Oil and Gas Investor

FEBRUARY 2020

Midland Basin independents push the drillbit farther in America's oil-rich sweet spot.

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Oil and Gas Investor

FEBRUARY 2020/VOLUME 40/NUMBER 2

Oil and Gas Investor

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ABOUT THE COVER: A roughneck on Precision Drilling Corp. Rig # 593 preps a new bit to make hole for Henry Resources LLC south of the Midland, Texas, airport in December. Photo by James L. Durbin.

Oil and Gas Investor (ISSN 0744-5881, PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX. Ride-along enclosed. Advertising rates furnished upon request. **POSTMASTER: Send address changes to Oil and Gas Investor, PO Box 5020, Brentwood, TN 37024.** Address all correspondence to *Oil and Gas Investor*, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Telephone: +1.713.260.6400. Fax: +1.713.840.8585. oilandgasinvestor@hartenergy.com

Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepayment required). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

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LATEST CONTENT

Laredo Petroleum Posts Production Beat, $900 Million Debt Offer
Laredo Petroleum Inc.'s operations benefited from improved cycle times and wider-spaced wells above its upper/middle Wolfcamp type curve, the company said.

Tim Dugan Takes COO Job At Private Appalachia Operator Olympus Energy
Privately held independent Olympus Energy LLC named Tim Dugan, who recently retired from CNX Resources, as its senior vice president and COO.

Resource Evaluation Gives Insight On Talos, Partners' Zama Discovery
Talos Energy Inc. said on Jan. 7 Netherland, Sewell & Associates Inc. put the best estimate of 2C gross recoverable reserves at about 670 million barrels of oil equivalent.

Oklahoma Pure-Play Chaparral Energy Regains NYSE Compliance
Chaparral Energy Inc., an operator in Oklahoma's Stack play, said it has regained full compliance with NYSE listing standards after the average closing price of its shares fell below the $1 per share requirement.

Encana Gets Shareholder Approval For Move To U.S.
Encana Corp., currently based in Calgary, Alberta, also plans to change its name to Ovintiv Inc. as part of its move out of Canada.

Apache, Total Make Significant Oil Discovery Offshore Suriname
Results from the Maka Central discovery prove "significant potential" for the entire 1.4 million acres that comprise Block 58 offshore Suriname, says Apache Corp. CEO John Christmann.

ONLINE EXCLUSIVES

Range Resources Goes 'Ex-growth,' Suspends Dividend
Analysts with Tudor, Pickering, Holt & Co. viewed going "ex-growth" as the right move for Range Resources Corp. given the current gas macro environment but continued asset sales to remain key.

Fueling The Next-Generation Workforce
Amid a looming talent crisis and an aging workforce, the energy industry must adopt new strategies to attract fresh talent.

IPTC: All Eyes On U.S. Shale, Says Bahrain's Oil Minister
Speaking during the opening day of IPTC, Bahrain Oil Minister Sheikh Mohammed bin Khalifa Al Khalifa said he sees producers challenged by rising energy demand in the future.

Videos

Executive Q&A: Camino Natural Resources' Growth Strategy
Seth Urruty, COO of Camino Natural Resources LLC, discusses staying attractive to investors plus utilizing technology.

www.HartEnergy.com/videos

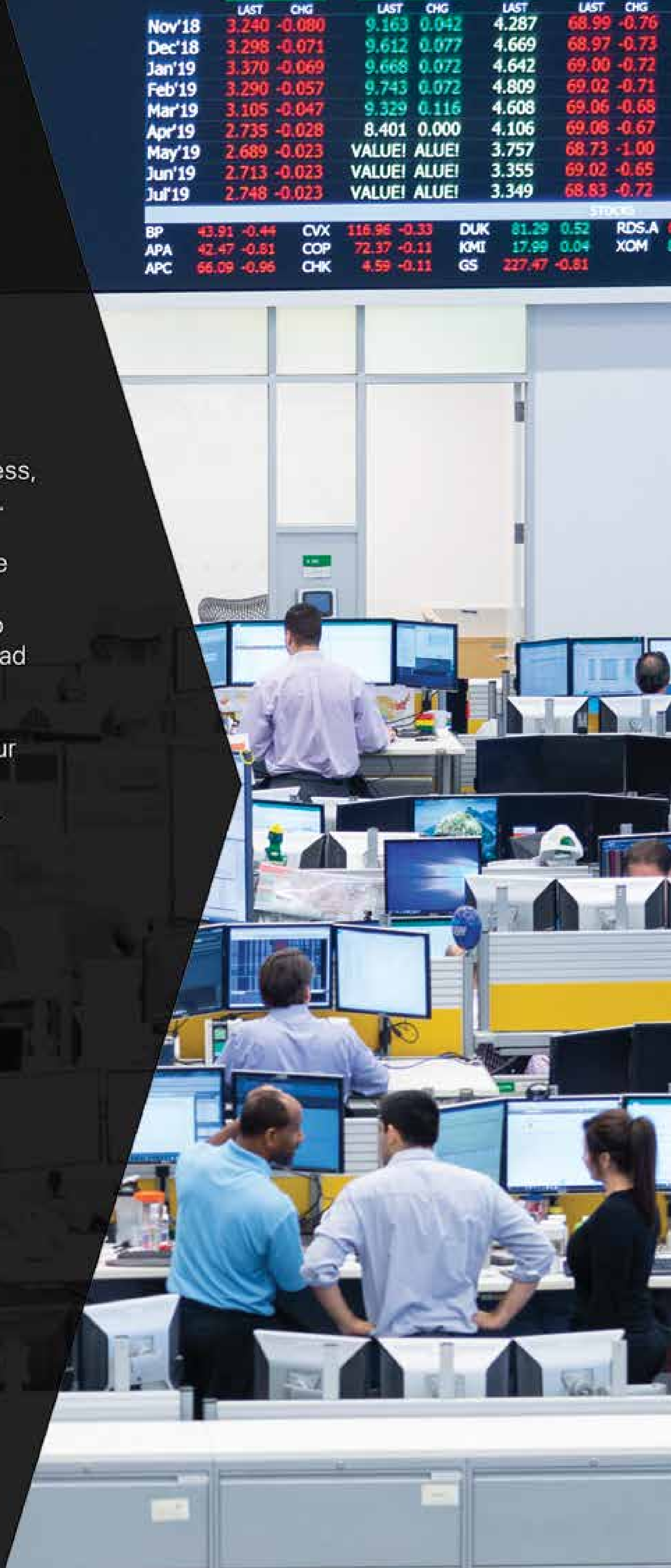
What's Trending

1. Permian Operator Lilis Energy Receives Take-Private Offer
2. Three Years After $1B Venezuela Deal, U.S. Oilfield Firm Shuts Doors
3. Enverus Reportedly To Merge With RS Energy In $1B Deal
4. The Real Price Of Occidental Petroleum's 'Costless' Oil Hedge
5. Domestic Energy Supply: DUC And Cover!

Awards Program

Join top industry executives to celebrate *Oil and Gas Investor*'s 25 Influential Women In Energy honorees at a gala luncheon on March 4, 2020. Network and dine with distinguished leaders who have risen to the top of their professions and achieved outstanding success in the oil and gas industry.

WomenInEnergyLunch.com



LAST CHG LAST CHG LAST LAST CHG
Nov'18 3.240 -0.080 9.163 0.042 4.287 68.99 -0.76
Dec'18 3.298 -0.071 9.612 0.077 4.669 68.97 -0.73
Jan'19 3.370 -0.069 9.668 0.072 4.642 69.00 -0.72
Feb'19 3.290 -0.057 9.743 0.072 4.809 69.02 -0.71
Mar'19 3.105 -0.047 9.329 0.116 4.608 69.06 -0.68
Apr'19 2.735 -0.028 8.401 0.000 4.106 69.08 -0.67
May'19 2.689 -0.023 VALUE! ALUE! 3.757 68.73 -1.00
Jun'19 2.713 -0.023 VALUE! ALUE! 3.355 69.02 -0.65
Jul'19 2.748 -0.023 VALUE! ALUE! 3.349 68.83 -0.72
BP 43.91 -0.44 CVX 116.96 -0.33 DUK 81.29 0.52 RDS.A
APA 42.47 -0.81 COP 72.37 -0.11 KMI 17.99 0.04 XOM
APC 66.09 -0.96 CHK 4.59 -0.11 GS 227.47 -0.81

CAPEX CAPITULATION

STEVE TOON,
EDITOR-IN-CHIEF

Looking back, 2019 was a stare down between investors and operators, with investors demanding the latter to hold the line on generating free cash flow. E&Ps, likewise, faced overcoming long-held habits of growing through the drillbit as fast as possible while smelling the sweet aroma of rising commodity prices throughout the year. Oh, to add a rig and a bit of boe per day!

Yet upstream operators might be passing the blink test, by and large.

There was a day when the industry measured success by growth rate and production volumes. Today, less is more on those metrics, at least in the minds of the capital providers. Now, more return of capital to said investors is less punishable in the markets.

In advance of fourth-quarter reports, several analysts have surveyed the field and found E&Ps to be breathing calmly as 2020 capex figures begin to be revealed.

"Continuation of capital discipline is another key factor that is a prerequisite for investors to become more sanguine on energy, and we think this continues into '20 regardless of oil prices," said U.S. Capital Advisors analyst Cameron Horwitz in a Jan. 9 report.

The USCA analysts surveyed fourth-quarter permitting and, while the Permian Basin and Eagle Ford Shale showed modest ramps, all other basins trended down, some sharply. "Bottom line, forward indicators are not suggesting E&Ps are aggressively planning to ramp back up this year, which is a positive for sentiment, in our view."

Better, at current strip, its models show an average return on capital employed increasing by 300 basis points to 8% in 2020 and half of its covered companies free cash flowing by 5%.

