes cycling, it causes dynamic loads, axial loads.

DE: The other thing that makes CO_2 a challenge, its critical point is about 80 F. And so, as you move across that phase boundary, you literally can get a 10X change in density. It's a lot less dense on the gas side than the liquid, and most fluids aren't like that, conventional oil and gas. So, you can have these huge changes. And that just, as [Stokes] was indicating, [makes] the slugging worse and the behavior in the wells worse.

JB: And this is a global challenge, too. I mean, we're talking about all different kinds of geographies, the U.S. Gulf Coast, Canadian oil sands, the Persian Gulf. Can you elaborate on all those different factors, the need to do everything on a global scale?

SS: I'm lucky in my role to have a global remit. I see projects in every continent, essentially. And we see them in the onshore environment, the offshore environment. Some of the interesting work we've done is on depressurization. So, if we have to do maintenance in the system, we have to go from pressure to ambient pressure to allow access and intervention. If we've got a project in the Middle East, very dry sand, that system's going to behave completely differently to something in Canada, in Alberta, for example, where it's very cold, and it's going to behave very differently to something in the North Sea where it's covered in seawater and cold, but with very high heat transfer. We see very different behavior in very different regions. And it's a great question because that does need expertise to understand how the system's going to behave.

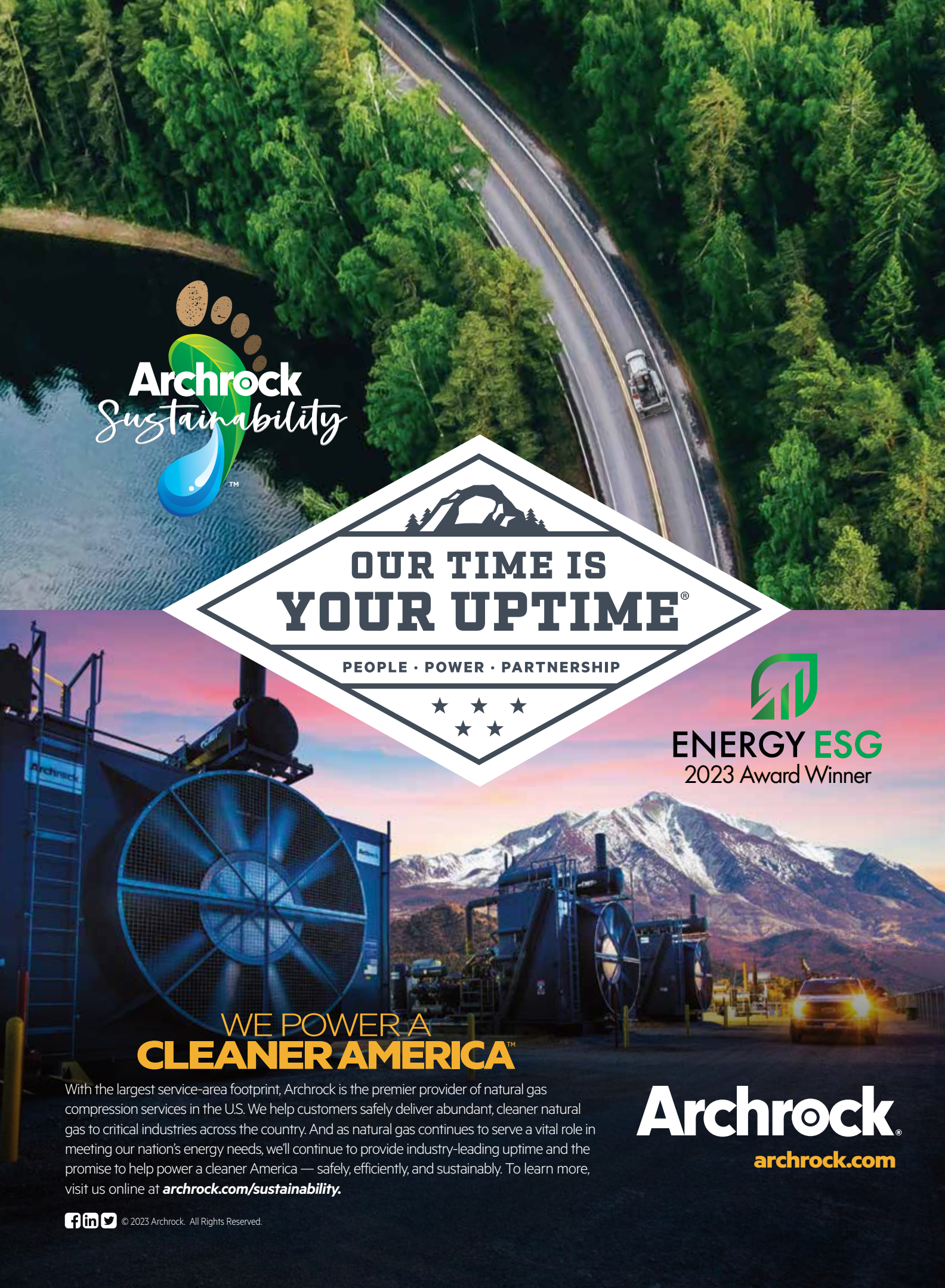
DE: People are also talking about transporting CO_2, not just in pipelines, but on rail cars. We've looked at some projects there. There are projects where they're looking at shipping. Because again, CO_2 is potentially generated and there's no storage in some locations, so they're going to have to transport it the most efficient way possible where they have the good reservoir.

JB: I know Wood recently announced a new partnership with CMG, the Computer Modelling Group. Can you touch a little bit on just what that'll entail, how important that'll factor into everything?

SS: CCS is complicated, as I've mentioned, and I would say in some ways more complicated than conventional hydrocarbon projects. And what we need to do as an industry is collaborate and also reduce hard basis of design between disciplines. So, where we do pipeline work in isolation, generate a document and then subsurface [has] to interpret that, and vice versa as well, we have to interpret that. What we're trying to do is create soft boundaries between disciplines. So, an end-to-end solution. And Wood, I should mention, do[es] carbon capture, carbon compression, dehydration. Now, we do reservoir engineering through our CMG partnership. We have an end-to-end CCS solution which is a very powerful offering and a very important offering in an industry that really needs that seamless integration between project components.

DE: Yes, because, again, the thing you have to remember is, unlike oil and gas where you just pull it out of the ground, you have to put this CO_2 down there and keep it there thousands of years. That's partly the thing that these reservoir engineers do, is look at the long-term stability of storing the CO_2. It's very important.

The other thing is the number of wells you need. In other words, your whole project floats on your worst well, and so you need to get that balance right. Because if you don't do it right, well, some power plant may not build the storage CO_2. In other words, it's getting that whole balance right. And in conventional engineering, if you're off a well or if you have a crappy well, it's not so bad, you live with it. But here, if you're very tight, it may be a problem. So, that's very critical to get all that correct. ■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Critical Challenges with Critical Minerals

China has pushed aggressively to secure critical minerals around the globe—can U.S. legislators address production and supply chain issues?

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China's relentless global pursuit of critical minerals, especially in places where the U.S. lacks a presence, means the U.S. must strengthen its supply chains at home and abroad.

This is according to panelists speaking at an event by the Aspen Institute's Energy and Environment Program, which released a report this year with recommendations to help policymakers address critical minerals challenges.

"We need to up the profile of metals and minerals and develop strategic pathways for protecting these supply chains that we need," said Melanie Kenderdine, principal and executive vice president of the Energy Futures Initiative, a Washington D.C.-based nonprofit focused on technology and policy innovation to accelerate the clean energy transition. "We are never going to have all of the supplies of metals and minerals that we need in the United States."

Stressing the importance of ongoing discussions with allies and trading partners—including China—as recommended in the Aspen Institute report, Kenderdine shared how she noticed China's footprint years ago on a trip to Rwanda.

Since then, China—which dominates the global market for processing and refining critical minerals such as cobalt, lithium and rare earths—has purchased lithium mines in Australia, South America and parts of Africa. "They are aggressively, smartly pursuing some of the things that they know we're going to need.… We need to be very, very mindful of their activities. We need to be very mindful that we are a major customer of theirs and at the same time, where we can, do what we can to meet some of the metals and minerals needs that we have for a clean energy transition."

Critical minerals are essential for clean energy technologies—such as energy storage and wind turbines—expected to play a pivotal role in the transition to a lower carbon economy. The report showed that the U.S. imported more than half of its consumption of over 51 different minerals in 2022. The country relied 100% on imports of 15 of these minerals, including natural graphite, a heat-resistant material used in solar panel and lithium-ion batteries, and manganese, which is also used to make batteries.

Critical minerals recommendations

The U.S. unveiled a strategy to address the critical minerals challenge during the Trump administration, and efforts to secure the supply chain have continued during the Biden administration.

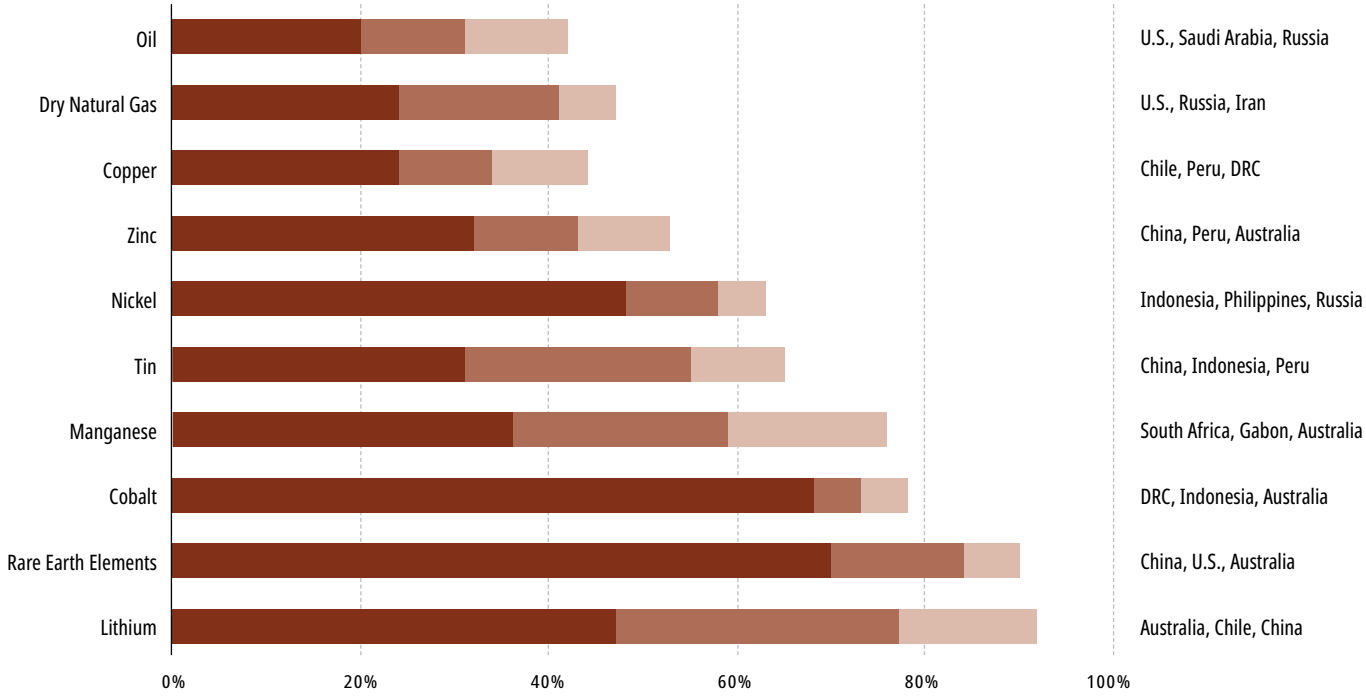
Still, "critical minerals require urgent attention from policymakers" not only because of their role in the climate and economy but also for national security interests. Demand is rising, supply chains are fragile and supplies are heavily geographically concentrated, the Aspen Institute said in its report.

Congress should focus on two objectives: responsibly [increasing] domestic and global production and processing of critical minerals at scale, and securing "responsible and resilient critical mineral supply chains that minimize vulnerability to external risks," according to Aspen.

Recommendations, which resulted from a

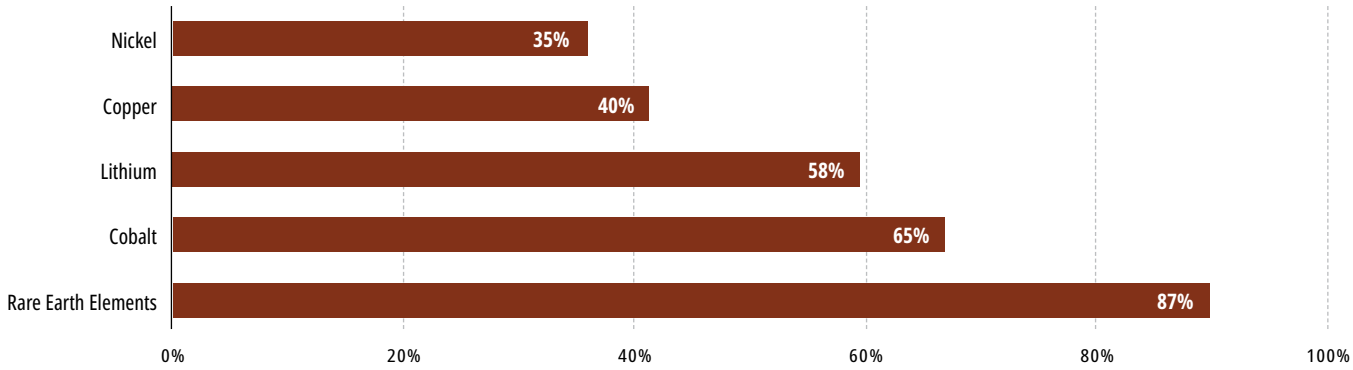
MARKET SHARE OF TOP THREE PRODUCERS

(OIL AND DRY NATURAL GAS IN 2021, MINERALS IN 2022)



Sources: USGS and EIA

CHINA'S MARKET SHARE IN TOTAL PROCESSING OF SELECTED MINERALS, 2019



Source: EIA

While the U.S. leads in oil and dry natural gas production, most critical minerals are produced in other countries and have to be imported. The U.S. relies entirely on imports for some minerals. For other key minerals, such as rare earth elements, the vast majority are produced by China, whose trade relationship with the U.S. is on nebulous grounds due to increased tension over Taiwan and China's activities in the South China Sea.

task force of experts who met in 2022 and 2023, centered on developing the "domestic foundation for more responsible and resilient supply chains" and maximizing "connections with strategic exporting and importing countries."

Meghan O'Sullivan, co-chair of the Aspen Institute and former deputy national security advisor under President George W. Bush, pointed out that permitting reform, addressing both supply and demand, and having a just and equitable development of resources in the U.S. were prominent in discussions.

"Even under the best circumstances, the United States would not be able to meet all of its needs by itself. And so, we urge Congress not to become too enamored with the Buy American provisions," O'Sullivan said. "Instead, we urge Congress to really focus on working with friends and allies and other partners around the world to agree on a common set of clearly defined environmental, social and governance standards for the production and processing of minerals."

