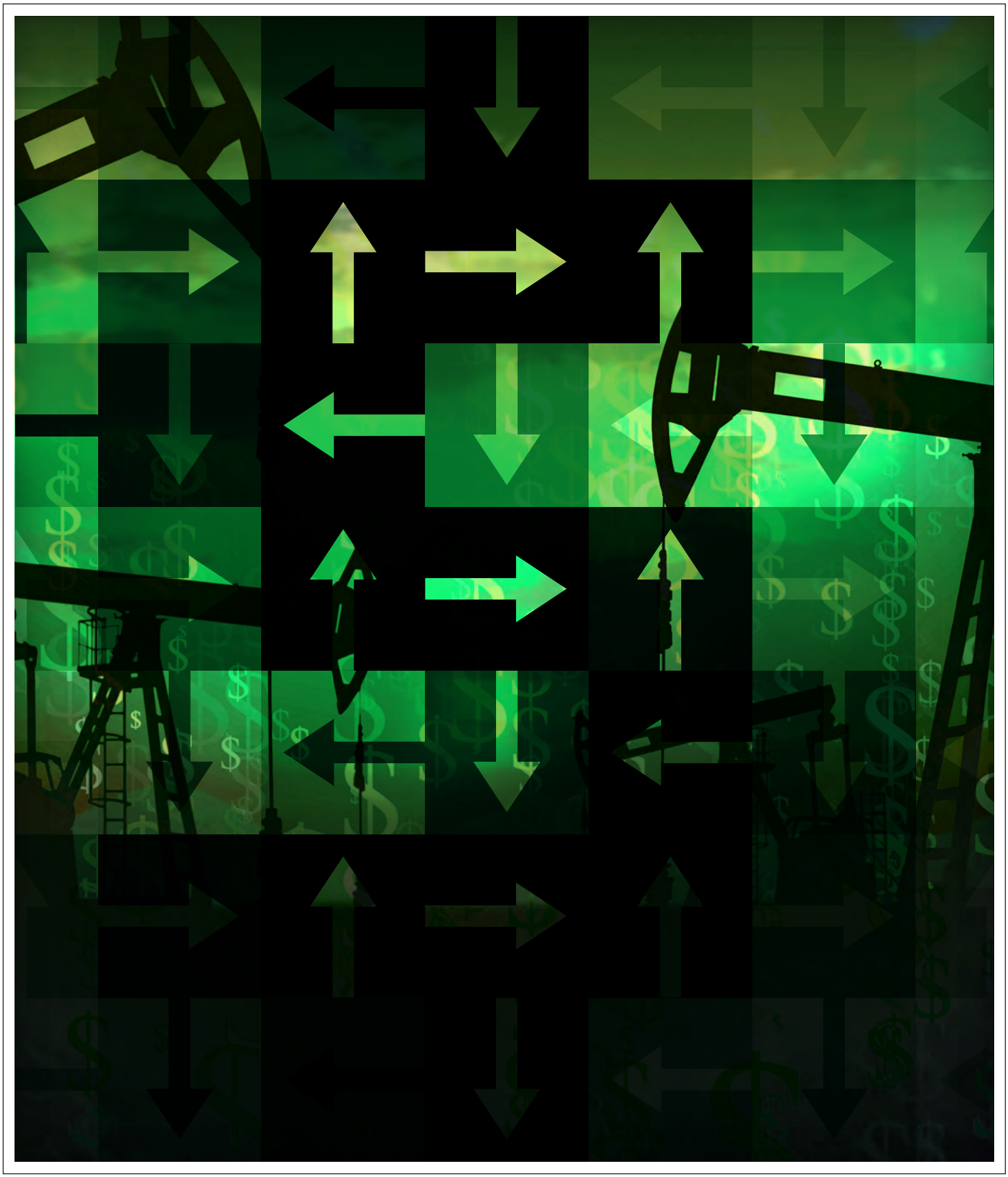
Oil and Gas Investor

JANUARY 2022



Will inflation cut into E&P free cash flows?

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	ASSET DIVESTITURE	INITIAL PUBLIC OFFERING	INITIAL PUBLIC OFFERING	ASSET DIVESTITURE
Co-Manager	Financial Advisor	Joint Bookrunner	Joint Bookrunner	Financial Advisor

$370 MILLION	$199 MILLION	$650 MILLION	$560 MILLION	$535 MILLION
LONESTAR RESOURCES	Cactus	TALOS ENERGY	MARTIN MIDSTREAM PARTNERS	LONESTAR RESOURCES
ACQUIRED BY PENN VIRGINIA CORPORATION	FOLLOW-ON OFFERING	SENIOR SECURED NOTES	HAS SUCCESSFULLY CONSUMMATED ITS DEBT EXCHANGE, FINANCING, AND CASH TENDER	CHAPTER 11 RESTRUCTURING
Fairness Opinion	Co-Manager	Senior Co-Manager	Financial Advisor	Financial Advisor

UNDISCLOSED	$270 MILLION	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED
NORTH AMERICAN TRANSPORTATION AND SERVICE PLATFORM	elkpetroleum	EAGLE FORD MINERALS PLATFORM	AETHON	VIKING MINERALS
CORPORATE CARVE OUT	ADVISOR TO THE AD HOC CROSSOVER LENDER	PRIVATE PLACEMENT OF EQUITY	ASSET DIVESTITURE	ASSET DIVESTITURE
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: Inflation has spread into grocery stores, clothing shops and especially energy commodities. Illustration by Robert D. Avila.

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LATEST CONTENT

Global Data: Higher Investment Is Needed For Eagle Ford To Facilitate Production Growth

By Hart Energy Staff

An additional $1.5 billion of investment is required to increase production by 10% in the Eagle Ford by the end of next year.

Oil Industry Veterans Partner To Bring More Solar Power To Permian Basin

By Velda Addison, Senior Editor

The group is working with Black & Veatch subsidiary Diode Ventures to develop and finance utility-scale solar projects in the Permian Basin.

US LNG Export Capacity Will Be World's Largest By 2022, EIA Says

By Faiza Rizvi, Senior Associate Editor

By the end of next year, EIA estimates U.S. export capacity to overtake those of Australia and Qatar, the two largest LNG exporters.

Private Equity Investor Lime Rock Closes $203 Million Acquisition Fund

By Hart Energy Staff

The acquisition fund, in which the Goldman Sachs Asset Management Vintage Funds served as the lead investor, received $134 million in new capital commitments to it and a separate co-investment vehicle.

Talos Aims To Operate First Active Carbon Sequestration Project On US Gulf Coast

By Hart Energy Staff

Talos Energy recently unveiled plans to develop a CCS project that CEO Timothy S. Duncan says could be the first active carbon sequestration project on the U.S. Gulf Coast.

ONLINE EXCLUSIVES

Permian Basin Producers Talk Today's Challenges With Eyes On Future

By Velda Addison, Senior Editor

Oil executives from ConocoPhillips, Diamondback Energy and Pioneer Natural Resources discuss shale innovation during global oil conference.

Measuring Methane To Achieve ESG Goals

By Faiza Rizvi, Senior Associate Editor

CEO of Boston-based Kuva Systems discusses why continuous emissions monitoring is crucial for oil and gas companies to meet ESG and methane intensity goals.

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By Velda Addison, Senior Editor

Taking the sustainable route when choosing which products to use in the oil field does not mean having to sacrifice price or performance, Integrity BioChem CEO says.

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By Larry Prado, Activity Editor

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Oil And Gas 2022 Outlook: US Shale Producers' New Perspective

Hear how U.S. producers are pivoting toward "a new math" from Amy Chronis and Kate Hardin of Deloitte.

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Energy Policy Watch: Ohio Congressman Discusses Biden's 'All-Out Assault On Fossil Fuels'

Ohio Congressman Bill Johnson gives his take on how President Biden's infrastructure and spending bills will affect the oil and gas industry plus the role natural gas produced in the U.S. has in addressing climate change.

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GREEDY GAS PRODUCERS? NAH

LEN VERMILLION, EDITORIAL DIRECTOR

Let me start off by saying I never asked to become a columnist again. As you probably know, this space has been occupied for the last few years by our friend, colleague and editor-in-chief, Steve Toon. With Steve's sudden passing, someone needs to step into this column space, which was also once occupied by Leslie Haines, the now semi-retired editor who built this magazine for most of its 40 years. So, I must admit, I'm a bit nervous stepping on to this ground.

Sure, I've been a columnist on and off throughout my career as a journalist, but I respect this specific page greatly, so hence my apprehension.

As the title of this column shifts from "From the Editor-in-Chief" to "No One Asked Me, But …" I'm summoning that wildcatter spirit. I am ready to explore the industry and ready to take on the challenge, albeit with a different style than my predecessors.

With that said, here it goes. Get ready for some streams of thought about what I've heard, seen and read as I cover the energy business.

Oil and gas greed?

Sorry, Sen. Elizabeth Warren, but your letter to 12 natural gas CEOs accusing them of "corporate greed" doesn't seem to have much merit. There's so much the senator from Massachusetts has overlooked about the natural gas market. I'm not the only one who thinks she's misguided. Toby Rice, CEO of the country's largest natural gas producer, EQT Corp., eloquently pointed out the shortcomings of her accusations in his letter released on Dec. 7.

I was fortunate enough to get the first interview with Rice merely an hour after his letter as we chatted on stage at the DUG East Conference in Pittsburgh. He wasn't interested in holding back, even pointing out that Sen. Warren has made similar greed accusations against other industries, including poultry producers and banking. Fair enough, if there's corporate greed sticking it to the masses, by all means call them out and more. But let's make sure we know what we are talking about first, Senator.

As Rice told me—and our audience—on stage, "The facts are clear. U.S. LNG powered by the Marcellus Shale is the biggest green initiative on the planet." He added, "We shouldn't be thinking about cutting down LNG exports, we should be thinking about doing more."

Here are some of those facts, courtesy of Rice's response to Sen. Warren and his comments to me at DUG East. The U.S. has brought down emissions by nearly 970 million tons per year, mainly because of the switch from coal to natural gas. Meanwhile, if the U.S. increases LNG exports to replace China's planned coal power plants with natural gas, Rice said it would reduce about 370 MMmt of CO_2, which is roughly equivalent to the emissions reduction impact of the entire U.S. renewables sector.

You can read Rice's full letter and view my interview with him at HartEnergy.com. While I can't fit all of his responses into this space, we have it covered extensively on our digital channels.

But is the gas certified?

One of the liveliest conversations we had at DUG East was about certified natural gas. I was able to chat on stage with Jennifer Stewart, longtime natural gas industry executive and a principal advisor for Equitable Origin, a non-profit organization that works to certify natural gas so that producers and buyers—hear that, people of France—understand that your gas has been produced under the highest social and environmental standards.

Before you scoff at the notion, understand a packed room of natural gas producers and investors took an active interest in engaging the conversation. It's clearly a subject that is being taken seriously in oil and gas circles. Hear that, Sen. Warren?

What was most notable during the session was the belief that while certification might not lead to premium pricing for natural gas, it most certainly will become the difference in whether or not you can actually sell your gas in the future.

I think it's obvious certified natural gas has more than piqued the interest of natural gas producers. Stewart and I had a hard time getting off the stage as we were bombarded with questions from the audience.

Don't think certification and ESG requirements are going away anytime soon.

Scoff at them at your peril.

WILL MARKET SMILE ON COLGATE?

DARREN BARBEE, SENIOR EDITOR

Could an oil and gas IPO happen in 2022?

It's possible, and if it happens, it will be by a company that has methodically built itself through Permian Basin dealmaking. Or it could be just the disaster that fossil fuel naysayers are hoping to see.

Colgate Energy Partners III LLC is reportedly considering an IPO, the first public offering since Vine Energy went public in March and was subsequently gobbled up in November by Chesapeake Energy Corp. in a $2.2 billion deal.

Colgate would likely hang back until the second quarter to launch an offering—possibly in April—and is just as likely to explore a sale. Or Colgate, which reportedly has strong free cash flow, could just go on being a private independent money maker.

Other IPOs date back to 2018, when Berry Petroleum went public. The last major offering in Permian Basin was Jagged Peak Energy's entry into the market in January 2017.

Colgate Energy, based in Midland, Texas, is a privately held Permian Basin E&P founded in 2015 and backed by Pearl Energy Investments and NGP. Colgate has played the long game in acquisitions, with roughly $1 billion in announced deals in the past four years.

In 2018, Colgate began serious acquisitions with Concho Resources Inc., which along with Luxe Energy II LLC, paid $280 million for about 22,000 net acres in Ward and Reeves counties, Texas.

Colgate subsequently acquired Luxe Energy LLC this year in an all-stock transaction. Luxe owned 22,000 net acres adjacent to Colgate's Reeves and Ward positions and averaged net daily production of 17,000 boe/d. Then, this year, it rattled off three deals in the Permian.

With deals flying this year, Colgate next agreed to buy acreage for Occidental Petroleum Corp., again in the Permian's southern Delaware Basin for $508 million. It was Colgate's second transaction in June after buying Luxe.

In November, Colgate once again seized on an opportunity to expand, this time purchasing 22,000 net acres in Eddy and Lea counties, N.M., for $190 million.

At the time, Colgate said that, pro forma, it would hold 108,000 net acres in Reeves, Ward and Eddy counties with production of about 62,000 boe/d. The company also said it was running five rigs, keeping with a more aggressive drilling pace for private companies in 2021.

Reuters reported that Pearl Energy Investments and NGP want to take Colgate public at a valuation approaching $4 billion, including debt, according to a report made by Reuters on Dec. 14 citing people familiar with the matter. Colgate and Pearl Energy did not respond to request for comment.

Colgate has had an easy time in the bond market paying for its deals. In June, the company made a private placement of 5.875% senior unsecured notes in the aggregate principal amount of $500 million—$100 million more than it originally proposed in its offering.

Reuters reported that Pearl Energy Investments and NGP are working with Credit Suisse Group AG for the Colgate IPO, which could launch by the middle of 2022. However, they cautioned the IPO plan had not been finalized, and Reuters noted the sources had spoken on condition of anonymity because the matter was confidential.

Still, E&Ps face an uphill battle as some consider oil and gas a sunset industry, said Chris Kalnin, CEO of BKV Corp., which owns assets in the Marcellus and Barnett shales.

Publicly traded oil and gas companies have seen their values steadily tick up since December 2020, but despite now throwing off cash returns to investors, they lag behind other sectors, even those "green" companies that may not produce revenue or income.

Kalnin, who spoke at Hart Energy's DUG East, said the reason is that investors see oil and gas as an industry with a limited shelf life. While the energy transition is occurring, it appears to be happening far slower than all of the chatter suggests.

Still, the ultimate trial for companies that test the public waters such as Colgate will be whether they can step into a market that has for years been overtly hostile to fossil fuels.

Colgate will have to make a compelling case not just that it can be profitable, but that it has a rigorous ESG plan. Look for Colgate to be the test case for E&P IPOs that make money but also have been squeezed out of the market by aspirational, cash-lite companies.

'SILLY SEASON' IS UPON US

JACK BELCHER, CORNERSTONE GOVERNMENT AFFAIRS

Things get weird during election years. With 2021 in our rear-view mirror, we move into what promises to be a wild ride. There is great pressure on the White House to take additional action in the coming months to get energy prices under control. High prices for gasoline, natural gas, electricity and heating oil going into the winter are contributing to a tremendous fall in President Biden's poll numbers. Coupled with inflation and some foreign policy chaos and uncertainties, energy prices threaten not only Biden's legacy but the chances of the Democrats holding on to either the House or Senate in the midterm elections.

So, what more can the president do to impact energy prices? Not a lot in the short term. He has already taken action to release stockpiles from the Strategic Petroleum Reserve. This is largely a symbolic gesture, since it generally only works when there is a temporary supply shortage, which is not the case currently. Right now, the situation is systemic. While OPEC has agreed to increase its output in December months after the Biden administration promised to warm relations with Saudi Arabia, prices will likely stay relatively high as the world, especially countries in emerging markets, continues to recover from the pandemic.

Longer term, the president could take action to encourage additional domestic production by ensuring regular federal oil and gas lease sales and a leasing and permitting approach that incentivizes and facilitates robust leasing and exploration activity. Given the administration's anti-fossil fuel campaign, however, such a reversal in policy is pure fantasy.

It is clear that efforts by oil-consuming nations can only go so far because there are only so many "emergency reserve" barrels consuming nations can burn before they are out of ammunition and even more vulnerable to producing nations. The irony is that the Biden administration's anti-fossil fuel campaign has made the U.S. more of a consuming nation and less of a producing one. Now they are forced to make nice with the Saudis, who have less respect for a U.S. that does recognize its own strength from its energy resources.

We can see from what is happening in Europe how high energy prices can wreak havoc on a region's economy. Much of Europe's energy woes are self-inflicted due to years of bad public policies that created an overreliance on renewables, began to phase-out nuclear and didn't provide enough in the way of gas storage or options for natural gas. Now the energy situation is becoming politicized. This is also likely to happen in the U.S.

Indeed, the Biden administration seems determined to continue to pursue its anti-fossil fuel agenda, while trying to keep energy prices from getting too high. However, that may be a challenge since boosting our own domestic supply does not seem to be part of the equation, nor does supporting our natural gas production for continued and increased LNG exports to the world.

Congressional action could further complicate matters for Biden's legacy and the midterm elections, but at least a portion of that risk could be diminishing. As of this writing, President Biden had signed the infrastructure package into law, but the House-passed budget reconciliation known as "Build Back Better" was stuck in the Senate where Sens. Joe Manchin (D-WV) and Krysten Sinema (D-AZ) had yet to sign on. While the House-passed bill made significant changes to the tax code, it did not contain many of the changes to the current tax code deductions that the oil and gas industry feared would be removed (percentage depletion allowance, deductions of geological and geophysical expenses, and intangible drilling costs). However, it still contained a large fee on "waste methane" from oil and gas facilities of $900 per ton of methane in 2023 ramping up to $1,500 per ton by 2025.

They call election year the "silly season," because impending elections can often cause politicians to become unpredictable and make sudden, even rash, decisions. The White House and Democratic leadership in the House and Senate are desperate to avoid losses in November and understand clearly that rising prices at the pump, grocery store and pretty much everywhere else these days is a surefire ticket to defeat.

The administration has already launched a Federal Trade Commission investigation into gasoline price fixing. A group of Democratic senators recently questioned our long-established policy of allowing LNG exports and similar questions have been raised about crude oil exports. With so much at stake, whether it's action from the White House or Congress, we should expect the unexpected.

EVENTS CALENDAR

The following events present investment and networking opportunities for industry executives and financiers.

EVENT	DATE	CITY	VENUE	CONTACT
2021				
IPAA Private Capital Conference	Jan. 20	Houston	JW Marriott Galleria	ipaa.org
NAPE Summit	Feb. 8-11	Houston	George R. Brown Conv. Ctr.	napeexpo.com
The Energy Venture Investment Summit	Feb. 16-17	Golden, CO	The Colorado School of Mines	theenergyventuresummit.com
DUG Midcontinent	**March 1-3**	**Oklahoma City**	**Oklahoma City Conv. Ctr.**	**dugmidcontinent.com**
LOGA Annual Meeting	March 7-8	Lake Charles, LA	Golden Nugget Hotel & Casino	loga.la
CERAWeek by IHS Markit	March 7-11	Houston	TBD	ceraweek.com
EnerCom Dallas	April 6-7	Dallas	Dallas Petroleum Club	enercomdallas.com
Energy ESG Conference	**April 13-14**	**Houston**	**TBD**	**hartenergyconferences.com**
Mineral & Royalty Conference	April 18-19	Houston	Post Oak Hotel	mineralconference.com
Women In Energy	**April 29**	**Houston**	**Marriott Marquis**	**hartenergyconferences.com**
Offshore Technology Conference	May 2-5	Houston	NRG Park	2022.otcnet.org
Energy Transition Capital Conference	**May 10**	**Houston**	**Omni Houston**	**hartenergyconferences.com**
Carbon Management Conference	**May 16**	**Fort Worth, TX**	**Fort Worth Convention Center**	**hartenergyconferences.com**
DUG Permian	**May 16-18**	**Fort Worth, TX**	**Fort Worth Convention Center**	**dugpermian.com**
Louisiana Energy Conference	May 24-27	New Orleans	The Ritz-Carlton, New Orleans	louisianaenergyconference.com
DUG Haynesville	**May 25-26**	**Shreveport, LA**	**Shreveport Convention Center**	**dughaynesville.com**
CIPA Annual Meeting	June 9	Carlsbad, CA	TBD	cipa.org
DUG East/Marcellus-Utica Midstream	**June 13-15**	**Pittsburgh**	**David L. Lawrence Conv. Ctr.**	**dugeast.com**
Unconventional Resources Technology Conference	June 20-22	Houston	George R. Brown Conv. Ctr.	urtec.org
IPAA Annual Meeting	July 20-22	Colorado Springs, CO	The Broadmoor	ipaa.org
DUG Bakken and Rockies	**June 28-29**	**Denver**	**Colorado Convention Center**	**hartenergyconferences.com**
EnerCom Denver	Aug. 8-11	Denver	The Westin Denver Downtown	enercomdenver.com
Energy Transition Conference	**Sept. 6-7**	**Houston**	**TBD**	**hartenergyconferences.com**
Natural Gas Conference	**Sept. 26-27**	**Dallas**	**TBD**	**hartenergyconferences.com**
Energy ESG Conference	**Oct. 11-12**	**Houston**	**TBD**	**hartenergyconferences.com**
A&D Strategies and Opportunities Conference	**Oct. 25-26**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Executive Oil Conference	**Nov. 15-16**	**Midland, TX**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Thursday, odd mos.	Fort Worth	Fort Worth Petroleum Club	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., even 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.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	ipaa.org

Email details of your event to Brandy Fidler at bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

Invested In —— What Matters

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- Junior debt: $10 - $50 million
- Equity: $10 - $25 million

Senior Debt | Junior Debt | Equity

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Oil and gas price expectations bolster bankers' confidence

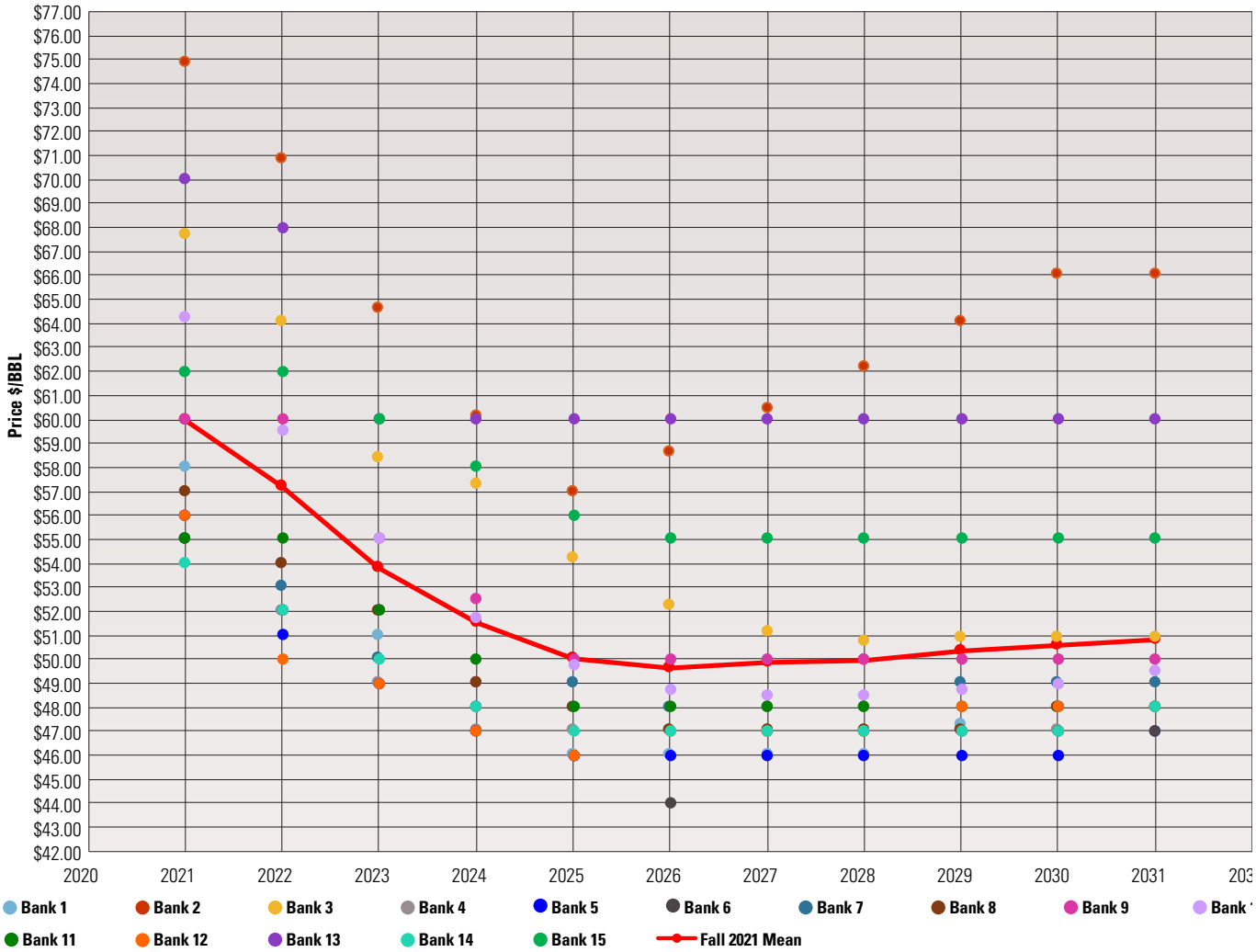
Bankers are confident that oil and gas prices will remain at lofty levels in 2022, making it more likely that producers will be able to borrow, Haynes and Boone LLP said in its fall price deck survey.

"I'm more optimistic that prices will continue to stay high because I don't see a lot of immediate rush to go out and overdrill and overspend for increased near-term productivity," Buddy Clark, partner and co-chair of the Haynes and Boone energy practice group, told Hart Energy. OPEC+ continues to be a wild card, but efforts by the Biden administration to tap into the strategic petroleum reserve won't alter the fundamentals of supply and demand, he said.

Fifteen banks participated in the survey, including lenders such as Wells Fargo & Co., Frost Bank, Amegy Bank and Japanese bank Sumitomo Mitsui Banking Corp. (SMBC Group). They provided price decks through 2031 to Haynes and Boone that will influence their oil and gas borrowing bases, which is the amount of credit a bank would be willing to extend to a producer. Each bank has its own proprietary method to determine its borrowing base,

Buddy Clark

Oil Base Case - Fall 2021



Source: Haynes and Boone LLP

but price is a principal factor in making those calculations.

Bank price decks in the fall survey are almost 10% higher than they were during the COVID-19 crash.

"It's kind of the starting yardstick that banks use to evaluate collateral to determine the borrowing base amount," Clark said, "but clearly location, location to market, access to infrastructure, the basis for getting the production to a market—those are factors that go into the borrowing base determination."

The banks align their expectations with the Nymex forward strip. Following the lead of commodities traders, the banks anticipate prices of both crude oil and natural gas to fall until 2025, then recover somewhat through 2031, the extent of the survey's time frame.

The banks' price deck is not necessarily a prediction of where prices will head but is part of the underwriting equation that's necessary to ensure their principle is repaid if a producer goes under. Because the Nymex strip changes constantly, the banks watch it as they redetermine price tags on commodities on a semiannual basis.

For example, the midday price of WTI on Nov. 22 was in the upper-$70s per barrel. The mean price of the banks surveyed has oil in the upper $50s in 2022. That could provide a path for a producer to impress a lender.

"If a bank's price tag has $60 oil for next year, but the producers able to put in hedges for the next year at $80, they're going to get a boost above the, call it a 'plain vanilla' borrowing base determination because the banks will take that into account," Clark said. "The price tag is really just one of their ways to manage one of the risks of repayment, and price risk is a big one."

The value of a price deck is that it is objective. It's an apples-to-apples comparison and one that banks—at least some banks—are willing to share. It also hints at what the sector can expect from lenders.