Reporting from its recent investor conference, Cowen energy analysts said E&Ps echoed consistent messages of focusing on free cash flow. "Budgets appear relatively set given the current $55/bbl-plus 2020 WTI curve, and we would not anticipate any incremental rig additions beyond what has already been communicated.

"In general, management teams are 'holding the line,' focused on high-graded zones, marginal capital efficiency gains and looking to raise investor confidence in free cash flow generation."

Oilfield prognosticator RBN Energy projects a 13% decline in capex this year, representing some $9 billion less capital deployed in the E&P space, with a total outlay of $61 billion. That follows a downdraft of 11% in 2019.

But what about old habits? Natural gas players might be feeling the pinch of $2/MMcf, but oil prices are flirting with $60 and briefly topping that with a little geopolitical buzz.

"With the recent rally in crude prices and capital budgets resetting, the question is whether producer capital discipline will hold in 2020? We think it will," noted Barclays in a Jan. 9 report. "We think large-cap E&Ps have made their choice and broadly will continue down the path of capital discipline." Several have already "downshifted" year-over-year 2020 production growth outlooks in favor of free cash flow, it said. "We think executives 'get it.'"

In its 2020 E&P Spending Survey released in December, Barclays estimates U.S. onshore spending to decline by 10% over 2019 figures.

But it's 2018 and 2019 figures that illustrate the large cap E&P community's "seismic shift" commitment to capital discipline, the analysts suggest. In 2018, the "plowback" ratio—drill-and-complete capex as a percent of discretionary cash flow—was 83%. 2019 marked a 10-year low at 80%. Compare that to 142% plowback in 2015. "Capex levels have been brought down to almost maintenance levels."

2020 could go even lower. "We expect the plowback ratio to be significantly lower than 2019 levels at 67% as the purse strings remain tight."

Small- to mid-cap E&Ps will follow a similar path, predicts Barclays. It expects SMID-cap upstream spending to decline by another 8% this year, following a 19% drop last year. This from a group that fundamentally needs to grow.

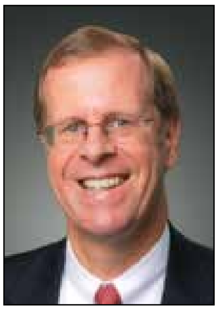
The majors and international oil companies are the iconoclasts. Barclays expects this group to increase North America spending by 6%, following a 14% uptick in 2019, offsetting other declines. "The majors are following through with aggressive unconventional growth plans and are showing they are largely oil price insensitive."

But the path forward is set, according to RBN analyst Nick Cacchione in a blog.

"There has always been an aura of excitement, adventure and risk surrounding the quest to unlock natural resources, from the California Gold Rush to the early days of Texas oil wildcatting," Cacchione said. "Today's exploration and production leaders may be just as passionate as their predecessors, but the riverboat gambler-type days of reckless spending in pursuit of growth now seem like a distant memory."

The gamble is whether investors will finally ante up if independents take capex chips off the table. 2020 could tell the tale.

UNCERTAINTY POST-SOLEIMANI



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

There's a certain irony that even as it noted a 34% climb in West Texas Intermediate (WTI) prices last year, the initial 2020 edition of The Wall Street Journal carried a story on the risk of more levered E&Ps being unable to roll over upcoming debt maturities. If that sounds odd, it's just a couple of the many themes that add up to an outlook that one research firm called "predictably unpredictable."

And that was before events in the Middle East highlighted the unexpected incidence of geopolitical risk.

The killing of Iran's major general Qassem Soleimani at the Baghdad International Airport in Iraq has led to heightened tensions in the Middle East and higher crude prices. The improved futures commodity curve for 2020, at around $60 per barrel (bbl) as of early February, has unexpectedly allowed E&Ps to hedge production at attractive prices and use increased cash flow to lower leverage or make returns to shareholders.

But the question for many observers remains whether the action taken to eliminate Soleimani will fade in terms of its impact on oil markets—somewhat similar to what happened following the drone attack on Saudi Arabia's processing facilities at Abqaiq—or if the death of the leader of the Iranian Revolutionary Guard Corps' Quds Force is a "game changer" leading to further escalation in military action.

Late last year, RBC Capital Markets' head of global commodity strategy, Helima Croft, forecast that Iran's Mideast strategy could bring it "closer to a direct confrontation" with the U.S.—albeit not quite the way it ultimately unfolded. And just a day before the death of Soleimani, "we continue to see Iraq as the potential tripwire for a direct clash between Washington and Tehran in 2020," she wrote.

A day later, upon the death of Soleimani, "we think the stage is set for a retaliatory spiral that could keep markets on edge well into 2020," observed Croft. Since Soleimani had overseen the activities of multiple armed proxy groups in Iraq and elsewhere, an "asymmetric response will likely involve the use of Iranian proxy groups throughout the Middle East," she said.

As of this writing, Iran itself retaliated with one attack, involving 15 missiles targeting two U.S. military bases in Iraq. President Donald Trump said the attack inflicted "minimal" damage and no loss of U.S. lives.

"I think we're set for a series of escalations," said Croft earlier. "This was just too dramatic of an incident to let it pass without a response." A short time later, a nonbinding resolution was passed with the backing of Shiite politicians, urging the caretaker prime minister of Iraq, Adel Abul-Mahdi, to rescind the country's invitation to host U.S. forces in Iraq.

Some 5,000 U.S. troops are based in Iraq in the wake of the earlier mission to defeat Islamic State forces. The importance of the U.S. troops in the country is that it gives "Iraqi patriots confidence to counter Shiite militias armed by Iran and resist Iran's strategic goal of making Iraq its political and military subsidiary," said a commentary in The Wall Street Journal.

In terms of regions most at risk of seeing disruptions in production, Croft identified Iraq, followed by Libya and Venezuela. In the event that WTI prices should reach $70/bbl, the possibility exists that the U.S. administration could tap reserves held in the Strategic Petroleum Reserve, she said. Also, Saudi Arabia would likely be under pressure to increase production, she added.

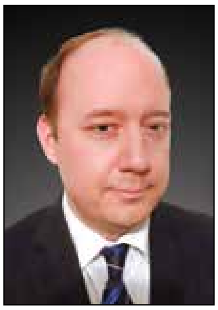
In the swirl of geopolitical events post-Soleimani, Citi bumped up its 2020 price forecasts for both Brent and WTI by $5/bbl, to $64/bbl and $61/bbl, respectively. News of Iran's retaliatory strike on the U.S. bases in Iraq prompted a $3/bbl jump to $71.22/bbl at the open for Brent, said Citi. However, prices retraced roughly 9% thereafter as a "tone of de-escalation" took hold in the absence of U.S. fatalities.

As with RBC, Libya is seen as an "area where geopolitical risks could crystallize sooner than expected," according to Citi. What started as a civil war "may soon degenerate into a regional scale conflict," with as much as 750,000 bbl/d of supply at risk. "A full disruption of supply, taking 700,000 bbl/d or more out of the market, would easily add $2 to $3 to Brent."

At a time of heavy geopolitical consequences, much depends on parties avoiding miscalculations of risk.

Heightened geopolitical risks early in the year could influence not only the "likely price path of oil priced in 2020," said Citi, but also the "probabilities of risks to the upside and downside."

'TIMES HAVE CHANGED'



DARREN BARBEE,
SENIOR EDITOR

Schlumberger Ltd. chairman Mark Papa told an audience at the International Petroleum Technology Conference on Jan. 13 that he expects shale production to grow by just 400,000 barrels per day (bbl/d) in 2020, according to the Journal of Petroleum Technology.

This echoes comments made in November by Centennial Resource Development Inc. CEO Mark Papa, who said at the time, "I now think that 2020 year-over-year oil growth will be roughly 400,000 barrels per day."

It's good to see that they agree. Papa's reasoning, regardless of the corporate hat he's wearing at any given time, is that shale oil is a finite resource.

"Most people will ascribe the low U.S. growth to capital discipline, but I think that the larger reason is what I've been talking about for several years—the shift to Tier 2 and 3 drilling locations in all shale plays and increasing parent-child issues in the Permian," he said during Centennial's November earnings call.

Wood Mackenzie, which Papa does not work for, also forecasts U.S. Lower 48 crude and condensate production, with a slightly higher growth forecast of 470,000 bbl/d in 2020. That compares with 2019 year-over-year growth of 1.1 MMbbl/d.

In case this looks like a green light to start pumping out more oil, a quick check with investors confirms, yes, they still don't like oil and gas companies. What's interesting, however, is that even they admit oil and gas companies are probably worth more than the current share prices allow.

An IHS Markit survey of institutional and private-equity investors, with a combined $98 billion of energy assets under management, found that 63% of respondents agree that the oil and gas sector is currently undervalued. Writing about the survey results on Jan. 13, IHS Markit vice chairman Daniel Yergin and senior vice president ambassador Carlos Pascual noted that while the stock market has boomed, the energy sector has been the "worst performing sector over the last decade."

"This is particularly ironic, since U.S. oil and gas production has boomed over the same period, making the United States the world's largest producer of oil and gas—and making the country virtually self-sufficient," they wrote.

Interestingly, they also found that investors in renewables resulted in subpar returns, with only a few investors citing success in the space, "noting the importance of selectivity and timing." Yergin and Pascual also say oil and gas investment isn't hurt by environmental, social and governance considerations.

Perhaps more telling is that two-thirds of respondents believe that there is potential for the industry to experience a "cyclical reversion" in the stock market and come back into favor with equity investors. To ward off any undue optimism: This may be the equivalent of saying Smurf-Berry Crunch could make a comeback as the greatest breakfast cereal of all time. Should it? Yes, obviously. But will it?

Papa, for his part, won't speculate on what "growth-challenged" shale plays would mean for the oil markets or investors—though he does offer that "the shale plays are going to not be as prolific as people are currently alleging that they are."