Eyeing areas with abundant metals and minerals, Kenderdine honed in on countries not currently exporting to the U.S. She said the U.S. could develop bilateral relationships with countries that include Bolivia, Chile, Kahzakstan, Laos, Madagascar, Mozambique, Tanzania and Ukraine, among others.

China's dominance covers the entire value chain. It produces about 70% of mined rare earth elements globally, controls nearly 90% of separation and about just as much of metallization and magnet production in the rare earth element supply chain.

"This dominance takes on additional significance since the United States relies on imports for all of its refined rare earth elements.… China is aware of its leverage," the report stated,

Processing plant at a lithium mine. The U.S. imported more than half of its consumption of over 51 different minerals in 2022.

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"and the government has signaled strategic intent to wield rare earth elements as an economic and geopolitical tool, as it did when it restricted exports of rare earth elements to Japan in 2010 following a diplomatic dispute."

Addressing tech, community concerns

Technology innovation is also part of the equation. Experts suggested Congress take steps to reduce demand for critical minerals by encouraging investment in technology and recycling.

"Substitutions are also incredible," said Rich Powell, CEO of ClearPath, which develops policies aimed at advancing emissions reduction technology.

Form Energy is among the companies behind such technology. The energy storage company developed a rechargeable iron-air battery technology that it says can deliver electricity for 100 hours and at less than one-tenth of the cost of lithium-ion.

"That's an entirely new battery chemistry that switches from a critical mineral like lithium to earth abundant minerals like air and iron, one of the most abundant minerals on the planet," Powell said. "That's the kind of break we might see through further investments in innovation, substitution."

Addressing community concerns is also critical, according to the experts.

The report recommends Congress "clarify and endorse the concept of Free, Prior and Informed Consent, making clear that it should be received from Tribal Nations directly impacted by critical minerals development." The concept involves obtaining consent from Indigenous Peoples for activities that take place on their land.

Heidi Heitkamp, former U.S. senator and panelist, shared her experience in working with tribal nations in North Dakota.

"I think that the question is how likely is it that we're going to get a reset, especially with indigenous populations, because the history's not good," Heitkamp said, going back to colonization before referring to Black Hills. "No one had any interests until they found gold and literally violated the Laramie Treaty. People don't want to hear that, but that's the truth. What about today would tell anyone that would soon be different tomorrow?"

Though not directly related to the critical minerals' discussion, Heitkamp brought up challenges associated with plans to site a CO_2 pipeline coming from ethanol plants into North Dakota.

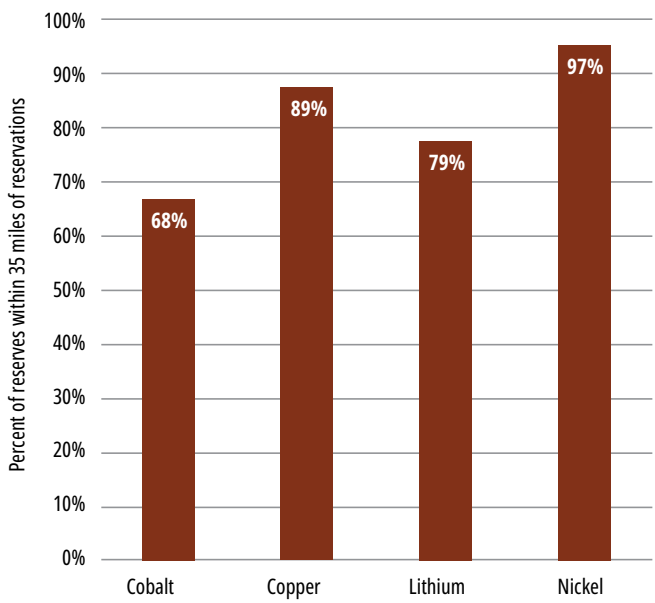
"The pipeline is being stopped by communities all along the path," she said.

Heitkamp added, "We've got to have a realistic conversation about the societal impacts of this transition."

Such conversations must be had if the U.S. is actually going to develop its own mineral resources. "We haven't even talked about the environmental impact," she added, referring to the impacts of extracting iron ore. The Iron Range in Minnesota, where taconite can be found, is also the site of conflict where the community fears tourism loss and other economic impacts.

"I think we go a long way in this report to acknowledge the past, because you cannot fix this without [an] acknowledgment of the past and reparations for the past. That's the dirty little secret here," Heitkamp said. "The second thing that you have to do is you have to build trust." OGI

Percent of U.S. Critical Mineral Reserves Within 35 Miles of Native American Reservations, 2021



Source: MSCI

U.S. CRITICAL MINERALS RECOMMENDATIONS

Develop the domestic foundation for more responsible and resilient supply chains

1

Permitting
Congress should streamline permitting by using a place-based approach and setting strict timelines on adjudication.

2

Free, Prior, and Informed Consent
Congress should clarify and endorse the concept of Free, Prior, and Informed Consent, making clear that it should be received from Tribal Nations directly impacted by critical minerals development.

3

Project Equity
Congress should endorse and further facilitate the ability of Tribal Nations to obtain equity in critical mineral projects.

4

Strategic Stockpile
Congress should continue to increase funding for the National Defense Stockpile, enabling it to effectively fulfill its mandate for defense and security.

5

Innovation
Congress should expand funding for R&D and undertake regulatory reform to promote substitution of alternatives, demand reduction, and recycling of critical minerals.

6

Workforce
Congress should implement a grant program for accredited mining programs in the United States and should earmark a certain proportion of funds for recruitment initiatives.

Maximize connections with strategic exporting and importing countries

7

Collaboration
Congress should resist reliance on Buy America provisions when crafting legislation related to critical minerals and seek to develop alternative international agreements to meet domestic needs.

8

Standards
Congress should work with federal agencies and international allies to establish clear standards for foreign mining projects that qualify for support.

9

Finance
Congress should increase funding for the Development Finance Corporation and provide it with an expanded authority, and priority, to invest in critical mineral projects abroad that meet—or can, with U.S. support, meet approved standards.

10

Trade
Congress should facilitate bilateral and multilateral frameworks that increase coordination of critical mineral supply chains and support the negotiation and passage of bilateral and multilateral trade agreements among countries that meet approved standards.

11

Information
Congress should help establish and fund a structure to improve demand projections and increase price transparency.

The Aspen Institute's Energy and Environment Program released a report in June making recommendations to help U.S. policymakers address challenges to protecting supply chains of critical minerals and metals essential to the energy transition.

Source: Aspen Institute

Hydrogen's Chicken, Egg Quandary Has Financers Flying the Coop

Though FIDs are slow going for hydrogen as the industry awaits clarity on incentives, some early investors are moving forward anyway.

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In hydrogen financing, there are plenty of chicken and egg paradoxes, chiefly surrounding demand and making offtake agreements. But bringing home the bacon may be the most vexing problem.

Few dollars are being put into actual projects in the U.S., according to a panel of experts speaking on financing in the hydrogen sector.

"Everyone talks about investing in hydrogen and very few people actually do it outside of big strategics and some technology plays like electrolyzers [and] fuel cells," Sean Shafer, managing partner for Energy & Industrial Advisory Partners, said during the Hydrogen Technology Expo North America conference in Houston.

The refrain is familiar, added Brian Hodges, a partner with Aurum Capital Connect.

"It's too early. It's too small. We don't have all the pieces in place yet," he said. "But there is a gigantic pool of capital out there, whether it's traditional banks, financial institutions. You've got sovereign wealth funds. Literally, everyone and their dog is interested in this space. But it's just that. We see a lot of MoUs [memorandum of understanding] getting signed. …We're on the cusp or right there, [but] there aren't massive amount of dollars flowing into the space."

Hydrogen backers are banking on it to help decarbonize a fossil-fuel dependent society. Hydrogen's flexibility and near-zero greenhouse-gas (GHG) emissions make it one of the must-haves to hit net-zero targets. Hydrogen can be used for energy storage, for feedstock and as fuel.

But, despite its potential and a slew of government incentives, demand uncertainty and need for more offtake agreements have slowed growth. Risks at the moment are plentiful, experts say.

The game changer, at least in the U.S., could come when federal guidance is released on the 45V tax credit, said Tanya Peacock, managing director for EcoEngineers, an energy transition firm. The production tax credit (PTC) awards up to $3/kg of hydrogen produced for projects with GHG emissions intensity of less than 0.45 kg of CO_2 per kilogram of hydrogen. The rules are not set yet, and the carbon intensity of upstream inputs could impact the pace of development.

Waiting three or four years for a new wind or solar project to be connected to the grid before even starting to finance a hydrogen project pushes into the PTC time frame, she said.

Policy is not the only holdup; there is also uncertainty brought on by politics, said Roxana Bekemohammadi, founder and executive director of the US Hydrogen Alliance.

Everyone is not on the same page, and politicians have their own agendas, she said.

That may or may not bode well for an industry that had a single-year infusion of $22.5 billion from the federal government alone—by her estimates—while not knowing what the future holds. And hydrogen is being met with opposition from some environmentalists.

Assessing risks

The biggest factor impacting hydrogen is offtake, Shafer said, adding infrastructure funds want to see five- or 10-year contracts with creditworthy offtakers.

"There's just not really the volume of demand to justify those and/or the people who are going to buy the hydrogen are not creditworthy," he said. "So that's a huge kind of chicken-and-egg problem that I don't know exactly how we crack."

The material handling and transport segments, along with existing gray hydrogen users, could fuel demand for green hydrogen, Shafer said. That includes basic needs such as forklifts and transport, he said, adding, "everyone is chasing mobility," but hydrogen fleets won't be adopted without consistent hydrogen supplies.

Another chicken-and-egg type of problem involves debt. Debt providers that underwrite debt hydrogen projects are considering it but not yet acting, he said.

Plus, "there seems to be a lack of middle capital to get smaller companies to get their projects more baked, where they can have the creditworthy offtakers … and write the big checks," Shafer said. "One of the reasons is, they're worried about losing all their capital: There's no downside protection right now in the industry."

By the end of January 2023, the hydrogen industry had announced plans for more than 1,000 large-scale projects—more than 1 gigawatts (GW), Hydrogen Council data show. The announced projects require direct investments of more than $320 billion through 2030. Only $29 billion has passed final investment decision (FID).

Costs are another concern, particularly for green hydrogen. Offtakers could be locking themselves into a "green premium," paying more

Velda Addison/Hart Energy

Center for Houston's Future CEO Brett Perlman (far left) moderates a session featuring Aurum Capital Connect's Brian Hodges, EcoEngineers' Tanya Peacock, US Hydrogen Alliance's Roxana Bekemohammadi and Energy & Industrial Partners' Sean Shafer at the Hydrogen Technology Conference in Houston.

today when cheaper alternatives exist.

"Unless they've got an ESG mandate that their shareholders are dictating, 'No, we don't care about the profits as much as we do about the mandate,' ... You've got some companies that are going ahead with that leap of faith, making the assumption that costs will come down, which they will," Hodges said.

He agreed offtake agreement and offtakers' creditworthiness are among the challenges for hydrogen's bankability.

"If you're not an Exxon Mobil, a large integrated, publicly traded company with a multi-hundred billion-dollar balance sheet, it's a 'no, thank you,'" Hodges said. "But that's where you see these policy initiatives stepping up. The DOE [Department of Energy] has been very active in financing some of these projects to the tune of multiple hundreds of millions of dollars per project."

Looking up, facing resistance

Utilities could be the stable, long-term offtaker the industry needs, Peacock said.

Utilities entered long-term, high-price contracts in California, she said, referring to the state's renewable portfolio standards. Contracts for renewables advance those energy sources with procurement requirements for California's load-serving entities. A similar arrangement could help hydrogen.

"These were even 20- and 30-year [renewables] contracts. We're only talking about 10-year contracts" for hydrogen offtake, she said.

The rule helped commercialize the wind and solar industries and brought prices down, she said. Hydrogen could follow a similar path.

"California has a renewable gas standard, which is similar to the renewable portfolio standard in a way, because it requires the gas utilities to buy increasing amounts of, right now, it's biomethane," Peacock said. "But the intention is that it includes hydrogen down the line," providing an opportunity for utilities to become that "stable offtaker with a strong balance sheet to de-risk some of the projects."

Politics, however, often get in the way of policy—even within the same political party.

"Essentially, we could show the science, we could show the economic impact, the job creation numbers, and we could probably get some policies through," Bekemohammadi said. "This year, it's been quite difficult, especially during midyear, for us in the legislative sessions because the environmental community is attacking hydrogen very strongly. Right now, definitely, there is no room for logic."

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Hydrogen energy project in Australia.

She added that some Democrats can't be convinced to support hydrogen, including at the state level. That could impact hydrogen hubs. "They actually can have a hydrogen hub that's being developed and encouraged by DOE, but then they're running state policies that are not supportive [and], if anything, detrimental to any hydrogen activity … I don't know how the industry moves forward until these policies are harmonized."

Who's investing?

Though FIDs are slow going for hydrogen as the industry awaits clarity on incentives, early investors are moving forward.

Large corporates, especially those with large venture arms, are the most active, Hodges said. He recalled how Airbus Ventures invested in Universal Hydrogen. American Airlines and JetBlue Ventures followed. That follow-the-leader mentality isn't necessarily a bad thing.

"But having the big corporates putting their money where their mouth is—not just because of the ESG mandates, but because it makes sense for their business, I think that's a good thing," Hodges said.

Early stage, pure-play startups that haven't passed proof of concept are getting funded by friends and family, he said, before institutional investors come in at Series A and Series B. Firms like Temesek and BlackRock pull together decarbonization partners, he added.

"There's a number of these funds out there. There are coalitions of like-minded investors that have a shared vision … That said, have they deployed a lot of capital? No," Hodges said, "but there are absolutely instances where that's happened," often where there is a creditworthy offtaker and a clear path toward cash flow and revenue.

Deals are getting done, especially on the technology side with electrolyzers and fuel cells, for example, Shafer added.

The investors include long-time energy players.

What's missing, Shafer said, is capital for the developer who needs, say, $5 million or $10 million to make the project attractive enough for an infrastructure fund to invest hundreds of millions more.

"The problem is, and I tell this to infrastructure funds every day, if you keep waiting for that project to get so big, it's not going to exist because either the guy is going to go bankrupt or Exxon Mobil is going to swoop in and take it off of you," he said. "If you go ask Exxon Mobil, 'hey, you want to invest with us?,' outside of very rare circumstances, they're going to say 'why? we don't need you. Yeah, we'll go invest with Chevron, not you,' because they have a much lower cost of capital than an institutional investor." OGJ

Nabors Launches Second Energy Transition SPAC

Nabors intends to raise $300 million with a proposed blank check company, or SPAC—its second of 2023.

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Nabors Industries is taking part of its energy transition effort to the public market with the launch of its second special purpose acquisition company (SPAC) this year.

