Oil and Gas Investor

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Independents search deep for solutions to mend broken relationships with investors.

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: Public E&Ps have found themselves on the outside of Wall St. looking in as their exposure to the market as a sector is at record lows. But this time the return to favor is not tied to commodity prices. Photo illustration by Robert D. Avila.

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LATEST CONTENT

How US Shale Gas Fits in Evolving Global Market
By Velda Addison, Group Senior Editor
U.S. natural gas production is declining as domestic consumption falls but global demand, including for LNG, is adding to optimism.

Permian Basin Operator Approach Resources Hitches Saddle to New Buyer
By Darren Barbee, Senior Editor
Bankrupt Permian operator Approach Resources appears to be headed toward a sale again—albeit for less than two-thirds of the original sales price.

Enterprise Cancels Midland-to-Echo 4 Pipeline Project
By Joseph Markman, Senior Editor
Amended agreements allow the company to move reduced volumes of Permian crude on existing pipelines.

Exploration Outlook: Key Oil, Gas Prospects to Watch Post-COVID
By Velda Addison, Group Senior Editor
Despite spending cuts made across the oil and gas industry, some companies are moving ahead with plans to drill exploration wells.

Exxon Mobil, Partners Make 18th Discovery Offshore Guyana
By Velda Addison, Group Senior Editor
The latest oil discovery was made by the Redtail-1 well in the southeast part of the Stabroek Block.

ONLINE EXCLUSIVES

Q&A: How Ethan Bellamy Found His Way Back to Oil and Gas
By Joseph Markman, Senior Editor

East Daley Capital Advisors' new midstream strategy director discusses structural changes in the industry, how the upcoming elections could affect energy and his new gig.

Oil Majors Work to Advance Offshore Wind Energy
By Velda Addison, Group Senior Editor

Executives from Equinor, Shell, Total and WindEurope discuss how producers of oil and gas are transferring knowledge to offshore wind.

Methane Leak Technology Bolsters Oil Industry's ESG Efforts
By Joseph Markman, Senior Editor

By providing details on emissions, oil and gas consultancy Kayrros helps companies to plug the leaks and impress investors.

Oil Experts Discuss Future of US Shale
By Velda Addison, Group Senior Editor

Limited growth, decline rates, consolidation, costs and ESG concerns were among the topics addressed.

Hart Energy's Unconventional Activity Tracker
By Larry Prado, Activity Editor

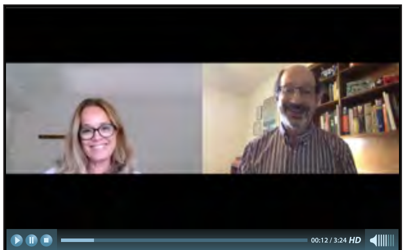
Updated weekly, Hart Energy's exclusive rig counts measure drilling intensity. They exclude units classified as rigging up or rigging down, and also exclude rigs drilling injection wells, disposal wells or geothermal wells. They are designed to offer the most accurate picture of what is actually occurring in the field.

HART ENERGY VIDEOS
By Jessica Morales, Director of Video Content

HartEnergy.com/videos

Leaders from 'Big 4'—Deloitte, EY, KPMG, PwC—Provide Recovery Outlook for Energy
Deloitte, EY, KPMG and PwC—joined Hart Energy to discuss the biggest hurdles facing their clients this downturn and what the oil and gas industry will look like post-pandemic.

Honeywell CTO on Remote Oilfield Tech, Data Analytics
Jason Urso, CTO of Honeywell Process Solutions, joined Hart Energy to explain the growing significance of remote technologies in the current environment in which oil and gas companies operate.



DNV GL's Liv Hovem on the Energy Transition and What it Means for Shale
The company's 2020 Energy Transition Outlook forecasts that carbon emission reductions will fall far short of the Paris agreement's 2050 goals.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PROMISES AND PIVOTS

STEVE TOON,
EDITOR-IN-CHIEF

Jefferies analyst Jason Gammel pegs second-quarter 2020 as the most difficult in the history of the U.S. shale industry. That's probably no surprise to those of you who lived it, but the chasm that was 2Q20 may become the catalyst for everlasting change. That is, changing the E&P business model from growth to value oriented.

Gammel asks, "Have U.S. E&Ps found religion?"

The road from cash-burn growth to shareholder-return value is littered with false starts, he noted in an August research report, but this time could be different, he dared surmise. "2Q transcripts indicate recognition that a change in business model is existential."

Investor explores the why and how to transform producers' DNA in this issue's cover story. But it's all for naught if producers do not buy in (at their own peril). Earnings calls post-2Q indicate the pivot to profit is on.

A long way from Wall Street, Midland, Texas-based Permian pure-player Concho Resources Inc. indicated in its 2Q call that it sees the light. CEO Tim Leach said, "We believe the future of our industry requires better capitalized companies, more capital discipline, less leverage and being more aware of market signals for growth."

Growth for growth's sake, he said, "isn't going to work in the future." After 2Q, "very few business plans were viable in our industry, so I think that forces the industry to re-evaluate itself."

Concho began the pivot a year ago, now exhibiting four straight quarters of free cash flow, which it did by lowering costs, which it used to pay down debt and pay a dividend. Its cash flow reinvestment rate is about 75%, and that's significant. Free cash flow is the litmus test for investors.

"We think the building blocks are falling into place as comments on Q2 conference calls highlight the industry's commitment to put down guideposts that will likely set equities on healthier footing over the next few years," noted Tudor, Pickering, Holt & Co. (TPH) analysts in an August research note. Specifically, committing to lowering capital allocation toward 70% to 80% of cash flow through the cycle.

"This should help ease investor concerns that free cash flow generation isn't something they will need to wait for on the horizon, but something that will be clear and present year in and year out at strip pricing."

Leading the pack and a model to others, per TPH: Pioneer Natural Resources Co., Devon Energy Corp., Marathon Oil Corp., Cimarex Energy Co. and Parsley Energy Inc.

Devon CEO Dave Hager, in the 2Q call, said, "We understand the maturing demand dynamics for our industry and recognize the traditional E&P growth model of the past is not a viable strategy going forward. To win in the next phase of the energy cycle, a successful company must deploy a highly disciplined, financially driven business model that prioritizes cash returns directly to shareholders."

Devon is modeling the 70% to 80% reinvestment target with a 5% or less "growth aspiration." With that excess cash it will pay a quarterly and special dividend along with opportunistic share buybacks. It is targeting debt reduction down to 0.5x to 1.0x debt-to-EBITDA. The Oklahoma City producer is making the hard turn away from the iceberg.

Parsley Energy, too, is four consecutive quarters into an "unwavering commitment" to free cash flow generation.

"Our mindset is that growth capital is not needed nor justifiable in a world with significant excess spare capacity," Matt Gallagher, CEO, said on its call. "Allocating growth capital into a global market with artificially constrained supply is a trap our industry is falling into time and time again. At Parsley we will avoid that trap and are committed to delivering healthy and sustainable free cash flow again in 2021."

Marathon Oil pivoted in 2018 with a reinvestment rate topping at 80% over the past two years. CEO Lee Tillman reiterated that commitment even as midcycle oil pricing trends lower. The company can deliver free cash flow breakeven at $35/bbl, he said in second-quarter comments.

"Even in a $40 per barrel oil case, our reinvestment rate would likely trend no higher than 80%. At prices north of $40 per barrel, our reinvestment rates would be well below 80%, and that incremental free cash flow would be taken to the bottom line."

The larger cap independents are in the midst of making the turn and messaging that strongly to investors. It remains to be seen if the mid-, small-and microcap E&Ps will follow suit. Their paths to success are murkier.

Nonetheless, the world is awash in their hydrocarbons. TPH said, "A cap on growth at higher prices is starting to finally hit home as the U.S. upstream space has realized the negative effect the U.S. has had on the global macro environment."

Jefferies' Gammel said, if true, this change of model is "probably the last and best chance to attract investment into the sector," but it will only work if U.S. E&Ps "have finally had their come to Jesus moment."


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PARDON THE DUST

DARREN BARBEE, SENIOR EDITOR

There are few better ways to make money vaporize than by placing a bet at the horse track.

To outsiders and gamblers alike, it progresses like the world's dumbest magic trick.

Bettors examine the horses and riders in the paddock. (Insider tip: The best dressed jockey should not be a factor.) Then, a $2 bet placed, they watch the race run. Presto-chango, the $2 transforms into a tiny, worthless ticket stub.

Enjoy your beer.

Which is why there ought to be a stalking horse track. Why bet against the house when you can bid for it? In truth, the stalking horse derby for bankrupt oil and gas assets has started to pick up some momentum.

At the crack of a bankruptcy judge's gavel, stalking horse bidders slowly lurch out of the starting gate, lower their long necks and graze among the bankruptcies.

The slowly revealed results are fascinating.

Zarvona Energy LLC's stalking horse bid resulted in a $115.5 million deal for Approach Resources. Mach Resources LLC closed a $220 million acquisition of Alta Mesa Resources. And Presidio Petroleum turned a $91 million deal with Templar Energy.

The three companies entered bankruptcy with a combined $4.9 billion in debt.

For a total payout of less than $430 million, the debt-laden assets sold for roughly $0.09 on the dollar. The total would have been higher, but Approach Resources and Alta Mesa were forced to negotiate new deals after the commodity collapse that began in March shaved away about $177 million in proceeds.

Buyers-in-waiting of distressed assets have long been expected during this downturn of apocalyptic proportions. And there's every reason to believe 2020 will be worse for companies than the calamitous 2016.

Through the end of August, bankrupt E&Ps have limped into bankruptcy courts with nearly $51 billion in secured and unsecured debt. That's more than the past three years combined. Only 2016 has seen a higher number of insolvent companies seeking Chapter 11 bankruptcy and a higher amount of debt.

Haynes and Boone LLP's bankruptcy monitor sees no near-term hope for U.S. producers and a reasonable expectation that a substantial number of producers will continue to seek protection from creditors in bankruptcy before the year is over.

Also notable is the total secured debt involved in 2020 producer bankruptcies, which already exceeds the total for 2016.

Haynes and Boone likens the disappearance of unsecured debts to the burning away of a heat shield that protected secured lenders.

Mari Salazar, senior vice president and manager for BOK Financial, said when she started in energy banking, banks felt secured if operators had proved developed producing assets. That confidence has plummeted as losses have soared in bankruptcy.

If "you were a senior secured lender and you really didn't have much of a risk for loss, that has really changed these days," she said. "You've seen articles where banks have taken $0.31 on the dollar or $0.50 on the dollar. And that's really what I think has changed the market."

The pandemic "allowed us to rethink how we're approaching our customers and needing to prepare ourselves for the fall and what that would look like," she added.

Banks, now aware of their vulnerabilities, will place stricter controls on lending.

"You're going to see tighter structures. We're starting to see that now [with] cash flow sweeps, tighter RP [restricted payment] baskets," she said.

More bankruptcy sales are inevitable, particularly as lenders grow weary of getting burned. In August, bankrupt E&P Lilis Energy Inc. said it would shift from restructuring to a sales process after investors balked at throwing more money at the company.

The Delaware Basin company had flirted with bankruptcy for a while and went to the courthouse in June with about $580 million in debt. But in August, Värde Partners Inc., the owner of Lilis' outstanding preferred stock, decided against investing more money.

For all the talk of racing and stalking horses and money, perhaps—the industry has a gambling problem. But it's more complicated. E&Ps have a love problem in that their investors don't love them.

In D.H. Lawrence's short-story The Rocking-Horse Winner, a boy furiously rides his rocking horse until, through some clairvoyance, he can predict a winning racehorse. All of this so he can give the winnings to his mother. Spoiler alert: All this rocking-horse riding eventually kills the poor boy.

Hope, oil and gas executives like to say, is not a strategy. The same might be said for wishful thinking. Abandoning prudence may ultimately have been the industry's biggest gamble.

Or as Lawrence would put it, they bought land for the riches, but the riches turned to dust.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
North American Crude Oil Exports Virtual Summit	Oct. 1		Virtual	spglobal.com
North Dakota Petroleum Council Annual Meeting	Oct. 7		Virtual	ndoil.com
North American Gas Forum	Oct. 20-22		Virtual	energy-dialogues.com/nagf
DUG Haynesville	**Oct. 28-29**		**Virtual**	**dughaynesville.com**
ONE Future Methane & Climate Strategies Workshop	Nov. 10-11		Virtual	onefuture.us.com
DUG East/Marcellus-Utica Midstream	**Dec. 2-3**		**Virtual**	**dugeast.com**
A&D Strategies and Opportunities Conference	**Dec. 8-9**	**Dallas**	**The Fairmont Hotel**	**hartenergyconferences.com**
SPE Sustainability Innovation & Technology Convention	Dec. 10-12	TBD	TBD	spegcs.org/events/5739/
2021				
IPAA Private Capital Conference	Jan. 23	Houston	JW Marriot Houston	ipaa.org
Energy ESG Conference	**February**	**Houston**	**Omni Galleria**	**energyesgconference.com**
NAPE Summit	Feb. 8-12	Houston	George R. Brown Conv. Center	napeexpo.com
Innovation & Entrepreneurship Summit	Feb. 24-25	Houston	Norris Conference Center, CityCentre	spegcs.org/events/4637/
CERAWeek by IHS Markit	Mar. 1-5	Houston	Hilton Americas-Houston	ceraweek.com
DUG Bakken and Rockies	**Mar. 25-26**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
Offshore Technology Conference	May 3-6	Houston	NRG Park	2021.otcnet.org
Williston Basin Petroleum Conference	May 11-13	Bismarck, N.D.	Bismarck Event Center	ndoil.org
Veterans In Energy Luncheon	**November**	**Houston**	**The Westin Memorial City**	**impactfulveteransinenergy.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.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	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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

NewsWell

Analysts see frac crew, activity growth ahead for US shale sector

After a quick and hard fall in May, the U.S. hydraulic fracturing sector could see crews rise to 170 by fourth-quarter 2021 with the Permian Basin and Eagle Ford Shale registering the largest year-over-year growth, analysts forecast.

The increase would be a rebound from the 60% overall drop in frac crews seen earlier this year, Westwood Global Energy Group data show, but is far below high activity levels seen during shale's heydays.

"We went from 262 to 102 frac crews," from the first to the second quarter this year, Luke Smith, analyst of frac HHP for Westwood, said during a webinar Aug. 25. "By the end of this year, we think that the Permian will become about 30% of the market for active frac crews, and some of the gas basins will be essentially about 40% of that number."

The firm forecasts frac crews will reach a quarterly average of nearly 100 during second-half 2020. That's far below the days of 400 or so frac crews recorded in 2018.

The outlook was delivered as oilfield service (OFS) companies cope with drastic spending and activity cuts made by E&P companies in response to lower oil prices and the coronavirus-driven demand slowdown. Drilling and completion activity collapsed alongside fracking as a result earlier this year. Many OFS companies have shuttered facilities, laid off thousands of workers and issued billions in write-offs related to pressure pumping and other parts of the business. Some have gone bankrupt.

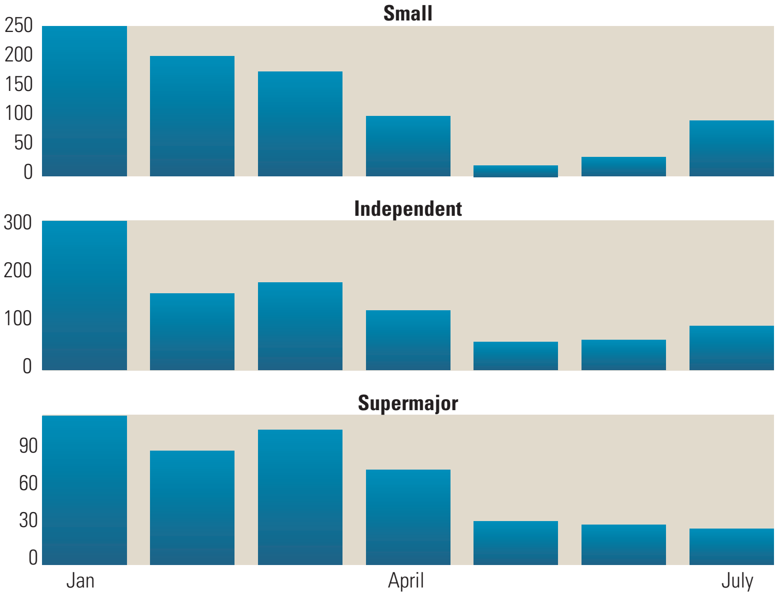
Oil prices have since steadily improved, stabilizing around $40/bbl after going negative in late April—an improvement courtesy of OPEC+ and U.S. production cuts.

Todd Bush, head of onshore for Westwood, pointed out that the companies the firm tracks have less than half of their revised 2020 budget left to spend this year. Westwood data show a group of E&Ps with 40% of their budget remaining for the second half of the year and a group of OFS pressure pumpers with nearly 45% left.

"One thing that's notable here is some of the U.S. gas producers have seen very little change to their capex and their program," Bush said, highlighting EQT Corp., Antero Resources Corp., Cabot Oil & Gas Corp. and Range Resources Corp. "The U.S. gas producers have really only revised about 19% to 20% compared to many of the other independents and many of the other supermajors that have capital revisions. So, we think this spending is going to have significant influence across the oilfield supply chain."

For the most part, however, E&Ps—supermajors and independents alike—slashed spending significantly.

Permian Basin Frac Activity
No. Of Pads Fracked By E&P Size

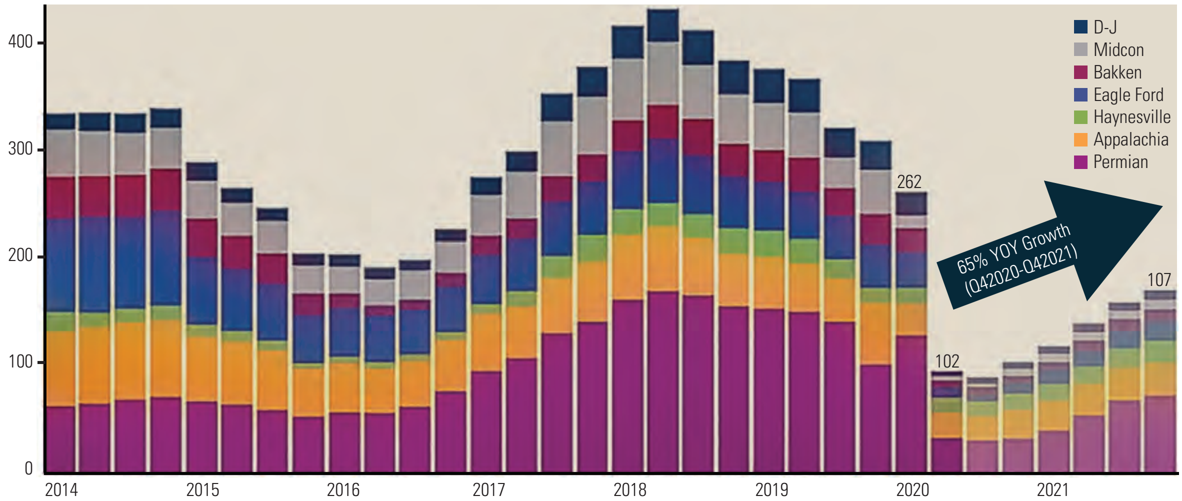


Source: Westwood Global Energy Group

Average Active Onshore Frac Crews

Source: Westwood Global Energy Group

Frac Crew Growth Since 2014



Source: Westwood Global Energy Group

This means less spending on dual-fuel engines, fleet upgrades or expansions, and less investment in e-frac, Smith said.

"We know that this reduction in capex is going to lead to essentially a reduction in horsepower," he added. "We've seen the utilization go from about 75% in Q1 to about 30% in Q2." He singled out a group of companies whose collective hydraulic horsepower (HHP) dropped from about 8.3 million HHP to 3 million HHP. "That's a pretty big reduction in horsepower coming in U.S. onshore from these companies. And of course, because we have a decreasing utilization, that means we have a decrease in frac crews."

Lower 48 mine utilization also dropped, falling 57% in manhours worked from second-quarter 2019 to second-quarter 2020, said Jonathon Clark, lead analyst of frac sand for Westwood.

"There was about a 44% decline from Q1 '20 to Q2 '20," he said.

Additional curtailments are expected this year and in 2021.

"Currently we're projecting to end 2020 with an imbalance of supply and demand of about 45 million tons. Our expectations are that mine owners will be eager to ramp up production in the near-term," Clark said. "But due to further pricing constraints, supply will eventually start to taper off beginning in 2022 with further mine utilization declines and eventual mine shutdowns. So again, our belief is really starting in 2022, we'll begin to see sand supply leveling to about 100 million tons annually. "

Tough market conditions have forced several companies into bankruptcy. Frac sand companies include Hi-Crush Inc., Vista Proppants and Logistics Inc. and Covia Holdings Corp.

Two major pressure pumpers—Calfrac Well Services Ltd. and FTS International Inc.—have also filed for bankruptcy.

E&P relationships, more than a particular basin, will determine the future of OFS companies, according to Smith. He pointed out frac crew market share by basin, highlighting challenges of some companies' E&P clients in various basins.

"If you've put all your eggs in one basket in one basin and with one company and they decide to essentially go from 15 drilling rigs to two and six frac crews to one, then that's something that a company will definitely be feeling," he said. "For some companies, the relationship with these clients of theirs is going to their future."

Having clients that have not cut back too severely helps, he added.

Looking forward, the situation appears better with higher oil prices and E&Ps beginning to increase activity.

"From Q4 2020 to Q4 2021 we definitely see considerable [frac crew] growth of something around 65% as far as year-over-year growth from those two quarters," Smith said, adding most of that growth will come from the Permian Basin and Eagle Ford. During that same time frame, Westwood forecasts about a 125% frac crew growth in the Permian and 100% growth in the Eagle Ford.

So when could activity return?

"Our anticipation is as it gets closer to that $55 to $60 range by kind of 2022, we're expecting more and more activity as well as capital to come back so that pressure pumpers, sand companies, logistic companies, everyone in the frac sand supply chain can be well-capitalized and ready to serve their E&P clients," Bush said.

However, capex revisions and guidance delivered by companies will be imperative to determine how the recovery transforms next year, he added.

—Velda Addison

Rystad Energy analyzes oil performance under Dem, GOP presidents

In contrast to conventional wisdom, U.S. oil production during Democratic administrations has outperformed output during Republican administrations since World War II, Rystad Energy said in a report released Aug. 25.

Since the Truman administration in 1945, the compound annual growth rate (CAGR) of oil production has averaged growth of 2.6% when Democrats controlled the White House, compared to a flat 0.1% average when Republicans were in charge.

"The turnaround for the U.S. oil industry came as George W. Bush exited Washington in 2009," Rystad said. "Boosted by thriving new production from shale and tight oil in response to advances in drilling technologies, production sky-rocketed through 2017 under Barack Obama's leadership.

"The 7.2% CAGR over this period is the highest in U.S. history for a single president, despite the oil market downturn in 2015 and 2016. It is in contrast with the broader opinion that Obama was generally more sympathetic toward the environment than his predecessor and successor."

Despite the current downturn, oil production has increased at an annual rate of 7.1% during President Donald Trump's administration. Since 2017, the U.S. has become a net crude oil and total product exporter for the first time since the 1950s, and net imports/exports have hovered around zero since 2018.

Trump has enforced various energy and environmental sector policies, Rystad said, noting executive orders to allow construction work to begin on the Dakota Access and Keystone XL oil pipelines. These projects were previously vetoed by Obama, partly due to environmental concerns in Nebraska.

Trump also submitted a formal request to withdraw the U.S. from the Paris Agreement and championed a reduction in the federal corporate income tax rate from 35% to 21%. This tax cut has improved liquidity of oil and gas producers. Rystad estimated that ExxonMobil's U.S. operations saved $193 million in corporate taxes in 2018, reducing asset breakeven oil prices by as much as 5.3%.

Democratic presidential candidate Joe Biden's ultimate goal is to make the United States carbon-zero by 2035. In July, he announced a $2 trillion investment plan, spread over four years, to counter climate change.

The Democrat's plan covers reforms in infrastructure, transit, the automobile industry and the power sector, and the former vice president claims it will create millions of new jobs along the way. Biden vowed on July 15 that, if elected, he would reenter the U.S. into the Paris Agreement, also stating a desire to "reverse Trump's rollbacks of 100 public health and environmental rules."

Biden supports the Green New Deal as an essential component in the fight against climate change and has stressed the "banning of new oil and gas permitting on public lands and waters." Rystad's analysis is that New Mexico is likely to lose the most from this plan, along with Wyoming and Colorado.

Rystad does not expect a potential federal land fracking ban to have any immediate impact on nationwide Lower 48 output (excluding the Gulf of Mexico) because activity would migrate from federal acreage to equally commercial state and private lands. It noted, however, that changes to the industry landscape from COVID-19 may negatively impact the industry more than previously thought.

Rystad expects an increased focus on the environmental aspects of U.S. oil and gas operations if Biden wins the November election, but while some additional environmental policies might challenge U.S. producers' economics, it is quite possible that Biden's policies will be beneficial for them, at least in the short term.

"A potential end to the ongoing trade war with China would surely help support demand and oil prices," Rystad said. "Similarly, an increase in measures to prevent the spread of COVID-19 would benefit oil prices in 2021 to 2022 in our view. A potential fracking ban on federal land would also most likely have a positive impact on oil prices in the short term.

"Taking all these factors into consideration, it seems entirely plausible that the U.S. oil and gas industry could benefit from a Biden presidency during the first quarters of his term amid a recovery in oil prices."

—Hart Energy Staff

EOG commits to 'staying disciplined' amid market uncertainty

If the oil market remains oversupplied, don't expect EOG Resources Inc. to grow production.

"We're a part of the solution and not part of the problem," Bill Thomas, the company's president and CEO, said Sept. 9 during the virtual Barclays CEO Energy-Power Conference. "We're committed to staying very disciplined and not supplying oil into an oversupplied market."

EOG, which reported in August its crude oil volumes dropped 27% from a year ago to 331,000 bbl/d in the second quarter, was among the oil companies that shut in wells as market conditions deteriorated earlier this year. Down from a peak of 107,000 bbl/d in May, shut-in volumes were expected to average about 25,000 bbl/d during the third quarter.

"We are a disciplined growth company … The No. 1 driver on disciplined growth is the market fundamentals, and I want to be super clear on this: We are not interested in growing oil in an oversupplied market," Thomas said.

Such discipline has accelerated throughout the industry in wake of the coronavirus pandemic, he added, applauding the efforts of others also making such moves. E&P companies have adjusted capital plans, cutting spending and deferring some projects as the coronavirus pandemic continues to impact demand and the workforce, global oversupply of oil and low oil prices.

EOG's premium drilling strategy, which started in 2016, focuses on wells capable of earning at least 30% direct after-tax rate of return at $40 crude oil and $2.50 natural gas prices. The strategy "ensures we have strong returns and cash flow through the cycles. It maintains a very low direct finding costs less than $10 per boe, and it helps us to achieve a higher capital efficiency each year as we continue to high grade and improve the premium inventory."

EOG has about 4,500 wells that generate a 30% rate of return at $30 flat oil prices, Thomas said. The company's focus will be on these wells as it aims to further reduce costs and increase returns.

Attention is also on pursuing exploration opportunities.

Earlier this year, EOG said it planned to test about six prospects in 2020.

"We see a lot of opportunity for EOG to continue to get better through all these exploration efforts," Thomas said.

Fresh off a drilling campaign that resulted in the discovery of up to an estimated 1 Tcf of natural gas offshore Trinidad, EOG is continuing its exploration drive.

"We have exploration efforts going on in that kind of environment in multiple places in the world, not just in Trinidad," Thomas said of offshore exploration in shallow water. "We're hopeful that'll be a meaningful part of the company. The other part is horizontal technology, and we've been looking for years for a meaningful horizontal play internationally. Geologically, they're abundant. The issue is the geopolitical risk."

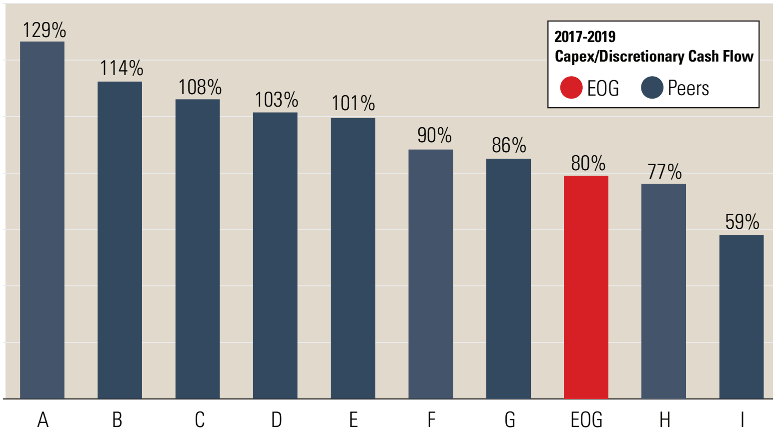
However, he added the company is seeing some opportunities nowadays as deal structures are modified, making the returns in some plays—with large reserve potential—just as good as or even better than EOG's U.S. assets.

EOG, which operates in several basins in the U.S. as well as in China and Trinidad and Tobago, didn't share details during the virtual conference on its international exploration pursuits but mentioned that most of its new exploration plays in the U.S. are on nonfederal acreage.

"We're really excited about our exploration effort. We believe we're going to bring in rock quality to the company that's better than our average quality right now," Thomas said. "That will lower our decline rate. That will lower our F&D cost, and it'll improve our returns going forward. I think it will continue to improve our capital efficiency."

From 2017 to 2019, the Houston-based company has generated a 14% average return on capital employed and $4.6 billion of free cash flow, while increasing the dividend by 72%, lowering debt by $2.2 billion and growing proved reserve base by 55%, Thomas said.

EOG Resources Reinvestment Strategy



Source: EOG Resources Inc., FactSet
[1]Peers include APA, COP, CXO, DVN, HES, MRO, NBL, OXY and PXD.

"We have done this by only reinvesting about 80% of our discretionary cash flow back into capex," he said.

Jeanine Wai, an analyst for Barclays and session moderator, mentioned new investment frameworks of several E&Ps being backstopped by reinvestment rates between 70% and 80% with single-digit growth.

"On strip prices, we see a wall of free cash flow coming for E&P, but historically it hasn't really materialized, and I think there's still a lot of skepticism in the market," Wai said. "But we think that providing these formalized frameworks are a way for the market to start capitalizing on that free cash flow given the commitment."

Wai asked whether formalization of the frameworks will be a catalyst as the industry looks to get generalist investors back in the sector.

Guidance on EOG's framework will be given after it gets more insight into the macro outlook, Thomas said. He pointed out that there has been a structural permanent shift in the E&P space.

Thomas pointed out how many of its peers—private companies and major integrated companies alike—have switched to a more disciplined mode. He believes the approach will help modify growth in the U.S.

"We think it will help stabilize oil prices and make it a much better environment for each one of us," he added. "The important thing to know about EOG [is] we are committed to being a part of the solution to rebalancing the market. We're not going to grow oil in an oversupplied market."

—Velda Addison

Lawyers consider pros, cons of stalking-horse bidders

Current oil and gas market conditions have caused an unprecedented number of E&P bankruptcy filings. However, these troublesome times also create an A&D opportunity for those prepared, said a group of lawyers in Summer NAPE's Aug 12 virtual roundtable, "Bankruptcy–Purchasing Assets Out of Bankruptcy (363 Sales)."

Although the current downturn presents new concepts and conditions that might make the acquisition process more challenging than in previous cycles, the lawyers expect E&P companies to continue to shed oil and gas assets out of bankruptcy, ultimately setting up a favorable landscape for stalking-horse bidders.

"If you are the stalking horse it gives you a leg up, allowing you to control the contours of what goes into the asset purchase agreement," said Sarah Schultz, partner at Akin Gump Strauss Hauer & Feld LLP.

As of June 30, 23 E&P companies in North America have filed for bankruptcy so far this year, according to Haynes and Boone LLP. That number is expected to significantly increase in the second half of 2020. Most recently, bankrupt E&P, Lilis Energy Inc., switched gears to a sales process after a restructuring support agreement (RSA) with its biggest investor fell through. The Permian Basin pure-play had voluntarily filed for Chapter 11 bankruptcy on June 29.

In an Aug. 17 release, Lilis said that per the RSA entered into with its lenders, the company will immediately begin pursuing a process to sell substantially all of its assets with a hearing on bidding procedures scheduled for Aug. 21.

Schultz noted that, in Chapter 11 cases, the timeline is very compressed so potential stalking horses have to be prepared to react quickly. While there is a premarketing process where the banker will reach out to inquire if the buyer is interested in purchasing certain assets, she said the process really starts when the procedures are approved by the bankruptcy court.

"Once those procedures are approved, that timeline from the date the order is entered until the date that the sale is going to be approved by the bankruptcy court can be very short like 50 days, which isn't a lot of time for your due diligence," she said. "But it is not unusual for the process to move incredibly quickly in Chapter 11 because, frankly, you have a company that doesn't have the luxury oftentimes of liquidity to fund an extended process."

Melissa Munson, Steptoe & Johnson PLLC member, agreed that stalking horse is the best position for a buyer but warned that there are a lot of risks with being the initial bidder like reputational costs and the repercussions of capped-bid protections. "Anecdotally, I think the stalking horse is in the strongest position to actually be the ultimate successful bidder when it comes to a 363 asset sale," Munson said.

"But, I think it's worth noting that you can put a lot of time and expense into doing the due diligence, negotiating the asset purchase agreement, and ultimately, you are not the successful bidder and you don't end up closing the deal," she continued. "While you do have some bid protections built in, sometimes those are caps and that expense can run well in excess of that cap, and other buyers are potentially going to piggyback on your hard work."

However, Munson noted the stalking-horse bidder's ability to help design the framework for the deal by setting the floor price for the 363 asset sale, negotiating the initial asset purchase agreement and—more importantly—the bidding procedures with the debtor.

"The intent of the bidding procedures is to set an even playing field and encourage additional interest from the field to maximize the value of the estate," she said.

The bidding procedures will include an outline of what the stalking horse is entitled to, and then ultimately it will include some language about how the sale is going to be approved.

In agreement, fellow member at Steptoe & Johnson Arthur Standish said controlling the terms of the purchase agreement is important and favors the stalking horse.

"Debtors and courts don't like to see bidding contests," Standish said. "So once the original asset purchase agreement is negotiated, most people, most bidders fall in line with that [agreement]."

To get a leg up on due diligence costs, Standish said the interested initial buyer should negotiate and help draft the ultimate sales order that the court approves and all the protections that come with it.

"By doing that, once the bidding procedures orders are entered into, it would short the due diligence period for any competing bidders that are out there, so you would have additional time to get your due diligence ahead of others," he said.

On the flip side, he notes these deals typically fall under the "as is, where is" clause, and they lack exclusivity.

"There's no sale protections in the bankruptcy process," he said. "You may get into it and spend a lot of money and the court may not end up approving your negotiated-bid protections and the procedures that you wanted. There could be delays in the process which could drive your costs, and if you actually lose the option, you may end up as a backup bidder."

To avoid this, he said, when shaping the contours of the contract, it is important to negotiate exclusivity provisions and no shop agreements, if possible.

As the stalking horse, the panelists agreed, it is important to be mindful of what the debtors as well as what the secured creditors behind the scene require while also negotiating in provisions that protect them as buyers. Specifically, Munson said it is very valuable for interested buyers to understand their risk tolerance "Because it's not going to be a perfect asset, a perfect transaction or a perfect position".

"If you want to participate in this space, be prepared to act early, act quickly, and you need to be prepared to act often because you're not always going to be the successful bidder," Schultz added.

—Mary Holcomb

Concho Resources eyes efficiency gains in Permian Basin

E&P companies have made significant strides in drilling and completion efficiency, but the head of a Permian Basin pure-play sees more opportunity ahead as it works with the oilfield service sector and experiments with different techniques.

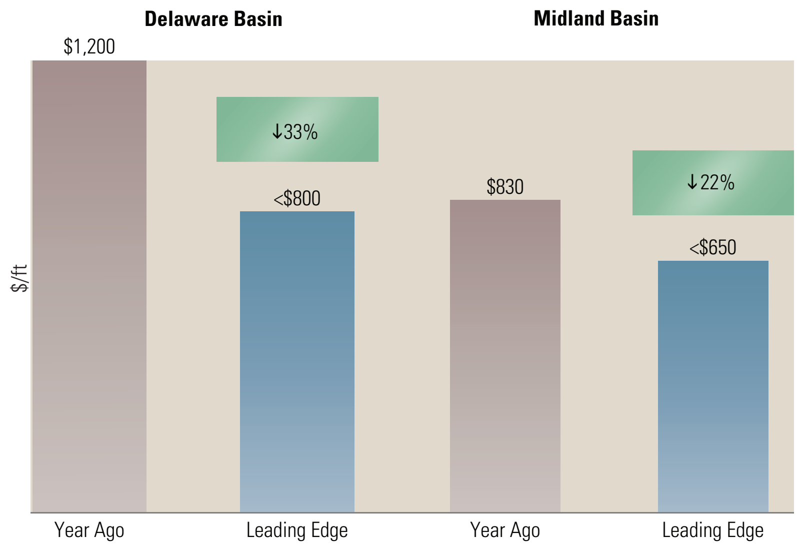
Speaking during the virtual Barclays CEO Energy-Power Conference this week, Concho Resources Inc. President Jack Harper said "The bottom line is we're drilling the wells and completing the wells faster and more efficiently. And we're doing it in ways that I think we can maintain outside of just the normal inflation."

The company reported a 35% increase in feet completed per day per crew for second-quarter 2020, up to 1,700 ft, compared to a year earlier. The number of feet drilled per day per rig also showed a 50% improvement, rising to 1,100 ft compared to 710 ft a year ago.

The improvements were delivered alongside drilling, completion and exploration (DC&E) well costs reductions of 33% and 22% in the Delaware and Midland sub-basins, respectively, year-over-year.

"We now think that for the full year our DC&E per foot across the company will be less than $800 per foot. … The leading edge well costs in the Delaware are less than $800 a foot and less than $650 a foot in the Midland Basin."

Concho Resources DC&E Efficiencies



Source: Concho Resources Inc.