Clearly, Papa wants to crank up production this year. The problem is that Wall Street is unfriendly to outspending cash flow. So Centennial may make a deal that Papa would not have contemplated during his time as chairman and CEO of EOG Resources Inc.

"If you look back at the background of when I was running EOG, we never monetize any of our assets in-house, any of our processing assets or anything like that," he said.

"We followed the same philosophy" at Centennial, he said. Papa said he believed keeping assets in-house leads to a better valuation.

"But times have changed here and clearly, there's an investor fixation with cash-flow outspend," he said.

In that light, Centennial is considering a divestiture of its southern Delaware Basin water infrastructure in Reeves County, Texas. The company operated 12 saltwater disposal wells in November and has a capacity to move 379,000 bbl/d of water. Centennial owns about 300 miles of pipeline to support its saltwater disposal system.

Papa said that other companies have looked at the assets in the past but that they weren't for sale.

"Still, facing a potential cash-flow outspend in 2020, we are saying, 'well, one way to solve that problem is to monetize SWD. And in fact, it would potentially solve it for multiple years down the road.'"

Times, indeed, have changed.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
NAPE Summit	Feb. 3-7	Houston	George R. Brown Conv. Center	napeexpo.com
IPAA Wildcatters' Ball	Feb. 7	Houston	The Astorian	ipaa.org
EnerCom Dallas	Feb. 11-12	Dallas	Tower Club	enercomdallas.com
DUG Bakken and Rockies	**Feb. 18-19**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
SPE A&D Symposium	Feb. 26	Houston	Petroleum Club	spegcs.org
Energy Capital Conference	**Mar. 2**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
Women In Energy Luncheon	**Mar. 4**	**Houston**	**Hilton Americas-Houston**	**womeninenergylunch.com**
LOGA Annual Meeting	Mar. 4-6	Lake Charles, La.	Golden Nugget Hotel & Casino	loga.la
OOGA Annual Meeting	Mar. 4-6	Columbus, Ohio	Hilton Columbus at Easton	ooga.org
CERAWeek by IHS Markit	Mar. 9-13	Houston	Hilton Americas-Houston	ceraweek.com
TIPRO Annual Convention	Mar. 23-24	Dallas	Hilton Anatole	tipro.org
PIOGA Spring Meeting	April 1	Pittsburgh	Rivers Casino	pioga.org
DUG Permian	**April 6-8**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
OGIS New York	April 20-22	New York	Sheraton New York Times Square	ipaa.org
Mineral & Royalty Conference	April 27-28	Houston	Post Oak Hotel	mineralconference.com
Texas Energy Alliance Annual Meeting	April 28-29	Wichita Falls, Texas	MPEC Convention Center	texasalliance.org
Offshore Technology Conference	May 4-7	Houston	NRG Park	2020.otcnet.org
DUG Haynesville	**May 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
Louisiana Energy Conference	May 26-29	New Orleans	The Ritz-Carlton	louisianaenergyconference.com
Midstream Texas	**June 2-3**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
CIPA Annual Meeting	June 4-7	Santa Barbara, Calif.	TBA	cipa.org
AAPG Annual Conv. & Exhibition	June 7-10	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
Innovation & Entrepreneurship Summit	June 10-11	Houston	Norris Center CityCentre	spegcs.org
DUG East	**June 16-18**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
IPAA Midyear Meeting	June 29	Newport Beach, Calif.	Pelican Hill	ipaa.org
Unconventional Resources Tech. Con.	July 20-22	Austin, Texas	TBA	urtec.org/2020
Western Energy Alliance Annual Meeting	July 29-31	Tabernash, Colo.	Devil's Thumb Ranch Resort	westernenergyalliance.org
Summer NAPE	Aug. 12-13	Houston	George R. Brown Conv. Center	napeexpo.com
EnerCom The Oil & Gas Conference	Aug. 16-19	Denver	Westin Denver Downtown	theoilandgasconference.com
DUG Eagle Ford	**Sept. 9-11**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wed., 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 Brandy Fidler, bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com.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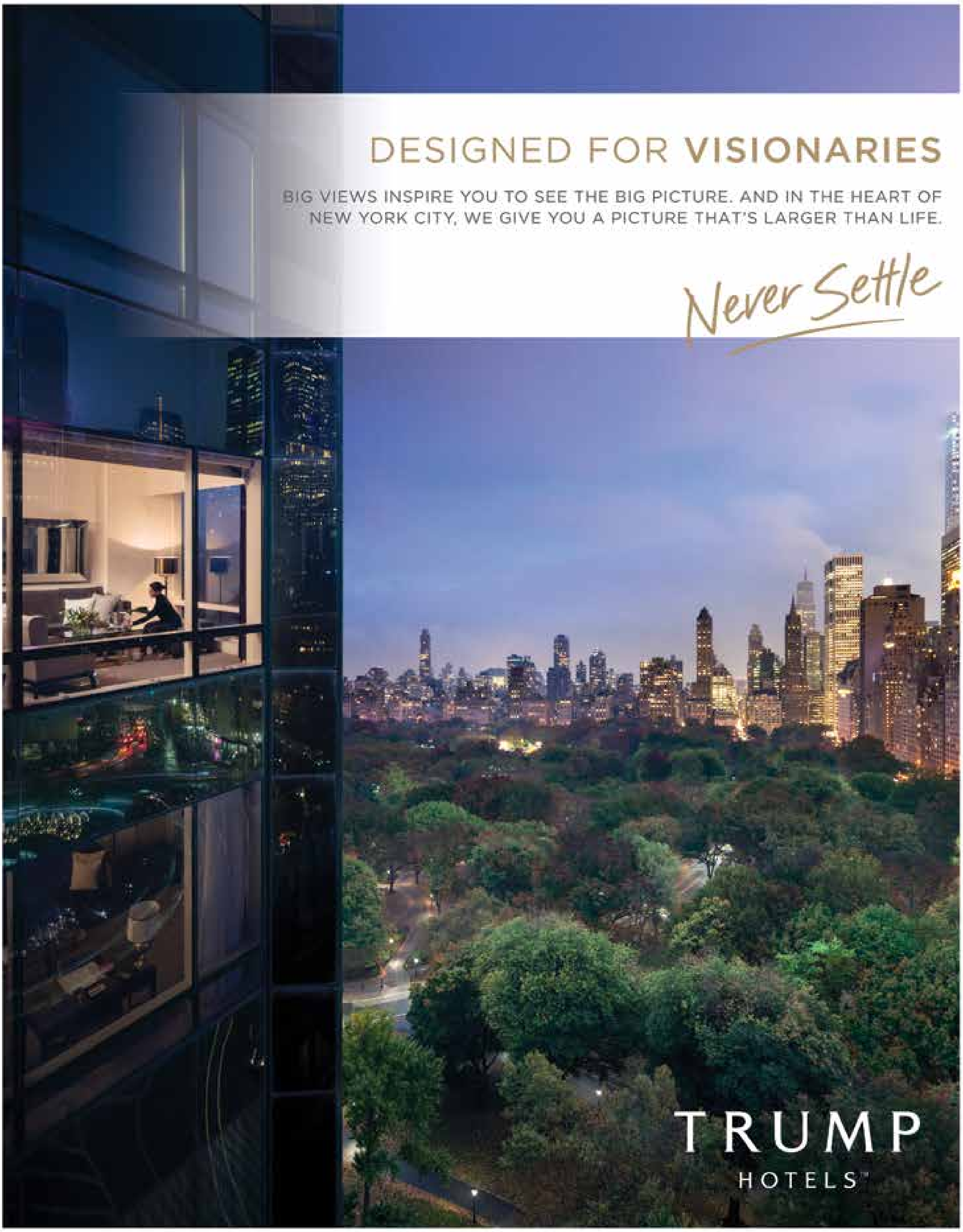
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Analyst shares what's next for U.S. shale

Anyone wanting to know what could be ahead for U.S. shale in 2020 should look at what has happened lately, according to analysts.

"Next year will be a lot like the last few quarters of this year," Todd Bush, head of North American unconventionals for Westwood Global Energy Group, said while delivering the firm's shale outlook at a recent event.

With the uncertainty of an election year, OPEC's maneuvering and the direction of oil prices, the research consultancy Appalachias drilling and completions activity will drop by 5% and 3%, respectively; a softening frac horsepower market; and a rebalancing of frac sand supply as demand rises by 12%, Bush said.

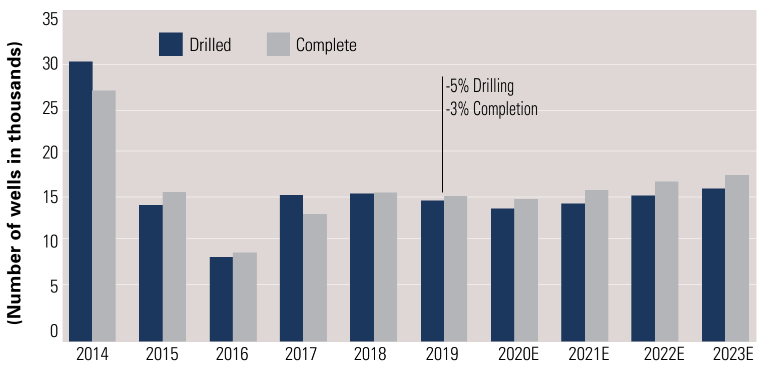
The consensus of a group of 20 to 25 analyst firms is that the price for a barrel of West Texas Intermediate crude oil will hover between $55 and $60 for the next 12 to 15 months, he added.

Through it all, the efficiency drive is set to continue throughout next year as operators and oilfield service companies strive to increase cash flow from operations. But the already present slowdown in production is expected to carry over into the New Year. This includes in the Midcontinent's Anadarko Basin, home of the resource plays such as the Scoop/Stack and Meramec, where Bush said production growth has been falling since January 2018.