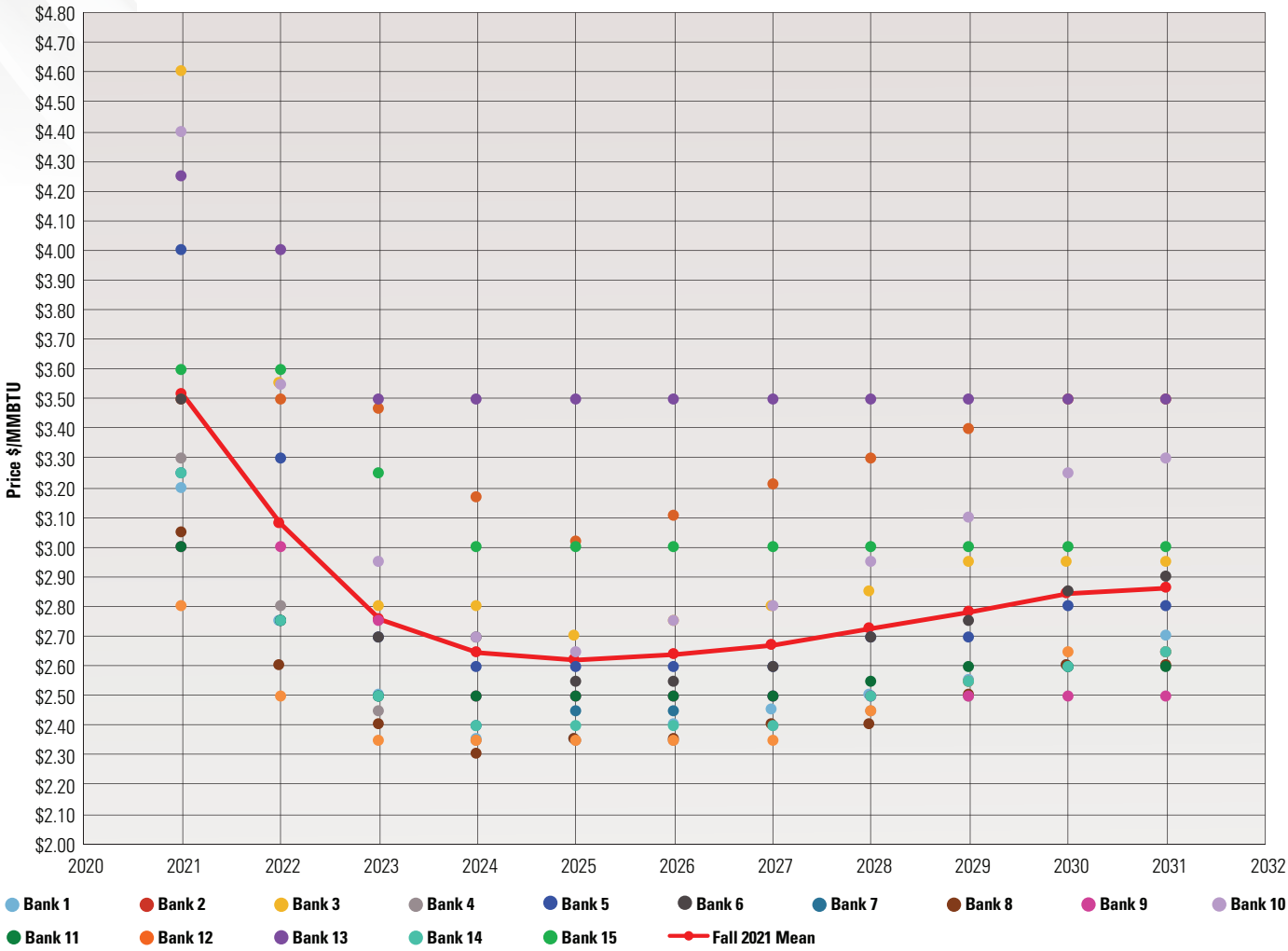
"It's a directional survey, if you will," he said. "It's certainly not a specific quantifiable dollar-for-dollar survey. But if we see that banks' price decks are up 10% from the prior time or up 20%, then you can be pretty confident that borrowing bases are headed in that direction, as well."

Of courses, surprises abound in the oil and gas sector. Clark said some recent strategic decisions owe more to political and social pressure than the economic fundamentals of the industry.

"I'm just shocked that some of the large majors are selling out of the Permian," he said. "I think it's a reaction to current political and social influences, not so much that [companies like Shell] have decided that oil will no longer be in demand five years from now. I don't think anybody is predicting that, so they're selling off assets because they're trying to improve their carbon footprint with respect to shareholders and activists.

—Joseph Markman

Gas Base Case - Fall 2021



Source: Haynes and Boone LLP

US shale gas could become 'biggest green initiative on planet,'

U.S. LNG holds significant potential to put the country on track to achieve its sustainability goals, according to Toby Rice, CEO of EQT Corp., the largest natural gas producer in the U.S.

"The facts are clear. U.S. LNG powered by the Marcellus Shale is the biggest green initiative on the planet," Rice told attendees of Hart Energy's DUG East & Marcellus-Utica Midstream conference and exhibition on Dec. 7. "We shouldn't be thinking about cutting down LNG exports; we should be thinking about doing more."

Rice said he is extremely bullish on natural gas, adding that the growth engine for domestic gas producers will be international LNG.

Making a clear case to ramp up LNG exports, Rice explained that out of the 30 billion tons of the carbon emissions globally, 14 billion comes from foreign coal powered generation.

"Put this in perspective, one of the reasons we've been able

Toby Rice

to bring down emissions in U.S. by over 970 million tons per year is because of the switch we made from coal to natural gas," Rice noted, stressing that natural gas production helps offset emissions from coal, which promotes sustainability.

Rice continued, "For every Bcf per day of natural gas that we use to power electricity, we are offsetting similar amounts of coal, which when burnt produces about 52 million tons of emissions per year."

If U.S. increases LNG exports to replace only China's planned coal power plants with natural gas, Rice said it would reduce about 370 million metric tons of CO_2, which is roughly equivalent to the emissions reduction impact of the entire U.S. renewables sector.

To capture this opportunity, U.S. would need to increase natural gas production by roughly 25% or approximately half the production increase seen between 2005 and 2020, a period during which U.S. saw declines in both CO_2 and methane emissions.

Amid increasing concerns over gas prices, Sen. Elizabeth Warren last month lashed out at top oil and gas producers, asking them to explain their decisions to "export record amounts of natural gas while imposing massive price increases" on consumers, accusing them of "corporate greed" while Americans struggle to pay their bills.

Responding to Sen. Warren's comments, Rice said the concerns are "misguided," noting that boosting natural gas exports has in fact helped bring down natural gas prices.

"Despite the elevated gas prices, the spot prices were well below

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the average price of natural gas for 2021 of $5.70 Mcf," Rice said.

"Why is that? It's because of U.S. shale and the work we're doing here in the Appalachian basin and all over the country. Yes, the price of natural gas has increased rapidly relative to 2020 as the economic engines of the world have reignited, but natural gas prices in 2020 were the lowest in over two decades, a year during which we exported LNG," he said.

Because of the shale gas boom and companies like EQT, Rice said consumers in U.S. continue to benefit from some of the lowest natural gas prices in the world.

Rice went on to say that the U.S. natural gas industry needs additional pipelines and more LNG facilities to offset carbon emissions. "Hopefully, our politicians can help us spread the word about natural gas benefits, move away from foreign coal and embrace natural gas," he said.

Rice said that LNG isn't just a clean fuel, but also fulfills the reliability and affordability criteria of the future energy mix.

"When we think about three criteria for energy of the future, it is cheap, reliable and clean. Everyone has been prioritizing the clean aspects of energy but we have been sacrificing reliability for the cleanliness of solar and wind," Rice explained.

He continued, "But now we're starting to see reliability come into play. In Texas, for instance, Public Utility Commission of Texas is starting to put a price tag on reliability, which is a game changer because it is one of the biggest criteria that natural gas provides in addition to being affordable and clean … Eventually people will realize that natural gas will meet their environmental ambitions."

—Faiza Rizvi

Chesapeake Energy aims to become an ESG trailblazer

Already known as a pioneer of the U.S. shale revolution, Oklahoma City-based Chesapeake Energy Corp. is aiming to continue its legacy as a trailblazer in the oil and gas industry.

"We will be one of the first operators and hope to be the

Morgan Hager

first operator to have responsibly sourced gas in two major shale basins—the Gulf Coast and Appalachia production," Morgan Hager, vice president of HS&E at Chesapeake Energy Corp., said during an opening keynote address at Hart Energy's Energy ESG Conference. "This will result in approximately 3 billion cubic feet per day of responsibly sourced gas."

What does that mean? According to Hager, Chesapeake's production of 3 Bcf/d of natural gas means that approximately 11 million homes in the U.S. will

be able to heat their homes and have electrical power with independently certified responsibly sourced gas.

"They will know the power that is coming to their homes was done so in a way that is responsible, ethical and driving us forward," she added.

Founded in 1989, Chesapeake Energy has experienced both the highs and lows of the oil and gas business, even at one point becoming one of the largest leaseholders of shale gas acreage in the U.S.

However, after experiencing a tumultuous chapter in the company's history that included filing for Chapter 11 bankruptcy, Chesapeake emerged from a restructuring process in early 2021 a smaller company freed of liabilities and more tightly focused on the sustainable production of natural gas primarily in the Appalachian and Haynesville shale basins.

As part of what former Chesapeake CEO Doug Lawler described as a business reset upon completing its restructuring, the company also unveiled lofty ESG goals in February 2021, including a commitment to achieve net-zero greenhouse-gas (GHG) direct emissions by 2035 and other environmental targets that would place Chesapeake on a path toward setting "a new standard of environmental excellence" in the oil and gas industry.

During her presentation on Nov. 29 that helped kick off the first-ever in-person energy ESG event, Hager gave an overview of the aggressive emissions reductions program Chesapeake has developed, adding that the company is not stopping there.

In addition to forming several partnerships to certify that its natural gas is responsibly produced according to strict standards and independent verification, Hager said Chesapeake is also working with third-party vendors to validate its GHG emission calculations and methodologies to ensure the highest level of reporting.

Both shareholders and the general public are also able to view the company's performance data and ESG program updates at a new microsite Chesapeake recently launched dedicated to the company's ESG reporting and progress toward its climate-related targets.

"With a dedicated ESG microsite, Chesapeake's commitment and path to delivering meaningful ESG improvements across our business are fully transparent," Nick Dell'Osso, Chesapeake's president and CEO, commented in a Dec. 1 release announcing the microsite.

Hager noted during her presentation on Nov. 29 how these were just a couple of examples of what Chesapeake is doing on the environmental side, which is only part of the ESG puzzle.

"The industry has always built a really strong cultural focus around protecting employees and contractors and focusing on the safety aspects of our business," she said. "We will continue to do that through ESG and look to see that social side incorporate that safety and really be a stronghold for us."

—Emily Patsy

EIA forecasts oil prices to fall in 2022

The rally seen this year in the oil markets, which included oil prices hitting a seven-year high in October, could be relatively short-lived.

Rising production from OPEC+ countries and the U.S. is set to increase global liquid fuels inventories and cause crude oil prices to fall in 2022, according to the U.S. Energy Information Administration (EIA).

"We expect that the price of Brent will fall from an average of $84/bbl in October 2021 to $66/bbl in December 2022, and the price of WTI will fall from an average of $81/bbl in October 2021 to $62/bbl in December 2022," the EIA wrote in a report on Nov. 18.

Still, spot prices of Brent and WTI have risen since their April 2020 lows to above pre-pandemic levels for most of 2021. In October, the price of Brent crude oil averaged $84/bbl, and the price of WTI averaged $81/bbl, the highest nominal prices since October 2014.

"We forecast that global oil inventories will begin building in 2022, driven by rising production from OPEC+ countries and the United States and slowing growth in global oil demand," the EIA wrote. "We expect this shift will put downward pressure on the Brent price, which will average $72/bbl during 2022."

Similarly, the International Energy Agency (IEA) also projects the oil market rally may ease as high prices could provide incentive to boost production, particularly in the U.S., according to a recent Reuters report.

Reuters reports that the IEA expects average Brent prices to be around $79.40/bbl in 2022. However, Rosneft said it may reach $120/bbl in the second half of 2022, according to the report citing TASS news agency.

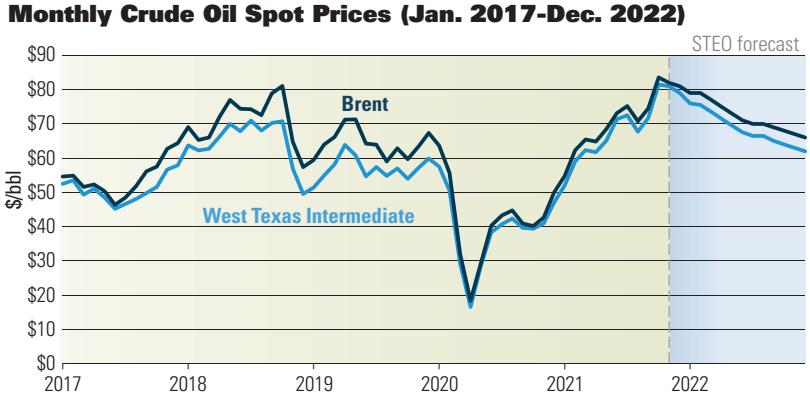
Since the third quarter, global consumption of crude oil and petroleum products has increased faster than production, which has caused lower inventory levels and higher crude oil prices.

"We forecast global crude oil demand will exceed global supply through the end of the year, contribute to some additional inventory draws, and keep the Brent crude oil price above $80/bbl through December 2021," the EIA wrote.

However, the EIA forecasts that global oil inventories will begin building in 2022.

Low crude oil inventories,

Monthly Crude Oil Spot Prices (Jan. 2017-Dec. 2022)



Source: U.S. Energy Information Administration

both globally and in the U.S., have put upward price pressure on near-dated crude oil contracts, whereas longer-dated crude oil contract prices are lower, likely reflecting expectations of a more balanced market, according to the EIA.

The futures markets are showing high prices for near-term contracts compared with longer-dated contracts, a situation known as backwardation. Crude oil inventory levels, among other factors, affect the difference between near-term and longer-term futures prices. Differences in prices between crude oil contracts for delivery in the near term compared with contracts for delivery at later dates indicate market expectations that inventory draws will moderate.

Low crude oil inventories in the U.S.—particularly in the transportation and storage hub of Cushing, Okla., where Nymex WTI futures contracts are physically settled—have likely contributed to additional backwardation in WTI compared with Brent.

—Hart Energy Staff

Talos Taps skills for carbon storage build-out along Gulf Coast

Carbon capture, utilization and sequestration (CCUS) opportunities are moving past theory as upstream players take strides to make the Gulf Coast a major carbon storage site. As the oil and gas industry shifts to net-zero emissions, large public independent energy company Talos Energy Inc. is relying on its oil and gas expertise to advance CCUS in the region.

"In-house, we have the conventional reservoir and seismic expertise, the data and the operating expertise," said Talos president and CEO Tim Duncan at Hart Energy's Energy Transition Capital Conference. "All those things have helped us build and manage the right reputational strength that we want on the E&P side and every ounce of those skills ought to be transferable to what we're doing on the CCUS side."

As a top producer in the U.S. Gulf of Mexico, Talos intends to use what it has learned to operate

Tim Duncan

the first major offshore storage site along the Gulf Coast. Duncan said the company has identified 40,000 to 70,000 acres of prime geology to build the site and estimates 225 to 275 million metric tons of CO_2 storage capacity.

"I'm trying to find acreage with the right geology and depths and the least amount of liabilities like old wells that have been P&A [plugged and abandoned] so I can then take it to a midstream and industrial partner and say 'this is the right spot,'" Duncan said. "We will do this anywhere we have the right geology; that's

a starting point for us. If that's offshore, that's great. If it's in the marshlands of Louisiana, that's fine, too."

Out of 12 bidders—along with its partner Carbonvert Inc.—Talos was selected as the sole winning bidder for the Jefferson County storage site located near Beaumont and Port Arthur, Texas. The award places the company among a small group of domestic independents with a physical project site dedicated to carbon sequestration and storage.

"Our job now is to try to figure out the right relationships that can make that project work, and we're working very hard on that right now," he said.

According to Duncan, producers should take notes from the midstream handbook for pipelines to be successful with CCUS projects around the Gulf Coast. For the Jefferson County project, Talos is taking the anchor-tenant approach to develop the site by working with emitters, as well as midstream providers, to advance the site.

"It's a midstream model with midstream returns, but it's over a longer period of time," he said. "But the drivers for making this successful is you have to be a low-cost producer and have experience with stores [storage] and you have to be able to scale."

He said as these projects get to five-year final investment decision, there will be an influx of participants looking to partner on these projects. But he warns it isn't like drilling an oil well, so producers have to be transparent about the returns and whole roadmap of a CCUS project.

"Typically, those offshore projects are seven years, but now we're talking about a 30- to 40-year project," he said. "This has a different return profile and is a different business in general, so there will be a lot of explanation needed as this develops."

"Our job is to not put our shareholders in the position where they don't understand what we're doing," he continued, "or they don't lose any confidence that we're not chasing the right projects or the right returns."

In the next 12 months, the company plans to identify three to four more storage sites across the Gulf Coast utilizing anchor tenant emitters at each site. Talos is actively advancing multiple potential projects across more than half a million acres, Duncan said.

"As we go all the way," he said, "we're going to need to be thoughtful about doing things, most of which is right through the wheelhouse of what we've done in the past, and some of these things require us to be thought-forward about how we think about injection technology, monitoring technology and how we think about engineering design on these projects."

"We're taking a very measured approach," he added. "These projects all have to stand up on their own two feet. Each of these will be their own separate projects that are big things, but there's a big market out there… We've launched something that we think is really interesting and we're not going to stop there; we're going to continue to focus on projects along the Gulf Coast."

—Mary Holcomb

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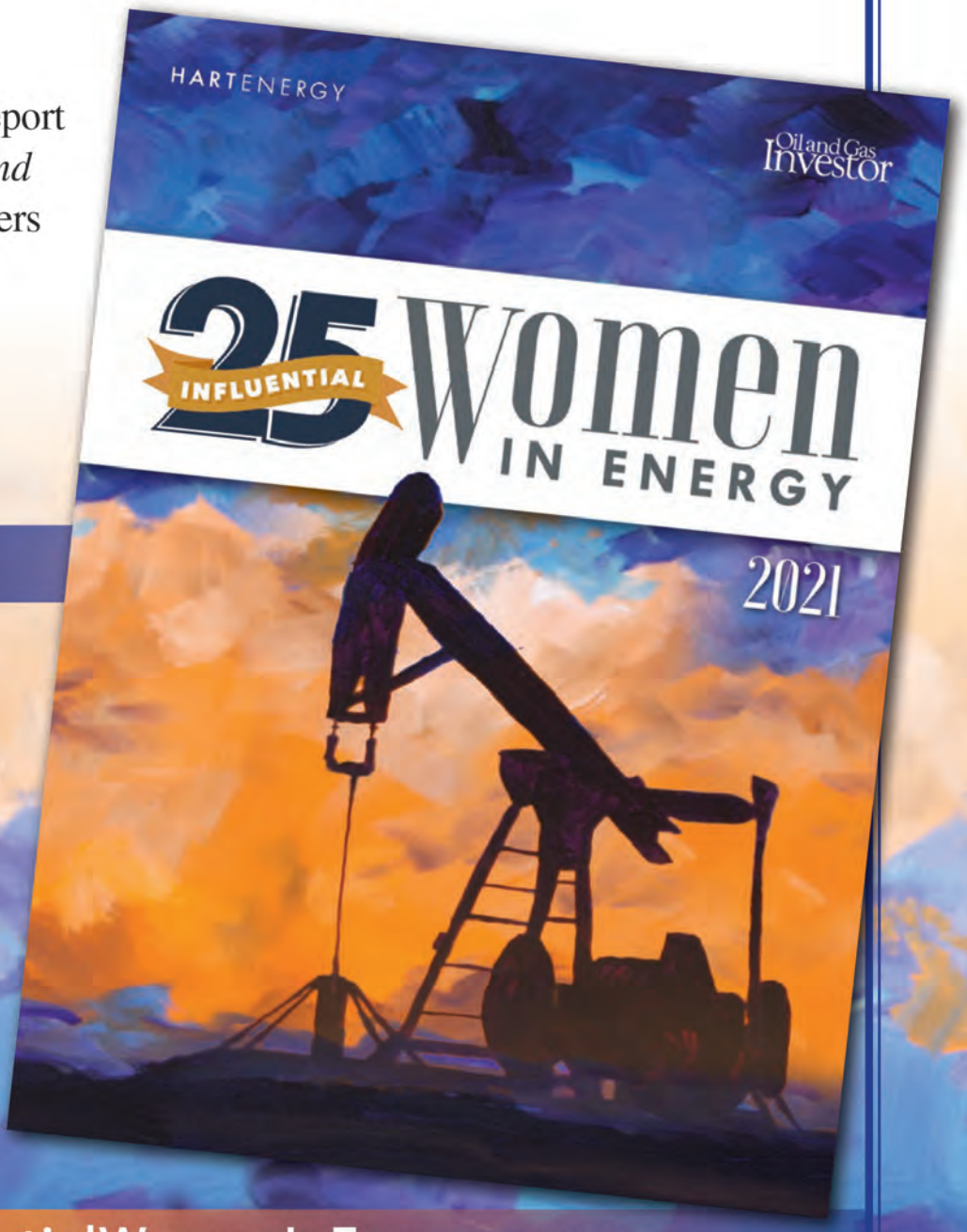

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Emission reductions in oil and gas largely from divestments

While some of the largest oil and gas producers have successfully lowered their emissions in line with sustainability goals, research and consulting firm GlobalData notes that a large portion of those reductions come from divestments. The analytics company forecasts global production to increase by 8% by 2026, stressing the need for stronger action to ensure methane emissions do not rise with it.

U.S. is the second-largest methane emitter from oil and gas operations at 12.3 Mt. Studies have suggested that the scope of the methane problem is larger than government reports have led people to believe due to the limitations of current measurement techniques.

"When emissions are reduced by divestment, those emissions have not disappeared but simply moved around," said Miles Weinstein, energy transition analyst at GlobalData.

"Emission intensity has been reduced in many cases, but in the face of increasing production, more efforts will be necessary to meet national and international climate targets. After all, the oil and gas industry is responsible for around a quarter of methane emissions globally."

GlobalData's latest report shows that Hilcorp Energy has been the largest methane emitter among upstream operators for the third year in a row, with reported CH_4 emissions at 3.4 Mt of CO_2 equivalent in 2020, and has the highest emission intensity among top emitters, at 11 Mt of CO_2 equivalent per boe/d. Meanwhile, Energy Transfer, a midstream company, is the largest emitter overall with 6.1 Mt- CO_2e.

Weinstein continued, "Hilcorp's emission intensity tripled in 2017, the same year a large number of wells were acquired from ConocoPhillips Co. Meanwhile, ConocoPhillips' emission intensity decreased 50% that year. Other companies have shared similar strategies that rapidly reduce their own emissions without greatly affecting the net total. However, many of the same companies do have plans in place to make real emissions reductions using technological improvements."

In the U.S., an estimated 21% of oil and gas methane emissions could have been abated at zero net cost or net profit in 2020. The emission abatement measures mainly include methods of capturing gas that would otherwise be vented to the atmosphere, and replacing gas-powered pneumatic devices with electric ones. The gas saved can then be used or sold, reducing costs or bringing revenue.

"While the U.S. has below-average emission intensity, there is a lot of room for improvement," Weinstein noted. "The good news is that solutions to drastically reduce emissions are available today—in some cases at zero net cost or even net profit."

He continued, "If gas prices continue to rise, so will the portion of emissions that can be economically abated."

The sector activities responsible for most of the emissions are oil and gas production, gathering and boosting, and natural gas distribution. Much of it originates from gas venting from

various equipment types and equipment leaks.

Weinstein explained that offshore oil and gas and onshore crude oil production are the sectors with the most potential for low-cost emissions abatement, mainly due to to their lower production of natural gas relative to oil. Meanwhile, he said onshore gas and downstream operations would have higher average costs as natural gas has a predominant role in production, transportation and processing.

With the recent announcement of the Global Methane Pledge at COP26, the EPA has proposed rules to regulate methane from existing sources for the first time. The regulation includes monitoring and fixing of leaks, especially where large leaks are likely, as well as regulations and emission limits on specific equipment. The regulation is expected to reduce methane emissions by 74% from 2005 levels by 2030. If approved, it would take effect in 2023.

Commenting on EPA's proposed regulations, Weinstein said they have much wider coverage than current ones, which applied to new sources only and did not result in significant reductions.

"The new regulations take a performance-based approach in some cases by allowing companies flexibility in the methods they use to meet the requirements. This is thought to be ultimately more effective than a prescriptive, one-size-fits-all approach. Thus, real progress on methane reduction is likely if the regulations are approved," he said.

—Hart Energy Staff

US majors push oil and gas' importance in low-carbon strategies

Oil and gas companies in the industry have rolled out a variety of measures to achieve their net-zero goals; however, top executives from Exxon Mobil Corp. and Chevron Corp. revealed plans that focus on advancements for both renewables and fossil fuels.

Innovation was the theme of the 23rd World Petroleum Congress (WPC), and accordingly, the CEOs of the two U.S. oil majors shared net-zero pathways that depend on both breakthroughs in low-carbon energy solutions and advancements to existing oil and gas infrastructure.

"Our industry can and should take a leading role in providing the products that enable modern life while developing the needed technologies and strategies to advance the lower-emissions future," Darren Woods, chairman and CEO at Exxon Mobil, said during an opening session on Dec. 6. "It's imperative that we do both and strike the right balance today, while making improvements for tomorrow."

Unlike its peers, Irving, Texas-based Exxon Mobil has yet to make a formal pledge, but revealed it was considering committing to net-zero carbon emissions by 2050, the Wall Street Journal reported in August. During the panel, Woods said the company would continue to develop fossil fuels, but will leverage its technical capabilities to achieve the largest emission reductions at the lowest cost to society.

"As the world transitions to a lower-carbon energy system, it's critical to strike the right balance,

ensuring that we continue to meet all the world's essential needs," Woods said. "The fact remains under most critical scenarios, including net-zero pathways, oil and natural gas will continue to play a significant role in meeting society's needs."

In February, Exxon Mobil launched its low carbon solutions business to focus on carbon capture and storage (CCS) innovation. The business has announced concepts for several CCS hubs where high-emitting industries can share infrastructure, expertise and assets to create cost-effective solutions at scale.

Additionally, Exxon Mobil, along with 10 other companies, have supported a concept for the large-scale deployment of CCS technology in Houston.

"We believe a project like this could annually capture about 100 million metric tons of CO_2 from area refineries, chemical plants and power generation facilities by 2040. That's equal to the greenhouse-gas (GHG) emissions from more than 20 million cars," Woods said.

Exxon Mobil plans to invest more than $15 billion by 2027 on initiatives to lower GHG emissions in its operations and to grow its low carbon solutions business, Woods said.

In Alberta, Canada, Canadian oil producer Imperial Oil Ltd. is working on a process that turns vegetable oil into renewable diesel at its 191,000-bbl/d Strathcona refinery. The success of the project will aid majority-owner Exxon Mobil (69.9% ownership) with its goal to produce more than 40,000 bbl/d of low-emissions fuels by 2025.

"We're continuing to advance research with our university partners and other stakeholders to explore and commercialize additional biophilic technologies that don't compete with food sources," he said.

Its effort will extend to its Permian Basin operations, where it intends to achieve net-zero emissions and eliminate flaring in the region by 2030.

"Our investments to electrify our operations in the region, coupled with our innovative work to identify and eliminate methane leaks and routine flaring puts us on this achievable path," he said.

Additionally, Exxon Mobil has placed a priority on sectors notoriously hard to decarbonize like commercial transportation and power generation, which account for more than 80% of the world's CO_2 emissions in the industry.

Similarly, San Ramon, Calif.-based Chevron is focusing its 140 years of expertise on progressing these massive sectors that will dictate the global transition to clean energy, according to chairman and CEO Mike Wirth.

"Our approach is straightforward: we're accelerating progress toward a lower-carbon future by driving down the emissions intensity of our oil and gas production today and investing to develop lower-carbon energy solutions for tomorrow," Wirth told WPC attendees on Dec. 6.

The aviation sector generates 11% of all U.S. transportation emissions, with total emissions growing at 4% to 5% per year. With major airlines pushing for solutions, Chevron is developing technology to produce sustainable aviation fuel.

"Sustainable aviation fuel can reduce emissions up to 80% on

a lifecycle basis compared to traditional jet fuel," he said. "It's compatible with modern aircraft engines and airport fueling infrastructure, and we've already begun producing them in our Southern California refinery."

In the agriculture space, Chevron's partnership with California Bioenergy LLC and California dairy farmers has helped it successfully produce and market dairy biomethane as renewable natural gas. Essentially, it is using advanced technology to capture methane emitted to the atmosphere and turning it into a valuable fuel with a negative carbon intensity on a lifecycle basis under California standard.

"Developing and scaling additional solutions including hydrogen and carbon capture will enable more industries to join in the drive toward a lower-carbon future. These industries built modern society, and people around the world rely on them every day," he said.

Like Woods, Wirth still sees the importance of oil and gas, pointing to the Biden administration's recent request for OPEC to boost oil production and the International Energy Agency's appeal to Russia to supply more natural gas to Europe.

"This reveals a fundamental truth that should inform any rational conversation about the future of energy: oil and gas will continue to play a central role in meeting the world's energy needs," he said.

However, the company still has a variety of projects underway to reduce the carbon intensity of the business including improving methane detection, rethinking facility designs, optimizing equipment, utilizing renewable power and deploying new operational practices.

In the Permian Basin, for example, Chevron has entered a partnership to build solar and wind power to support operations. The company expects this project to reduce its emissions in the region by 300,000 tonnes per year.

"Innovation will be critical to meeting the expanding energy needs of a growing world," he said. "Breakthroughs will be needed, technologies must be developed and deployed, and global energy challenges must be solved on a massive scale."

—Mary Holcomb

US LNG export capacity to reach new milestone by 2022

The U.S. is on the verge of dominating the global LNG market, according to a recent report by the U.S. Energy Information Administration (EIA).

The U.S. began exporting LNG from the Lower 48 in February 2016 and, seemingly overnight, became the world's third-largest LNG exporter following the rapid development of export terminals across the country. Now, based on the slew of announced project plans for capacity expansions, the EIA is predicting U.S. LNG export capacity will be the world's largest by 2022.

"In 2022, U.S. LNG export capacity will exceed that of the two current largest global LNG exporters, Australia (11.4 Bcf/d) and Qatar (10.3 Bcf/d)," the EIA said in the report published on Dec. 2, attributing the milestone

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to new LNG liquefaction units (called trains) expected to be placed in service in 2022 at Sabine Pass LNG and Calcasieu Pass LNG.

According to announced project plans, the EIA lists the following U.S. LNG export capacity expansions will occur between December and fall 2022:

Completion of Train 6 at the Sabine Pass LNG export facility. Train 6 will add up to 760 MMcf/d of peak export capacity. Train 6 began producing LNG in late November 2021, and the first export cargo from this train was expected to be shipped before the end of 2021.