The Midland, Texas-based company has attributed the improvement to efficiency gains and service cost pricing.

Operational and cost efficiency remain among the priorities for U.S. shale players that have faced a rough first half of the year with low oil prices, global oversupply and a worldwide pandemic that has slowed demand.

With watchful eyes on the markets while keeping tabs on debt, free cash flow and spending, many E&Ps are also focusing on maintaining efficiency as they ponder when to grow production and deploy more capital.

Several operators have discussed simultaneous fracs, or simul-frac, in another move toward capital efficiency. Using a single crew, the technique could increase lateral footage and complete more stages quicker compared to zipper-frac operations.

"When performing zipper-frac operations on a four-well pad, you are essentially stimulating two wells, while the other two sit idle. Simul-frac operations eliminate this idle white space by continuously making forward progress across all four wells," Halliburton explained on its website. "During a simul-frac operation, you are pumping down two wells while perforating the other two, allowing you to complete more lateral footage in the same amount of time compared to current zipper-frac operations."

Harper said Concho, which has partnered with Halliburton on several projects, could try the technique before the end of the year.

"Like everything else, it has the potential to lower cost, which is very positive," Harper said, noting it's not without potential issues. "But I think that along with several other small incremental changes can really continue to enhance our efficiency and the industry's efficiency as we move forward. So, we will definitely try that. But there are other items that are just always percolating in the background as well."

Turning to the topic of well spacing, Harper said the company's move back to wider spacing has gone as expected.

"But these are the same assets in the same plays with, frankly, better cost. So, it's a better economic outcome today," Harper said. "I'm happy to see the results there. But it's not entirely surprising, given that we're really operating in the same areas in the same rock that we were back in '16, '17 and '18."

Concho has also experimented with different flowbacks, or slowbacks, and lift methodologies, Harper said.

"The initial rates may be slightly muted from previous points in time, but you should see a flatter decline," he said. "I think that's an important point to make. Not only does slowing down our activity level moderate our decline rate, but you can also help your near-term declines" by bringing back wells slower and opting to use gas lift.

"We will continue to experiment with that, and we think that there could be a very modest rate of return impact," he added.

—Velda Addison

Analysts forecast more E&P bankruptcies to come

As the oil and gas sector emerges from a tumultuous first half of 2020, an energy consultancy group warns the worst could be far from over for E&P companies.

Despite already surviving a global oil price war, COVID-19 economic shock and crude's first trade below zero, Rystad Energy forecasts an exponential increase in the number of North American E&P bankruptcy filings by year-end 2022.

"While an improvement in oil prices towards $40 per barrel WTI saved a significant number of E&Ps and prevented early Chapter 11 filings in June to July," said Artem Abramov, Rystad Energy's head of shale research, "the current price environment is in no way sufficient for a large number of E&Ps in the medium-term."

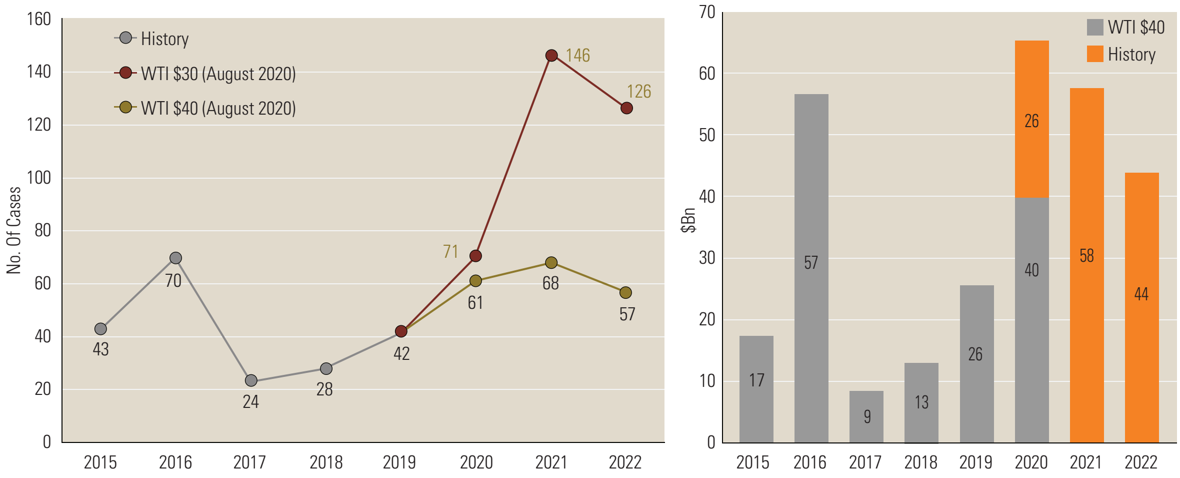
Even at $40 WTI, about 150 more E&Ps in North America will need to seek Chapter 11 protection through 2022, according to Rystad Energy analysis.

More than 50 oil and gas firms have filed for bankruptcy since oil prices crashed in March, according to the most recent report by Haynes and Boone LLP, which noted E&P filings at 32 for the year as of July 31. The law firm estimates the amount of cumulative debt held by bankrupt E&P companies stands at about $40 billion.

In a scenario with WTI continuing to hover around $40 over the next two years, Rystad expects another 68 Chapter 11 filings from E&Ps in 2021 and 57 more in 2022.

Rystad said its E&P Chapter 11 model is based on a cash flow analysis covering about 10,000 active North American oil and gas E&Ps. The model is designed to present a macro-level outlook rather than look at individual company insights, as the capital structure for a majority of small and private

North American E&P Chapter 11 Case And Debt Scenarios



Debt estimate assumes $40 WTI oil and $2.5 Henry Hub natural gas prices.
Source: Haynes and Boone Oil Patch Bankruptcy Monitor, Rystad Energy research and analysis

E&Ps is based on assumptions and matches the actual number of Chapter 11 cases.

If WTI price levels remain largely unchanged and Rystad's Chapter 11 forecasts materialize, this would bring the total number of North American E&P filings for 2020 to 2022 to nearly 190, compared to 207 during the five-year period of 2015 to 2019. That would also bring total Chapter 11 North American E&P debt for 2020 to 2022 to about $168 billion, 36% higher than the $122 billion recorded in 2015 to 2019.

"As hedging programs set at WTI $50-plus per barrel expire in the second half of this year, we anticipate greater financial pressure on the industry unless WTI prices recover further," Abramov continued in the statement.

—Emily Patsy

Range Resources sets 2025 net-zero emissions target

Range Resources Corp. has set a goal to achieve net-zero greenhouse gas emissions by 2025, the U.S. shale producer said in an Aug. 26 release.

The Fort Worth, Texas-based independent E&P company's net-zero ambitions follow emissions reductions targets set by several international oil majors including BP Plc and Royal Dutch Shell Plc as the sector continues to face pressure from investors and activists over climate change. Williams Cos. Inc., a pipeline company based in Tulsa, Okla., also unveiled net-zero carbon emissions targets on Aug. 26.

Range, a natural gas and NGL producer with operations focused on stacked-pay projects in the Appalachian Basin, said it is already a leader in emissions reductions among its peers. Citing third-party data from Rystad Energy, the company puts its ranking among the lowest in CO_2 emissions intensity in a group of 58 global oil and natural gas producers.

"Given our vast energy resources, low breakeven costs and best-in-class environmental efforts, Range will continue to play a key role in safely supplying cleaner, abundant energy while providing value for all stakeholders through a sustainable approach to our work," CEO Jeff Ventura said in a statement on Aug. 26.

Range, which claims to have pioneered the Marcellus Shale in 2004, currently holds roughly half a million net acres in Appalachia primarily in southwest Pennsylvania. The company expects Appalachia production to average about 2.15 Bcfe/d for 2020, according to a recent investor presentation.

To achieve its new emissions reductions goals, Range said it plans to continue investing in new technologies and engineering solutions, implement best-in-class emissions reductions practices and develop improved methods to reliably verify emissions through measurement. Continued

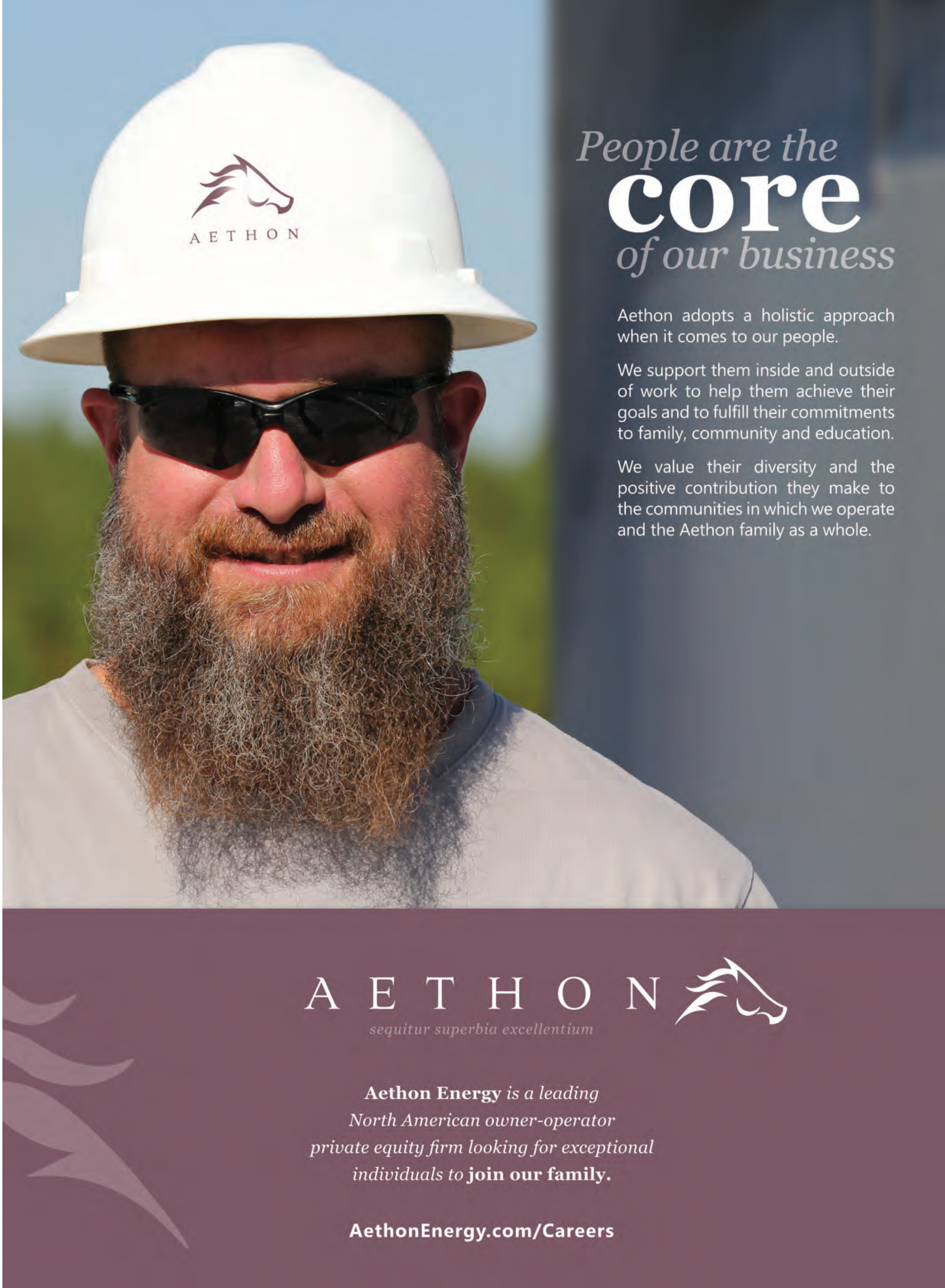
Range Resources ESG Priorities And Progress

Governance culture
- Management and oversight of sustainability factors fully integrated into daily operations;
- Proactive ongoing outreach to shareholders soliciting feedback on ESG efforts; and
- 33% of independent directors are female.

Health and safety leadership
- Zero incidents resulting in work restrictions or days away from work experienced by Range employee workforce in 2019; and
- 3,179 hours of safety-related training completed by workforce over past year.

Environmental stewardship
- Net-zero greenhouse gas direct emissions by 2025 through continued emissions reductions and the use of carbon offsets associated with reforestation and forest management, as well as the consideration of all other available and emerging offset methodologies;
- Continue reducing greenhouse gas emissions intensity with interim objective of further reduction of 15% by 2025 compared to 2019 greenhouse gas emissions intensity levels;
- Reduced greenhouse gas footprint by 47% in absolute greenhouse gas emissions since 2017;
- Recycled 147% of produced water volume through water sharing program.

Community impact
- Contributed over $442,000 to more than 350 nonprofit and civic organizations across core operating footprint; and
- Over 700 employee hours volunteered at company-sponsored events and community initiatives.


AETHON
People are the
core
of our business
Aethon adopts a holistic approach when it comes to our people.
We support them inside and outside of work to help them achieve their goals and to fulfill their commitments to family, community and education.
We value their diversity and the positive contribution they make to the communities in which we operate and the Aethon family as a whole.
AETHON
sequitur superbia excellentium
Aethon Energy is a leading North American owner-operator private equity firm looking for exceptional individuals to join our family.
AethonEnergy.com/Careers

emissions reductions also include the use of carbon offsets associated with reforestation and forest management.

As an additional interim goal, Range also intends to further reduce greenhouse gas emissions intensity relative to 2019 levels by 15% by 2025.

The new emissions reduction targets were announced alongside the publication of an updated corporate sustainability report by Range on Aug. 26.

"We have made significant progress toward our strategic sustainability goals over the past year," Ventura said, adding this has resulted in "significant cost savings" for the company.

In addition to its net-zero goal, the report highlights progress Range continues to make toward its broader ESG priorities, according to the company release.

Range's sustainability report is informed by multiple best practice sustainability reporting standards and frameworks, the release said. These include guidelines and recommendations by the Global Reporting Initiative, the Sustainability Accounting Standards Boards, Task Force on Climate-related Financial Disclosures and IPIECA's (formerly known as the International Petroleum Industry Environmental Conservation Association).

Analysts hopeful for US GoM production recovery

The streak of record annual production growth in the U.S. Gulf of Mexico (GoM) could come to a halt this year after offshore players delayed projects and cut spending; however, momentum will return, analysts say.

"We do have several projects that are coming online toward the end of this year and into 2021" plus more in 2022, Justin Rostant, principal analyst for U.S. Gulf of Mexico upstream at Wood Mackenzie, said Aug. 19 during a Houston Energy Finance Group webcast. "We think that we're going to have peak production in 2022 and then taper off from there and level out."

Data from the U.S. Energy Information Administration show production from GoM federal waters dropped from about 1.98 MMbbl/d in January to about 1.61 MMbbl/d in May as the oil and gas industry waded through uncharted territory. Like their onshore counterparts, offshore operators are navigating continued oil market volatility amid a global pandemic, less demand and resource oversupply.

Wood Mackenzie had forecast the GoM region, which accounts for about a quarter of the world's deepwater production, would see about $10 billion in annual capital investments between 2016 and 2020, Rostant said.

Then, March happened, and oil prices fell.

GoM players responded quickly by cutting about $4 billion of 2020 capex plus "significant" opex cuts, according to Rostant, who noted cuts ranged by company from about 20% to 50%. The cuts, he added, came from projects in various phases. Uneconomic wells were shut in, and maintenance programs accelerated.

"The focus of companies here wasn't to cancel projects—just to delay that spend and delay those projects as much as possible, trying to conserve cash in that low-price environment in 2020," Rostant said.

Wood Mackenzie doesn't anticipate any greenfield projects will be sanctioned this year.

Earlier this year, the energy research and consultancy forecast GoM production was on course toward another production record of 2.2 MMboe/d. Rough market conditions prompted analysts to lower its forecast by 200,000 boe/d. However, with major projects still in the works, production recovery is anticipated next year.

"We're not seeing any cancelations, just delays," Rostant said.

Exploration programs also saw cuts. Some companies opted not to pursue options for rigs to drill additional wells. The number of wells spud in 2020 is expected to be the lowest seen in the last 10 years, according to Wood Mackenzie.

However, some companies are still pushing forward with exploration programs and running rigs. Others pushed planned 2020 exploration wells to 2021, giving analysts hope for a future uptick in GoM exploration alongside continued focus on low-risk infrastructure-led exploration.

The GoM remains an attractive region with favorable economics.

Operational efficiencies gained in recent years have improved the GoM's competitiveness with tight oil. The analyst pointed out how some subsea tiebacks and standalone GoM developments have lower WTI breakevens at 10% IRR than some tight oil plays in the U.S.

Plus, Rostant said the GoM has about 1.7 MMbbl/d of production with a post-tax short-run marginal cost of less than $15/bbl, "so companies could weather a short-term price drop."

Those costs are basic expenses required to operate the facility, royalties to the government, and transportation, processing or handling costs. "When we take all those costs into consideration, you're running at $15 if forward prices are $20. You're doing okay," he said. "Obviously, prices are back up into the $40 range."

Economics have kept some companies—a mix of independents, privates and majors—in the successful hydrocarbon province, which still has untapped volumes of oil and gas. Though others have left as company strategies shifted.

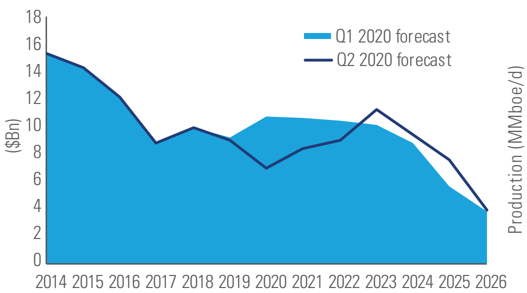
M&A activity ramped up in 2018 and 2019, Rostant said. Deals included Kosmos Energy Ltd.'s acquisition of Deep Gulf Energy and Talos Energy Inc.'s acquisitions of ILX Holdings, Castex Energy and Venari Resources.

Rostant pointed out in his presentation that "asset sales have gone for steep discounts" but "future private exits could be difficult but also provide opportunistic acquisitions" as the implied long-term oil price has ranged from the low $20s/bbl to $50/bbl.

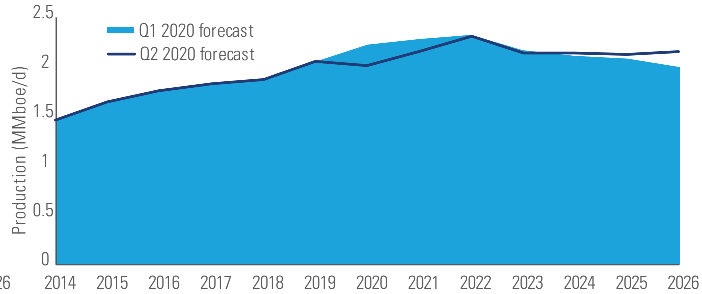
Still, don't expect fire sales given oil price uncertainty, he warned.

Wood Mackenzie's list of potential sellers includes Fieldwood Energy LLC, which earlier this month filed for Chapter 11 bankruptcy—its second time to do so in the past two years. Potential sellers also include Occidental Petroleum Corp., which bought Anadarko Petroleum Corp. along with its massive

US GoM Capex Profile



US GoM Production Profile



Source: Wood Mackenzie

deepwater portfolio, he said.

"Now they are in a bit of trouble from needing to raise cash," having had a couple of transactions in Algeria and Ghana fall throughthrough," Rostant said. "We anticipate [Occidental] may need to raise some cash immediately. They may look at their portfolio in the Gulf of Mexico to try and do some divestitures there."

Potential buyers, according to Wood Mackenzie, include Total SA and Petronas.

Rostant described Total as a big player worldwide with aspirations to return to the GoM. He noted the company has expressed interest in purchasing Occidental assets elsewhere but deals fell through. "If [Occidental] is a potential seller here in the Gulf of Mexico, then Total could be a natural partner there to pick up some of their assets," he said.

Malaysia's Petronas has also been looking to diversify. The company's subsidiary, Progress Resouces USA Ltd., partnered with Equinor ASA and Repsol SA at the Monument prospect in GoM and announced earlier this year they struck oil.

"We do not anticipate Petronas is going to be a one-shot player in the Gulf of Mexico," Rostant said. "They're going to want to grow their portfolio."

The GoM, however, is not without risks. Political risks have surfaced as Democratic presidential nominee Joe Biden's climate initiative could impact activity in the GoM. Wood Mackenzie evaluated the impact potential bans could have on oil and gas permitting in four scenarios.

"Each scenario gets more and more prohibitive. We see the impacts are becoming more and more drastic," he said, later adding "If the Democratic Party wins, things will be more difficult."

—Velda Addison

Oil and gas companies need top-down diversity plans

A lack of workforce diversity can damage the bottom lines of oil and gas companies, panelists at the recent GasTech Virtual Summit 2020 said, with the current downturn harboring the potential to exacerbate those issues.

"Sometimes diversity efforts take an active step in the wrong direction," said Julie Mayo, energy transactions partner and head of U.S. oil and gas at the Norton Rose Fulbright international law firm. "We certainly saw that to some degree in the 2008 economic crisis and also the 2014 oil price crash, where diverse employees were disproportionately impacted by layoffs, furloughs and salary cuts. Those choices have consequences because we all know that a larger number of women in leadership roles leads to higher profits, and that's just looking at gender diversity."

Companies represented by the four panelists already have formal programs in place. Tracy Lothian, Singapore-based senior vice president, LNG at Exxon Mobil, has been among those spearheading the Power Play initiative, which connects women in the LNG business. The program will announce its 2020 awards on Sept. 16. Awards, she said, and can illustrate accomplishments in ways that statistics cannot.

"We really shouldn't be having to justify that women improve the business results," Lothian said. "This showcasing is so important. Providing all of this information to everyone—to small companies, large companies, individuals looking in at the industry—so that we can really push through and have a paradigm shift."

Gender is just one aspect of any company's diversity policy. Sempra Energy has sponsored eight "community conversations" or online forums for employees to discuss social justice issues in the wake of this summer's unrest. The dialogue has led to Sempra creating a racial equity action plan.

"Within our employee population, we are targeting

Gulf Of Mexico Potential Biden Election Scenarios

Scenario 1	Scenario 2	Scenario 3	Scenario 4
• No new exploration leases • No exploration leases awarded from 2021. • Exploration continues on blocks already leased. • Discoveries can be developed.	• No new exploration leases • No further exploration drilling from 2021. Existing discoveries can be moved ahead to development.	• No new drilling • No exploration, appraisal or development drilling. • Production from existing wells is allowed.	• Production shutdown • A halt to production from federal lands and waters from 2022.
Result: curtailed exploration.	Result: sector set on a declining path.	Result: rapid terminal decline.	Result: death blow for U.S. GoM; minimal additional impact to Alaska.

Source: Wood Mackenzie

unconscious bias training, and I think this speaks to an inclusive environment across all people," said Lisa Glatch, Sempra LNG's president and COO. "Experts tell us that we all have unconscious bias—we just do. Unconscious bias education just gives us the ability to begin really recognizing that and minimizing these blind spots and so overcoming this bias is certainly one of the goals as we try to build the most inclusive culture that we can."

Sempra's plan has three goals:

- Increase the number of employees from underrepresented communities in its workforce, with a particular focus on Black boys;
- Increase the number of organizational leaders at all levels from underrepresented communities with a particular focus on Black and Asian-Americans; and
- Create enterprise-wide initiatives to support communities of color with targeted volunteer and charitable giving programs.

At Baker Hughes, 35% of the U.S. workforce is from minority groups and women make up 21% of the company's senior leadership.

Because of the COVID-19 pandemic, "I believe that the strategy on diversity is getting an acceleration," said Maria Sferruzza, the company's senior vice president for Asia-Pacific. Among the initiatives are supporting STEM education by providing in-class mentors.

While the pandemic has taken a wrecking ball to the country's health, economy and psyche, Mayo has identified positives that have emerged in the workplace.

"One of the most interesting aspects of working from home to me has been that, in some ways, it feels like it's leveled the playing field," she said. "Men—and women—who previously believed that work could only be done in the office and only during business hours now are forced, in a way, to understand and appreciate the value of remote and flexible work."

In the past, those accommodations had been viewed through a gender-based lens as primarily offered to women and specifically to mothers, said Mayo, who endorsed how Zoom has made employees' full lives visible.

"Seeing people's whole lives reminds us that we are each more than our work," she said.

"Hopefully, an increased openness to employees' circumstances and acceptance of their authentic selves will also open the door to furthering efforts on racial equality and social justice," Mayo said. "One of the things that we think about in the racial equality and social justice movement is this idea of making sure that everyone can bring their authentic self to work because that's what makes people feel fulfilled. That is one of the things that really contributes to fulfillment in our professional lives—feeling like we can be ourselves where we spend so much of our time and put so much of our energy."

—Joseph Markman

HOW TO MAKE E&Ps INVESTABLE AGAIN

Wall Street kicked U.S. independents to the curb, fed up with a decade of capital destruction, misaligned executive incentives and an indifference to environmental impacts. Do E&P management teams have the chutzpah to transform their models to win back investors?

ARTICLE BY
STEVE TOON

What's the sentiment today of investors buying into the E&P space? Capital One Securities senior E&P analyst Phillips Johnston pulls no punches. "Pretty much zero," he scoffed. "It's the most hated sector on Wall Street." It's a reality U.S. oil and gas producers are finally facing: Public money is gone, and this time it's not cyclical.

STEVE TOON

Energy accounts for less than 3% of the S&P 500 today, its lowest weighting in 20 years and a fall from a 13% peak earlier this decade. That number represents all of energy, with E&Ps a minor subset of the whole. Over the past 10 years, the S&P 500 returned 230% while the S&P Oil & Gas E&P index returned negative 70%.

Phillips Johnston, Capital One Securities senior E&P analyst, says investor sentiment toward the oil and gas sector is the worst in 22 years. "Investors want the sector to quit destroying capital," he said.

The sector is a capital vortex. And Wall Street is angry at being duped.

"It's a despised sector," said Johnston, based in New Orleans. "I've been covering energy since 1998, and I've never seen anything like this." While some energy-dedicated hedge funds and mutual funds remain invested given their sector mandate, long-only generalist investors began to steadily flee the E&P space following the late-2014 collapse in oil prices and have been virtually absent from it over the past three to four years.

"Investors want the sector to quit destroying capital," he said.

As shale boomed, producers built their models on and their stocks were rewarded for fast production growth, which built net asset value (NAV). At the time, the world needed more gas and oil—it was an era of scarcity with growing demand. But that all changed. Now the world is awash in both commodities—largely due to the success of the shale innovators—at a time when the environmentally minded want to reduce or eliminate both. The return on investment never materialized.

"Let's be frank," Parsley Energy Inc. CEO Matt Gallagher said in the company's second-quarter conference call. "North American E&Ps are in a battle for investment relevance, not a battle for global market share. Allocating growth capital into a global market with artificially constrained supply is a trap our industry is falling into time and time again."

Since the oil price collapse in late 2014, the E&P sector has outspent cash flow by $41 billion and impaired "a staggering" $211 billion in assets, reported Devin McDermott, head of North America oil and gas research for Morgan Stanley. Prior to this 2020 down spike, the U.S. E&P business model was already in a state of transition, he said.

"Over the past decade the debate has shifted from peak supply to uncertainty around peak demand and ultimately what is the role of oil and gas broadly in our energy mix. This change necessitates a strategic shift away from growth. Investors have begun to emphasize returns and free cash flow.

"Much of the U.S. E&P industry has struggled to make this transition."

And therein lies the crux of the problem.

The end of the growth model

Given the shale land grab that began over a decade ago and the heavy emphasis on growth, the U.S. independents have destroyed capital as far back as 2007, Johnston estimated, "and that's a long track record of management teams doing the wrong things." When generalist investors look at other sectors that have generated returns and free cash flow during the same time period, "it's tough for them to look past that."

PESKYMONKEY / SHUTTERSTOCK.COM

While the bulls have returned to Wall Street, not many are running after E&Ps.

LOWELL GEORGIA

RETREAT TO MEGACAPS

There was a time when upstream oil and gas companies were exciting places to be, said Diane Jaffee, a senior portfolio manager with Los Angeles-based TCW Group. "There was unbelievable growth in the U.S., different innovative techniques, which allow companies to find oil and gas faster and cheaper. And that was exciting. Then the world came crashing down in the summer of 2014."

Jaffee, herself based in New York, oversees three funds: TCW Relative Value Large Cap, TCW Relative Value Dividend Appreciation, and TCW Relative Value Mid Cap. Those funds used to include independent E&Ps. Those are memories now.

The correlation between E&P valuations and commodity prices began to bifurcate in 2014, she noticed, with stocks underperforming commodities. "Upstream became a no man's land for investors," she said, finding favor only with "super nichey" hedge funds and specialty investors. "And that's a shame. It used to be a staple in everybody's portfolio, and now it's not."

TCW joined the exodus. The fund manager divested of all of her E&P holdings in two phases, the first in the fall of 2014, and again in 2018. "We eliminated all of our E&Ps." Presently, its largest energy oil and gas holdings are Chevron, Baker Hughes and refiner Marathon Petroleum—and that's all. "The super megacaps have wildly outperformed," she said.

Chevron, of course, is a major with upstream, refining, marketing and services. She liked the company's recent deal—still pending—to acquire Noble Energy Inc. and its strong assets, particularly those offshore Israel. "Noble was always regarded as a premier company, and Chevron didn't seem to overpay." In contrast, not pursuing Anadarko Petroleum in a bidding war with Occidental Petroleum was "super smart."

Baker Hughes—one of the Big Three global service providers—is her second largest holding. When it merged with GE's oil and gas business it became more international, less focused on the U.S. It's even more intriguing to her now that it is formally separated from GE. Baker rates high on governance as well. "It's incumbent on management to think about their shareholders. E&P companies have not done a good job of that."

Investors want more diversified, bigger companies until E&Ps refocus on shareholder returns, she affirmed. Her own portfolios reflect that.

"Frankly, the stain from investing in E&Ps—because the old methodology of paying management teams for just growth, growth, growth—clearly isn't working anymore."

E&Ps "for the most part haven't refocused on total shareholder return," said TCW Group portfolio manager Diane Jaffee, "and that's why we have shied away."

The aggressive growth rates pursued by E&Ps over recent years contributed to the global supply glut, and investors now are demanding that producers "really slow down" and not grow beyond a low- to mid-single-digit production growth rate, said Johnston.

"Historical metrics don't really matter that much right now. It's all about, can these companies generate a return on capital? All these companies are saying the right things right now, but there's no real track record there."

The call by the investment community to transition from growth to value began three years back, but Stifel managing director Michael Scialla said the absolute collapse in prices during the second quarter of 2020 spurred a lot of management teams to urgent action. "We've got to take drastic steps. We don't need to grow at all, and some companies were growing at double digit rates. All of a sudden they've had to slam on the brakes."

Compounding the problem of disastrous returns, another existential headwind facing the industry is that the investment community views hydrocarbons as a waning industry—rightly or wrongly—with peak demand occurring within the decade, said Mark Viviano, head of public equities at Kimmeridge Energy. He calls this "terminal value risk."

Kimmeridge, a New York private-equity firm focused on upstream energy, is raising a fund to invest private capital in public equities, led by Viviano, with the intent to drive E&P transformation as an activist investor.

"If you polled most non-oil and gas investors, the general view would that be that oil demand peaks over the next 10 years. And, unfortunately, I think there is this association with peak demand and almost zero demand, not really understanding the time period to replace that magnitude of demand after it peaks. But, again, it's an academic debate. It doesn't matter if that fear is what's driving valuations in the sector.

"The perception is real, and it's being reflected in the valuation of these securities."

Following the oil price collapse in early 2020, leading E&Ps are now urgently redefining their models, notable in their latest second-quarter earnings calls. How do E&Ps change their strategy to bring capital back into the space? "It's a simple shift away from growth toward returns. Less production growth, more return of cash. That's resonated well with investors," McDermott said.

In a nutshell: total repentance.

First and foremost, free cash flow

Delivering sustainable free cash flow is the first step in promoting investor interest, according to Scialla, based in Denver. Over the past five years, the U.S. E&P sector has spent some 120% of cash flow every year to drive growth, he said. The lead foot on the accelerator has to stop.

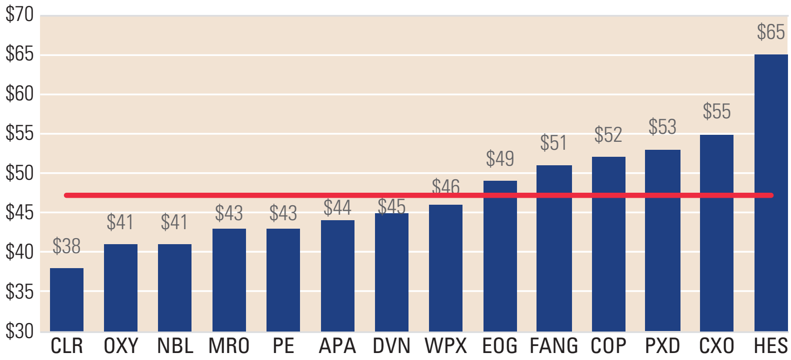
"There's a perception out there that U.S. growth is not needed," he said, "at least for now, and maybe for a long time." With an eye to the Paris Climate Accord, investors anticipate global demand to peak in a few years.

"And if that's the case, then why are these companies spending most of their cash flow to grow? They need to be thinking about how to best monetize the inventories they have as efficiently as possible." And while oil and gas producers might argue the premise or at least the timing, "That's the investor mindset right now."

With this in mind, Scialla said the goal of every large-cap company should be to cap their spending at 75% or less of cash flow. He points

Going forward, more companies will move to constrain capital investment and return cash even as oil prices rise, said Devin McDermott, head of North America oil and gas research for Morgan Stanley. "That is a necessary step for the industry."

Oil Price Required For 10% FCF Yield In Maintenance Mode



Source: Capital One Securities

to Pioneer Natural Resources Co. and Parsley Energy as larger E&Ps guiding that over the next couple of years they will put 60% or less of cash flow into the ground. "That's pretty attractive free cash flow," he asserted.

That number, however, is unrealistic for small and mid (SMID) caps, he believes, which should aim for 80% to 85% free cash flow spend. But, "It certainly can't be close to 100%," he said. "That's not what investors want."

Kimmeridge's model puts a hard cap at 70% of cash flow reinvested, with the first 30% applied to either the balance sheet or shareholders, depending on the company's leverage profile. No exceptions.

"After that, with the 70% of cash flow, some companies will be able to grow, some companies will remain flat, and some will shrink depending on their asset quality and cost structure," said Viviano. "But this idea that everybody should be targeting a growth rate in a sector where demand is growing maybe one to one and a half percent in a good year doesn't make sense."

Viviano emphasized Kimmeridge is not anti-growth per se. "If you can spend 70% of your cash flow and still grow volumes, that's fine. But growing volumes at the expense of shareholder returns is no longer acceptable in this industry."

Contrary to the upstream sector as a whole, Cimarex Energy Co. has always been returns focused, said Karen Acierno, vice president of investor relations. "That's always where we start. Growth is more of an outcome of that—although we've had some pretty decent growth over the years." Cimarex avoids production targets.

Her advice to Cimarex's producer peers: "You have to let go of growth. Free cash flow is a choice at the end of the day," she said. "You have an idea of what your cash flow is going to be, and you choose how much you're going to invest. So you just make the decision to invest less, and you know you're going to grow less."

NAV, once the featured metric to drive market cap, is less important, and growth is certainly less important, she said. "It's time to generate cash flow. We've been working to buy acreage and delineate it, so now let's develop it."

Generating cash flow, however, is unpredictable in a volatile market. Coming into 2020, Cimarex guidance hinged on $50/bbl oil with an upward bias. "We were in a place where we could generate a significant amount of free cash flow," she said. Then, "Everything fell apart. And shareholders started asking, 'What do you do from here? Are you committed to generating free cash flow?'"

The message from investors—even at the bottom of the cycle—is, do you have the ability to generate positive cash flow?

For Cimarex, the answer is yes. Even in the wild ride of 2020, they anticipate generating free cash flow well in excess of their dividend by year-end. Going into 2021 and beyond, the Denver-based operator expects to limit capex to 70% to 80% of cash flow, resulting in free cash flow of 20% to 30%.

Free cash flow generation is easy when prices are at the top of the cycle, but generating dollars at the low point will make E&Ps more investable. Goaded by the oil price collapse this spring, companies are compelled more than ever to drive down corporate cost structures and breakevens to defend against low price cycles.

"We've seen companies make good progress on that so far this year," Morgan Stanley's McDermott said. "At the start of 2020, the average company that we cover required about $45 per barrel to fund all of its costs, including interest and any distributions or dividends that the company had and maintenance capex. That same number today across the same subset of companies is $38 per barrel.

"So you've driven efficiencies in response to the oil price collapse. Part of that is cost cuts, part of that is high grading, part of that is supply chain deflation, but managing for a lower-for-longer oil world to bring down your breakeven so you can generate outsized free cash flow in the recovery is important."

The E&P sector remains bloated with G&A expenses as well, keeping cost structures too high, Johnston said. As much as 50% of G&A costs or more need to be chopped out.

"Although many companies have been cutting overhead over the past couple of years, there's still way too much G&A cost embedded in the publicly traded sector right now. Privately held E&P companies tend to operate with significantly less G&A burdens than their public counterparts. The latter needs to exercise capital discipline and continue to squeeze costs out of the system. That self-help approach will help generate better returns and free cash flow."

How? First, cut the head count. "These companies can definitely be run in a more nimble manner," he said. Second, executives are still paid "way too much relative to what they do. That amount of compensation could be cut massively."

As a case in point, of the 40-plus E&P companies that Capital One currently follows, the combined total compensation for the top five executives at each company was close to $20 million on average in 2019, with some companies reporting more than double that amount.

"This is especially egregious when you consider the terrible share price performance and the fact that over half these companies now have a market capitalization below $1 billion."

Cleaning up the debt

Once achieved, the highest and best use of free cash flow comes into question. Although investors are eager to see a return of capital by E&Ps, following the shock of the severe price collapse earlier this year, debt reduction is a higher mandate for many E&Ps today. It's a first screen for these same investors too.