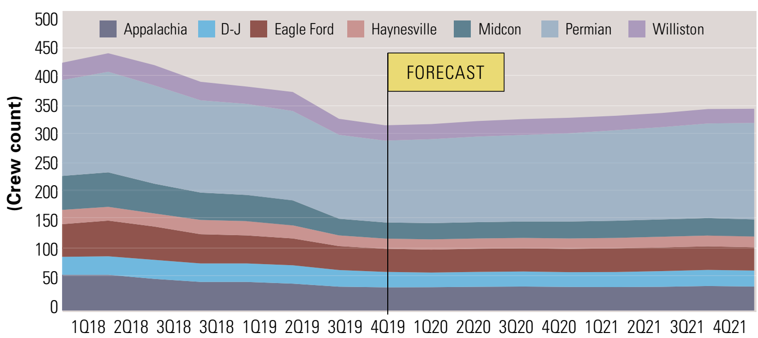
Data from the U.S. Energy Information Administration's (EIA) latest drilling productivity report show oil production in the Anadarko Basin was expected to drop by 12,000 barrels per day (bbl/d) to 551,000 bbl/d in December compared to a month earlier.

Also seeing production drops is the Eagle Ford, where the EIA said oil production was forecast to fall by 14,000 bbl/d to 1.368 million bbl/d.

Lower 48 Drilling And Completion Outlook



Frac Crew Forecast



Source: Westwood Global Energy Group

"The Permian is still in the growth trajectory," Bush said, though production growth appears to have peaked in September 2018 at 44%.

In the past six months, 31% of the frac activity in the Permian's Delaware sub-basin has come from EOG Resources Inc., ExxonMobil Corp., Occidental Petroleum Corp., Concho Resources Inc. and Chevron Corp. The most active companies that are fracking in the Midland sub-basin are Pioneer Natural Resources Co., Endeavor Energy Resources LP, Encana Corp., ExxonMobil and Parsley Energy Inc., accounting for 36% of the activity, Bush said.

While the rig count has fallen about 27% this year, the number of wells drilled has dropped by only about 5%, a feat attributable mainly to improved cycle times and footage drilled per day, Bush said.

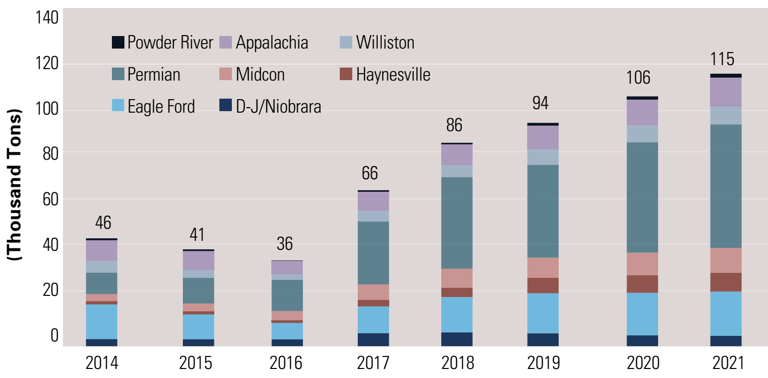
Permian player Pioneer Natural Resources, for example, said it saw a 30% year-over-year improvement in cycle times during the third quarter. Its focus on lean manufacturing methods played a role.

Westwood gains insight by monitoring more than 21,000 well pads in major U.S. unconventional plays—including the Permian, Eagle Ford and Midcon—every two to three days using data from regulatory agencies, news sources and satellite imagery. So far, the firm has captured more than 1.7 million images of wellsites since 2016 to monitor activity such as new pad construction.

Westwood expects Lower 48 drilling activity to fall by 5% and completions by 3% with some basins declining faster than others. "As we get into 2020, we're going to see more DUCs [drilled but uncompleted wells] being completed. The drawdown in DUCs is really happening now and moving into 2020," Bush said, noting it will probably continue through first-half 2021.

"From a bullish scenario if oil gets up to the $62 to $65 range for WTI then certainly there will be some healthy activity and increased cash flow; increased sentiment will come from that," Bush said, "vs. more of a bear case where at $45 [per bbl WTI] we'd expect more pullback in the

Lower 48 Frac Sand Demand



Source: Westwood Global Energy Group

D-J, Eagle Ford and the Bakken and still a healthy amount of activity in the Permian."

The firm's base case, which was used for the 2020 outlook, puts WTI at about $55 through 2020 with E&Ps maintaining current spending plans and limited expansion. Activity is expected to drop in fourth-quarter 2019 and increase in third-quarter 2020, according to the outlook.

In early December, there were 322 active hydraulic fracturing crews in the Lower 48, down about 12% from fourth-quarter 2018, Westwood data show. "Some of the largest drops have been in Williston … but activity is still pretty strong when it comes to the Permian," Bush said.

The count is expected to gradually increase throughout 2020, reaching about 340 frac crews in 2021.

"One thing that we're pretty optimistic about is some of the public frac companies coming back and pulling equipment," nearly about 1.2 million hydraulic horsepower off the market—notably in the Midcontinent. That makes for a "healthy supply and demand balance," he added.

On the efficiency front, Bush said there are some new solutions from frac equipment suppliers coming to the market that could lead to gains. These include new layouts, designs and frac pumps, he said.

Meanwhile, companies continue "doing more with less." As the frac crew count has dropped, the number of stages per frac spread has jumped with more lateral feet drilled and more proppant pumped. Westwood data show that every major basin saw double-digit percentage increases in stages per frac spread during the third quarter compared to a year earlier. The exception was the Denver-Julesburg (D-J) Basin.

About 40% of the stages fracked were in the Permian, where Bush said several companies—including a 30% jump by Centennial Resource Development Inc. in the Delaware Basin—have increased stages

per day. In 2020, the Permian is expected to account for 43% of stages fracked.

In all, total stages are expected to dip slightly—by 3%—in 2020 amid the activity slowdown before rising by 4% in 2021, Bush said.

Companies have been increasing the amount of sand used in hydraulic fracturing operations since 2017, but nowadays completions tailored for specific reservoirs are evolving with some areas seeing the amount of proppant and fluid per foot flattening over time.

Plus, today's slowed pace of growth has put pressure on sand suppliers.

Westwood places frac sand demand at 94 million tons for 2019, which Bush said may be a "little optimistic." Sand demand is forecast to rise to 106 million tons in 2020 and to 115 million tons in 2021, with the largest markets being the Permian Basin, Eagle Ford, Marcellus and Utica.

With supply outpacing demand, the rebalancing continues following a run-up in sand supplies that hit 157 million tons in 2018, the firm said. Lower 48 frac sand supply is forecast to be about 140 million tons in 2019 and 112 million tons in 2020.

The frac sand supply is expected to rebalance with a 12% increase in demand in 2020.

The supply of Northern White Sand rebalanced in early 2019 through mine closures, according to Westwood. In the Permian, Westwood expects five to seven mines to lower production or close. But new mines are opening in the Rockies, Midcontinent and Haynesville, the firm said.

—Velda Addison

Midcon E&P asset buyers sticking to shopping lists

Upstream oil and gas asset packages are increasingly being carved into a la carte offerings to attract winning bidders, according to Jason Reimbold, managing director of E&P asset-marketer BOK Financial Securities Inc.

In the past, most offerings went to a single-winning bidder. "It was an exception in years past where … an offering was split between a couple of buyers, [each] interested in pieces," Reimbold said at the recent DUG Midcontinent conference.

Today, "the exception is finding a single buyer for an entire asset as opposed to selling the asset in strategic lots," he said.

"That seems to be where the market—for now—has migrated."

Driving this is prospective buyers that have "the wherewithal and the mandate to make acquisitions." They want details, details, details.

"The parameters are very specific and, if the square peg does not fit exactly within those parameters, it's not a buy for them," Reimbold said. "That has resulted in many of our offerings being sold to multiple buyers and [often] not simply as many as two; some as many as five at this point, actually."

That deals are getting done at all, though, is a point to be made

in the midst of a dearth of closings, he added. "We would like to get back to the times when we were selling to just one. However, we're going to figure out how to be successful given the conditions."

In the first three quarters of 2019, 33 packages in the Scoop/Stack were put on the market and 10 closed. Overall, of 74 Midcontinent offerings in that timeframe, 16 closed.

He noted that bids are being made. "We have not yet put an asset on the market in Oklahoma that we failed to receive multiple competing offers for," he said.

The greatest value has gone to the core Stack acreage at the intersection of Blaine, Canadian and Kingfisher counties, Okla., averaging between $8,000 and $10,000 an acre. In the $6,000 to $8,000 range has been the perimeter of that area as well as the core Scoop play in central Grady County, straddling some of McClain County in Oklahoma.

"That sweet spot" that fetches $8,000-plus "has shrunk," Reimbold said.

Despite the slowdown in transacting, "we have achieved some consideration beyond PDP in everything we transacted out here the last 18 months," he added.

"That's taken some doing and these are the multiple-buyer scenarios that I mentioned earlier."

The industry can't prop up oil and natural gas prices, he said, "but what we can do is figure out how to be successful, whatever the conditions may be."

—Nissa Darbonne

Occidental's Anadarko acquisition tops deals of last decade

Over the past decade, which saw both the shale land grab and one of the worst oil market crashes, the U.S. oil and gas industry experienced a whirlwind of dealmaking with total dollar value reaching into the hundreds of billions.

However, the largest oil and gas deal in the U.S. of the decade is this past year's acquisition of Anadarko Petroleum Corp. by Occidental Petroleum Corp., according to a new report published by energy data provider Enverus on Jan. 2.