Increase in LNG production at Sabine Pass and Corpus Christi LNG terminals as a result of optimizing operations. The U.S. Federal Energy Regulatory Commission (FERC) approved an increase in annual LNG production at these two facilities by a combined 261 Bcf per year or 700 MMcf/d (11.5%) through uprates and modifications to maintenance. Individually:

- FERC granted approval to increase LNG production at Sabine Pass LNG from 1,509 Bcf per year to 1,662 Bcf per year across six liquefaction trains, an increase of 10%.
- FERC approved an LNG production increase at Corpus Christi LNG from 767 Bcf per year to 875 Bcf per year across three trains currently in operation, an increase of 14%.

New LNG export facility Calcasieu Pass LNG in Louisiana comes online. The project consists of nine blocks, each containing two mid-scale modular liquefaction units for a total of 18 liquefaction units with a combined peak capacity of 1.6 Bcf/d. Commissioning activities at Calcasieu Pass LNG started in November, and the first LNG production was expected before the end of 2021. All units are expected to be placed in service by fourth-quarter 2022.

As of November, the EIA estimates existing U.S. LNG nominal baseload liquefaction capacity was 9.5 Bcf/d and peak capacity was 11.6 Bcf/d, which includes uprates to LNG production capacity at Sabine Pass and Corpus Christi.

"By the end of 2022, U.S. nominal capacity will increase to 11.4 Bcf/d and peak capacity to 13.9 Bcf/d across seven LNG export facilities and 44 liquefaction trains, including 16 full-scale, 18 mid-scale and 10 small-scale trains at Sabine Pass, Cove Point, Corpus Christi, Cameron, Elba Island, Freeport and Calcasieu Pass," the EIA said in the report.

In addition, FERC and the U.S. Department of Energy have approved another 10 U.S. LNG export projects and capacity expansions at three existing LNG terminals—Cameron, Freeport and Corpus Christi—totaling 25 Bcf/d of new capacity. Developers of some of these projects announced plans to make a final investment decision in 2022.

"By 2024, when Golden Pass LNG—the eighth U.S. LNG export facility—completes construction and begins operations, U.S. LNG peak export capacity will further increase to an estimated 16.3 Bcf/d," the EIA added.

—Hart Energy Staff

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SPOTLIGHT ON UNIVERSITY LANDS

Brian Owen, University Lands

Maryam Schellstede, University Lands

The steward of the Permanent University Fund (PUF) Lands looks for growth in the Southern Midland Basin. Brian Owen and Maryam Schellstede are the key commercial and technical contacts for the industry to interface with University Lands.

Q. What are the unique advantages and features of operating on University Lands (UL)?

Owen: The biggest advantage for oil and gas lessees operating on UL is working with one entity, UL, on both the surface and minerals through straight forward agreements, a transparent rate and damage schedule for surface damages, and UL's quick turnaround process for approving well locations, pipeline ROW, frac ponds, etc. It translates to operators having a single point of contact for surface operations and single point of contact for mineral development. Because of UL's large acreage position, we also have the ability and advantage to enter into development agreements that allow operators to maintain large leasehold positions while conducting their operations at a predictable pace as opposed to constantly moving rigs and operations to maintain a large area of leases.

As for leasing UL minerals, with some exceptions discussed later, we lease acreage via public sealed bid lease sales. UL typically tried to have lease sales once a year through EnergyNet. Our royalty income flows into the corpus of the Permanent University Fund (PUF), which now totals more than $30 billion and distributions from which benefit the University of Texas and Texas A&M Systems. Our lease forms and royalty payment procedures are also highly transparent.

Schellstede: With our scale, we have a vast amount of data and have invested in a highly capable subsurface team, so operators making an entry into the Permian can leverage UL to get a running start. We are unique in that we manage surface and minerals but do not buy or sell them—our position stays what it is. That is beneficial for a few reasons. First, it means we are in it for the long game and work with operators to ensure that best practices for full field development are realized and implemented. Second, we are focused on the Permian Basin and our acreage position from a technical perspective. So we have expertise in the subsurface and surface practices and can study what works over time. Lastly, we can prioritize mutually beneficial negotiations and opportunities with our lessees and be responsive to the market when necessary.

Q. Apart from the lease sale, what are the ways in which operators interact with UL?

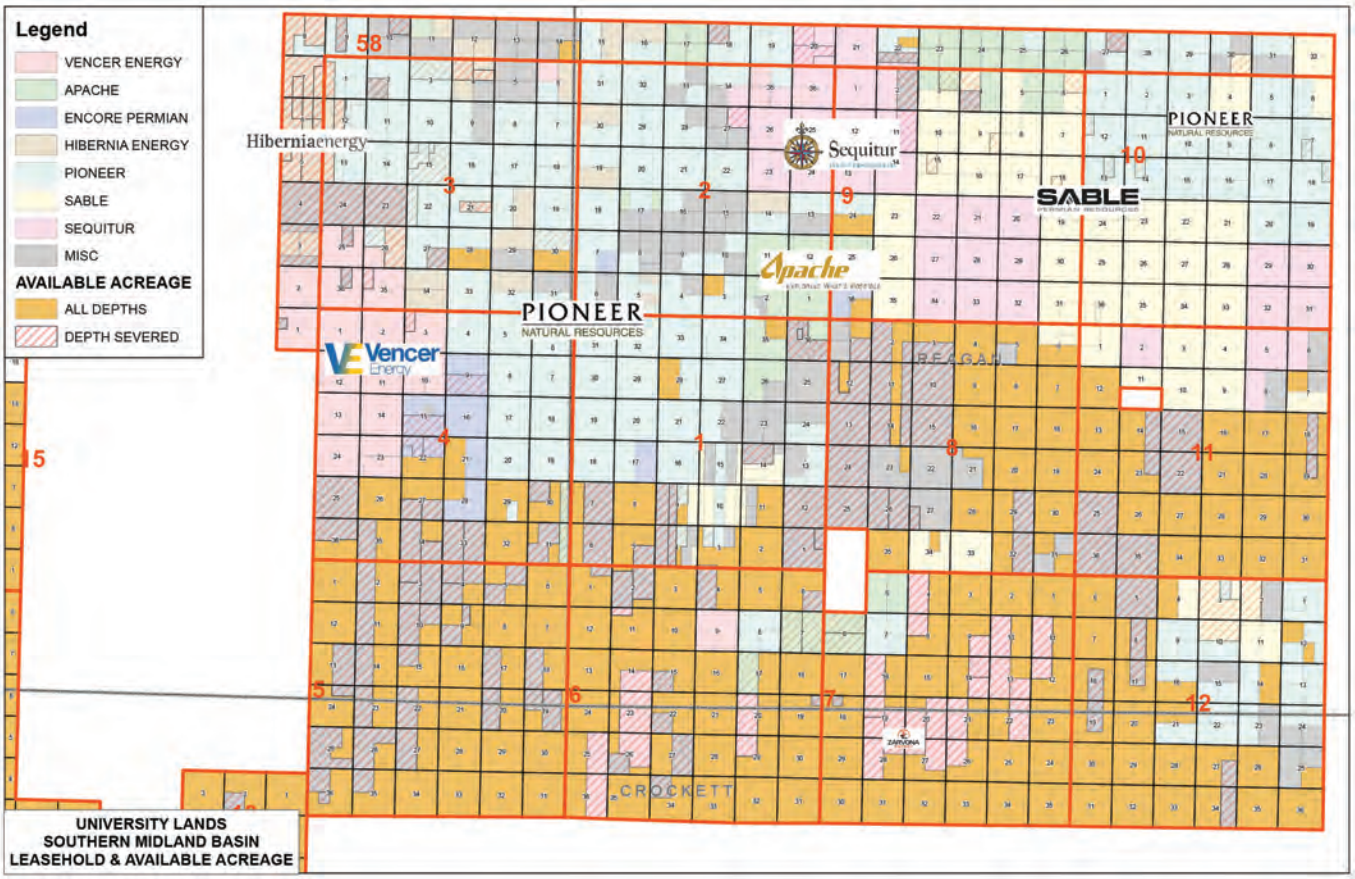
Owen: Operators with existing UL leases can negotiate directly for acreage that immediately offsets their productive acreage without going through the formal lease sale process. We do this by negotiating and issuing a contract for development that requires a bonus, generally a two-year term, and a drilling obligation.

As mentioned above, operators who acquire a substantial amount of acreage can enter into a continuous development agreement, whereby they commit to full, efficient and predictable development of the acreage and in return they get flexibility with respect to expirations as long as development commitments are being met.

Schellstede: That's right. I'll double click on the concept of fully and efficiently developing the acreage. We have industry experts that study and interpret what is working and what isn't, and they translate that into best practices for lessees. We want to help our lessees be successful on the lands. It means increased revenue for the state and maximizes the value of our minerals, while ultimately benefiting both parties. When we negotiate continuous development agreements, we understand and integrate economics, potential and optimal field development into drilling and completions obligations.

Q. Why is the Southern Midland Basin important to UL?

Schellstede: There are several considerations. First, we own a lot of acreage there, more than 450,000 acres, or almost 2x our holdings, in the Delaware and Northern Midland basins combined. Second, it is the place where we have substantial amounts of highly prospective acreage that is unleased. More than 50,000 acres are available where our type curves show attractive returns available for development. Third, it is in rapid transition in terms of operator mix. Pioneer is a long-time player, and the only public company playing at scale and by far our largest producer. But we have also had an influx of well-capitalized and capable private operators who are applying newer completions techniques with strong well results.



Q. Besides commodity prices, what has created the turnaround in the Southern Midland Basin?

Schellstede: Well-capitalized and capable operators have entered the Southern Midland Basin, and their well results speak for themselves. We are seeing better recovery due to completions enhancements. The key is that these more intense completions are designed with optimized spacing and co-development. Operators are also using new, effective ways to reduce costs—a few examples include recycling water, simul-frac and in-basin sand. They've really cracked the code on delivering high-return wells while maximizing NPV of the acreage.

Q. What is your vision in a year from now?

Owen: Assuming Waha and NGL pricing stays reasonable, then we look to have a group of capable and well-funded operators engaged in efficient and continuous development. We have both large areas of recently released oil and gas leases that are now available to lease as well as operators who are currently marketing their assets that represent unique opportunities for acquisition and development for UL and operators. We anticipate that both our unleased acreage and marketed assets will be in the hands of capable operators with strong plans to develop the minerals.

Schellstede: There were more than 2.2 million horizontal lateral feet drilled on UL in the Southern Midland Basin in 2014. In 2019, less than 20% of that amount was drilled. We would like to see activity back to 600,000 to 900,000 horizontal feet per year, and that can happen at reasonable prices with a good stable of operators.

Q. How can interested operators learn more?

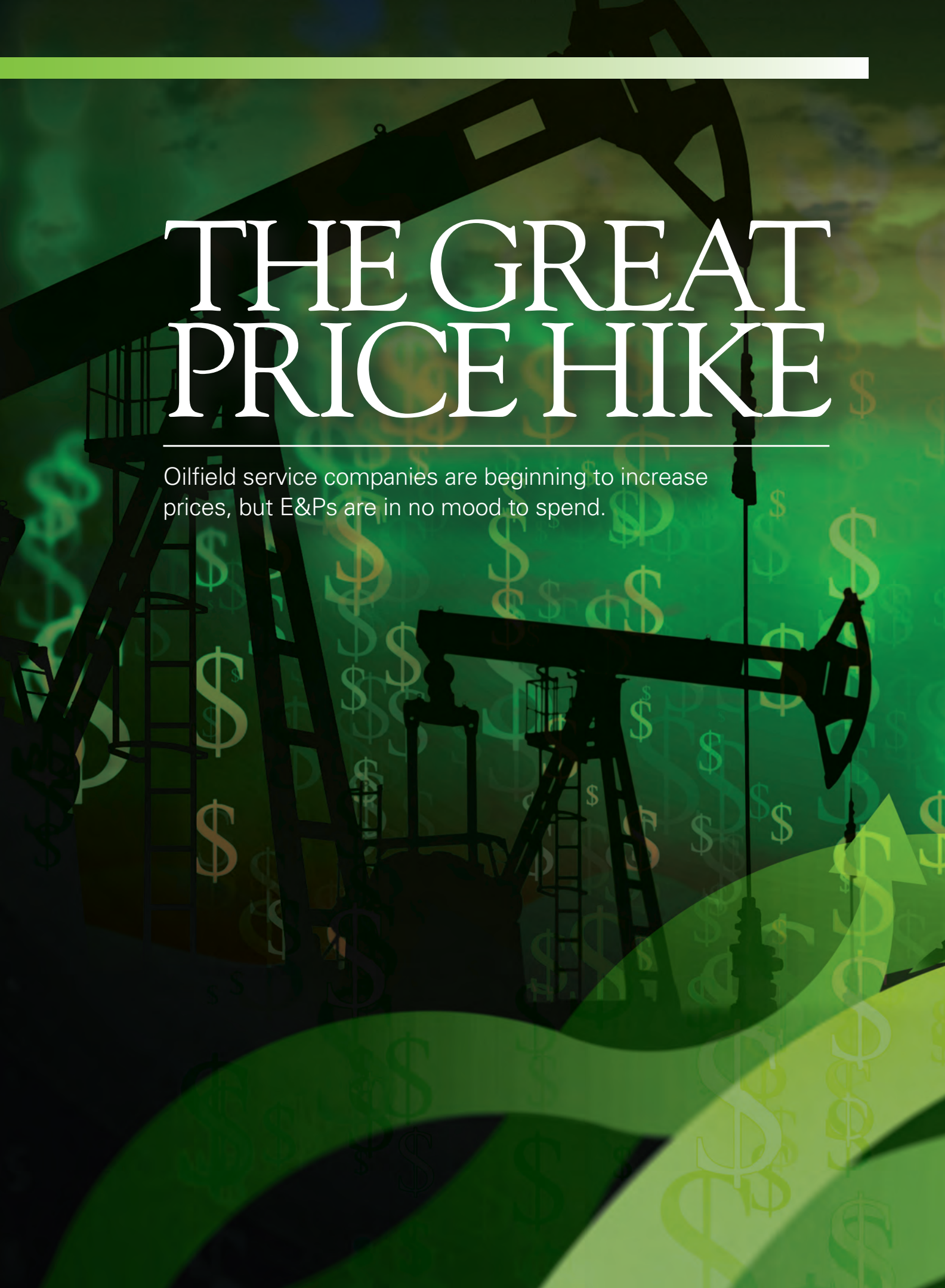
Schellstede and Owen: Our website has a tremendous amount of information (www.universitylands.utsystem.edu/). You can also reach out to us directly and have conversations with our team. ☐

UNIVERSITY LANDS

universitylands.utsystem.edu

THE GREAT PRICE HIKE

Oilfield service companies are beginning to increase prices, but E&Ps are in no mood to spend.



ARTICLE BY
DARREN BARBEE

ILLUSTRATIONS BY
ROBERT D. AVILA

Inflation, that strange phenomena in which too much money results in too few things, has spread into grocery stores, clothing shops and especially energy commodities.

Each area has taken a different path to higher prices, but oil and natural gas prices have surged beyond all other areas in the past 12 months, according to the U.S. Department of Labor Statistics.

WTI prices have made a starling recovery since April 2020, when prices averaged $16.55/bbl. In November 2021, WTI spot prices averaged $79.15, nearly five times higher.

Some politicians have labeled this price gouging, despite rising production that's been unable to keep pace with recovering demand as the planet reopens from the pandemic.

Yet oil and gas companies themselves are fretting over rising prices as they enter 2022. As the industry settles into a recovery based largely on self-restraint, E&Ps are girding themselves against sizable cost increases from pressure pumpers, drillers and other service providers.

The inflation faced by the broader economy pales in comparison. The International Monetary Fund predicts that U.S. inflation will find its trough at about 2% by mid-2022 after peaking at the end of last year.

Oil and gas companies? They're bracing for price hikes of up to 15% this year.

And while inflation may not inflict a mortal wound to E&P cash flows, there are clear indications it will take a bite out of the returns that industry leaders want as their gold standard.

E&Ps are already looking to squeeze more efficiency out of their operations this year as they brace for double-digit growth in service costs.

For oilfield service companies, the test of their pricing powers is the continued hyper-sensitivity of the commodity market. After Brent crude oil spot prices averaged $81 in November, prices tumbled on news of the pandemic's most recent variant, Omicron, in much the same way prices stuttered because of the Delta variant.

"Oil and gas activity and upstream spending in U.S. land has been exposed to significant volatility in the last two years," said Artem Abramov, head of shale research at Rystad Energy.

Underlying the rising costs is a diffuse, but clear tension between public E&Ps that have shown relentless discipline and spendthrift private companies that tore through inventory in 2021. Rystad Energy sees public company's accelerating activity in 2021.

While private operators' aggressiveness in the oil patch drove spending in 2021, "we anticipate significant growth in 2022 from public and private operators alike," said Abramov.

Nevertheless, the past link between commodity price and oilfield service companies pricing powers has become less certain.

James K. Wicklund, managing director at Stephens Inc., said oilfield service companies find themselves in a different kind of oil and gas landscape, in which E&Ps are strict adherents of capital discipline.

The normal correlation between rig counts, frac spread, or completions and oil prices has "broken down," he said.

Bernstein analyst Bob Brackett said inflation may serve to keep that discipline intact. "For companies desiring to keep capex budgets flat in 2022 … an additional 5% to 10% inflation obviously implies less 'productive' spending and potentially less volume growth," he said.

And commodity prices are expected to cool, which may dampen oil and gas activity. The Energy Information Administration (EIA) projected in November that WTI would fall to $62/bbl in December 2022 from an average $81/bbl in October 2021.

And while the oil and gas industry is preparing to increase spending in 2022, more than half of those outlays will be just to keep pace with escalating oilfield service prices, Rystad said in a Dec. 1 report.

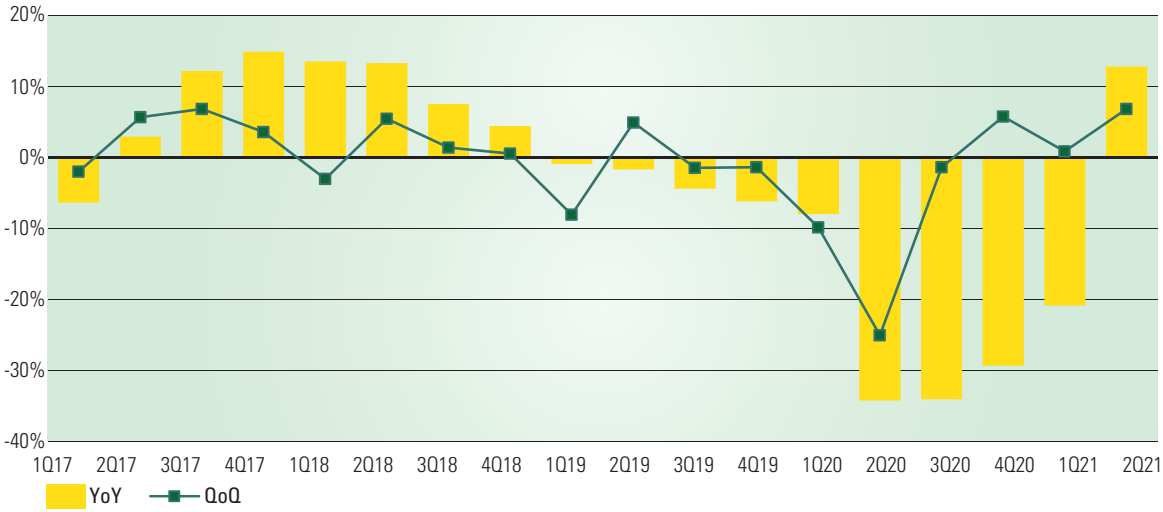
U.S. shale expenditures are projected to climb $13.6 billion this year. The industry is expected to spend $83.4 billion this year—a 20% increase over 2021.

But the largest share of that spending increase will foot higher service costs.

Service price inflation will account for roughly 67% of increased spending, or about

The normal correlation between rig counts, frac spread, or completions and oil prices has "broken down," said James K. Wicklund, managing director at Stephens Inc.

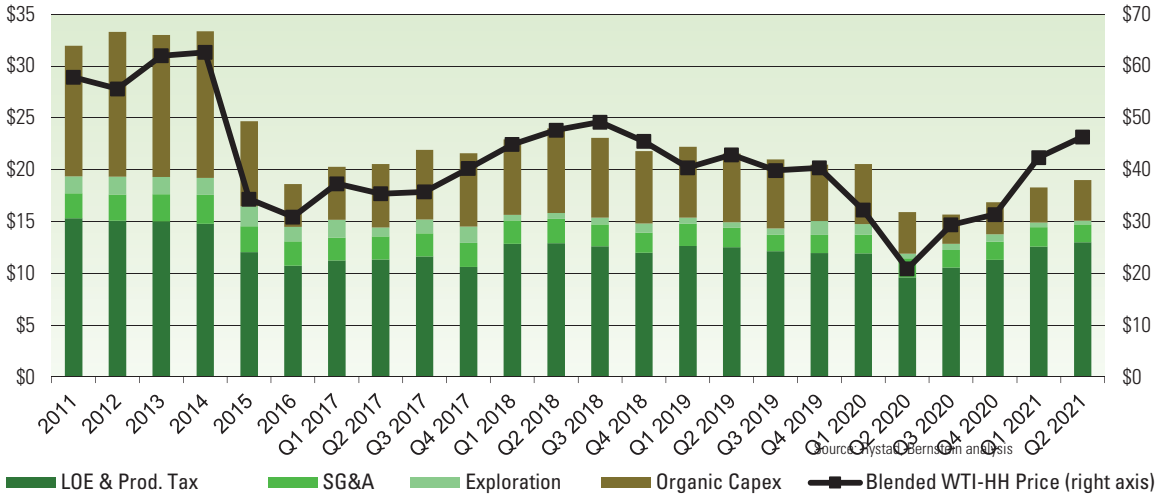
Oil Field Services Revenue Growth



Source: Rystad, Bernstein analysis

After nine consecutive quarters of revenue losses, service companies finally saw a modest increase in revenue in 2021, and analysts expect revenue to grow further this year.

U.S. E&P Cash And Capital Costs Vs. Commodity Price ($/Boe)



Source: Company reports, Bloomberg, Bernstein analysis

E&P companies saw a modest increase in operational expenses in 2021 and are bracing for inflation of up to 15% from oilfield service companies in 2022.

$9.2 billion, Rystad said. E&P efficiency gains could claw back about $4.2 billion in savings to offset rising prices.

That sets up potential imbalance between E&Ps and oilfield service companies, with inflation, the result of higher service costs, labor shortages and supply chain delays.

In some respects, oil and gas companies and supermarkets are battling the same foe: the sudden need to deliver after a period of dormancy.

Turning down work

Service companies themselves are facing an unprecedented situation.

"Today, we are turning down business as an industry because there's a shortage of people," Wicklund said.

There simply aren't enough bodies. After years of attrition, service companies have been shrinking or selling off assets or, as in the case of 270 oilfield service companies, filing for bankruptcy in the past six years, according to Haynes and Boone LLP data.

In third-quarter 2020 alone, 27 oilfield service companies filed for bankruptcy, the worst quarter since 26 bankruptcies were filed in second-quarter 2016.

Are those labor shortages "a huge part of inflation? Absolutely," he said.

However, Wicklund said that OFS inflation is largely keeping up with their own costs, not adding meaningfully to those companies' margins.

Even companies that are beating, say 10% inflation with a 14% pricing increase are still only netting a 4% price increase.

"That's good, but that's not blowing anybody's doors off," Wicklund said.

For oilfield service companies, there is likely to be some incrementally positive pricing improvements this year. And that should eventually result in higher margins for OFS providers.

"But is it going to explode to the upside? That's the part that's harder to see."

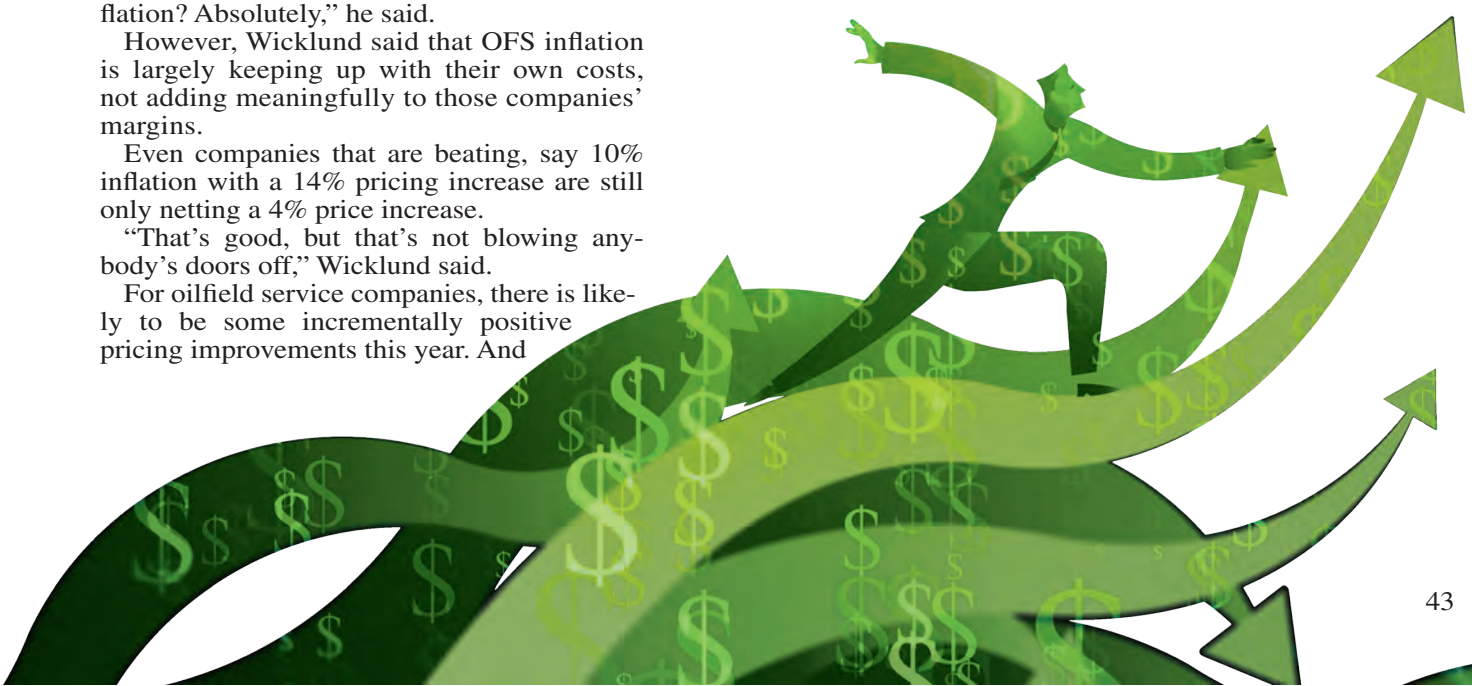
For now, service companies seem to be happy not to be "bleeding cash anymore."

E&Ps sees the battle lines drawn over keeping spending steady. Centennial Resource Development, for instance, is eyeing ways to combat oilfield service costs, which could increase $800/ft well costs by 10% to 15%. Centennial's management believes it could offset that through continued cost efficiencies, Gabe Daoud Jr., managing director and analyst at Cowen & Co., wrote in a Dec. 6 report.

Some companies have seen a rise in tubulars due to scarcity, for instance.

Matador Resources sees itself well-positioned on tubulars due to its relationships with providers. But the company is also eying inflation of 10% to 15% relative, largely driven by pressure pumping, "which is consistent with commentary from other E&Ps," Daoud said.

Companies such as Ovintiv are counting on their supply chain management and field efficiencies to offset what they expect to be about 5% to 10% of inflation in 2022.



Ion Bria, director of energy and industrials at Fitch Ratings, said Fitch's coverage portfolio has seen problems but not any major issues that caused oil and gas projects to halt.

Whiting Petroleum Corp., which plans to keep its activity levels somewhat similar to the previous year, is likely to budget for a 10% hike in capex due to inflation, Cowen said.

Supply chains

Producers and oilfield service companies have both been trying to meet rising costs driven in recent months by the relentless pressure of supply-chain boondoggles even as commodity prices have risen.

Depending on the sector, energy companies have dealt with those delays differently, but it's clear they are being felt even if they're difficult to quantify.

Ion Bria, director of energy and industrials at Fitch Ratings, said the Fitch's coverage portfolio has seen problems but not any major issues that caused oil and gas projects to halt.

"Throughout the year, we've heard that sourcing replacement parts became a little bit more difficult as the year progressed," he said.

Like all other businesses, costs continue to spiral up.

The Federal Reserve Bank of Dallas' take is an energy sector facing multiple quarters of sharply rising costs. Among oilfield services firms, the index for input costs increased to a record high, an indication of significant cost pressures.

In a survey by the Dallas Fed, only one of the 47 responding oilfield service firms reported lower input costs in the third quarter. Among E&P firms, the index for finding and development costs increased along with lease operating expenses.

Oilfield service companies also said it was taking longer to receive items needed for work. Among oilfield service firms, the Dallas Fed's index for supplier delivery time increased from 14 in the second quarter to 26.7 in the third, the highest since the survey began in 2016.

The index measuring delays in deliveries also hit a record high. E&P also reported longer waits for supplies.

In September, the Dallas Fed Energy Survey showed oilfield service costs continuing to increase while input costs—tubulars, as an example—also rose to a record high "indicative of significant cost pressures."