The new SPAC will aim to raise $300 million, which it will use to buy out companies that specialize in alternative energy, energy storage, emissions reduction and carbon capture, utilization and sequestration, as well as other energy transition businesses, according to Nabors' June regulatory filing.

Nabors began making startup venture investments in recent years, based on the theory that the firm's wide-ranging expertise, coupled with its global footprint, would help emerging, innovative companies to scale up and "expedite their penetration into what we see as probably one of the largest macro investment business [events] in history," said Guillermo Sierra, Nabors' vice president for strategic initiatives—energy transition.

"The energy transition is expected to still be somewhere in the order of $300 trillion of capital being spent over the next several decades into it, making it literally the largest reallocation of capital in human history," Sierra told Hart Energy in an exclusive interview. "Bridging that gap requires an inordinate amount of large-scale deployment of new ideas and new technologies. We have focused on those technologies and ideas that we have something of value to add."

In its prospectus filing with the U.S. Securities and Exchange Commission, Nabors said the SPAC, Nabors Energy Transition Corp. II, will raise the $300 million through the sale of 30 million units. Each unit consists of one Class A ordinary share and one-half of one warrant. Each whole warrant entitles the holder to purchase one Class A ordinary share at a price of $11.50/share.

Nabors intends to list the SPAC units and shares on the Nasdaq Global Market under the ticker symbol "NETDU." If the securities are approved, the company expects trading to begin on the 52nd day following the prospectus.

In February, Nabors' first SPAC, Nabors Energy Transition Corp., signed an agreement to merge with Australia-based Vast Solar. The combined entity will be renamed Vast and will trade on the New York Stock Exchange under the ticker symbol "VSTE."

"The market has been fickle. Part of the reason why is because an overwhelming majority of SPACs were, and I'm really not underrepresenting this, three dudes and a laptop and $8 million. We are not that."

—Guillermo Sierra, *vice president for strategic initiatives—energy transition, Nabors Industries*

The use of SPACs, also called "blank check" companies, has gained popularity in recent years within the energy industry and shown mixed results. The model is designed to create a public market presence in which a sponsor—the investors that own the SPAC—can raise money to acquire a particular kind of company within a specific time frame, usually between 18 months and two years.

Nabors has operated as various entities for more than 100 years. Since the late 1980s, the firm has grown into one of the global drilling sector's largest contractors.

That's a big part of the difference between Nabors and the sponsors of other SPACs that failed, Sierra said.

Vast, the company that resulted from Nabors' first SPAC, filled a need and hit the public market at an attractive price.

"The proof is in the pudding," Sierra said.

Still, he said, it has been a challenge to launch a SPAC in recent years.

"The market has been fickle. Part of the reason why is because an overwhelming majority of SPACs were, and I'm really not underrepresenting this, three dudes and a laptop and $8 million," Sierra said. "We are not that. We are not in the stock market because we want to flip or take financial economic immediate benefit out of the value of the structure. We are here in this market because it's another tool for us to invest beyond our traditional means." OGI

Romito: ISSB Celebrates a Little Too Soon

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In late June, the International Sustainability Standards Board (ISSB) officially launched its first two standards. The intent of these new standards, which will be broadened over the next 12 months, is to "establish a globally common and comprehensive language for sustainability disclosure, as well as underlining the strong connection between economics and climate."

The formal release of the standards coincided with the ISSB ringing the opening bell at the London Stock Exchange where Emmanuel Faber, the ISSB chair, proclaimed, "today is a great day for the reconnection of global finance with the living world."

Given the prolific number of self-congratulatory superlatives flung loosely around social media, it may be prudent for ISSB proponents to pump the brakes on this "momentous" occasion and objectively ask what was really achieved. Unfortunately, the answer is nothing material. Yes, on a superficial level, it makes for a catchy headline, but in terms of measurable substance, the ISSB pronouncement achieves nothing except further solidifying a rhetoric-laced echo chamber and placing additional burdens upon those who can least afford it. This supposed feat adds yet another tier of reporting to the already messy ESG disclosure lasagna that currently plagues the global capital markets.

When you peel away the self-praise, ISSB's directive is more about winning control of the ESG framework arms race rather than incentivizing the creation of functional technologies required to decarbonize. Jockeying for reporting supremacy is resulting in a variety of unintended consequences, which ultimately impede the long-term health of the global capital markets. To be fair, the ISSB is not the only group guilty of publishing immaterial announcements. Incorporating yet another layer of ESG-focused reporting mandates will not deliver an improved environmental, social or governance construct. It also will not enhance returns, expedite functional innovation, or make energy any more affordable, accessible or reliable.

The S&P 1500 is generally considered the most efficient measure of the U.S. equity market because it aggregates roughly 90% of U.S. listed equities. The top 10 holdings comprise nearly 30% of the weight within the index and the median market capitalization is approximately $4.3 billion, implying most of the liquid U.S. equity market is comprised of small and midcap companies.

Winning incremental long-term capital was already a rigid dogfight before the onslaught of ESG-related reporting directives. The collective goal should center on how to best reward the management teams whose functional technologies consistently result in excess alpha.

There exists zero correlation between excess alpha and framework completion, and the energy transition must prioritize capital discipline and returns to facilitate consistent reinvestment. By continually changing eligibility rules in the capital markets and allowing ESG-focused disclosures and biased ratings to disproportionately dictate access to capital, we are burdening smaller corporates with a laundry list of immaterial constraints that adversely impact the health of the public markets. Why are there roughly 30% fewer U.S. publicly traded companies today compared to 2000? In part, the answer centers on the degree of regulatory burden we continually embed in the capital markets.

Empirical data analyzed in the "2023 Statistical Review of World Energy," published by the Energy Institute, notes that record increases in solar and wind installations in 2022 failed to cut into the share of fossil fuels makeup in the global energy mix. Global emissions also rose again despite the record growth of solar and wind capacity. The capital markets want to decarbonize, but they do not want to do so at the expense of reliable and affordable energy. Adding a new framework solves the symptoms but not the virus. In other words, added reporting does not facilitate enhanced efficiency or augment the number of publicly traded companies needed to foster effective competition.

The long-term innovative capabilities of the global capital markets are heavily reliant on small and mid-cap companies. While we must hold management teams and boards accountable for their long-term strategy, we should also alleviate them from the needless constraints which impede their ability to compete, grow and innovate. Groups like the ISSB should pause on the social media barrage while we collectively figure out how to reverse the trend of public company contraction, and reprioritize innovation, capital discipline and alpha over new ESG questionnaires.

Capital markets players can and should revert to the basics. The current state of the capital markets convinces corporates not to go public. Reasonable ESG disclosure can assist in establishing a valuation premium, but we must also acknowledge that capital is finite and increasingly more expensive. Companies should be afforded the right to self-appoint a set of non-fundamental disclosures which validates valuation premium and not fall prey to what a set of index funds superficially

Transition in Focus

ENERGY STORAGE

Canada Unveils Billions in Incentives for EV, Battery Projects

Canada has agreed to dole out up to C$15 billion (US$11.3 billion) in performance incentives to the Stellantis-LG Energy Solutions (LGES) joint venture in support of electric vehicle and battery projects the companies are building in Ontario.

The move, made jointly by the governments of Canada and Ontario, incentivizes the automakers to make Canada home to its projects amid competition from the U.S. The subsidies were offered as Canada aims to strengthen its auto manufacturing sector while transitioning to low-carbon energy sources.

The agreement is similar to the previously announced deal with Volkswagen Group for up to C$13 billion (US$9.8 billion) in performance incentives for a battery plant the company plans to build in North America.

"As part of the auto pact for those two deals agreed on by both governments, the federal government will provide two-thirds of funding and Ontario will provide one-third of funding, for these two projects, as a direct response to incentives offered by the U.S. government," the Canada and Ontario governments said in a joint statement. "These performance incentives are contingent on, and proportionate to, the production and sale of batteries from each project, and should the incentives offered under the U.S. IRA [Inflation Reduction Act] be reduced or canceled, so would the performance incentives under the agreement."

In addition to creating jobs, the incentives will help strengthen the EV supply chain and related sectors, the governments said.

HYDROGEN

DOE Plans to Invest Up to $1B to Spur Clean Hydrogen Demand

Hydrogen players voiced concern about the lack of demand incentives to give the sector a boost, and the U.S. Department of Energy (DOE) responded with plans to invest up to $1 billion in subsidies to encourage the use of clean hydrogen.

The DOE's notice of intent (NOI) and request for information (RFI) comes as part of the regional Clean Hydrogen Hubs (H2Hubs) initiative, which includes up to $7 billion—funded through the Bipartisan Infrastructure Law—to establish six to 10 regional hubs across the U.S. The latest effort aims to give producers and end users in the H2Hubs market certainty to unlock private investment.

The NOI is looking for the best way to engage the private sector in driving demand—seeking potential benefits and risks, operating models, governance structures and equipped implementing partners. The DOE said it will also take into consideration dialogue from the energy industry, investment firms, nonprofit groups, non-governmental organizations and public response from the demand-side RFI issued last year.

Demand-side support for clean energy commercialization could include "direct procurement through a request for proposal or reverse auction; advanced market commitments; and guaranteed price floors," according to the Office of Clean Energy Demonstrations.

The demand-side support mechanism could also include pay-for-delivery contracts, offtake backstops, feasibility funding to support analysis by off-takers or other measures that strengthen demand for clean hydrogen and increase revenue certainty for H2Hubs.

SOLAR

First Solar Lands $1B Revolving Credit Facility

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First Solar plans to add about 8 GW of new capacity through 2026.

U.S.-based solar panel manufacturer First Solar has entered a five-year revolving credit and guarantee facility for $1 billion.

First Solar plans to add about 8 GW of new capacity through 2026. The addition will boost its global manufacturing footprint of more than 20 GW.

"This agreement underscores First Solar's bankability and is underpinned by the strong fundamentals that drive our business today," First Solar CEO Mark Widmar said in the release. "We are focused on exiting this decade in a stronger position than we entered it and liquidity is a crucial differentiator that we intend to maintain. This revolving credit facility provides us the financial headroom and flexibility we need, while also balancing our ability to grow in response to demand for our technology."

J.P. Morgan Chase Bank acted as lead arranger and administrative agent for the facility, which includes up to $250 million available for the issuance of letters of credit, according to a news release. Other participating banks include Joint Lead Arrangers Bank of America, Citibank, Credit Agricole CIB, and PNC Bank, and lenders BNP Paribas, Goldman Sachs Bank USA, HSBC Bank USA, MUFG Bank, Standard Chartered Bank and Truist Bank.

SolarBank Invests in Photovoltaic Developer

SolarBank Corp. acquired an aggregate of 42,500 limited partnership units of the Solar Flow-Through 2016-I Limited Partnership, which is part of the Solar Flow Through Funds (SFF) group, for a total purchase price of about $2.5 million, the company announced in a July 10 press release.

SFF is a renewable and clean energy project developer and operator in Canada developing solar photovoltaic power generations.

In undertaking this transaction, SFF is aiming to consolidate its existing limited partnerships into a single corporate entity in order to obtain a listing on a stock exchange either by way of a direct listing or a business combination with a publicly listed company.

SolarBank and SFF have an existing, long-term relationship with a number of SFF solar power projects. SolarBank recently submitted proposals on SFF's behalf to the province of Ontario, Canada. As a result, SFF and its co-investors received 60 MWh of battery energy storage contracts from the province.

SolarBank is an independent renewable and clean energy company based in Canada and the U.S. Like SolarBank, SFF is also an independent renewable and clean energy company based in Canada engaged in solar photovoltaic generation.

WIND

US Gives Green Light to Ocean Wind 1 Project Off NJ

Construction plans for the 1.1-GW Ocean Wind 1 project being developed by Ørsted have been approved by the Bureau of Ocean Energy Management (BOEM), paving the way for the nation's third commercial-scale wind project in federal water.

Located offshore New Jersey, the project is estimated to produce enough clean electricity to power more than 380,000 homes, BOEM said Ørsted plans to construct up to 98 wind turbines and up to three offshore stations about 13 nautical miles southeast of Atlantic City.

"Ocean Wind 1 represents another significant step forward for the offshore wind industry in the United States," BOEM Director Elizabeth Klein said in a statement. "The project's approval demonstrates the federal government's commitment to developing clean energy and fighting climate change and is a testament to the state of New Jersey's leadership in supporting sustainable sources of energy and economic development for coastal communities."

Approval of the project's plan for construction and operations came amid U.S. efforts to develop 30 GW of offshore wind capacity by 2030. Ocean Wind 1 will become the third large-scale wind project being developed offshore, following Vineyard Wind offshore Massachusetts and South Fork Wind offshore Rhode Island and New York.

Commercial operations are scheduled to start in 2025.

BP, TotalEnergies Victorious in $14B Wind Auction Offshore Germany

Germany's offshore wind journey started a new chapter in mid-July as the country's regulator named energy giants BP and TotalEnergies as top bidders in an auction that brought in €12.6 billion (US$14 billion).

The winning bids mark both companies' entry to the German offshore wind market amid a push toward development of lower-carbon energy resources.

Four sites were up for grabs—three in the North Sea and one in Baltic Sea—with a total combine volume of 7 gigawatts (GW), according to German energy regulator Bundesnetzagentur. The auction, which utilized a dynamic bidding process for the first time after several zero cents per kilowatt hour (kWh) were submitted, took place as German targets 30 GW of offshore wind capacity by 2030.

"The results confirm the attractiveness of investing in offshore wind energy in Germany," said Klaus Müller, president of the Bundesnetzagentur. "Competition in offshore wind power has never been so high."

BP landed rights to develop two sites, with winning bids of €1.83mn/MW for site N-11.1 in the North Sea and a bid of €1.56mn/MW for another site in the North Sea. Located in water depths of about 40 m, the sites have combined generating capacity of 4 GW. Total bids for BP were about €$6.7 billion.

TotalEnergies was awarded two concessions: a 200-sq-km site in the North Sea capable of producing 2 GW of electricity and a 100-sq-km, 1-GW site in the Baltic Sea with a 1-GW potential. Together, the wind farms will produce enough electricity to power 3 million homes, the company said. Its bid for the two sites totaled about €5.8 billion. OGJ

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The U.S. is aiming to have 30 GW of offshore wind capacity by 2030.

Freeport LNG's Trains Back on Track After Major Derailment

While the facility's three trains have restarted 10 months after a fire-related shutdown, the company's ability to add a fourth train is uncertain.

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Most days, tiny Quintana Island on Texas' Gulf Coast south of Houston lures visitors with a bird sanctuary, RV park and beaches. But for worldwide attention, there's no contest: three liquefaction trains operated by Freeport LNG.

Economically, the trains make up a critical part of the U.S. LNG export infrastructure. Freeport's 15 million tonnes per annum (mtpa) facility is the seventh-largest in the world and second-largest in the U.S. Its capacity is equivalent to 2.2 Bcf/d—enough to power and light a metropolitan area the size of San Antonio for a full day.

So, when something goes wrong in Quintana, the world pays attention.