"Companies with banged up balance sheets are pretty much uninvestable right now," Johnston said. If net debt to EBITDA is 2.5x or greater, or if sizable debt maturities are looming, he said, "it's usually a nonstarter—most investors will move on."

Balance sheet strength is imperative, Scialla confirmed.

"That has shot to the top of the priority list, even before thinking about returning capital. Even companies with pretty solid balance sheets feel like oil prices could turn around quickly again and feel they need to be prepared to weather the storm if it's coming again. They're paying down debt with cash flow, which is the first step for a lot of companies to become a more attractive investment vehicle for value-oriented investors."

Even "rock solid" companies are talking about paying down debt with free cash flow before they do anything else. "That just tells you how negative oil prices scared people. It took a pretty extraordinary event to trigger that. With more than 6 million barrels of spare capacity out there, if we have a second wave of the virus and it turns back down, they want to be prepared for the worst."

Before March, leading companies were targeting debt ratios of 2x debt to EBITDA. Yet that metric can quickly jump to 4x without adding new debt if oil prices and thus EBITDA gets cut in half. That simple metric can trigger debt covenants, Scialla noted. As a result, "A lot of companies are targeting one and a half times now, or even lower than that."

Few investors are willing to look at companies that have any financial risk, he said. "They feel like they're already looking at a risky investment in this space, and they don't want to double down. Some companies with good assets would be great investments if they could just get their debt levels down, but I don't sense a lot of interest."

The favored solution by Wall Street for overlevered names, he said, is use cash flow to pound on the debt. "A lot of companies are doing that. If you can hold your production flat or grow it slightly and generate a lot of free cash flow to improve the balance sheet, that's the sweet spot."

A number of companies with strong balance sheets are choosing this path. Among those: Parsley Energy, PDC Energy and Cimarex Energy. Those with above-average debt that are doing so: Apache Corp., Marathon Oil Corp. and Continental Resources Inc.

Cimarex's $750 million issue comes due in 2024, plenty of time to refinance. Yet in its

E&Ps have to let go of growth as a value driver, said Karen Acierno, vice president of investor relations for Cimarex Energy Co. "Free cash flow is a choice at the end of the day. You just make the decision to invest less, and you know you're going to grow less."

STEVE TOON

Investors say they will return to oil and gas stocks when oil and gas companies provide exceptional returns for them.

Investors want to invest in E&Ps with scale and that stand out in a crowded landscape. Here, New York City's Central Park.

LOWELL GEORGIA

St. Paul's Chapel on Broadway was built in 1766 and is the oldest church in Manhattan.

STEVE TOON

SEEING RED

Energy historically accounted for between 40% and 70% of investments within Van Eck's Global Hard Asset Fund, launched in 1994 with a focus on natural resources. No more. "As we stand today, it's the smallest it's ever been," said Shawn Reynolds, portfolio manager.

Reynolds is not a generalist investor. He's an engineer and geologist, having worked at various E&Ps before becoming an upstream analyst and then resource fund investment manager. Even with that bias, he can't risk the allocation.

"It's a career risk to go barreling into the energy space right now, and that's just from a performance standpoint. Unless I see two or three years of performance out of the E&P space, there's just no way I could ever allocate to it."

Reynolds sits on an investment committee for a large hospital with an $8 billion portfolio. The committee meets once a quarter, and each member receives a sheet that shows how the funds are invested. The investment categories are listed in a column, top to bottom, best to worst, about 50 lines, showing 1-year, 3-year, 5-year and 10-year performances.

"Every line is green except for the very last line, which is where energy sits. It's red. And by a lot. So these people who have fiduciary responsibilities to these funds ask, 'Why the heck do we have this allocation to energy, because they've been disastrous?'"

The silver lining is that the allocation is so small they'll let it ride, he said, but the allocation is definitely not increasing. "As a fiduciary myself, it would be really hard to advocate raising the exposure to that space when everything's red over the past 10 years. That's what the industry is up against."

In his role as a portfolio manager, Reynolds meets with E&P boards regularly. In early September, at one of their annual meetings, the board asked him, "What do we have to look like?"

"I said, 'Make yourself look like a real company. Deliver returns on capital you invest that are higher than your cost of capital.' I hate to be that blunt, but the industry clearly, clearly, clearly lost track of that. It's what we all learned in any basic business class."

During the early days of shale, investors did not expect that, as capital was testing a new phenomenon and new technologies, but after 10 years, "you have to start generating a return on that."

"We've been really frustrated in the space for a couple of years because of the lack of ability to pivot their business model." Compounding that, he said, "The decarbonization energy transition winds have started to blow quite hard" as well.

The sad part of this year is contrasted in fourth-quarter 2019 results, he lamented. "A number of them had really started to deliver." Then OPEC-Russia wiped out one leg of the stool, and COVID-19 the second leg. "Now we're balancing on just one, and it's absolutely disheartening."

Is there room for a growth E&P any longer? "There's always room for one, but there's no room for an industry that delivers that way."

Investors will return only when the industry delivers a 2x performance compared with other sectors and it hurts investors to *not* be allocated to energy, he said. "That's the only time you'll get money flowing back into the space."

Eventually he expects 10 to 12 E&Ps to succeed at growing their companies in the high single digits and be able to deliver high single digit returns of cash over a 10- to 15-year period. When that occurs, "that's going to be special."

second-quarter conference call management announced it would use excess cash flow after paying the dividend to retire the 2024 notes with cash, with a target debt to EBITDA of less than 1.0x. "We think we can do that at $35 oil," Acierno said, "just to illustrate the quality of our assets."

Acierno emphasized that Cimarex's balance sheet is strong and has been over the years, but with WTI falling into the teens in April then negative, the company now feels compelled to protect it further. In addition to paying investors a dividend, "Reducing debt has become an important part of our use of free cash flow after investment," she said.

SM Energy is an exception, however, Scialla noted. The Midland Basin operator, with a market cap shy of $200 million, refinanced debt in the second quarter, albeit at a higher coupon, but extended maturities and lowered absolute debt—both good. The Denver-based producer exited the quarter with a 2.45x net debt to EBITDA. But instead of using cash flow to further pay down absolute debt, it instead chose a path of keeping EBITDA high and growing at a double-digit rate.

"The stock reaction to that was pretty negative on the quarter," said Scialla.

The choice by smaller E&Ps is a double-edged sword, he acknowledged.

"If you hit the brakes too hard, the EBITDA dries up so fast that you're still not going to delever the balance sheet."

Echoing that, SM CEO Jay Ottoson explained on the second-quarter conference call, "In these downturns people have a misunderstanding about levered companies; we really don't have an option to just stop activity and watch our leverage skyrocket. That's just not what you should expect a fairly levered company to do."

When prices drop as they did in March, Ottoson explained, the company cut activity very quickly. Then as costs bottomed, it once again increased activity to keep cash flows up and leverage down. "And that's what you should expect levered companies to do in this part of the cycle."

Kimmeridge's Viviano takes exception.

"The mistake the industry has made historically is trying to delever through growth. They spend more money and grow production." But when oil prices go down, they're left with high absolute debt, and the leverage ratio blows out. "That's why we've seen so many bankruptcies so far this year."

The first 30% of free cash flow generation should go toward paying down absolute debt, he said, and as debt diminishes, they will have the ability to increase the return of capital to shareholders. "Not every company is going to be able to do this, and consolidation is the natural outcome for what we're asking."

Viviano agrees leverage ratios should be 1x at midcycle prices but notes that those midcycle prices likewise need reset to the mid $40s.

The absolute collapse in prices during the second quarter of 2020 spurred a lot of management teams to "urgent action" to reform business models, said Stifel managing director Michael Scialla. "We've got to take drastic steps."

Although certain investors will never invest in fossil fuels, most will as long as they see commitments toward ESG principles, said Shawn Reynolds, portfolio manager for Van Eck. "We're one of them."

"So if you move from $45 down to $35 in the cyclical downturns, your leverage ratio is still reasonable, not the 4x or 5x we've seen from some companies over the last six months."

To get there, any free cash flow should be used to pay down absolute debt, he said, countering SM's strategy.

If everybody was at 1x mid-cycle pricing before the COVID-19-induced demand destruction, "you wouldn't be seeing the destruction we've seen on the capital side from bankruptcies this year. That's a goal the industry should have."

Cash back to shareholders

Once a company commits to generating cash flow over growth and tames the balance sheet, the next wise move is to get those excess Benjamins to shareholders.

"As we move through the next few quarters, you'll see more and more companies move in the direction of constraining capital investment and focusing on returning cash rather than reinvesting that cash as oil prices rise," McDermott predicted. "That is a necessary step for the industry."

This can be accomplished via three primary ways: a dividend, variable dividend or share buybacks. Overwhelmingly, everyone agrees that establishing a competitive dividend is imperative going forward.

"Debt pay down is currently the main priority for most E&P companies. Once financial leverage ratios are reduced to 1.5x or lower, investors want to see a lot of that free cash flow returned back to shareholders, mainly in the form of dividends," Johnston said.

Paying dividends forces capital discipline, he believes, and for the last year and a half, he has been advocating for E&P companies to pay out most of their free cash flow in the form of regular base dividends plus variable dividends.

In early August, Pioneer Natural Resources and Devon Energy Corp. both announced that they will soon begin doing just that. Johnston believes that other E&P companies with solid balance sheets will eventually follow suit, a trend that could help attract generalist investors back to the sector.

For TCW's Jaffee, dividends are a priority. As group managing director for the West Coast asset manager, Jaffee oversees investments for three funds. None of those include E&Ps at this time.

Jaffee tracks five valuation factors when choosing investments: price to cash flow; price to sales; price to book, and price to earnings ratios, but the fifth one is "super important": dividend yield. "The company has to meet one of those five valuation factors, but having a dividend yield that is equal to or greater than the broader market … is very important to us."

Over time, on average, 40% of total returns comes from dividends for the broad-based market, she said, "so dividend returns—and the sustainability and growth of that dividend—are very important."

E&Ps, however, get anxiety attacks at committing to a dividend, as the uncertainty of commodity prices puts their ability to pay at risk in low price cycles. Nonetheless, generalist investors seek certainty of returns, and not meaningless returns either.

"You can't have a token 1% dividend—that's not going to do much for anybody,"

Scialla said, but companies need to start somewhere. "Investors want to see something in the high single digits. That would get their attention in a market that is struggling to find yield in safe investments."

"What is their interest in investing in an oil and gas company that's not going to pay you back an above-average dividend?" questioned Shawn Reynolds, portfolio manager for New York investment house Van Eck's Natural Resource Equities strategies.

"I mean, the universe of investors that are going to invest in the oil and gas space and betting on oil and gas prices has diminished to a very, very small number. So there's got to be a different reason to bring them back in."

Investors view dividends as high quality cash flows, McDermott said. Base dividends must be sustainable through the cycle, but being too aggressive in growing the dividend can have an opposite affect with investors, he warned. "Once you implement a dividend, you can always cut it, but there's more negative reputational damage when you cut it" should prices collapse.

Cimarex initiated its dividend in 2006 at the dawn of the shale era, counterintuitive to most other fast-growth E&Ps of the day, and has maintained and grown it ever since. This past quarter it paid 22 cents per share, yielding some 3.4%.

Investors "do want cash returned to them," affirmed Acierno. "They certainly haven't seen it in share prices. E&P stocks have been underperformers for some time," she said, but regular dividend levels need to be sustainable. "It's fine to allocate a certain portion of your cash flow to a dividend, but you don't want that to get out of hand, especially in the lower part of the cycle."

Pioneer Natural Resources and Devon Energy, in second-quarter calls, floated the idea of a so-called variable—or special—dividend which would be in addition to their nonvariable base dividends. It would serve as an upside modality to return cash to shareholders when commodity prices are elevated—and retract if prices waned, leaving the base in place. Essentially, it's an option on price.

"I think some investors are open to the idea," Scialla said. "Rather than chase growth when prices are higher, give that money to us. If you keep your production flat, that's doable for some of these companies."

A Capital One survey of investors showed 60% of investors preferred a fixed-plus-variable dividend as the primary method of returning cash to shareholders, vs. 8% for fixed alone and 11% for share repurchases.

To Jaffee, however, the idea of a variable dividend, which was a new thought to her, was unappealing.

"That would be very hard for typical mom and pop endowments and pension plans to invest based on that strategy. A dividend payout strategy is a sign of good governance. So if you say 'We can't know what the commodity is going to do, so we're going to pay a variable dividend,' not a lot of people are going to sign up for that. At the end of the day it becomes a bet on the commodity."

Share buybacks are a traditional and third way to return cash to shareholders, but opinions differ.

Buysiders are inundated with value-accretive opportunities in today's marketplace; U.S. independents are not one of them presently.

FRANCESCO FERRARINI/SHUTTERSTOCK.COM

THE INSIDER ACTIVIST

Mark Viviano is on a mission to reform the E&P sector—from the inside out.

The upstream buyside analyst and portfolio manager left Wellington Management in February after 17 years to join New York private-equity house Kimmeridge. The strategy: invest private capital into public E&P equities—big enough to play the role of activist from within.

"Over the last few years at Wellington I had grown increasingly frustrated that the sector had become uninvestable. I either needed to abandon the sector and find something else to cover or completely redesign how we invest in it and play a role in reforming the sector."

In May, Kimmeridge launched its Kimmeridge Energy Engagement Partners Fund with a target of $500 million. Fundraising has surpassed $150 million thus far, according to SEC filings. Viviano is managing the strategy.

"Traditional engagement with management teams and boards wasn't bringing out the degree of change or urgency I thought was necessary," he said. "And we don't think you get these changes by asking nicely because they continue to get paid for the status quo. There's no incentive for them to change.

"But activism does have that ability to serve as a catalyst because when you're threatening the CEO's and board of directors' jobs through potential proxy battles, you tend to see an acceleration of change."

Setting up the rules of battle, in a white paper titled "Preparing the E&P Sector for the Energy Transition: A New Business Model," Kimmeridge in February posted its demands for E&Ps to attract investors back to the space:

- Provide visibility into returning 100% of the enterprise value to shareholders through dividends and buybacks within 10 years.
- Commit to reinvesting less than 70% of cash flow at strip pricing and place a cap on annual reinvestment rates at 80% in the case of better price environments.
- Reduce balance sheet leverage targets to 1.0x Net Debt/EBITDA or below.
- Align management compensation with the interests of shareholders through lower cash base salaries, higher equity ownership, pay for absolute share price performance and tiered change of control payments that reward selling and consolidation.
- Make capital allocation decisions with an understanding of the environmental impact, including the discontinuation of freshwater use for fracking, zero gas flaring and a commitment to carbon neutrality.

Viviano emphasized that Kimmeridge's form of activism will be different than historical references. Those focused on selling assets or other portfolio management maneuverings to temporarily drive up share price by exploiting the sum of the parts. "They haven't fundamentally changed anything in the business.

"We're trying to address the root cause of the problem around capital allocation, governance and environmental performance rather than just putting a Band-Aid over the problem through portfolio management."

Kimmeridge is unique in this role as the firm itself owns and manages E&P operations through its private-equity arm. "We haven't seen dedicated energy activism before," he said. "We're doing this with the credibility of being an upstream operator ourselves. That's very different than any other activist in the sector that are coming at it from a financial perspective and not an oil and gas perspective."

And if he can effect change in a few, herd mentality will create a stampede of others doing the same. "If companies embrace the changes and are rewarded through either higher valuations or a better shareholder base, you will see other companies adopt these changes."

McDermott favors them, although admitting that share buybacks have not worked out well historically. This, he said, is because industry tends to buy back shares at the top of the cycle when valuations are high and cuts off buybacks when prices fall. Rather, a fixed, consistent buyback program through the cycles and over a multiyear period becomes a part of a total returns package that investors can count on.

ConocoPhillips did this as part of its 2016 remodeling. "It was a value proposition that investors like. You can count on it over every quarter. Investor feedback was positive. Consistency in the return metrics back to investors is important."

Johnston takes an opposing view. "A proven way to destroy capital has been for companies to keep a stock buyback program on automatic pilot, regardless of what the share price is doing," he said. "In an upcycle, in a strong market, share buybacks look good on paper. But in a bear market, a downcycle, they've proven to destroy value. If a company does buy back stock, I would rather management be opportunistic and price-sensitive rather than take the autopilot approach."

Beating the market

It's not enough for E&Ps simply to return a modest amount of cash to shareholders. It is imperative that the total return proposition be competitive with other cyclical sectors in the broader market, McDermott said. Particularly, the expected return for the S&P 500 is about 8% including dividends plus growth. "E&Ps should offer a cash return proposition that is at least comparable with that."

But just matching the market in cash returns is not enough to be competitive, he contends. E&Ps must beat it.

"To be in line with the S&P 500 is not going to get investors excited. You have to be better than the broader market for investors to take capital out of other investments and put it in oil and gas." That total return proposition can be a combo of free cash flow plus growth in that cash stream, he said.

Pioneer Natural Resources is strategically positioning itself to do this. It is downshifting its growth to 5% to 7%, down from 20% to 25% during the wide-open era with a 70% to 80% governor on spending. Adding a possible variable dividend together with its common dividend would yield another 5% approximately to direct investor returns.

With 10% total return vs. the S&P at 8%, Pioneer is beating that market threshold to lure investors back into the stock. Pioneer, said McDermott, is positioning "to survive and thrive in a lower-for-longer oil price environment while returning cash back to investors consistently over a period of time. That's what investors want to see."

Capital One's Johnston measures free cash flow yield as a defining metric and, at $45 oil, the sector's free-cash-flow yield is not high enough compared to industrial stocks to attract generalist investors, he said. "Either oil prices need to go up significantly without stock prices going up significantly, or some of these E&P stocks need to rerate lower, which is pretty depressing to think about considering how much they've underperformed."

Scialla sees it similarly: "If you look at the free-cash-flow yields these companies need to

Like NYC entertainment venues waiting to re-open their doors to spectactors, oil and gas companies are eager for shareholders to return for new performances.

STEVE TOON

STEVE TOON

be competitive with other industries, it probably needs to be in the double-digit range."

Viviano takes the goal of returning cash to shareholders a step further. E&Ps should make it their mission to return 100% of enterprise value within 10 years, he said. The reason comes back to the perceived terminal value risk for investors.

"If investors think oil is going away in 10 years and you provide visibility into returning 100% of the capital, then you're taking that risk off the table." And if oil demand by some miracle continues to be around in 10 years, "now it's all option value, right? You're not asking the investor to pay for it. I think investors are willing to take that risk."

That playbook is taken from the refining and tobacco industries, which each faced terminal value headwinds in the past. In response, both shifted from growth to value with a 10-year payback and were able to outperform the market.

The way we pay

The topic of executive compensation is a sore spot with investors who were burned while management reaped rewards. "The shale boom of the past decade has been a fantastic phenomenon for the U.S. as a whole and has helped keep a lid on global oil prices, but to many outside observers looking in, it seems like the only folks that made any money during the boom were management teams," said Johnston.

Management compensation has remained high regardless of share price performance and incentive plans have been skewed, he said. "Investors lost money while management teams made money. There's been a lot of frustration about management compensation, especially in the last five years."

E&Ps suffer from a clear misalignment of management incentives, said Viviano. "Management teams seem to find a way to get paid no matter what the shareholder experience looks like. We're a big believer that all long-term compensation should be tied to performance."

Earlier this summer, Morgan Stanley conducted a survey on E&P executive compensation, which revealed that 80% of the industry still has a heavy weighting toward growth in their executive incentive plans. "In a world that doesn't need more oil, having volume growth in management compensation is not something investors are looking for," McDermott said.

Instead, investors want management incentives tied to shareholder return and capital efficiency metrics.

Investors are fed up with executive compensation untethered to total shareholder return, Scialla said. Executives receiving exorbitant bonuses in years where their stock gets cut by half, for example, puts a black eye on the industry. "That just can't happen. That's hard to overcome."

Ultimately, it's a trust factor. "Investors don't have a problem with management teams making a lot of money. They should—they're under tremendous pressure. But they should make money when investors make money, and that's why management compensation has to be tied to total shareholder return."

The fundamental problem is E&P executive performance is measured against a narrow band of peers that make up less than 5% of the global oil and gas market, said Viviano. "That just doesn't provide the right incentive to radically evolve the business model. It creates this herd mentality where they all act in tandem."

Peer groups instead should reflect the broader energy market. "The idea is you're not just competing for capital against other E&Ps. You're competing for relevance across the broader sector."

Jaffee concurred. "They have to think about not just their total shareholder return among other energy peers, but among other choices investors can make, whether it's technology, industrials or utilities. Investors don't have to invest in energy." Good governance is incumbent upon management to think about their shareholders, she said, and "the E&P companies just have not done a good job of that."

Johnston noted that some companies are beginning to include total return metrics in their executive comp incentives, such as absolute share price performance.

"That's obviously shareholder friendly, as it ties a component of executive compensation directly to share price."

As compensation plans continue to shift away from growth-based metrics and toward share price performance and other metrics like free cash flow, cash-flow-per-debt-adjusted share and return on invested capital, the change could go a long way in terms of attracting institutional investors back to the sector.

The call to consolidate

To investors on the outside of the sector looking in, the industry remains very fragmented. Size matters, as does cost efficiency. Small companies unnecessarily burn capital through G&A and cost of capital.

For companies that fall below $1 billion in market capitalization, it is increasingly difficult to attract capital, said Morgan Stanley's McDermott. "Liquidity is not there, and the stocks tend to be more volatile. Generally speaking, the smaller producers are taking overhead costs and spreading them over a smaller resource base. They tend to be higher cost structure companies."

Jaffee's interest starts at $1 billion, same as the Russell mid-cap index. "It would be rare to go outside that universe."

Scialla puts the line of demarcation at $2 billion. "Bigger is better these days. Management teams are getting the message that you've got to be a couple of billion before you're even going to be looked at. Even if you are high quality, these companies are feeling the pressure to get bigger as fast as they can to get on the radar screen of the generalist investors."

Shale is now a scale industry, according to Reynolds. Economies of scale and large swaths of contiguous acreage define the winners. "It's not about whether you're going to find the oil; it's about how much you can find and how

TCW Group portfolio manager Diane Jaffee said E&Ps "for the most part haven't refocused on total shareholder return, and that's why we have shied away."

Facing page, a woman enjoys the simple pleasure of feeding an eager flock of pigeons on the crowded sidewalks of Manhattan.

Mark Viviano, head of public equities at Kimmeridge Energy, is raising capital to reform E&Ps as an activist investor. "Management teams seem to find a way to get paid no matter what the shareholder experience looks like. We're a big believer that all long-term compensation should be tied to performance."

cheaply you can get it out of the ground, and that demands scale. It's a completely different mindset than the early days of shale.

"You have to be behemoths in this space to actually make money doing it."

That's bad news for SMID-cap public companies, which played a critical role in the acreage acquisition and delineation phase of shale.

"How do we get broad-scale investors back into the space? I don't think it's with a bunch of small guys scrambling around putting something creative together. It's in the established players that have scale and the capability of squeezing value out of the acreage they own."

And the way to compete for that capital is through consolidation.

"If you want to attract sizable, large institutional investors you need to have more liquidity and more market cap," McDermott said. And if growth isn't an option, consolidation is the alternative.

Consolidation doesn't necessarily have to be a big company buying a small one, he noted, as mergers of equals work well. "If you have geographic overlap, two relatively small companies combining into one larger one can drive that scale, can increase market cap, can boost free cash flow, can boost returns and allow you to have a competitive value proposition."

But even that tactic requires a low-premium merger of equals, which remains a stumbling block to executing these combinations. McDermott highlights the merger between D-J Basin neighbors PDC Energy and SRC Energy as a model for others. The $1.7 billion all-stock deal in 2019 reflected a 4% discount for SRC shareholders while creating the second-largest operator in the play. "Stocks traded up on the back of it, and we have a bigger, better scaled company now."

G&A reduction is a compelling reason to combine, Johnston stated. "Investors definitely want to see consolidation take place in the oil and gas patch. Too many companies are sub-scale, and there is too much overhead in the space."

In some cases, most G&A overhead costs of a company can be eliminated if it is acquired by another company, he claimed. Case in point: When Parsley Energy agreed to acquire Jagged Peak in late-2019, the targeted G&A savings that Parsley laid out to investors by 2021 amounted to roughly 85% of Jagged Peak's standalone G&A cost. "Getting rid of that overhead would go a long ways in terms of improving returns and free cash flow."

Although most everyone in the industry and investor-verse agree that no- to low-premium consolidation is necessary to drive value, yet the marriages simply aren't happening to any degree. Why? Because management teams are incentivized not to.

Most E&P management compensation structures today involve little stock ownership and fairly modest change of control payouts relative to annual compensation. The result? No-premium mergers simply mean the absorbed company walks away with no upside. And who wants to do that?

"That's one of the challenges," said McDermott. "Generally, compensation is not set up to incentivize those types of deals. While it might be in the best interest of shareholders, it's not necessarily in the best interest of management teams. And that disconnect between management incentives and what's best for shareholders is one of the investor frustrations with the industry today."

Change of control premiums in management compensation are a driver of consolidation. Those companies with above average change of control premiums tend to transact; those below average don't.

"All of them want to be the surviving entity, and nobody wants to relinquish the reins to let somebody else take over the company," said Scialla. External pressures, though, will probably drive consolidation to fruition, he said, particularly if oil prices don't surprise to the upside.

"It's going to force difficult decisions. They should band together. The alternative is to continue to work for a company where the stock price is less than a dollar, so it's the lesser of two evils."

Should smallish companies just hang on for better days? Better days won't change investors' minds this time, he surmises.

"The guys that are kicking the tires [of the sector] are not asking to give me your smallest company that has the most upside, or a company with a lot of leverage to boost returns. They're asking for the highest quality name that is not going to go bankrupt if things don't turn out the way we think they might."

Small publics have no choice but to consolidate, Reynolds believes. "There's very, very little public capital available to them." Yet egos and bloated compensation are keeping small companies from coming together, Reynolds stated. "Get your ego out of the way and don't pay yourself $3- to $10 million a year for nothing. Come up with something creative that you can consolidate around."

Taking emissions seriously

Environment, social and governance (ESG) was a big consideration among investors before E&Ps went into survival mode in March, and it remains so ongoing, said Johnston. "It's another headwind facing the sector and will continue to be important."

And traditional oil companies need to be particularly mindful of the "E" aspect, Van Eck's Reynolds said. Particularly emissions.

Although U.S. independents are struggling to retrofit their business models to total shareholder returns, they can't ignore ESG directives in the meantime, he said. "They've got to do both."

A large cohort of investors will never invest in fossil fuels, he admitted, but "that's OK. You're never going to satisfy them." The other 95% of investors, though, are going to want to invest and see commitments toward ESG principles. "We're one of them."

Foregoing ESG efforts by denying climate change science misses the point at the company's risk, he said. "It doesn't matter if climate change is true. The science doesn't matter; it's the perception. More and more people are demanding responsible investing, and you can't hide from it. So you either have to do it or be left behind."

Scialla said, "It's definitely one of the major criteria for new investors looking at the space. ESG is even more important for this industry than for others because it's a carbon emitting industry and they need to do everything they can to limit emissions as much as possible."

"We don't think investors should be totally void of energy names," Jaffee clarified the investor viewpoint. "We really don't. We do think that everything starts from the top, so if you have good governance, then other things like methane and carbon footprint will come to the forefront. So I really do believe that there is a place for energy in the portfolio, but I also think that smart companies are moving to a lower carbon footprint."

Acierno does not believe the push for ESG investment principles is a temporary fad. "I don't think it's going away. More and more investors are interested in the environment and see fossil fuels in the rearview mirror. We do think there's a place for us during whatever transition occurs. We just have to be good stewards of the environment."

She noted Cimarex is "laser focused" on reducing emissions, particularly around flaring, and executive compensation is partially tied to that. "We are committed to and are getting improvements."

Kimmeridge believes strongly E&Ps should be environmentally responsible and has published a white paper on its website spelling out just how that should look. With the world more and more focused on sustainability, oil and gas companies run the risk of seeing continued exodus from the space. But Viviano also thinks engaging with industry rather than divesting is a better strategy to address environmental deficiencies.

"The industry needs to align its environmental footprint with the Paris agreement," he said. "which is to see dramatic reductions in greenhouse gas emissions over the next 20 to 30 years. Companies need to set long-term targets on environmental performance to align with that, because that's the only way you're going to bring investors back into the sector."

Living for another day

Forced by black swan circumstances, many E&Ps are in the process of retooling their corporate structures to better align with shareholder interests, while many others have yet to pivot or are stranded without capital or scale. The unspoken variable is whether management teams will hold the line on capital discipline and the promise to return cash to shareholders once prices rebound, or will higher prices be like giving a drink to a drunk?

Scialla is understandably hesitant to say it's different this time, as E&Ps have chased every upcycle in history with new growth, "but it really does feel like it's different. I don't think we're going back to the old ways."

Investors have been burned too many times and the cycles are shorter to where, if oil spikes to $60, investors won't chase companies spending more than their cash flow to generate growth, he said. "These management teams have to take a look at how we survive in this new world. How do we attract the types of investors that should move into this space?"

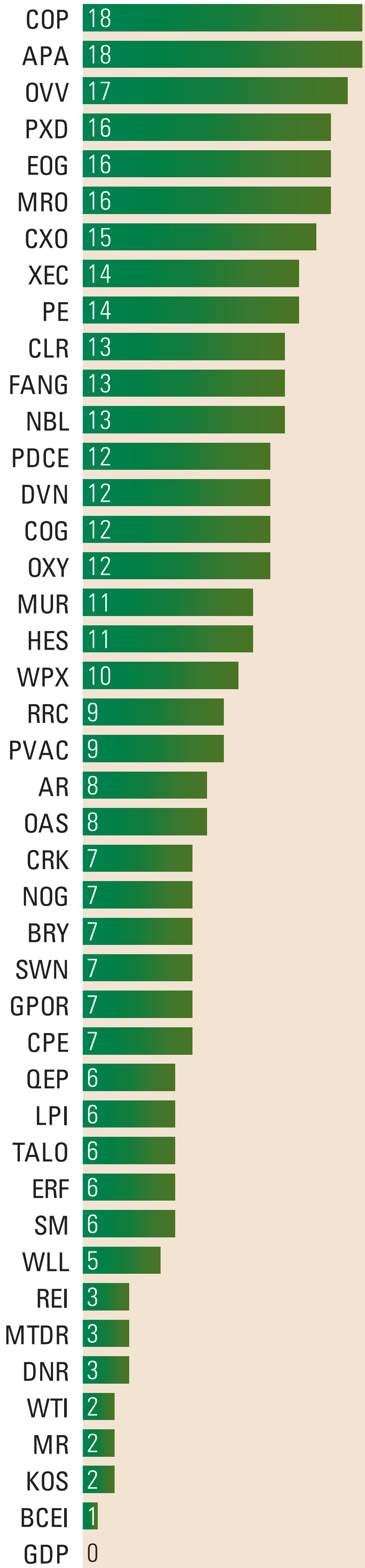
Asked when investors might engage with E&Ps again and reflate the stocks, Jaffee balked. She wasn't committal for five years as an outlier, but she acquiesced, "I don't believe it's never." The investments, she said, have to be less commodity sensitive to investors. "They are less willing to play the commodity game through their stocks. If they want to do that, they can do it through a hedge fund or private equity."

Rather, investors want disciplined management focused on total shareholder return measured against all sectors.

"We would need to see a longer track record on that. That's why we shied away. We need at least a few quarters of them really thinking about constraining their growth and thinking about total shareholder return. Conoco did it; others have been lagging."

And before Jaffee ponders E&Ps again, she's waiting for the test. "It would be intriguing to see, when commodity prices go up again, whether they stick to the disciplines they embraced when commodity prices were down. We have to see management walk the walk. We would definitely be intrigued by that." ☐

Executive Compensation Scorecard



Source: Capital One Securities

Capital One ranked 2019 executive compensation for covered E&Ps against four metrics: as % of market cap; 2020 unhedged EBITDA; cash comp as % of total comp; and per boe. A point system was assigned to each metric with the highest overall score being the highest-ranked companies. Report published Jul. 2, 2020.

HAYNESVILLE & FLUSH

Castleton Resources LLC is now the U.S. E&P consolidation platform of investment-grade Tokyo Gas Co. Ltd.

INTERVIEW BY
NISSA DARBONNE

Haynesville- and Cotton Valley-focused Castleton Resources LLC, one of U.S. shale's headline-makers this past year, hasn't had a rig drilling for it in two years. "[Acquisitions have] been a better use of capital by a factor of two," said Craig Jarchow, president and CEO of the Houston-based producer.

In December, it bought Shell Oil Co.'s Haynesville position for an undisclosed sum. In August, it picked up the legendary Terryville Field in north-central Louisiana for $245 million from Range Resources Corp.

Also in August, minority owner Tokyo Gas America Ltd., a subsidiary of Japan's largest gas utility, Tokyo Gas Co. Ltd., upped its stake from 46% to 70% from Castleton Commodities International LLC (CCI), the international energy trader that formed the E&P in May of 2017.

Castleton Resources, which will be renamed TG Natural Resources LLC, now owns more than 315,000 net acres in East Texas and North Louisiana, producing nearly 500 MMcfe/d net.

Using TG Natural Resources as its base, Tokyo Gas "will continue to aim for further business expansion in East Texas and Louisiana," Kazuya Kurimoto, president and CEO of Tokyo Gas America, said in a press release.

Oil and Gas Investor *visited with Jarchow shortly after closing the Tokyo Gas deal and after a hurricane ripped through western Louisiana.*

"The hurricane literally passed right above the Terryville assets," he said. "We had some trees down, but the power outages were temporary. Only a small amount of production was offline temporarily, so we really dodged a bullet."

Jarchow began his career as a geologist and geophysicist, including for Amoco Corp. and Apache Corp., and joined energy private-equity firms First Reserve Corp. and Pine Brook Road Partners.

The plans for TG Natural Resources are to keep consolidating as long as the numbers work. It may lead to an IPO.

"The challenge you have as a small company is in being heard by the people who discriminate among operators—so you're not just another Haynesville or Bakken or Permian player and no different than anyone else."

Investor What's the walking rig in the room that no one is talking enough about?

Jarchow I'm sure you're hearing about it too: Capital is fleeing the upstream sector. I think this is why Range and Shell went with us: They viewed the financial risk of Castleton closing as being lower. In both cases, financing was a nonissue.

With some of these recent bankruptcies, the commercial banks are being impaired substantially. It used to be that the first-lien, reserve-based loans were almost never impaired in a bankruptcy. They are now. This is causing a number of banks to get out of this business.

We in the upstream business need to rethink how we're financing our operations. The cost of capital is going up. There won't be access to nearly as much first-lien, revolving credit facilities—very cheap debt—from commercial banks because they're leaving.

The anchor-tenant banks will still be around, but these facilities are going to be smaller, and we're going to have to be more creative with the other parts of our balance sheet. In my mind, that's one of the biggest—if not *the* biggest—challenges that we face as an industry in the next six to 12 months.

Investor In past cycles, such as after the 1980s, the commercial banks eventually reappeared. Will that happen here too?

Jarchow In time, some of them will be back. Some of them may never be back. Some have said, "We want to get out of fossil fuels altogether."

I don't think that that's going to be a fleeting policy on their part. No matter what you think about that decision, I don't think it's something you reverse easily. So getting out for those reasons—no fossil fuels, no fracking—they may never come back.

Investor Reading oil and gas-operators' 8-Ks, there seems sometimes to be 861 nanocap E&Ps out there. Will they go away?

Jarchow It's more difficult to be a very small public company now. Capital is fleeing this business. But the other thing that's going on is all of this algorithmic trading—a huge percentage on any one day is algorithmic, essentially driven by computer programs or index funds or ETFs.

The active investors are playing a smaller role, and these are the people who roll up their sleeves and meet with management teams and study plays, and they're the ones through which other companies are differentiated in the market's mind.

The challenge you have as a small company is in being heard by the people who discriminate among operators—so you're not just another Haynesville or Bakken or Permian player and no different than anyone else.

You need to be a certain size to get the attention of active investors. And that size is much bigger than it used to be because of all the automatic trading.

Investor What do you think the minimum size is now?

Jarchow It's hard to say. I'm certain it's not a $50 million market cap, that's for sure. It's a lot bigger than that.

Investor There are fewer Haynesville operators—less than a dozen now. Where is this going?

Jarchow It's getting to be a shorter list. Natural gas is a bit better than it was, but it's still pretty low. And if you play your cards right, it's still a very good living, but it's not easy. And you name a basin in the U.S. and there are too many companies and there is too much G&A and not enough economy of scale. This is just a fact.

When we acquired the Shell assets, we literally added zero additional ongoing G&A. And, with the Range property, it will increase our production 60% and only increase our G&A 7%. That's the way consolidation should happen: We need to get our costs down.

"When we acquired the Shell assets, we literally added zero additional ongoing G&A. And, with the Range property, it will increase our production 60% and only increase our G&A 7%. That's the way consolidation should happen."

Here in the Haynesville, there are just too many companies, and they are largely private companies. And they're all pretty good companies. And we're all pursuing different strategies, succeeding to one extent or another.

Since a lot of these companies are owned by private equity, you would expect that at some point they would be consolidated or they would be consolidators. It's just a question of time.

So we will have fewer companies. The number keeps going down with each new deal, and that needs to happen—not only in our basin, but throughout North America; there's just too much cost in the system.

Investor Plans for going public?

Jarchow Well, we're trying to continue to grow. And one of the things about successful companies is they eventually outgrow their investors. That's one of the definitions of success. At some point, if you're a successful company, you have to continue to access capital in the form of equity capital.

We have a long way to go before we outgrow Tokyo Gas and CCI. But, if at some point we do, it's not a bad thing. It's a measure of success.

Any management team should be prepared to go public. Otherwise you're doing your investors a disservice. If you are unwilling to go public, you are cutting off an avenue for your investors to achieve liquidity, a lower cost of capital or multiple expansion.

If you're a successful company, you'll outgrow your investors. So, yes, we are prepared to go public. We have no plans to do that anytime soon—just because, well, we haven't outgrown our investors yet.

Investor How did you come to pick natgas as your weighting and in the East Texas Basin?

Jarchow It all began with CCI, our parent company. They're big traders in a lot of commodities but particularly in natural gas. There was a view that this would be an advantaged location.

Tokyo Gas is our other big owner. They're the majority owner now. And they're very interested in natural gas. That's their focus.