"It is also taking longer for [oilfield service] companies to receive inputs," according to the survey.

The index the Dallas Fed uses for measuring delays in deliveries also increased to a record high. Similarly, among E&P firms, the index for supply delivery times more than doubled.

Among companies monitored by Fitch Ratings, businesses have taken mitigation measures, such as additional preventative maintenance more frequently, as well as increasing their inventory of parts and diversified their suppliers.

"It did not get to a point where it got us to be concerned that this will become an even bigger issue going forward, where we would have to start incorporating it in our analysis," Bria said.

As Wicklund noted, labor is increasingly a concern, according to an oilfield service company surveyed by the Fed.

"Wages are up 20%, and companies are poaching employees from competitors. We are finding it difficult to increase prices to match our increase in costs," according to the survey.

The rise in spending also isn't uniform. In the Permian Basin and Haynesville Shale, upstream spending in 2021 increased by roughly 23% to 24% and even higher in the Niobrara, Rystad said. In Appalachia and the Eagle Ford, however, spending was up by 3% to 6%.

However, the Bakken and the Anadarko Basin saw the range of spending decline by 7% to 14% last year.

As the new year begins, Rystad sees the Eagle Ford, Niobrara and Anadarko region outpacing national spending growth as rigs have increased in those regions in 2021.

The Bakken is forecast to increase spending growth by 19% and the Permian by 17%.

Among gas plays, Rystad projects that Appalachia operators will increase spending by 15%, while the Hayneville increases by 10%.

Wicklund said that prices have generated some momentum, but "nobody out there yet is well ahead of inflation on their pricing," he said.

Embrace inflation?

Not everyone sees oilfield service inflation as a detriment to the industry. Proponents argue that despite higher bills at E&P companies, they have managed the price hikes in stride.

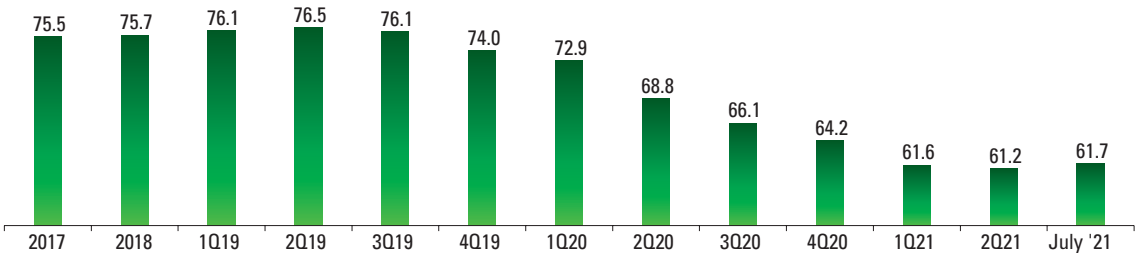
In a September report, Brackett noted that despite no inflection in rigs and frac spreads in second-quarter 2021, oilfield service revenues rose 7% quarter-over-quarter, "suggesting pricing power/inflation."

While the industry saw higher capex per barrel in the second quarter, cash costs remained in-line with the first quarter.

"So, pressures were felt more on capex rather than opex," he said.

Broader inflationary trends in the economy don't tend to affect oilfield prices, and oilfield service inflation is typically correlated to oil prices.

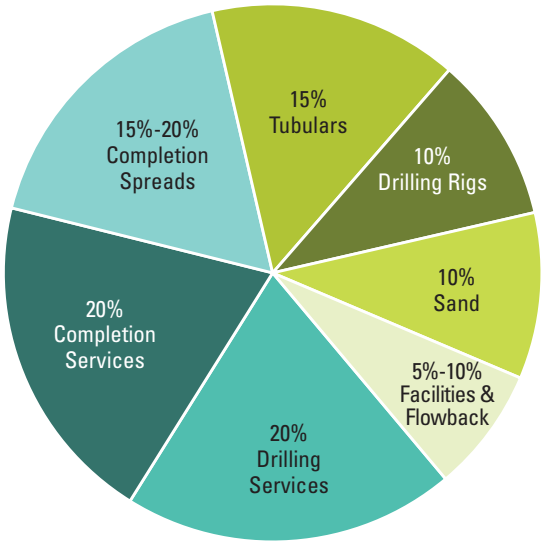
Upstream Oil And Gas Payroll Employment (Thousands), Texas



Source: BLS, Texas Workforce Commission, Federal Reserve Bank of Dallas, Rystad, Bernstein analysis

E&Ps and oilfield service companies cite labor shortages as an area of concern in 2022.

Typical Shale Well Cost Breakdown



Source: Company reports, EIA, IHS, Bernstein analysis and estimates

"Because oil price drives oilfield inflation, we are thus fans of inflation; revenue rises faster than cost," Brackett said.

But Wicklund said the end of E&Ps' days of wild spending will have consequences for oilfield service companies.

"E&P companies, for the first time in 12 years, are spending 70% of cash flow instead of 100% or, as much in one year, as 140% of cash flow," Wicklund said.

Consider 2018, a year in which E&Ps outspent cash flow by roughly 120% compared to current estimates of spending 70% of cash flow—with the remainder either directed to paying down debt or returning cash to shareholders.

"That means to get to the same level of spending I had in 2018, I need a $93 oil price today," he said.

Wicklund also said oilfield service companies do have some limited pricing power, but for now, it's modest. A company that has a preferred drilling crew, for instance, could help increase a day rate by $250 but not on the order of $2,000.

Wicklund said the service industry would do well to follow the model E&Ps have been forced to follow by shareholders, one that places capital discipline and returns first.

Pressure pumpers, for instance, shouldn't add additional capacity for the next few years until their returns are sustainable.

"But, you know, next year if we start building new rigs and adding frac fleets, we're just exacerbating the pricing issue," he said.

Wicklund noted that two or three companies have started oilfield service companies with assets bought at auction.

"So, you may not get the pricing pressure pumping pricing explosion that we've seen in the past. At least, not yet," he said.

More useful, in his view, were the jolts that caused prices to tumble in November, a reminder of the need for discipline.

"This is where the whole industry gets a lesson. 'Listen, let's be careful.'" □

DENBURY'S ROAD FROM EOR TO CCUS

Denbury Inc.'s President and CEO, Chris Kendall, is proud of his company's history with EOR. Now, he knows that commitment has put the company in a leadership position when it comes to carbon capture and sequestration.

INTERVIEW BY
LEN VERMILLION

Carbon capture utilization and storage (CCUS) is a hot topic among the oil and gas industry. As the world tackles climate change and zeroes in on zero-emission goals, figuring out how to minimize the impact of carbon emissions is vital for the long-term health of producers.

It might seem baffling to some or impossible to others. But at least one producer has already established itself as a leader in carbon sequestration, and that stems from its long-time commitment to EOR.

Denbury Inc. has established its reputation as a company "that is doing it" when it comes to sequestration. CEO Chris Kendall talked about the company's success at length at Hart Energy's Energy Transition Capital Conference in Houston. He recently connected with Hart Energy's editorial director, Len Vermillion, to further the discussion.

In this interview, Kendall discussed his thoughts on CCUS and why the industry isn't as far-off from permanent sequestration as some may think. He also delved into the company's unique position as the policy changes thanks to two decades of commitment to EOR.

How'd they do it?

Len Vermillion: Let's talk about CCUS first. What are your thoughts on it, and how can it help emissions reduction in the industry? You're doing a lot of it, so I want to get your thoughts from an operator point of view.

Chris Kendall: When we think about reducing emissions in the atmosphere, if you're like me, the first place your thoughts go are to wind and solar and to what we can do with that. I think that's the right place for thoughts to go first. That's what we've seen as the big movers in energy transition in reducing carbon emissions and our whole energy complex. And those have grown rapidly.

"When we're talking to industry right now, we are telling them that we can provide them certainty today in EOR because we have that."

Unfortunately, they are only going to be able to grow at some rate, and every day you see signs of how they run into challenges. Whether it is space to put the facilities, permitting along the way (or) endangered species in some of these areas that you would think were ideal candidates. The bottom line is that you have that.

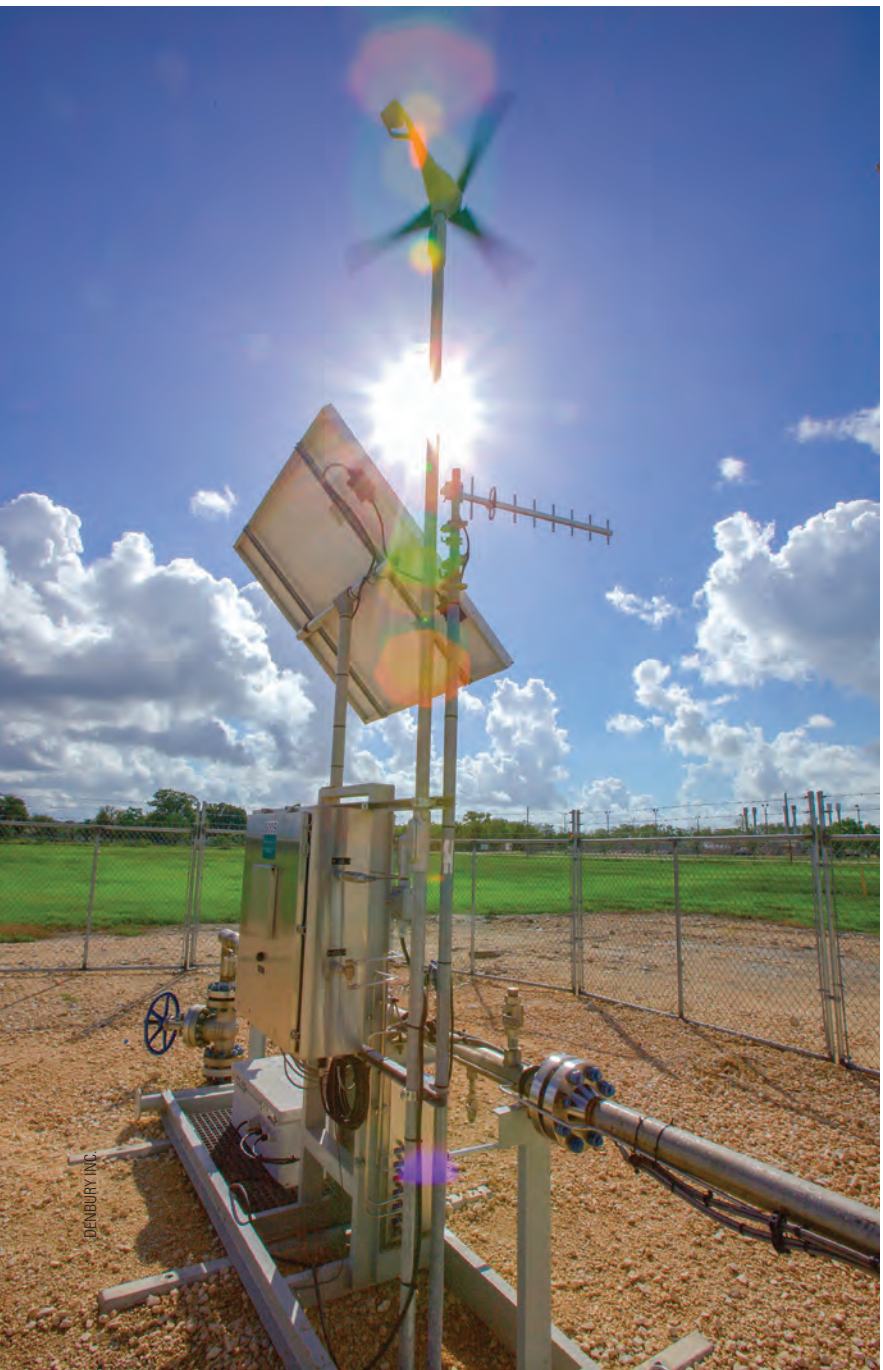
Then you have energy demand in the world still growing year-in, year-out, at 1% and change. Your pie is getting bigger along the way. There needs to be more than just this. There needs to be more than biofuels. There needs to be more than some of the other low-emission energy sources that we've talked about. What's fascinating to me is when I look back on what Denbury has done over 21 years of the EOR business, moving massive amounts of CO_2—10, 11 million tons a year right now—and putting massive amounts of CO_2 underground using technology that is existing, this is not something that needs to take a technological leap to work. This is something that can be done at a much greater scale than it is today.

Just for example, today we're taking 3 million tons of industrial source CO_2 a year out of that whole amount of CO_2 I mentioned and putting that underground. The question is, how can you put more industrial source CO_2 underground? When I look at what the world is doing with industrial source CO_2, just to kind of

throw out a couple of numbers that might show where we are and what the opportunity is. Today, the world is capturing about 40 million tons of CO_2 from industry a year. Of course, the world is emitting more than 30 billion tons a year, so 40 million is just not much.

The International Energy Agency (IEA) put together this scenario for a net-zero future by 2050, where all carbon emissions are offset. You would see that wind and solar are top, and you'd expect that, and those will continue to grow. But the great No. 3 in there, which I think surprised people, is carbon capture. To go with my other end of the spectrum from that 40 million tons a year to what the IEA is talking about in 2050 is taking that 40 million to over 7 billion tons a year. So, you can see we're not even in the first inning of this game. We are just scratching the surface. But even the IEA shows that carbon capture can play that big of a role in offsetting the 30, 40 billion tons a year of CO_2 emissions that the world has.

Denbury Inc.'s EOR operations at Hastings Field is located south of Houston.



And we can do it at scale. We can do it with geology that we know about that we've been using for years and years for EOR. We can use people that are trained in handling CO_2 for EOR to put CO_2 in other places where it's safe and secure. We can even use the same infrastructure we have now.

So, we are very fired up about it because we see the scale (and) we see the place that Denbury has in the space. And then we just see the opportunity, fundamentally to make a difference in carbon emissions, which is what we're all after. I think we can really do it here.

LV: Denbury is kind of unique, and you have already been doing this. You're not new to this. I think you mentioned 21 years of EOR. Why were you actually doing this when everybody else was into shale and everything else?

CK: I have always said that we're a unique company, and that has been through good and bad. We've remained unique. Through that, you talk about CCUS and how you end up in CCUS. The problem with just going straight to some plant and capturing emissions off of the plant and putting the CO_2 underground is it's an expensive proposition. So up until now, at least, people haven't been willing to just go out and spend hundreds of millions of dollars to do that. But what did work was enhanced oil recovery. It started from being able to produce oil from older oil fields that can only be extracted using, essentially, a solvent. Just like you'd use a cleaning fluid and some household application, CO_2 at the right conditions underground is a solvent for oil.

We actually built a business over a couple of decades that had a lot of CO_2 involved that we could pump into oil fields and use that solvent effect to get oil out. We did very well with that. But it was all in the context of a world that needed more oil. And now we're in kind of a different place.

I mean, the world's going to need somewhat more oil for some time in the future, but it's not this endless growth that might have been what people thought 10 years ago or so. To do more of this business, we needed more CO_2, and that's how we started connecting to some folks who would be capturing industrial CO_2, like Air Products down in Texas.

We pay them to take the CO_2 because it was valuable enough for us in the production of oil. All that justified this pipeline system for CO_2 that is the longest operated pipeline system in the United States, which Denbury has. It led us to have almost 300,000 hp (horsepower) of CO_2 compression in our fleet to get CO_2 to a liquid form to use it. It's led us to build a staff of over a 100 technical people who are either engineers for pipelines that move CO_2 or wells that we drill and operate that inject CO_2. (It's led to) the geologic work of looking under the surface to make sure that the CO_2 is going where we want it to and staying there. We were able to take all that, and then when we see where we are today, now you have a new policy in place that has actually significantly enhanced some of the

industrial emitter decisions whether to add that expensive equipment.

Where we see it taking off to where it is going from that base on enhanced oil recovery—I need to interject one thing here, enhanced oil recovery, what I talked about, the CO_2 stays in the ground. It comes out with oil, but we separate it and put it back in the ground immediately—the net effect is that we're putting CO_2 permanently underground.

There are ways that we can put CO_2 underground that never need to come back out that aren't associated with oil production. We can continue doing industrial recovery. The fact that we use so much CO_2 to produce oil makes it incredibly low carbon. And then we can go beyond that and just inject CO_2 underground, using what we have already in terms of people and pipelines.

LV: Will you increase those pipelines or that infrastructure? Is that an investment that you will have to make as long as, well, everybody else is?

CK: Oh yeah. What's neat about it, Len, our intent is to grow this business significantly. What we won't probably grow significantly is the oil side. We think that the 50,000 barrels a day or so that we operate at is a good level, and it can generate enough cash for us to invest in the growth of the capture and the expansion side. Now, we have a backbone from this incredible 1,000-plus-mile pipeline infrastructure that we can build off. So, we're not starting from scratch. But what we can do is we can take that backbone, and then we can put extensions into high-emission areas that we might not quite be in today.

Or, we can expand the capacity to where it can move more, which is fairly straightforward in this business. We can invest in underground storage outside of enhanced oil recovery. So, acreage that can be used just for storage. We'll be making investments in that probably not in the last few weeks of this year, but we'll start to see some of that next year. What we love about it is the oil side of the business (is) it already has some really great qualities to it, (and it) can fund those investments that we want to make.

LV: You were talking about the utilization part of CCUS that often gets overlooked. Can you tell people what that involves, and how it can be used?

CK: Well, it's a very tricky question, and to date, the primary utilization that is in the CCUS acronym is enhanced oil recovery. You have this great ability to put literally millions of tons of industrial CO_2 underground using that. For example, today we are injecting, on any given day, about 10,000 tons of CO_2 just for that. What's also nice about that is that's under existing law and existing permits. So, if another plant came tomorrow and said, "We'd like to send you our emissions," we could take them and put them into EOR with no new permits or anything. We could do that under what we have today. Now, if you go beyond EOR and you're looking for an answer to the "U," there are a lot of interesting things being looked at.

I see some that I think have some potential. One area is called electra fuels where they will use carbon dioxide as an input to help produce low-carbon electricity. There's some potential for that I think we'll see. But beyond that, everything that I see looks very challenged in how much scale you can apply. A good example is just seeing some folks looking at injecting CO_2 into concrete when it's being mixed, and it gets ingrained in the concrete and is pretty effective at permanently locking up the CO_2.

But I'm sure what you've seen, when you've seen concrete mixing plants, they're not in areas that are convenient to refineries and power plants. You have to transport the CO_2 to the mixing site, which I think is a real challenge to the scalability. So to me our recovery is a proven, scalable way of utilizing CO_2. Maybe this electra fuels concept can be something that could grow. Otherwise, I think your best choice is to bury it underground in safe places.

Denbury Inc. began producing oil from its EOR operations at Hastings Field in 2012.

DENBURY INC.

Denbury Inc. initiated CO_2 injection in the West Hastings Unit during 2010 upon completion of the construction of the Green Pipeline.

LV: I guess what we're talking about really is permanent sequestration? How far do you think we are away from that?

CK: Yep, and we're not far. One of our key strategies right now, Len, is for Denbury to add a series of storage sites along our infrastructure that will be storage of that nature, sequestration. There are other projects underway where that's happening as well. The challenge with that, and we see it across the whole industry, is that to inject CO_2 in this manner, you require an EPA (Environmental Protection Agency) Class VI permit. To date, as far as I know, there have only been two Class VI permits that the EPA has ever issued in the United States. There are many more being put into the process right now, but then there's uncertain timing of the approval. In the past, it was more than five years, which is terrible.

The EPA has stated that they think they can do them now in two years, which is more tolerable, I'd say. But it's still two years. So, there's a tremendous effort right now being put forward to make all this happen. And many different classics permits are being put together. But I think that we're probably a couple years away from seeing the first of those.

When we're talking to industry right now, we are telling them that we can provide them certainty today in EOR because we have that. And then we can transition into sequestration when it's permitted. And they like that, because that lets them start their projects now without wondering what happens if somebody's permit does not get approved.

LV: Are a lot of people starting projects at this point?

CK: There are a handful. It's early days, still. Just as an example, the panel I just got off of, the CEO of California Resources said that they have initiated Class VI permitting for some work that they're doing in California. Honestly, just a week or so ago, this agreement that we announced for a sequestration site with Gulf Coast Midstream Partners, they had already initiated the process as well. That's to the southwest of Houston. There's some of it, but it's like I said, it's early days. I think in another year or two we'll start to really see a good number of these coming together.

LV: What is carbon-negative oil? Because I think you were talking about that before. Kind of explain it to me.

CK: I'm glad you asked. I'm going to the Aspen Institute Global Energy Forum, which is an awesome event because it brings together people from all ends of this spectrum. There are people like me that are leading this company or even people (who) are just leading straight up energy companies, E&Ps. Then you have people in the government who are adamantly opposed to that. And it's a nice forum for everybody to just talk about these issues in a safe environment. But along the way, what was interesting is a lot of these guys said, "Look, we love what you're doing and how you guys can manage CO_2, but you're producing oil, and we just can't tolerate that."

We said, "Yeah, but it's a low-carbon oil." And they didn't quite get it. We really started to work on some numbers around it and the bottom line, Len, is that it takes a lot more CO_2 to get a barrel of oil out of the ground than it will ever emit once you get it out of the ground. And just to put some numbers around that, the total emissions that you get from a barrel of oil. I don't know if you've heard of EPA Scope 1, 2 and 3 designations, but Scope 1 is direct emissions like your motors that you're running to do your business, whether it's a vehicle or a compressor. Scope 2 is electricity that you use, for example, indirect emissions.

So, the electricity that you use, you have to count the emissions for how that electricity was generated. It depends on where you are. You may be someplace it's all renewable. You may be someplace it's all coal. For Denbury's business, just for example, those Scope 1 and 2 emissions together are just shy of 200 pounds of CO_2 per barrel.

So, you say, OK, 200 pounds per barrel, that's interesting. But Scope 3 emissions are what a lot of people really struggle with, and those are the emissions that are primarily associated with the combustion of the gasoline or the diesel or the jet fuel that's created from

the oil. The number, just to compare that 200 pounds that I mentioned, the Scope 3 emissions of a barrel of oil are 1,000 pounds. It's a big number compared to your Scope 1 and 2.

Together, you're looking at 1,200 pounds per barrel. EOR, like I said, the CO_2 stays in the ground permanently. On average for our company to produce that barrel of oil takes about 1,700 pounds of CO_2. So when we look at it, we say, "Well, we're injecting 1,700 pounds per barrel. The total footprint of that barrel is 1,200 pounds. This is actually a carbon negative barrel, unlike any other in the world." We put it in our public materials, and people really see it. They understand what we're talking about now.

We're actually working with a third party to get the carbon intensity score verified so that we can have a little bit more in our hip pocket when we're talking about it. But that's what it is. We called it blue oil just because it's something that we think is distinctly different from other oil. And we only count it, Len, when we're using industrial-source CO_2. We use natural-source CO_2 for part of our business, but about a quarter of our production is based on industrial-source CO_2, and that's where that really comes into effect.

LV: Just let me ask about the forms and the taxes. What's the future of 45Q tax credit for sequestration, and how will that help get more companies on board?

CK: It's great to have what we have, and what we have today was put in place just literally at the beginning of this year. So, we are still early days, even in 45Q. And just to put it in perspective. We have a tax credit of $50 per ton of CO_2 that is sequestered under that program.

If we look at the whole spectrum of cost of capture, the nature of the plant has a very low cost of capture. Then you have plants that have a very high cost of capture. For example, a coal-fired power plant has a very complicated emission stream to capture CO_2. Why that matters is that a $50 credit is basically going to enable you to attack very low cost to capture industries like natural gas processing or ammonia manufacturers, but it won't touch the coal plants. The coal plants, you need to get up above $100 a ton.

Then there's a whole bunch of different high-emission industries like cement manufacturers, for example. So, what we see happening in the policy right now is that $50 a ton is enough to get people excited and to get them started. But it is broadly recognized that if we really want to achieve those big numbers, like I mentioned that the IEA put out, policy needs to move much faster. And so, in a bipartisan way, Republicans and Democrats both support this, but in a bipartisan way, they've put in this reconciliation bill that's sitting in, I think it's sitting in the house right now. I think there's a chance it'll get voted on in the next few days.

But there is an enhancement to 45Q that increases at $50 per ton to $85 per ton. And that will allow another more than a hundred million tons per year of emissions in the U.S. to be captured, so we're excited about that. I think there's a good likelihood that either in that form or some other form, it will pass, and it will come out here. It'll just make things that much better. Ultimately, I think that we need even more incentives to honestly capture those more complicated emissions, like coal-fired power. And I think those will come. I'm not sure what it will look like or when they will come, but the support is there on both sides of the aisle.

> "There are ways that we can put CO_2 underground that never need to come back out that aren't associated with oil production. We can continue doing industrial recovery. The fact that we use so much CO_2 to produce oil makes it incredibly low carbon."

LV: Why should operators really be excited about CCUS, and why should they really take it seriously and be part of it?

CK: I love that question, Len. I mean, it's very straightforward for us because of our legacy EOR business and all of the CO_2 expertise that we developed along with that, but operators, in general. I said this to a couple thousand people at a petroleum conference in North Dakota a few months ago. "Look, instead of being viewed as being part of the problem,"—which I don't really agree with but that is a way that we're viewed as an industry—"instead of being viewed as part of the problem, we can be viewed as part of the solution. If we use the same technologies that we have used in oil and gas, whether that's building and operating pipelines, drilling wells, looking underground and having a good understanding of what is underground and how secure fluids can be contained there. Every bit of that applies to CCUS."

I had a town hall with our company, and I said, "Guys, oil and gas is, we're always depleting our reservoirs. You're doing your best when you're maximizing how fast you are putting yourself out of business." Kind of, if you think about it. I said, "This world we're going into, it will never end. Not in our lifetimes. There will be emissions from ammonia plants and steel plants and cement plants and power plants for a long time. And we can be a key part of making those emissions low and helping achieve this lower carbon future, using the same skills that we have." It's just incredibly invigorating to our company. I mean, a lot of people, especially the young folks in the industry, they're getting beat up by what they see in the news and even some of their friends. This is something where we can be part of the solution, which I just think is fabulous. □

OIL AND GAS ACCOUNTING: ESG AND SUPPLY CHAIN COMPLEXITIES

Illustration by Robert D. Avila

Panelists:

Kristie Ondracek
CFO/COO
TXCPA Houston
(Moderator)

Heather Bain
Managing Member
Bain CPA Business Strategies LLC

Mohamad Al-Kawafha
Audit Principal
Briggs and Veselka Co.

Leslie Warren
Deals Director
PwC

In part two of our accounting roundtable, panelists get into some of the big issues of the day, particularly the role of the board of directors, ESG-related reporting and supply chain issues.

Editor's Note: *This is the second of a two-part series. Part one can be found online at HartEnergy.com and in the December issue of* Oil and Gas Investor.

We assembled a group of CPAs that work with oil and gas clients for an outside opinion. In this second part of our two-part series our panelists and guest moderator take a look at the pressing questions you'll have to deal with when it comes to ESG reporting, corporate governance, Securities and Exchange Commission (SEC) disclosures and dealing with supply chain woes.

"Even though the supply chain issues are facing larger companies as well, the smaller companies don't necessarily have the resources to make things happen as quickly for the rescheduling."

—Heather Bain, Bain CPA Business Strategies LLC

Kristie Ondracek (moderator) As you are meeting with the governance of the companies that you are helping, auditing and servicing, what are some of the governance issues you're making sure that they are aware of that they're talking to their board about and, vice versa, that the board is asking about?

Leslie Warren I would say one of the biggest things, overall, that boards are focused on is executive compensation and how those executive targets or a company's key performance indicators, or KPIs, are aligned with thriving shareholder value. Also, a lot of companies I've seen lately have been shifting those KPIs to include ESG-related metrics and tying executive compensation directly to achieving a company's greenhouse-gas emissions reduction goals or whatever it may be. I think some of that's even matriculating further down the organization below the C-suite. And so that's, I think, one of the biggest trends that I've noticed more recently with clients.

Mohamad Al-Kawafha I kind of echo Leslie for what she said, and maybe I could add is also how they look at the long-term projections. It's just how they compare it and make sure that the company will be able to meet those projections, how realistic, especially with the commodity volatility now. It's just like how much they want to spend into capex and how much they want a key for cash flow to please the investors. I know that they have the problem of trying to please the shareholders (and) at the same time, they're trying to be aggressive on the business.

The second thing I would think about is ESG. I know it's important, and a lot of them start thinking about it from the large caps because I think there are a lot of investors that will be interested in it. (Also) because a lot of (the) younger generation are interested in ESG, which is driving the company business to the future.

The same thing is about what the advice management regarding supply chain now seems it's an issue, which is going to be impacting the bottom line, and their bottom lines are already squeezed. That's going to squeeze it even more. So, what the board is doing is to now advise management to be able to make sure that they are finding alternatives to make sure that their operations are not interrupted.

Heather Bain I'm seeing that the small producer space is becoming more and more competitive, especially with the rise in oil and gas prices and the simultaneous reduction of available vendors. Rigs are being scheduled many more months in advance than they were a year ago. So, it's a very competitive space, and the differentiating factor for attracting talent and attracting opportunities for getting the attention and loyalty of your vendors. How responsible will you be, and how attractive is your company for attracting contractors, employees and building the loyalty with the vendors that you work with?

Warren I think to both Mo and Heather's points, it'll be interesting to see how the board plays a role in ensuring that not just the company is meeting their ESG targets or exceeding those, but how their customers are also meeting their ESG targets and then what that means. I think as Heather mentioned, there's an aspect of being the company that others want to do business with, and then maybe the inverse of that is every customer that an upstream producer has, would they consider not having someone as a customer if they're not meeting their ESG targets? I think it'll also be interesting to see what role the board and management play in making those decisions as well.