At 11:28 a.m. on June 8, 2022, something did. Freeport suffered a catastrophic failure in one of the facility's lines that led to a vapor cloud explosion, with a fireball filling the sky.

An estimated 239,610 cf of methane gas was released into the atmosphere, with about 50% consumed in the fireball, according to a redacted report released in October by the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA).

A full year later, the Freeport accident highlights a time in which a single supplier could tip the scales of global markets—and continues to raise questions about the viability of the company's planned multibillion-dollar expansion on the island.

The incident reduced the export capacity of Freeport LNG, and the U.S. overall, at a time when European gas supplies were threatened by the Russia-Ukraine war. Prior to Freeport's shutdown, U.S. LNG exports peaked in March 2022 at 11.7 Bcf/d, according to the U.S. Energy Information Administration (EIA).

By the time Freeport fully shut down, monthly U.S. exports declined by about 14.5% to an average 10 Bcf/d from June to December.

With Freeport back online, U.S. LNG exports are expected to exceed 12 Bcf/d, and the U.S. will remain the world's largest LNG exporter, according to a March EIA report.

Freeport LNG referred Hart Energy to its "Freeport LNG Sustainability and Community Investment Report 2022" when asked about lessons learned from the fire.

On March 8, Freeport LNG received regulatory approval from PHMSA and the Federal Energy Regulatory Commission (FERC) to restart the last of its three trains.

Operations at Freeport LNG's trains, as well as operations at two LNG storage tanks and a single dock, have allowed the company to again service its customers, the company said in its report.

"With the return to service of … the third LNG storage tank anticipated this summer, the full restoration of the facility is nearly complete," Freeport LNG chairman, CEO and founder Michael Smith said in the report.

Freeport LNG's restart is important for global LNG trade in general, and for off-takers such as TotalEnergies, BP, Osaka Gas, JERA and SK E&S, which look to benefit financially from the resumption of gas flows.

Specifically, France's TotalEnergies said during its first-quarter 2023 webcast that it expects operational benefits to positively impact its LNG sales in coming quarters. Japan's Osaka surmised in a May press release that it will no longer have to rely on replacement LNG volumes.

Fourth train time crunch

Freeport LNG was originally designed to import LNG. A subsequent rise in U.S. gas production allowed the country to reduce its dependency on gas imports. The facility was eventually refitted to operate as an LNG export facility.

Commercial operations related to Train 1 commenced in December 2019, with Train 2 starting operations in January 2020 and and Train 3 starting in May 2020, according to the IFO Group. Freeport LNG has shipped cargoes to 28 different countries since commencing operations in 2019, the company says.

The three-train facility leads Quintana Island in job creation and economic growth, according to Freeport LNG. The company says over $13 billion in direct investment went into building the first three trains while economic benefits of exporting at full capacity are between $5.5 billion and $8 billion annually.

In May 2019, Freeport LNG received authorization to build a fourth train. But a variety of factors, including the pandemic and last year's explosion, may test Freeport's ability to meet federal deadlines to build it.

A fourth train would add an additional 5.1 mtpa, or 0.67 Bcf/d, and boost the export facility's capacity to 20.1 mtpa when complete, according to Freeport LNG.

LNG cargo with tugs arrive at Freeport LNG.

Source: Pietro D. Pitts/Hart Energy

"2022 made clear that no matter how good your record, the need to be vigilant and continuously improving never ceases; we must always strive to be better."

—Michael Smith, ***chairman, CEO and founder, Freeport LNG***

Freeport LNG initially expected to make a final investment decision (FID) on Train 4 in 2022, with operations commencing in 2026, the company reported in a corporate brochure on its website. To date, the FID has still not been made.

In May 2022, Freeport asked FERC for an extension through 2028 to construct the train. FERC granted an extension through May 2026 instead. At the time, construction of the Train 4 project had not commenced due to delays caused by the COVID-19 pandemic.

A second extension has since been granted by the FERC for an additional 26 months, meaning a new deadline of Aug. 1, 2028, Enverus told Hart Energy. The consultancy said it expects the project to cost one-third of the $14 billion related to the first three trains.

"Pending FID, which may get pushed into 2024, it is anticipated that a minimum 48-56 month construction period would be required," Enverus said. "This results in a potential in-service date that is pushing close to FERC's latest deadline. Given two previous extensions, combined with project opposition, time is of the essence as requesting a third extension seems risky."

Like the first three trains, the fourth train would utilize electric motors with variable frequency drive for the cooling and liquefaction compression power, and result in negligible incremental emissions, according to Freeport LNG.

"We continue to progress our efforts on Train 4, which has already received all regulatory approvals," Freeport LNG corporate communications director Heather Browne said in an emailed response to questions. Browne did not provide requested cost details or a potential start date for the train.

FERC, the main agency responsible for permitting LNG facilities, and the U.S. Department of Energy (DOE), responsible for authorizing exports of LNG, have already approved permits. Freeport LNG has also received approval from the Texas Commission on Environmental Quality, as well as with several other federal, state and local agencies.

All this came prior to the April 2023 roll-out by the DOE

Liquefaction Project Facilities

1) Stratton Ridge Meter Station 2) Underground Storage Cavern 3) Storage and Trucking Facility 4) Liquefaction Pretreatment and Compression Facility 5) 42-inch Pipeline 6) Regasification 7) Liquefaction

Source: Freeport LNG

of a new policy that implies it will be stricter on permit extensions to export LNG to non-FTA countries.

"While an initial off-take agreement with Sumitomo was announced back in 2018, the current state of T4's contracts is not known as the original in-service date will not be met and additional off-takers have not been announced," Enverus said, but added, "the company said it is engaged in active negotiations with potential off-takers, particularly in European markets. Further announcements have not been made."

Once in operation, assuming an average LNG value of $7/MMBtu, exports from Train 4 will provide positive economic benefits of approximately $1.7 billion per year, according to Freeport LNG.

'Hard lessons' of Freeport mishap

Many of the visitors to Quintana Island may have been oblivious to the potential danger lurking nearby.

Less than 100 yards from a main plant entrance, bird watchers stroll a section of the beach with binoculars and cameras in hand. At the nearby RV park, visitors take in the Texas summer heat with cigarettes and beers in their hands.

Along the coastline that serves as the marine entrance of LNG barges, fishermen cast nets in waist-deep water. Kids kick around soccer balls while others brave the waves of the brown-tinted waters common along the Texas coasts. Other than worries about strong rip currents, parents pay no attention to passing LNG barges and small teams of tugboats ferrying them to and from Freeport LNG's docks.

While no fatalities were associated with last year's June 8 fire at Freeport LNG, another major incident could attract their attention.

According to an October 2022 report by the IFO Group, the direct cause of the explosion and fire related to "contact between flammable vapor (methane) and an ignition source (open and damaged electrical conduits and circuitry) in the pipe rack following the Loss of Primary Containment (LOPC), which resulted in a vapor cloud explosion and a small secondary pool fire on the northeast end of the pipe rack in the elevated LNG drainage trench."

The IFO Group also cited root and contributing causes including pressure safety valve (PSV) testing procedure and car-seal program deficiencies, facility operator fatigue due to significant overtime needs and the personnel's inability to recognize an abnormal operating condition and related hazard, including "those related to pipe movement and the recognition of pipe movements/stresses," among others.

Freeport had no formal PSV testing procedure to ensure they were properly returned to service after testing with isolation valves car-sealed in their correct open positions.

"At the time of the incident, operators at FLNG [Freeport] were trained to assist with PSV testing by observing another, more experienced operator, and then expected to be able to perform oversight of contractor-led PSV testing with no further training and without the aid of a written procedure or process," according to IFO Group's report.

Freeport LNG's recent safety performance data showed a slight uptick in recordable incidents in 2022 compared to 2021. The company recorded 899,709 exposure hours to direct employees, with the June 8 incident alone in 2022, compared to 831,545 exposure hours and no incidents in 2021. Non-project contractor exposure hours totaled 584,270 with four incidents in 2022 compared to 325,016 exposure hours with no incidents in 2021.

In terms of greenhouse gas (GHG) emissions and environmental data, the company also showed improvements in 2022 compared to 2021. Direct GHG were 341,361.2 metric tons (mt) of CO_2 in 2022 compared to 749,599.6 mt in 2021, while indirect GHG were 855,109 mt compared to 2,889,683 mt, respectively.

However, methane emissions creeped up to 548.9 mt in 2022 compared to 202.24 mt in 2021, according to the report.

Quintana Island residents expressed anger during the one-year anniversary town hall, according to New York-based Climate Nexus, which helped to organize a live broadcast of the discussions with the non-profit Texas Campaign for the Environment (TCE).

During the town hall, residents reiterated calls that Freeport LNG be held accountable while requesting transparent and up-to-date safety standards at the facility.

"2022 made clear that no matter how good your record, the need to be vigilant and continuously improving never ceases; we must always strive to be better," Freeport LNG's Smith said in the company's report.

"The hard lessons learned in 2022 will stick with and guide our company as we move ahead. We are committed to re-establishing our reputation as a reliable source of U.S. LNG for decades to come, and making Freeport LNG stronger and safer than ever," said Smith, who founded Freeport LNG in 2002. OGI

Pitts: Energy Transition and e-Mobility in Mexico

The country faces many of the same challenges as markets in North America and Europe.

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Mexico, with some 133 million citizens and severe air quality issues in many of its major cities—especially its capital, Mexico City—continues to embrace electric mobility or e-mobility.

That e-mobility push and transition away from combustion engines will have a significant impact on two fronts.

First, increased domestic production of hybrid and, more importantly, electric vehicles (EVs) will spur employment and economic opportunities.

Second, fewer vehicles using fossil fuels will eventually reduce the production of CO_2 and the ill effects its release has on the health of many citizens in Mexico—and beyond, since CO_2 isn't contained by borders.

From introduction to production

Mexico has come a long way since 2010 when Toyota started to sell its Prius hybrid model. While the introduction of the model jump-started Mexico's e-mobility push, the release of the Nissan Leaf 100% EV one year later raised the e-mobility bar with the introduction of vehicles that don't rely on gasoline or diesel.

Fast forward to 2023 and the production of EVs in Mexico is on track to surpass the 200,000 milestone after achieving production of over 158,000 EVs in 2020-2022, according to data revealed by InTiCa Systems. Mexican officials have already floated the idea of reaching the 500,000 milestone by 2030, according to InTiCa.

Beyond the aforementioned Asian hybrid and EV models, customers looking to move away from combustion engine vehicles in Mexico can choose from models like the Ford Fusion hybrid, the Ford Mustang Mach-E (the first EV made in Mexico), the Audi Q5 hybrid, the BMW 330 hybrid, the Chevrolet Blazer EV and Equinox EV, as well as Build Your Dream (BYD) Yuan Plus EV, among other options.

While the bulge bracket name in the EV space, Tesla, has also introduced its EV to the Mexican market, the U.S.-based company has gone one step further. This year, Tesla unveiled plans for a mega factory to be located in Santa Catarina in Mexico's northern Nuevo León state. Tesla eyes building the plant in less than 9.5 months, which was the time it took to build its plant in Shanghai. Under such a timeline, production from Tesla's Mexico plant could start sometime in 2024.

Complaints about cost

It wouldn't be prudent to talk about Mexico's e-mobility push without mentioning the headwinds, many of which continue to haunt even developed regions like North America and Europe.

The elevated prices of EVs and the lack of e-mobility infrastructure are the main complaints of both existing and potential EV customers.

The price of an EV in developed North America and Europe is out of reach for many. In developing Mexico, it's the same. As such, many EV purchases in Mexico are by people with the financial means to do so and, in many cases, done to highlight their class status while boasting about their efforts to reduce their carbon footprint.

Unlike the U.S., where many people live in homes, Mexico's economic capital, Mexico City, is dominated by mid-rise and high-rise multifamily residences, especially in the more affluent parts of the city like Polanco. Developing charging stations for large multifamily developments is doable but much more complex than a simple garage hook-up in a single-family dwelling in the States.

In earthquake-prone Mexico City, many residents are likely to opt for a flat or townhome built to withstand an earthquake rather than one that had a charging station in the underground parking garage.

Away from home, the charging options are limited. Most office buildings don't offer charging stations and Liverpool, an upscale mall concept, seems the best and only option. Where's Whole Food's parking lot when you want and need it? Well, it's not in Mexico—at least not yet.

While gasoline prices in Mexico, which are 1.3x the average price in the U.S., have helped to push customers to hybrids since they are cheaper than EVs, the e-mobility headwinds are keeping them out of EVs for now.

Further development of Mexico's e-mobility movement will depend on customers' ability to buy and operate the technology, a clear regulatory political framework to allow the technology to be bought and even subsidized in the early days, and then development of the EV industry itself.

Mexico's e-mobility push is impressive but many pundits say the country is easily 10 years behind developments in the U.S., if not more. If Mexico, like North America and Europe, builds the necessary e-mobility infrastructure, the customers may come around to EVs—but only if "the price is right." OGJ

LNG Exporter SE Asia Eyes More Imports

The 11-country Southeast Asia region remains a net LNG exporter, but falling reserves are pushing some countries to eye LNG imports.

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The Southeast Asia region, primarily a net exporter of LNG, is increasingly eyeing a future where rising imports could revert the trend, according to Poten & Partners.

Overall, Southeast Asia is a major LNG-exporting region due to its gas-rich geology, but declining gas reserves are quickly pushing a number of countries to import LNG, said Irwin Yeo, business intelligence senior LNG analyst at Poten & Partners.

Yeo said LNG demand potential existed in Southeast Asia due to falling gas production and rising demand, but cautioned that there were external and internal headwinds to overcome.

Internal challenges range from alternative fuels and policy uncertainty to infrastructure issues, while external challenges involve competition among established buyers for term LNG, as well as renewables and green energy development, Yeo said.

"[The] current LNG price decline could offer a window of opportunity for new buyers—some have already moved to take advantage," Yeo said, adding that firms needed to weigh the risks of importing LNG.

Firms want to avoid "overcommitting to expensive LNG, which could turn into a fiscal, political and even social hot potato, [while] missing the window to buy due to cautious evaluation, only for prices to rise again," Yeo said.

Major trading and maritime hub

Southeast Asia is comprised of 11 countries—Indonesia, Thailand, Malaysia, Philippines, Vietnam, Singapore, Brunei, Myanmar, Cambodia, Laos and Timor-Leste—with a population of nearly 688 million, about 8.6% of the global population, according to United Nations data.

The region is a major trading and maritime hub, due to its privileged West-East trading routes—this also includes LNG. As of April 2023, the region's GDP was around $3.9 trillion or 3.7% of the global total, according to the International Monetary Fund.

Brunei, Malaysia and Indonesia are Southeast Asia's principal LNG exporters. In 2022, the three countries exported over 47 million tonnes per annum (mtpa), which was about 12% of the global market, according to data in Poten's "Global LNG Outlook."

"[The] current LNG price decline could offer a window of opportunity for new buyers—some have already moved to take advantage."