In total, Enverus tracked $775 billion of U.S. oil and gas M&A this decade, with 73% spent on shale assets. Though by the end of the decade, asset buying has grown largely out of favor as E&Ps turn to corporate consolidation to meet investor demands that have emerged in recent years.

"Investors who funded the shale revolution over the last decade have become vocal in advocating for payouts and cut back on providing new capital," Enverus senior M&A analyst Andrew Dittmar said in the report. "That flowed through to limited M&A and a negative reaction to deals for much of the year."

Occidental's acquisition of Anadarko highlighted 2019's consolidation in the shale patch. The deal, which Enverus values at $57 billion, including debt, is in the ballpark of ExxonMobil Corp.'s 2009 acquisition of

XTO Energy Inc. as the most spent on shale in a deal. Enverus estimates 75% of the deal value in Occidental's acquisition of Anadarko was in shale, including the Permian Basin.

In 2019, the Enverus report said U.S. oil and gas M&A reached a five-year peak of $96 billion. However, the annual total was substantially skewed by Occidental's acquisition of Anadarko.

Backing out the Occidental-Anadarko deal, 2019 saw $39 billion in deals or just one-half of the average $78 billion for annual U.S. oil and gas M&A during the past 10 years.

The Permian Basin continues to be a key driver of U.S. oil growth and a significant contributor to M&A, the Enverus report said. In particular, the Permian accounted for more than 60% of deal value during fourth-quarter 2019. Also, most of 2019's marquee deals focused on the Permian.

After the Occidental-Anadarko deals, 2019's largest corporate transactions were Callon Petroleum Co.'s $2.7 billion merger with Carrizo Oil & Gas Inc., WPX Energy Inc.'s $2.5 billion buy of private Felix Energy II LLC and Parsley Energy Inc.'s $2.3 billion acquisition of Jagged Peak Energy Inc.

Enverus also noted that WPX's acquisition of EnCap Investments LP-funded Felix Energy in December was notable for several reasons.

Besides being the largest deal of the fourth quarter and the fourth largest deal of 2019, the firm said the acquisition of a premier private-equity position in the Permian Basin shows there are still exits available for the "built-to-sell" model of private-equity portfolio companies.

"In the past 10 years, we watched U.S. shale upend global energy markets and transform the U.S. into a net energy exporter," Dittmar concluded. "We're now at an inflection point where shale matures from a growth industry to one that generates dividends and share buybacks for its investors. Completing that transition and setting the stage for the next 10 years will likely require a round of consolidation, and 2020 sets up the needed pieces for this to occur."

—Emily Patsy

Report: OFS needs to retool for success

If beleaguered oilfield service (OFS) companies take strategic moves, pulling levers focused on portfolio strategy, pricing and digital models among others, their efforts could collectively lead to an additional $20 billion each year in revenue.

That's according to a recently released report by Deloitte titled, "Down but not out: Transforming oilfield services." Analysts with the firm studied data from 70 OFS companies, looking for ways they can restructure their businesses to better withstand volatile market conditions and meet the needs of oil and gas companies.

Among the key ways to improve earnings are ditching noncore business lines, while scaling up core capabilities; creating a flexible pricing structure; clearly connecting cost centers to revenue; and enhancing existing capabilities with digital technology.

Some service companies have already taken steps on the path. Several have teamed up with digital giants—such as Microsoft and

Top 10 Deals Of Last Decade

Date	Buyer	Seller	Value ($MM)	Deal Type	U.S. Play
04/24/10	Occidental Petroleum Corp.	Anadarko Petroleum Corp.	$57,000	Corporate	Multiple
12/05/12	Freeport-McMoRan Inc.	Plains E&P	$16,300	Corporate	Multiple
07/15/11	BHP Billiton	Petrohawk Energy Corp.	$15,100	Corporate	Multiple
07/26/19	BP Plc	BHP Billiton	$10,500	Property	Multiple
03/28/18	Concho Resources Inc.	RSP Permian Inc.	$9,500	Corporate	Permian Basin
08/14/18	Diamondback Energy Inc.	Energen Resources	$9,200	Corporate	Permian Basin
06/19/17	EQT Corp.	Rice Energy Inc.	$8,200	Corporate	Marcellus
11/01/18	Encana Corp.	Newfield Exploration Co.	$7,700	Corporate	Scoop/Stack
11/23/11	KKR; NGP; et al.	Samson Investment Co.	$7,200	Corporate	Conventional
02/24/12	Riverstone; Apollo; et al.	El Paso Corp.	$7,150	Property	Conventional

Source: Enverus

Top Five Deals Of 2019

Date	Buyer	Seller	Value ($MM)	Deal Type	U.S. Play
04/24/10	Occidental Petroleum Corp.	Anadarko Petroleum Corp.	$57,000	Corporate	Multiple
08/27/19	Hilcorp Energy Co.	BP Plc	$5,600	Property	Alaska
07/15/19	Callon Petroleum Co.	Carrizo Oil & Gas Inc.	$2,740	Corporate	Delaware/Eagle Ford
12/16/19	WPX Energy Inc.	Felix Energy II LLC	$2,500	Corporate	Delaware Basin
10/14/19	Parsley Energy Inc.	Jagged Peak Energy Inc.	$2,270	Corporate	Delaware Basin

Source: Enverus

Halliburton Co.—or automation specialists—Schlumberger Ltd. and Rockwell Automation's Sensia joint venture—to leverage their combined digital expertise, elevating their technology portfolios.

Others have exited service lines, steering focus to other areas. Schlumberger and CGG SA, for example, left the offshore seismic acquisition fleet business.

Yet, a few have joined forces to better position themselves. Pressure pumpers C&J Energy Services Inc. and Keane Energy Group Inc. merged to become NexTier Oilfield Solutions Inc.

But there is still room to improve in the service sector.

"OFS players still have a chance to build a financial structure that enables profitable growth. Increasing margins could be key," according to the report's authors, Duane Dickson, Alex Fleming and Thomas Shattuck. "If these 70 companies could increase margins to 2014 levels (admittedly a big challenge), they would collectively earn an additional US$20 billion each year—and potentially more than US$30 billion per year across the entire OFS industry."

Business models that worked at $100 per barrel oil aren't working today, according to the analysts, which highlighted how the OFS sector has seen its market capitalization drop by between 50% and 90% since 2014. Oil prices dropped by 45% during the same time frame.

While E&P companies' earnings are rebounding somewhat, thanks in part to the OFS offerings, the struggle continues for the latter. Service providers have seen operating margins squeezed with revenues falling faster than costs, the analysts said.

"Doing more with less—or perhaps more accurately in many cases, doing more for less—is negatively impacting balance sheets," Deloitte said in the report. "Of the OFS companies analyzed, total shareholder return plummeted by more than 50% between first-quarter 2014 and first-quarter 2019. Only five companies out of the 70 reported positive shareholder returns across the period."

Considering the low-hanging fruit is "mostly gone" with U.S. oil and headcounts, for example, below 2009 levels, Deloitte said the sector should focus on five levers to improve its performance:

Portfolio strategy: A realistic assessment of whether to serve markets in the same capacity should be undertaken, according to the report. This could lead to divesting assets, consolidating operations or exiting service lines. The task, Deloitte said, shouldn't be about "pruning" the portfolio but rather paying attention to whether resources are being spread too thin or whether projected financial performance reflects market potential.

"Companies also should break the instinct that they need to be good at everything they do; sometimes it is fine for a function to perform adequately at a lower cost," Deloitte said.

Commercial approach and pricing: Knowing customers' needs and behavior, being aware of costs to deliver such services as a bundle and then creating a pricing schedule are keys to improvement, the report said.

The method of operation for some OFS companies has been to charge different prices in different regions for the same services lacking commercial logic, Deloitte said.

"Oilfield service commercial leaders should pivot from a decentralized to a more structured and sophisticated approach to pricing," the report said.

Operating model design: With costs and revenue out of sync despite reduced spending, operating models is another area highlighted in the report. Complicating sound operating models are "overlapping functions, decentralized internal systems and a lack of connection between overall corporate strategy and the individual business units."

Ways to improve include focusing more on what's important and spending less time and money on "peripheral activities." The goal is to "align outputs and inputs, with corporate structure supporting service delivery."

Integrated business planning: Silos and communication still pose challenges for OFS companies, especially for large integrated companies. Better planning is the solution, according to Deloitte.

"The core idea is that each part of the organization adjusts [its] capabilities to meet demand according to the plan, even if it may often change. Managers can then make decisions that minimize the guesswork," the report said. "This process should be intentionally designed based on the results of an operating model exercise; attempting to patchwork a paradigm using existing blocks could very likely result in relapse into sub-optimized, traditional execution."

Digital solutions: Digital technologies can improve efficiencies for both OFS companies and their clients. Using data as an example, the analysts said service providers should aim to use data to enhance existing capabilities.

"The overall goal of a digital tool set is to lower the latency of decision velocity, process execution, information movement and analysis, while improving reliability, predictability, cost and transparency," the report said. "There are a number of opportunities to use large and small digital solutions to improve internal performance. New operating models should be linked and grounded in the productivity that can flow from these solutions."

Deloitte analysts believe cost-cutting measures and higher revenue could triple margins for the OFS sector, possibly adding more than $30 billion in additional annual earnings for the industry. "There is a lot of money on the line," analysts said.

—Velda Addison

Technology has key role as midstream adapts

The midstream sector faces significant challenges now, and the profitable response to some of those issues must include adopting new technology.

That was the message of Sanjeev Daruka, head of midstream development for Siemens Oil & Gas, in a keynote address on Dec. 4 at the 10th annual Marcellus-Utica Midstream Conference & Exhibition.

"We need to focus on longer-term operational excellence," Daruka told attendees at the Hart Energy event. "The time for building and quickly flipping assets is gone, we have to hold the assets. In other words, operating expense is very important, it's as important as capital expense.