Ondracek As accounting professionals we all take CPE (continuing professional education) courses to learn more. Can you give insight to other accounting professionals on how are you learning about ESG and getting up to speed so you can be a service to your clients? And how are you telling your clients about ESG and what is important?

Al-Kawafha The ESG topic is still evolving. Because there is no framework that you can say what you're supposed to disclose and what you're supposed to do, a lot of companies are trying to learn or they're trying to see what they need to include into the financials.

I think at the moment it's a learning curve. Everyone is trying to do their best to put the information that they believe is going be relevant. But I think the best way is just going to be attending as many CPEs and reading the financials for other public companies that were already started. So at least you can start getting familiar with what is required to be disclosed.

I think a lot of the concern for companies is, "Should we disclose more or should we disclose less?" Because the concern if they disclose more is going to be deterring to some of their investors or because the whole point of it is just to kind of attract investors or to give them more transparency about the company's business and how they are doing to take care of their employees, their environments (and) everyone within the group. Or, if they did disclose less, is it going to have an impact because they said they're not disclosing enough information. I think it's going to be evolving, as this is a learning curve to everyone.

Ondracek It's fine trying to find that happy medium, that happy balance of what to disclose, to get the investors, what to disclose, not to lose investors.

Bain I am tracking the FASB sustainability accounting standards board. They have a lot of research already in the ESG space. I also look at the SEC as the guidelines are being pulled out, but primarily those two entities are a great source of information for what you should be tracking even as a small business.

Warren I was going to say the sustainability accounting standards board or the FASB as Heather mentioned is probably one of the most popular sources of information that I'm familiar with currently. Given that there still is really no authoritative GAAP (generally accepted accounting principles) or SEC literature out there on a lot of things related to ESG, it feels like drinking from a fire hose. I do think that just being a sponge to absorb as much information that's out there that comes from reputable, more authoritative sources is probably the best thing that anyone can do right now.

As Mo mentioned, there's a ton of free CPE and information out there that I know a lot of the big firms put out, PVC (planned value control) included, that is trying to get people up to speed as quickly as possible on everything ESG.

But it's interesting because the problem or the issues are already here. Companies are already trying to form joint ventures and enter into contracts and execute transactions for everything that is under this umbrella of ESG. Then they look to the accounting groups at their companies, or they look to accounting professionals that are their advisors and they say, "OK, how do we account for this?"

It's one of the things where some of the guidance obviously does exist. There's a lot of guidance for the power utility sector that is being looked to by analogy. So trying to find the right analogous GAAP that's out there and trying to help companies work through those two. There's definitely something that we've been spending a lot of time on in our firm.

Ondracek We have talked a little bit about this, but I would like to know about the supply chain issue because that would go under risk and uncertainties for the SEC filing. How are your clients feeling about the disclosure?

Bain When you're asking about supply chain, are you saying supply chain impacts on the forecasts? Because that's what I'm hearing the very most. Like I mentioned before for small E&P companies, many of them are struggling with delays in drilling, which were supposed to take place by now, like late summer, early fall, because of supply chain issues in rig scheduling and chemicals and just different delays they're not able to drill the wells and complete the wells within the timeframe that they originally anticipated. That is going to carry over into (this) year. So, they have to explain that. That's a really huge issue for the smaller companies because they don't get the priorities that the larger companies are getting.

And even though the supply chain issues are facing larger companies as well, the smaller companies don't necessarily have the resources to make things happen as quickly for the rescheduling. So, forecasts are off by as much as two quarters, which is quite a big difference.

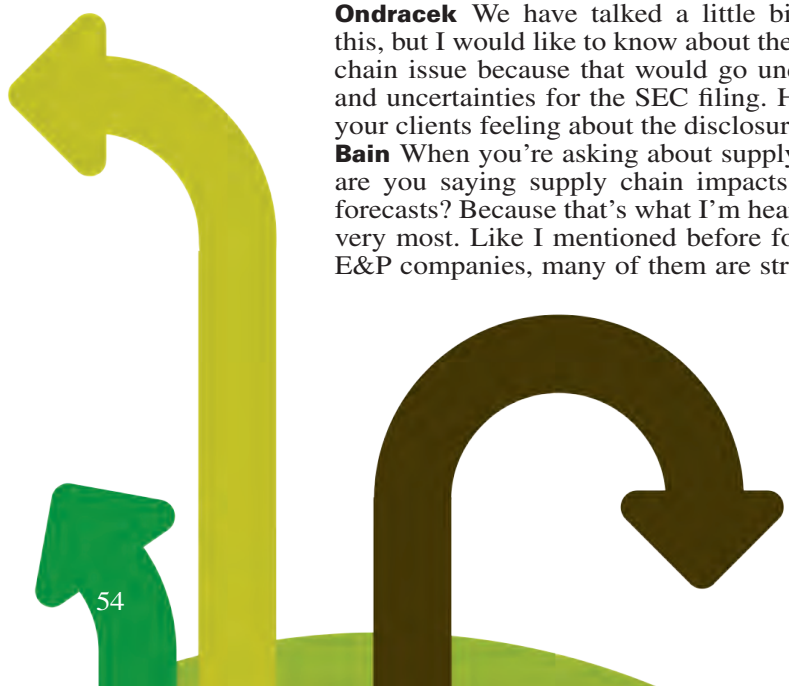
Ondracek Heather, that's a really great point; they're going to be behind schedule. So that's going to be impacting 2022, 2023 because of the catch-up.

Al-Kawafha The way I look at it is it's probably going to be a challenge for a lot of the service companies. I know they're getting a lot of pressure from the E&P company on selling just because of the prices. So, now the inflation probably is going to increase the supply chain.

The shortage problem is going to increase the prices of the ports. And I'm not sure if they could pass it to the E&P companies. So, this is one question that probably is going to impact them from inventory (and) valuation, (and) probably there is no concern from impairment. The issue is just more of capturing that. They're just there to provide support to say it's on the ship or where it is, or where it's left. And then the shipping terms, I think, is not a big concern. It's just more about the disruption of business, delays (and) cash flow management. Because if they're trying to sell it again, when they're going to get their collection back and when they buy it is what the buying term versus the sell term. So, that's probably a source that is going to squeeze an industry that's really struggling with obtaining debt. So, it doesn't even have a lot of leverage in having cash flow to support their operation.

Ondracek That's a really great point, especially about the cash flow. They are being squeezed, and you just have one more disruption to the business that's going to impact their reporting. Warren I don't deal with supply chain issues or questions directly, but I guess I would say to Heather's point about smaller producers, especially to the extent that they're still public companies and they're putting out production forecasts or they're putting out their guidance. I think the struggle of managing those drilling delays and bringing wells online and how that's impacting their production volumes.

I think it is probably a big concern from (an) investor relations perspective, managing your analyst expectations, and how that's impacting your overall stock price. Then, it is going to impact your ability to go try to do any type of significant stock acquisition if you're a slightly larger company, but then also might hurt you if you're the target of a larger entity as well. □



OIL & GAS STARTUPS STANDOUT

New private companies establish their footprints to showcase innovative ways of doing business during a difficult time.

ARTICLE BY MICHELLE THOMPSON

Launching a successful oil and gas business can be a challenge during the best of times, but starting one up in the past several years has been proven particularly tricky.

Rollercoaster commodity prices, a shift to renewable energy and heightened governmental regulations are among the challenges companies have navigated. Throwing a global health crisis into the mix has only added to the volatility, but shaky times haven't discouraged ambitious, new companies from starting up and standing out.

Whether they're tapping into established relationships to succeed or utilizing new technologies in tried-and-true basins, new companies are emerging with innovative ideas on how to make the industry more productive, strategic and collaborative.

From family-run operations to longstanding professional partnerships, three growing companies in three thriving basins have shared how they're navigating challenges, adjusting to evolving standards and remaining competitive.

Leveraging experiences

Petroleum engineer turned successful executive Don Dotson has big goals for Vencer Energy LLC, the new domestic, upstream startup

company he leads, as it grows its presence in the Midland Basin.

"Starting Vencer has been both fun and challenging, as you'd expect when forming a new venture," Dotson, president and CEO. "Although Vencer is early in its life cycle, our team has a lot of expertise, motivation and confidence that we will succeed at building a sizable, profitable and respected company that provides a best-in-class work environment with a rewarding culture for our employees."

Vencer was launched in July 2020 with backing from Vitol, one of the largest energy and commodities trading firm in the world, with the mission to acquire mature, economically accretive, producing oil and gas assets in key basins. The company's overall approach is to target scalable, operated assets with long-life reserves and low-base decline rates. Its goal is to generate "exceptional returns" through low-cost undertakings and strategic management.

Vencer executives rapidly mobilized a highly skilled organization in less than four months and have shown tangible results by leveraging their decades of combined experience to position the new company for growth as a large-scale, reputable oil and gas enterprise.

In April 2021, Vencer announced its first acquisition to buy Hunt Oil Co.'s Midland Basin assets. The assets encompass 44,000 acres across five Midland Basin counties and daily production reaching about 40,000 boe/d, with plans to expand its Permian Basin presence through strategic business development efforts, exploitation and an aggressive D&C program.

Dotson elaborated on his key focus areas when developing the organizational structure.

"Of most importance, the Vencer team must have a diverse and significant amount of expertise and experience in all facets of the oil and gas space," he said. "Possessing this, we can draw on our commercial, analytical or data-driven and operationally focused approach along with administrative strengths to optimize our operations and successfully execute our projects. Teamwork and collaboration are also essential contributors to success."

Ben Marshall, head of Americas at Vitol, said the purchase would help establish Vencer as a significant shale producer in the nation.

"We expect U.S. oil to be an important part of global energy balances for years to come, and we believe this is an opportune time for investment into an entry platform in the Americas," Marshall said in a statement. "Vitol has a long history of investing in quality upstream assets, and we are pleased to add this business to our global portfolio. This acquisition represents an initial step to building a larger, durable platform in the U.S. Lower 48."

Dotson is banking on the belief in long-term rewards beyond the ongoing COVID-19 pandemic, despite some critics predicting an impending shift toward renewable sources of energy.

Dotson, who's been working in the oil sector for more than three decades, said demand for oil is likely to grow as economic growth

Founded in 2017, Stronghold Energy II Operating LLC focuses specifically on the Central Basin Platform.

STRONGHOLD ENERGY OPERATING II

STRONGHOLD ENERGY OPERATING II

Father and son duo Steve and Caleb Weatherl founded Stronghold Energy II Operating LLC in 2017.

continues. "Many of us who have been through multiple cycles are optimistic as we see the building blocks in place for strong demand while supplies have some uncertainties. Most companies haven't forgotten the lessons learned during the last downturn and are being strategic and disciplined with their development capital. This is assisting greatly by providing a measured approach to supplies and ensuring the recovery of our industry."

Dotson began his career as a petroleum engineer at Amoco Production Co. before joining Samson Resources and Samson International, where he transitioned into management.

As the leader of Vencer, he said he's hopeful to build a company "that is recognized by our investors and industry partners as an organization that creates value through strategic acquisitions, focusing on optimal operational practices and executing accretive capital projects.

"We aspire to be a top tier company in ESG [and] safety and regarded as a partner and employer of choice. We've started with exceptional staff, great assets with significant upside and have entered at what we believe is the optimal time in this cyclical business to maximize any basin in the Lower 48."

He added, "Our company name, Vencer, means to overcome. Although we anticipate there will be bumps in the road, external factors we cannot control and lessons learned, we expect and believe that we'll achieve success in the oil and gas industry for the benefit of our investors and staff."

"We believe that massive underinvestment in oil and gas brought on by economic, market and political conditions have created a very unique opportunity for a small independent like us to capitalize on favorable drilling opportunities and investments," said Travis L. Wheat, president and CEO, Trigo Oil and Gas LLC.

All in the family

Father and son duo Steve and Caleb Weatherl are combining their complimentary skills to apply modern technology to the most prolific part of the Central Basin Platform through their company, Stronghold Energy II Operating LLC.

The pair's backgrounds seem like a match made in industry heaven. Steve, the chief executive, is an accomplished geologist who helped lead the establishment of some of the first economically successful horizontal Wolfcamp wells in the Midland Basin. President and CFO Caleb is a Harvard University business school graduate with strong financial connections.

"When I decided to go independent, we felt like Caleb's financial background with my technical background would be a great fit for a team," Steve said.

This isn't the duo's first collaboration. Steve first launched a family-owned company called Weatherl Energy Investments LP before he and Caleb started Stronghold Energy Partners. The latest iteration, Stronghold Energy II, was capitalized in 2017 with a $150 million commitment led by Warburg Pincus.

The new company was formed after the Weatherls identified a unique opportunity to modernize activity in the Central Basin Platform.

"We felt like the Midland and Delaware basins, while the rock is great, were getting a little overheated in terms of the prices that people were paying," Caleb said. "We saw an opportunity to take some of the technological advances from the shale revolution of the past decade, particularly with regard to completions that had been broadly applied in the Midland and Delaware basins but had not been broadly applied in the Central Basin Platform yet, and apply those to the Central Basin Platform."

The Central Basin Platform was one of the first areas in the Permian Basin to be developed. About half the oil historically produced in the Permian has come from the Central Basin Platform, but in more recent years has been shadowed by zones with more modest but very economic oil cuts.

Before partnering up with his father, Caleb worked in the energy vertical at Bain Capital LP, a leading multi-asset alternative investment firm. He also did some consulting for McKinsey & Co.

His exposure to the industry began much earlier; growing up in Midland, Texas, he remembers going to the office with his father as a child and taking a natural interest in the oil and gas world.

"He really taught me everything from the ground up," Caleb said. "What is a joint interest bill? What is a revenue check? What is a joint operating agreement? How do you drill a well? How do you frac a well?

"He spent a lot of time just really mentoring me and teaching me the industry from the ground up. I was able to marry that knowledge that he imparted to me with my business background in consulting and finance."

Steve described his son as a quick study whose strong analytical skills allow him to thrive in a multitude of ways.

"He did grow up around the industry and would come with me to look at morning reports prior to the time that you could get them emailed."

Things have been working out well for the company so far; it has more than doubled its overall oil production since acquiring Devon Energy Corp.'s southern Central Basin Platform assets in early 2019 and has proven up hundreds of additional locations prospective for development.

"Our net revenue interests are very high because we have old, producer-friendly leases and so our economics—if you look at it from

STRONGHOLD ENERGY OPERATING II

Stronghold Energy has more than doubled its overall oil production since acquiring Devon Energy Corp.'s southern Central Basin Platform assets in early 2019.

an internal rate of return standpoint or a payback period standpoint—are really competitive with core shale economics in the Midland or Delaware basins on all of our remaining inventory," Caleb said. "We just feel really fortunate to have such a great asset."

Building through partnerships

Relationships can make or break a burgeoning oil and gas company, and in the case of Trigo Oil and Gas LLC, strong connections put the company on the fast track to success.

When Travis L. Wheat founded Trigo in 2018 with the intention of pursuing mineral and royal rights in the Delaware Basin, a bigger opportunity soon presented itself as executives observed large-scale divestments in the region. The company wisely anticipated that unique drilling opportunities would present themselves in beneficial market conditions.

"We believe that massive underinvestment in oil and gas brought on by economic, market and political conditions have created a very unique opportunity for a small independent like us to capitalize on favorable drilling opportunities and investments," said Wheat, president and CEO.

With that in mind, the company plans to continue pursuing development and strategic partnerships to increase its footprint in the Delaware Basin, where it's leveraging its past and present partnerships to outpace competition.

"We put together a lot of acreage in the Delaware Basin over the last several years for a small group, but we would not be here unless we had developed great relationships with landowners and our partners," Wheat said. "Our current development would not be possible unless it was for our current partners putting a tremendous amount of trust and faith in us.

We are competitive, but we are only able to be competitive because we have formed great relationships and partnerships."

Trigo was born through parent company Wheat Resources LLC, which enjoyed a slow burn of success since launching in 2012. It began by acquiring leases, mineral rights and surface rights throughout Ward, Loving, Pecos and Reeves counties, Texas, and would then sell down, or sometimes all, of its interest and use the profits to buy something bigger. It repeated

Devin Speir, partner of Trigo Oil and Gas LLC, said the practical management of resources has been crucial for the company's success.

Trigo Oil and Gas LLC partner and vice president of land and legal, Michael Vinson, said raising capital has been a challenge as the company continues to grow.

the strategy until it had enough capital to lease operable size tracts of at least 320 acres.

As the company grew and launched Trigo, it wasn't always a smooth process. Although 2020 was a notoriously difficult year for the industry, things were tough for the company in 2019 as well.

"There wasn't really any activity, and we had decent oil prices but little to no cash," Wheat recalled. "[There were] no acquisitions minus a few publics, but they were all-stock transactions, which did not benefit the small independent. No one was buying, selling, drilling or investing. You even had some of the biggest private equity firms making a transition from oil and gas and closing down E&P portfolios."

Fortunately for the company, things worked up after it landed two partners in Oklahoma City and began pursuing its ultimate goal of operating.

"We put together several thousand acres in the Delaware Basin, but we would not be here unless we had developed great relationships with landowners, operators and our partners," Wheat said. "Our current development would not be possible without our partners in Oklahoma City putting a tremendous amount of trust and faith in us."

Though the company itself is relatively new, Wheat and his partners have combined decades of experience within the industry, where they've worked tirelessly to forge relationships that have since become the cornerstones of Trigo, which serves as its parent company's operating and mineral branch.

The practical management of resources has been crucial for the company's success, said partner and vice president of business development Devin Speir.

"Aside from being a privately owned company, fundamental to Trigo is pragmatic stewardship of the resources given to us, investment in the relationships we depend upon and honest and transparent dealings with all stakeholders," Speir said. "When these are fundamental in your company, all other things tend to fall into their proper place."

Partner Michael Vinson, vice president of land and legal, said raising capital has been a challenge as the company continues to grow.

"It is the life blood of any organization, and the last several years, it has been incredibly tough to raise capital for oil and gas developments," Vinson said. "I think we beat down nearly everyone's door to put together the capital to drill our current prospect. We had lots of meetings to pitch our prospects, and we had lots of nos, but persistence bore fruit and we are grateful for that." □

The sun rises behind Stronghold Energy II Operating LLC's McKnight frac operations in the Central Basin Platform.

STRONGHOLD ENERGY OPERATING II

HELD FOR RANSOM

Energy companies, starved of resources from downturns, are increasingly susceptible to cyberattacks, introducing complications to transactions.

ARTICLE BY
DARREN BARBEE

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Cybersecurity has become "top of mind" for companies engaged in M&A, said Bryan Benoit, Grant Thornton's partner-in-charge of the firm's U.S. energy advisory.

Last December, a hacker known as Robotnik went shopping for some malicious code, finally choosing a ransomware program called Sodinokibi, like a customer checking out at a Best Buy for bad guys.

An advertisement for Sodinokibi offered the hacker a cut of up to 70% of the illicit gains from the program. On Dec. 14, the hacker cordially wrote to the advertiser in Russian: "Hello, this is Robotnik. I want to return to work," according to a federal indictment unsealed in January.

The eventual ransomware attack, as described by the FBI, extorted thousands of businesses by encrypting their data and demanding millions of dollars to unlock it. The attack shut down businesses, crippled cash registers in Sweden, local government computers in Texas and affected the software company Kaesya.

The proliferation of ransomware and other cyberattacks against such a variety of targets might suggest businesses share an equal risk. Each day about 2,000 new attacks are launched, according to 2020 FBI statistics.

But what's clear to software experts and the American Petroleum Institute itself is that the energy industry has become a preferred hunting ground for hackers. And those attacks have started to have a direct effect on a core way in which the oil and gas sector is continuing to streamline itself and build scale—through transactions.

Most recently, Superior Plus Corp. reported it was the subject of a ransomware incident on Dec. 12 that impacted the U.S. and Canadian propane and distillates supplier's computer systems.

The company temporarily disabled certain computer systems to investigate the incident and was in the process of bringing the systems back online.

Cybersecurity has become "top of mind" for companies engaged in M&A, said Bryan Benoit, who serves as Grant Thornton's partner-in-charge of the firm's U.S. energy advisory in Houston.

Any number of factors, such as ESG concerns, can affect the cost of capital and discount rate attributable to assets, potentially lowering the purchase price.

As Grant Thornton looks to measure the level of risk a company might be exposed to in a deal, cybersecurity has become a new and highly technical area of concern. The U.S. Securities and Exchange Commission (SEC) is already taking actions that suggest far more stringent requirements for disclosure, particularly regarding private information.

Weighing the relative risk of a company with loose—or less than ideal—cybersecurity controls also require ways to analyze and evaluate the relative price of assets, Benoit said.

"The discount rate basically says that a dollar today is worth more than a dollar tomorrow because a dollar tomorrow is at risk," Benoit said. It changes the rules regarding disclosure, and dealmakers have to find new ways to evaluate the risk to what they expect an asset to generate.

Cynthia J. Cole, a partner at Baker Botts, said she's "absolutely seen deals fall apart" due to not only data security issues but for potential data privacy reasons.

Recent deal activity leads him to believe that the cyber health of a potential oil and gas company acquisition has quickly risen to the top 10 or even top five areas of interest to dealmakers.

Cybersecurity in the oil and gas space has clearly lagged in some areas, at least partly because of the brutal commodity price downturns experienced by the industry.

Cynthia J. Cole, a partner at Baker Botts who specializes in cyber and privacy issues, said she's "absolutely seen deals fall apart" due to not only data security issues but for potential data privacy reasons.

"I've seen financings not go through because the investor is like, 'Whoa, whoa, whoa, wait a second. This is a lot more expensive than I thought,'" she said. "The potential upside is a lot less than I thought it was going to be because there's a big ramp up to compliance."

Cyber experts agree as well that not only are cyber intrusions going to increase, they're also almost inevitably going to be successful. Instead, they stress ways to limit the damage to companies, quickly discover intrusions and already have systems in place that limit day-to-day business communications from operational controls.

"There's no way you can prevent the security incident [or] the breaches from happening," said Derek Han, who leads Grant Thornton's national cybersecurity and privacy practice. "There's no way you can't because nobody is perfect.

"You have to assume a bad thing will happen to you one day, but make sure you really have a resilient infrastructure and processes; you can respond to that really quickly [and] contain the damages really quickly," he said.

What makes those involved in oil and gas dealmaking nervous is that in many cases, they continue to see cases in which companies aren't taking those crucial steps.

"You have to assume a bad thing will happen to you one day, but make sure you really have a resilient infrastructure and processes," said Derek Han, leader for Grant Thornton's national cybersecurity and privacy practice.

Soft targets

The most infamous attack on energy assets in 2021 on Colonial Pipeline caused havoc and affected millions of Americans. Colonial was forced to shut down a major pipeline system because of a ransomware attack likely caused by a single weak link.

The company wasn't infiltrated through an elaborate hack, according to analysis by the company, but likely through outdated security protocols. The company had continued to use an outdated network that may have been compromised using a stolen password, possibly obtained on the dark web.

"We believe the attacker exploited a legacy virtual private network profile that was not intended to be in use. We are still trying to determine how the attackers gained the needed credentials to exploit it," Colonial Pipeline president Joseph Blount testified at a June Senate hearing.

Blount recounted that the May 7 attack forced the company to rapidly shut down 5,500 miles of pipeline, with delivery points in 13 states. The company transports about half the fuel consumed on the East Coast, providing energy for more than 50 million Americans either directly through gas station pumps or to cities and first responders.

Colonial may have been in the spotlight, but many small and midsize oil and gas operators and pipeline companies are in the same position. As they've limped along during industry downturns, they've had to choose between survival and spending on security. Along with obsolete but still active systems, they have left themselves susceptible to intrusions and takeovers.

Now, as oil and gas prices recover, the energy sector, including companies engaged in oil and natural gas production, has become the second most popular target for hackers looking for a quick payday, API said in October 2021.

Even the federal government's efforts have lagged behind. In July 2021, the U.S. Department of Energy released its first new blueprint

M&A CYBER INSPECTION

The internet has opened businesses up to an endless Barbary Coast of potential, many based in countries hostile to U.S. interests. Cybersecurity's security due diligence has taken on multiple levels, from surveys of network infrastructure to appropriate disclosure.

In dealmaking, Mike Hoffman, a principal industrial consultant at Dragos Inc., said his approach is to look at a company's cybersecurity holistically through the view of the network as well as a more detailed and technical inspection of a potential company's cybersecurity.

Hoffman said owner-operators taking charge of another company should first perform an architecture assessment that includes a full understanding of how the data is monitored and controlled through a system called Supervisory Control and Data Acquisition.

"I've actually done this as an asset, owner-operator taking charge of another [asset]," he said.

Hoffman said he asks for drawings, security controls and anything that lets him understand how the computer system has been pieced together and implemented.

"The first thing I do to make sure their architecture is properly done and [to see] what remediations will need to occur to bring it up to the purchasers' standards," he said.

A buyer should also be at firewall rules and other protocols, although "that won't tell you if the company you're purchasing has been compromised."

Hoffman said a buyer would also want to collect information, including monitoring network traffic.

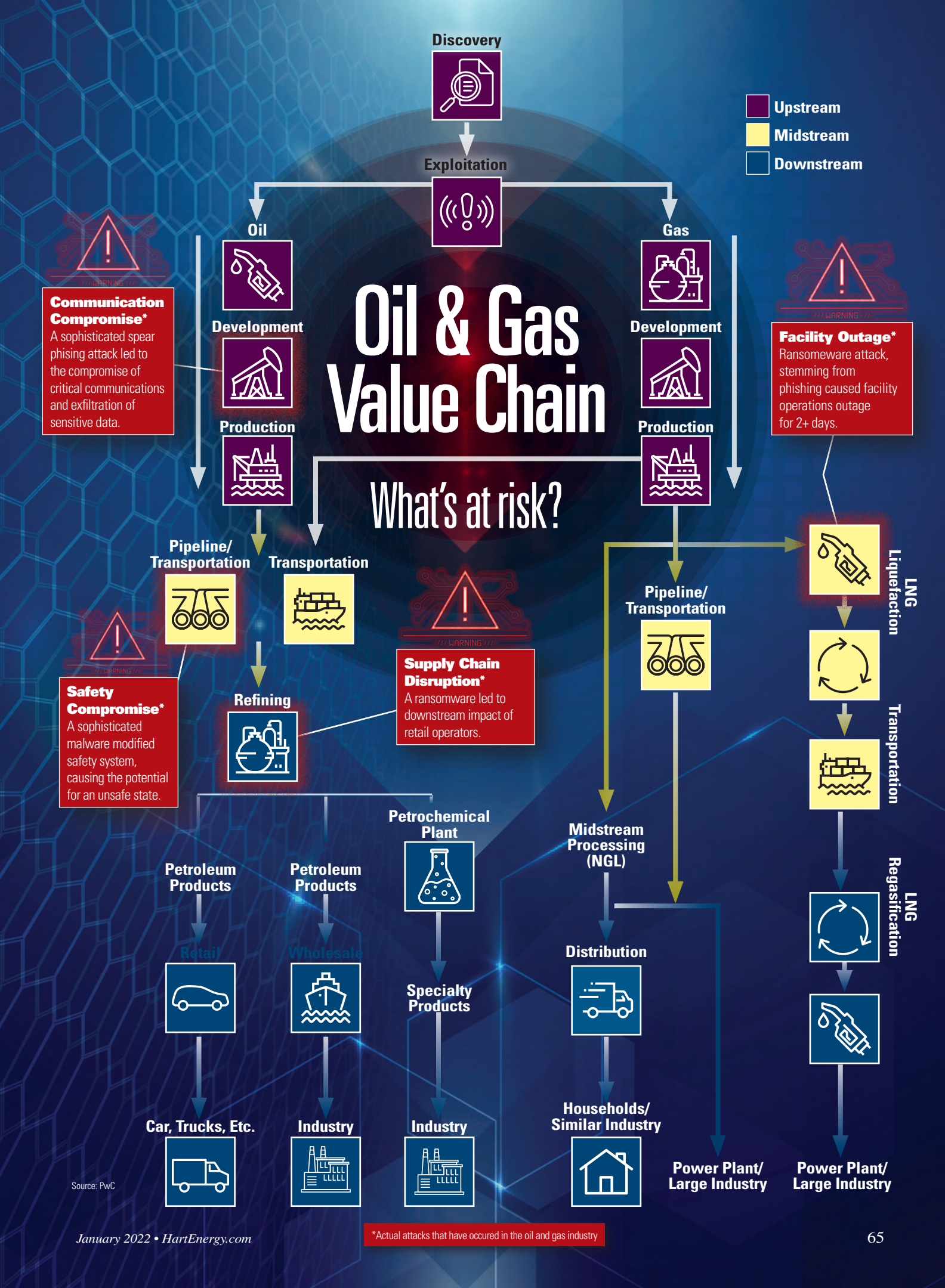
"You're going to either do a threat hunt across that information that you've gathered or a compromise assessment to understand that," he said.

Once the network is clearly understood, "let's actually look inside, look at the logs of the systems and look at the data that's flowing back and forth. And to understand if there's an adversary in the environment, if there's malware trying to beacon out on those kinds of things."

Hoffman said the right amount of rigor will give a buyer an overview of how well the company has operated from a security perspective.

Oil & Gas Value Chain

What's at risk?



Source: PwC

*Actual attacks that have occured in the oil and gas industry

The oil and gas industry is in different stages of cyber preparedness, said Mike Hoffman, a principal industrial consultant at Dragos Inc.

Joe Nocera, leader of PwC's Cyber & Privacy Innovation Institute, said that the oil and gas sector has long been a target of hacks, though the motivations have changed over time.