So we have two owners that are very familiar with the natural gas market and felt that being long in this location was a good match with the rest of their portfolio because they have offsetting positions elsewhere.

"One of the things about successful companies is they eventually outgrow their investors. That's one of the definitions of success. At some point, if you're a successful company, you have to continue to access capital in the form of equity capital."

Investor Tokyo Gas and Osaka [Gas USA Corp., now a majority owner in neighbor Sabine Oil & Gas Corp.] both took several years to choose and raise their stakes in the Haynesville.

Jarchow They're very sophisticated investors. These are world-class companies. Whatever they invest, they are pretty careful about it. They think it through. They dip their toe in the water initially. They look for good partners, and when something is working, they grow that.

That's Tokyo Gas' approach to us. They originally invested in our company in May of 2017. They have been a part of our board. The familiarity, the trust, the business relationship, the partnership—not only with management, but also between CCI and Tokyo Gas—that's all been built over time.

Investor Natgas was unloved at the time you picked the Haynesville. Did that help? You were getting things a lot cheaper.

Jarchow That's been part of our thinking. This is a cyclical business—oil and gas. Things go in and out of favor. Natural gas has been out of favor for a long time. So we have been able to seize the opportunity from that. Part of what it takes to succeed in this business is contrarian investment that ultimately works out and being able to stay in the game when commodity prices are very low.

It's not so easy to buy low and sell high. The problem is that, when commodity prices are low, nobody has any money. The capital retreats. So buying low is hard.

But we've been able to do the Terryville deal with Range. And we're very pleased with what we got.

Investor Is it the Cotton Valley over there?

Jarchow There are other payzones, but it's really a Cotton Valley story. Terryville's reason for being is a very big fault in the subsurface. It looks like a crescent pointing north. And these Cotton Valley sands are truncated against the fault.

Some of the Cotton Valley zones are overpressured, and there are some very favorable reservoir conditions in and around that fault that made Terryville Field what it is today. It's a Cotton Valley story.

Investor When will you pick up a rig again?

Jarchow Our thinking two years ago, when looking at acquisitions and at the numbers, was that acquisitions were a better use of capital than drilling and completions. It's not that we don't have economic Haynesville locations; we have lots of them. It's not that we don't have lots of other projects we can do. We just feel it is a better use of our capital.

Sometimes we forget in this industry that our business is about allocating capital. Sometimes that means drilling and completing wells. We've been focused on business development and acquisitions.

And at the end of last year, we acquired the Shell Haynesville assets. And then we just followed with Terryville. In both cases, if you look at how much we paid per proved Mcfe, we paid less than what it would cost us to find it with the drillbit. So this use of capital indeed proved to be the most effective.

Investor Does having Tokyo Gas' and CCI's credit standing help win deals?

Jarchow I think that's why both Shell and Range decided to engage with us on these acquisitions. They, first of all, view us as closers—that we would close the deal that we started. And they viewed the financing risk as much lower, just because we have such substantial partners in Tokyo Gas and CCI.

Investor Associated-gas production is down in oil basins, and LNG exports are picking back up. What might natgas prices look like this winter?

Jarchow It's going to be very interesting in the next 12 months. Some respected analysts are saying prices will be at or above $3 toward maybe the second half of next year and that we might even be challenging $4.

I wish this proves to be true. But we never count on it. Gas is about $2.50 now [in early September,] and that's fine with us. If it goes up, we'll be very happy, but we by no means require it. Our business is very strong financially. We can make a very good living at current low gas prices.

And that's how we in the Haynesville and other gas producers think about our businesses: "The analysts think it's going to go up a bit, and that's nice, but let's not count on it." And we certainly aren't.

But you're right about the LNG facilities and the associated gas. In the near term, hopefully it will be a nice opportunity for us to make a little bit more money.

Invesor Castleton's owners are gas traders, so you're likely hedged.

Jarchow Yes, yes. We are.

Investor You're not drilling or completing right now, so lower OFS costs aren't coming your way?

Jarchow Right. Costs are down. But these prices won't go on forever because these service firms are just trying to keep the lights on right now and equipment wears out, so it won't last forever.

We'll start to see capital charges for upgrading and maintaining equipment that we're really not paying right now.

We still are drilling and completing wells in our nonoperated positions with other operators, and we get the AFEs. So we pretty well know what's going on from a price perspective.

But, right: We currently have no rigs running, and it's not because we don't have good locations. We do. It's just that acquisitions are a better use of capital right now. ☐

HIGHER NATURAL GAS PRICES LIFT PRODUCERS' SPIRITS

DUG Haynesville virtual program offers well-timed insights

Natural gas producers along the Texas-Louisiana border will play leading roles in the upstream sector's recovery from the depths of its 2020 market disruptions. That positive news ranks as a key takeaway from the FundamentalEdge report published Sept. 9 by data services leader Enverus.

Producers nationwide dramatically trimmed 2020 spending plans as commodity prices fell alongside dropping demand, one notable result of the COVID-19 pandemic. Rig activity was cut and production declined nationwide as oversupply overtook the market, particularly in oil-directed plays. In turn, associated gas production dropped – and the so-called "dry gas plays" made up the difference as natural gas prices rose to multi-year highs this summer.

"For all that happened to oil, to some degree the inverse is true for natural gas," said Rob McBride, senior director of strategic analytics at Enverus. "Natural gas is well poised for the near future. Since the historic crash a few months ago, gas has slowly crept up, but drilling rigs haven't yet followed suit."

While crude oil demand cratered with the "double black swan" of a Saudi-Russian crude oil "price war" and coronavirus shutdowns, gas-reliant industries like heating and power weathered much better.

Timely updates from leading players

Now Enverus projects dry natural gas production in the Haynesville to grow by 5 Bcf/d over the next five years – and the annual **DUG *Haynesville* conference** provides the perfect opportunity to get firsthand updates on what's happening and what's coming for this productive region.

A "frac-side chat" with **John D. Jacobi**, CEO & president of **Javelin Energy Partners** and co-founder of **Covey Park Energy**, promises to provide unique perspectives on the Haynesville play's past and future prospects. Registrants also will hear C-level executives from leading Haynesville producers like **Goodrich Petroleum**, **Aethon Energy** and **Rockcliff Energy**, as well as Ark-La-Tex players like **Castleton Resources**, **New Century Exploration**, **Sabine Oil & Gas**, and **Velandera Energy Partners**.

"For all that happened to oil, to some degree, the inverse is true for natural gas. Natural gas is well poised for the near future."

Originally set as an in-person conference and exhibition, the event became another pandemic casualty due to the state's social distancing restrictions. Now the show will go on(line) **October 28** in virtual format. Online registration takes only a minute or two at dughaynesville.com. Best of all, registration is available at no cost thanks to generous support from Hart Energy's sponsors. □

MIDCONTINENT AGGREGATOR

Led by industry icon Tom Ward, Mach Resources this year bagged the vast portfolio of Alta Mesa Resources out of bankruptcy and for a song. His premise: Prepare to be the last owner of any asset acquired. And he's far from done.

ARTICLE BY
DARREN BARBEE

April 2020 came and went, but there was something familiar about the times, something anachronistic about Mach Resources LLC's purchase of Alta Mesa Resources. It was déjà vu all over again for an industry stuck on repeat.

At least, that's how it felt for Tom L. Ward.

Alta Mesa was once expected to have a market capitalization of $3.8 billion. The company's worth never approached half that amount. It ended its public run with a value, as adjudged by Wall Street, of just under $27 million.

In the spring, Alta Mesa signed away its Midcontinent leases and midstream infrastructure for $220 million, ending the company's brief rise and tortured fall through bankruptcy.

Mach Resources was the only serious bidder likely because it's one of the few companies with the capital and the appetite to take on the Oklahoma assets. But this is a scenario made by design. Ward's game plan, hatched two years ago, was to make Mach Resources an acquirer of distressed and overlooked assets.

Assessing the downturn, Tom Ward, CEO of Mach Resources LLC, said "We're in a time period that you need to be prepared to own these assets. And own them through depletion."

Ward doesn't fault Alta Mesa's management team for its financial woes. The company had been run by the highly respected CEO Jim Hackett, who previously headed Anadarko Petroleum Corp. Alta Mesa's troubles are part of a larger, universal ailment afflicting the industry, Ward said.

For the last decade or perhaps two, oil and gas companies have consistently lost money and, as an industry, "We've tended to over promise and under deliver," he said.

Ward's been talking about the gap in returns since 2015. In a May 2016 interview on CNBC's Squawk on the Street, Ward was already convinced the industry model was off kilter, saying the industry's "dirty little secret is you can't really spend within cash flow and grow production."

"I don't necessarily think there's anything that the [Alta Mesa] management team did wrong as much as that there's been capital fleeing the industry for the last year or so," he said. "And it's getting more difficult to raise capital. That was pre-pandemic and price war, post-pandemic it became nearly impossible."

Industry commentators often compare today's COVID ravaged market to the disastrous oil glut of the 1980s, particularly 1987. Ward sees it more as a reflection of the oil and gas industry when he and Aubrey McClendon, who co-founded Chesapeake Energy Corp. on a handshake, began making deals in the 1990s.

Those times were filled with heartbreak but also rife with opportunity.

"And I think this is similar to 1998 when we were at Chesapeake and we were starting a growth," Ward said. "What we're doing today is very motivating to me. We are trying to thrive at a time when the industry is collapsing all around us."

In 1998, the collision of several events sent oil and gas prices into a tailspin. Warmer than expected weather, an increase in OPEC oil quotas and a financial crisis in Asian markets sent oil prices to lows of about $10/bbl, according to the Dallas Federal Reserve Bank. Worldwide, planned engineering and industrial construction projects were canceled.

"Chesapeake at that time had raised some capital, and we were able to go buy some properties," Ward said. "We had an idea that future prices couldn't stay as low as they were because nobody had any money to drill. We also had a firm belief that natural gas prices could not stay at those prices because of new demand. This is very close to the way we see the industry today."

Two decades later, the world has changed, but the strategy remains sound. Ward has capital with his partners at Bayou City Energy. And he has long rejected the idea of building new companies focused on growth.

"I've been very hesitant to invest capital into a growth through the drill bit company. That's why we never competed really in the STACK or SCOOP or Permian or any of the highly competitive locations as other companies were doing," he said. "This was not because there weren't good places to drill. However, the cost of entry was too high."

William McMullen, Bayou City Energy's founder and managing partner, said Ward's philosophical approach meshed well with Bayou City's objective to put economics first ahead of the rock. "Good rocks do not necessarily make for good investments." Since 2018, the Houston private-equity firm and partner Mach Resources have set out to consolidate.

"There are too many E&P companies, and Tom and I have really set out to roll up the Anadarko Basin. That consolidation is our focus. We are big believers in scale in this market."

Mach Resources isn't running many rigs, instead operating "as cheaply as possible" by purchasing leasehold and infrastructure along with the reserves at significant discounts.

"I think at most we ran two or three rigs across half a million acres that we control in Oklahoma now," he said.

Mach Resources instead operates owned compression and saltwater disposal systems as well as a power grid.

"That allows us to produce oil and gas as low-cost as we possibly can," he said.

Ward believes that within the next few years, prices will begin to adjust. Even if that does not happen, Ward is making deals that he believes are profitable enough they will ensure investors, capital providers and Mach Resources will earn returns.

"That's my goal, to make sure that we do our job so that other capital providers who have trusted us will make exceptional returns."

It's a tall order for any company to make such assurances. But Ward set out, far before the pandemic, to capitalize on opportunities within the upstream space.

It was a journey that began in Oklahoma, of course, where Ward was born and helped usher three previous companies into existence. By a quirk of the calendar, Mach Resources made its first Midcontinent acquisition in 2018. Within months, Alta Mesa would write down its own assets by $2 billion.

Midcon recon

After 40 years in the oil and gas industry, Ward has witnessed some wild cycles.

"The entire energy complex is going through a very difficult period of time, and the Midcontinent region is more challenged than others," Ward said.

It's also the sort of era that Mach Resources was built for. The company was designed to acquire distressed assets in the Midcontinent, to run lean and deliver free cash flow. The pandemic has only aggravated the symptoms that companies there have been struggling with for years.

"We find ourselves in a niche position to offer something that others really can't provide right now," he said. "The basic fact is there has to be a fundamental shift in how our industry operates and manages cash flow.

"Outside of large public companies, there's little access to capital, widening debt to EBITDA ratios and a banking industry that wants out of the business.

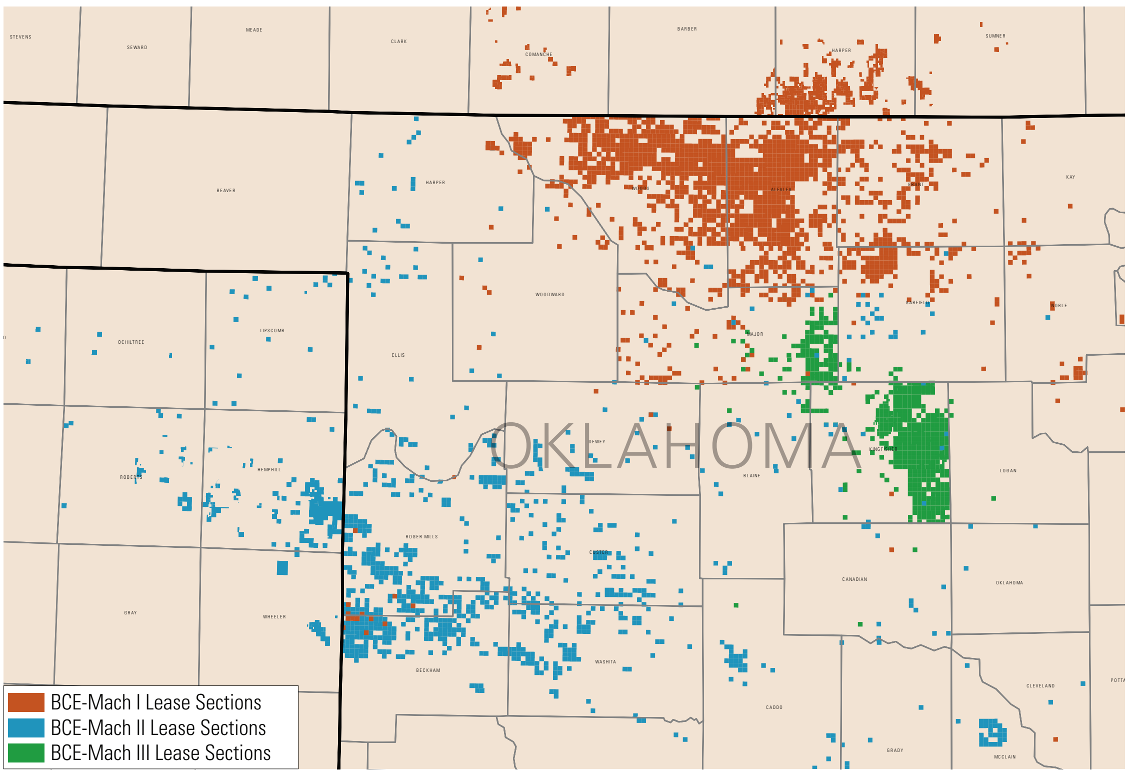
"All of those things added together signal that there has to be a change. And that's what we bring. We focus on being efficient."

Ward wanted to create a company that would roll out cash while remaining ultra-efficient. Mach Resources employs what Ward calls his "SWAT team" of personnel who oversee 2,500 operated wells and interests in 5,500 wells.

"We oversee our business with 90 corporate employees and $18 million in G&A," Ward said. With each acquisition, whether its 100 wells or 300, the goal is to hold overhead steady.

Alta Mesa's G&A costs were roughly $40 million when Mach Resources purchased the

BCE-Mach Asset Overview



Source: Mach Resources

In April 2020, Mach Resources' footprint ballooned to 500,000 net acres following the acquisition of Alta Mesa's 130,000 net acre position and its Kingfisher Midstream infrastructure.

ROAD OF HUMILITY

Whether he would consciously admit it or not, Ward is, and remains, a pioneer of the Oklahoma oil and gas story and the shale revolution.

Ward said he started out just wanting a job. In 1982, Ward was unemployed for a couple of months and did farm work for a family outside of Clinton, Okla., working in the fields.

"I really didn't care to cut wheat the rest of my life," Ward said.

With help from investors, he started an oil and gas business in 1982 to buy distressed assets. His premise: In a time of no capital, a little bit of money and an idea can be a powerful combination.

"You can make a way. You can make a living. That's all I was trying to do, was make a living," he said.

Ward said he never anticipated doing any of the things he's accomplished.

"There's nothing really special about me. Other than I associate myself with very smart, good people," he said.

About that time, he met a man named Aubrey McClendon, who had hit upon the same strategy of buying distressed oil and gas assets inexpensively.

"We were the only two at our age group … and we were competing with each other," he said.

So the two decided to team up, later forming Chesapeake Energy Corp.

More than four years after McClendon's death, Ward sees his friend as a visionary that has been wrongly vilified, particularly in the press.

"I don't think he gets enough credit for leaving a company that had $35 billion worth of enterprise value when he left. And we started it with a meager amount," Ward said. "He did more things for our industry than anyone else in history, that I know of."

Ward's assessment of his own legacy is free of any superlatives.

"I have never really dwelt on legacy. If the company continues to operate on what we call the 'road of humility,' where we put the good of one another ahead of self-interest, commit to making things better than the day before, learn to be content in all situations and serve those that are less fortunate we can look back at what we have accomplished and be pleased."

Mach Resources' Alta Mesa Acquisition

Net acreage	130,000
Operated wells	900
Production (boe/d)	30,000
Reserves (MMboe/d)	72
Midstream pipeline (miles)	453
Gas processing capacity (MMcf/d)	350
Produced water capacity (bbl/d)	157,000
Water disposal pipeline (miles)	224
Legal adviser	Kirkland & Ellis LLP
Financial Adviser	UBS Securities LLC

Source: Mach Resources

company in April and more than $55 million in 2019.

"That has been reduced by basically 10 times just by moving [it] into our organization," Ward said. "By operating on a large scale we are able to reach our goal of making distributions, paying down debt and maintaining positive cash flow."

It's part of the reason the company stays in the Midcontinent. It's also where Ward has maintained a presence. He knows the towns, the land and the geology. He knows Oklahoma, where he grew up in the small town of Seiling, went to college, met his wife and built billion-dollar companies.

A lifetime of insider knowledge was put to bear in Mach Resources' first acquisition—a deal that closed in April 2018 with Ward's former company, Chesapeake Energy.

Most of the leases Mach purchased from Chesapeake were acquired after he had left the company to start SandRidge Energy and later Tapstone Energy. Ward was with Chesapeake when the company began buying in parts of Woods, Woodward and Major counties in the Chester Formation from 1998 through 2006.

"The Miss Lime basically was developed after I left Chesapeake because the formation has a much higher water content," Ward said. "And so really the idea around the Miss Lime was to develop that high water cut well at a time when energy prices were much higher. And so that's what we did at SandRidge and what Chesapeake did."

Ward said he's comfortable with the oil play, which stretches from northern Oklahoma into Kansas and was present at the inception of horizontal drilling there.

Part of the allure of acquiring Chesapeake's Mississippi Lime position in 2018, however, came from its readymade infrastructure.

"You have the infrastructure in place with the Chesapeake assets we were able to acquire," Ward said. That included 500,000 bbl/d of disposal capacity.

"We don't use all of that, even today," he said.

Mach also hasn't had to drill any new disposal wells and was able to put rigs to work in the play.

"It's been a very efficient use of capital for us, to own not only the Chesapeake asset but also a couple of other assets that we purchased after that, in the Miss Lime," he said.

Six acquisitions later, Alta Mesa offered a similar bounty. Amid bankruptcy, Alta Mesa produced 30,000 boe/d, of which 67% was liquids. Alta Mesa also controlled 900 operated wells and 130,000 net acres, with about 90% HPB.

A price drop due to falling oil prices amid a pandemic and oil price war was a bonus. Initially, Mach Resources bid $320 million for Alta Mesa's assets. After prices dropped, Mach walked away with the company for $100 million less.

Including Alta Mesa's acreage tucked into Mach Resources, the company has built a 500,000 net acre Midcontinent position in two years, through seven acquisitions.

More significantly, the Alta Mesa deal gave Mach Resources control of Kingfisher Midstream's (KFM) sprawling infrastructure, including 453 miles of gas gathering pipeline, 108 miles of oil pipeline and gas processing capacity of 350 MMcf/d.

"That gives us a leg up on competition," Ward said. "The Alta Mesa acquisition was a very efficient use of capital, and the KFM midstream system was a giant windfall for us. Much like the use of the water disposal system in our first acquisition, the midstream system allows us to minimize our expenses to create value."

“We find ourselves in a niche position to offer something that others really can’t provide right now. The basic fact is there has to be a fundamental shift in how our industry operates and manages cash flow.

—Tom Ward, Mach Resources

McMullen also views the Alta Mesa deal as a bargain, though the purchase was negotiated at a difficult time for WTI. A week and a half after closing the deal, oil prices sank into negative territory at about negative-$37/bbl.

“There was certainly some anxiety on our part,” McMullen said. “Our bet was simply that at $30 to $40 oil [prices], you can [generate] free cash flow … of close to $10 million a month because of the integration of the upstream and the midstream we purchased.”

Invisible upside

For all the deals Mach Resources has made, the company sticks to some basic rules of thumb. Chief among them is that assets must be purchased for a price that allows the company to make decent rates of return off production—without upside.

Cash has to roll off and back to the company and the investor.

McMullen said Mach Resources and Bayou City have been disciplined deal makers for roughly three years, carefully underwriting acquisitions to capitalize on new assets.

“We have very low leverage across our assets,” McMullen said, adding he expects to have net zero debt by the end of the year on the recently purchased AMR assets.

“There are a lot of distressed operators out there, and we want to be nimble and move quickly on those opportunities,” McMullen said.

Disregarding future growth forces the company to game out how deals will pay for themselves.

“We have always had a model of making distributions. We have cash on cash returns after debt service after capex, and we make distributions to our investor,” Ward said. “But the only way to do that is to buy at a price that only values the reserves that are producing.”

Drilling isn’t out of the question, if it can be done at a discount. Alta Mesa’s assets include what Ward described as a large area that hasn’t been depleted. The company had two rigs running consistently until February, when prices dropped.

Significant well results aren’t the company’s aim, however. The company instead touts the 40% reduction in drilling and completion costs from early 2019 to early 2020.

Mach has completed two DUCs and has a few more in its inventory it may experiment with. But for now, the company has paused further drilling to focus on expansion through acquisition.

At higher prices, Mach Resources might put out a rig, but it will be stingy with any capex. The company may put one or two rigs back to work next year. But Ward reiterates that growth is not the answer to the industry’s current misery.

“We’ll be working in very highly selective areas that we don’t feel will have the competition or depletion from other areas,” he said.

William McMullen, founder and managing partner of Bayou City Energy, said the present number of distressed operators presents opportunities for Mach Resources’ nimble acquisition strategy.

MACH RESOURCES

Along with a significant acreage position, the Mach Resources-Alta Mesa deal provided Mach with control over Kingfisher Midsteam’s gathering and processing infrastructure.

Ward does see an eventual rebalancing of the oil and gas markets. While he believes the industry needs $50 oil to survive, he doubts investors will return until prices rise substantially. However, factoring in OPEC, world demand and other areas makes the calculation difficult. An easier equation is to solve for natural gas.

Ward has previously been critical of moves made by Chesapeake into the Haynesville Shale. And the commodity has been the bane of many producers. But the numbers are hard to ignore.

In 2010, the U.S. produced 55 Bcf/d of natural gas. Today, natural gas production is down slightly to 89 Bcf/d after peaking last year at 92.21 Bcf/d, according to the U.S. Energy Information Administration (EIA). EIA projects that in 2021, production will fall to 86.59 Bcf/d.

"Gas has been a hated asset for more than a decade," Ward said. But over the next five years, demand for natural gas will rise somewhere between 10 Bcf/d and 15 Bcf/d.

"We're really losing about a Bcf a day per month, and our demand continues to move up," Ward said.

Even adding 200 more rigs in the Permian, a doubling of Haynesville rigs and a doubling of the Northeast rigs by 2021, Ward said the U.S. might maintain production in the 80 Bcf/d to 83 Bcf/d range.

"I don't know how and where you are going to find that capital today," he said. "It's just a very interesting time to be looking at natural gas."

Mach Resources commodity of choice remains oil. But the company's Midcontinent assets necessarily mean a lot of gas production. The company averages 58,000 boe/d of production, including roughly 30% oil and 30% natural gas.

Ward also expects Mach Resources to continue to acquire assets largely by searching for the best pieces among the wreckage of the oil and gas industry.

"Ultimately what you're seeing is that in each deal that we've looked at, there's been billions of dollars [in value] wiped away," Ward said. "The equity is obviously gone. The second liens are basically gone. The companies are moving toward bankruptcy, and there has to be some type of consolidation or sale."

For Mach Resources, each deal is examined through in the same strategic light: that the company will operate them "as if it will be the last owner."

"I do believe good can come out of this. New investors can come," he said. "We're in a time period that you need to be prepared to own these assets. And own them through depletion." □

Mach Resources' April 2020 acquisition of Alta Mesa Resources exhibits the company's acquisition strategy in action.

MACH RESOURCES

A CSI ON WTI

Nymex paper-trading of WTI normally represents the spot price. On April 20, the paper was worth less than zero.

ARTICLE BY
NISSA DARBONNE

ILLUSTRATION BY
ROBERT D. AVILA

A numismatist walks into Nymex and buys 10 contracts—each for 1,000 barrels—for May delivery of WTI to Cushing. At settlement on April 20, it loses $92,490.

Okay, futures aren't bought by actually walking into Nymex. But Robert Mish and his firm—he's president; Susan Mish is office manager—are among the many who lost that day when holding contracts for May delivery of WTI.

One trader reported being unable to sell his contracts—the brokerage app couldn't comprehend a sub-$0 trade.

Harold Hamm, founder of Continental Resources Inc., estimates producers alone lost $500 million, factoring for the "calendar month average" used in their contracts. The month's average fell $3/bbl.

Bloomberg and other media estimate traders lost $500 million.

Looking over Nymex trading activity for April 20 to April 21, the Mishes, who are coin dealers (physical, not Bit), found peculiar trading by London-based Vega Capital London Ltd.

Their firm, Menlo Park, Calif.-based Mish International Monetary Inc., filed a civil suit in federal court in Chicago—where Nymex owner CME Group is headquartered—in August against Vega and John Does 1-100, alleging a scheme to manipulate the WTI market.

The Mishes didn't name the other members of the class action, stating "the class is so numerous" it's impractical. The members are, essentially, everyone holding May WTI paper on April 20— that is, themselves "and all others similarly situated."

Except, of course, the defendants, they state.

'A lawful market'

Trading of WTI for May delivery closed on April 20 at a negative $37.63/bbl. The price had plummeted $58.17 during the day.

The Mishes allege Vega et al., beginning April 20 and into April 21, "acted to intentionally manipulate" the May contract price. On April 20, they "worked together to aggressively sell" May-delivery barrels to depress the price.

But why? Before April 20, Vega traders had purchased trading at settlement (TAS) contracts to buy the May oil at whatever the April 20 closing price would be.

"In other words, Defendant Vega had a large financial incentive for the May 2020 contract to trade and ultimately settle at the lowest possible price on April 20, 2020," the Mishes state.

In the last minutes of trading, the price declined more than $25 a barrel. Meanwhile, on April 21, the contract closed at $10.01/bbl—"a more than $47-a-barrel increase from" the Monday close.

They posited that, because of Vega et al., they "were deprived of a lawful market." Vega's sole director, Adrian Spires, et al. "intended to affect or acted recklessly with regards to affecting the [May contract price] and engaged in overt acts in furtherance of such intent."

They added that Vega's work "was spectacularly successful."

'A huge profit'

Except for an admin email address, Vega did not provide contact information at its website; there is only the message "Website Currently In Development." It did not respond to Investor's email request for an interview.

The Illinois court docket didn't show in early September any activity yet on the case since it was filed.

According to the Australian Financial Review (AFR), Spires went to work in 1994 after high school—Latymer Upper School on King Street along the Thames and tucked between Kensington Palace and Wimbledon.

His job was trading futures—back while it was still done as public outcry in pits—at the London International Financial Futures and Options Exchange (LIFFE). (LIFFE became part of Intercontinental Exchange ICE in 2014 and is now ICE Futures Europe.)

In 2016, Spires and a colleague he had met at a subsequent job at Tower Trading Group formed Vega. The partner, Tommy Gaunt, quit in 2019, according to AFR.

Vega didn't respond to AFR's emails for comment either. The journal added that the Vega "website has remained under construction since Vega was founded."

"Vega's selling collided with an exodus of buyers," AFR reported. "… Oil's dive into negative territory meant that Vega ended up being paid for many of the contracts it sold as the market was falling—and for all those it bought at the -US$37 settlement price via TAS, locking in a huge profit."

The windfall to Vega is unusual, AFR added: "In a trillion-dollar energy ecosystem dominated by the likes of BP [Plc], Glencore [Plc] and Royal Dutch Shell [Plc], prop firms [like Vega] are bit players."

'Teeth gnashing'

Leah McGrath Goodman wrote for Institutional Investor on May 6, "Inside the Biggest Oil Meltdown in History," that the first $0 trade was at 2:08 p.m. Eastern.

That was about the time oil producers based in Houston, Dallas, Oklahoma City, North Dakota and West Texas were wrapping up lunch.

In that minute, 83 contracts traded at $0, "touching off an unprecedented freefall into negative territory," she wrote.

"What took place instead [of a typical Nymex afternoon] was 20 minutes of unalloyed chaos, followed by another 24 hours of teeth gnashing, confusion and bewilderment as the market collapsed… ."

This had never happened "in a standardized, exchange-traded contract," she added, "let alone the most heavily traded benchmark crude oil contract in the world, representing the lifeblood of the world's industrialized nations."

"It usually takes a crisis to show the fundamental good or bad of a market. Certainly that [May contract] did," said Continental Resources Inc. CEO Harold Hamm.

Many Oil and Gas Investor sources had considered in early April—many had even expected—that May oil could trade at $0. None spoke aloud of the possibility of less than zero—as if speaking the words was akin to saying "Voldemort."

Goodman reported in early May, though, that energy economist Ed Morse, Citigroup's global head of commodities research, had said the words out loud in early April, projecting sub-$0 WTI trading was a possibility.

And CME Group itself provided notice to traders on April 8 that "if major energy prices continue to fall towards zero in the coming months," it wrote, it had a plan "to support the possibility" of sub-$0 trading to "enable markets to continue to function normally."

This plan CME had for handling sub-$0 trading was to allow the May WTI contract to fail, based on the April 8 statement. If WTI declined to average between $8 and $11, it would switch to the Bachelier model.

It usually uses the Geometric Brownian Motion and Black-Scholes models, each of which is derived from Louis Bachelier's "The Theory of Speculation" PhD thesis (1900).

An awkward description of the Bachelier model is "animal spirits on a random walk." Or "market-price changes gone wild." That was Nymex on April 20.

'The system failed'

Continental's Hamm wrote to the CFTC on April 21 that there wasn't anything normal about that plan. "Not only did WTI crude futures trade negative, they settled at a bizarre -$37.63." In effect, "The system failed."

(On April 8, CME had added in its statement that it would send one-day notice before implementing the Bachelier model. It gave that notice on April 21, stating it would go into effect at the close of trading April 22 "and will remain in place until further notice.")

In its April 8 notice, CME Group had emphasized—it used the all caps in "not"—that "negative strike prices will NOT be listed in any [WTI or other] energy markets until this model change is made per the plan above and may not occur even if the modelling changes do happen."

The plan it referenced as being "above" was that it would provide one-day notice of the model change.

Craig Pirrong, director, energy markets, at the University of Houston's Global Energy Management Institute, called the crisis of the May contract "one of the most epocal days in the history of oil trading."

'Somebody knew something'

Just before noon on April 20, CME Group reminded WTI traders that sub-$0 was a possibility. Well, that "sent the May contract plummeting to approximately $4 a barrel," Hamm wrote to the CFTC.

In the last 22 minutes of trading that day, the price fell nearly $40/bbl. In three minutes alone—from 1:24 p.m. to 1:27 p.m. CDT—it fell some $25.

Hamm wrote to the CFTC that the combination of the odd CME announcement the morning of April 20, the CME's "sudden change in computer models during a time of increased volatility" and the rapid price drop "strongly raises the suspicion of market manipulation or a flawed new computer model.

"The sanctity and trust in the oil- and all commodity-futures markets are at issue as the system failed miserably and an immediate investigation is requested and, we submit, is required," he concluded.

He told Investor in August, "Was there insider dealing? Somebody knew something that allowed them to create that [pricing failure]."

He welcomed the Mishes' lawsuit. "Seeing this play out, this is going to be a real eye opener into exactly what happened and how [Vega et al.] took that much money from U.S. producers in one day."

(Editor's note: In the interview, which is part of Hart Energy's DUG Midcontinent virtual-conference proceedings, Hamm stated "$500 billion." His office clarified to Investor that he meant $500 million.)

'Dysfunctional farmers market'

Hamm's use of "bizarre" isn't the first time that descriptive was attached to a Nymex event. Nymex itself was virtually destroyed in 1976 by the Great Potato Scandal. Goodman wrote a book about it, "The Asylum: The Renegades Who Hijacked the World's Oil Market" (2011).

Nymex didn't trade energy futures at the time. It traded butter, cheese, eggs and such, including potatoes.

The story is that McDonald's had picked Idaho potatoes for its fries and McDonald's was becoming a behemoth potato buyer. J.R. Simplot was the "Idaho potato king" and wanted Nymex to trade potatoes based on the large Idaho market and not the small Maine-potato market.

A farmer and grade-school dropout, self-made billionaire Simplot saw Nymex as a back-alley type of operation fraught with market manipulation. Meeting with impasse through normal channels to achieve change, he shorted the over-sold Maine potatoes and didn't deliver them.

The litigation notes around it are summarized as "when the sellers of almost 1,000 contracts failed to deliver approximately 50 million pounds of potatoes, resulting in the largest default in the history of commodities futures trading in this country."

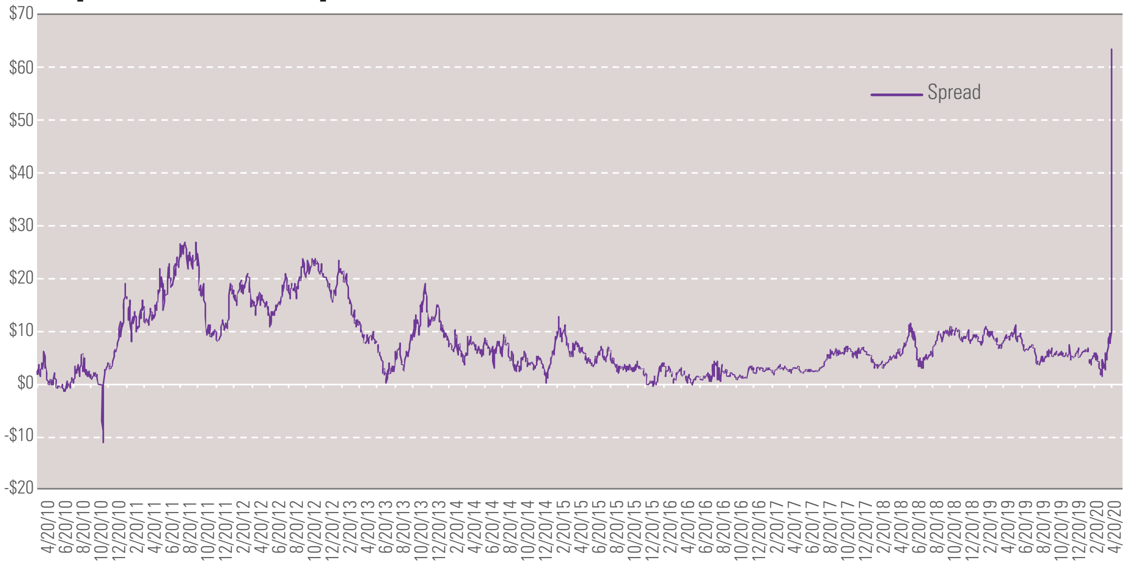
(The newly formed CFTC fined Simplot $50,000 and forbade him from trading for six years.)

Lots became of that—a whole book worth of events as Goodman documented in hers—but Nymex was forbidden by the CFTC from trading in any other futures unless it was something it had traded before.

The exchange's newly named, 27-year-old chairman—in her book, Goodman described him as the "unlikely savior of a dysfunctional farmers market"—found it had once traded a heating-oil contract. So it had that.

In the 1980s, President Reagan deregulated crude oil and, then, natural gas. Nymex became papered in energy futures. It IPOed in 2006 and, eventually, CME Group, its long-time rival over in Chicago, came to own it.

Prompt Contract Price Spread For WTI And Brent



Source: Baker Institute, NASDAQ

Typically Brent and WTI move together, but on April 20 WTI disconnected from its typical relationship with Brent and petroleum product prices.

'Every single barrel'

Goodman wrote in her May article, "In all, 14,913 crude oil contracts exchanged hands at negative prices on April 20, according to CME data."

She got in touch with Michel Marks, "the father of the Nymex crude oil futures contract" that was born in 1983 and who was the 27-year-old who became chairman of Nymex in 1977.

"Black swans are hard to anticipate," Marks told her. "The bottom line is to maintain a fair and orderly market."

CME Group Chairman and CEO Terry Duffy told CNBC on April 22 that "The futures market worked to perfection."

He added that it had announced two weeks earlier that it was "going to allow negative price trading. So this was no secret that this was coming at us.

"We have to do things to allow the market to go to a price that is reflecting the fundamentals of the product."

As for Hamm's complaint with the CFTC, Duffy told CNBC that Hamm and others should have "stood in there and taken every single barrel of oil if it was worth something more" and he questioned why they didn't.

"The true answer is it wasn't at that point in time," he said.

'No convergence with reality'

But what happened on April 20 on Nymex didn't actually represent "the fundamentals of the product" in the real market, others have pointed out.