"How do we get the costs out and make ourselves more profitable? How do we get more reliable equipment out in the field so we don't have to worry as much about personnel costs? To me, technology can make it possible.

"If you want to stay competitive, you need to think about lower capex, lower land space, as well as lower maintenance obligations," and those steps depend on rapidly advancing technology, he added.

Commodity prices won't stay low forever, he said, and action now will enable the midstream to enjoy greater profitability when natural gas and crude oil returns become more favorable.

Centrifugal compression, Daruka said, is one important technology that can significantly lower costs as it increases reliability. Centrifugal compressors enable midstream operators "to deliver more with less" in comparison to industry-standard reciprocating compressors.

He said centrifugal compressors can reduce capex for a new natural gas processing plant by 20% to 30%, then reduce operating costs when a plant goes onstream due to lower maintenance expenses. Also, gas turbines typically can reduce permitting time and expense because of lower air emissions.

Midstream operators already are moving toward larger plants that offer lower unit costs, he said. An industry standard for plants with a capacity of around 60 million cubic feet per day (MMcf/d) has migrated toward a 200 MMcf/d standard, and 300 MMcf/d plants also have become more common. However, midstream firms can't make such cost-lowering commitments without accurate production forecasts from their upstream customers.

And often, oil and gas producers can't provide such projections.

"We need to get upstream and midstream on the same page to achieve these economies of scale," Daruka said. Producers must provide accurate numbers to their midstream service providers to gain the cost reductions they want.

Personnel costs are a significant concern, he said, as a substantial number of midstream veterans retire—and replacing those veterans with new employees has proved difficult.

"Where will they come from?" he asked. "The new generation is opting for very different careers. They are opting for technology jobs … are we planning for that? If not, we need to."

That interest in technology plays into a potential strength for the sector if operators embrace the trend, Daruka emphasized.

Technology, in particular remote operation, will allow midstream firms to reduce personnel costs, but there are capital costs involved.

"The [remote] sensors are not cheap, but computing power is very cheap. Transmitting the signal to the control room—the bandwidth—is also cheap. The whole digital world is becoming affordable," he added. And it's important to remember tremendous computing power allows thorough analysis of operating data "so we can fix problems in time" and avoid unplanned outages.

Daruka closed with a traditional, but not surprising, safety message.

"My safety moment is to embrace technology," he said. In doing so, the midstream will be able to meet many of the challenges it faces as the energy industry evolves through greater reliability and lower costs.

—Paul Hart

Directional drilling leads to advances for Chevron

Steps taken a few years ago by Chevron Corp. to investigate inconsistencies in the company's Permian Basin operations led to standardized operating procedures and a digital leap that ultimately moved its directional drillers from rig sites to a remote center.

Flash forward to today, and the company is running 100% of its drilling operations in the Permian from its remote operations center in Houston and seeing benefits, according to Kelsey Prestidge, performance drilling engineer for Chevron. These included improvements in rate of penetration, cycle times and lessons learned being shared across different parts of the basin.

"You have directional drillers all sitting together in the same room talking about different ideas, what they've seen in the past and sharing that knowledge," Prestidge said during a recent Upstream Intelligence by Reuters Events webinar about automating decision-making in directional drilling.

"We're expecting to see more and more improvements especially as we grow as a remote center in learning how to optimize what we're doing, working with our business partners to understand where their limitations are now and how we can go in with laser focus to address those issues and help them get better."

The company also is on a mission to produce 900,000 barrels of oil per day in the Permian's Midland and Delaware sub-basins by the end of 2023. The ramp-up in production comes as some oil and gas companies, including independent E&Ps, carry out plans to spend less money overall on new drilling while working to produce better returns for shareholders.

However, continued optimization and improved efficiency remains at the forefront for shale players, including Chevron, which is using a factory approach for accelerated development in the Permian.

Prestidge said Chevron has a few rover teams set up throughout the field for support. Its responsibilities include picking up and laying down bottomhole assemblies, for example, troubleshooting and mentoring new field personnel. Communication from the field to the center involves use of what Prestidge described as a walkie-talkie type system along with chat features so everyone is aware of what is happening.

The transition of directional drillers to remote centers—a move also made by Hess Corp. a few years ago—involved improved workflows and communication along with ditching the "I don't like change" mentality and getting a ton of feedback from everyone involved.

"The one thing that made us really successful as a team was we were very collaborative," she added. "We also had the same 'why,' and our team was empowered … [by] our leadership team to make remote directional drilling successful. We weren't afraid to fail."

In the remote center, Chevron has pods—one each for directional drilling, measurement while drilling and geosteering—centrally located so they are in constant communication about what's happening, what's not working and what needs to change. Before, the teams were all in different locations communicating back and forth via email, operating in silos and making decisions based on information they had at hand.

The company has seen significant improvement in communication and increased collaboration between teams as well as improved asset development, Prestidge said.

Still, there are challenges and opportunities that come along with supporting drilling operations remotely using real-time data.

—Velda Addison

Oklahoma's Stack 'a victim' of pace, space and more

Some oil and gas operators in Oklahoma's Stack area were going too fast when parent-child issues weren't understood yet, leaving the play's reputation in recovery now, according to Scott Pittman, CFO of Chaparral Energy Inc.

"At some point, people will start to believe there are differentiating companies within the Stack," Pittman said at the recent DUG Midcontinent conference.

A pure-play horizontal Meramec and Osage Formation developer, most of Chaparral's more than 200,000 surface acres—with about 130,000 net—is HBP by old, legacy verticals. It was less driven by the need to HBP while the Stack rose in prominence during the past five years among U.S. oil plays.

"It has given us a chance … to develop at a reasonable pace," Pittman said. "I think one of the items the Stack and [adjacent] Merge has been a victim of is pace," he said.

In 2018 and into 2019, having transitioned to multiwell pads in sections, it came to better understand parent-child well issues. "Our understanding has really started to differentiate [us from others] who may or may not have stubbed their toes" as they were drilling multiwell pads "at a pace that may have been in front of what was their understanding of the play."

Generally, IP-30s aren't much of an indicator of a well's ultimate performance. Going quickly can accelerate returns or can belatedly indicate uneconomic returns.

"2018 is really where the Stack got a bit of negative publicity from a number of different companies," he noted. It was due to the pace. "This was a play that was still in a delineation phase rather than a development mode. A number of companies were throwing a large amount of rigs at it very quickly and over-spacing."

IP-90s are needed for a better picture. The IP-30s may have been good, but "it was the IP-90s

that really matter." It takes 30 days to drill and complete a well with one rig. "It takes another 30 days to see the IP-30 and another 30 to see the IP-60 before you think you have a problem."

Pittman said it is at IP-90 you realize you have an issue.

Instead, "if you go slowly with two to three rigs, which is what Chaparral did, you have the ability to see that," he said. "If you go quickly, you end up with a situation where you've drilled five wells [before] you realize you have a problem.

"And, if you've done that with eight or 10 rigs," he added, "it's a dramatic problem, especially in an environment where there's limited access to capital."

During the shale revolution's early years, operators—and "I was probably part of that propaganda," Pittman said—were "telling investors that geology doesn't really matter. 'Here's the type curve and the location count. Just do the math and that's what it looks like.'

"It turns out that drilling at really deep depths in a hugely technical environment isn't just math," he said. Instead, "it turns out geology actually matters."

Operators have to be mindful of neighbors. In Oklahoma's Kingfisher and Canadian counties, "you were seeing people say they were going to be able to put eight to 12 to 16 wells in a section."

Chaparral is looking at four to eight wells per section instead. "One of the challenges you have in a number of different basins—and ours is no different—is having private-equity [sponsored] companies that are still drilling single-well laterals along a section line," he said.

That compounds the issue. In Chaparral's guidance to investors on well counts per section, Pittman said, "we've taken all of that into account—not just our parents but parents of other companies from other section lines whether or not they've drilled it down the center or up against the edge."

It matters. "It's a continuous problem and one of the reasons we sit down and try to identify the best wells we can," he said.

Chaparral isn't any different among operators who've overstepped, he added. "We've had some toe-stubs along the way as well. But, generally, we're hitting at or above our type curves ... We're generating positive economic returns even in this environment with NGL prices collapsing."

In one nine-well pad, for example, Chaparral "probably spaced it one too close," he said.

"It might have been [better with] eight, perhaps seven. We learned a tremendous amount from it." Yet, Chaparral earned "an economic return—a 40% ROR [rate of return]—and that has to do with our ability to keep costs down."

It will continue to align with fewer rather than more, such as in an upcoming three-well development. "You might see more developments like this where you say, 'Yeah, you can probably do [one more well here]. But what's the point of the risk? It's just a single well.'"

—Nissa Darbonne

Anadarko Basin's wastewater, frac sand woes

Sand and water are largely considered as indispensable ingredients to hydraulic fracturing. Though, as oil and gas operators have continued to optimize completion designs, providers of services related to these key resources have had to adjust.

Experts in sourcing proppant and completion water as well as in produced-water recycling and disposal recently described current best practices and challenges in the Midcontinent region during Hart Energy's DUG Midcontinent conference.

"On a year-by-year basis there is about a billion barrels of water difference between the amount of water that's going down a disposal well and the amount that could be potentially used or reused for hydraulic fracturing," said Rob Bruant, director of product at B3 Insight.

The handling of produced water from oil and gas development has presented an ongoing issue for the U.S. fracking industry.

In July, Bloomberg reported that the Permian Basin would need roughly $9 billion over the next decade to mitigate produced water from the shale play. The Permian's water growth will call for nearly 1,000 additional saltwater disposal (SWD) wells by 2030, according to Raymond James analyst Marshall Adkins.

As a multibasin issue, experts in the Anadarko Basin are also seeing challenges with current water utilization practices, i.e. recycle, reuse and SWD wells.