—Irwin Yeo, *senior LNG analyst, Poten & Partners*

Other countries in the region, including Thailand, Vietnam, Philippines and Myanmar, are major natural gas producers; however, their production is mostly sold domestically or exported as piped gas (intra Southeast Asia, China), according to Yeo. Timor-Leste and Cambodia are home to probable gas reserves, but none are commercialized.

On the LNG import side, Southeast Asia, more specifically Ta Phut, Thailand, imported its first cargo in 2011. Other countries such as Singapore, Malaysia, Indonesia, Myanmar and the Philippines followed. In 2022, the region imported over 20 mtpa, which was around 5% of the global market, according to Poten data. By the summer of 2024, these volumes will be on the verge of 30 mtpa.

To date, Southeast Asian firms from PTT and Petronas to Pertamina have acquired nearly 16 mtpa of contracted LNG, according to Poten.

Overall, the Asia Pacific region is expected to import around 386 mtpa by 2032 compared to 268 mtpa in 2023, according to Poten data.

Vietnam, which is on the cusp of joining the importers' club, is eyeing its first discharge in July, while Myanmar, which received LNG between 2020 and 2021, has halted imports for the moment. Singapore remains well-positioned as a regional LNG hub while Malaysia and Indonesia have no import pressure yet, Yeo said. OGI

An LNG tanker is docked at AG&P's Philippines LNG (PHLNG) Terminal in Batangas Bay, Manila. In 2022, Southeast Asia imported over 20 million tonnes.

Photography by AG&P

LNG SPAs Signed by Southeast Asian Buyers

	BUYER	SELLER	FULL VOLUMES (MMT/Y)	TENURE (YEARS)	START DATE
THAILAND	PTT	QatarEnergy	2	20	2015
		BP	1	20	2017
		Shell	1	15	2017
		Petronas	1.2	15	2017
		Cheniere	1	20	2026
MILAYSIA	Petronas	Venture Global LNG	1	20	2026
		BP	1	12	2023
SINGAPORE	Pavilion Energy Sembcorp	BP	0.28	10	2024
		Pertamina Trading (PPT)	0.8	5	2019
		QatarEnergy Trading (QET)	1.8	10	2023
		Chevron	0.5	6	2023
		TotalEnergies	0.4	5	2025
INDONESIA	Pertamina	Cheniere	0.76	20	2019
		Total Energies*	1*	15	2020
		Woodside	0.6	15	2022
		Mozambique LNG**	1	20	TBC
PHILIPPINES	San Miguel Corp Power	Vitol	1.5	14	2023
		Total	15.84		

*Swap deal

**Condition precedent on MZLNG start-up

Source: Poten LNG Contract Intelligence Service

Mexico Embraces EVs, but Headwinds Persist

E-mobility may be here to stay, but the challenges of battery cost, charging infrastructure and financing persist.

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MEXICO CITY—Like many countries, Mexico is increasingly embracing the electromobility wave, and in parallel, also confronting headwinds associated with expanding e-mobility, experts argued during a recent webinar.

"Mobility is not some fashion trend, it's a tendency that's here to stay," said Daniel López, Evergo Emobility's chief commercial officer, during the "Electromobility: Will Mexico be Ready?" webinar organized by the Center for U.S.-Mexican Studies at the University of California San Diego School of Global Policy and Strategy and the Mexican Council on Foreign Relations.

López said this was evident because all the major automakers in the world have announced plans to eventually phase out fossil fuel power vehicles and replace them with electric vehicles (EVs).

Mexico is home to 133 million citizens, ranking the country as the world's 10th largest in terms of population, according to Worldometer. Automakers in Mexico offer consumers numerous EV models that are 100% electric, López said.

While prices for EVs still aren't accessible to all citizens, they are available across major categories: passenger, commercial transport, public transport, merchandise transport and heavy transport—including the cement and mining sectors, López said.

López said the infrastructure around charging stations needs to undergo significant growth as consumers continue to argue about a lack of information about non-working and working charging stations, charging rates, and operational hours.

Sales of EVs in Mexico are expected to surpass 200,000 units in 2023 compared to around 158,000 units sold between 2020 and 2022, said Guillermo García Alcocer, the planning and performance evaluation vice president at Mexican university Instituto Tecnológico Autónomo de México and former president of the Mexican Energy Commission.

As a result, sales are expected to grow at least 25% in 2023 compared to around 160% in 2022 and just under 80% in 2021, Alcocer said.

E-mobility, which encompasses EVs and their supporting infrastructure, is rapidly transforming the automotive industry. Plans worldwide to transition to cleaner EVs will create new opportunities for sustainable transportation and economic growth, the experts concurred.

Hart Energy

A Tesla dealership in the Polanco neighborhood of Mexico City.

E-mobility against fossil pollution

Mexico faces air pollution issues in many of its major cities. In particular, the country's capital and economic and financial heart—Mexico City—boasts 22 million habitants, according to data from the United Nations. The city, situated in the valley of Mexico on land that was once a lake, is known for its contamination and poor air quality.

While the air quality in Mexico City has improved in recent years, the city is still considered moderately polluted, with levels greater than the maximum limit established for one year by the World Health Organization (WHO), according to details on Mexico's government website.

E-mobility can combat bad air quality caused by carbon emissions generated by the transport sector in cities in Latin America with more than 5 million habitants, electromobility and energy expert Yolanda Villegas said.

Villegas said over 13 cities in Latin America had very bad contamination problems, affecting over 150 million people living in cities surpassing WHO air quality limits.

"Over 95% of the energy needs of the transport sector are derived from petroleum derivatives … which opens [opportunities] for the e-mobility sector," Villegas said.

For Villegas, the e-mobility push continues to face headwinds related to the price of batteries, a lack of charging infrastructure and the subsequent financing.

While electrification is generally associated with reducing carbon emissions and pollution levels, Odón de Buen, a former general director for the National Commission for the Efficient Use of Energy, didn't agree.

"Electrification doesn't [necessarily] mean a lower carbon footprint … this will only come as the electric network gets more efficient and reduces the burning of fossil fuels [and] renewable generation increases," said. OGI

Transition's Demands Are Unrealistic for Latin America

Trinidad and Tobago's minister of energy and energy industries stressed the need for regional energy security in the face of the high cost and other challenges posed by the energy transition.

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The Latin America and the Caribbean (LAC) region needs energy security, Stuart Young, Trinidad and Tobago's minister of energy and energy industries, said in June.

"We are led down different pathways that I personally don't believe are quite realistic," Young said, referring to the energy transition during his keynote speech at the Caribbean Sustainable Energy Conference in the Caribbean island's capital of Port of Spain.

Shutterstock

Trinidad and Tobago's port in downtown Port of Spain.

A number of smaller Caribbean islands face headwinds to generate electricity and steps need to be taken to assist them, Young said.

"I beg and plead with the multilateral lending agencies … because, in my view, the only way renewables become bankable in some of these jurisdictions is there has to be an element of grant funding," he said.

"So, if you are really interested in reducing emissions globally, you have to contribute because these smaller countries are not going to be able to afford it," Young said.

Young said the Caribbean region needs to take charge of its own destiny. To that end, he said Trinidad continues to advocate for joining forces with Guyana and Suriname to provide energy security for the rest of the region.

Trinidad has about 10 Tcf of gas reserves, enough to last about 10 more years, according to BP's "Statistical Review of Energy," and is primarily a gas producer and exporter of LNG, ammonia and methanol.

Guyana, where an Exxon Mobil-led consortium has found recoverable resources of over 11 Bboe in the Stabroek Block, continues to boost oil production and has significant associated gas resources. The consortium includes Hess Corp. and China's CNOOC.

Suriname's Block 58, where APA Corp. and TotalEnergies are drilling adjacent to Stabroek, could also contain sizable oil and gas resources, according to reports from Rystad Energy.

Bankability headwinds

Young said bankability was a real issue for Latin America and smaller islands in the Caribbean, as well as their ability to reduce emissions, upgrade plants and move to renewables.

"And that's where the concept of bankability comes in. Another very frustrating concept," he said.

Young said the economies of small developing islands were experiencing negative effects of climate change, including beach erosion, droughts, excessive rainfall and flooding.

He said he was concerned, despite "all of these nice sounding concepts" like the energy transition that he said were "being pushed on us by the rich, developed countries."

Young said the LAC region was being told to move toward renewables, solar, geothermal and wind turbines without consideration to cost.

"Nobody talks about how these costs have been driven up. We all say, 'yes, the cost has come down,' but in reality … the cost is a lot higher than it was before the Russian-Ukraine war."

Young said Trinidad would continue to produce its oil and gas resources because they drive the economy, but said the country had the necessary infrastructure to go through the transition.

"Trinidad and Tobago is well-poised. We have the opportunity right in front of us to make sure that we go through this transition properly. [We've] done what is necessary and responsible towards reducing emissions," Young said. OGJ

Around the World

NORTH AMERICA

Morgan Stanley: US LNG Exporters Could See Cargo Cancellations

U.S. LNG exporters could see cargo cancellations later this year amid ongoing gas storage injections in Europe and weaker LNG demand in Asia, Morgan Stanley said in June in a research report.

Asia consumption needs to rise to absorb an eventual slowdown in imports into the EU because "absent higher Asia imports, there is some risk of a moderate amount of U.S. cargo cancellations in late third-quarter 2023," Morgan Stanley said. "While the build rate of EU inventories has slowed somewhat in recent weeks, storage is still on pace to hit 100% full by September."

Morgan Stanley's EU strategist Martijn Rats said there are steps that could head this off.

"In order to prevent this, EU LNG imports need to fall by 2 mt [metric tons] to 3 mt per month on average in the third quarter (6-8 mt lower quarter-over-quarter). To absorb the resulting 'excess' LNG cargos, Asia imports would need to rise 10% in the third quarter [versus] the second quarter," Rats said. "While some of this uptick should occur from demand seasonality due to summer weather, underlying consumption also needs to increase relative to the recent trend."

Amid weakness in demand, prices for the JKM Asian benchmark have continued to fall and are now below $10/MMBtu with a second-quarter average of approximately $11/MMBtu, the consultancy said.

"Despite lower prices, demand still has not recovered. Over the last four weeks, global demand ex-Europe is up only 1% year-over-year. In Asia, the picture is mixed. China and India have both shown strong year-over-year increases in LNG imports (+15% and +14% year-over-year, respectively). However, this strength has been offset by continued weakness in Japan (-16%) and South Korea (-15%)," Morgan Stanley said.

FERC OKs TC Energy's North Baja Pipeline Expansion

TC Energy will boost pipeline capacity to the U.S.-Mexico border by 495 MMcf/d after the Federal Energy Regulatory Commission (FERC) approved its request to place the North Baja Xpress (NBX) project in service.

The approval will allow for additional gas deliveries to the southwest and Mexico, Oren Pilant, East Daley Analytics energy analyst, said in a June research report.

NBX was designed to expand capacity on the North Baja pipeline by upgrading one existing compressor station and two existing meter stations in Arizona and California, according to TC Energy's website.

The North Baja pipeline is bi-directional and spans 80 miles from Arizona and California to the Mexico border. There, it connects to another line linked to Sempra Energy's Energia Costa Azul LNG import terminal in Baja California, Pilant said.

The pipeline can ship up to 600 MMcf/d northbound and 500 MMcf/d south to Mexico. Currently, the pipeline transports 380 MMcf/d from the El Paso Natural Gas system, nearly all of which flows to Mexico. The El Paso system interconnects with the North Baja pipeline in Ehrenberg, Ariz., where it supplies an average 745 MMcf/d (50% utilization) to the Southern California Gas distribution system, peaking at more than 1 Bcf/d, according to Pilant.

Source: TC Energy

Cheniere Inks Second Deal with China's ENN LNG

A Cheniere Energy affiliate signed a 20-year agreement to deliver 1.8 mtpa of LNG to a subsidiary of China's ENN Natural Gas Co. Ltd.

The sale and purchase agreement, or SPA, is the second long-term agreement signed between Cheniere Marketing and China's ENN LNG. An initial SPA was signed in October 2021 by the companies, Cheniere said in a June press release.

"This SPA further supports China's structural shift to natural gas as a growing primary energy source, powering its economy while enabling improved environmental performance with flexible, reliable and cleaner liquefied natural gas," Cheniere President and CEO Jack Fusco said in the release.

Under the SPA, ENN LNG subsidiary ENN LNG (Singapore) will acquire the LNG from Cheniere Marketing on a free-on-board basis. The purchase price will be indexed to the Henry Hub benchmark gas price and include a fixed liquefaction fee. Initial cargo deliveries are slated to start in mid-2026, ramping to 0.9 mtpa in 2027, Cheniere said.

Delivery of the remaining 0.9 mtpa is dependent on a FID for the first train—the seventh train related to the Sabine Pass Liquefaction Expansion Project—and will commence upon the start of commercial operations of train seven.

Terms associated with the SPA extend until the 20th anniversary of the start of commercial operations of train seven, Cheniere said.

LATIN AMERICA AND THE CARIBBEAN

Noria Energy

Noria Energy's Aquasol 1.5 MW pilot floating solar project in Córdoba, Colombia.

Noria Energy Launches 1.5-MW Solar Project in Colombia

California-based Noria Energy launched a new 1.5-megawatt (MW) pilot floating solar power system on the reservoir at Colombia's Urrá Dam, the largest such project of its kind in South America.

Aquasol—a combination of the words "water" and "sun" in Spanish—was installed at the 340-MW Urrá hydropower plant in the Sinú River basin in Córdoba, Colombia, Noria said in a June press release.

The project consists of over 2,800 solar modules and will produce nearly 2,400 megawatt-hour of power in its first year—enough to offset the amount of energy it takes to operate the dam, Noria said.

Noria, with partners 1Solution, DISICO SA, G&C, Isigenere and Seaflex, designed, developed and installed the floating photovoltaic system for the independent power producer URRÁ SA ESP.

"Aquasol is expected to avoid more than 1,540 tons of carbon dioxide emissions every year, and generate over $1.2 million in additional electric power revenue over 20 years," according to Noria.

Colombia's Urra hydroelectric dam is one of the largest in Colombia, holding back 1.6 Bcm of water, according to Noria. The company's push to diversify its energy generation potential led it to explore synergies from combining floating solar with hydroelectric reservoir resources.

The aim of Aquasol is to "demonstrate that hydroelectric dams dealing with fluctuating water levels can pair with floating solar generation to boost energy reliability and increase production," Noria said in the release.

With the floating solar, the "surrounding water allows for cooler, more consistent temperatures, increasing operating efficiency by 10%-15%, and these systems have numerous water quality benefits that increase the value of the body of water," according to Noria's website.

Noria plans to collect and compare data from Aquasol's production and efficiency to that of a ground-mounted onshore solar system. The data will be used to design and model larger-scale systems to maximize the generation potential of floating solar and hydroelectric dams, Noria said.

"Worldwide, around 60% of renewable energy comes from hydropower. That represents countless opportunities to deploy floating solar that can maximize zero-emission energy generation and diversify clean energy sources," Noria CEO Jonathan Wank said in the release.