AFR wrote that, "Whether Vega's windfall was a result of savvy trading, blind luck or something else, the idea that a relative minnow could have such a profound impact calls into question [Duffy's] declaration that the futures market had 'worked to perfection.'"

Michael Lynch, president, Strategic Energy and Economic Research, wrote in a Forbes blog the morning of April 21, "The oil industry faces a serious challenge, but this bizarre occurrence does not reflect the reality of the physical market.

"Storage is filling but still available, and the crisis is on the paper market, not the 'real' world."

Goodman wrote that a former exchange official told her "The futures market demonstrated no convergence with the physical market that day. It demonstrated no convergence with reality."

CFTC Commissioner Dan Berkovitz stated on May 7, "The CFTC must determine the causes of this unprecedented price movement and divergence from physical markets ...

"A critical question that both the [CFTC] and the CME must answer is the extent to which trading in WTI on that date resulted from unique circumstances or actions or [if it] reflects structural issues with the contract that may persist or recur in the future."

'Oversupply of paper'

Berkovitz noted that TAS contracts were among "trades that settled on the penultimate day of trading."

April 20 came off like having two aces in the hole and seeing three more on the flop. The divergence in the real, versus the paper, market was glaring.

"April 20: WTI At -$37, Brent At $26! What Happened? What Comes Next? The Stories That Will Be Told." That's the headline of a Baker Institute blog by Ken Medlock, the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics.

The paper market for crude oil is supposed to reflect the real market—the spot price—for crude oil, he wrote. "April 20 revealed something that many people found to be outright unbelievable; the price for May [WTI] collapsed by more than $50/bbl into previously uncharted, negative territory.

"Moreover, WTI disconnected from its typical relationship with Brent and petroleum product prices."

"We have to do things to allow the market to go to a price that is reflecting the fundamentals of the product."

—Terry Duffy, chairman and CEO, CME Group

Energy economist Phillip Verleger said, "The proper functioning of the futures market is critical not just to the oil industry's future, but to the future of the banking and broader financial system."

Gasoline futures remained similar to the spot price but "not WTI. Why?" Everything suggests "a massive oversupply of paper, not physical, oil," he wrote.

While what regulatory change will result is yet unknown, "The die has been cast for the status quo to, at the very least, be challenged."

'Price doesn't conform'

Berkovitz noted in his May 7 statement that the difference in price between the May and June contracts was $58/bbl, a "mega-contango." He cited Craig Pirrong, director, energy markets, at the University of Houston's Global Energy Management Institute.

At Pirrong's "Streetwise Professor" blog, he titled his April 20 entry "WTI—WTF?" He wrote, "Today was one of the most epochal days in the history of oil trading, which is saying something."

One trader, "Darrin W.," replied to Pirrong on April 22, "I can assure you that there was LOTS of manipulation going on. I'll give you one example: Once the contract went negative, Interactive Brokers traders were trapped because their trading platform wasn't supporting negative prices."

Trade orders were getting a "price doesn't conform" error message, Darrin W. wrote. "Essentially, we were therefore all trapped." Everyone was "stuck for the open interest."

He concluded, "That alone is robbery, and it's just one way in which the markets were being manipulated that day."

Another of Pirrong's readers replied that "Cushing means 'godforsaken place'" and that "I tell my students 'I've been to Cushing, so you don't have to.'"

Berkovitz chaired a CFTC committee meeting the morning of May 7. The meeting was previously scheduled on another topic. He acknowledged that in his opening comments but added, "before we turn to that, I would like to address what I know is on many members' minds … ."

The April 20 price decline from $17.73 at open to negative-$37.63/bbl at close was a "40 standard deviation event," he said.

The physical price diverged from the paper price; essentially, the market failed.

"The futures market demonstrated no convergence with the physical market that day. It demonstrated no convergence with reality."

—Leah McGrath Goodman

'Not Zoom'

Both Berkovitz and Goodman cited energy economist Phil Verleger, who wrote in an Energy Intelligence article in late April. In it, Verleger, principal, PK Verleger LLC, noted that some of the May WTI contract's demise could be derived from United States Oil Fund LP (USO) and other ETFs.

Investment in USO shares had been pouring in much like buying "not Zoom" stock in March. In the latter, the ZOOM ticker was held by a virtually defunct company, Zoom Technologies Inc.; the Zoom stock people actually wanted was ZM for Zoom Video Communications Inc.

But the order errors pushed defunct ZOOM from a penny to $60 before the ZOOM ticker was shut down by the SEC on March 26.

Meanwhile, in the case of USO, buyers thought they were buying barrels for cheap and holding them in storage. Plans among those who didn't understand the stock may have been to sit on the barrels (via the stock) until a better oil-price day.

But USO's stated MO was to hold only paper barrels—and it was required in its model to buy and dump them each month. Its MO is a public GPS.

Buying the stock on March 10 was only a bet that a May barrel would be worth more on April 10. This past April, it wasn't.

Before a 1-for-8 reverse split on April 28, USO shares began 2020 at about $12.75. They closed on April 21 at the equivalent of $2.75. Soon after trading the week of April 20, it announced that it would divvy up its funds to invest in more months of futures than in just the prompt month.

The ETF's sponsor, United States Commodity Fund LLC, has received notices from the CFTC as well as from the SEC.

'Happy to sell'

Verleger wrote that USO's May WTI buying through April 10 is why prices for that contract didn't fall sooner. In USO's model, it was simply doing what it had told its investors it did—buy a month, then dump the month.

"Producers and traders holding inventories were happy to sell to the fund, no doubt welcoming the opportunity to lock in higher prices before a price collapse that they anticipated," Verleger wrote.

As soon as April 13, USO was out. But "The USO effect was still there because it pulled in more shorts—that is, it allowed more producers to hedge, leaving the market more exposed to the risk of a squeeze by the shorts, which is what happened."

Like Hamm and others, Verleger concluded that "The proper functioning of the futures market is critical not just to the oil industry's future, but to the future of the banking and broader financial system.

"Negative prices cannot be allowed to occur again."

'Market was played'

Hamm told Investor, "It usually takes a crisis to show the fundamental good or bad of a market. Certainly that [May contract] did."

Hamm co-led Platts' and Argus' launch this summer of American Gulf Coast Select crude. "It takes the inherent storage issue away," he said.

"As long as you have ships that can load with the waterborne barrel, you don't have the [Cushing] storage overhang issue that these people [on Nymex] played off of.

"Incidentally, storage was never a problem," he added. "The storage at Cushing was never filled.

"It all had to do with the way the market was played and the skepticism it created and the way they were able to buy all of those positions the day before." □

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ENERGY AND THE ELECTION

More or less regulation? Will the pace of climate change measures accelerate? What about Washington gridlock? When the polarized electorate chooses leaders, it will also choose a course for national energy policy.

ARTICLE BY
JOSEPH MARKMAN

ILLUSTRATION BY
ROBERT D. AVILA

Oil and gas executives can expect increased pressure on environmental, social and governance (ESG) issues following the November elections, experts forecast.

That means demands to reduce flaring, carbon footprint and overall environmental impact. Fossil fuel companies also will be under a microscope to demonstrate there is a public good associated with what they do.

That's not just the forecast of the impact on the industry if former Vice President Joe Biden is elected president. That's also the forecast if President Donald Trump wins reelection.

"All that's going to happen regardless of who's elected because that's coming from the investment community. That's not coming from politics," Ken Medlock, senior director of the Center for Energy Studies at Rice University's Baker Institute for Public Policy, said. "In many ways that's more powerful than who's elected because that's how you get money."

After the election, fuel companies will be under a microscope regardless of who wins, said Ken Medlock, senior director of the Center for Energy Studies at Rice University's Baker Institute for Public Policy.

Scenario 1: A Biden victory

While investor pressure will continue on a steady course, public policy could move in a drastically different direction if Biden wins. A year before the election, oil and gas executives were sounding the alarm about the threat to the industry from an administration led by Sen. Elizabeth Warren (D-Mass.). When Sen. Bernie Sanders (D-Vt.) became the favorite for the nomination, that also rattled energy industry cages. Warren and Sanders are staunch proponents of the Green New Deal and opponents of fossil fuels.

Biden, though, has made a career of being a moderate. Should the oil and gas industry be concerned if he wins?

"I would say, initially, yes," Medlock said. "I think as time passes and you see some of the anti-establishment proposals coming forward, I think there's more reason for pause. That said, there's a history with a lot of these companies and Biden—the history being the Obama administration—and the relationships were not always negative. There might be a little more comfort because they know who he is."

Biden's climate change plan begins with a promise of a series of executive orders to put the U.S. on the road to net-zero emissions by 2050. The orders would impose aggressive methane pollution limits, purchasing zero-emissions vehicles for government use, rigorous new fuel economy standards and permanent protection of the Arctic National Wildlife Refuge, among other steps.

His plan also includes proposed legislation to create enforcement mechanisms, massive investment in clean energy and climate change research and innovation, and rapid deployment of clean energy across the economy. And in a challenge to natural gas development: a 100% reliance on noncarbon feedstock for power generation by 2035.

For oil and gas executives not yet unnerved, "The Biden Administration will take action against fossil fuel companies and other polluters who put profit over people," the plan reads on the campaign's website.

The policy promises that "Vice President Biden has committed that [the Biden for President campaign] will not accept contributions from oil, gas and coal corporations or executives."

While it is expressed in unyielding tones, Medlock questions whether it reflects a total commitment.

"The one thing that I wonder about is how much of this is real and how much of this is to energize the base, get out the vote," he said. "I think that remains to be seen. Certainly, a lot of that language has been worked into the platform, but you can look historically at platforms, it doesn't always translate into policy when the person's elected."

Lean to the Left

But Kathleen Sgamma, president of the Western Energy Alliance, takes Biden at his word.

"It's clear that he's moving more to the left, and I think he's moved so far to the left that he'll have trouble coming back," Sgamma said. "He's made a lot of promises to people—net-zero promises and such—that I have a hard time seeing him come back from that."

She acknowledged that Biden is at heart more moderate than Sanders and Rep. Alexandria Ocasio-Cortez (D-N.Y.), co-author of the Green New Deal. But commitment to that ambitious program requires rapid development of an abundant and affordable energy source to replace oil and natural gas, first by 2035 for electricity generation, and then for zero emissions by 2050. She calls that kind of an effort unrealistic.

"Lucky for Biden, he would be well out of office before then so he doesn't have to actually deal with the consequences," Sgamma said.

Western Energy Alliance President Kathleen Sgamma said that gridlock after the election could, if necessary, prevent radical anti-fossil fuel programs from becoming law.

The Biden plan relies on step-change adoption of renewable sources of energy. Development of renewables has proceeded rapidly but not to the point of shoving fossil fuels to the sidelines. The U.S. Energy Information Administration (EIA) projects electrical generation from renewable sources such as solar and wind to exceed that from coal and nuclear by 2021. It will not surpass natural gas until 2045. The EIA projects the share of renewables in the U.S. power generation mix to double to 38% in 2050 from 19% in 2019.

"Even though there's been a large percentage growth in the wind and renewables space, solar, etc., if you look at the power generation of those sources vs. traditional thermal power, there's a huge gap," Cliff Vrielink, co-managing partner of Sidley Austin's Houston office and global leader of the law firm's energy and infrastructure practice, told HartEnergy.com. "So, the implementation of those goals would be pretty dramatic."

And possibly risky.

"Coming back to the 2035 goal, I think the implementation of a lot of these climate goals can have real-world consequences," Vrielink said. "Those consequences can simply be higher power prices, higher transportation costs, higher fuel prices, higher heating prices. You look at folks in Boston in Massachusetts. They have heating costs that are multiples of what they would be if they were to have more access to gas on the Eastern Seaboard. I think that is the limiter on one of these acceleration pushes: how it impacts people's wallets."

Scenario 2: Trump wins re-election

Even in a year marked by profound uncertainty, few would doubt this: In a second term, the Trump administration will continue its efforts to deregulate.

"A second Trump administration means that we move forward with reasonable oil and gas development in the United States and realize the strategic value of our energy supply," Sgamma said.

But then what will happen? In all likelihood, there will be increased opposition to those efforts.

Cliff Vrielink, co-managing partner of Sidley Austin LLP's Houston office, said there are always trade-offs in energy policy and called for a thoughtful treatment of them.

The president's power to set policy agenda for other offices and direct federal agencies has an impact on oil and gas, said Kevin Garber, a Babst Calland shareholder.

"I think the resistance will grow dramatically if he is elected and continues to push along that line," Medlock said. "I'm not sure that even if he tried he would be all that successful."

Resistance to the Trump agenda, Vrielink believes, will not be diminished much by the president's reelection because environmental groups have already scored victories in the courts and have seen their strategy of prolonging litigation bear fruit.

"So, I think it's really more a question of, do their efforts accelerate or not?" he said. "For the oil and gas business, there are not going to be a lot of people in Washington pushing hard to advocate for that industry."

There are limits to presidential power, as evidenced by this summer's setbacks experienced by the Dakota Access Pipeline and the Atlantic Coast Pipeline on the pro-oil and gas Trump administration's watch. Most obvious are the other co-equal branches of the federal government—legislative and judiciary. But there are other forces at play, as well.

The Atlantic Coast project scored a victory in the U.S. Supreme Court in June, but Dominion Energy and Duke Energy pulled the plug in July, citing costs that were expected to climb from $5 billion to $8 billion. The EIA projects natural gas prices to remain flat for the next decade, so clearly market forces play an important role in the success of oil and gas development, Kevin Garber, shareholder in the Babst Calland law firm, said. The Mountain Valley Pipeline project is another that has been slowed by ongoing litigation as the judiciary deals with statutes enacted by Congress decades ago, Garber said.

"Perhaps we are focusing too much on a single office being able to determine the course of things, but the office is clearly important in setting a policy and directing the agencies," he said.

Not to mention the power to nominate judges for the federal bench, Sgamma said.

"In the case of the Dakota Access Pipeline, that case is ripe for appeal, and I would assume that will be successful on appeal," she said. "That's why the president is so important, because who picks the judge is important."

Babst Calland shareholder Jean Mosites said that the difficulties the Trump administration's deregulatory efforts have faced show that some forces, such as federal processes, simply can't be avoided.

But even a president must engage with an entrenched system.

"One of the things that the Trump administration has really encountered with trying to roll back regulations is there are certain things you can't get around," Jean Mosites, shareholder with Babst Calland, said. "You have to do things in a certain process, step by step. So, that kind of framework for what agencies do still is going to be something that any administration has to deal with. If you're going to change rules, whether you're this administration or another one: How do you do it? It takes a long time."

Polarization frustration

If Democrats are able to take control of the White House and both houses of Congress, Medlock sees a significant push in support of green agendas.

"What's usually first pushed out of committee is aspirational, and then it gets watered down a little bit because there's a rationalization that has to occur, even within a party," he said. "What that looks like in that particular circumstance is tough to say because if the Senate swings, that generally means you're going to have some energy-producing states that have Democrats as senators, and they're going to be cautious."

If, however, Biden were to win with the Democrats maintaining their majority in the House and Republicans still controlling the Senate, "We might be setting ourselves up for a bunch of gridlock. In which case, every company in every industry is going to be very actively lobbying for various positions to make sure their voices are heard."

Sgamma sees that gridlock in a positive light.

"Let's say the Senate flipped Democrat," she said. "It's still going to be so closely divided that it will still be gridlocked, as it is now with Republicans in control. Even when Republicans had the House and the Senate and the presidency, there was just too slim of a margin in the Senate. It remains a moderating force just like when the Obama administration couldn't get cap and trade [in 2010] even though it had the House and the Senate. The Senate just is a moderating force on that kind of radical proposal."

But if gridlock is required to counter extreme positions, that could be a symptom of an inability to meet in the middle. Vrielink would prefer that both parties consider long-term economic consequences for the country and the people.

"Unfortunately, in our political discussions nowadays, there is not much balancing and weighing of the pros and cons anymore," he said. "That, to me, has led to increased polarization. Historically, there's always a pro and a con, and there's always a balancing act. That needs to take place. There's a lot that can be done, but there are tradeoffs. We, as a country, need to be honest about those tradeoffs and thoughtful about them." □


24

PREPARING FOR THE TURNAROUND

NOV CEO Clay Williams discusses the future of onshore and offshore oil and gas development, the impact of the energy transition on oilfield service providers and more amid the challenging energy climate.

Amid the continued presence of COVID-19 and distressed market conditions, the question of transformation is on the oil and gas industry's mind now more than ever. What will the future of oil and gas look like, what will remain the same and what will need to change?

National Oilwell Varco (NOV) is at the fore of answering this question in the oilfield service sector. As one of the leading global providers of onshore and offshore equipment and technology, the firm continues to invest in new technologies and seek forward-looking solutions to industry challenges, according to Clay Williams, chairman, president and CEO of NOV.

Williams recently provided an exclusive video interview in which he shared his views on the way forward for oilfield service companies. The following is a transcription of that interview, edited for style and clarity. The full video interview can be found at HartEnergy.com.

What does an oilfield service company look like to you in the future? How is your company positioned to make that shift?

One of the challenges we've been facing in oilfield services has been the rising cost of capital, because our financial performance has not been very good through the past several years of the downturn.

Plus, you've got this narrative of pivoting away from oil and gas, peak oil demand, and a lower carbon world, which makes it hard for the providers of capital to invest in our industry. And that's important because we have a very capital-intensive industry.

Going forward, our industry is going to have to put up better financial returns, but above all, we're going to make sure that we're adding value to the operations of oil and gas companies because they're facing similar challenges, and if the value that we bring to their operations isn't tangible and demonstrable, they can't afford to pay for it. All of us across oil and gas are going to have to head to a world where we're more efficient and better at what we do.

"What you've seen is the oil field practicality in action. Very clever, innovative designs, the application of technologies, including some digital technologies, have continued to reduce the cost of offshore barrels, and I'm confident that trend's going to continue into the future."

Where do you see offshore and shale fitting in this new energy world?

You know, oil and gas are such critical commodities to global economies, to our standards of living. Before the COVID-19 downturn, we reached 100 million barrels a day of demand. Frankly, we need oil from all sources; we need it from unconventional shales; we need it from the offshore; we need it from conventional sources globally. I think the future is going to be characterized by oil coming from a diverse base of supply, and I think that's necessary to make sure that the world continues to be supplied with affordable energy.

How is your company helping deliver shale technologies to new plays outside of the U.S.?

Unconventional shales grew global production by 5 million barrels a day in just a few short years, so we find our customers, national oil companies and global international oil companies watching very intently what's going on in the unconventional shale world, perhaps with a little bit of trepidation.

But as they've realized that this is a very impactful technology and it's really reshaping the supply of oil globally, many recognize it's an opportunity to deploy these technologies in their own basins. In places like Argentina with the Vaca Muerta Formation, Saudi Arabia with unconventional gas drilling, China, we're seeing greater demand for directional drilling technologies that deliver horizontal wellbores along with demand for hydraulic fracture technologies, and these are really two enabling technologies that make unconventional work.

How do you see E&Ps evolving in the offshore to drive better returns?

Offshore has not stood still through the downturn either. Unconventionals did a great job dropping their costs and seeing continued rising production through the downturn. But there's an awful lot of smart people working in offshore as well, and it's a big prize in the offshore with the reserves that have been discovered in deepwater and other places.

Through advancements in subsea lifting and separation in offshore structures, FPSOs, flexible pipe, the processing and separation units, we've reduced the weight and the cost of these things. Those technical advancements coupled with deflation in drilling, improvements in drilling efficiencies as drilling has continually gotten better and better through the downturn, along with deflation and other services required to develop offshore fields have dramatically improved their cost positioning.

And I would add that this industry is made up of really, really smart people who love a good challenge, and the past six years have been nothing if not a good challenge.

What you've seen is the oilfield practicality in action. Very clever, innovative designs, the application of technologies, including some digital technologies, have continued to reduce the cost of offshore barrels, and I'm confident that trend's going to continue into the future.

Nevertheless, the oil and gas industry has a reputation for being a slow adopter of new technology and of running behind on the adoption of digital technologies. How do you see the current downturn impacting technology adoption?

I've got to tell you, I bristle a little bit when I hear that the oil and gas industry doesn't understand digitalization. We were the first big data industry; most of the Cray computers that were built in the 1970s and 1980s were built specifically to handle the enormous digital data sets that came out of geophysical shoots that supported the oil and gas industry. What I would submit is that, actually, the oil and gas industry is very, very experienced and realistic when it comes to dealing with data and with digital technologies, meaning we understand the practical limits and the challenges that we face when you deploy digital technology.

Specifically data cleanliness, competing protocols, formatting, the maintenance of connectivity in the remote places where we work, the problem of garbage in, garbage out—these are things that I began to deal with on my first day as a young engineer in this industry in the 1980s. Our generation, I think, is very familiar with not just the promise of digital, but most importantly, the limitations and the practical challenges that we face as we deploy digital solutions.

Nevertheless, I don't want to give you the wrong impression. I think digital technologies will continue to evolve. We've seen a dramatic reduction in the cost of the storage of data, dramatic improvements in the transmission and the collection of data, and the processing speeds with which we manipulate data, and that all extends the boundaries and the possibility of digital solutions.

I think it's incumbent on all of us to stay abreast of those developments, to make sure we're deploying digital solutions to improve our business along the way.

I'll give you a good example. For instance, we, through the downturn, used augmented-reality technology and remote monitoring with our TrackerVision™ system to enable our customers to perform factory acceptance testing on equipment prior to delivery. This is something that previously was always done in person. Our customers would come to our factories and accept equipment, but augmented-reality technologies has enabled a new way of doing that.

With more people working remotely it appears the opportunities are growing for digital systems. Where does digital go from here?

It's really up to us as providers of these things to develop solutions that help them navigate these challenges and don't overpromise and underdeliver.

I'm very proud to say that NOV has a great track record in this area. For over 20 years, for instance, our eHawk™ system has monitored networks on offshore drilling rigs, a couple hundred offshore drilling rigs, and helped us help our customers manage their networks. Our Martin-Decker Totco product line for 80-plus years has been the leading provider of rig instrumentation systems, meaning the rig dashboard, the electronic drill recorders that act as data historians on hundreds of rigs globally. We have the only high-speed data transmission capability to the bottom of the hole with our IntelliServ™ network that transmits data at 55,000 bits per second.

In 2016, we introduced the industry's first commercial predictive analytics product that monitors subsea BOPs. We recognized in the data we could see a potential SPM valve failure 14 days before the valve actually failed. We began offering this predictive analytics service, and since then have expanded it from subsea BOPs to surface drilling equipment and now offer dozens of potential failure modes that we can predict in advance. These are all great examples of where we've applied digital technologies to improve our operations, the operations of our customers.

What new digital technologies has NOV focused on to drive better operations? Which of these are you most excited about?

We've continued to invest through the downturn despite having to cut costs. In October, for instance, we're going to be commercializing a new data platform that I'm very excited about called NOV MAX™, which is basically edge technology that we've been working on for about three years. It takes the challenges of data management that I mentioned earlier head on. What that means is, military grade encryption, up to 12 kilohertz data density, full disaster recovery, including the necessary ISO 27001 certifications, universal translator, so we can accept over 30 protocols of data.

We can output over 15 different types of protocols of data, depending on what our customer wants, and put that data out to their cloud, to our cloud, to our portal for our customers to access to their office. Think, oilfield Netflix, and our role in that is to be a custodian of their data, to work through the tedious processes of cleaning it. It's built on ruggedized hardware. It's edge hardware that can run their proprietary applications in the field or third-party apps or our own apps.

In addition to that, we've had great success with our operating system for drilling rigs, a system we call NOVOS™. We've sold about 160 rigs thus far, and so it's being used now widely across certain customers' operations, and they're getting great results with it. Later this year we're going to be introducing hardware that works with that software foundation, and the hardware will enable drilling automation, true drilling automation, which has been a goal of this industry for decades. And, importantly, we're going to launch this hardware upgrade for rigs that's very, very affordable and will fit well the NOVOS digital foundation we've been laying to put in place automation.

These are just two examples of things that we've been working on through the downturn, and I'm very pleased to say we've got many, many others across the organization as well.

There are many E&Ps and service companies struggling, looking for a new strategy in today's environment. What would you say differentiates your company from others?

I think NOV is a little bit unique in the oilfield ecosystem in that we're mostly an equipment provider. Most of our revenues come from providing equipment and spare parts and services to other oilfield service companies. So, in many ways, we're sort of a second derivative from E&P spending in the space.

What that means is we have a very large install base across numerous categories of equipment, and it's an install base that lends itself to digital solutions, efficiency enhancements and better care and feeding with respect to the maintenance and service and repair of that equipment. We've been very focused on that as well.

Climate change remains a dominant topic of conversation and a concern. In building a new energy system that is renewable or more sustainable, how do you see the oil and gas industry contributing to this effort?

First and foremost, I think climate change and the pivot to new sources of energy is an enormous opportunity for all industries and all businesses. And I think oilfield services in

"The oil and gas industry is very, very experienced and realistic when it comes to dealing with data and with digital technologies, meaning we understand the practical limits and the challenges that we face when you deploy digital technology."

particular is well-placed to capitalize on that. If you look at what's required in energy, energy is really all about infrastructure and capital investment. And if you look back at energy transitions through the centuries, it's been gated by the fixed base and installed base of equipment and machines and infrastructure that provide that energy and use that energy for the benefit of consumers. That doesn't turn on a dime, but when it does turn, it requires a lot of project management expertise, a lot of capital formation expertise, and it calls for the application of technology. These are things that we do very well in oilfield services.

I think our industry can and will play a big role in that transition, and in our own company we've been making very targeted investments in this area for the past several years, and we're pretty excited about what the future holds.

What is your outlook for the year ahead, and what do you see as the greatest challenge? What about five years from now?

Unfortunately, the severity of this downturn may well be the worst this industry has ever seen, dating back to the 19th century. We're in a place that the industry hasn't been before, and I would love to tell you that I think it's going to turn around quickly, but realistically I don't [think that]. I think we're in for the next year or two of continued necessary restructuring and doing the painful things around cost reductions that are required for us to do.

However, I do think the world has set itself up for a potential turnaround quickly in commodity prices. The evaporation of spending and activity in our industry of oil-and-gas-company capital expenditures, of new drilling, and so forth, there's always a price to pay with that, number one. Number two, with a billion barrels or more of excess storage and inventory, demand has to exceed supply for a meaningful amount of time before that billion barrels of excess inventory can flow back into the market and be burned off to get back to a normal place.

And any time this industry gets in a position where supply is insufficient to equal demand, the world potentially has a problem. That problem being potentially masked for a period of time while the excess inventory burns off, I think may well be the foundation for commodity price shock in the future. So this industry, I think in the next five years, not in the next year or two, but in the next five years, is very likely to be asked to step up very, very quickly and grow production as quickly as possible to put supply and demand back in balance.

It's a really fascinating time for the armchair student of the industry, which I sometimes consider myself to be. It's a fascinating time with respect to this industry.

What advice do you have for young professionals in this industry as we navigate this downturn?

I understand that it looks very challenging and some might even say bleak right now. I would tell you, you're part of a great critical industry that has made the world better, that has lifted many, many [people] out of poverty. In fact, I believe that no other industry has done more to lift standards of living of mankind than the oil and gas industry.

"In the next five years, [this industry] is very likely to be asked to step up very, very quickly and grow production as quickly as possible to put supply and demand back in balance."

The other day I was standing in my driveway, and I made an important observation about my automobile, which I rely on pretty heavily—it runs on gasoline, a product of our industry, as does my wife's, as do my kids', as do all of the cars driving around Houston, save for a few Teslas that I see every day, as do essentially all of the automobiles on the planet. Nearly 100% of automobiles require our product to go. 100% of aircraft require our product to go. 100% of the tractor-trailer rigs that deliver all the Amazon packages to my house require our product to go. 100% of construction equipment that build buildings, that maintain roads, rely on our product. 100% of tractors and combines that produce the food that feed the planet run on our product. This is a critical product.

You think about all those categories of equipment. How many tens of trillions of dollars are invested in that capital infrastructure globally? And guess what, none of it goes without oil and gas. Oil and gas, our customers, and the owners of that equipment rely on you and me to deliver oil and gas efficiently, and safely, and cost effectively so that all that capital equipment can run.

This industry is going to be around a long time. It won't be around forever. And I do think that we will pivot to lower carbon sources of energy, but I think you and I have a role to play in that as well, as I mentioned earlier. And I think that's a great opportunity for all of us.

So, it's a tough industry, it's not for the faint of heart. When things cycle down, it looks very bleak. What I'm most grateful for today in 2020, frankly, is having lived through some of these down cycles and having lived through to the other side. And what I would tell you is there's always another side, and there will be this time around, too. We're going to see prosperity return. We're going to get busy again. I would tell you to hang in there. This is going to get better, and you'll look back at this time and realize that you probably grew more through the downturn than you may fully appreciate right now. When I look back on my own career, I credit the downturns and the tough times that I went through for really making me who I am. □

RETHINKING PAYMENT FOR PERFORMANCE

Cracks have begun to show in the traditional performance metrics for executive compensation, and there's a growing push to reconsider them in the new environment.

ARTICLE BY SHARON PODSTUPKA AND MARK ROSEN

ILLUSTRATION BY ROBERT D. AVILA

Choosing performance metrics and setting incentive award opportunity targets in executive compensation programs is hard in any industry. It's even harder in highly cyclical industries, with oil and gas posing a particular challenge due to the frequent cycles that are extreme at both the lower and higher ends. Companies and their boards must balance a variety of issues such as motivating performance (even if the company may enter bankruptcy or a restructuring in a downturn); retaining critical leadership talent (especially if on the upswing, executives become recruiting targets); and ensuring stockholder support, which can be tricky at any time.

Decisions and communication about metrics and compensation levels have always sent important signals to current and potential investors about where a company is focused, its strength of position within its own industry and how it intends to create stockholder value over the long term. And we know there is no shortage of armchair quarterbacks in executive compensation—regulators, institutional advisory firms, the media, activists and so on.

Of course, the critics are less vocal when times are good—a rising stock price solves a lot of problems. When an industry sector outperforms the market, most agree that companies with performance results at the top of their industry should pay their executives above target awards. On the other hand, criticism of management is often intense in a difficult market, and at the same time, the need to retain an effective leadership team is more important than ever.

So, is it also reasonable for a company to pay its executives target or above target award levels when it outperforms its industry peers but the entire industry sector is underperforming the broader overall market?

With the world turned upside down, the answer is not straightforward. The traditional lens through which "pay for performance" has historically been viewed is cracked. What happens now for boards that must make 2020 performance assessments without the benefit of relevant benchmarks or experience with such a tumultuous year?

Flaws in relative performance metrics

Let's start with an examination of peer comparisons and how that may have complicated the current scenario. Over the last decade, the use of relative performance metrics, such as relative total shareholder return (rTSR), as a dominant performance metric in long-term incentive plans has exponentially increased, and it has become one of the most prevalent metrics in the oil and gas sector. Approximately 75% of companies use rTSR in their incentive plans.

The use of rTSR specifically has grown in part as a result of proxy advisors looking at three-year rTSR to evaluate pay for performance, which is happening despite Institutional Shareholder Services (ISS) clearly stating they do not endorse rTSR, or any specific plan design, for that matter.

The concern is that as certain industries struggle more than others, the prevalence of relative performance metrics such as rTSR in executive pay packages may be leading to a pay-for-performance disconnect. In particular, plan designs heavily weighted toward relative measures may be driving above target payouts even when the industry comparator or peer group underperforms the overall market and the stockholders have taken it on the chin.

But compensation isn't a theoretical discussion. It's easy to rush to judgment and think we see pay-for-performance disconnects—especially when looking from a distance only at low sector performance. The reality is true pay for performance is not just about results tied to financial metrics.

Boards see the actions executives take in real time to navigate complex situations. They see decisions made that are intended to put their company in stronger future positions, such as acquisitions, expansions or investments. They see leadership behaviors that drive engagement and productivity throughout the workforce. Of course, boards also know full well that companies must produce results, so if the executive team isn't driving performance in some fashion, they usually don't stay employed very long.

However, if the executive team is doing the right thing, how does a company keep them through the toughest times while still being true to a pay-for-performance philosophy?

The answer is balancing metrics and improving communication. As the economic landscape is rattled by seismic changes brought on by COVID-19 and the price of and demand for oil remains low, we have an opportunity to reexamine specific areas of executive compensation design to help ensure that these programs include guardrails that protect against unintended consequences while aligning the best interests of stockholders with those of senior executives.

We must also increase the dialogue between companies and investors—meeting disclosure requirements alone is not enough. In a struggling industry, ongoing and active discussions are perhaps the most important guardrails in ensuring stakeholders understand a company's intentions.

Relying on more absolute metrics

Ten years ago, relative performance metrics were rare. Most incentive plans, whether annual or long-term, were built primarily on absolute metrics, that is a target—usually financial but also possibly strategic—set by the board that is based on company performance. Under these types of plans, incentive award targets were straightforward and set based on business plans and forecasts.

The challenge with absolute metrics is that many times what can be reasonably achieved

Matrix Approach—Internal Metric And Relative TSR

			Relative TSR Modifier		
			Bottom Quartile	Median (2nd and 3rd Quartile)	Top Quartile
		Preliminary / Unadjusted Payout	Multiplier		
			75%	100%	125%
Internal Financial Performance Metric	Below Threshold	0%	0% (0% x 75%)	0% (0% x 100%)	0% (0% x 125%)
	Threshold	50%	37.5% (50% x 50%)	50% (50% x 100%)	62.5% (50% x 125%)
	Plan	100%	75% (100% x 75%)	100% (100% x 100%)	125% (100% x 125%)
	Challenge	200%	150.0% (200% x 75%)	200% (150% x 100%)	Capped at 200% (200% x 125%)

Source: Pearl Meyer

In this relatively complex plan design, the number of shares earned is based on achievement of an internal financial performance metric, and the results of internal performance are modified based on relative TSR.

simply isn't very good compared to historical performance or other industries. For example, when the price of oil is $30, it's not realistic to expect the same level of financial performance as when the price of oil is $60. There is nothing wrong with setting a performance target based on forecasts and what reasonably can be achieved. Executives don't control the price of oil and gas, and their ability to deliver financial performance is limited to the environment in which they operate.

Yet, boards and executives alike know there needs to be accountability for achieving performance targets and creating stockholder value. While setting performance targets based on expectations is reasonable, pay that's divorced from the stockholder experience is not.

As such, investors must understand the rationale behind the goal-setting process, as well as understand what the performance expectations are and why target performance goals are considered to be appropriately robust. These concepts are complex and should be addressed in ongoing discussions and clearly summarized in disclosures. This scenario is where communication is critical.

Enduring standards—the holy grail?

Some companies consider setting performance targets based on "enduring standards," a metric that transcends the performance cycle and works independent of forecasts. Exceeding the cost of capital is an example of an enduring standard. If you create value when your earnings exceed the cost of capital, then it makes sense that incentives should be paid. When cash flow is less than the cost of capital, value is destroyed, and incentives should not be paid. It would appear to be the holy grail of compensation measures.

But something went awry when setting enduring standards in the oil and gas industry: Commodity prices got in the way.

Even with an enduring standard, when you mix in the volatility of oil and gas prices, things can go sideways quickly. It may not be reasonable to pay at maximum when prices spike if the organization underperforms its peers. Likewise, if targets set in a downcycle are taking into account a low pricing environment, it may not be reasonable to pay target in the downcycle and maximum in an up cycle.

Adjustments in comparative metrics

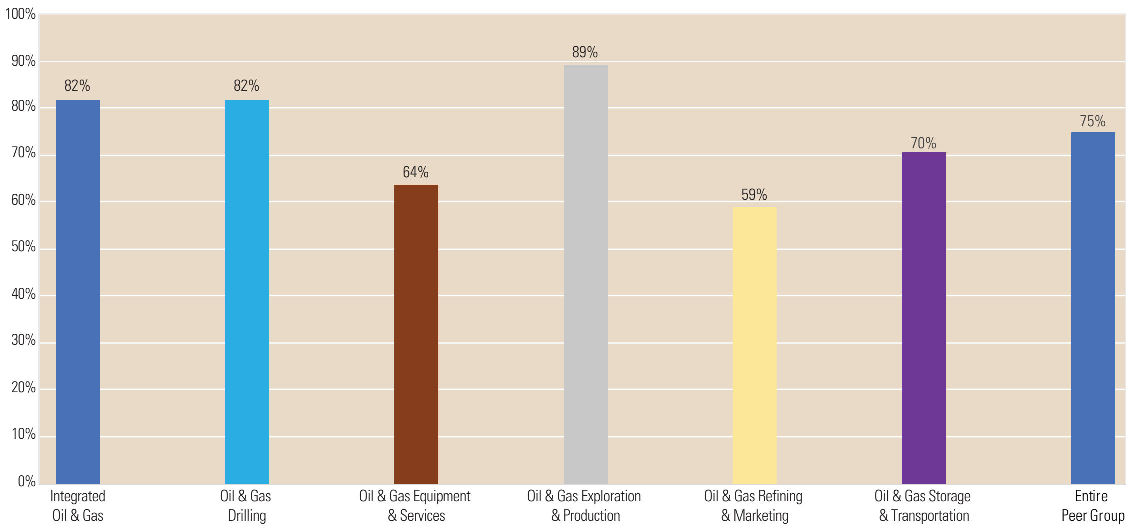
Despite the drawbacks, incentive plans that use relative performance metrics (including rTSR) can still be effective as long as they have a few guardrails built in. Here are a few things you can do to fix the flaws.

Revisit the comparator group. How is the comparator group selected? Is it composed only of a company's direct peers, or does it include some companies in general industry? Expanding the comparator group to include companies that compete for investors suggests that a company pays for relative sector performance but also pays for relative market performance.

A better comparator group could include a mix of same sector and general industry companies, or there could be two separate comparator groups (one group could be the sector group, the other could be a mix of general industry companies or an index; for example, capital intensive industrial companies in the S&P 500).

Of course, if the sector is underperforming, we must keep in mind that the company's stock price will be lower relative to other industries, which in a way is self-regulating. While award payouts (assuming they are stock-based) may be above target for above sector performance, for an underperforming sector the lower stock prices will result in lower realized compensation.

Percent Of Oil And Gas Sector Companies Using TSR As A Performance Measure



Source: Pearl Meyer

*Oil and gas sector companies with over $500M of revenues traded on a US or Canadian exchange.