Aware that production plays a significant role in water utilization, Bruant's data forecast a decline in the next few years in the number of wells that are spud and subsequently completed, although, a rebound is expected in 2024 and 2025. "Even if we expect to see modest growth in oil and gas production and even a slight downturn in rig activity and number of wells drilled, we still think that there's going to be a pretty sizeable differential between water volume that is being subsequently disposed in a saltwater disposal well and the water that could potentially be reused for well completions," he said.

Bruant said one thing that is problematic for the state of Oklahoma and the interpretation of the data is that there isn't a really good understanding of produced water volumes on a per well basis. But, even if 100% of produced water was recycled and/or reused, that wouldn't accommodate all the produced water.

According to Bruant, SWD wells would still be needed and "other opportunities for beneficial use of [the] water either inside the oil and gas industry or outside the oil and gas industry."

An easier and low-cost alternative, he said, is evaporation techniques or ponds to manage the water. However, with produced water having variable compositions throughout Oklahoma, the solids load remaining after this process presents further obstacles.

Bruant explained that the best mitigation alternative toward saltwater disposal is the concentration of the produced water.

"Splitting the stream into a fresh or pure water stream and a concentrated brine—that concentrated brine then gets sent to a disposal well," he said. "Therefore, you're basically using less subsurface volume for disposal and ultimately you have—potentially—another product that can be used with the new oil and gas industry or outside of it."

—Mary Holcomb

2020 Hart Energy Events:

The world depends on energy, and energy professionals depend on us.

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DUG BAKKEN AND ROCKIES
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March 2
Dallas, TX
Fairmont Hotel – Dallas

25 INFLUENTIAL Women IN ENERGY
March 4
Houston, TX
Hilton Americas – Houston

CONFERENCE & EXHIBITION
DUG EAST
MARCELLUS-UTICA **MIDSTREAM** CONFERENCE & EXHIBITION
June 16-18
Pittsburgh, PA
David L. Lawrence Convention Center
CO-LOCATED

CONFERENCE & EXHIBITION
DUG EAGLE FORD
Sept. 9-11
San Antonio, TX
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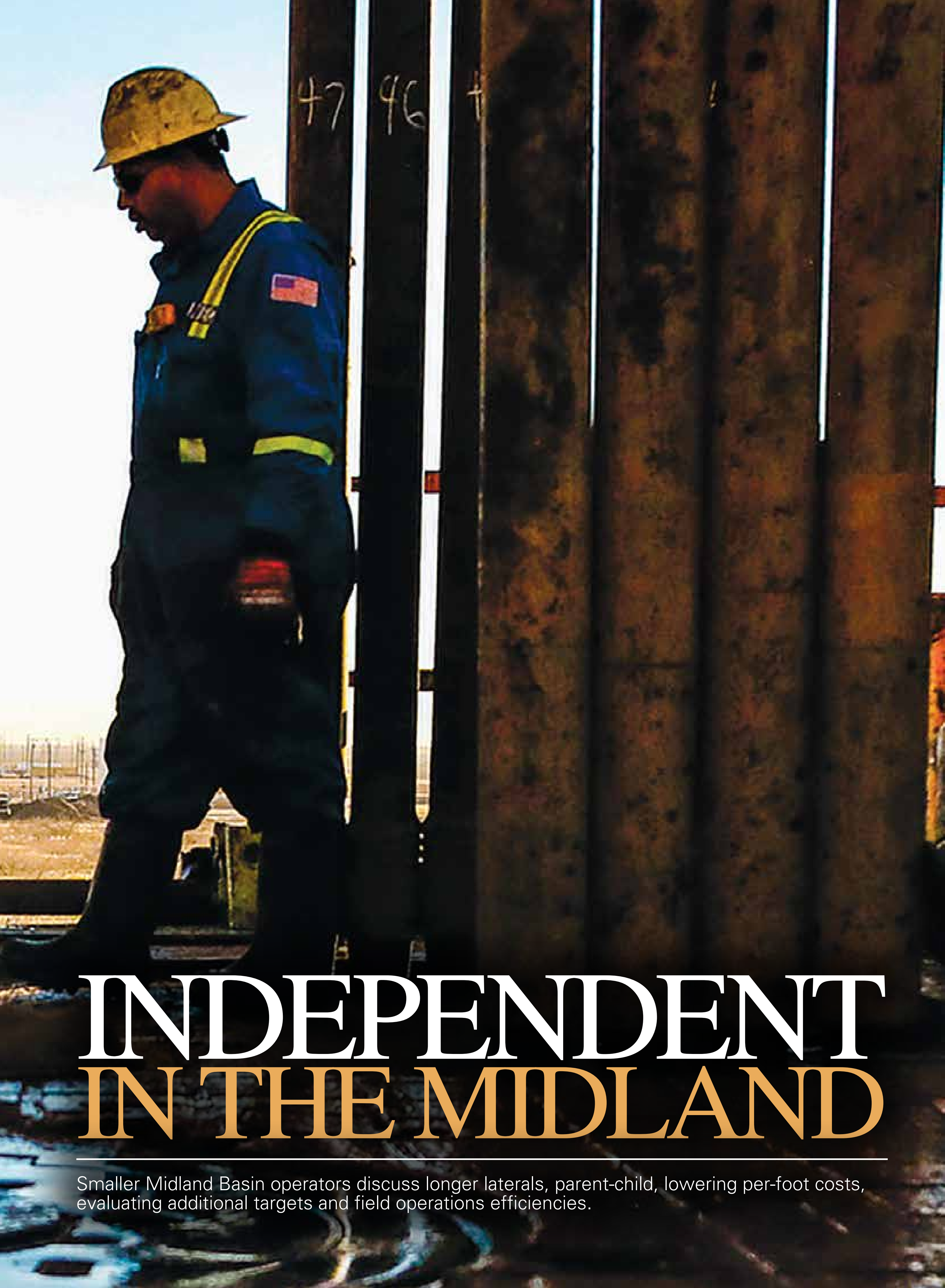

INDEPENDENT
IN THE MIDLAND

Smaller Midland Basin operators discuss longer laterals, parent-child, lowering per-foot costs, evaluating additional targets and field operations efficiencies.

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Overleaf, Precision Drilling Corp. Rig #593 crew make hole for Henry Resources LLC south of the Midland airport in December. Facing page, Rig #593 has been drilling continuously for Henry for three years to date.

Some deals are still getting done in the Midland Basin. Longtime E&P executive Jack Hightower picked private-equity-backed Grenadier Energy Partners II LLC as the platform purchase for his SPAC, Pure Acquisition Corp., which will trade as HighPeak Energy Inc. upon closing.

In the $615 million (75% cash) deal for 23,000 net acres Fort Worth, Texas-based HighPeak will launch with 73,000 net and 12,000 barrels of oil equivalent per day (boe/d) of production, 80% oil, in Howard County, northeast of Midland, Texas. The Woodlands, Texas-based Grenadier ranks on R.W. Baird & Co. Inc.'s monthly summary of top operators by U.S. play on several measures. First three-month gross production—58,583 boe, 92% oil—per operated well is $2.8 million of revenues, averaging $269 per lateral foot.

Of all the upstream SPACs, or special purpose acquisition companies, launched in the past few years, the Pure deal is the first to focus on the Midland Basin. Mark Papa's SPAC picked the Delaware; Jim Hackett's bought in Oklahoma's Stack play; Steve Chazen chose the Eagle Ford and Austin Chalk.

Plans for the Grenadier portfolio are four rigs making 2-mile laterals in drilling spacing units (DSUs) containing 875 gross, 725 net, landing locations in Wolfcamp A and lower Spraberry. The package comes with 97 gross operated and nonop wells, two-thirds Wolfcamp A and a quarter lower Spraberry.

Arun Jarayam and Michael Glick, analysts with J.P. Morgan Securities LLC, reported in December that the Midland Basin's average six-month cumulative production among the top 18 operators grew 3% year-over-year to 12.7 boe per lateral foot, 79% oil.

Parsley Energy Inc. rocketed to No. 1 on the list from No. 13 a year earlier. "Parsley Energy's 2019 wells were by far the most productive in the [Midland] with production of 22.3 boe per foot, 81% oil, which was 75% above peers and a 73% improvement from its 2018 wells," Jarayam and Glick wrote.

With leasehold that's virtually all HBP, "you're driven by technical reasons for drilling one prospect vs. another," said David Bledsoe, president, Henry Resources LLC. "You're not driven by leasehold reasons. That's a good position to be in."

In Glasscock County immediately east of Midland, Laredo Petroleum Inc. added 4,475 net acres, producing 1,400 boe/d, 55% oil, for $65 million. It estimates 45 gross, 35 net, locations in lower Spraberry and upper and lower Wolfcamp.

John Daniel, senior research analyst for Piper Jaffray & Co., reported from an October field trip that several operators aren't seeing much more productivity gains from new wells "with no major step changes ahead, unless there is some unforeseen technological breakthrough."

The Delaware Basin may make modest gains, he wrote, but the Midland "feels more mature." Regarding M&A, activity may rebound, he added, as "some management teams noted they could receive the license to hunt for more inventory in 2020."

For miles and miles

This past spring, Surge Energy US Holdings Co. put a 3.4-mile lateral in Wolfcamp A in Borden County north of Howard County. No one had made a 3.4-mile lateral well in the Permian Basin before. Secondly, Borden isn't supposed to be economic for horizontal Wolfcamp; it's on the Shelf edge.

"Most people would have said, 'You get north of Howard County, it doesn't work,'" said James Welch, Surge CFO. "Well, we've got some pretty good wells in Borden that I think disproved that. It's an example of our innovative culture."

Houston-based Surge is a subsidiary of Shanghai-traded Shandong Xinchao Energy Co. Ltd., operating in the northern Midland Basin as Moss Creek Resources Holdings Inc. in Howard and adjacent Borden. The former, as per Marshall Adkins, managing director and head of energy investment banking for Raymond James, is "the highest oil-cut county in the Midland Basin."