Besides boosting the total generating capacity of hydroelectric dams, Noria's floating solar systems can also assist to keep energy flowing when low water levels or other adverse conditions reduce hydroelectric output, the company said.

Noria's floating solar system has been designed to sit on top of the water and withstand fluctuating water levels of up to 120 ft.

Placing solar facilities on water also avoids land-use conflicts, and pairing them with dams "takes advantage of existing interconnection and other energy infrastructure," Noria said.

Mexico Authorizes Exports from Altamira Fast LNG Project

Mexico's Ministry of Energy, known as the Energy Secretariat, issued an export permit to New Fortress Energy (NFE) for its Altamira Fast LNG facility.

"This permit is the final piece to the puzzle for launching our first fast LNG in Altamira," NFE Chairman and CEO Wes Edens said in a June press release.

"Obtaining this authorization not only paves the way for operations to commence at our new LNG hub in the third quarter of [2023], but it also advances our efforts to expand access to cleaner, cheaper and more reliable energy to customers around the world."

The permit will allow NFE to export up to 7.8 mtpa through April 2028, and will support the company's initial 1.4 mtpa fast LNG facility to be located offshore northern Mexico.

Construction of the unit is more than 90% complete, NFE said.

NFE plans to deploy multiple 1.4 mtpa capacity fast LNG units as part of efforts to create a fast LNG hub off the coast of Altamira, Tamaulipas, the company announced in October in another press release.

The units will utilize Mexico's Federal Electricity Commission's existing and underutilized pipeline capacity on TC Energy's Sur de Texas-Tuxpan pipeline to receive requisite feed gas.

NFE has already received authorization from the U.S. Department of Energy to export U.S.-sourced LNG to Mexico and other free-trade agreement countries.

Fast LNG harnesses existing floating LNG technology and combines it with a modular approach, allowing for scalability, affordability and speed of natural gas liquefaction, according to NFE. OGJ

Hacktivism, Geopolitics Breed Cybersecurity Fears

A DNV report cites geopolitical uncertainty and the regulatory environment as driving increased investment by the energy sector in keeping assets safe.

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Spurred in part by geopolitical, regulatory and hacktivist concerns, companies are spending more on cybersecurity this year than in the past, according to a new DNV report.

Cybersecurity has moved from being largely a technology risk to a business risk, particularly in the energy sector, prompting companies to increase investments. Even so, there is a disconnect between the perception of investment level—and sense that money is being spent on the right things—depending on the role of the respondent surveyed for DNV's "Energy Cyber Priority 2023: Closing the Gap between Awareness and Action."

Jalal Bouhdada, DNV's global segment director for cybersecurity, told Hart Energy prior to the report's release that the level of innovation in the energy sector has brought many opportunities, but also created cyber risk.

"The industry can definitely battle those bad guys and ensure that our infrastructure and critical infrastructure will remain safe and reliable for the future," he said.

The recipe for cyber-resilience calls for understanding risk, communications and collaboration, he said.

Withstanding an attack starts with getting the basics right, he said.

"You cannot protect what you don't know. That's the first thing. Understand your risk profile. Understand your weaknesses, and prioritize what matters most," he said.

With clear visibility about assets and their associated risks, he said, companies can set up cybersecurity programs that mitigate those risks. And training for breaches can help companies respond quickly should an attack be successful, he added.

"It's really about how you respond to this type of incident. You have the capacity, you have the support, you have also the speed and the training and the readiness to be able to restore your operation and keep your business up and running," Bouhdada said.

Companies have shifted their view of cyber threats, he added. Cyberattacks can harm people, assets and the environment, causing financial repercussions.

"There is a sense of urgency from companies as this topic becomes a business risk and not necessarily just a technology risk," he said. "The boards and senior management are becoming more nervous about this, and they are seeing that, 'Hey, if we don't do anything, then we can be the next victim.'"

"We are seeing, really, that there is a transition from knowledge, or being aware of the issue, to moving into action."

—Jalal Bouhdada, *global segment director for cybersecurity, DNV*

Survey says

In the report, 77% of respondents agreed that their organization treated cybersecurity as a business risk.

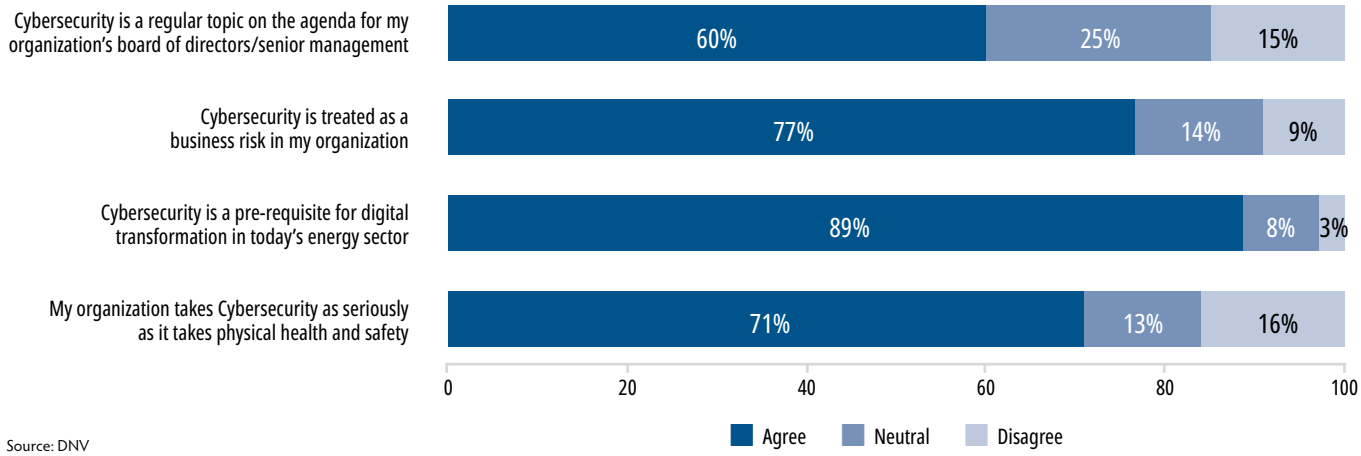
For DNV's second annual report, respondents reported higher geopolitical and hacktivist concerns this year than they had before Russia invaded Ukraine in February 2022. Before the invasion, 65% surveyed were concerned about attacks from hacktivists and 57% were wary of malicious foreign powers and state-sponsored actors.

Following the invasion, hacktivism concerns rose to 71% and state-sponsored fears were up to 63%. Those concerns subsided slightly in 2023, with 69% reporting being concerned about hacktivists and 62% about foreign attacks.

But a slight disconnect existed between how C-suite and operations-level respondents viewed their organizations' cybersecurity response: 74% of C-suite and 67% of operations employees reported that their company's focus on cybersecurity had increased due to growing geopolitical tensions in the past year. In the C-suite, 87% thought geopolitical uncertainty had made their organization more aware about potential cybersecurity vulnerabilities for their OT systems, compared to 71% at the operations level.

DNV said that 59% of energy professionals

Cyber is seen as a top business and strategic risk



Source: DNV

Respondents to a DNV survey regarding cyber priorities were asked, "To what extent do you agree or disagree with the following?" Percentages reflect net agreement, (i.e., moderately or strongly agree).

surveyed said their organization is investing more in cybersecurity in 2023 compared with last year.

"We are seeing, really, that there is a transition from knowledge, or being aware of the issue, to moving into action," Bouhdada said.

At the same time, there is concern that the money is not being spent efficiently, he said.

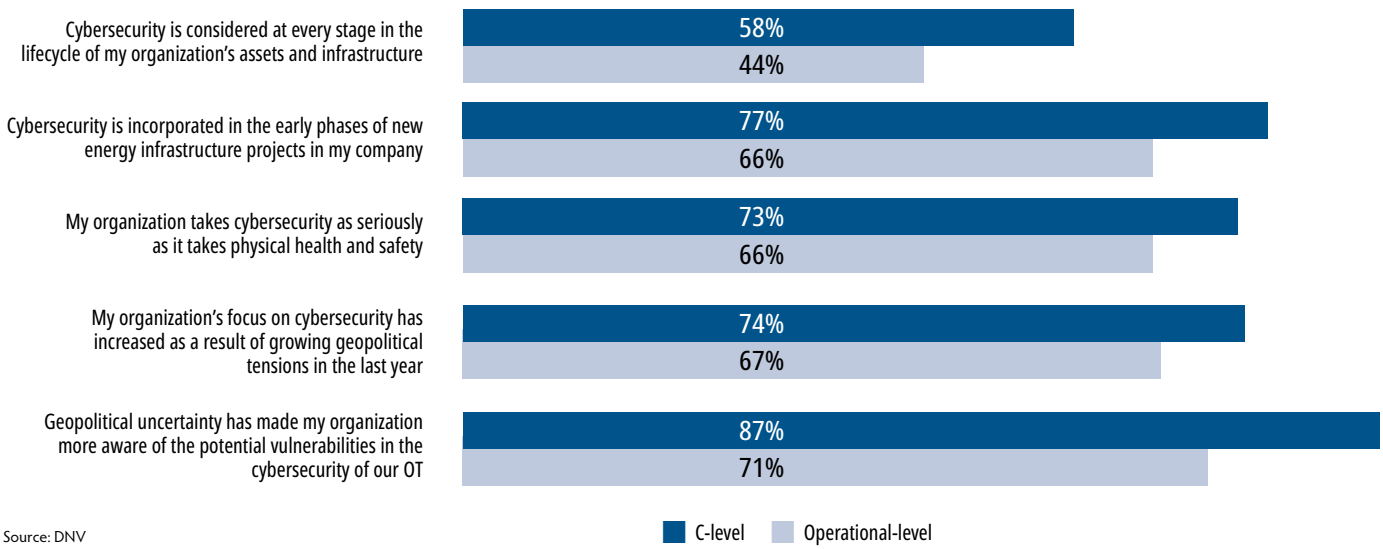
He said some respondents did not believe the investment was enough, while a portion did not think resources were being wisely allocated. This indicates there may be "a lack of efficiency in how those budgets and resources are used," he said.

According to the report, 49% of respondents thought their companies would devote more funding to cybersecurity to meet changing regulatory requirements. Another 38% thought an incident or near-miss within the organization would prompt funding, while 34% thought an incident or near-miss that affected another organization in the sector would fuel further funding.

Cybersecurity is shifting from primarily a technology risk into a business risk.

DNV

The C-suite has a different perspective than employees closer to operations



Source: DNV

Percentage of agreement or disagreement with the statements in the DNV cyber priorities survey varied by whether the respondent was in the C-suite or in operations

Respondents were nearly even on whether leadership or customer pressure would lead to greater funding, with 29% seeing internal impetus leading to more spending and roughly a quarter saying customer interests would.

Less than a quarter—24%—told the survey that a clearer assessment of weaknesses and vulnerabilities would lead to additional funding. Such assessments are commonly considered one of the most important steps in cyber defense.

The where matters

The report also indicated that the location of an organization influenced the approach toward cybersecurity. Among Asia-Pacific companies, 64% were more likely to respond that cybersecurity was considered at every stage of the life cycle of the organization's assets and infrastructure. That compares with 52% of European companies, 48% of companies in the Americas, or 45% of those in the Middle East and Africa.

"The risk profile and appreciation for, and also the culture for cybersecurity is not the same in different regions," Bouhdada said, noting some regions are compliance- and regulations-driven while others are based more on risk.

No matter what drives an organization's approach to cybersecurity, Bouhdada said security should be addressed holistically and for the long term.

"Cybersecurity is really a continuous effort," he said. "There is always the need for more investments and funding, because this ecosystem is becoming more complex and the sophistication of attack is increasing." OGI

Tackling Emissions with Teamwork

Executives from Devon, Hess and other companies emphasized collaboration to meet net-zero goals at URTeC.

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Reaching net-zero emissions by 2050 may be a goal for nearly every company associated with oil and gas, but it's becoming clear that E&Ps can't hit those goals alone.

During the opening plenary session of the Unconventional Resources Technology Conference (URTeC) in Denver, executives emphasized the need for collaboration among industries, governments and fellow competitors to achieve those goals by 2050.

Developing technology is not enough for the oil and gas industry to overcome the "valley of death" it faces, said Amy Henry, CEO of Eunike Ventures, a Houston-based technology company. While Henry acknowledged she isn't completely sold on the idea that net zero emissions goals will be reached by 2050, she said inter-industry collaboration is the key to at least getting close to those goals.

"Energy has its own valley of death to cross over, so … do we have a collaborative mindset?" she asked. "Because a lot of these technologies are not going to come from within the energy vertical. They're going to come from other verticals like biotech, space and aerospace."

Neil McMahon, managing partner at private equity firm Kimmeridge Energy, is already seeing some of the fruits of collaboration within the energy industry. McMahon wants to "make unconventional resources investable in a low-carbon world" and is beginning to see that through the prioritization of ESG objectives.

"But one of the big things we've found is through peer pressure, through activism … you can do things such as planting trees and generating offsets to offset your emissions. You can take this industry forward, up until the point where hydrocarbons are no longer needed or priced out of the market," he said. "Unconventional resources are required to meet global energy demand. We just need to make them investable and they need to be relevant in the current world."

Clay Gaspar, COO of Devon Energy, shares a similar mindset with McMahon about raising the "investability" of unconventional resources as part of a three-pronged approach to the company's sustainability efforts.

"We have to make sure that we are always raising not just our investability and our economic standards, but our environmental

Hart Energy

At the opening of the 2023 Unconventional Resources Technology Conference, executives from Devon, Hess and other companies said net zero goals require collaboration.

standards as well," Gaspar said. "We have long-term goals, but in our first prong, we're thinking a whole lot about [controlling] the controllables: driving down our Scope 1 and 2 emissions.

"How do we flare less? How do we drive down our greenhouse-gas emissions and really think about our facility design to make our emissions significantly better?" he said. "We're making money on those, so they're pretty easy decisions. It's a matter of prioritizing, applying the right technology and understanding."

Hess Corp. is embracing partnerships to address emissions, said CTO Rob Fast. He said Hess is working with Guyanese officials to store greenhouse-gas emissions and prevent deforestation.

"We are sharing data … we're gathering in the field and trying to collaborate, to understand which methods for reduction and storage work, which ones may need help and how do you tie these disparate sources of data together to really understand and control and reduce emissions?"

Fast said Hess is also investing $750 million in Guyana over the next 10 years to prevent deforestation, which could account for up to 20% of greenhouse-gas emissions going forward.

Teamwork seems to be the only suitable course of action to reach the emissions goals within the energy industry, panelists said.

As Gaspar put it: "The only thing smarter than a single one of us is a collection of us. The only thing smarter than a collection of us is a diverse collection of us." OGJ

Nanobubbles, NGL Show Promise in Oil Recovery

'Fluffy water' and recyclable propane treatments are helping to boost recovery.

PAUL WISEMAN
CONTRIBUTING EDITOR

Cost, access and inefficiency drive the push for EOR research and the results—using nanobubbles and NGL—are showing promise.