INTO THE GRAY

The risk of cyberthreats has radically intensified concerns among insurers in the past 18 months, Cynthia J. Cole, a partner at Baker Botts who specializes in cyber and privacy issues, said, to the point that even underwriters offering coverage for post-deal liabilities are now more wary of covering potential data liabilities.

Cautious buyers and wary financial underwriters and insurance companies are increasingly unwilling to enter deals with companies that use primitive cyber defenses or, in some cases, don't ask the right questions.

Disclosure can be complicated. Cole said the U.S. Securities and Exchange Commission (SEC) has lately taken a more aggressive approach to how security is described by companies.

In August, the SEC fined a U.K. educational publisher $1 million for inadequate disclosure of a cyberattack, even though the attack hadn't resulted in any material damage to the business, according to Gibson, Dunn & Crutcher LLP. At issue was the company's statements that implied no major data privacy or confidentiality agreement had occurred.

Cole said disclosure laws typically require public notification if two or more pieces of personal information are exposed through a cyberattack. But even in cases where that threshold hasn't been met, companies tread carefully on how they describe the incidents.

That's also prompted a far more careful stance by reps and warranties companies, which take on "risks of unknown circumstances" for buyers or sellers, Cole said.

Knowing the right questions to ask about a cyber intrusion or an attack is particularly important.

"In the past, let's say that [cyber disclosure] question mattered a little less," Cole said. "Now the rep and warranty insurance companies are saying, 'Hold on a second, hold on a second. Not only did you not ask the right question in the first place but then you sort of asked the question and you didn't get an answer that really meets our standards.'"

The result is that insurers aren't willing to cover problems as they arise.

"I'm seeing pressure from the insurers saying, 'You have to ask that question specifically, and you need to get a direct answer, or we're just going to exclude it.'"

for defending against cyberattacks in about eight years. Since its previous assessment, commonplace technologies such as cloud computing, mobile devices and artificial intelligence have seen widespread adoption without input from the department. The latest blueprint also addresses evolving threats such as ransomware and supply chain risks.

Colonial reportedly paid roughly $5 million in ransom, though the U.S. Department of Justice was able to recoup some of the money.

"Being extorted by criminals is not a position any company wants to be in," Blount said. "As I have stated publicly, I made the decision that Colonial Pipeline would pay the ransom to have every tool available to us to swiftly get the pipeline back up and running. It was one of the toughest decisions I have had to make in my life."

Blount said his decision was based on restoring critical infrastructure as quickly as possible and noted that the company took steps in advance of making the ransom payment to follow regulatory guidance while informing law enforcement so that they could pursue those responsible.

Colonial also engaged Dragos Inc., an industrial cybersecurity firm, to help with the strengthening of its cyber defenses.

Mike Hoffman, a principal industrial consultant at Dragos, said the oil and gas industry is in different stages of cyber preparedness. Hoffman previously served as principal industrial control systems security engineer at Royal Dutch Shell Plc and said that downstream assets have been the predominant focus of oil and gas companies as they look to lock down critical assets.

"Downstream predominantly has been the area where there has been the most maturity," he said. Midstream and upstream onshore assets have been squeezed by tight economics that have made them perhaps the least protected.

"Especially in upstream operations, there's not a whole lot of loose money around to start spending on security projects," Hoffman said. "That said, there's upstream operations that have seen a lot of mergers and acquisitions going on. That's definitely a ripe area where companies coming in absolutely need to be concerned about the [security] environment they're taking over."

The relative size of a company or its profit doesn't determine whether a company will be disrupted by hackers.

"The adversary can still come to you and use you as essentially a playground or a laboratory for a different type of an attack," Hoffman said. "We've actually seen this quite often, where again, a lot of these smaller companies, they may not have a very good security posture."

On Nov. 13, for instance, Australia's Strike Energy Ltd. sent out an email to its shareholders disclosing that its primary electronic communications had experienced a "security event" that resulted in emails with news about the company being disseminated via email.

"Please disregard and delete these emails immediately as they were sent without the company's knowledge or permission," it said. "Strike is currently investigating how this communication was sent and will take steps to ensure that any issues are remedied as soon as possible."

Companies also may not know the extent to which they are vulnerable.

In some cases, mobile devices can be exposed to attack. An application easily downloaded by security teams—or attackers—can scan for devices that are connected to the internet that may be in use in the field.

Smaller companies often don't have good backup plans or may be more prone to attacks because of poorly designed software architectures. Even in cases in which both exist, monitoring of digital traffic needs to be in place. And without proper due diligence, companies in the process of purchasing an asset will see

unintended consequences such as picking up malware that wasn't identified during the purchase.

"We've seen before where a company will look to purchase something and begin to kind of dive in and get malware for instance … connecting to that network," he said. "So around mergers and acquisitions, that's a huge piece to highlight and something that the companies need to take into account."

Breach charges

Earlier this year, after engineering studies were completed and various delays on a deal stretched on, a seller finally admitted to a potential buyer that management had been locked out of the company's servers. A hacker was demanding a ransom in Bitcoin, a CEO familiar with the transaction told *Oil and Gas Investor*.

"You're never immune, unfortunately; everyone is subject to ransomware or other attacks," Baker Botts' Cole said.

In recent deals in which cybersecurity has taken a larger role in transactions, Cole has seen that some oil and gas companies simply aren't prepared for the rigors that await them at the deal making table.

When she represents buyers, she often sees sellers that haven't conducted external testing of their vulnerabilities. Sellers are asked for information such as results of network penetration testing, their internal incident response plan and whether they've simulated a response through tabletop exercises.

"It's relatively shocking," Cole said. "You get nothing, or you get, like, three pieces of paper," she said. "It's absent.

"The problem is how do you properly scope a purchase price … if you don't really get the information that you need? If you can't really properly assess the company's data security?"

Joe Nocera, leader of PwC's Cyber & Privacy Innovation Institute, said that the oil and gas sector has long been a target of hacks, though the motivations have changed over time. For years, the target for intruders was a company's intellectual property or a nation-state aiming to penetrate critical infrastructure.

Now, companies are chosen far more indiscriminately.

"With ransomware, we see more of a criminal that's motivated by financial gain," he said. "And so I think that has caused the frequency and severity of these attacks."

Seenu Akunuri, leader of PwC's U.S. energy and mining valuation practice, said attacks seem to have focused on the most disruption, which has tended to mean midstream assets that move hydrocarbons.

But E&Ps are now seeing increased scrutiny during the due diligence process.

Nocera said that companies need to also consider whether a company being acquired has already been breached, whether an actor is already inside its system but also the maturity or the capability of the targeted cybersecurity systems.

SAMPLE SECURITY Q&A

- Discuss your current data security infrastructure, and comment on any interruptions, outages or suspension of systems.
- Have you ever identified a vulnerability, breach or attempt thereof, including criminal or fraudulent activity?
- What is your schedule for carrying out regular vulnerability assessments and penetration tests?
- What are your alerting mechanisms in the event of a breach?
- How are access credentials selected, allocated and monitored (including via audit) within the company, including with respect to backup, deletion and destruction as well as avoidance of unnecessary collection (e.g. are employees/contractors granted access to sensitive data only if necessary?)
- How do you terminate system access of departing employees and monitor their compliance with ongoing confidentiality obligations?
- What is your policy on remote access by employees and using personal and mobile devices for work?
- Do you have a comprehensive written security management program with expected components for your industry in light of the sensitive/critical data in your business? Is the program periodically reviewed for sufficiency?
- Describe your security protocols for physical materials, including physical storage and transportation of documents, shredding, policies for locking the office, etc.
- Does the company vet third-party vendors' security infrastructures, policies and records? Do you ensure audit rights in all vendor contracts?

Source: Baker Botts

"What's the likelihood that they could be breached going forward? It's one thing to disclose a breach that you know about. It's another to be able to assess the likelihood that you could be vulnerable going forward," he said.

Finally, the thornier questions are what should be disclosed.

"Every company gets attacked every day," Nocera said. "In many cases, they'll be these little micro-breaches where an individual user clicks on a link and their workstation gets compromised."

Then there are breaches in which far more information is exposed, perhaps on a financial level. Depending on the way in which the company's information systems are designed, that could lead to compromising production operations.

But even those disclosures require some thought.

"The debate that we see in the industry is, is there enough clarity on what's material and therefore it needs to be disclosed? And how do we disclose information in a responsible way that doesn't give the attackers a road back to our vulnerabilities?" Nocera said.

Robotnik nabbed

In November, the Justice Department said it had arrested Yaroslav Vasinskyi after he had crossed into Poland and seized $6.1 million from a Russian national who was also alleged to have been involved in the ransomware attacks.

Vasinskyi had worked on creating ransomware since March 2019, according to a federal indictment. □

Seenu Akunuri, leader of PwC's U.S. energy and mining valuation practice, said attacks seem to have focused on the most disruption, which has tended to mean midstream assets that move hydrocarbons.

FEWER PROJECTS, MORE CASH

East Daley Analytics' annual midstream outlook sees the companies it tracks generating $90 billion in free cash flow. How will they deploy it in the energy transition?

ARTICLE BY
JOSEPH MARKMAN

In early December, East Daley Analytics released its 2022 Dirty Little Secrets report, an annual undertaking that explores midstream's role in the future of energy. What follows is a discussion of the findings with Ajay Bakshani, capital markets analyst at East Daley and a co-author of the report and Hart Energy senior editor Joseph Markman.

A video of the discussion is available on the HartEnergy.com website. The full version of East Daley's report, which includes coverage of midstream companies, is set to be released in January.

East Daley forecasts a bump of 5 Bcf/d of associated natural gas production between now and 2025, with most of that increase coming from the Permian Basin. Gas demand will increase by 7 Bcf/d during that time, mostly from LNG export projects.

Can you share the key highlights the report found on the outlook of the midstream sector?

A lot of things have changed over the past couple of years. Eighty-dollar oil today is not the same as $80 oil in 2019 and, as a result, midstream infrastructure today was not underwritten to growth forecast today. And so, the industry is in a place where it hasn't been for a while, where there's no big wave of projects in sight.

In the report, we wanted to break down what this means for midstream within each commodity—crude, natural gas and NGL—where capital can go, and really examine the near-term potential of energy transition within the space. Here at East Daley, we built the largest asset database of the U.S. midstream sector, and it gives us a lot of unique insight into commodity fundamentals and how that translates to financial and operational risk.

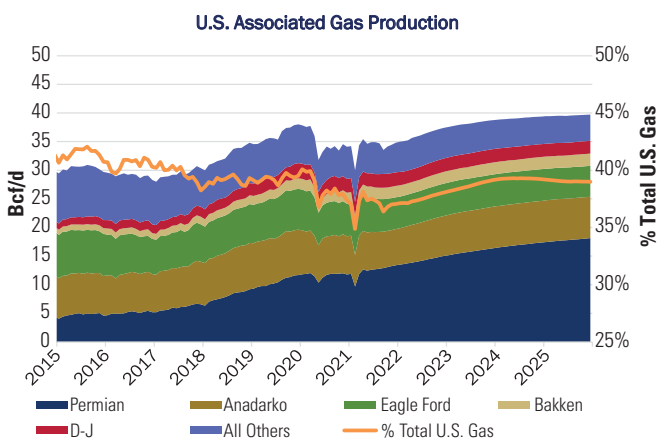
When we aggregate all that data, we can build our company level forecasts, and that's really where we got to the big story here. Midstream is going to generate a lot of cash over the next four years—$90 billion, we expect, for the 25 companies that we actively follow.

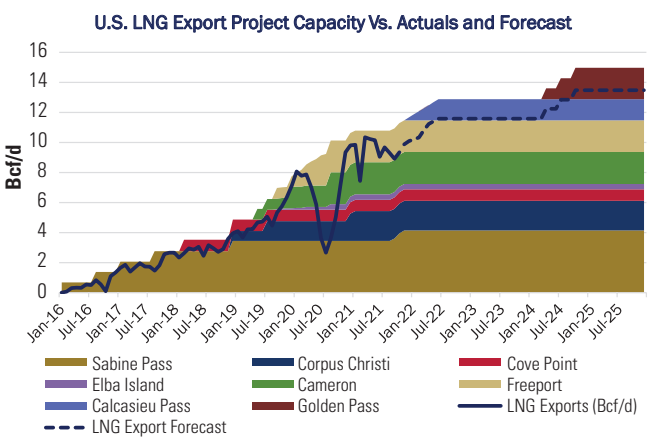
After the buildout in 2019, infrastructure still largely remains overbuilt. And while production is growing again and filling this capacity, it's growing at a much slower pace than initially expected. So, companies are finally seeing the returns on the billions of dollars of capital they invested in the last five years, but with slower production growth, the need for new projects is going to be less frequent, and there are simply going to be less projects to chase after.

So, before, companies would be making a lot of cash flow but they'd be investing in the next big growth project and now, they don't really have that opportunity. A lot of the questions we then had were, what are they going to do with this cash? And where can they find this new growth?

One possibility is energy transition, which has really become a hot topic in the last year, but even there, we don't see large-scale opportunities just yet. We think that's going to be a lot further out—post-2025, maybe more, even in the 2030s.

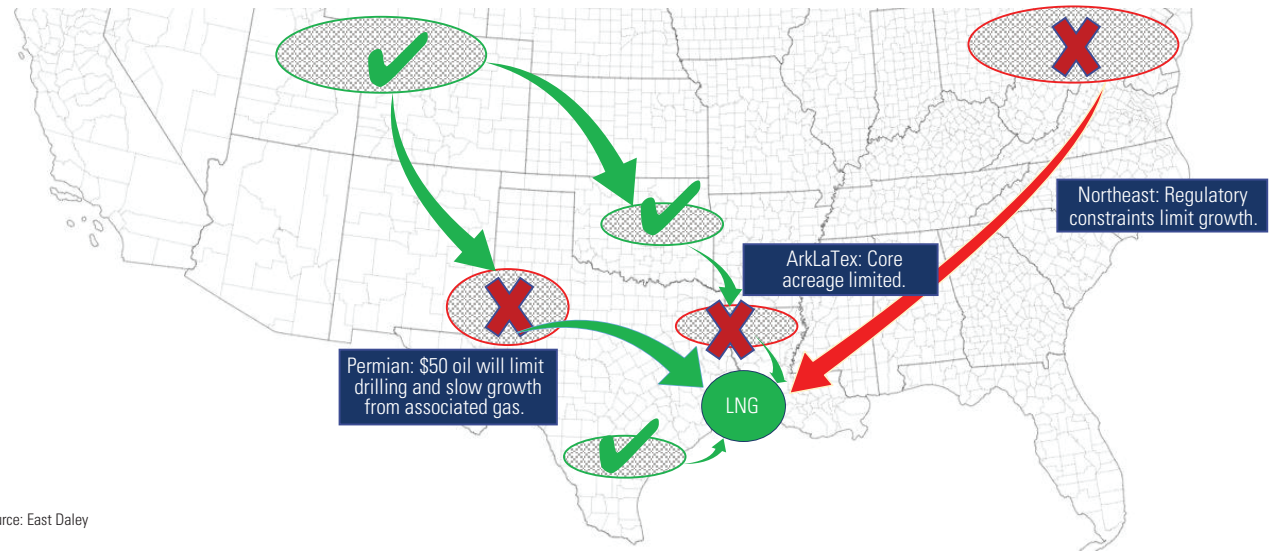
Based on our research, midstream can really do it all in the next few years. There's going to be selective new infrastructure that's needed,





Source: East Daley

Tier 2 Gas Basins



Source: East Daley

especially for gas and NGL, and in the Permian Basin and Ark-La-Tex. And while we acknowledge that the energy transition, and especially carbon, is going to be a huge opportunity, there's really a timing mismatch where large-scale projects are likely not going to be available during this 2021 to 2025 time frame where we expect companies to generate over $90 billion in free cash flow. And this is free cash flow after already planned growth projects, planned distribution growth, as well as repurchases.

I want to ask you about the role of natural gas in the energy transition. Now, it is a fossil fuel. Some folks are simply dead set against natural gas because it is a fossil fuel, and that creates some challenges in terms of drilling, transport, even utilities, that choose it over a renewable option. How do you see this playing out?

So the reality is that natural gas will be needed to backstop renewable power. If electrification continues to ramp up, renewable development and battery storage technology may not be able to keep up. If you look at it from a global perspective, it becomes even clearer that natural gas will be needed to meet rising power demand, especially in developing nations that need it and deserve a cheap, reliable source of power. And from a climate perspective, those nations burning natural gas would be infinitely better off than them burning coal.

Additionally, if carbon capture technology advances and you capture the CO_2 cost from burning natural gas, that would significantly improve the emissions footprint of natural gas. We're seeing progress in this area, especially with what NET Power has been doing down in Texas with capturing carbon emissions from power generation. So there's potential for natural gas to become cleaner as well.

You state in the report that associated gas production would lower the Henry Hub price and lead to a lower rig count in gas basins. I'm wondering what that impact might be in Appalachia, in the Marcellus and Utica. Assuming there are fewer oil rigs and less associated gas in the Permian Basin and Eagle Ford, how would the Henry Hub price compare them with the hubs in Appalachia?

In a scenario where associated gas is down and there is still strong LNG demand, that's going to push the Henry Hub price up because more gas will have to come from these gas basins that are more price sensitive to Henry Hub. So the impact to Marcellus, specifically, would be muted initially because the Dominion South basis would strengthen under the assumption that Marcellus growth slows or declines temporarily.

But with Dom South currently trading at about 50 to 60 cents below Henry Hub, Marcellus producers would be less impacted because they receive a lower Henry Hub price but a slightly better in-basin price overall. So, it's net negative for Marcellus operators because many of them hold firm transportation contracts with delivery to the Gulf Coast or to demand centers on the East Coast that are more tied to these Henry Hub prices.

In the event that low oil prices curtail crude and therefore associated gas production in the Permian, basins such as the Rockies, Eagle Ford and SCOOP/STACK would need to hike natural gas output to meet rising demand from LNG and power generation.

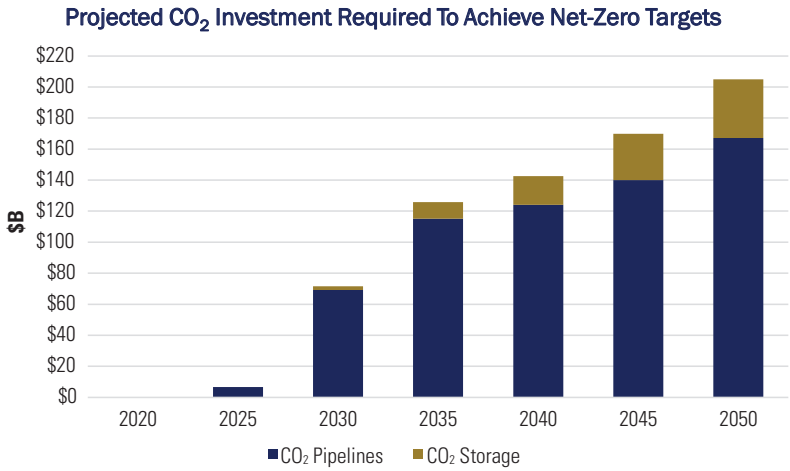
In the report, you mention what are known as Tier 2 basins for natural gas production. If the price of oil drops below $50—which it's not looking like it will anytime soon, but given the nature of this industry, it likely will at some point—if that happens and Tier 2 basins such as the Eagle Ford, SCOOP/STACK and Rockies are called upon to fill in the gaps, how sustainable is this?

There is sustainable gas resource located in Tier 2 basins. We have not done a full analysis on the longevity of these plays, but we're confident that they could sustain U.S. supply, if needed, for a significant amount of time if called upon.

That will really depend on how long oil will stay at $50 and depress associated gas growth, but there's definitely a lot of gas in these basins. As far as prices, I would say they would need to stay at about $4/MMBtu before these players really start seeing a lot of drilling activity. I think that seems reasonable in the 2030 to 2040 time frame, though, especially if we have LNG facilities continuing to be built and, again, sustained declines in associated gas.

In our report, we show that LNG demand is going to be the majority of natural gas demand growth within the U.S., and there are facilities that

Midstream is going to generate a lot of cash over the next four years, said Ajay Bakshani, capital markets analyst, East Daley.



Source: Princeton Net-Zero America

The Princeton Net-Zero America project estimates that investment between $170 billion and $230 billion will be needed in CCUS between now and 2050.

are planned to be online. There is already a significant amount of capacity that is going to be online in the next four years, and then there's another 25 Bcf/d of projects that's already FERC-approved and just waiting for a commitment and the demand to show up. And so, U.S. LNG is really ready to seize that moment.

Can you talk about the Mountain Valley Pipeline (MVP)? How important is it now, especially in light of what has happened with PennEast and Atlantic Coast?

Even with MVP, we expect that capacity is going to fill up relatively fast. Natural gas can come from other basins to fill in the gap in terms of this idea of the Tier 2 pull, but of course, that'll be at a higher cost than the Northeast. So, you know, if more egress capacity could come from the Northeast, that would definitely help supply cheaper gas, and cheaper gas would definitely help with natural gas' continued use as a source of power.

You're also saying in the report that it will take a while for capital to be devoted to large-scale net-zero projects. When?

That's definitely post-2025. I think it could start becoming a driving force within the space in the 2030s, but the initial projects could definitely come before that, specifically for carbon. For hydrogen, I think it's still too early to tell. The technology is still in its very early stages, but that timeline is probably further out than carbon.

Most midstream net-zero investment so far has been for relatively small-scale projects.

I think there might be some potential in other forms of climate-friendly projects like biofuels, renewable diesel and renewable natural gas. We've seen some midstream companies get more involved in those types of projects, from NuStar [Energy LP] and Magellan [Midstream Partners] with their biofuels to [Kinder Morgan Inc.'s] acquisition of Kinetrex [Energy].

Those might not have the same potential overall as what a carbon network and industry might have in the future, but right now there's at least more clarity around the cost and returns there. Like, Kinder is spending $500 million in total on both the acquisition and additional capital cost to develop these RNG (renewable natural gas) facilities for Kinetrex, and they expect to earn a 6x multiple, or about $80 million annually, in EBITDA. Now RNG and renewable fuels are still a relatively small business, so they're probably not that many opportunities there. But right now, at least those opportunities are more concrete.

That's a lot of confidence in the future.

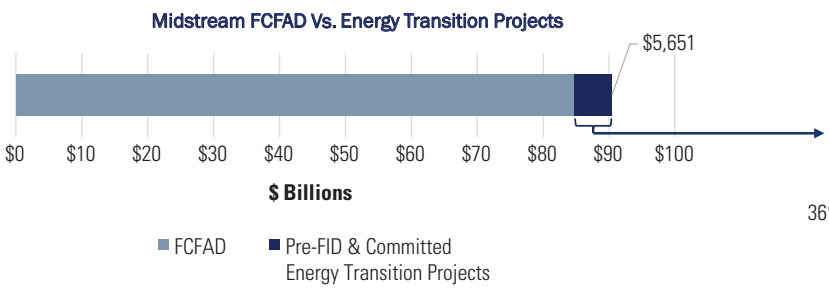
Yeah. If you look at the studies that have been put out, specifically the Princeton Net-Zero America study, there's a lot of infrastructure that will be needed for a full carbon network within the U.S. They expect about $230 billion that needs to be invested in the carbon network for the U.S. to actually achieve net zero. Most of that, by their estimates, are also in that 2030 and beyond that time frame. And again, that's also in a best-case scenario where the U.S. can and will achieve net zero by 2050.

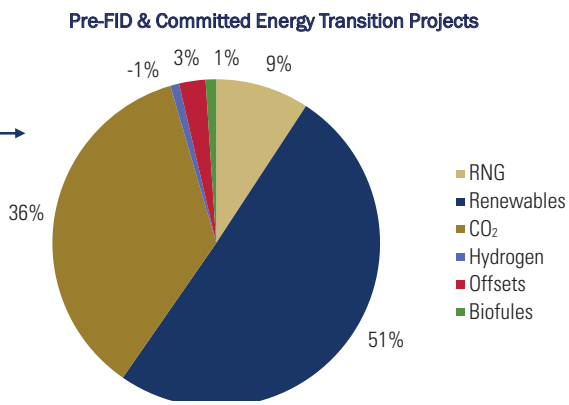
We're confident that it could happen, and we do think that the model fits well, especially within midstream. And obviously, a lot of the pipes can be reutilized for transportation of carbon, but we're just not there yet.

And, I presume, reutilized, upgraded for the transportation of hydrogen, ultimately?

Ultimately, yes. There are still some questions around the cost of that because hydrogen can be very corrosive to these pipelines. It's not a simple conversion by any means to convert these pipelines. Even to transport carbon, it's not a simple conversion.

And another thing to consider is, if natural gas does continue to have a strong role in the energy transition and helping the world achieve its climate goals while supporting continued economic and population growth, not all those pipelines can be reutilized. Some of those pipelines are going to be full, and so that's another thing to consider as well. ☐





Source: East Daley

2021 ENERGY ESG TOP PERFORMERS AWARDS

This recognition program applauds those making a significant impact out in the field, in their communities and in the office.

Hart Energy announced the honorees of its Energy ESG Top Performers Awards in front of roughly 300 industry professionals attending its annual Energy ESG Conference on Nov. 29 in Houston.

Hart Energy worked with Clear Rating LLC, a valuation advisory, securities rating agency and ESG analytics firm, as the official ESG analytics and technology provider. Clear Rating provided assessments of nominees using its proprietary evaluation framework. Hart Energy's expert panel then used the Clear Rating assessments to determine recipients of its inaugural Energy ESG Top Performer Awards.

"Energy companies don't often get credit for their work in these areas," said Len Vermillion, Hart Energy's editorial director. "We created these awards to spark much deserved recognition. Measuring ESG progress is a complex endeavor, so we were thrilled to partner with Clear Rating, whose expertise helped ensure high standards for the awards."

To learn more about Hart Energy's ESG Award honorees, visit **HartEnergy.com/Energy-ESG-Awards** for in-depth profiles on each recipient.

Energy ESG AWARDS

The Winners:

ESG Champion

Allyson Anderson Book
Vice President for Energy Transition
Baker Hughes

Public E&P
- CNX Resources
- Pioneer Natural Resources
- Continental Resources

Public Midstream
- Crestwood Equity Partners
- MPLX

Public Service Company
- Baker Hughes
- Schlumberger
- TGS
- Vallourec

Private E&P
- PureWest
- Sentinel Peak Resources
- Tug Hill Operating

Private Midstream
- Kodiak Gas Services
- XRI Holdings

Private Service Company
- Danos
- Milestone Environmental Services

CLEAR RATING

Truth. Transparency. Trust.

Clear Rating is an independent advisory firm that provides bespoke valuation reports, securities ratings coverage, and full-service ESG evaluations.

Clear Rating Target Areas:

Valuation Reports:

- Establish funding valuation range
- Detailed custom assessments
- Traditional and alternative methodologies
- Applicable to companies, projects, or alternative assets
- Quantitative and qualitative factors considered
- Risk adjusted and marked to market

Private Securities Ratings:

- Holistic assessments using a multidimensional rating methodology
- Thorough industry and operating model analysis
- Regulation D, A, or CF securities
- Easily updated with clear paths for improvement
- Increase visibility and enhance price discovery for investors

ESG Ratings & Analytics:

- Criteria compiled from leading sustainable reporting frameworks
- Industry specific evaluation metrics and benchmarks
- Full blockchain ledger integration with immutable audit trail
- Easily updated with clear paths for improvement
- Interoperability with internal systems and external contractors

Preparation is Key

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Standardization – We provide standardized ratings to enhance efficiency and comparability
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Goodrich Petroleum Agrees To $480 Million Sale To Paloma

GOODRICH PETROLEUM CORP. recently agreed to a merger with an affiliate of **Paloma Resources LLC** that would effectively end Goodrich's tenure as a publicly traded independent E&P company.

According to a company release on Nov. 22, Goodrich entered into a definitive merger agreement, pursuant to which a subsidiary of **Paloma Partners VI Holdings LLC**, an affiliate of **EnCap Energy Capital Fund XI LP**, will commence a tender to acquire all of Goodrich's outstanding common shares for roughly $480 million in cash.

Upon the completion of the transaction, Goodrich will become a privately held company, and shares of Goodrich common stock will no longer be listed on any public market.

Based in Houston, Goodrich Petroleum engages in the exploitation, development and production of natural gas and crude oil primarily in the Haynesville Shale in North Louisiana and East Texas, the Tuscaloosa Marine Shale in eastern Louisiana and southwestern Mississippi and the Eagle Ford Shale trend in South Texas. The company has been led by Walter G. "Gil" Goodrich since 1995.

Due to the oil price environment, Goodrich has recently been concentrating the vast majority of its exploitation and development efforts on natural gas on its existing leased acreage in the core of the Haynesville Shale in North Louisiana where, according to its third-quarter presentation, it holds 32,000 net acres.

The sale of Goodrich comes at a time when A&D activity in the Haynesville Shale has been heating up, including **Southwestern Energy Co.**'s acquisition of private equity-backed **GEP Haynesville LLC** in a cash-and-stock transaction valued at $1.85 billion.

Rob Turnham, president and COO of Goodrich Petroleum, commented on the Southwestern-GEP transaction and how it relates to Goodrich during the company's earnings call in early November.

"If you apply those metrics to us, the stock is worth more, that's not surprising," said Turnham, according to a transcript of the call by Seeking Alpha.

"We're certainly still trading well below our peers on an enterprise value to EBITDA multiple, and yet we still have a pristine balance sheet," he continued. "So we think as we continue to post numbers on the scoreboard, you're going to see EBITDA grow dramatically."

"And we feel like we ought to get recognition for that as the numbers are posted. So more good news to come," he added.