Approximately 75% of oil and gas companies use TSR as their performance measure.

Balance relative metrics, such as rTSR, with other measures. If only 25% of the total long-term incentive grant is based on rTSR, it's unlikely that compensation will be unreasonable. Balanced with other measures, a relative metric can complement the others.

For example, mixing an absolute metric based on a forecast with a relative metric can provide balance. Targets based on a forecast provide an incentive tied to a reasonable estimate of what you think you can achieve. Matching it up with a relative metric provides context.

If you could have done better than forecasted, your relative metric won't payout as well. If you exceeded the forecast but in hindsight that success was easier to achieve than forecasted, the relative metric won't payout as high. This can be accomplished by two separate measures or by a matrix in which the weighted scores (in the cells) may be weighted more, for example, to absolute TSR.

Consider the payout schedule. Most rTSR plans pay between 150% and 200% of target for rTSR performance at the 75th percentile or above. Beating 75% of your peers is pretty good. However, most plans also pay target for median performance. Institutional advisors and some institutional investors have stated that they do not consider paying target for median performance robust. Threshold performance is often set at the 25th or 35th percentiles and often pays 25% to 50% of target.

Let's face it—paying 50% of target while underperforming 75% of your peers is probably not aligning pay and performance where 25% of target seems more reasonable. However, if the comparator group includes both direct peers and some general industry comparators, suddenly the median doesn't look so bad. Having general industry comparators adds ballast. It's harder to achieve higher relative performance when the sector is down, easier when the sector is up relative to the general market.

Explore using a modifier. A modifier based on relative performance can ensure payout is not inappropriate. If performance compared to the comparator group is high, payout may be higher. If performance is lower, payout is cut back.

Having a two-way dialogue is key

To be successful, there must be a two-way dialogue between companies and investors to ensure that everyone is on the same page. That's because in an underperforming sector that's paying target or above target awards to executives, messages are rarely straightforward.

Business results need to be put into proper context. Complex concepts need to be broken down and explained, and the rationale for payouts needs to be bulletproof. Even the best-written proxy statement would not mitigate the risk of messages being open to misinterpretation.

Because incentive plans send strong messages to stockholders and potential investors about what is important to the company, stockholder outreach should be a top priority. Stockholders should greet invitations from boards and senior management to engage in conversations with open arms—even when things on the surface seem clear cut. These are the opportunities for everyone with a stake in the value of a company to discuss performance targets, debate their reasonableness and gain consensus that forecasted performance goals are worth target payouts.

These discussions should be summarized in proxy statements disclosures as a recap of who was involved in the discussions (directors, senior management, investors, etc.), when/how many conversations took place, what was heard and what was changed (or not) as a result. This not only keeps a history of the feedback and response but also demonstrates a level of ongoing involvement between companies and their stockholders beyond say-on-pay.

Moving forward

Setting performance targets isn't easy in a static environment. Throw in commodity prices and a pandemic, and it becomes that much more difficult. But taking a balanced approach with absolute and relative metrics and communicating your intentions can help safeguard both executive and investor interests.

While it may be a bit more time intensive to design such a plan, it will align incentive payouts with the stockholder experience and will ensure executives' opportunities are reasonable through the economic cycle. (Don't forget they have alternatives.) With thresholds that are achievable and safeguards that help avoid unintended consequences, the company is much better positioned overall to survive and thrive through all the unpredictable cycles to come. □

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Sharon Podstupka is a principal in the New York office of Pearl Meyer. Across a wide range of industries she develops internal communications that educate and engage people in their pay programs. She has extensive experience in developing critical shareholder communications that clearly explain pay-for-performance in the context of today's challenging say-on-pay environment. Her key areas of expertise are communication strategy, stakeholder management and content development. Ms. Podstupka holds a BFA in communication arts from New York Institute of Technology, Old Westbury.

Occidental Rockies Assets Fetch $1.33 Billion

OCCIDENTAL PETROLEUM Corp. agreed to the sale of a chunk of Rockies assets for about $1.33 billion, the Houston-based independent E&P said Aug. 19.

Global alternative investment management firm **Orion Mine Finance** agreed to the acquisition, comprising Wyoming, Colorado and Utah land grant assets that included approximately 4.5 million mineral acres and 1 million fee surface acres.

As part of the agreement, Occidental will retain all cash flow from currently producing oil and gas properties on the position, which it said are primarily cost-free royalties. Also not included in the sale is approximately 2.5 million mineral acres derived from the land grant in Colorado, including Occidental's core position in the Denver-Julesburg (D-J) Basin.

"This transaction significantly advances the progress against our $2 billion-plus divestiture target for 2020," Occidental President and CEO Vicki Hollub said in a news release.

"We will retain our core oil and gas assets in the Rockies, including the prolific D-J Basin in Colorado and the highly prospective Powder River Basin in Wyoming," Hollub added.

Occidental has been focused on reducing debt through asset sales since last year's acquisition of Anadarko Petroleum, which included the assumption of almost $40 billion in debt.

In June, Occidental closed the sale of its Greater Natural Buttes asset in Utah. Despite the asset producing about 33,000 boe/d in the second quarter, during an earnings call earlier this month Hollub said the cash flow impact from the sale was immaterial due to low gas prices.

BRIDGET CALIP/SHUTTERSTOCK.COM

Occidental is also still marketing assets in Ghana. However, the company no longer plans for the divestiture of the Algerian assets it had once hoped to sell to France's **Total SA**, with Hollub now describing them as a "core asset" on the company's earnings call.

"As we've said before, we will balance divestiture timing with value realization, and we'll not sacrifice value just to close transactions quickly," Hollub added.

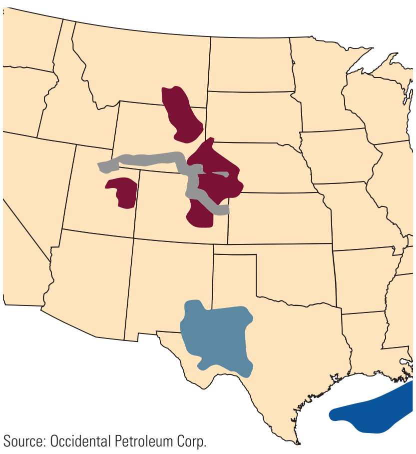
In its sale of land grant assets, Orion is acquiring mineral rights to the world's largest known trona deposit, according to the Occidental press release.

Trona is a mineral used to make soda ash, the principal ingredient in baking soda, global glass manufacturing, pollution control systems, as well as other critical chemical applications. The properties will be held under **Sweetwater Royalties**, a new base metals and industrial minerals royalty company, managed by Orion.

The transaction is expected to close fourth-quarter 2020. Occidental was advised by **RBC Capital Markets**, **CBRE Group Inc.**, and **Latham & Watkins LLP**. Orion was advised by **Citi** and **Shearman & Sterling LLP**.

—Emily Patsy

Occidental Petroleum Onshore Acreage



Source: Occidental Petroleum Corp.

2Q20 Net Production

	Oil (Mbbl/d)	NGL (Mbbl/d)	Gas (MMcf/d)	Total
Permian Resources	258	108	596	465
Permian EOR	105	27	51	141
D-J Basin	107	78	763	312
Other Domestic	15	7	204	56
Total	485	220	1,614	974

Includes ~0.6 MM land grant minerals associated with core D-J operating areas, which is also included in the Rockies acreage total.
Note: Acreage amounts presented on this slide are net acres.

Rockies	Land Grant	Permian
1.3 MM acres	7MM acres[1]	1.3 MM acres

Kosmos Energy Divests Frontier Exploration to Shell

KOSMOS ENERGY LTD. on Sept. 9 agreed to sell select frontier exploration assets in a farm-down worth up to $200 million as the Dallas-based company continues to focus on proven basins with superior returns and shorter payback.


RED IVORY/SHUTTERSTOCK.COM

In a company release, Kosmos said it entered an agreement with a subsidiary of **Royal Dutch Shell Plc** to farm down interests in its portfolio of frontier exploration assets. The consideration consists of an upfront cash payment of about $100 million, plus future contingent payments of up to $100 million.

Under the terms of the agreement, Shell will acquire Kosmos' participating interest in blocks offshore São Tomé & Príncipe, Suriname, Namibia and South Africa. Kosmos expects to realize approximately $125 million in total savings across capex and general and administrative expenses over the next two years as a result of the transaction, according to the company release.

"The contingent payments locked into the agreement with Shell ensure we retain upside from frontier exploration with no further investment," Andrew G. Inglis, Kosmos Energy's chairman and CEO, added in a statement.

Kosmos, a full-cycle deepwater independent E&P company focused along the Atlantic Margins, is listed on the New York and London stock exchanges. The company's key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico (GoM), as well as a gas development offshore Mauritania and Senegal.

The proceeds from the farm-down enable Kosmos to accelerate high-graded exploration opportunities, according to Inglis.

Following the farm-down transaction, Kosmos will retain a focused exploration portfolio with over 6 Bbbl of gross resource potential in the GoM and West Africa.

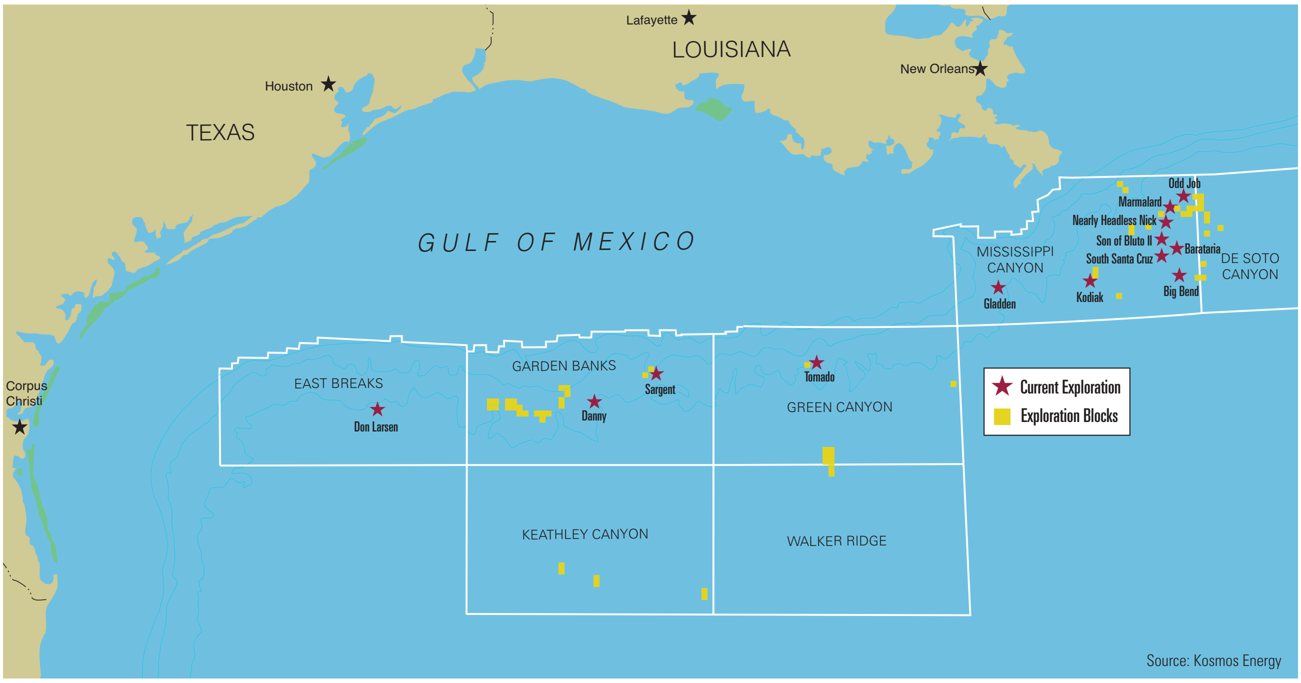
"With this transaction, we are continuing to focus our exploration portfolio on proven basins that offer superior returns with shorter payback and significant resource potential," he said.

Kosmos expects to close the transaction in fourth-quarter 2020. The sale will have an effective date of Sept. 1 and is subject to customary conditions including government approvals.

The transaction's contingent payments are $50 million payable upon each commercial discovery from the first four exploration wells drilled across the assets, capped at $100 million in aggregate. Three of the four wells are currently planned for 2021.

—Emily Patsy

Kosmos Energy Gulf Of Mexico Assets



- >1 Bbbl gross prospectivity
- Current inventory of ~25 oil prospects
- De-risked through 3D WAZ coverage
- Lowers risk, CoS >= 50%; <$30/bbl WTI breakeven
- Limited number of competitors
- Near field tie-backs through underutilized third-party infrastructure
- Hub scale prospects of 100MMbbl to 200-plus MMbbl of oil
- Play extensions into Norphlet and Wilcox
- Lower carbon - average carbon intensity of ~8 kg/boe vs. ~20 global average

Northern Oil & Gas Enters Permian In EOG Deal

NORTHERN OIL AND GAS INC. on Sept. 10 made its first acquisition outside of the Williston Basin, where the company touts itself as being the largest nonoperator.

In a company news release, Northern said it acquired nonoperated interests within the Delaware Basin from an undisclosed seller. The deal includes acreage and proposed wells in New Mexico's Lea County operated by **EOG Resources Inc.**, a top Permian producer.

Based in Minnetonka, Minn., Northern invests in nonoperated minority working and mineral interests in oil and gas properties as part of its strategy as "the natural consolidator of nonoperated working interests," Northern CEO Nick O'Grady said.

However, after actively building data in the Permian Basin for two years, O'Grady said he now sees a window of opportunity opening up for expansion of its strategy outside of the Williston.

"The 2020 downturn in the energy sector has made the Permian Basin competitive for the first time, inclusive of acreage costs, on a full cycle return basis with our Williston Basin program," he said in a Sept. 10 news release.

The Permian acquisition consists of interests in approximately 66 net acres, on which 1.1 initial net wells have been proposed. The proposed wells are expected to be spud in late 2020 or early 2021 and turned in line beginning in second-quarter 2021. Monthly peak production of approximately 1,400 boe/d is projected from the initial wells.

Total acquisition costs plus the initial development costs on the proposed wells are expected to be approximately $11.9 million. Northern expects approximately 54% of this capital to be incurred in 2020, all of which would be within the company's previously stated 2020 capital budget.

Upon turning the proposed wells in line, Northern said the assets will be accretive to EV/EBITDA, corporate return on capital employed, earnings per share and free cash flow metrics in 2021 and beyond.

ALEXANDER LUKATSKIY/SHUTTERSTOCK.COM

"Returns matter: The capital markets continue to ignore our stellar capital allocation process that has led to the highest return on capital employed of any public oil-centric E&P," O'Grady said, adding that with the company's first Permian deal, "We continue to carefully invest countercyclically in high return future cash flows and inventory to capture upside, while ongoing operations continue to improve."

—Emily Patsy

Permian's Lilis Preps For Bankruptcy Sale

LILIS ENERGY INC. is switching gears to a sales process after a restructuring agreement with its investor fell through.

The Permian Basin pure-play voluntarily filed for Chapter 11 on June 29, succumbing to bankruptcy following months of struggling to make debt payments. Concurrent with the Chapter 11 petitions, Lilis entered a restructuring support agreement (RSA) with affiliates of **Värde Partners Inc.** that if consummated was expected to reduce its debt by more than $34.9 million.

However, on Aug. 17, Värde Partners, which collectively owns all of Lilis' outstanding preferred stock, declined to pursue a new money investment in the company to sponsor its Chapter 11 plan of reorganization, Lilis said in a company release.

In a statement on Aug. 17, Joseph C. Daches, who serves as Lilis' CEO, president and CFO, said that while the company is "disappointed that the Värde Funds declined to pursue the new money investment contemplated by the RSA, we are confident there will be significant interest in the company's highly contiguous block of approximately 16,000 net acres located in the deep and overpressured portion of the Delaware Basin, including Winkler and Loving counties in Texas and Lea County in New Mexico."

Värde Partners, a Minneapolis-based alternative investment firm, had approached Lilis at the beginning of this year with a nonbinding cash take-private offer after the company missed several payments on its revolving credit agreement resulting in a borrowing base deficiency.

Lilis ended up selling a chunk of its Permian acreage in New Mexico's Lea County, which it said in a February release would fund repayment of a "substantial portion" of its borrowing base deficiency. However, the company was still unable to make the final payment of $7.75 million due June 5 and was forced to enter forbearance that month.

For the majority of 2019, the Fort Worth, Texas-based independent E&P company struggled to generate returns, even temporarily suspending drilling and completion operations at one point last year. Despite reporting improved operational efficiencies and G&A cost savings in its third-quarter results, by late 2019 it hired **Barclays Capital Inc.** as financial adviser to explore strategic alternatives.

In accordance with the terms of the RSA that Lilis entered into with its lenders, the company will immediately begin pursuing a process to sell substantially all of its assets through the Chapter 11 process, which may be pursuant to section 363 of the bankruptcy code or a Chapter 11 plan.

The proposed form of bidding procedures was previously filed with the U.S. Bankruptcy Court for the Southern District of Texas, Houston Division, on July 13, and will be scheduled for hearing and approval by the court on Aug. 21.

Vinson & Elkins LLP is legal adviser to Lilis. Barclays Capital is serving as the company's investment banker, and **Opportune LLP** is its restructuring adviser.

—Emily Patsy

Panhandle Oil And Gas Enters Haynesville Shale

PANHANDLE OIL AND GAS INC. entered the Haynesville Shale through the acquisition of two packages of mineral and royalty assets from **Red Stone Resources LLC**.

In an Aug. 27 company release, Panhandle said it agreed to acquire the two packages totaling approximately 795 net royalty acres in the SCOOP and Haynesville plays for $6.9 million in cash and stock. Commenting on the transaction, Panhandle President and CEO Chad Stephens said the acquisition fits well with the strategy to grow the Oklahoma City-based company on an accretive basis.

"These assets are a nice blend of producing properties, near-term development opportunities and upside potential in core areas with active drilling programs by high quality and well capitalized operators," Stephens said. "It also marks our entry into the Haynesville play of East Texas and Louisiana, which we believe has significant potential and provides good development visibility."

Earlier this year, Panhandle named Stephens, an industry veteran who previously served on the executive team at **Range Resources Corp.**, as its CEO as part of a leadership transition tied to a shift in strategy by the company to increase its focus on the mineral acquisition market.

Panhandle, whose history dates back to 1926, originally operated as a co-op until 1979 when it became a public company through a merger with **Panhandle Royalty Co.** Today, the company owns roughly 258,000 net mineral acres principally located in Oklahoma, North Dakota, Texas, New Mexico and Arkansas. Approximately 71% of the mineral acreage is unleased and undeveloped, according to a company release.

Red Stone Acquisition Highlights

Haynesville Package *(Harrison, Panola and Nacogdoches counties, Texas)*	
Net revenue acres:	509
Current net production:	1,032 Mcf/d (100% natural gas)
PDP gross wells:	23
Gross wells in progress:	23
Gross undrilled locations:	26
SCOOP Package *(Grady County, Okla.)*	
Net revenue acres:	286
Current net production:	18 boe/d (61% oil)
PDP gross wells:	78
Gross wells in progress:	21
Gross undrilled locations:	97

Source: Panhandle Oil and Gas Inc

In its entry to the Haynesville Shale, Panhandle will acquire approximately 509 net revenue acres in East Texas in Harrison, Panola and Nacogdoches counties. Four rigs are currently running on the acreage with key operators including **Aethon Energy Management LLC**, **Comstock Resources Inc.** and **Rockcliff Energy LLC**.

The SCOOP package of the Red Stone acquisition covers approximately 286 net revenue acres in overriding royalty interests in the Springboard area of Oklahoma's Grady County. Panhandle said all 28 sections included in the SCOOP package have producing wells and leases HBP. Key operators include **Continental Resources Inc.** and **Marathon Oil Corp**.

Combined, the two packages are currently producing 1.1 MMcfe/d consisting of 6% oil, 1% NGL and 93% natural gas. Estimated reserves are 7.4 Bcfe, 87% natural gas, and the company expects next 12-month production of 625 MMcfe.

Further, Panhandle is estimating $1.1 million of cash flow to be generated from the assets over the next year.

The purchase price consists of $6.4 million in cash and $500,000 in Panhandle common stock. Panhandle intends to raise the cash portion of the purchase price through an underwritten public offering of common stock the company launched concurrently with the announcement of the Red Stone acquisition on Aug. 27.

The effective date of the Red Stone acquisition is June 1. The stock issued in connection with the acquisition will be subject to the same terms and conditions as the other subscribers for the offering. Stifel and Northland Capital Markets are acting as joint book-running managers for Panhandle's equity offering, with Stifel acting as representative of the underwriters.

Panhandle expects the transaction to close in first fiscal-quarter 2021.

—Emily Patsy

Newpek Exits Texas Shale

FREEZEFRAMES/SHUTTERSTOCK.COM

NEWPEK LLC said on Aug. 18 it had divested its Texas assets, including all wells and leases in the Eagle Ford Shale and Edwards Shale.

The transaction has an implied value of $88 million for Newpek, resulting from the cancellation of its obligations in joint venture and operating contracts.

Newpek's exit from the Lone Star State is part of a strategy being pursued by its parent company, Mexican conglomerate **Alfa**, to unlock value via its fully independent subsidiaries through the divestiture of oil and gas assets outside Mexico.

In a release Alfa said Newpek transferred its assets in Texas to **Ensign Operating LLC** and **Reliance Eagleford Upstream Holding** in exchange for a complete cancellation of its obligations. Further details of the agreement were not disclosed.

Sidley Austin LLP lawyers led by Tim Chandler represented Houston-based **Ensign Natural Resources LLC** in its acquisition of Eagle Ford Shale and Edwards acreage from Newpek and a concurrent renegotiation of its gathering and other midstream agreements with Ensign's primary midstream provider.

Newpek also closed its administrative office in Irving, Texas, and moved remaining functions to Monterrey, Mexico, according to the company release.

Alfa added it will recognize an extraordinary gain of $58 million in third-quarter 2020 EBITDA as a result of the transaction.

—Hart Energy Staff

TRANSACTION HIGHLIGHTS

EAST TEXAS

■ **Empire Petroleum Corp.** formed a partnership to jointly develop recently acquired East Texas properties following a significant investment from The Woodlands, Texas-based **Petroleum Independent & Exploration LLC (PIE)**.

Based in Tulsa, Okla., Empire Petroleum has current producing assets in Texas, Louisiana, North Dakota and Montana. The company looks for assets where its operational team can deploy rigorous field/well management techniques to reduce unit operating costs and improve margins while optimizing production.

In an Aug. 11 release, Empire Petroleum said PIE had agreed to invest approximately $3.4 million through a securities purchase agreement providing PIE with the opportunity to own up to 40% of Empire equity and two board seats. Additionally, PIE agreed to provide Empire a loan for up to $2 million for worker development within its current East Texas assets.

"As a significant investor in Empire, combined with the operational expertise and capital to implement an initial robust workover program, we believe PIE is a terrific partner aligning with all shareholders," Mike Morrisett, president of Empire Petroleum, said in an Aug. 11 statement.

According to the Empire release, PIE has identified the first of many workover/recompletion programs to potentially uplift field production in the company's Fort Trinidad Field asset in Houston and Madison counties, Texas. The properties contain approximately 91% working interest and 83% net revenue interest and have been recently producing from multiple pays of the Glen Rose, Edwards and Buda formations.

PIE, led by Phil Mulacek, will contract operate the Fort Trinidad Field. The group has been responsible for world class discoveries, such as the Elk and Antelope fields in Papua New Guinea, which were acquired by **Exxon Mobil Corp.** and **Total SA** in 2017, the release said.

HAYNESVILLE

■ **Posse Resources LLC** boosted its footprint in the Haynesville Shale with the acquisition of all of the remaining mineral and royalty assets held by the inaugural fund of **Live Oak Resources Partners LLC**.

Privately-held Live Oak focuses on the aggregation and management of royalty and mineral interests and nonoperated working interests in the Haynesville Shale of North Louisiana and East Texas. The remaining assets held by its inaugural fund Live Oak Resource Partners I LP, which closed in July 2016, included North Louisiana royalty acreage.

Live Oak President and CFO Andrew Keene said in a news release that the Live Oak team has closed more than 600 transactions in the past five years comprising more than 18,000 royalty acres.

In a joint release by the Houston-based companies on Aug. 19, Live Oak said it sold the remaining assets of its inaugural fund to **Oak Ridge Royalties LP**, an entity newly created by Posse Resources.

MIDLAND BASIN

■ **HighPeak Energy** and **Pure Acquisition Corp.** completed their previously announced business combination on Aug. 24, forming an independent E&P company focused in the Permian Basin.

Pure Acquisition, a blank check company formed in November 2017, had agreed to the business combination in May following a scuttled three-way merger agreement between the companies and private-equity-backed **Grenadier Energy Partners II**.

Previously, Pure and HighPeak, which share board members and are both led by industry veteran Jack D. Hightower, had agreed to acquire Grenadier, backed by **EnCap Investments LP** and **Kayne Anderson Capital Advisors**. However, the crash in oil prices earlier this year forced a renegotiation of terms, and the transaction was terminated, according to a filing with the U.S. Securities and Exchange Commission.

The combined company, set to trade as HighPeak Energy Inc., will hold a 51,000-net-acre position in the northern Midland Basin primarily in Howard County, Texas. Current net production is about 2,600 boe/d from legacy horizontal wells that have recently been brought back online after voluntary production curtailments made in response to the global pandemic, according to a company release on Aug. 24.

NEW MEXICO

■ A large auction of federal oil and gas leases in New Mexico ended on Aug. 27, attracting far less interest from drillers than recent sales in the state, according to results posted on **EnergyNet**'s online auction site.

The results reflect the weakened state of the industry as it struggles with sharply lower demand and prices.

The Trump administration's U.S. Bureau of Land Management (BLM) sold 93 land parcels covering more than 45,000 acres in New Mexico on Aug. 27, a day after holding a much smaller sale of 2,800 acres. The Aug. 27 sale included one parcel in Texas.

The two-day auction's average bid per acre was $169, according to results from online auction site EnergyNet. That is well below the $1,386/acre the state took in at a sale in February, just before states locked down to slow the spread of the coronavirus.

Prior to this week's sale, drilling parcels in New Mexico auctioned during the Trump administration averaged $5,500/acre, according to conservation group Center for Western Priorities.

BLM plans to hold several lease sales next month for parcels in Nevada, Wyoming, Montana, North Dakota Colorado, Utah, Alabama, Louisiana, Michigan and Mississippi.

LOWER 48

■ Activist investor **Elliott Management Corp.** is seeking to break up **Noble Energy Inc.**'s $5 billion sale to oil major Chevron Corp., a Bloomberg reporter tweeted on Sept. 9.

A notice posted on the U.S. Federal Trade Commission website on Sept. 8 showed the hedge fund had built a stake in Noble Energy.

In response to the tweet, Braden Reddall, manager, external affairs at Chevron, said the company's offer "represents a fair value for the business and that the transaction will create long-term value for shareholders of both companies."

"We continue to expect the transaction to close in the fourth quarter," Reddall added.

Chevron said in July it would buy Noble Energy in an all-stock offer in the first major deal in the energy sector since the coronavirus crisis crushed global fuel demand and sent crude prices to historic lows. Noble

TRANSACTION HIGHLIGHTS

shareholders are expected to vote on the deal on Oct. 2.

Noble and Elliott were granted early termination under the FTC's Hart-Scott-Rodino Act, which is a legal requirement when an investor buys shares in a firm above a certain threshold and seeks to hold discussions regarding strategy, management changes and others.

CANADA

■ Canadian oil producer **Whitecap Resources Inc.** said Aug. 31 it would buy **NAL Resources Ltd.**, owned by **Manulife Financial Corp.**, for C$155 million (US$118.59 million) as it looks to boost its core Alberta and Saskatchewan assets.

Whitecap said it would issue 58.3 million of its shares to Manulife in exchange for all the issued and outstanding shares of NAL, which operates in Canada's Saskatchewan and Alberta. Insurance and financial services provider Manulife will own about 12.5% of the combined company.

The deal marks growing interest in mergers among smaller Canadian oil producers to bolster their portfolios, as uncertainty about future oil demand persists.

The COVID-19 pandemic destroyed fuel demand and left dozens of energy companies without the prospect of drilling their way out of debt or bankruptcy, making consolidations a viable solution for many smaller players.

Separately on Aug. 31, Calgary, Alberta-based oil and gas company **Obsidian Energy Ltd.** offered two shares for every share of **Bonterra Energy Corp**.

U.S. oil producer **ConocoPhillips Co.** has also targeted assets in Canada in a US$375 million deal with **Kelt Exploration Ltd.** in Canada's Montney shale oil play.

SERVICE & SUPPLY

■ **Baker Hughes Co.** agreed to sell the surface pressure control (SPC) flow business unit in its oilfield equipment segment to **Pelican Energy Partners LP** for an undisclosed amount on Sept. 10.

The sale follows comments CEO Lorenzo Simonelli made recently about downsizing Baker Hughes' oilfield services and equipment portfolio in preparation for the energy industry's transition to a low-carbon future. Baker Hughes has already started to shed some oilfield assets as part of a company strategy to bolster its footprint in technologies needed for renewables.

The deal also comes as the big three oilfield service providers shift away from the high-cost shale industry. **Schlumberger Ltd.**, for example, made headlines last week with the announcement of the sale of its North America fracking business, **OneStim**.

The sale of Baker Hughes SPC Flow unit consists of wellhead product sales and service as well as a rental offering of frac trees, valves and zipper manifolds. As part of the agreement, Baker Hughes will retain the SPC projects business comprising surface and subsea product offerings in the Middle East, Africa, North Sea and Asia.

Baker Botts provided legal counsel to Pelican Energy Partners for the transaction. **McDermott Will & Emery** served as legal counsel to Baker Hughes, and **BofA Securities** acted as its financial adviser.

OKLAHOMA CITY

■ One of the industry's first major deals of the third quarter closed on Sept. 1 without any oil and gas assets changing hands. **SandRidge Energy Inc.** said in a Sept. 1 release that it sold its skyscraper in Oklahoma City for $35.4 million in net proceeds, a figure that represents more than half of the company's $61 million value on Wall Street.

The sale should alleviate any concerns that SandRidge would reenter bankruptcy after exiting bankruptcy in 2016 and shedding roughly $3.7 billion in debt.

The independent E&P company announced plans to sell the building on May 15, along with other cost cutting moves, as it grappled with falling commodity prices amid the pandemic. The brick and mortar tower and annex with parking was purchased by the state's Commissioners of the Land Office.

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James X Browning James X Browning, Managing Director - Audience Development	September 19, 2020

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EASTERN US

1 ***Ascent Resources*** announced results from a Utica Shale completion in Ohio's Belmont County. The #4H Albert SW KKW BL produced 680 bbl of oil, 21.88 MMcf of gas and 260 bbl of water daily. It was drilled in Section 25-9n-6w and is in Barnesville Consolidated Field. It was drilled to the southeast to a total depth of 24,597 ft, 8,587 ft true vertical, and tested after acidizing and fracturing. Ascent Resources is based in Oklahoma City.

2 A ***Gulfport Energy Corp.*** Utica Shale discovery was reported in Belmont County, Ohio. The #4B Dornon 210642 is in Key Consolidated Field and was drilled to 23,624 ft (9,929 ft true vertical) in Section 13-6n-4w. It flowed at a daily rate of 27.65 MMcf of gas with 425 bbl of water. It is producing from a perforated zone between 10,027 and 23,470 ft. Gulfport's headquarters are in Oklahoma City.

3 Houston-based ***EAP Ohio LLC*** completed two Jefferson County, Ohio, Utica Shale wells in Annapolis Field. Located in Section 17-11n-4w, #6H McCoy 17-11-4 initially flowed 21.527 MMcf of gas and 567 bbl of water per day. Production is from an acidized and fractured zone at 8,730-18,018 ft. It bottomed in nearby Section 15 and was drilled to 18,164 ft with a true vertical depth of 8,600 ft. The offsetting #10H McCoy 17-11-4 was drilled to 14,855 ft with a true vertical depth of 8,562 ft. It flowed 17.653 MMcf of gas and 469 bbl of water per day after fracturing. Production is from a perforated zone at 8,810-14,771 ft.

4 A Utica Shale discovery in Jefferson County, Ohio, flowed 38.403 MMcf of gas and 148 bbl of water per day. ***Ascent Resources***' #6H Faldowski was drilled in Section 14-8n-3w in Limestone Field. The total depth is 20,912 ft (9,762 ft true vertical). Production is from an acidized and fractured zone at 10,065-20,736 ft.

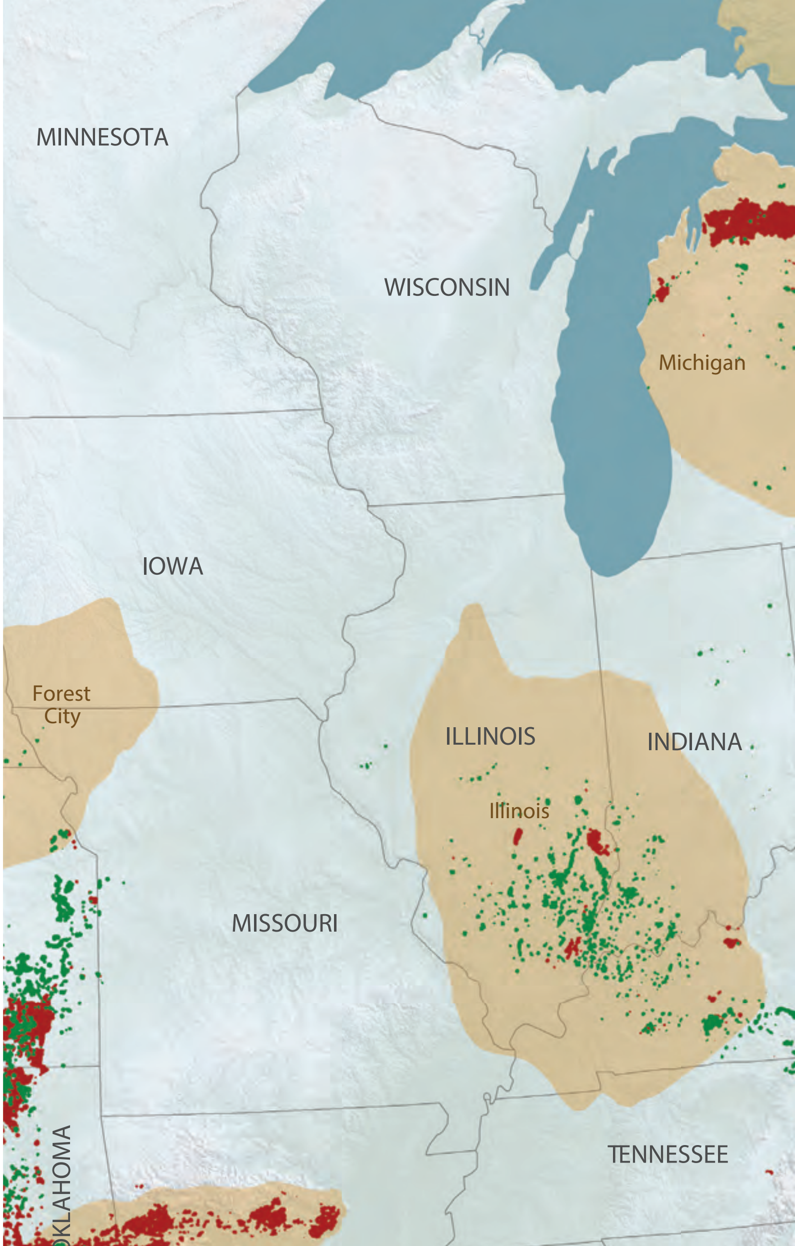
5 Results from a Columbiana County, Ohio, Utica Shale well were announced by Oklahoma City-based ***Chesapeake Operating Inc***. According to IHS Markit, #210H Sevek 18-12-3 is in Section 18-12n-3w, and it produced 25.774 MMcf of gas and 1,519 bbl of water per day. The Vulcan Field well was completed after acidizing and fracturing. Drilled to 21,429 ft, 8,466 ft true vertical, it is producing from an unreported zone. Additional details are not currently available.

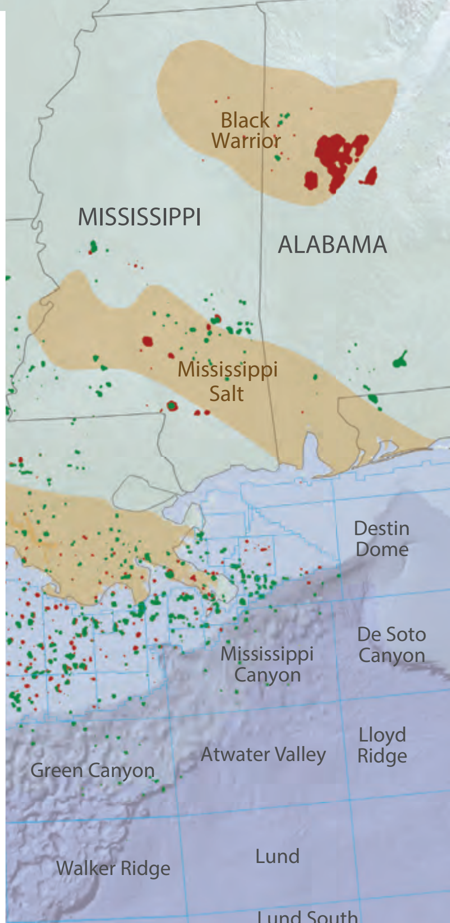
6 ***EAP Ohio*** reported a Utica Shale completion in Jefferson County, Ohio, that flowed 30.18 MMcf of gas and 1,023 bbl of water per day. The #5H Williamson 12-10-3 was drilled in irregular Section 12-10n-3w in Fairfield Field to 21,435 ft (8,772 ft true vertical). It was tested after acidizing and fracturing, and production is from perforations at 9,170-21,285 ft.