Even as drilling costs rise, leasing on government lands is getting tighter. At the same time, current production methods leave as much as 90% of the reserves in the ground, and many producers believe it is more efficient to revisit current formations than to rely solely on drilling for new production.

Nano Gas Environmental and C3 Oilfield Services are making advances in EOR and IOR technologies. Nano Gas Environmental uses a specially designed nozzle to inject thousands of nanobubbles of nitrogen into the reservoir to boost oil recovery, while C3 is updating NGL injection into formations in a process called Single Shot IOR technology.

Fluffy water

Nano Gas Environmental co-Founders Len Bland, CEO, and Jeff Hardin, chief scientist, were looking for something revolutionary when they found nanobubble technology. The process could multiply the amount of gas a liquid could hold. Bland nicknamed it "fluffy water." They considered it to be world-changing.

"We have to be part of it," Bland said.

While the gas increase has not been fully measured, Bland and his team think it is 3,500 times the amount of gas that would be in water naturally. Nanobubbles are invisible under a light-based microscope but become visible and measurable with a device called a NanoSight.

"You can see them using dynamic light scattering, which is shooting a bunch of lasers through the liquid," Bland said.

That extreme concentration alters the liquid's physical, biological and chemical characteristics. The company has used all three for EOR, cleaning produced water and eliminating dredging for sewage lagoons.

Nanobubbles stay evenly distributed throughout the liquid and reduce surface tension with surrounding surfaces. They attach to downhole rocks, making them water wet, which pushes out the oil and sends it to the surface.

The patented Nitro Nano process achieves concentration levels in a single pass that could take other methods multiple passes to reach, according to the company.

Under high pressure, the bubbles become as hard as stainless steel ball bearings. This allows them to penetrate and drive oil out from interstitial cracks, much as fracturing does.

In the lab, in the field

The company originally used the procedure to clean produced water for companies that wanted to do three things: recover oil for sale into the market, reduce dangerous hydrogen sulfide and iron sulfide, and drop out total suspended solids from the water. Nanobubbles accomplish all three, which is why, Hardin said, "we create reusable produced water."

They also used nanobubbles to recover oil and remove solids from tank bottom water. That

Nano Gas Environmental

At an oil well in Kansas, nanobubbles leave the gray trailer to be mixed into water from the red frac tank. Four wells tested in Kansas showed production increases of at least 200% after the treatment.

C3 Oilfield Services

C3 Oilfield Services' SingleShot uses NGL to carry their proprietary technology deep into formations. There it can clean up paraffin, condensate blockages and other oil flow inhibitors.

temporarily increased the oil's API gravity by up to 22%, allowing it to flow and become a salable product.

"If we can do that there," Hardin said, "we should be able to recover oil in an oil well."

Nitro Nano showed positive results in the lab. Starting with a core infused with 12° API gravity oil, they subjected the core to EOR-ready saltwater, with no results after four days. In the same amount of time, Nitro Nano released oil and gas, with some of the observed gas possibly being nitrogen bubbles.

The company has now tested the process on four stripper wells. The company said each well saw production increase to 200% of the normal rate. A Kansas well in a limestone formation achieved a 540% production improvement after 90 days, and was still at 200% after 150 days. The other three are in sandstone formations in Oklahoma.

Those tests were done as one-time stimulation injections, keeping the treatment close to the wellbore. Bland suggested that those wells could be treated again in six months or so, "like with an acid job. The difference is, we have water and nitrogen that we're pulling from the air. It's all natural."

The ultimate goal, however, is to use nanobubbles on a larger scale.

"We think it will work terrifically as a waterflood. We want to test that application, as well," he said.

The company aims to expand testing to more productive wells to determine if the procedure scales up production in that category.

One shot

In 2019, Oil Technology Group asked Universal Chemical Solutions's (UCS) Susan Starr, vice president of engineering, and Dave Szabo, engineering adviser, to research the use of NGL such as propane and butane in EOR. The company wanted to operationalize its initial production, which used propane and butane in a "huff and puff" cycle to potentially double a shale well's ultimate recovery.

"NGLs have been used over the decades anecdotally for remedial well treatments and for spiking field gas into the gas injection stream in miscible enhanced oil recovery floods, commonly known as water alternating gas injection," Starr said.

During their research, Starr and Szabo connected with Tadd Wallace, president of C3 Oilfield Services, who had experience using NGL in fracturing at his previous company, Gas Frac Energy Services. The three realized their complementary ideas and experience would speed the project. In 2020, after a year's worth of R&D, the company patented Single Shot IOR technology.

The purpose was to "address anything impeding the reservoir's ability to flow hydrocarbons," Starr said.

In fractured wells, she said, the purpose is to re-establish a well's original stimulated rock volume.

Single Shot's technology involves a chemical mixture designed to address the cause of the damage that is carried deep into the formation by NGL. Starr said most other stimulation methods involve water, which seems counterintuitive in water-sensitive formations. She sees Single Shot as the first reasonable alternative to water-based fluids.

There is also the challenge that treating hydraulically fractured horizontal shale wells involves diverting the treatment fluid from the well's heel. Single Shot was designed to include multiple diversion states to push the fluid "beyond the path of least resistance," she said.

Developing the treatment

They began by focusing the design on horizontal shale wells with laterals of 5,000 ft or longer. In those laterals, much of the frac water gets trapped in the formation, reducing the amount of oil it can release. Starr said that University of Texas Professor Mukul M. Sharma hypothesized in a 2015 paper that "the natural connection to the natural fracture system during the hydraulic fracturing process distributes the frac fluid way beyond the induced fracture system."

From that hypothesis, she added, "we believe this trapped water impedes the reservoir's ability to flow oil toward the hydraulically fractured wellbore. The Single Shot IOR treatment employs a surfactant that has an affinity for water and will transfer from the NGL to water, making the water less viscous and letting it flow much more easily."

Testing involved partnering with UCS, which had the equipment and initial production to pump NGL. Although the researchers' original focus was on horizontal wells, treating those wells with NGL in the field could be prohibitively expensive with standard equipment. So, they started the testing process on vertical wells.

But they also realized that the horizontal process was so costly because it used much more horsepower than was needed for Single Shot. The company developed fit-for-purpose equipment to make the procedure more cost-effective for operators, Starr said.

"To our knowledge," Starr said, "previous attempts at using NGLs for remedial well stimulation did not use additives or diversion. Single Shot combines the NGLs with chemistry, principally surfactant and inhibitors designed specifically for use in propane and butane, and diversion techniques to attempt to open up damaged intervals. The Single Shot proprietary [initial production] IP is designed to eliminate emulsification of the NGLs or the oil/water it contacts downhole. The surfactant is designed to transfer from the NGL to water it contacts in the formation and mobilize the water that is interfering with oil/gas production."

Single Shot also works on paraffin.

"We developed an inhibitor that is carried in the NGL into the formation. The NGLs dissolve the paraffin in the tubulars and the inhibitor is designed to prevent deposition for a period of time during production," Starr said.

To date, C3 has tested the procedure on 14 wells, all of which experienced improved production.

"Half the treatments focused on proving up the technology while the other half applied the technology to treat well damage and increase IPs," Starr said. "Our vertical well treatments have proven successful in cleaning out condensate blockage in gas wells in the Rodessa and Olmos formations in Texas and removing water block in water-sensitive gas formations like the Jack Fork in Oklahoma." OGJ

One Solution to Orphaned Wells? Consider Adopting

The USGS has documented about 150,000 orphaned wells in the U.S. in need of plugging, but a government scientist wants industry to consider other options, including recompletion and CO_2 storage.

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More than 150,000 documented orphan wells exist in the U.S., and it's estimated that at least 1 million more are waiting to be discovered.

That's both a huge problem and an opportunity, Nick Gianoutsos, a physical scientist for the U.S. Geological Survey (USGS), said during an address on the "Challenge of Orphaned Wells" at Unconventional Resources Technology Conference (URTeC) in Denver.

Orphaned wells—for which no one is financially liable—present a number of risks. But they also may hold potential.

Many states allow orphan wells to be adopted, Gianoutsos said. New completion techniques could return some wells to productivity or to be repurposed for a variety of uses, including carbon sequestration.

But left abandoned, they represent a risk to people and the environment.

"Leaking orphaned wells benefit no one. They waste natural resources, contaminate water and pose a threat to the environment," Gianoutsos said.

They also pose hazards to hydraulic fracturing and can leak methane and hydrogen sulfide, H_2S, into the environment. An estimated 14 million people live within a mile of one of the documented wells.

"Orphan wells come in all shapes and sizes," he said. "Some have infrastructure intact. Some are open holes. Some are below ground and out of sight.

"When you're dealing with orphaned wells, you never know what you're going to get."

Finding undocumented orphan wells takes some sleuthing—in some cases combining ground observations with detection technologies such as drone-mounted aeromagnetic surveys and laser imaging, detection and ranging (LIDAR) surveys with historical records.

"Where are orphaned wells located? Pretty much everywhere there is oil and gas drilling," he said. "Everywhere we see oil and gas drilling, we see orphaned wells."

Orphan wells have existed since the beginning of the oil and gas industry, he added.

In August 2022, the USGS data identified 117,672 known orphaned wells in 27 states. Less than a year later, the number identified mushroomed to about 150,000, he said.

Currently, Ohio has the most identified orphaned wells—more than 20,000—while about 5,800 have been located in Texas.

Using IHS Markit data, Gianoutsos said, a pattern has emerged: the number of wells that become orphans track fairly consistently with the overall number of wells drilled in any given year. Ultimately, about 1.5% to 2% end up orphaned.

"Most companies are responsible and clean up," Gianoutsos said. "There are a handful of companies that make everyone look bad."

Adopt a well?

The federal government has allocated $4.7 billion for plugging and remediating orphan wells, but Gianoutsos says adoption may be a better option.

"The only thing better than plugging an orphaned well is adopting an orphaned well," Gianoutsos said.

In states that allow adoption of wells, some could be brought back online at low cost using modern recompletion methods, he said. New uses could also be found for the wells.

"There's been a lot of interest in wells being repurposed for geothermal, carbon dioxide storage and wastewater disposal," he said.

Progress on that front, however, has been constrained by "a lot of unknowns" and a general lack of well information, he said.

"Any time you have rock and steel and cement and time, things are going to start to break down," he said. "In areas where water is highly corrosive, the corrosivity of the water can really break down the casing. Seismicity can crack the cement."

Younger wells, he noted, tend not to be as deteriorated as older wells, which makes them better candidates for repurposing, he said.

It also presents the "opportunity to reduce pollution and greenhouse gas emissions and create new jobs," he said. OGI

Tech Bytes

P-Scan 5 can be deployed by divers or ROVs.

FORCE Technology

Next-Gen Subsea Inspection Scanner Launched

FORCE Technology has introduced a new generation of its P-Scan ultrasound scanner for subsea inspections, the company announced in June. The P-Scan 5's extended modular platform now enables inspection teams to acquire data from previously inaccessible parts of compact subsea infrastructure.

It can be deployed by divers or ROVs and the system uses AI and machine learning for data analysis and interpretation, helping optimize the reporting workflow.

Clariant Launches New Demulsification Solution

Clariant Oil Services announced in June it was launching a new, more sustainable demulsification process called PHASETREAT WET for the oil and gas industry.

PHASETREAT WET was designed to meet stricter environmental requirements for oil and water separation while helping operators reduce operational costs, simplify logistics and mitigate safety risks, Clariant said in a press release.

The company said the process reduces chemical volume by up to 75% for offshore operators. For onshore operations, the solution offers additional benefits such as decreased dosages for demulsifiers and de-oilers, improved water treatment quality, more efficient oil treatment and reduction of injection points.

Halliburton, Nabors Collaborate on Well Construction

Halliburton Co. and Nabors Industries announced in June they are collaborating on technologies for well construction automation.

Covered technologies include the Halliburton Well Construction 4.0 digital surface and subsurface drilling technologies, the LOGIX Autonomous Drilling Platform and the Nabors SmartROS universal rig controls and automation platform and RigCLOUD high-performance digital infrastructure platform.

Initially deployed in Iraq, the companies' technologies automate well construction services from planning to execution across both subsurface and surface equipment and environments. Halliburton and Nabors said they will engage in further opportunities to expand projects for other customers across the globe

ABS, A&M Start New Research Projects

ABS and Texas A&M Engineering Experiment Station kicked off a batch of new, funded research projects with the signing of a research agreement at the Zachry Engineering Education Complex on the Texas A&M University campus, ABS said in June.

Research topics include ammonia as fuel, ship electrification, carbon capture and sequestration, trusted AI and safety of industrial wearable visualization technologies.

"These projects seek to adapt, as appropriate, emerging techniques and technologies to enhance the safety of the maritime industry and bring about a smooth transition to clean energy," Dr. Sharath Girimaji, head of the department of ocean engineering and ABS ocean engineering department chair, said in a press release.

inVision Mobile Connects Users to Data

Intelligent Wellhead Systems introduced inVision Mobile to connect users of the IWS inVision Technology Platform with wellsite operational data, the company announced in June.

Intelligent Wellhead Systems

Intelligent Wellhead Systems' inVision Mobile

With inVision Mobile, users can view key data from a cell phone or tablet. They can inspect pad progress and current well activity, a live frac tree and live valve positions. When running frac and wireline data through IWS safety and efficiency controls, users can analyze frac and wireline plots remotely, as well as a pre-

set frac and wireline plots with the most pertinent data.

"By giving operators even greater, easier access to operational data at the wellsite, they can respond immediately to changing conditions," Bill Henn, vice president of business development for IWS, said in a press release.

Acoustics Tool Launched for Well Flow Diagnostics

TGT

The ChorusX acoustic platform enables energy companies to find and map fluid flow throughout the well-reservoir system.

TGT Diagnostics said in June it was launching a new diagnostic resource designed to locate and characterize flow in oil and gas wells.

The ChorusX acoustic platform enables energy companies to find and map fluid flow throughout the well-reservoir system with greater ease and precision, TGT said. An array of eight nano-synchronized sensors records high-resolution flow sounds across a range of intensities and frequencies. A phase analysis workflow combines acoustic field modeling with a waveform-matching algorithm. This combination delivers radial distance to acoustics and flow diagnosis, according to TGT.

Ken Feather, TGT's chief marketing officer, said in a press release that ChorusX is designed to extend spatial and audible reach to record the lightest, quietest and furthest flows; recognize different types of flows; and pinpoint flow sources radially and in depth.

TGS Launches Well Data Analytics Platform

TGS has launched the cloud-based Well Data Analytics platform, which brings together subsurface data, powerful visualization and advanced analytics, according to a June company announcement.

The platform leverages the TGS data portfolio, which encompasses every major U.S. basin, to deliver access to competitive well data within seconds, enabling efficient analysis and decision-making. The analytics tool also provides access to cloud-based well data resources that are QC checked and ready to use.