Paloma Partners VI is the latest investment of Paloma Resources, a Houston-based private oil and gas company backed by **EnCap Investments LP** and **Macquarie Americas**. Founded in 2004, Paloma has successfully built and sold several iterations throughout the U.S.

Paloma's tender offer for Goodrich will be priced at $23 per share, which according to the release represents a 7% premium to the Nov. 19 closing price of Goodrich's stock and a 47% premium to its year-to-date volume-weighted average price.

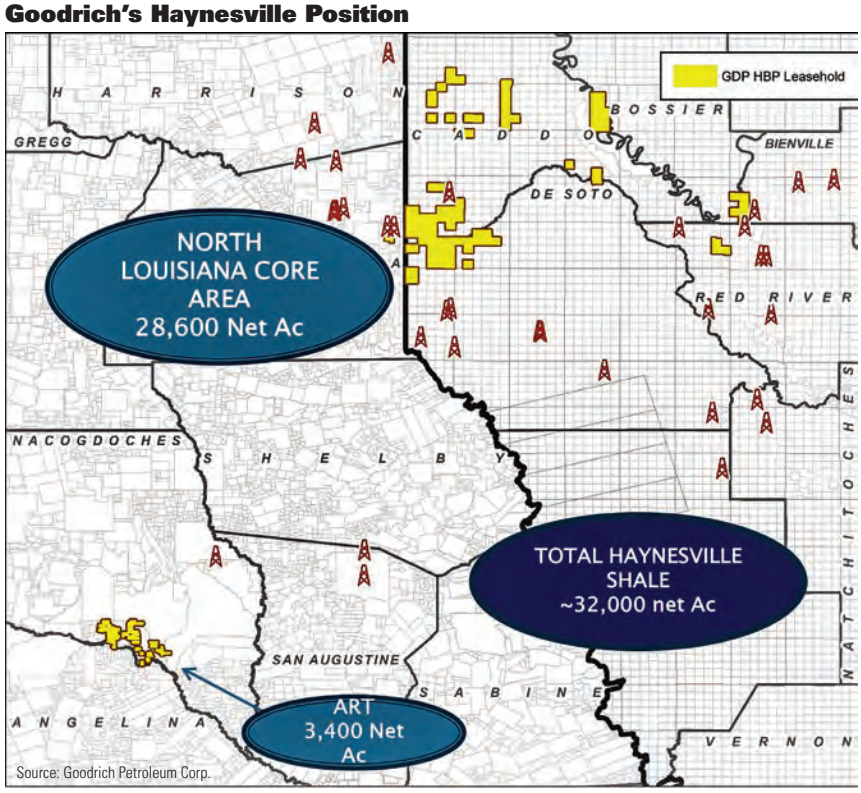
The release also noted that Paloma has secured from EnCap equity financing commitments for the entire acquisition, including assumption of debt, to complete the transaction, expected in December.

The offer price in the transaction has been unanimously approved by the Goodrich board of directors. Certain stockholders of Goodrich have also entered into tender and support agreements pursuant to which those stockholders have agreed to tender their Goodrich shares pursuant to the tender offer.

Tudor, Pickering, Holt & Co. is financial adviser to Goodrich, and **Vinson & Elkins LLP** is serving as its legal adviser. **Greenhill & Co.** is Paloma's financial adviser and **Hunton Andrews Kurth LLP** is its legal adviser.

—Emily Patsy

Goodrich's Haynesville Position



Source: Goodrich Petroleum Corp.

Centennial Completes Asset Sale

CENTENNIAL RESOURCE Development Inc. closed its previously announced sale of noncore assets to affiliates of **Henry Resources LLC** and **Pickering Energy Partners LP** for a cash purchase price of $101 million.

"This divestiture enhances our financial flexibility as we head into next year," Centennial CEO Sean R. Smith said in a Dec. 1 news release.

Centennial Resource Development is a Denver-based independent oil and natural gas company focused on the Permian Basin whose approximately 71,500 net acres are concentrated in the Delaware Basin.

The properties sold include approximately 6,200 net leasehold acres and related assets located on the southernmost portion of the company's Reeves County, Texas, position. Third-quarter estimated average net production associated with the divested acreage was approximately 1,600 boe/d (64% oil), or less than 3% of total company production.

According to statements made by Smith in early November, Centennial's near-term capital is focused on other areas of its portfolio and plans for proceeds from the sale were to reduce borrowings on the company's revolver.

As of Sept. 30, Centennial had roughly $494 million of liquidity with no senior note maturities until early 2026. The company expected net debt last 12-month EBITDAX to be about 1.5 times by year-end 2021, according to an investor presentation published on Nov. 3.

Chevron, Exxon Mobil Top GoM Spenders At Federal Auction

U.S. OIL MAJORS Exxon Mobil Corp. and **Chevron Corp.** were among the top buyers at a federal auction of oil leases in the U.S. Gulf of Mexico on Nov. 17 that generated more than $190 million—the highest since 2019.

The auction was a boon for federal coffers, but a potential setback for the climate policies of President Joe Biden, whose administration tried to suspend federal lease sales to fight global warming before a court forced them to proceed.

The U.S. was also among nearly 200 nations that adopted the Glasgow Climate Pact this month in a deal that for the first time asked governments to accelerate cuts in planet-warming emissions by limiting support for fossil fuels.

In the sale, the Bureau of Ocean Energy Management (BOEM), an arm of Biden's Department of Interior, offered 80 million acres, accounting for almost all available unleased Gulf of Mexico blocks. About 1.7 million acres were sold.

Chevron was the auction's biggest spender with $47.1 million, followed by Anadarko, owned by **Occidental Petroleum Corp.**, **BP Plc** and **Royal Dutch Shell Plc**.

Exxon Mobil rounded out the top five, snapping up nearly a third of the tracts that sold for $14.9 million, making it the biggest buyer by acreage.

One analyst said Exxon Mobil's purchase of 94 shallow-water blocks could be preparation for the company's first carbon capture and storage project, a proposal that Exxon Mobil floated in April.

Occidental's Anadarko subsidiary, meanwhile, placed the highest single bid in the Nov. 17 auction—more than $10 million—for a tract in the deepwater Alaminos Canyon.

The sale's proceeds of about $191.7 million made it the highest yielding auction since March of 2019.

A Gulf of Mexico auction conducted by the administration of former President Donald Trump last year brought in $121 million.

The average price per acre sold in the Nov. 17 auction was around $112 compared with last year's $233.

Separately, Biden on Nov. 17 criticized U.S. oil majors for elevated retail fuel prices.

In a letter to the Federal Trade Commission, Biden noted that the nation's two largest oil and gas companies—Chevron and Exxon Mobil—were on track to double their profits while American families are paying more at the pump.

ConocoPhillips Continues Divestments After Shell Permian Deal

U.S. OIL AND gas producer **ConocoPhillips Co.** will quit Indonesia, selling its assets there for $1.355 billion to domestic energy company **Medco Energi Internasional** and beef up in Australia as it continues to reshape.

The deals follow ConocoPhillips' move to double down on U.S. shale with a $9.5 billion purchase of **Royal Dutch Shell Plc**'s West Texas properties and a $13.3 billion deal for **Concho Resources Inc.** and its exit from Canada's oil sands, U.S. offshore and British North Sea fields.

The largest U.S. independent oil producer said on Dec. 8 it would sell its subsidiary that indirectly owns a 54% stake in the Indonesia Corridor Block Production Sharing Contract (PSC), which has two oil fields and seven gas fields, and a 35% shareholding interest in **Transasia Pipeline Co**.

At the same time, ConocoPhillips said it was exercising its right to buy up to an additional 10% stake in **Australia Pacific LNG** (APLNG) from **Origin Energy** for up to $1.645 billion, pre-empting an offer from private equity firm **EIG Partners** for that stake.

"The Asia Pacific region plays an important role in our diversification advantage as an independent E&P, and these two transactions enhance that advantage by lowering our aggregate decline rate and diversifying our product mix," ConocoPhillips CEO Ryan Lance said in a statement.

ConocoPhillips' subsidiary currently holds a 37.5% APLNG interest and would own as much as 47.5% upon the closing of the deal, expected in the first quarter of 2022.

ConocoPhillips' full-year 2020 production from APLNG was about 115,000 boe/d. By comparison, the Indonesia assets it is selling produced about 50,000 boe/d.

RBC Capital Markets analyst Scott Hanold said ConocoPhillips continues a "proactive A&D strategy to streamline and high grade its global portfolio."

The update is a slight positive for the company but a fairly neutral event for the shares, he said. The company's shares were down 0.5% at $74.17.

MedcoEnergi said the Corridor PSC assets it is acquiring fit well with its Sumatra operations and would boost its oil and gas production to 155,000 boe/d, up about 40% from its current production capacity.

Contango Completes Merger, Forming Crescent Energy Co.

INDEPENDENCE ENERGY LLC successfully merged with **Contango Oil & Gas Co.** on Dec. 7 to create **Crescent Energy Co.**, a premier, diversified and well-capitalized U.S. energy company focused on consolidation.

Crescent's Class A common stock will trade on the New York Stock Exchange under the ticker symbol "CRGY" at the open of trading on Dec. 8, 2021, and as previously announced, each eligible share of Contango common stock issued and outstanding immediately prior to the effective time of the transaction will be exchanged for 0.2000 shares of Crescent Class A common stock.

Crescent's investment approach will build on a long track record of prioritizing cash flow through financial discipline and risk management, focused on delivering attractive risk-adjusted investment returns and predictable cash flows across cycles.

Crescent had production of approximately 119,000 boe/d on a pro forma basis in the second quarter of 2021 from a diverse set of attractive assets across the Lower 48 states, providing a stable platform from which to grow the business.

Independence is an upstream oil and gas business built and managed by **KKR**'s Energy Real Assets team, with a scaled portfolio of low-decline, producing assets across the Eagle Ford, Rockies, Permian and Midcontinent regions.

Contango, a Fort Worth, Texas-based independent oil and gas company, has positioned itself as a consolidator completing four significant acquisitions in the last 18 months.

"We appreciate the strong support for this transaction from the Contango shareholders, which we view as further affirmation of the significant benefits it will deliver," John Goff, chairman of Crescent, said. "The combined expertise of the Contango and KKR teams along with a much greater scale affords us the ability to continue to take advantage of industry consolidation."

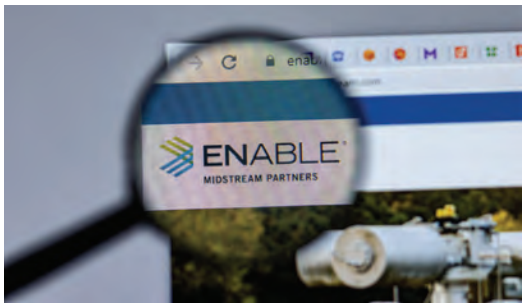
With the transaction now closed, Crescent is positioned to continue its demonstrated strategy of employing a differentiated business model that combines an investor mindset and deep operational expertise; investing capital with discipline and a focus on cash flow; acquiring and developing a portfolio of low-risk assets; engaging on key ESG principles with a commitment to continuous improvement; and providing downside protection through strong risk management.

The combined business will be managed by KKR's Energy Real Assets team and led by David Rockecharlie, head of KKR Energy Real Assets, who will serve as CEO and as a member of the board of directors.

John Goff will be chairman of the board of directors, which is composed of nine members, five from legacy Independence, three from legacy Contango and one non-legacy representative.

—Hart Energy Staff

CenterPoint Begins Midstream Exit



CENTERPOINT ENERGY INC. completed the sale of its stake in **Enable Midstream Partners LP** on Dec. 2, kicking off the Houston-based company's multibillion dollar exit from the midstream space.

"We are now firmly on an accelerated path to reducing our exposure to the midstream industry," Dave Lesar, president and CEO of CenterPoint, commented in a company release on Dec. 2.

The sale was part of a previously announced $7.2 billion all-stock merger agreement with Dallas-based **Energy Transfer LP** that underwent an extended investigation by the Federal Trade Commission. The terms of the merger agreement, however, were approved earlier this year by Enable's two largest unitholders, CenterPoint and **OGE Energy Corp.**, which together owned approximately 79% of Enable's outstanding common units.

Upon closing of the merger, CenterPoint received approximately 201 million Energy Transfer common units and $5 million in cash in exchange for its Enable common units and general partner interest, respectively. In addition, CenterPoint exchanged about $363 million of Enable Series A fixed to floating non-cumulative redeemable perpetual preferred units for $385 million Energy Transfer Series G fixed-rate reset cumulative redeemable perpetual preferred units.

The closing of the Enable and Energy Transfer merger also triggered the settlement of the previously announced contingent forward sale of 50 million Energy Transfer common units, or approximately 25% of CenterPoint's total Energy Transfer common unit holding.

"This transaction aligns with our newly unveiled 10-year growth strategy that focuses on investing in the footprint of our pure-play regulated business," Lesar added in the CenterPoint release.

As for Energy Transfer, closing of the transaction removes overhang though a rerate story remains longer-dated on few follow-on catalysts, according to analysts with **Tudor, Pickering, Holt & Co.** (TPH).

In a release announcing the transaction in February 2021, Energy Transfer described the acquisition of Enable Midstream, formerly based in Houston, as a credit-accretive bolt-on with expectations for the deal to further Energy Transfer's deleveraging efforts and generate over $100 million of annual cost efficiencies.

"While deal close improves balance sheet metrics and earnings potential, we expect debt paydown to remain the primary use of FCF [free cash flow] through 2022 as leverage tracks in the low-4s with material unit buybacks likely deferred until 2023 despite recent equity underperformance," TPH analysts wrote in a Dec. 3 research note. "A lack of near-term catalysts necessitates comfort with our longer-dated rerate expectation, but 2023 FCV/EV continues to screen near the top of the large-cap group at nearly 9%, which opens the door to significantly increased capital returns over time."

After the announced close of the Enable transaction, Energy Transfer said it now owns and operates more than 114,000 miles of pipelines and related assets in all of the major U.S. producing regions and markets across 41 states.

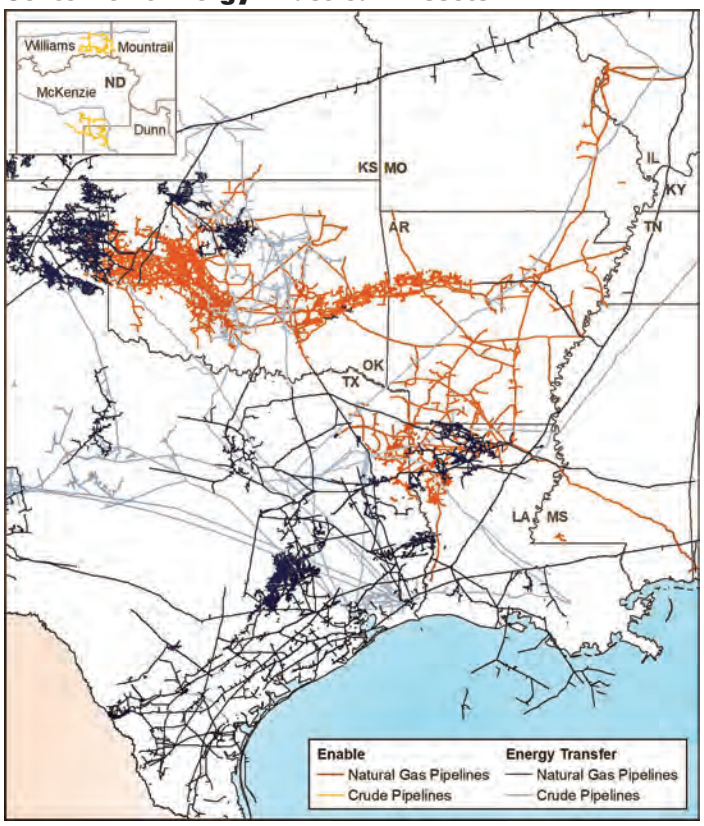
In particular, the company noted the addition of Enable's natural gas gathering and processing assets in the Anadarko Basin in Oklahoma, along with intrastate and interstate pipelines in Oklahoma and surrounding states and the boost to Energy Transfer's gas gathering and processing assets in the Arkoma Basin across Oklahoma and Arkansas, as well as in the Haynesville Shale in East Texas and North Louisiana.

As part of the terms of the merger agreement, Enable common unitholders received 0.8595 Energy Transfer common units for each Enable common unit. Additionally, each outstanding Enable Series A preferred unit was exchanged for 0.0265 Series G preferred units of Energy Transfer. The transaction also included a $10 million cash payment for Enable's general partner.

Citi and **RBC Capital Markets** were financial advisers to Energy Transfer for the transaction, and **Latham & Watkins LLP** acted as its legal counsel. **Goldman Sachs & Co. LLC** acted as financial adviser to Enable, and **Vinson & Elkins LLP** provided the company with legal counsel. **Intrepid Partners LLC** was financial adviser, and **Richards, Layton & Finger PA** provided legal counsel to Enable's conflicts committee.

—Emily Patsy

CenterPoint Energy Midstream Assets



Source: CenterPoint Energy Inc.

MINERALS AND ROYALTIES

■ **PHX Minerals Inc.** recently completed the acquisition of royalty acreage in the SCOOP play while selling two packages of nonoperated legacy working interest wellbores located primarily in the Arkoma Shale and Western Anadarko Shale plays of Oklahoma.

"These transactions are a continuation of our strategy to high-grade PHX's asset base by divesting legacy working interest wellbores and reinvesting the proceeds in higher margin minerals in our core areas of focus," president and CEO Chad Stephens commented in a Dec. 1 company release.

Two undisclosed buyers agreed to acquire the two packages of assets totaling 193 nonoperated legacy working interest wellbores for a total of $2.5 million plus the assumption of approximately $500,000 of asset retirement obligation.

The recent working interest divestitures and royalty acquisitions are expected to have a neutral effect on overall production during 2022, according to the release.

"We have targeted for divestiture our working interest wellbores that represent the lowest percentile of working interest wellbores by dollar value," Stephens continued. "Therefore, we expect that future divestitures will include fewer gross wellbores but higher net proceeds to PHX."

The working interest divestitures, along with the Fayetteville wellbores PHX that were sold, generated net proceeds of roughly $4.6 million and represent 692 total gross legacy wellbores divested and approximately $670,000 in aggregate asset retirement obligation removed from the company's balance sheet. On a pro forma basis, PHX has 1,089 legacy working interest wellbores remaining.

The new royalty acreage acquisition announced Dec. 1 along with the cash acquisitions disclosed by PHX in November, represent a full redeployment of net proceeds received by the company for the working interest divestitures.

The latest acquisition, completed by PHX for $1.4 million, comprised approximately 172 net royalty acres located primarily in Oklahoma's Carter and Stephens counties.

■ **PrairieSky Royalty Ltd.** entered into a definitive agreement with **Heritage Royalty** to acquire over 1.9 million acres of royalty lands for total cash consideration of CA$728 million.

"With this acquisition, PrairieSky consolidates a complementary and historic asset base, one of the largest blocks of fee mineral title acreage in Canada, with our incomparable existing royalty portfolio," president and CEO Andrew Phillips commented in a company release on Nov. 29.

The acquisition includes current estimated royalty production of 2,700 boe/d (92% liquids), from which PrairieSky said it expects to generate approximately $65 million of royalty revenue in 2022, excluding any leasing, compliance and other revenues associated with the royalty lands.

In addition to the royalty acreage throughout Alberta, Saskatchewan and Manitoba, PrairieSky picked up over 1.7 million net acres of fee simple mineral title lands and extensive seismic assets that are complementary to the royalty lands as a result of the transaction. In particular, the acquisition will reunify a preeminent fee simple mineral title asset across Alberta, Saskatchewan and western Manitoba with PrairieSky's existing royalty portfolio of approximately 16.3 million acres, according to the release.

PrairieSky plans to fund the proposed acquisition, expected to close in December, through a new CA$500 million term loan provided by **TD Securities Inc.**, and a concurrent CA$200 million bought deal equity financing led by TD Securities and **RBC Capital Markets** as joint book-runners and co-led by **CIBC Capital Markets** and **BMO Capital Markets** on behalf of a syndicate of underwriters. The acquisition has an effective date of Dec. 31.

■ **Tailwater Capital LLC** recently launched a royalties business led by former **Concho Resources** executive Doug Prieto to deepen the firm's investment in key U.S. basins.

"Tailwater's full immersion approach to energy and growth infrastructure has set us apart as nimble, creative investors who take a long-term approach," Edward Herring, co-founder and managing partner of Tailwater, commented in a company release on Nov. 5.

Based in Dallas, Tailwater currently manages more than $3.7 billion in committed capital, and the team has executed more than 100 energy transactions in the upstream and midstream sectors representing over $22 billion in transaction value.

The recently formed **Tailwater Royalties LLC** will focus on the acquisition of minerals and royalties across multiple basins throughout North America, including the Permian Basin, Williston, Eagle Ford and Rockies. Through the new entity, Tailwater said it seeks to leverage its positioning and insights to invest in diversified, value-added strategies.

NORWAY

■ British energy supplier **Centrica** and its partner, German utility **Stadtwerke Munchen**, have agreed to sell their oil and gas assets off Norway for a total of $1.1 billion, Centrica said on Dec. 8.

The buyers are **Sval Energi**, a unit of Norwegian private equity firm **HitecVision**, as well as state-controlled oil and gas firm **Equinor**.

Centrica, whose 69% share of the proceeds is expected to be worth around 560 million pounds (US$741.38 million), said the deal was aligned with its strategy to reduce exposure to carbon-intensive oil and gas exploration and production.

Sval said in a separate statement on Dec. 8 it would pay $1.03 billion for a majority of **Spirit Energy**'s assets, which it said was the largest deal on the Norwegian continental shelf since 2019.

The acquisition, which includes stakes in seven producing fields and several potential developments, will boost Sval's production by around 40,000 boe/d to 60,000 boe/d by 2023, Sval added.

RENEWABLES

■ **Exxon Mobil Chemical Co.** acquired **California-based Materia Inc.**, a technology company that has pioneered the development of a Nobel prize-winning technology for manufacturing a new class of materials, the company said on Dec.

7. The innovative materials can be used in a number of applications, including wind turbine blades, electric vehicle parts, sustainable construction and anticorrosive coatings.

The acquisition includes Materia's headquarters and technology center in Pasadena, Calif., and its manufacturing facility in Huntsville, Texas. Exxon Mobil intends to operate the business under the Materia company name as a wholly owned affiliate.

PAPUA NEW GUINEA

■ Papua New Guinea-focused **Oil Search Ltd.** said on Dec. 7 its A$8.8 billion (US$6.21 billion) buyout by **Santos Ltd.** received overwhelming support from its shareholders, with more than 95% of votes cast in favor.

The deal would create a global top 20 oil and gas company and make Santos the largest shareholder in PNG's biggest resource project, the PNG LNG project, run by **Exxon Mobil Corp**.

The buyout still needs approval from PNG's competition watchdog and national court. If all approvals are received, the deal will take effect on Dec. 10, which will be the last day of trading in Oil Search shares in Australia and PNG, the company said.

CANADA

■ **Cenovus Energy Inc.** said Nov. 30 it had reached agreements to sell its **Husky Energy** retail fuels network and the **Wembley** assets in its conventional business for combined total cash proceeds of nearly CA$660 million.

The transactions mark the latest asset sales since the Canadian oil and gas producer laid out debt reduction plans at the start of 2021 following close of its all-stock merger with Husky Energy.

"This is another demonstration of Cenovus delivering on opportunities to continue to optimize our portfolio and unlock value from assets that will not attract significant investment in our business," Alex Pourbaix, Cenovus' president and CEO, commented in a company release.

Earlier in November, Cenovus announced the substantial achievement of its interim net debt target of $10 billion, the doubling of its quarterly dividend as of fourth-quarter 2021 and the establishment of a normal course issuer bid program for the repurchase of up to 146.5 million of the company's common shares.

Proceeds from the latest transactions, however, will advance net debt repayment toward the company's longer-term target of $8 billion and enhance the company's capacity to increase shareholder returns.

"With these latest transactions, we now expect to realize more than $1.1 billion of total proceeds from sales announced in 2021," Pourbaix added.

PERMITS

According to Enverus, during 2021 the Midland Basin accounted for about 44% of all rigs operating in the Permian Basin and about 22% of all rigs operating in the U.S. The trend appears to be continuing. The Midland Basin counties of Midland, Martin and Howard received the most new permits (63, 58 and 40 respectively). In the Delaware Basin portion of the Permian, 78 new permits were issued for New Mexico's Lea County, the largest number for any county in the U.S.

In Oklahoma, there were 71 permits issued, 12 each for Canadian and Grady counties and the remaining 43 permits for the rest of the counties in the state.

Meanwhile, interest in the Haynesville and Bossier shales is still high, with permits in Louisiana, including 12 in Caddo Parish and eight in DeSoto Parish. The majority of the Marcellus Shale permits (21) were issued for Tioga County, Pa.

There was a slight increase in permits for the northern Gulf of Mexico during November, with 32 new permits (17 for Mississippi Canyon and nine for Green Canyon).

In the west, Colorado issued the most permits for Weld County (33) and Adams County (17) for probable Niobrara Shale exploration. Providence Operating's 17 permits were for Adams County in the Denver-Julesburg Basin. The bulk of permits issued in California were for Kern County, with 45 new permits.

Note: Permit information is not available from the North Dakota Department of Mineral Resources.

Permits Issued By Operator

Operator	Total
Chevron Corp.	43
XTO Energy Inc.	34
Pioneer Natural Resources Co.	31
EOG Resources Inc.	31
Diamondback E&P	28
Repsol	19
Providence Operating	17
Blackbeard Operating	16
Extraction Oil & Gas	15
Devon Energy Production Co.	15

Permits Issued By State

State	Total
Texas	566
New Mexico	101
Oklahoma	71
Pennsylvania	56
Louisiana	54
Colorado	52
California	49
Northern Gulf Of Mexico	32
Utah	27
Alaska	15

Permits Issued By County

County and State	Total
Lea, N.M.	78
Midland, Texas	63
Martin, Texas	58
Kern, Calif.	45
Howard, Texas	40
Weld, Colo.	33
Reeves, Texas	25
La Salle, La.	23
Tioga, Pa.	21
Mississippi Canyon (Gulf of Mexico)	17

Data from Rextag ENERGY DATALINK

RIG COUNT

According to Enverus Rig Analytics, the rig count is up 0.6% on the month of November and up 73% on the year. The most notable changes occurred in the Permian Basin and the Gulf Coast.

The change in the Gulf Coast was driven by single-rig declines by individual operators. Four of those operators were running only one rig to begin with, resulting in the active operator count in the Gulf Coast dropping to 57 from 61.

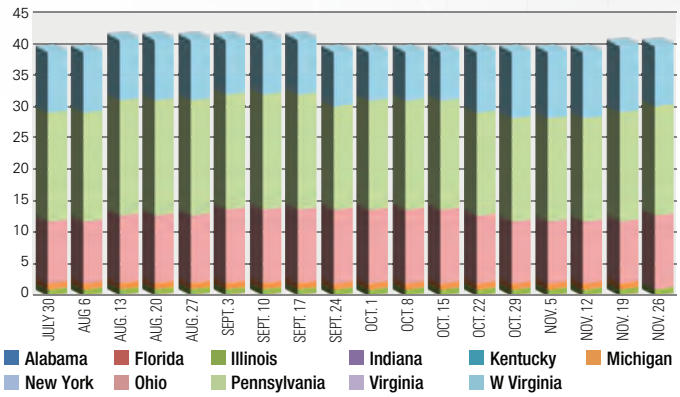
Oil prices are still up about 57% this year and some energy firms said they plan to increase spending in 2021 and 2022 after cutting drilling and completion expenditures in 2019 and 2020. While there was a price surge in natural gas—futures were up 96% so far this year—it has not yet encouraged drillers to search for more gas.

Even though producers were not drilling many new gas wells, the U.S. Energy Information Administration (EIA) projected gas output from the biggest shale basins would rise to a record high for a seventh month in a row in December.

According to the EIA, this is in part because companies were completing oil and gas wells drilled long ago. This has prompted some analysts to project that drilling will have to increase soon or production will decline as the number of DUC declines. November was the 16th month in a row that the number of DUCs declined, the longest streak on record, according EIA data going back to 2014.

Eastern U.S. Rig Count

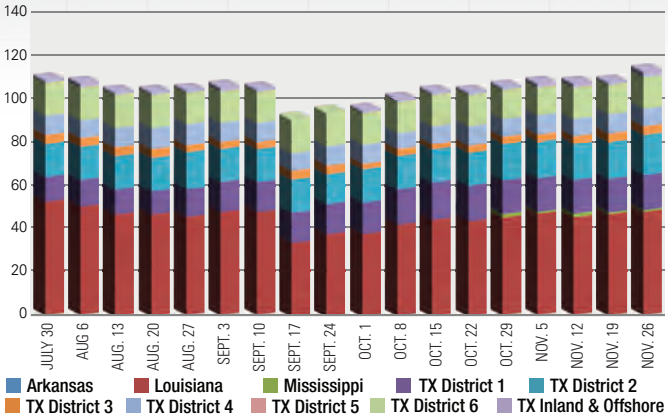
July 30, 2021-Nov. 26, 2021



Source: Baker Hughes Co.