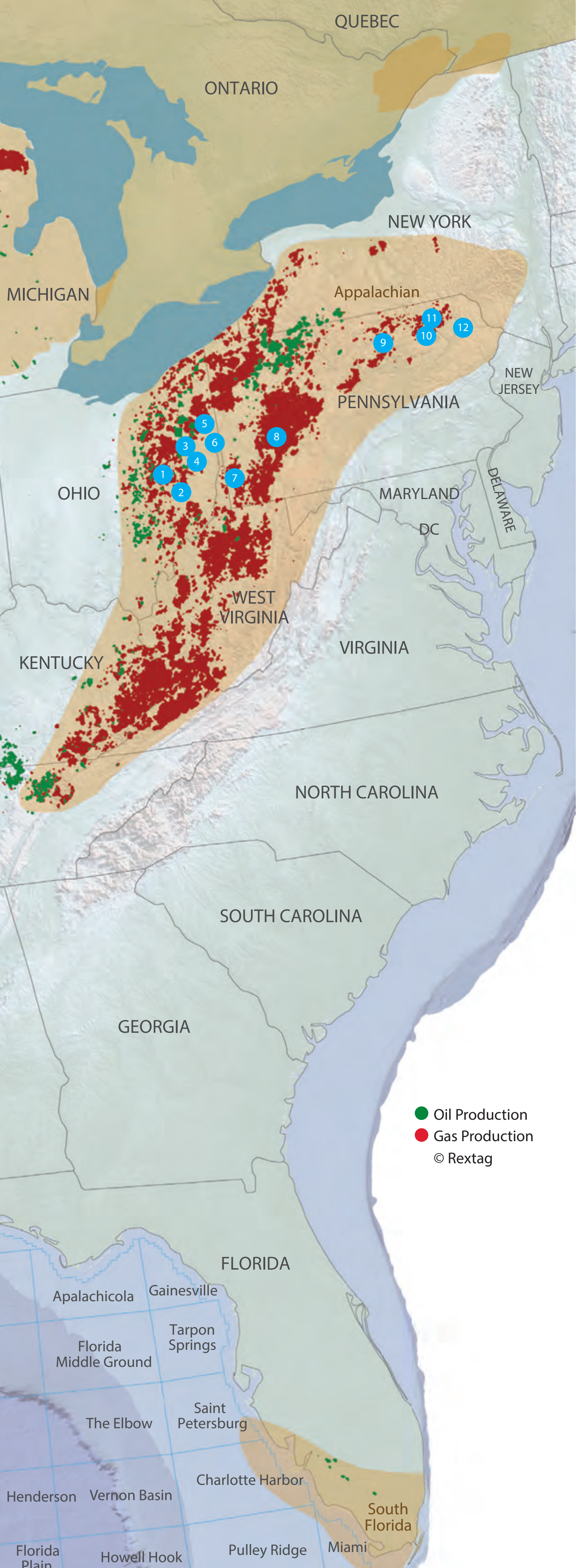
7 ***Range Resources*** completed two Marcellus Shale wells from a drillpad in Washington County, Pa. The Amity Field ventures are in Section 6, Prosperity 7.5 Quad, Morris Township. The #11H Strawn Robert Unit was drilled to 27,692 ft (7,320 ft true vertical) and initially flowed 40.4 MMcf of gas and no reported water per day. The shut-in casing pressure was 2,500 psi, and production is from perforations at 7,970-27,597 ft. The #13H Strawn Robert Unit was drilled to 19,846 ft (7,535 ft true vertical) and flowed 40.2 MMcf of gas per day. The shut-in casing pressure was 1,750 psi, and production is from perforations at 8,166-19,773 ft. Range is based in Fort Worth.

8 ***CNX Gas Co.*** completed a Utica Shale gas discovery in Pennsylvania's Westmoreland County. The #1DHSU Shaw is in Section 8, Vandergrift 7.5 Quad, Washington Township. It was tested flowing 10.712 MMcf of gas per day from fractured perforations at 17,229-22,069 ft. The horizontal well was drilled to the north to 22,560 ft with a true vertical depth of 13,226 ft. The Murrysville Field well had a shut-in casing pressure of 3,700 psi.

9 Two Lycoming County, Pa., Marcellus Shale discoveries were announced by Dallas-based ***Chief Oil & Gas*** in Eldersville Field. Both wells were drilled from a drillpad in Section 8, Grover 7.5 Quad, McNett Township. The #2H Hemlock Ridge Estates W was drilled to 22,854 ft with a true vertical depth of 8,737 ft. It produced 25.78 MMcf of gas per day with a shut-in casing pressure of 3,482 psi. Production is from perforations at

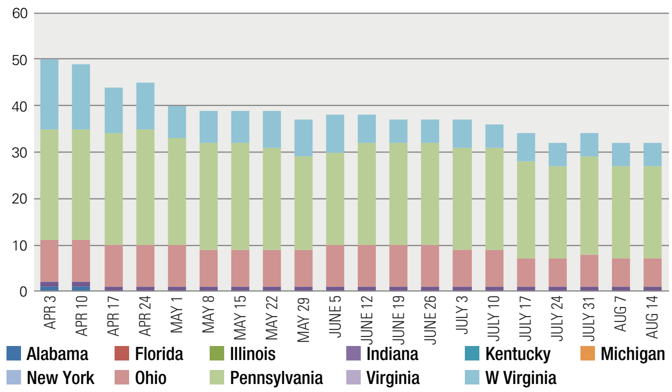






Eastern US Rig Count

Apr. 3, 2020-Aug. 14, 2020



Source: Baker Hughes Co.

9,291-22,697 ft. The #1H Hemlock Ridge Estates West has a total depth of 22,233 ft and a true vertical depth of 8,787 ft. It initially flowed 27.234 MMcf of gas per day. The shut-in casing pressure was measured at 3,256 psi, and production is from perforations at 9,647-21,999 ft.

10 Two Bradford County Pa., Marcellus discoveries were announced by ***Chesapeake Operating Inc***. The Herrick Field wells were drilled from a drillpad in Section 7, Laceyville 7.5 Quad, Wyalusing Township. The #106HC Brown Homestead flowed 44.24 MMcf of gas per day. It was drilled to 18,120 ft, and the true vertical depth is 7,251 ft. The shut-in casing pressure was 3,414 psi, and production is from a perforated zone between 7,508 and 18,106 ft. The #5HC Brown Homestead produced 48.644 MMcf of gas per day. It was drilled to 17,314 ft with a true vertical depth of 7,248 ft. The shut-in casing pressure was 3,434 psi, and production is from fractured perforations between 7,237 ft and 12,299 ft.

11 ***Southwestern Energy Co.*** announced results from four Marcellus Shale completions drilled at a Herrick Field pad in Section 9, Le Raysville 7.5 Quad, Stevens Township in Bradford County, Pa. IHS Markit reported that #9H McMahon was drilled to 19,255 ft (6,342 ft true vertical) and flowed 19.2 MMcf of gas per day with a shut-in casing pressure of 1,835 psi. Production is from fractured perforations at 6,342-19,183 ft. The #8H McMahon was drilled to 19,060 ft (6,325 ft true vertical) and flowed 16.368 MMcf of gas per day with a shut-in casing pressure of 1,362 psi from perforations at 6,447-18,989 ft. The #10H McMahon was drilled to 19,366 ft (6,405 ft true vertical) and flowed 18.288 MMcf of gas per day with a shut-in casing pressure of 1,894 psi, and production is from perforations at 6,430-19,334 ft. The #12H McMahon was drilled to 18,979 ft (6,294 ft true vertical) and flowed 19.104 MMcf of gas per day with a shut-in casing pressure of 2,077 psi. Production is from perforations at 6,217-18,907 ft. Southwestern's headquarters are in Spring, Texas.

12 Four Susquehanna County, Pa., Marcellus Shale completions were announced by Houston-based ***Cabot Oil & Gas***. The Lenox Field wells were drilled from a single pad in Section 1, Lenoxville 7.5 Quad, Lenox Township. The #10H Forwood E was drilled to 16,777 ft, 7,034 ft true vertical, and flowed 17 MMcf of gas per day with a shut-in casing pressure of 775 psi. Production is from perforations at 8,113-16,699 ft. The #6H Forwood E was drilled to 24,000 ft, 6,942 ft true vertical, and produced 32.2 MMcf of gas per day with a shut-in casing pressure of 1,200 psi and is producing from perforations at 7,964-23,930 ft. The #7H Forwood had a total depth of 13,082 ft and a true vertical depth of 7,452 ft. It flowed 11.8 MMcf of gas per day with a shut-in casing pressure of 600 psi. Production is from a perforated zone between 7,721 ft and 13,006 ft. The #5H Forwood E was drilled to 16,133 ft, 7,498 ft true vertical, and initially flowed 23.4 MMcf of gas per day with a shut-in casing pressure of 950 psi. Production is from perforations at 7,477-16,056 ft.

GULF COAST

1 ***CML Exploration*** has completed a dual-lateral oil well in the Dimmit County (RRC Dist. 1), Texas, portion of Pearsall Field. IHS Markit reported that #301 CR initially flowed 405 bbl of 44° API crude, 100,000 cu ft of gas and 20 bbl of water from commingled openhole zones at 4,130-13,052 ft and 4,676-15,532 ft. The Maverick Basin well was drilled from a surface location in Section 582, Hugh Vandeverer Survey, A-850. The first lateral bottomed about 1.6 miles to the southeast at a true vertical depth of 4,707 ft in Section 1, H&GN RR Co Survey, A-151. The second lateral had a true vertical depth of 4,550 ft and bottomed more than 2 miles to the northwest in Section 613, John Sharp Survey, A-814. Tested on a 20/64-inch choke, the flowing tubing pressure was 800 psi. CML's headquarters are in Austin.

2 An Austin Chalk-Sugarkane Field completion was reported by San Antonio-based ***Ageron Energy***. Located in Karnes County (RRC Dist. 2), Texas, #1H Bolf AC Unit flowed at a daily rate of 1,022 bbl of 39° API oil with 975,000 cu ft of gas and 588 bbl of water. It is in Erasmo Seguin Survey, A-10, and was drilled to a total depth of 13,835 ft with a true vertical depth of 10,412 ft. Tested on a 24/64-inch choke, the flowing tubing pressure was 1,160 psi, and the flowing casing pressure was 60 psi. Production is from perforations between 10,880 and 13,502 ft.

3 Two Austin Chalk discoveries were announced by ***BPX Energy*** in the Sugarkane Field portion of Karnes County (RRC Dist. 2), Texas. The wells were drilled from a pad in Ramon Musquiz Survey, A-7. According to IHS Markit, #1H Gallo Rojo A AC was drilled to the north to 16,073 ft with a true vertical depth of 10,705 ft. It flowed 3,431 bbl of 42.8° API oil, 5.039 MMcf of gas and 375 bbl of water per day from perforations at 11,501-19,945 ft. The parallel #2H Gallo Rojo A AC was drilled to 16,089 ft, 10,748 ft true vertical, and produced 1.926 bbl of 43° API oil, 2.981 MMcf of gas and 249 bbl of water per day from a perforated zone at 11,275-15,960 ft. BPX Energy, based in Denver, is a subsidiary of ***BP***.

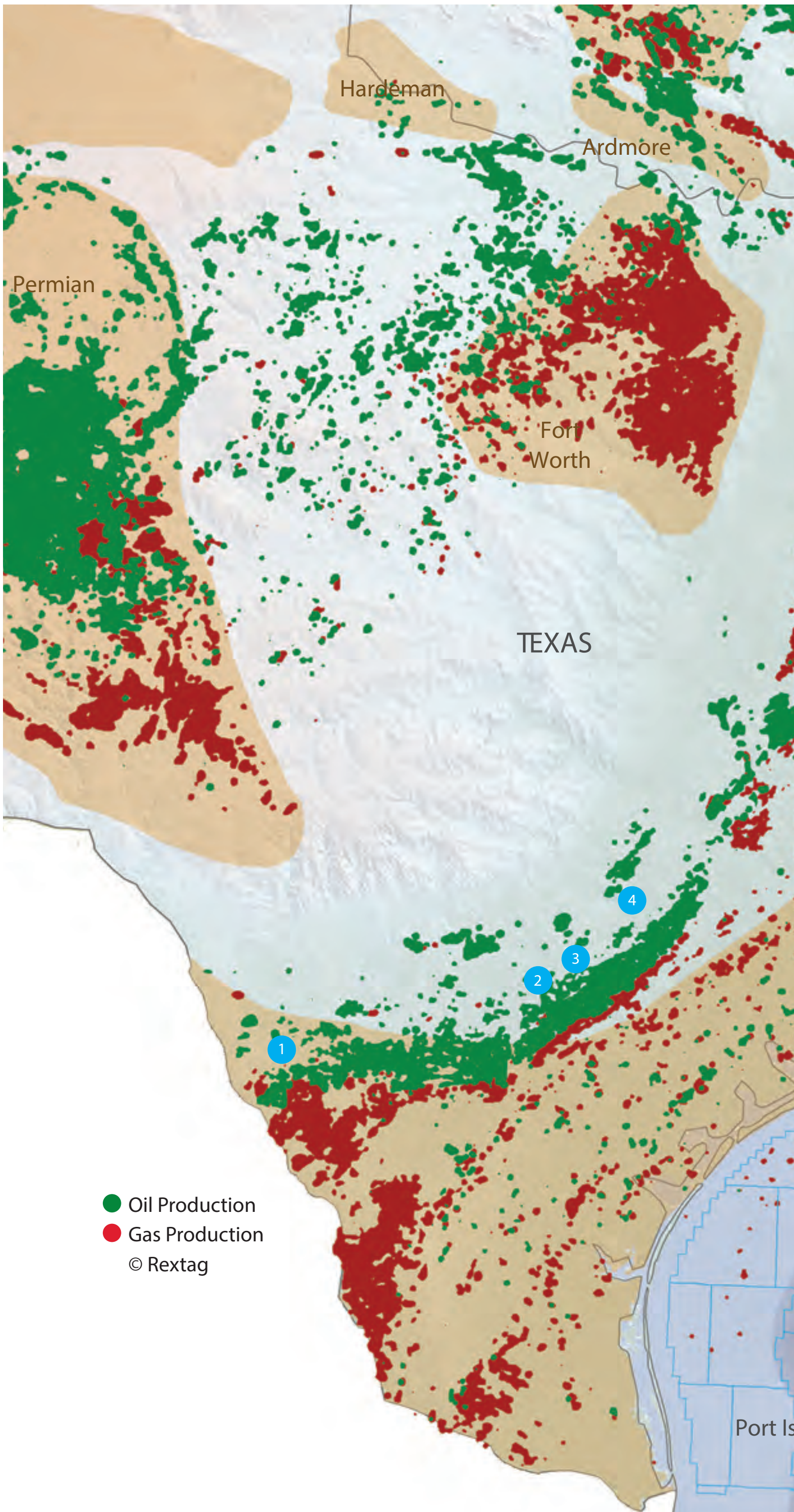
4 ***Marathon Oil Corp.*** reported an Eagle Ford completion in Texas' Gonzales County (RRC Dist. 1). The Eagleville Field well, #100H Barnhart (EF), is in James Tennel Survey, A-449. It was tested on a 26/64-inch choke flowing at a daily rate of 2,367 bbl of 44° API oil, 961,000 cu ft of gas and 1,887 bbl of water. Drilled to 18,620 ft, 10,245 ft true vertical, it is producing from perforations between 9,973 ft and 18,493 ft. Marathon is based in Houston.

5 ***GEP Haynesville*** announced results from a Haynesville Shale producer in Sabine Parish, La. The #001-Alt Olympia Minerals 23-26HC is in Section 23-9n-12w and produced 37.182 MMcf of gas and 447 bbl of water per day. The Bayou San Miguel Field well was drilled to 22,541 ft with a true vertical depth of 12,734 ft. Tested on a 32/64-inch choke, the flowing casing pressure was 8,348 psi. Production is from a fractured and perforated zone at 12,910-22,482 ft. GEP is based in The Woodlands, Texas.

6 ***Aethon Energy Operating***, based in Dallas, completed a Sligo Field-Haynesville Shale well. The #1 Treat 14-23HC is in Section 14-17n-12w in Bossier Parish, La. It was fractured in 80 stages and produced 15.504 MMcf of gas and 51 bbl of water daily. Drilled to 21,142 ft, the true vertical depth is 10,982 ft. It was tested on a 24/64-inch choke with a flowing casing pressure of 6,905 psi, and production is from perforations at 11,125-21,102 ft.

7 In West Cameron Block 73, ***Walter Oil & Gas Corp.*** completed #002S0B1 OCS G23736 ST00BP01 as a directional producer. It was drilled to 18,450 ft with a true vertical depth of 17,958 ft. It flowed 270 bbl of 43° API condensate with 15.141 MMcf of gas and 33 bbl of water per day. Production is from a perforated Lower Miocene zone at 16,300-16,580 ft. Gauged on a 19/64-inch choke, the flowing tubing pressure was 10,900 psi, and the shut-in tubing pressure was 12,000 psi.

8 In Louisiana's Pointe Coupee Parish, ***Pennington Oil & Gas Interests*** completed an Austin Chalk well. Located in Section 48-5n-11e, #1 Rougon HRS pumped 205 bbl of 42.7° API oil, 185,000 MMcf of gas and 275 bbl of water per day. The Profit Island Field well was directionally drilled to 19,834. Gauged on a 7/64-inch choke, the flowing tubing pressure was 8,773



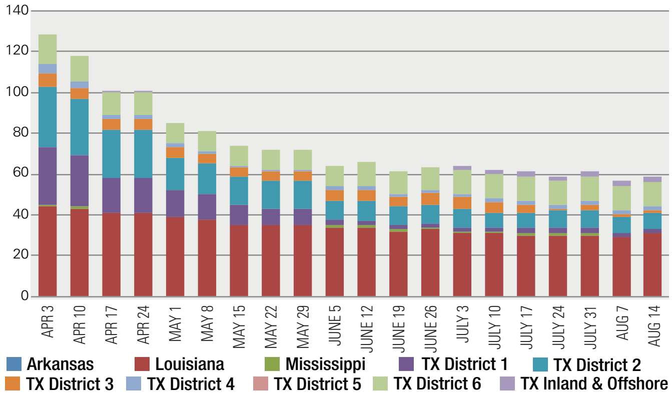
psi, and the flowing casing pressure was 2,235 psi. Production is from acidized and fractured perforations at 17,513-17,673 ft. Pennington's headquarters are in Baton Rouge.

9 A deepwater bypass has been scheduled by ***Beacon Offshore Energy*** at the company's Tabasco prospect. The venture will be in the eastern half of Green Canyon Block 35 at #1 (BP) OCS G36624. The permit indicates that the bypass is expected to be kicked off at 11,670 ft. Area water depth is 1,850 ft. According to the prospect's exploration plan, as many as three tests will be drilled in the eastern half of the tract. A partnership of four companies led by Beacon acquired the drilling rights to Green Canyon Block 35 in 2019. Oil and gas production in this part of the deepwater Gulf comes from two fields—Manta Ray and Prince—in the Ewing Bank area to the north. Beacon's headquarters are in Houston.

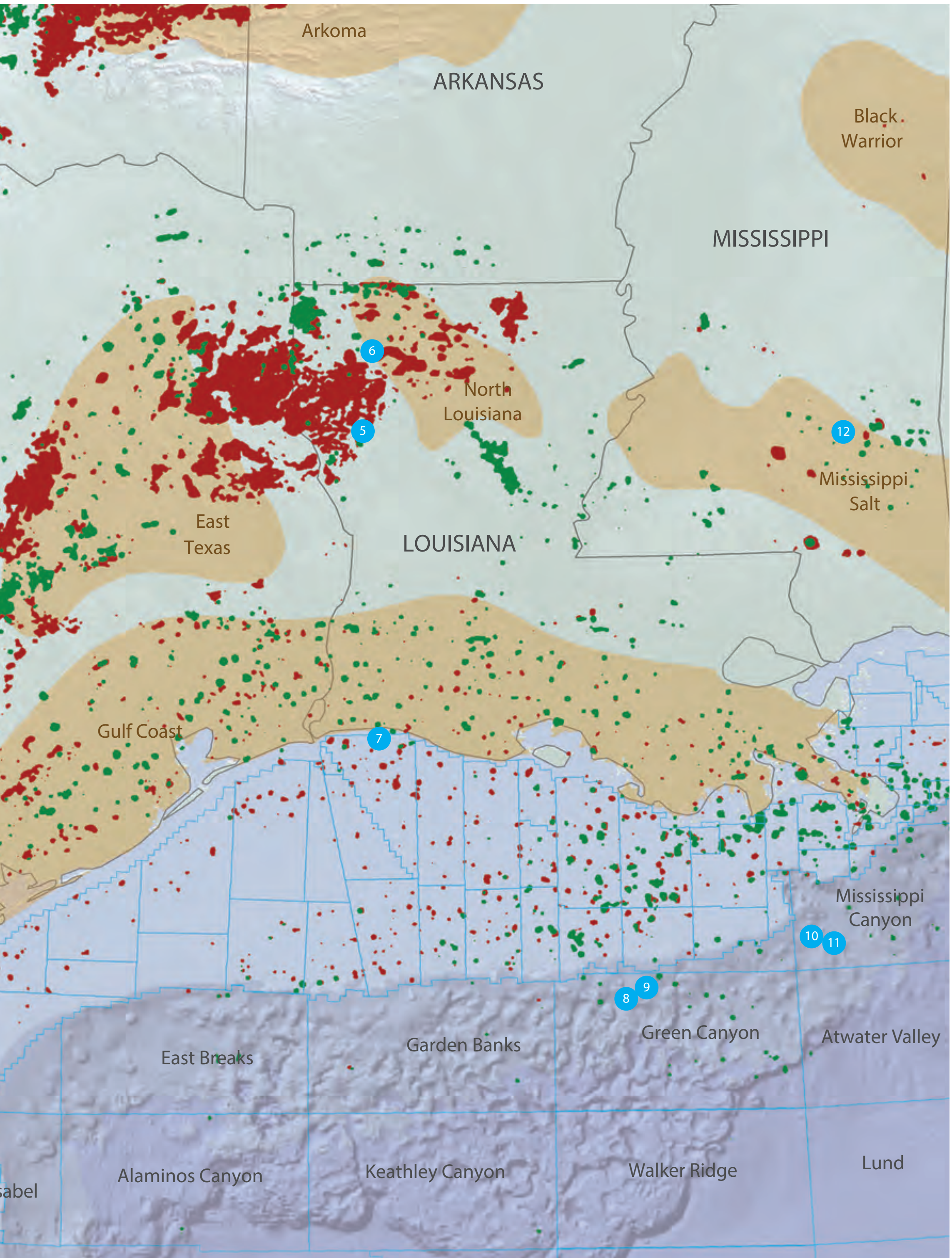
10 A ***Beacon Offshore Energy*** Miocene discovery was completed in Mississippi Canyon Block 794. The company's #0SS003S0B OCS G34909 ST00BP00 flowed at a daily rate of 6,152 bbl of 30.6° API oil, 11.905 MMcf of gas with 18 bbl of water. Production at the 23,275-ft well is from perforations in a Miocene zone at 22,765-22,886 ft. The Claiborne Field well was tested on a 49/64-inch choke, and the flowing tubing pressure was 7,883 psi. Claiborne Field was discovered and initially developed in 2017 by ***LLOG***.

Gulf Coast Rig Count

Apr. 3, 2020-Aug. 14, 2020



Source: Baker Hughes Co.



11 An Upper Miocene discovery was announced in Mississippi Canyon Block 934 by Houston-based ***Shell Oil Co***. The #0A006S1B OCS G07976 initially flowed 11,995 bbl of 27° API oil, with 10,000 cu ft of gas per day with no reported water. It was drilled to 18,620 ft, and the true vertical depth is 17,826 ft. Gauged on an 88/64-inch choke, the flowing tubing pressure was 4,963 psi, and production is from perforations at 18,423-18,465 ft.

12 A Cotton Valley oil well was reported by ***Venture Oil & Gas*** in New Home Field in Smith County, Miss. The #1 King 8-7 flowed at a daily rate of 258 bbl of 46° crude and 510,000 cu ft of gas from perforations at 15,546-15,660 ft. The directional well was drilled to 15,900 ft and is in Section 8-10n-13w. It was tested on an 8/64-inch choke, and the flowing tubing pressure was 2,350 psi. With its latest completion, the Laurel, Miss.-based company has drilled five wells in New Home Field, and they are the only Cotton Valley producer in this part of Mississippi.

MIDCONTINENT & PERMIAN BASIN

1 A Wolfcamp well in Eddy County, N.M., was tested flowing 4,544 bbl of oil, 10.925 MMcf of gas and 9,581 bbl of water per day. ***Oxy USA Inc.***'s #036H Corral Fly 35-26 Federal Com is in Section 2-25s-29e. The Purple Sage Field well was drilled to 20,483 with a true vertical depth of 10,364 ft. Tested on a 37/64-inch choke, the shut-in casing pressure was 1,600 psi, and production is from a perforated zone at 10,537-20,387 ft. Oxy USA is a subsidiary of ***Occidental Petroleum***.

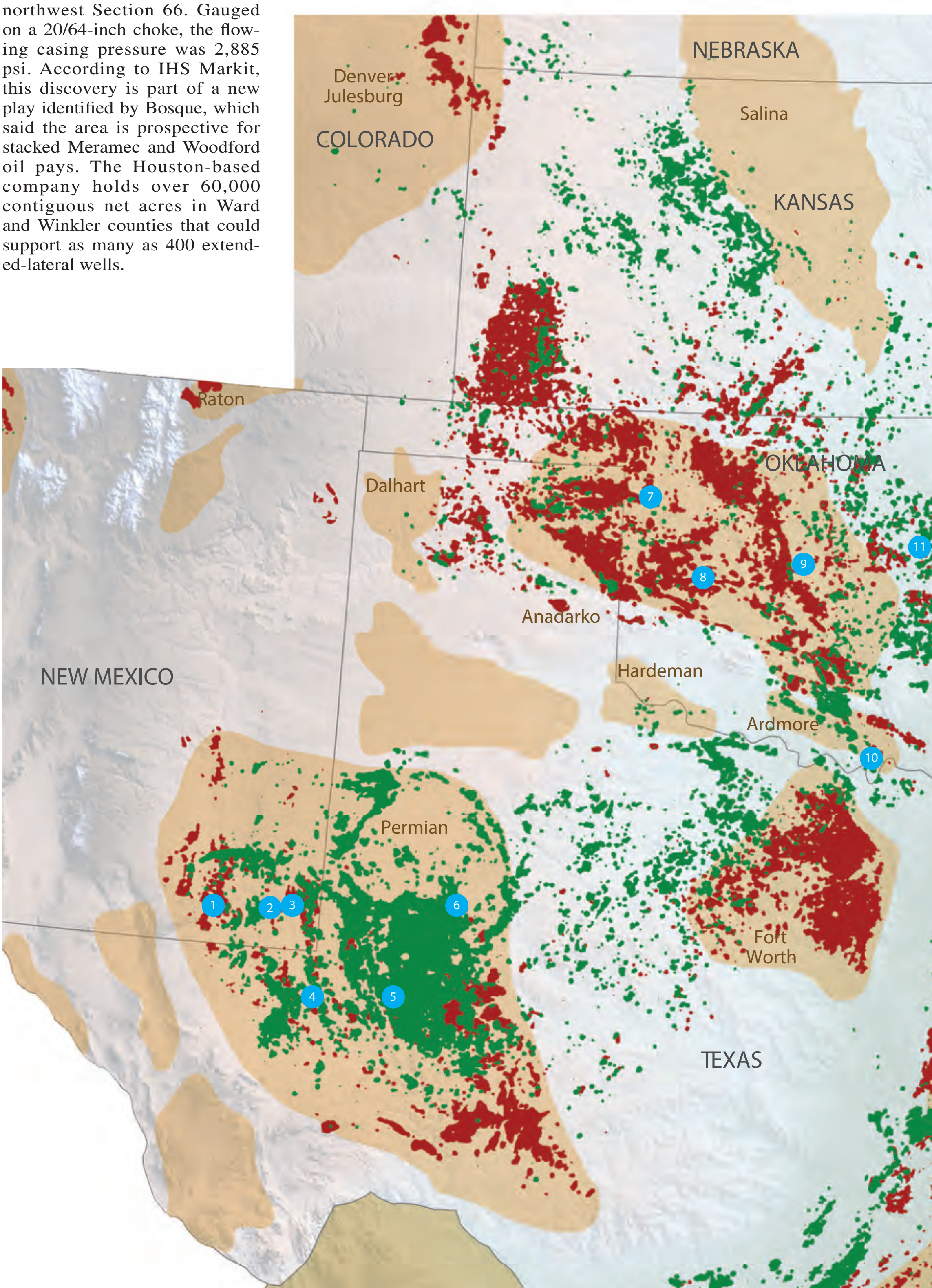
2 ***EOG Resources Inc.*** completed two Bone Spring wells in Lea County, N.M. The Red Hills North Field wells were drilled from a pad in Section 28-24s-34e. The #308H Stonewall 28 Fed Com was drilled to 20,392 ft, 10,357 true vertical, and initially flowed 3,279 bbl of 43° API oil, 5.139 MMcf of gas and 4,203 bbl of water per day. It was tested on a 64/64-inch choke. The shut-in casing pressure was 762 psi, and production is from fractured perforations at 10,317-20,392 ft. The #309H Stonewall 28 Federal Com was drilled to 20,347 ft, 10,315 ft true vertical. It was tested on a 64/64-inch choke flowing 3,741 bbl of oil, 4.89 MMcf of gas and 4,247 bbl of water per day. The shut-in casing pressure was 832 psi, and production is from a fractured and perforated zone at 10,367-20,347 ft.

3 ***COG Operating LLC*** reported results from an extended-lateral well that was completed as a Wolfbone oil producer in Lea County, N.M. The #704H Pork Pie State Com flowed 562 bbl of crude, 763,000 cu ft of gas and 3,936 bbl of water per day. Production is from acid- and fracture-stimulated perforations at 12,381-22,080 ft. The flowing tubing pressure was 3,000 psi during testing on a 12/64-inch choke. Drilled to 22,235 ft (11,973 ft true vertical) the well is in Section 15-24s-35e, and the lateral bottomed approximately 2 miles to the north in adjacent Section 10. COG's headquarters are in Midland, Texas.

4 ***Bosque Texas Oil LLC*** completed a deep horizontal Delaware Basin well in Ward County (RRC Dist. 8), Texas. The #1H King George flowed 1,278 bbl of 48.5° API crude, 3.26 MMcf of gas and 2,605 bbl of water per day from acid- and fracture-treated Mississippian perforations at 13,647-18,663 ft. The well is in Section 65, Block F, G&MMB&A Survey, A-33. It was drilled to 18,685 ft (13,856 ft true vertica), and the lateral bottomed about 1.5 miles to the northwest Section 66. Gauged on a 20/64-inch choke, the flowing casing pressure was 2,885 psi. According to IHS Markit, this discovery is part of a new play identified by Bosque, which said the area is prospective for stacked Meramec and Woodford oil pays. The Houston-based company holds over 60,000 contiguous net acres in Ward and Winkler counties that could support as many as 400 extended-lateral wells.

5 ***COG Operating LLC*** announced results from two Upton County (RRC Dist. 7c) Texas, wells in Pegasus Field. The ventures were drilled from a pad in Section 11, Block 41, T&P RR CO Survey, A-49. The #4804BH TXL-Powell A10 was drilled to 20,200 ft with a true vertical depth of 9,448 ft. It flowed 1,399 bbl of 42° API oil, 2.016 MMcf of gas and 2,096 bbl of water daily from fractured Wolfcamp perforations at 9,746-20,067 ft. The #4813LH TXL-Powell A8 was drilled to 19,538 ft (8,760 ft true vertical) and flowed 898 bbl of 42° API oil, 830,000 cu ft of gas and 1,818 bbl of water per day from Spraberry at 9,033-19,434 ft.

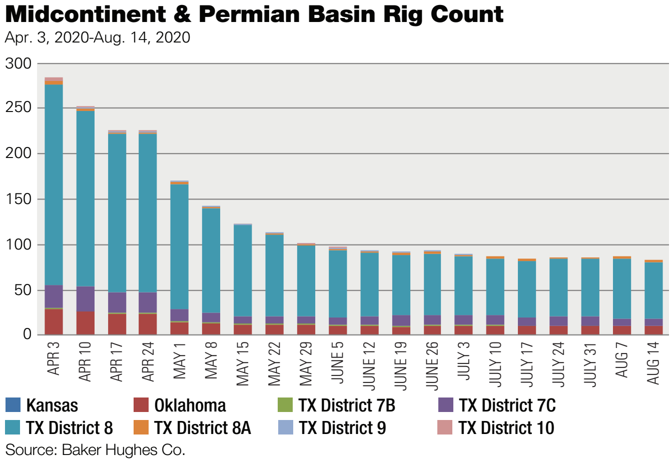
6 In Texas' Howard County (RRC Dist. 8), Houston-based ***Occidental Petroleum Co.*** completed two Spraberry Field wells from a pad in Section 24, Block A, Bauer & Cockrell Survey, A-573. The #1H Santana 2430D flowed 1.162 bbl of 37° API oil, 1.041 MMcf of gas and 1,472 bbl of water per day from commingled Spraberry and Dean perforations at 7,905-18,781 ft. Drilled to 19,005 ft, the true vertical depth is 7,786 ft. The parallel #1H Santana 2916SA produced 215 bbl of

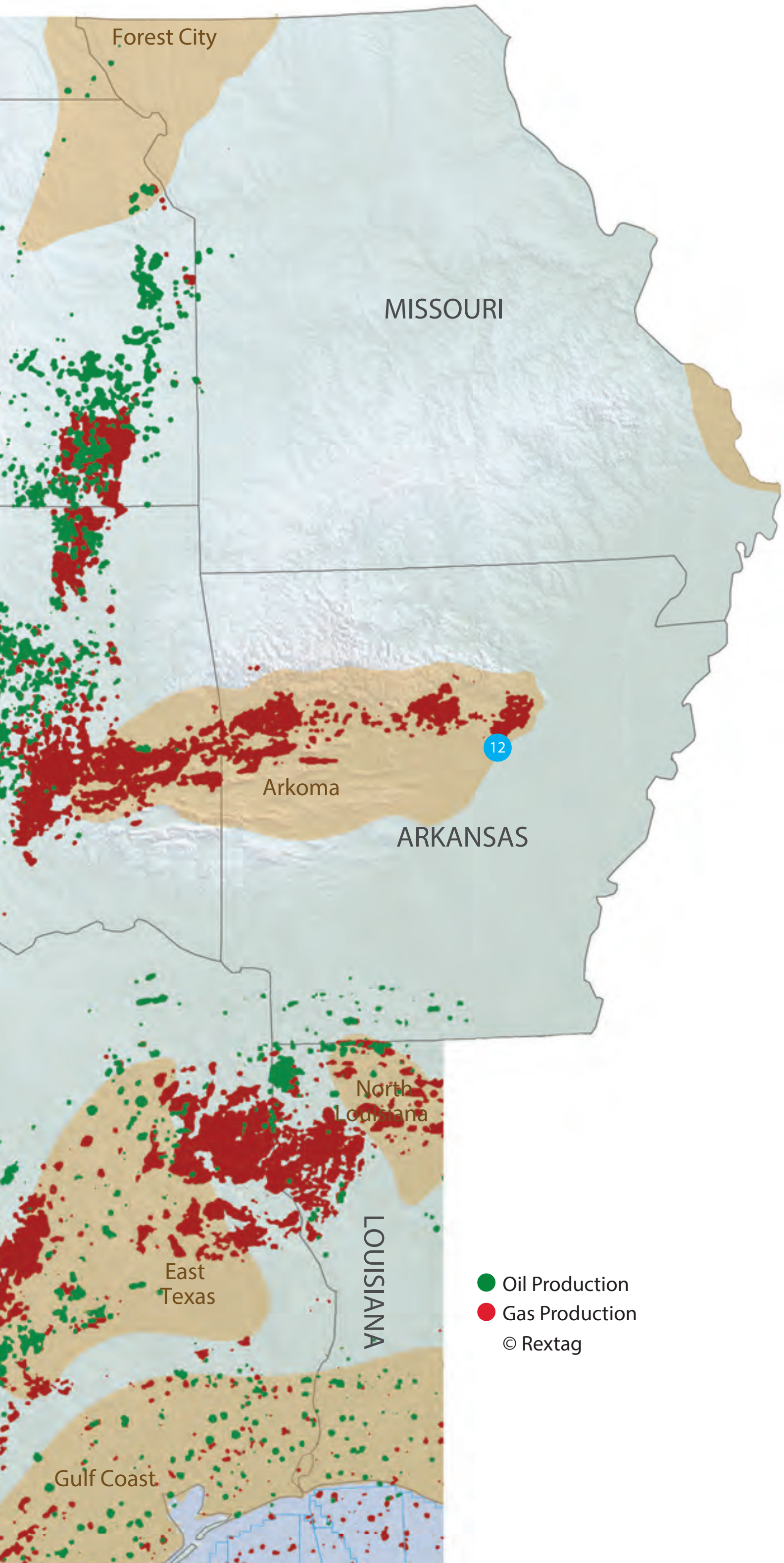


36° API oil with 155,000 cu ft of gas and 3,317 bbl of water per day from a Spraberry zone at 7,247-19-847 ft. It was drilled to 29,102 ft, 7,025 ft true vertical. Both wells bottomed to the southeast in Section 16.

7 ***Mewbourne Oil Co.*** announced a Cherokee discovery in Ellis County, Okla. at #1HR Goldfinger 21/28 BO. The Grand West Field discovery initially flowed 402 bbl of 45° API oil, 490,000 cu ft of gas with 1,123 bbl of water daily from perforations between 10,310 and 19,459 ft. Located in Section 21-18n-24w, the venture was drilled to 19,692 ft, and the true vertical depth is 10,222 ft. Gauged on a 20/64-inch choke, the flowing tubing pressure was 2,200 psi. Mewboune is based in Tyler, Texas.

8 A horizontal Washita County, Okla., gas producer in Burns Flat Field was completed by ***Crest Resources Inc.*** The #3-21H Sasseen initially flowed 3.311 MMcf of gas, 58 bbl of 54° API condensate and 335 bbl of water per day from Des Moines at 13,468-18,100 ft. The perforated interval was acidized and fracture stimulated. It was tested on a 25/64-inch choke, and the flowing tubing pressure was 1,500 psi. The new producer was drilled to 18,154 ft and is in Section 16-10n-18w. The true vertical depth is 12,437 ft, and it bottomed to the south in nearby Section 21. Crest's headquarters are in Tulsa.