TGS

TGS' new Well Data Analytics platform

Well Data Analytics combines adaptable search workflows, multivariate map-based visualizations and analytics, advanced time-series plotting, benchmarking tools and customizable dashboard layouts with well data and well performance data in a cloud-based application. These features allow users to benchmark, predict and optimize well performance more easily and with more accuracy, the company said.

New Mapping Service Uses Close to Bit Tool

A new near-bit shallow and ultra-deep resistivity service is intended to increase well placement accuracy.

In June, Halliburton introduced its EarthStar X service as part of its iStar intelligent drilling and logging platform. The service company says the EarthStar X service's near-bit, ultra-deep reservoir mapping sensor increases well placement accuracy—detecting geological changes early and enabling quick well trajectory correction to remain in the most productive zones and maximize asset value. Integrated shallow resistivity measurements allow early reserves evaluation and accurate fluid characterization to further improve reservoir insight while lowering operational complexity and risks.

The EarthStar X service maps geology in three dimensions using ultra-deep azimuthal resistivity measurements and inversion processing to geosteer, geostop and geomap. Real-time fluid and bed boundaries visualization can place the well in the reservoir's most productive zone and increase the section's net-to-gross value, the company said. The industry's closest ultra-deep azimuthal resistivity sensor to the bit can detect formation changes early and make timely well path adjustments to avoid early exits.

Honeywell Introduces Performance Solution

Honeywell said in June its new Upstream Production Performance Suite will help eliminate unplanned downtime, prevent failures and recover autonomously from known failures.

The company said its new three-tiered suite automates and digitalizes operations from the wellhead to the control room and provides operators different levels of control and monitoring options. Honeywell said the suite enables oil and gas companies to improve production efficiency and asset reliability while reducing operating costs with intelligent controls and predictive analysis.

Project to Test Coriolis Meters for Multiphase Flow

TÜV SÜD

The research program is intended to validate the performance of Coriolis meters in multiphase flow.

TÜV SÜD National Engineering Laboratory, a U.K. flow measurement technology lab, announced in June that it had launched an international research project to validate the performance of Coriolis meters when used in multiphase flows. The

research aims to increase confidence in measurement results and improve fiscal accuracy for oil and gas operators.

While Coriolis meters are one of the most accurate flow metering technologies for single phase flow measurement, they are increasingly being used for multiphase flow situations. Operators, however, have no way to substantiate the multiphase performance in both flowrate and density measurements.

Chris Mills, a senior consultant, said the lab is seeking partners to join the project.

Software Speeds Up Field Development Planning

SLB and Quorum Software introduced a joint digital planning solution to automatically evaluate project economics and halve the time needed for field development planning, according to a June press release.

SLB and Quorum said the new field development planning solution, which leverages Quorum's Planning Space business planning and petroleum economics offering within the FDPlan agile field development planning solution from SLB, is now commercially available. In June 2022, the companies announced an agreement to integrate their solutions within the cloud-based Delfi digital platform.

"With subsurface and petroleum economics connected, customers can quickly assess their global asset portfolio to prioritize their development projects, lowering costs, maximizing returns and significantly reducing time to value through streamlined field development planning processes," said SLB's Trygve Randen, senior vice president of digital products and solutions.

The solution brings petroleum economics data into the earliest stage of asset evaluation and incorporates corporate standard fiscal regimes, prices and currencies, the companies said. The solution unites subsurface data, domain workflows and corporate decision-making to increase collaboration among development geoscientists, engineers and petroleum economics teams for faster and better-informed decisions.

Tyson Greer, chief products officer at Quorum, said the integrated solution will enhance performance and profitability for energy companies "with seamless connectivity between petrotechnical data and business planning."

Rebellion's Orphan P&A Program Listed on ACR

In June, Rebellion Energy Solutions announced that its methane abatement and land restoration project became the first orphan oil and gas well plugging project to be listed by the American Carbon Registry (ACR).

The wells plugged in Rebellion's Heartland Project are more than 40 years old and have been unattended for more than a decade. Rebellion assumed ownership of the wells and privately funded the project to plug the wells. No state or federal funds were used, the company said.

In May, Rebellion completed the project in a historic Oklahoma oil field, which it said permanently abates approximately 74,000 metric tons of CO_2e.

Rebellion's business model for methane-abatement and land-restoration projects provides a sustainable platform for project funding through sales of durable, verifiable carbon-offset credits generated under the ACR framework. OGI

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2023				
KIOGA Annual Convention & Expo	Aug. 20-22	Wichita, Kan.	Hyatt Regency	kioga.org
Texas Energy Forum	Aug. 23-24	Houston	Petroleum Club of Houston	usenergystreamforums.com
2023 OGA Annual Conference	Aug. 28	Norman, Okla.	Norman Hotel & Conference Center	okgas.org
SEG/AAPG IMAGE Conference	Aug. 28-Sept. 1	Houston	George R. Brown Conv. Ctr.	imageevent.org/2023
Carbon and ESG Strategies 2023	**Aug. 30-31**	**Houston**	**Norris Centers**	**hartenergy.com/events**
SPE Offshore Europe Conference & Exhibition	Sept. 5-8	Aberdeen, Scotland	P&J Live	offshore-europe.co.uk
Solar Power International	Sept. 11-14	Las Vegas	The Venetian Conv. & Expo Ctr.	re-plus.com
GPA Midstream Convention	Sept. 17-20	San Antonio	Marriott Rivercenter on the River Walk	gpamidstreamconvention.org
World Petroleum Conference	Sept. 17-21	Calgary, Alberta	BMO Centre, Stampede Park	24wpc.com
America's Natural Gas Conference	**Sept. 27**	**Houston**	**Westin Galleria**	**hartenergy.com/events**
Energy Capital Conference	**Oct. 2**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
A&D Strategies & Opportunities	**Oct. 3**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
Offshore WINDPOWER 2023	Oct. 3-4	Boston	Hynes Convention Center	cleanpower.org
Clean Energy Technology	**Oct. 23-24**	**San Antonio**	**Marriott Rivercenter on the River Walk**	**hartenergy.com/events**
OTC Brasil	Oct. 24-26	Rio de Janeiro	Centro de Convenções SulAmérica	otcbrasil.org
39th USAEE/IAEE North American Conference	Oct. 23-26	Houston	Omni Hotel	usaeeconference.com
WEA Wildcatter of the Year	Nov. 4	Denver	Sheraton Denver Downtown	westernenergyalliance.org
Louisiana Energy Golf Open	Nov. 6	Lafayette, La.	Oakbourne Country Club	loga.la
Energy Transition North America 2023	Nov. 7-8	Houston	TBD	reutersevents.com
IPAA Annual Meeting	Nov. 6-8	San Antonio	JW Marriott San Antonio Hill Country	ipaa.org
Rice Energy Finance Summit	Nov. 10	Houston	Rice University	business.rice.edu
OK Petroleum Alliance Fall Conference	Nov. 15-16	Oklahoma City	The National Hotel	thepetroleumalliance.com
Executive Oil Conference & Exhibition	**Nov. 15-16**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
DUG Appalachia	**Nov. 29-30**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
URTeC Latin America	Dec. 4-6	Buenos Aires, Argentina	Hilton Buenos Aires	urtec.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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For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

Oil and Gas Investor

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EOG On Its New Frac Design: 'No Comment'

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Securities analysts ask but get no real answer: "What's the new completion design?"

EOG Resources is reporting 22% greater production from Delaware Basin Wolfcamp wells in which it's used this new design and 20% greater EUR.

So, what is it? That was asked myriad ways at least a dozen times in EOG's earnings call in May—but non-answered as many times as well.

Bob Brackett, an analyst with Bernstein Research who notoriously doesn't hold back, asked in June in a Bernstein conference. Again, the reply was a non-answer.

Arun Jayaram, an analyst with J.P. Morgan Securities, asked in a J.P. Morgan conference, also in June. Still, a non-answer.

The background: EOG has tested the new completion design in 39 Wolfcamp wells. In these, first-year production was 22% greater than that of similar wells which were completed with its typical design and EUR was up 20%. It expects to use the new design in 70 or so of its more than 350 new Delaware Basin wells this year.

Erin Faulkner, a senior editor at Enverus, acknowledged the news in a report this summer but didn't have the recipe, either. EOG "has been tightlipped about the method," she wrote.

Follow the clues

Here's what we do know that may be clues in unlocking the new EOG frac-design cryptex without losing the frac.

- EOG first used the design in the Eagle Ford beginning in 2016, according to Ezra Yacob, chairman and CEO. It's been successful, "but we didn't see the same uplift that we see in the Permian," he said in the May earnings call. "… It really has to do with the difference in rock type and their geological properties between the two plays."

  But, he added, it is the design it has switched to in the Eagle Ford and "in a lot of our emerging plays."

- It's more expensive but not by much.

- EOG is rolling it out in the Permian slowly, Yacob said, as "we just don't want to outrun our learnings."

- Its use is bespoke. Billy Helms, EOG president and COO, said at the J.P. Morgan conference, "We have learned that it is not going to work on every type—on every target. It's going to be applicable to a lot of the deeper targets that we are seeing."

- Depending on the mechanics of the rock it's being applied to, "it involves constructing the wellbore in a way that lends itself to this new technique," he added.

- The production uplift is in both oil and gas, Jeff Leitzell, executive vice president, E&P, said in May.

- EOG plans to test the recipe in some shallower formations, Leitzell added. But since the job costs more, "we just want to be mindful about how quickly we're testing it and be strategic about the pace that we're going ahead and putting these in the ground."

- Helms said the rock type is critical "to why it works in some areas and so we're cautiously moving through our program to make sure we test as we go to understand which targets lend themselves best to this design change and which ones don't."

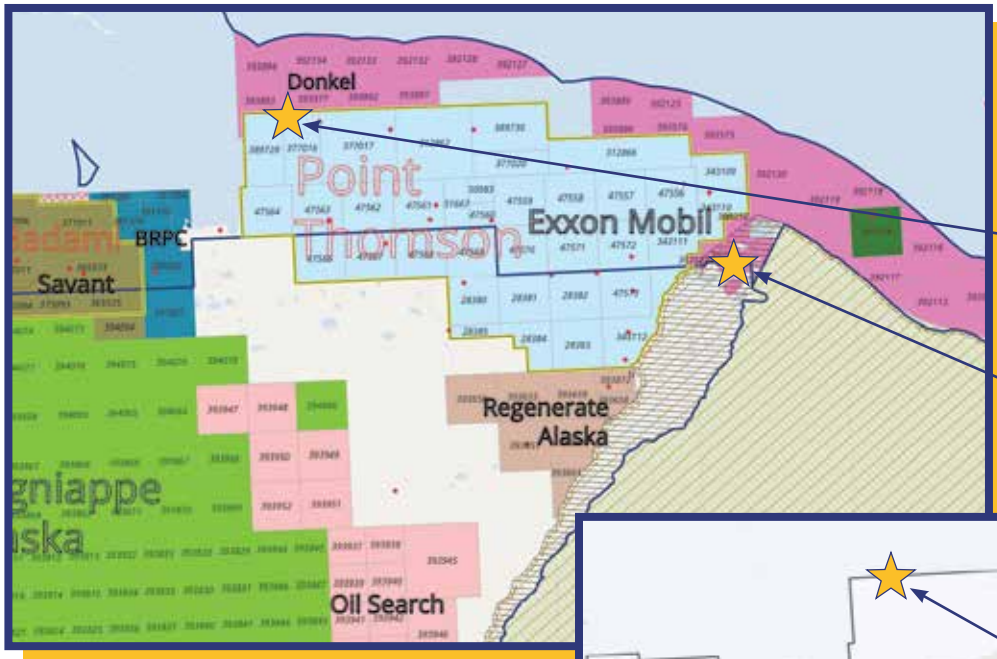
- Helms didn't say application in the wrong rock could be fatal. Rather, the caution is only "because it does cost a little bit more and we want to be very disciplined on how we apply that across the fields so we maximize the economics."

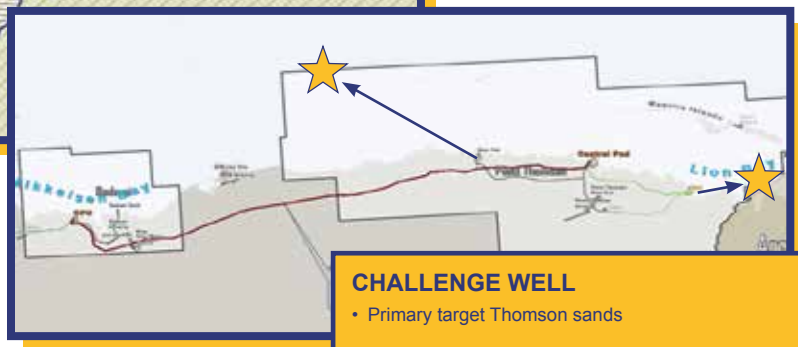
- EOG is "actively testing it in all of our emerging plays," Leitzell said, and will be "evaluating those results throughout the year."

- Yacob said at the Bernstein conference the learnings are bi-directional in EOG's multiple basins—the Powder River, Eagle Ford, Denver-Julesburg, Williston, Anadarko and Barnett; essentially, EOG is in all of the U.S. shale plays except the Fayetteville and Haynesville.

  "We're able to utilize data from across different basins, different geologic environments, different pressure regimes," Yacob said. "And that's really what continually helps our modeling and geologic understanding of any of the plays that we're in." OGI

Donkel Oil & Gas Alaska





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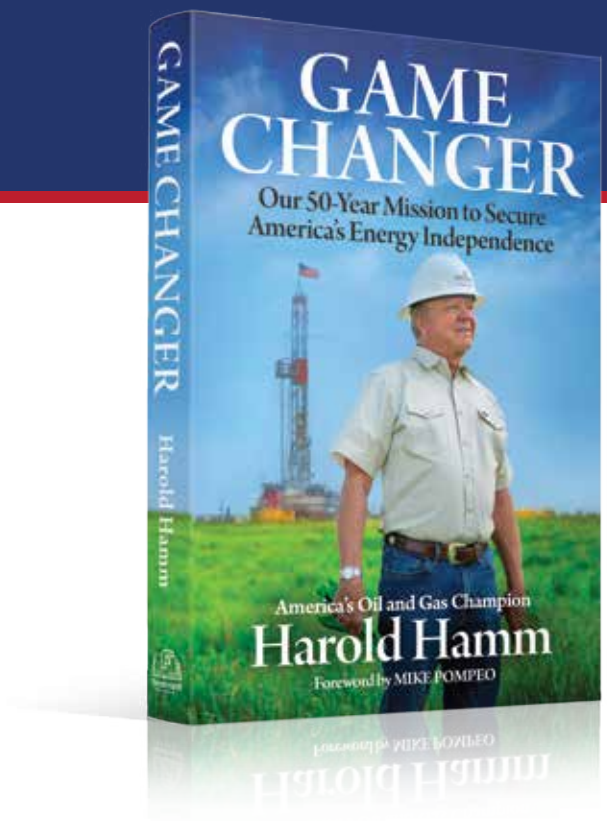

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