Gulf Coast Rig Count

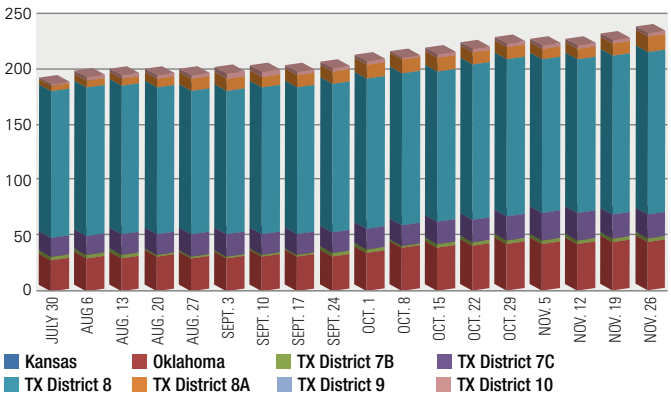
July 30, 2021-Nov. 26, 2021



Source: Baker Hughes Co.

Midcontinent & Permian Basin Rig Count

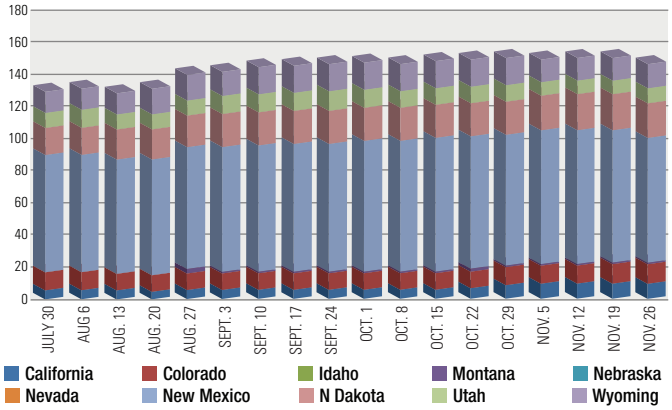
July 30, 2021-Nov. 26, 2021



Source: Baker Hughes Co.

Western U.S. Rig Count

July 30, 2021-Nov. 26, 2021



Source: Baker Hughes Co.

FOCUS ON Piceance-Uinta Basin

Uinta Basin Top Operators

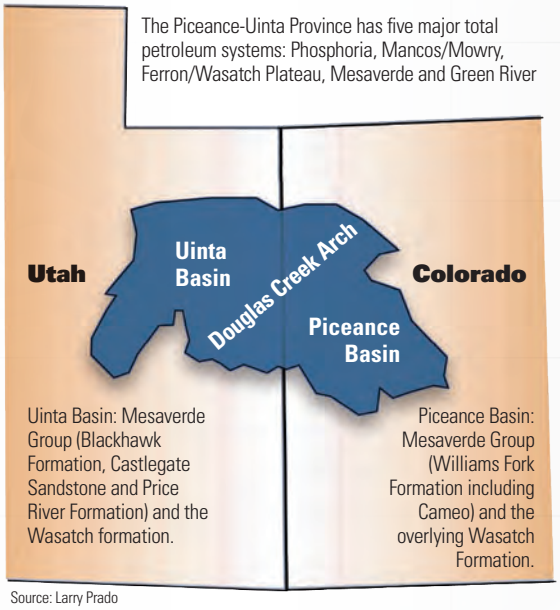
	MMboe
Kerr-Mcgee (Occidental Petroleum)	218.29
Newfield Production Co.	85.29
EOG Resources Inc.	40.84
ConocoPhillips Co.	39.27
EP Energy	37.07
Bill Barrett Corp.	31.99
QEP Energy Co.	29.93
Crescent Point Energy	27.82
XTO Energy Inc.	24.61
EnerVest Operating	22.49

Uinta Basin Top Producing Formations

	MMboe
Wasatch	347.83
Green River	205.43
Mancos	72.23
Mesaverde	54.54
Uteland Butte	21.96
Navajo	11.52
Entrada	6.63
Cane Creek	5.64
Dakota	4.64
Castle Peak	3.98
Blackhawk	1.87

The Piceance-Uinta Province straddles the eastern border of Utah and the western border of Colorado. The Uinta and Piceance basins are Laramide structures that are separated by the Douglas Creek Arch. The basins are mostly bounded by major faults, including the Charleston-Nebo thrust and the Uinta Basin boundary fault.

Continuous tight-gas resources are found in all or parts of Delta, Garfield, Gunnison, Mesa, Moffat, Montrose, Ouray, Rio Blanco and Routt counties in Colorado and all or parts of Carbon, Duchesne, Emery, Grand, Sanpete, Sevier, Wasatch and Uintah counties in Utah. The Piceance-Uinta basins cover approximately 4.09 million acres across the two states.



Source: Larry Prado

The source-rock intervals are in the lower part of the Tertiary Green River Formation, the lower part of the Cretaceous Mesaverde group, the coals in the Ferron Sandstone member of the Mancos Shale and Mowry Shale. Recently, several companies have made Niobrara discoveries in the Piceance Basin in Moffat County, Colo.

In 2019, the USGS assessed the Mesaverde Group and Wasatch Formation tight-gas resources in two continuous (unconventional) accumulations in the Piceance-Uinta Province.

The overall total mean resources in the Uinta Mesaverde Tight Gas aAssessment Unit (AU) and the Piceance Mesaverde Tight Gas AU are 24 Tcf of gas. For the Uinta Mesaverde Tight Gas AU, total mean resources are 19.3 Tcf of gas and the Piceance Mesaverde Tight Gas AU, total mean resources are 4.7 Tcf of gas.

Picenance Basin Top Operators

	MMboe
WPX Energy Inc.	219.18
TEP Rocky Mountain	201.96
Ovintiv Inc.	157.25
Caerus Piceance	113.24
Laramie Energy II	51.04
Terra Energy	46.79
Chevron Corp.	43.91
Bonanza Creek Energy Inc.	28.36
Exxon Mobil Corp.	12.88
Berry Petroleum Co.	8.89

Piceance Basin Top Producing Formations

	MMboe
Wiliams Fork-Cameo	781.39
Mancos	20.39
Niobrara	14.83
Fort Union	14.81
Corcoran	1.27
Wasatch	1.09
Dakota	0.48
Shinarump	0.25
Morrison	0.22
Mesaverde	0.22

Data from Rextag ENERGY DATALINK

INTERNATIONAL HIGHLIGHTS

Two western Pacific Rim countries are making plans to use and develop hydrogen as a fuel. Highly industrialized Japan has a severe lack of hydrocarbon resources. In 2017, Japan became the first country to adopt a national hydrogen framework, and it plans to reach 1 gigawatt of power capacity based on hydrogen by 2030. Japan plans to use hydrogen for power, transportation, homes, heavy industry and potentially refining. Japan is also a leader in fuel cell technology, especially fuel cell vehicles, and would like to export the technology.

The development of hydrogen supply chains is a major agenda, including maritime transport. The country is also planning to establish a manufacturing technology base by 2030 to produce hydrogen from domestic renewable sources.

The Australian government is providing funding for a feasibility study for a proposed Japanese-backed hydrogen export facility near the LNG hub of Gladstone, Queensland. The study will investigate a hydrogen production facility capable of producing up to 36,500 tons per year of green hydrogen, with exports shipped in liquid hydrogen shipping vessels to Japan anticipated in 2026. Other hydrogen projects are being planned for Western Australia and "hydrogen valleys" in South Australia, with the first scheduled for New South Wales.

—Larry Prado

1 *Mexico*

Lukoil is underway at an exploration well at Block 12 in the Gulf of Mexico. The #1Exp-Yoti West is targeting turbidite deposits of Upper and Lower Miocene. The venture will provide geological and geophysical data needed to make a decision on further exploration of Block 12. Lukoil acquired the license for exploration and production of hydrocarbons in 2017. The block is located 50 km off the coast of the state of Tobasco, Mexico. Water depth in the region ranges from 150 m to 400 m. The Block 12 joint venture partners include **Eni** (40%) and Moscow-based operator Lukoil (60%).

2 *Suriname*

TotalEnergies announced results from flow-testing of a Sapakara South appraisal well and drilling results from an exploration well in Block 58, offshore Suriname. At the #1-Sapakara South flow test, the well flowed at a restricted rate of 4,800 bbl of 34° API oil during a 48-hour period with a gas-to-oil ratio of 1,000 cu ft/bbl. According to the company, a Campano-Maastrichtian reservoir at #1-Sapakara South has an in-place resource estimate of 325-375 MMboe. The #1-Bonboni is the first exploration well in the northern portion of Block 58. In the primary Maastrichtian and Campanian objectives, the well encountered high-quality, water-bearing reservoirs. In a Maastrichtian objective, the well penetrated 16 m of net pay in a single zone with 25° API oil. The well will be plugged and abandoned. Paris-based TotalEnergies is the operator and holds a 50% working interest with **APA Suriname**, holding 50% interest.

3 *The Gambia*

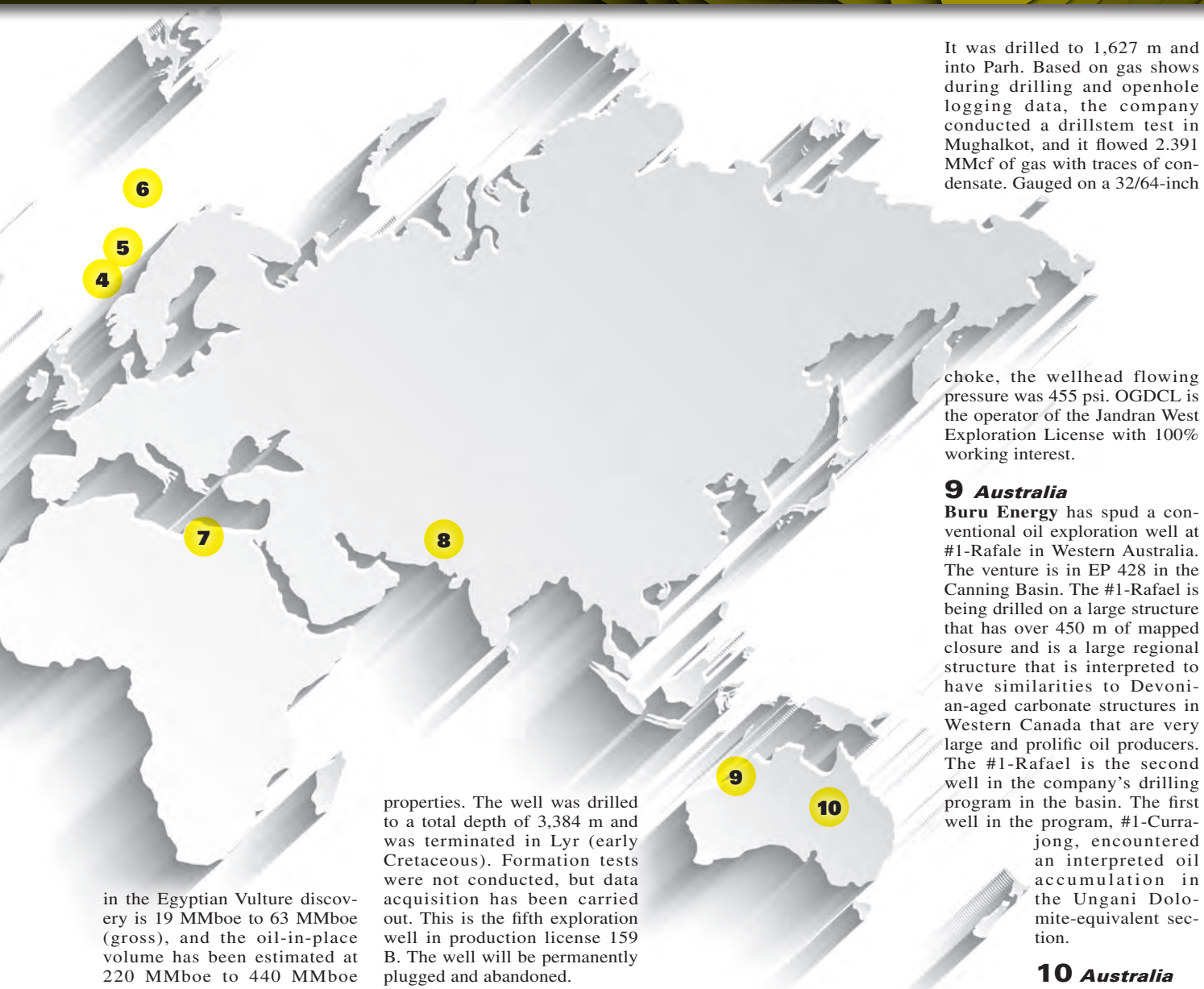
FAR Ltd. is underway at exploration well #1-Bambo in offshore Block A2 in The Gambia. The venture is being drilled in 930 m of water, and planned depth is 3,400 m. FAR will drill into a series of vertically stacked targets with a combined estimated recoverable prospective resource of 1.118 Bbbl, (559 MMbbl unrisked). The venture will be testing two shallower horizons that have not been tested previously. The site is south and along trend from the SNE oil field in Senegal in the highly prospective Mauritania-Senegal-Guinea-Bissau-Conakry (MSGBC) Basin. Melbourne, Australia-based FAR operates Block A2 and #1-Bambo with 40% interest in partnership with **Petroliam Nasional**, with 40% via farm-in and **Erin Energy**, holding the remaining 20%.

4 *Norway*

Wintershall Dea completed an appraisal well on the Bergknapp oil discovery in the Norwegian Sea. The #6406/3-10 A confirmed oil discoveries in Garn and Tilje and proved an additional gas accumulation in Are. Based on results from the appraisal well, the size of the Garn and Tilje discoveries is estimated to be between 40 MMbbl and 84 MMbbl of recoverable oil equivalent. Are is estimated to hold an additional 13-56 MMbbl of recoverable oil equivalent. Wintershall Dea is the operator of the PL 836S Bergknapp license with a 40% share. Partners **Spirit Energy** and **DNO Norge** hold 30% each.

5 *Norway*

Stavanger-based operator **Equinor** announced a discovery at the Egyptian Vulture exploration well in PL939, the second well in a seven-well exploration program. The #6407/1-9 in the Norwegian Sea encountered light oil in the primary target in the Lower Cretaceous (Cenomanian) Intra-Lange with 13 m net sand in a 37 m oil-filled gross interval. The upper part of the Lange Sand interval has a high net-to-gross ratio with 16% porosity. The preliminary estimate of recoverable resources



in the Egyptian Vulture discovery is 19 MMboe to 63 MMboe (gross), and the oil-in-place volume has been estimated at 220 MMboe to 440 MMboe (gross). Further appraisal will be required to understand the flow potential of the reservoir and future development wells. The well is about 20 km from Asgard Field and 23 km from Kristin Field. It was drilled to 3,936 m and will be plugged and abandoned as planned. **Longboat Energy** is a partner in the prospect.

6 *Norway*

Equinor, operator of production license PL 159 B, has concluded the drilling of appraisal well #6507/3-14. The objective was to delineate the discovery in Lange and to further evaluate the reservoir's properties. The well encountered a 45-m thick section of the Lange, of which a total of 24 m was sandstone layers with moderate reservoir properties. The well was drilled to a total depth of 3,384 m and was terminated in Lyr (early Cretaceous). Formation tests were not conducted, but data acquisition has been carried out. This is the fifth exploration well in production license 159 B. The well will be permanently plugged and abandoned.

7 *Egypt*

Eni announced new discoveries in Egypt's Western Desert at the Meleiha and South West Meleiha concessions. Preliminary estimates of the resources for these new discoveries are 50 MMboe of hydrocarbons in place. Two wells were completed at the Meleiha development lease, #1X-Jasmine W and #21-MWD Jasmine. The #1X-Jasmine W encountered 113 ft of net hydrocarbon pay in Jurassic sandstones (Khatatba) with good petrophysical properties. During a production test, it produced 2,000 bbl of 49° API oil and 7 MMcf of associated gas per day. At #21-MWD Jasmine, the well hit 51 ft in Cretaceous sandstones of Alam El Bueib. It was tested flowing 2,500 bbl of oil per day. At the South West Meleiha development, #4X-SWM-4X encountered 36 ft of net oil sand in Cretaceous sandstones of Bahariya. During a production test, it initially flowed 1,800 bbl of oil with 300,000 cu ft of gas daily. The new discoveries have potential for additional appraisal and production wells that will be immediately planned in order to sustain the Agiba production plateau. Eni's headquarters are in Rome.

8 *Pakistan*

A gas discovery was announced by Mumbai-based **Oil and Gas Development Ltd.** (OGDCL) at #1-X Jandran West. The well is in the Jandran West Exploration License in Kohlu District, Balochistan Province, Pakistan. It was drilled to 1,627 m and into Parh. Based on gas shows during drilling and openhole logging data, the company conducted a drillstem test in Mughalkot, and it flowed 2.391 MMcf of gas with traces of condensate. Gauged on a 32/64-inch choke, the wellhead flowing pressure was 455 psi. OGDCL is the operator of the Jandran West Exploration License with 100% working interest.

9 *Australia*

Buru Energy has spud a conventional oil exploration well at #1-Rafale in Western Australia. The venture is in EP 428 in the Canning Basin. The #1-Rafael is being drilled on a large structure that has over 450 m of mapped closure and is a large regional structure that is interpreted to have similarities to Devonian-aged carbonate structures in Western Canada that are very large and prolific oil producers. The #1-Rafael is the second well in the company's drilling program in the basin. The first well in the program, #1-Currajong, encountered an interpreted oil accumulation in the Ungani Dolomite-equivalent section.

10 *Australia*

Vintage Energy announced flow test results from a Cooper Bain well in South Australia. The #1-Odin initially flowed 6.5 MMcf of gas per day during testing on a 36/64-inch choke. It was drilled to a total depth of 3,140 m, and intersected conventional net gas pay interpreted in the Toolachee, Epsilon and Patchawarra. The flowing wellhead pressure was 1,823 psi. The well will be shut-in for 10 days to gather pressure data, and it was producing 38 bbl of water per day. A production logging tool will be run in the perforated sections of Toolachee and Epsilon. The venture is in PRL 211. Adelaide-based Vintage holds a 42.5% interest along with partners **Metgasco** (21.25%), **Bridgeport** (21.25%) and **Impress** (15%).

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Commonwealth Fusion Systems	N/A	Cambridge, Mass.	$1,800	Closed on more than $1.8 billion in Series B funding to commercialize fusion energy. The round was led by Tiger Global Management with participation by new investors, including: Bill Gates; **Coatue**; **DFJ Growth**; **Emerson Collective**; **Footprint Coalition**; **Google**; **JIMCO Technology Fund**, part of **JIMCO**, the Jameel Family's global investment arm; **John Doerr**; **JS Capital**; Marc Benioff's **TIME Ventures**; **Senator Investment Group**; a major university endowment; and a pension plan, as well as current investors, including: **Breakthrough Energy Ventures**; **The Engine**; **Eni**; **Equinor Ventures**; **Fine Structure Ventures**; **Future Ventures**; **Hostplus**; **Khosla Ventures**; **Lowercarbon**; **Moore Strategic Ventures**; **Safar Partners**; **Schooner Capital**; **Soros Fund Management LLC**; **Starlight Ventures**; **Temasek**; and others.
Chesapeake Energy Corp.	NYSE: CHK	Oklahoma City	$1,000	Announced that its board of directors has authorized the repurchase of up to $1 billion in aggregate value of its common stock and/or warrants from time to time. Acquisitions under this repurchase authorization are to be made through open market or privately negotiated transactions.
Nabors Energy Transition Corp.	NYSE: NETC	Houston	$240	Priced IPO of 24 million units at $10 per unit. Units were to be listed on the New York Stock Exchange and trade under ticker symbol "NETC.U" beginning on Nov. 17. Each unit consists of one share of the company's Class A common stock and one-half of one redeemable warrant, with each whole warrant entitling the holder thereof to purchase one share of the company's Class A common stock at an exercise price of $11.50 per share. **Citigroup** and **Wells Fargo Securities** were joint book-running managers and representatives of the underwriters, which were granted a 45-day option to purchase up to an additional 3.6 million units at the IPO price to cover overallotments, if any.
EQT Corp.	NYSE: EQT	Pittsburgh	$231.5	Priced an underwritten public offering of about 11 million shares of its common stock by certain shareholders who had received the shares as a part of the company's acquisition of **Alta Resources Development LL**C's upstream and midstream subsidiaries. Underwriters were granted a 30-day option to purchase roughly up to an additional 1.6 million shares. EQT will not sell any shares of its common stock in the offering and will not receive any proceeds from the sale. **Citigroup** and **RBC Capital Markets** were joint book-running managers.
Northern Oil and Gas Inc.	NYSE American: NOG	Minnetonka, Minn.	$200	Priced an underwritten public offering of 10 million shares of its common stock, which includes 9.5 million shares being offered by the company and 500,000 shares being offered by selling stockholders **Cresta Investments LLC** and **Cresta Greenwood LLC** at $20 per share. Underwriters have also been granted a 30-day option to purchase up to an additional 1.5 million shares from the company. Proceeds will be used to fund the cash purchase price of the pending acquisition of substantially all of the nonoperated Permian Basin assets owned by certain entities affiliated with **Veritas Energy LLC**. Pending such use, proceeds may be used to repay outstanding borrowings under its revolving credit facility. If the Veritas acquisition is not consummated, proceeds will be used for general corporate purposes, which may include the repayment of outstanding indebtedness. **Morgan Stanley & Co. LLC** is lead bookrunning manager. **BofA Securities** is joint bookrunning manager.
PrairieSky Royalty Ltd.	TSX: PSK	Calgary, Alberta	CA$200	Entered into a bought deal equity financing whereby a syndicate of underwriters led by **TD Securities Inc.** and **RBC Capital Markets** as joint bookrunners and co-led by **CIBC Capital Markets** and **BMO Capital Markets** have agreed to purchase about 14.9 million common shares of the company at $13.40 each. Underwriters were granted a 30-day option to purchase up to an additional 15% of the of the common shares issued pursuant to the financing to cover over-allotments, if any. Proceeds will be used to fund a portion of the purchase price of Western Canadian royalty assets from **Heritage Royalty**.
Viper Energy Partners LP	NASDAQ: VNOM	Midland, Texas	$150	Announced that the board of directors of Viper's general partner increased the authorization of its common unit repurchase program to $150 million and extended the authorization indefinitely. As of Sept. 30, Viper had expended approximately $57.4 million, or roughly 38%, of the increased authorized amount. The company intends to purchase common units under the repurchase program opportunistically with cash on hand, free cash flow from operations and proceeds from potential liquidity events such as the sale of assets. Any common units purchased as part of this program will be retired.

DEBT

Occidental Petroleum Corp.	NYSE: OXY	Houston	$2,000	Commenced cash tender offers to purchase up to a maximum combined aggregate purchase price of $2 billion of outstanding senior notes. Offers expired on Dec. 8.

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
PrairieSky Royalty Ltd.	TSX: PSK	Calgary, Alberta	CA$500	Entered into a binding agreement with **TD Securities Inc.** for a new two-year term loan, which will include financial and other covenants and pricing identical to PrairieSky's existing $425 million revolving credit facility which matures on Feb. 28, 2025. Funding under the term loan will take place concurrently with closing of a pending acquisition of Western Canadian royalty assets from **Heritage Royalty**.
SilverBow Resources Inc.	NYSE: SBOW	Houston	$460	Entered into an amendment to its senior secured revolving credit facility under which the $300 million borrowing base has been increased by $160 million to $460 million in connection with its regularly scheduled semiannual redetermination and in conjunction with closing of a previously announced acquisition in October. Concurrently also entered into an amendment to its second lien facility, which extends the maturity date from December 2024 to December 2026 subject to paying down the principal amount of the second lien facility from $200 million to $150 million. SilverBow intended to make the $50 million payment later in November.
Battalion Oil Corp.	NYSE American: BATL	Houston	$235	Closed an agreement with a group of lenders for a new first lien delayed draw term loan facility for up to $235 million bearing interest of LIBOR plus 7% on drawn amounts. Initial borrowings of $200 million will allow Battalion to repay all outstanding loans and obligations under the company's previous senior revolving credit facility and add significant cash to the balance sheet after fees and expenses. The company will have approximately $35 million of additional capacity under the term loan which will be available for future development of the company's Monument Draw asset in the Permian Basin. **Macquarie Group** was sole lead arranger and is serving as a lender, letter of credit provider and a hedge counterparty for the company. **Weil, Gotshal & Manges LLP** was legal adviser to Battalion, and **Sidley Austin LLP** was legal adviser to the lending group.
Tidewater Inc.	NYSE: TDW	Houston	$175	Closed offering of 8.5% senior secured bonds due 2026. An application will be made for the bonds to be listed on the Nordic ABM within six months of the issue date for the bonds. The bonds were privately placed in the U.S. in accordance with U.S. securities laws and sold outside the U.S. pursuant to Regulation S under the Securities Act of 1933. Proceeds will be used to refinance outstanding debt and for general corporate purposes.

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Energy ESG CONFERENCE	**April 13-14, 2022** Houston, TX
25 INFLUENTIAL Women IN ENERGY	**April 29, 2022** Houston, TX *Marriott Marquis*
Energy TRANSITION Capital CONFERENCE	**May 10, 2022** Houston, TX *Omni Houston*
CARBON MANAGEMENT	**May 16, 2022** Fort Worth, TX *Fort Worth Convention Center*
CONFERENCE & EXHIBITION DUG PERMIAN +EAGLE FORD	**May 16-18, 2022** Fort Worth, TX *Fort Worth Convention Center*
CONFERENCE & EXHIBITION DUG HAYNESVILLE	**May 25-26, 2022** Shreveport, LA *Shreveport Convention Center*
CONFERENCE & EXHIBITION DUG EAST	**June 13-15, 2022** Pittsburgh, PA *David L. Lawrence Convention Center*
CONFERENCE & EXHIBITION DUG BAKKEN AND ROCKIES	**June 28-29, 2022** Denver, CO *Colorado Convention Center*
energycapital CONFERENCE	**Fall 2022** Houston, TX *Omni Houston*
Energy TRANSITION Capital CONFERENCE	**Fall 2022** New York, NY
NATURAL GAS CONFERENCE	**Sept 26-27, 2022** Dallas, TX
Energy ESG CONFERENCE	**October 2022** Houston, TX
A&D STRATEGIES AND OPPORTUNITIES CONFERENCE	**October 25, 2022** Dallas, TX *Fairmont Hotel*
EXECUTIVE OIL CONFERENCE & EXHIBITION	**Nov 15-16, 2022** Midland, TX *Midland County Horseshoe Arena*

VIEW EVENTS

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COMPANIES IN THIS ISSUE

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

$375 A BARREL

NISSA DARBONNE, EDITOR-AT-LARGE

Spoiler: It's the spot price for biofuel.

A forum hosted by Denver-based law firm Davis Graham & Stubbs in November included a panel on the energy transition outlook.

The question posed by Mave Gasaway, a partner: "Net-zero emissions by 2050. Is it possible?"

Jack Collins, president of BPX Energy, the U.S. onshore business of BP Plc, said, "I'm optimistic. I believe in human ingenuity, believe in technology and advancement, and really, truly believe it is a necessity.

"We can all have debates on the climate. 'Do you believe that the climate is changing?' and 'Do you believe that you need to reduce emissions going forward?'"

But the capacity to change the trajectory exists, he said. "We absolutely have the ability in this world, with … the human creativity we all have and exhibit day in, day out, in whatever our professions are.

"I truly believe we can solve this. We will solve this. There needs to be a lot of effort." There "needs to be a *will* to solve it going forward."

But, yes, "100%, we can get there. We must get there."

I was on the panel and hadn't brought a filter. Something about making it through 2020: The filter's been tossed. Or maybe it's too much Twitter. No matter, I suggested that the oil and gas industry's personnel themselves will be the leaders of achieving climate goals.

Some industry members' reticence to participate has been a concern. And word that some members of the renewables industry don't want to hire oil and gas people has been a concern too.

"The industry is filled from bottom to top, top to bottom, with the best and the brightest. The oil and gas industry knows how to make energy," I offered.

Blue and green energy industries should recruit from oil and gas—and vice versa. "It would do great harm that not all of the different sectors of energy work together to make this work. It is, in fact, 'all of the above.'"

Another panelist, Terry Kulesa, co-founder and CEO of IR1 Group, a biofuels developer, said all of the "managers that we hire come from the oil and gas industry." And that's not a coincidence, he added.

Rather, "they're very knowledgeable. They know all the systems, the pumps, the valves, all of it."

The company's founders have been involved in development of 10 biofuels plants to date with some 400 million gallons of capacity.

Its job postings result in "a hundred resumes for any job from these engineers" with Exxon Mobil Corp., Shell Oil Co. and others, Kulesa said.

"People want to come over from that side. They see (the transition) happening. And especially the young people coming out of college—they all want to work for 'the next wave.' They're very knowledgeable, very capable, and we would be lost without them."

In response to an attendee's question, Collins said what he worries about is, "If we don't transition, we will completely lose investor confidence in the company going forward."

Investors want returns, of course. "We believe that we can actually improve our return on capital employed by making these (transition) investments going forward," he said.

As BP announced its pivot to investing in other forms of energy and in lower-carbon operations and products, the stock price "didn't 'go Tesla' on us or anything," he noted.

But, over time, BP is proving its tack. "It's delivering on it." And, "at the end of the day, that's what our customers want. It's what our investors want. That's what the world needs."

Kulesa said he gets $375 a barrel for biofuel. So the returns are there. "There is a lot of return right now in that space."

Collins added that, while BP's oil and gas production will decline in some areas, it is expected to grow onshore the U.S. "Oil and gas will be a part of the energy mix in the energy transition going forward."

In how the transition is fulfilled, "the role that oil and gas will play will be critical," he said. "It won't happen overnight. There are going to be massive investments across the world—trillions and trillions of dollars to rethink how we deliver energy in a decarbonized way."

Collins concluded that the energy transition is a massive challenge, "but just to reiterate: I'm optimistic. We got this."

Gasaway concluded, "Well, with 2- and 4-year-old children, I feel very encouraged by those answers."






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