9 ***Citizen Energy III*** completed two horizontal wells in the Canadian County portion of Oklahoma's Anadarko Basin. The #1-R1H-12 Caldwell flowed 226 bbl of oil, 897,000 cu ft of gas and 1,033 bbl of water per day from acid- and fracture-treated perforations at 12,087-22,307 ft in Woodford Shale. The flowing tubing pressure was 3,225 psi when tested on a 16/64-inch choke. The well was drilled to 22,416 ft from a pad in Section 12-12n-9w. The lateral bottomed nearly 2 miles to the north at 11,891 ft true vertical in Section 1-12n-9w. The offsetting and parallel #2H-12-1 Caldwell was tested though Mississippian perforations at 11,674-21,892 ft following acidizing and fracturing. The initial potential was 100 bbl of oil, 1.332 MMcf of gas and 881 bbl of water per day. The total depth is 21,988 ft, and the true vertical depth is 11,475 ft. Citizen is based in Tulsa.

10 A horizontal Woodford producer was completed in the Marietta Basin in Love County, Okla., by Irving, Texas-based ***Exxon Mobil*** subsidiary ***XTO Energy Inc***. According to IHS Markit, the Marietta Southeast Field venture, #1-9H4X5 Horseshoe Bend, was tested flowing 624 bbl of 45° API oil, 1.908 MMcf of gas and 6,595 bbl of water per day. Production is from fracture-stimulated perforations at 16,791-25,001 ft. It was drilled to 25,966 ft in Section 9-8s-2e and had a planned true vertical depth of 17,000 ft. The lateral bottomed about 1.5 miles to the northwest in Section 5. Tested on a 20/64-inch choke, the flowing tubing pressure was 4,562 psi.

11 A Skinner Sand well was announced in Creek County, Okla., by ***WFD Oil Corp.*** The Edmond, Okla.-based company's #1-29 Vanorsdol is in Section 29-15n-9e. It produced 135 bbl of oil with 160,000 cu ft of gas per day with no reported water. It was drilled in Iron Post Field to 3,757 ft and was tested after acidizing.

12 ***Merit Energy*** has recompleted a horizontal Fayetteville Shale well in Arkansas' White County in B-43 Field. IHS Markit reported that #2-25H Carthel Langley 7-9 flowed 437,000 cu ft of gas per day from perforations at 7,970-12,452 ft. The Arkoma Basin well was originally tested in 2012 flowing 2.539 MMcf of gas per day from the same set of perforations. It was horizontally drilled to 12,543 ft (7,421 ft true vertical) in Section 25-7n-9w. Merit is based in Dallas.

WESTERN US

1 ***XCL Resources***, based in Houston, has released details on a horizontal Uinta Basin producer in Uintah County, Utah, that was completed in March 2020. The #23-74H-21 Butcher Butte is producing from an unreported Wasatch zone flowing 161 bbl of crude, 36,000 cu ft of gas and 730 bbl of water per day. Gauged on an 8/64-inch choke, the flowing casing pressure was 3,126 psi. It is in Section 23-2s-1w and bottomed about 2 miles to the north-northwest in Section 14. The total depth is 20,405 ft (10,548 ft true vertical). The Bluebell Field well was originally permitted by ***Axia Energy II***—Axia has permitted another 12 horizontal tests from the Butcher Butte pad with oil objectives in the Uteland Buttes and Castle Peak.

2 Three directional Uteland Buttes tests have been permitted by ***CH4-Finley Operating LLC*** from a pad in Uintah County, Utah. The Independence Field, wells, #16-16-3-1E Cox , #21-01-3-1E Cox and #21-02-3-1E Cox will be drilled to respective depths of 8,039 ft (8,005 ft true vertical), 8,101 ft (7,967 ft true vertical) and 8,171 ft (7,972 ft true vertical). The Uinta Basin pad will be in Section 16-3s-1e. The first test will bottom to the northeast, with the other two bottoming to the southeast and southwest under adjacent section 21-3s-1e. CH4-Finley is based in Fort Worth.

3 ***Samson Resources Co.*** completed an extended-lateral Powder River Basin well in Converse County, Wyo. The #4075-3625 1SH Spearhead, according to IHS Markit, flowed 1,406 bbl of 39° API crude, 703,000 cu ft of gas and 1,277 bbl of water per day from acid- and fracture-stimulated perforations in Shannon at 11,162-20,903 ft. The initial hole was abandoned at 15,828 ft (10,928 ft true vertical) in Section 36-40n-75w. The successful Hornbuckle Field sidetrack reached a total depth of 21,010 ft (10,906 ft true vertical) and bottomed 2 miles to the north in Section 25. Gauged on a 22/64-in. choke, the flowing tubing pressure was 1,513 psi. Samson Resources is based in Tulsa.

4 Results from a Niobrara well were announced by ***Samson Resources Co***. The #34-3031 39-74 NH Allemand Fed initially flowed 2,413 bbl of 49° API oil with 4.375 MMcf of gas and 1,224 bbl of water per day. The Hornbuckle Field was drilled in Section 30-39n-74w in Converse County, Wyo., to 22,326 ft (12,207 ft true vertical). It was tested after 47-stage fracturing with a shut-in casing pressure of 3,000 psi during testing on a 28/64-inch choke. Production is from a perforated zone at 12,298-22,061 ft.

5 According to IHS Markit, ***Rebellion Energy II*** completed two Campbell County, Wyo., wells drilled from a pad in Section 8-41n-7w. According to the company, #4174-6-7-4NH Diablo E had an initial 24-hour rate of 3,060 bbl of oil equivalent per day (80% oil) from a 9,143-ft Niobrara lateral. The venture bottomed about 2 miles to the north-northwest in Section 6-41n-74w. The proposed depth was 21,817 ft (11,294 ft true vertical). The vertical pilot hole reached approximately 13,591 ft. The offsetting and south-trending #8S 4174-17-20 MWB-1H Coronado W was completed in an 8,271-ft Mowry lateral with a daily rate of 2,283 bbl of oil equivalent (50% oil). It had a planned depth of 23,052 ft (12,711 ft true vertical) with a planned bottom-hole location in Section 20-41n-74w. Rebellion's headquarters are in Tulsa.

6 Houston-based ***EOG Resources Inc.*** completed a Parkman well in Campbell County, Wyo. The House Creek Field venture, #0508-01H Congo, is in Section 5-42n-72w and was drilled to 16,820 ft (7,446 ft true vertical). It was tested after 22-stage fracturing flowing 1,017 bbl of 57° API condensate, 1.459 MMcf of gas and 1,095 bbl of water daily. Production is from perforations at 7,854-16,754.

7 ***Upland Exploration LLC*** has completed two Denver-Julesburg Basin wells from a multiwell pad in Section 21-11n-64w in Weld County, Colo. The #22-1NH Little Lady produced 1,149 bbl of 34° API crude, 1.485 MMcf of gas and 700 bbl of water from an acid- and fracture-treated Niobrara zone at 7,968-12,484 ft. It was tested on a 1-inch choke with a flowing tubing pressure of 518 psi and a flowing casing pressure of 344 psi. The well was drilled to an estimated total depth of 12,587 ft and an estimated true vertical depth of 7,693 ft. The offsetting #22-2CH Little Lady was completed in an acid- and fracture-treated Codell zone at 8,075-12,747 ft flowing 311 bbl of 34° API crude, 338,000 cu ft of gas and 600 bbl of water per day. Gauged on a 1-inch choke, the flowing tubing pressure was 338 psi, and the flowing casing pressure was 103 psi. The well was drilled to an estimated total depth of 12,856 ft and an estimated true vertical depth of 7,902 ft. The bottom-hole location for both wells was about 1 mile to the northeast in Section 22. Upland is based in Boerne, Texas.

8 In McKenzie County, N.D., Houston-based ***Oasis Petroleum*** completed an Upper Three Forks and a Middle Bakken well from a Banks Field drillpad in Section 32-153n-97w. The #5397 42-32 8T Joplin was drilled to 22,585 ft with a true vertical depth of 11,191 ft. It was tested after 33-stage fracturing flowing 743 bbl of oil, 1.555 MMcf of gas and 1,555 bbl of water daily from Three Forks perforations at 11,698-22,514 ft. It was tested on a 20/64-inch choke, and the flowing casing pressure was 3,300 psi. The #5397 42-32 7B Joplin was drilled to 22,479 ft, 11,089 ft true vertical. It was tested after 33-stage fracturing flowing 1,183 bbl of oil with 2.807 MMcf of gas and 1,213 bbl or water per day from Middle Bakken perforations at 11,588-22,401 ft. Gauged on a 22/64-inch choke, the flowing casing pressure was 3,250 psi.

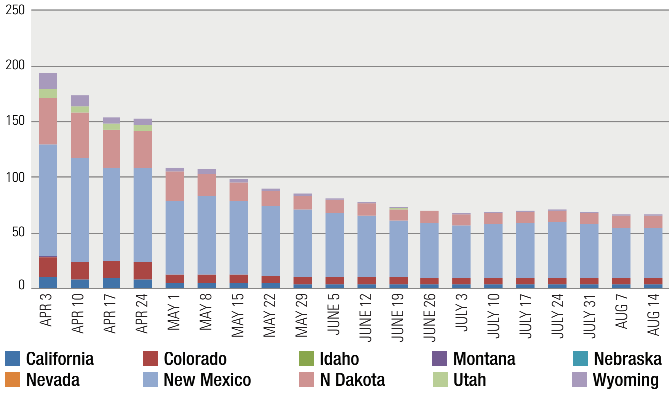
9 ***Hess Corp.*** completed two more wells at its Stenbak prospect in Williams County, N.D. The Tioga Field wells were drilled from a drillpad in Section 25-158n-95w. The #158-95-2526H-5 TI-Stenbak was drilled to 20,172 ft, 9,673 ft true vertical, and bottomed in Section 26. The well flowed 824 bbl of oil, 691,000 cu ft of gas and 1,763 bbl of water daily from Three Forks perforations at 10,112-19,997 ft. It was tested on a 32/64-inch choke after 35-stage fracturing with a flowing casing pressure of 793 psi. Within one-half mile to the south, #158-95-2526H-6 TI-Stenbak was drilled to 20,084 ft, 9,579 ft true vertical. It produced 946 bbl of oil with 946,000 cu ft of gas and 2,247 bbl of water per day from Middle Bakken at 9,954-19,912 ft. Gauged on a 38/64-inch choke, the flowing casing pressure was 710 psi after 41-stage fracturing.

10 An Upper Three Forks venture in Dunn County, N.D., initially flowed 5,172 bbl of 41° API oil, 3.785 MMcf of gas and 4,884 bbl of water per day. ***Marathon Oil Co.***'s #34-12TFH Ritter was drilled in Section 12-146n-94w. The Bailey Field discovery was drilled to 21,287 ft, and the true vertical depth was 10,761 ft. Production is from perforations at 11,114-21,154 ft. Gauged on a 64/64-inch choke, the flowing casing pressure was 1,200 psi.

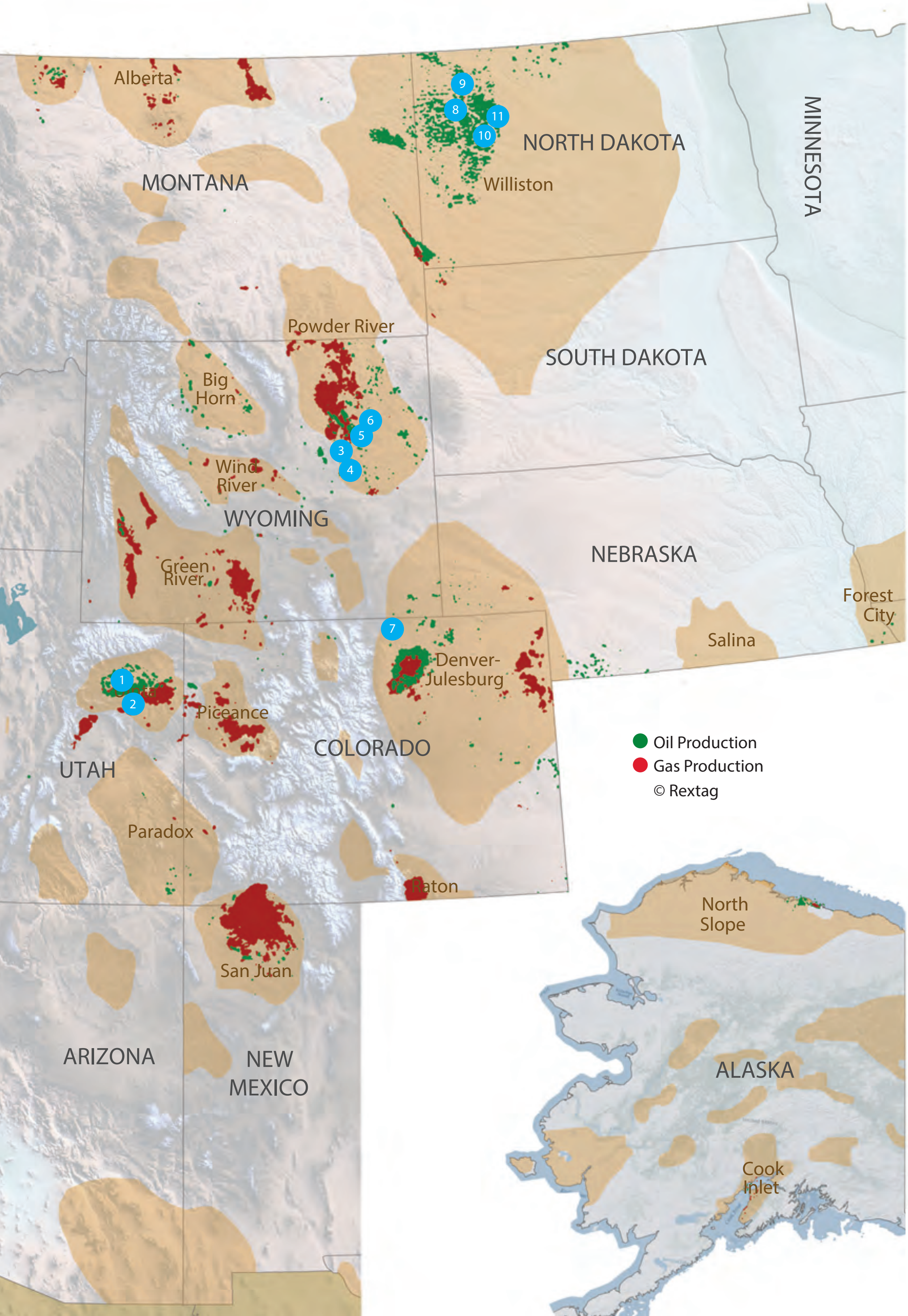
11 ***Rimrock Oil & Gas*** announced results from an Upper Three Forks discovery in Heart Butte Field. The #8-2-3-4H3U Skunk Creek was drilled to 21,199 ft (10,737 ft true vertical) and bottomed to the northwest in Section 3. The Dunn County, N.D., venture initially flowed 1,730 bbl of oil with 960,000 cu ft of gas and 2,345 bbl of water per day after 45-stage fracturing from a perforated zone between 11,169 and 21,116 ft. Rimrock's headquarters are in Greenwood Village, Colo.

Western US Rig Count

Apr. 3, 2020-Aug. 14, 2020



Source: Baker Hughes Co.



INTERNATIONAL HIGHLIGHTS

The world's largest oil company, Saudi Aramco, reported that its quarterly earnings fell more than 73% compared to a year ago, as the coronavirus pandemic drastically cut worldwide demand for oil and hurt oil prices. Aramco earned $6.6 billion in the second quarter of 2020 compared to $23.5 billion from 2019 second quarter earnings.

The company will continue paying a quarterly dividend of $18.75 billion, almost three times its cash flow. Aramco is locked into paying that amount ($75 billion a year) because of commitments made in the run-up to its initial public offering on the Saudi stock exchange. Nearly all of the dividend money will go to the Saudi government, which owns more than 98% of the company.

Earlier in 2020, Aramco cut production then increased it during a price war with Russia. In May, Saudi Arabia reduced production through an agreement reached under pressure from the Trump administration. Under that agreement, the Saudis are able to increase production by 500,000 bbl/d in August but without a discernible impact on prices so far.

Brent crude prices have risen from their April lows of under $20/bbl to around $44/bbl but still remain down about one-third on the year.

—Larry Prado

1 Bahamas

Bahamas Petroleum Co. has been given an extension to its exploration period to drill an offshore Bahamas test, #1- Perseverance, in the Cooper Block. The extension was granted due to the force majeure declaration called because of the current COVID-19 pandemic in the Bahamas. The extension deadline is April 2021. Drilling operations will include managed pressure drilling. The venture is targeting a recoverable P50 prospective oil resources of approximately 700 MMbbl with an upside of 1.44 billion bbl. Bahamas Petroleum is based in the Isle of Man.

2 Guyana

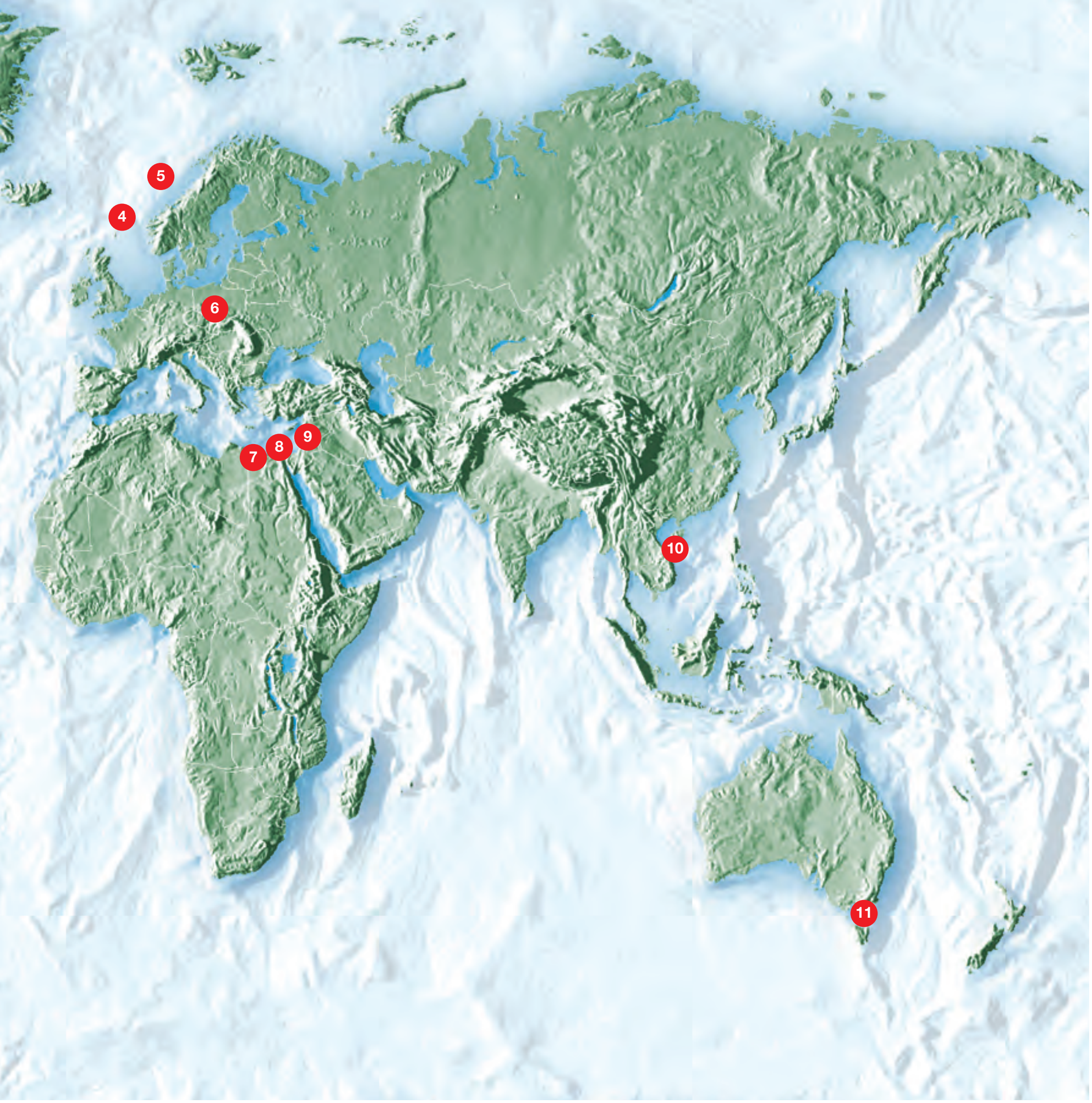
Exxon Mobil announced two additional reservoirs in the Stabroek Block in offshore Guyana. The additional reservoirs are adjacent to and southeast of the Yellowtail Field discovery well. According to partner ***Hess Corp.***, these are the 17th and 18th oil discoveries on the Block. The new findings increase the recoverable resource base to more than 8 Bboe. The most recent well, #2-Yellowtail, was drilled about 1 mile southeast of #1-Yellowtail to appraise its size, and it found the two new discoveries adjacent to the discovery reservoir and below it. Drilling operations were recently suspended due to the COVID-19 pandemic, but operations are continuing at exploration well #1-Redtail, which is northwest of #1-Yellowtail. The reported net production from the Liza Field averaged 22,000 bbl of oil per day in the second quarter of 2020, but that the field would hit 120,000 bbl oil per day in the third quarter after the commissioning of water injection equipment and bringing gas injection fully online. Exxon Mobil is based in Irving, Texas.

3 Suriname

Another discovery was reported in offshore Suriname's Block 58 by Houston-based operator ***Apache Corp***. The #1-Kwaskwasi was drilled to 6,645 m and hit 278 m of net oil and volatile oil/gas condensate pay in multiple stacked targets in Upper Cretaceous Campanian and Santonian intervals. The shallower Campanian interval contained 63 m of net oil pay and 86 m of net volatile oil/gas condensate pay. Samples indicate API gravities between 34° and 43° API. The deeper Santonian interval contains 129 m of net hydrocarbon reservoir. After completion operations are done at #1-Kwaskwasi, the rig will be moved to drill #1-Keskesi East. Apache has identified at least seven distinct play types and more than 50 prospects within the thermally mature play fairway. Apache holds 50% interest along with partner ***Total***.

4 Norway

Neptune Energy has confirmed the commercial discovery of oil at the Dugong prospect in PL882 in the Norwegian sector of the North Sea. The volumes are estimated to be in the range of 40–120 MMbbl of oil equivalent. The discovery has significantly de-risked another prospect in the license estimated by Neptune at 33 MMboe and an estimated total resource potential in PL882 to as much as 153 MMboe. The Dugong prospect consists of two reservoirs that are at a depth between 3,250 m and 3,500 m. Area water depth at the site is approximately 330 m, and it is close to production facilities. The discovery well, #34/4-15 S, and the down-dip sidetrack, #34/4-15 A, proved oil in the Viking and Brent Groups of the prospect. These are the first exploration wells in production license 882. The well will be plugged and abandoned. Neptune Energy is the operator of PL882, Block 34/4, and #34/4-15 S with 40% interest in partnership with ***Concedo*** (20%), ***Petrolia*** (20%), and ***Idemitsu Petroleum*** (20%).



5 ***Norway***
Houston-based ***ConocoPhillips*** has received a permit to drill #6507/4-1 in offshore Norway's production license PL 1009. The area in this license consists of parts of blocks 6507/4 and 6506/6. The well will be drilled about 27 km southwest of Skarv Field. A rig will be moved to the site after it finishes drilling a wildcat well #16/1-33 S for ***Spirit Energy*** in production license PL 780. ConocoPhillips is the operator and holds 65% along with partner ***PGNiG***, 35%. This is the first exploration well to be drilled in the license.

6 ***Poland***
Polish Oil and Gas Co. completed another well in the Mielec–Bojanów fields at #2K Korzeniowek. Together with the previous appraisal well in the area, #1 Korzeniówek, it will add approximately 9.5 Bcf of gas per year to the Warsaw-based company's gas output. Both discoveries are in Debica County and produce from the Carpathian Foredeep Basin (Miocene).

7 ***Egypt***
In the Western Desert in the Southwest Meleiha Concession, ***Eni*** announced another discovery in the Faghur Basin. The #6X-SWM-A was drilled to 15,800 ft and encountered 130 ft of net oil pay in Paleozoic sandstones of Dessouky. It was tested flowing approximately 12,000 bbl of oil per day and is about 130 km north of the Siwa Oasis in the basin. The well was already placed on-stream with an output of 5,000 barrels of oil per day. Rome-based Eni is the operator of the concession with partners ***BP*** (37.5%), and Total (25%).

8 ***Egypt***
Eni announced a gas and condensate discovery at the #1 Bashrush prospect in the North El Hammad Concession in the Egyptian sector of the Nile Delta in the Mediterranean Sea (Block 7). The discovery well was tested flowing about 32 MMcf of gas per day. The test was constrained by equipment capacity and is projected to be capable of an output of up to 100 MMcf of gas per day with 800 bbl of condensate per day. Operator Eni holds a 37.5% operating interest in the Concession, with ***BP*** holding 37.5% and ***Total*** the remaining 25%.

9 ***Israel***
Zion Oil & Gas has received drilling plan approval from the Israel Ministry of Energy for #2-Megiddo Jezreel on the 99,000-acre Megiddo-Jezreel license area in northeastern Israel. The well has a planned depth of 4,000 m. According to the company, the rig delivery has been delayed due to the COVID-19 epidemic and restricted visa issuance within Israel for Zion's rig crews. Zion's headquarters are in Dallas.

10 ***Vietnam***
New testing by ***Eni*** at exploration well, #2X-Ken Bau in offshore Vietnam's Block 114 in the Song Hong Basin has confirmed a significant hydrocarbon accumulation. The well is in 95 m of water and was drilled to 3,658 m. It encountered more than 110 m of pay in several intervals of Miocene sandstones interbedded with shale. Preliminary estimates of Ken Bau accumulation provide a range between 7 Tcf and 9 Tcf of gas in place with 400 MMbbl to 500 MMbbl of associated condensates. Additional drilling, seismic surveying and testing are planned. The well will now be plugged and abandoned. Eni is the operator of Block 114 and the Ken Bau discovery with a 50% interest in partnership with ***Essar E&P*** holding the remaining 50%.

11 ***Australia***
A gas discovery in offshore Australia's Otway Basin was reported by ***Origin Energy Ltd.*** at #1-Thylacine. The well is in Tasmanian permit T/30P. Preliminary estimates of in-place reserves may be more than 600 Bcf and may exceed 1 Tcf. The 281-m gross gas column is in the Cretaceous Waarre Sand. Additional testing and exploration are planned. Partners in the project are Sydney-based Origin with 30%, ***Woodside Petroleum Ltd.***, 50% and ***Benaris International Ltd.*** 20%. Woodside will operate the Thylacine development.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
East Resources Acquisition Co.	NASDAQ: ERESU	Boca Raton, Fla.	$300 million	Completed IPO of 30 million units at a price of $10 per unit. Each unit issued will consist of one share of Class A common stock and one-half of one warrant, each whole warrant entitling the holder thereof to purchase one share of the Class A common stock at an exercise price of $11.50 per share. Company intends to grant underwriters a 45-day option to purchase up to an additional 4.5 million units. Proceeds will be used for the purpose of entering into a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses in the energy industry in North America. **Wells Fargo Securities LLC** was sole book-runner.
Southwestern Energy Co.	NYSE: SWN	Spring, Texas	$137.5 million	Priced underwritten public offering of 55 million shares of its common stock at $2.50 per share. Underwriters have been granted a 30-day option to purchase up to roughly 8.3 million addition shares of stock. Proceeds will used to partially redeem **Montage Resource Corp**.'s issued and outstanding notes that it will assume upon the closing of its recently announced merger with Montage. **Citigroup**, **Goldman Sachs & Co. LLC** and **J.P. Morgan** are representatives of the underwriters and joint book-running managers. **BofA Securities**, **BMO Capital Markets**, **RBC Capital Markets** and **Wells Fargo Securities** are also joint book-running managers.
Tellurian Inc.	NASDAQ: TELL	Houston	$35 million	Entered a securities purchase agreement with certain institutional investors for the sale of 35 million shares of common stock at a price of $1 per share. **Roth Capital Partners** was placement agent.

DEBT

Apache Corp.	NASDAQ: APA	Houston	$1.25 billion	Priced underwritten public offering of $500 million of 2025 notes and $750 million of 2027 notes. Proceeds will be used to purchase a portion of outstanding senior indebtedness in cash tender offers, repay a portion of outstanding borrowings under its senior revolving credit facility and for general corporate purposes. Joint book-running managers for the notes are **J.P. Morgan Securities LLC**, **BofA Securities Inc.**, **BMO Capital Markets Corp.** and **Scotia Capital (USA) Inc**.
Husky Energy Inc.	TSX: HSE	Calgary, Alberta	C$1.25 billion	Launched a public offering of 2028 notes. Proceeds will be used for general corporate purposes, which may include, among other things, the repayment of its $500 million unsecured nonrevolving term loan credit facility. Notes were sold through a syndicate of agents led by **RBC Capital Markets**, **CIBC Capital Markets** and **Scotia Capital Inc**.
Kinder Morgan Inc.	NYSE: KMI	Houston	$1.25 billion	Closed a public offering of senior notes, which included $750 million 2031 notes and $500 million 2050 notes. Proceeds will be used for general corporate purposes, including refinancing upcoming debt maturities. **BofA Securities**, **J.P. Morgan**, **MUFG**, **RBC Capital Markets**, **Barclays**, **BMO Capital Markets**, **Mizuho Securities**, **Scotiabank**, **Société Générale** and **TD Securities** were joint book-running managers.
Pioneer Natural Resources Co.	NYSE: PXD	Dallas	$1.1 billion	Priced a public offering of 2030 notes at 99.205% of the principal amount. Proceeds will be used for general corporate purposes, which may include, but are not limited to, the repayment or repurchase of 2021 and 2022 notes or other corporate obligations. **BofA Securities Inc.**, **J.P. Morgan Securities LLC**, **Wells Fargo Securities LLC**, **Barclays Capital Inc.**, **BMO Capital Markets Corp.**, **Citigroup Global Markets Inc.**, **Morgan Stanley & Co. LLC**, **MUFG Securities Americas Inc.** and **TD Securities (USA) LLC** are joint book-running managers. **Credit Suisse (USA) LLC**, **Goldman Sachs & Co. LLC**, **RBC Capital Markets LLC**, **Scotia Capital (USA) Inc.** and **U.S. Bancorp Investments Inc.** are senior co-managers. **BBVA Securities Inc.**, **CIBC World Markets Corp.**, **Citizens Capital Markets Inc.**, **PNC Capital Markets LLC** and **Truist Securities Inc.** are co-managers.
Cenovus Energy Inc.	NYSE, TSX: CVE	Calgary, Alberta	$1 billion	Completed public offering in the U.S. of 2025 notes. Proceeds will be used to repay short-term indebtedness outstanding under the company's $4.5 billion committed credit facility and other short-term indebtedness. **BofA Securities Inc.**, **BMO Capital Markets Corp.** and **Scotia Capital (USA) Inc.** were active joint book-running managers. The offering was supported by additional advisers including **RBC Capital Markets LLC**, **TD Securities (USA) LLC**, **ATB Capital Markets Inc.**, **CIBC World Markets Corp.**, **Barclays Capital Inc.**, **Credit Suisse Securities (USA) LLC**, **Desjardins Securities Inc.**, **J.P. Morgan Securities LLC**, **Mizuho Securities USA LLC**, **MUFG Securities Americas Inc.**, **National Bank of Canada Financial Inc.**, **SMBC Nikko Securities America Inc.** and **Wells Fargo Securities LLC**.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Targa Resources Partners LP	NYSE: TRGP	Houston	$1 billion	Priced an upsized offering of 2031 notes at par. Proceeds will be used to fund a concurrent cash tender offer of 2024 notes, to pay fees and expenses thereof, and to redeem any 2024 notes that remain outstanding after consummation of the tender offer. Remaining proceeds will be used to reduce borrowings under its senior secured revolving credit facility.
Gibson Energy Inc.	TSX: GEI	Calgary, Alberta	C$650 million	Closed an offering of senior unsecured medium term notes consisting of $325 million of 2025 notes and $325 million of 2027 notes. Proceeds will be used for the redemption of its outstanding 2024 notes, reduce outstanding indebtedness under its revolving credit facility and for general corporate purposes. Notes were offered through a syndicate of investment dealers led by CIBC Capital Markets and RBC Capital Markets, as well as BMO Nesbitt Burns and Scotia Capital.
Boardwalk Pipeline Partners LP	NYSE: BWP	Houston	$500 million	Priced a public offering of 2031 notes. Proceeds retire all of the outstanding 2021 notes of Texas Gas Transmission LLC at or near maturity. Remaining proceeds will be used for general partnership purposes, which may include growth capex, repayment of future maturities of long-term debt and additions to working capital. Pending such use, proceeds will temporarily used to reduce borrowings under its revolving credit facility. Barclays, J.P. Morgan, Mizuho Securities, MUFG, BMO Capital Markets, Citigroup, Regions Securities LLC, TD Securities, Truist Securities, US Bancorp and Wells Fargo Securities are joint book-running managers. BofA Securities, Goldman Sachs & Co. LLC, Morgan Stanley and RBC Capital Markets are co-managers.
Concho Resources Inc.	NYSE: CXO	Midland, Texas	$500 million	Priced an offering of 2031 notes issued at 99.761% of par. Proceeds will be used for general corporate purposes, including, together with cash on hand, to redeem all of its outstanding 2025 notes. BofA Securities, J.P. Morgan and Wells Fargo Securities will act as joint book-running managers.
Helix Energy Solutions Group Inc.	NYSE: HLX	Houston	$200 million	Priced an upsized offering of 2026 notes. Proceeds will be used to fund the cost of entering into the capped call transactions and, together with cash on hand, repurchase outstanding 2022 and 2023 notes in privately negotiated transactions. Wells Fargo Securities LLC and Evercore ISI are joint book-running managers.

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.

MAKE THE DOWNTURN LAST?

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Someone supposedly said, while languishing in the county jail in the Old West, or maybe it was in an old movie about the West, "Knowing you're gonna' hang in the morning really focuses the mind."

We might be sitting here in a similarly prickly situation today, like that poor soul in jail. People throughout this industry are reeling, but they are also focusing: They are looking anew at every aspect of their business strategy, assets in their portfolio, decisions they've made, the balance sheet, the staff, the joint ventures. If the price of oil can't seem to get above $40/bbl and stay there, and global demand for the commodity remains so wobbly, and natural gas prices are not worth discussing, then everyone in the oil and gas business knows what they face.

But whatever direction macro factors take, executives know how to respond, and the industry will be the better for it. Yes, some good companies will fall by the wayside, which is a disappointing thing, terrible for employees and investors. But for those who remain, new efficiencies and better responses will propel them to greater heights. In this way, the one good side effect of this awful downturn—disciplined focus—will last.

Best practices are constantly refined and then shared. Savings are achieved. For example, Spur Energy Partners CEO Jay Graham shared with us at our virtual DUG Permian Basin and Eagle Ford conference that the company can drill a well in the Yeso Trend in fewer days, and has reduced LOE by 20%, compared to when it acquired the assets just more than a year ago. Matador Resources crowed at press time about how low its drilling and completion costs have become in the Permian Basin; many other E&Ps have done the same over the past year.

On the conference calls for the second quarter, many more E&P chiefs echoed these themes: reduced costs per foot drilled, more productive wells, cautious spending for the rest of the year, more hedging, lean staff, less G&A. Certainly these actions are to be applauded, but investors may be skeptical for a while yet, hoping that if and when oil and gas prices climb again, the newfound discipline lasts.

One industry veteran we spoke with, who has worked for majors and independents, offered a great way to think about things: Is any action or decision, asset or staff person, one of convenience or ego, or really a necessity? During the boom days, egos often ran wild, if we'd care to admit it. The pullback from that is often painful, but it has to happen, and it is.

One source explained to us his unusual way to analyze E&P company efficiency at a glance: If you go to the main parking lot of your company on a Saturday morning and the lot isn't at least 20% full, then something is wrong. If some employees have so much to do that they have to work a little extra, that means the company hasn't become top-heavy with too many employees, such that everyone can comfortably accomplish the work that needs to be done in a 40-hour week.

Of course, figuring out what needs to be done and what is nice to get done, is the real trick. Focusing the mind. Discipline is here, but how long will CEOs hold to it? I think this will continue to be the new standard of operations. SNAFU: Situation normal, all focused up.

Widespread, insistent calls from investors demanding cash flow and returns will not go away. The Institute for Energy Economics and Financial Analysis released a study in September that showed that for the 34 E&Ps it examined, all of them had negative cash flow from 2010 to 2019—the shale revolution's first and best decade. Producers spent more than they made. Sure, the result was a stupendous technical feat that upended old geopolitical beliefs.

CEOs appear to have seen the light. They are holding production flat, in order to rein in spending this year and probably through next year—unless the price of oil rises well into at least the $50s.

If the resulting lack of robust completion activity lasts long enough, the natural decline curve in every field will kick in, and at some point, supply may not be enough to meet demand. No one can predict exactly when that would be. For now, domestic production is down to about 10.5 MMbbl/d or 10.8 MMbbl/d from last year, but the EIA's most recent Short Term Energy Outlook foresees recovery to about 11 MMbbl/d next year. A lot of that increase will come from wells turned back on and DUCs completed. The number of rigs at work is low, probably too low to keep production flat.

We look forward to CEOs soon giving us their thinking on all this and unveiling preliminary 2021 drilling plans; their comments should start rolling through any time now.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Oil and gas is here to stay.
And so are we.
The last few months have challenged everyone in extraordinary ways as a virus temporarily crushed demand. As we begin to ramp back up, our country and the world will need oil and natural gas, especially the light, sweet crude and abundant, clean-burning natural gas our domestic producers provide. Our industry continues to demonstrate its ability to adapt and to succeed. At Continental, we are built to meet all challenges and seize every opportunity. You would expect nothing less from America's Oil Champion. To learn more about us and our new ESG approach, visit clr.com.
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