Surge's Medusa Unit C 28-09 3AH consisted of a total of 24,592 feet of hole with a vertical depth of 7,102 feet for total lateral displacement of 17,935 feet, drilled in 18 days by Latshaw Drilling & Exploration Co.'s conventional mud motor Rig #10, staying 100% in zone with ProDirectional services.

Surge didn't provide IP and production-to-date details in December. But the results were compelling enough to continue the extra-extended-lateral program. "We currently have five wells that are 3 miles or longer," said Phil Webb, COO.

"We're seeing strong results from our 2.5-miles-and-longer program in Borden. We're going to continue that longer-lateral program."

All five of the 3-mile-plus wells are in Borden in Wolfcamp A. The Medusa DSU has two wells, both more than 3 miles.

It chose Borden for the tests because the leasehold there—Surge bought its Midland leasehold in 2015 shortly after its founding—was largely undrilled, Webb said; its Howard leasehold already had many wells, thus DSUs had been laid out for mostly 1.5-mile wells.

"As we started laying out the [Borden] units, we built our learnings from Howard and created a longer-lateral program. We felt we could take what would be 5 miles of subsurface potential and, instead of drilling three 1.5-mile wells, we could drill two 2.5-mile wells. It's combining well sticks two for three," Webb said.

"We would capture capital efficiencies, and it made sense from a reservoir-development and economic standpoint, combined with our land position."

Staying in zone for more than 3 miles is one challenge. Pushing sand farther than a 5K run with sufficient pressure to reach the toe without duning is exponentially harder. The Medusa completion involved 52 stages with TTS SlicFrac diversion for 2,200 pounds of proppant per lateral foot. The pumper was Universal Pressure Pumping; wireline, GR Energy Services.

Then there are the plugs for stage spacing. Dissolvable plugs are common. These don't have to be removed; they basically melt over time.

Midland Basin Stratigraphy Of Interest

Permian
Clear Fork
Upper Spraberry
Joe Mill/Middle Spraberry
Lower Spraberry
Dean
Wolfcamp A
Wolfcamp B
Wolfcamp C
Cline/Wolfcamp D
Pennsylvanian
Strawn

Endeavor Energy Resources LP has encountered a few primary-infill well issues; otherwise, it's mostly only drilled parent wells, according to Lance Robertson, COO.

But, Webb said, the extended laterals are being completed mostly with physical plugs, using dissolvable plugs closer to the toe. "So far, we have been able to drill out all the way to TD [total depth] with 100% mechanical success."

When it fits

Houston-based Sequitur Energy Resources LLC plans 3-milers this year. Its longest to date is 2.5 miles, said Scott Josey, chairman and CEO. Its shortest are 1.5 miles; the average across its leasehold is about 8,700 feet.

Midland-based Endeavor Energy Resources LP, with more than 370,000 net acres in the Midland Basin, is working on further blocking up its position to allow for yet-longer laterals. Its average lateral length in 2019 was 2 miles.

"We've put more than 20 2.5-mile-lateral wells into sales this year," said Lance Robertson, COO and senior vice president of development. "At the end of the day, we look at productivity per horizontal foot compared with the cost of development per foot."

So far, they've worked out. "We wouldn't hesitate to do that again," he said.

But beyond 2.5 miles, Endeavor isn't as confident in the value, he added. "We would drill some of those where there might be a surface issue, such as in or near a community. I think [the 3-miler] will be there on an as-needed basis."

Meanwhile, Midland-based Henry Resources LLC doesn't have plans for 3-milers either. Science-ing it isn't necessary in this case; its leasehold isn't configured for it.

"We just don't have those opportunities today. If we did, we would certainly look into it," said David Bledsoe, Henry president.

Henry has locations for 2.5-mile laterals, and a handful of them are on the schedule. "We don't have any heartburn about the 2.5-mile laterals," he added, so 3 miles are probably achievable.

"There are issues that come up the longer you drill, certainly. And it's not so much the drilling; it's fracking and clean-out operations and keeping the length of lateral clean and producing," Bledsoe said.

"But technology is always pushing us up the learning curve."

Dedicated rig

Henry Resources had one rig drilling for it in early December and has averaged 1.5 the past few years. "We run one or two. That's where we've been," Bledsoe said.

A Permian operator since founded by Jim Henry in 1969, its 20,000 operated acres are about 80% HBP currently; net wells needed to hold the balance are fewer than five. To not have to race around miles of the Midland Basin, trying to HBP acres, has been nice.

"You're driven by technical reasons for drilling one prospect vs. another," Bledsoe said. "You're not driven by leasehold reasons. That's a good position to be in."

As operators were negotiating lower service costs after 2014, many were also effectively picking crew members. At times, operators were paying raises for them.

At Henry, the constancy of its rig schedule has meant familiarity with crews, so suggesting high-grading to vendors wasn't necessary. "We've been using the same vendors for several years," Bledsoe said.

If seeing Precision Drilling Corp.'s Rig #593 while driving around the Midland countryside, for example, it's drilling for Henry; the rig is dedicated to Henry. In December, the crew was on a Henry job just south of the Midland airport.

"Those guys have been drilling only Henry wells for the last three years," Bledsoe said. Similarly, "the frac crew we've been running is the same frac crew we've been fracking with."

That crew had just finished a five-well job

and was to return to another Henry job by this month. With just one or two rigs at any time, Henry's frac schedule has gaps. "We don't have enough business to keep a frac crew busy 100% of the time, so we schedule them six-plus months in advance.

"About half the time or a third of the time, they're on other people's wells. But, when they're with us, they're the same guys we've been fracking with."

They're part of the team. "They've been drilling and fracking Henry wells for multiple years. They know how we think. We know how they think."

Vertical to horizontal

Endeavor had 10 rigs and four frac spreads at work in early December. "We'll carry that activity into [2020] unabated," Robertson said.

He sees opportunity for reduced oilfield service pricing. "Our experience is [that] strategic service providers want to align themselves with operators who are most efficient. This helps everyone involved get more work done," Robertson said.

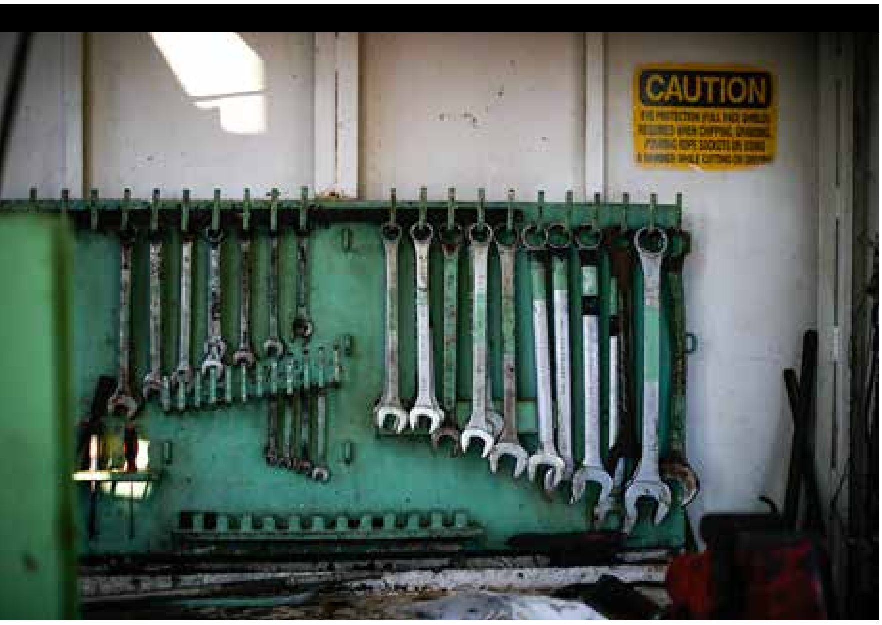
For example, "if we can get 20% more stages completed in a month, that's more margin revenue for our service partners. They, in return, share [that] with us in the form of lower costs."

They are "our extended team, and that team gets better the more we practice together—like any team. There's no question it works to our benefit and theirs."

Although a Permian Basin operator since founded by Autry Stephens in 1979 with a first Spraberry well, Endeavor only began develop-

Wolfcamp is at a shallower depth in the southern Midland than north, so wells are less expensive to drill, said Scott Josey, chairman and CEO, Sequitur Energy Resources LLC.

Henry Resources targets the Wolfcamp and Spraberry zones equally across its drilling program.



The toolbox at the Precision Rig #593 doghouse.

ing its leasehold with horizontals four years ago.

Many longtime privately held basin E&Ps were confronted in the past decade with a point at which they had to decide whether they were going to become unconventional-resource shops or retire. Many, such as the Bass family, sold.

Endeavor didn't; it became a tight-rock shop. Among personnel, it brought in Robertson in 2017 from Marathon Oil Corp., where he had been vice president of U.S. unconventional resources; prior, he was vice president of engineering and exploitation at Pioneer Natural Resources Co.

Third-quarter production was 133,000 boe/d, up 86% from third-quarter 2018. "While we were good on the vertical side," Robertson said, "we've had to learn from our peers across the basin and through our own efforts to be effective at our horizontal development."

That vertical legacy helped with having its position approximately 95% HBP. And the leasehold is practically free. "All of those assets were acquired on a low-cost basis over the years, and they've already been fully depreciated," Robertson said.

So returns are measured on new-well development and operating cost "and not also on the [land] purchase, if you will."

Like Henry Resources, where Endeavor drills next isn't motivated by a need to HBP. "This lets us focus and build infrastructure in concentrated, high-quality areas," he said. The tasks at hand aren't all over the map, "which allows our team to be more efficient."

More targets, maybe

Endeavor is landing in Wolfcamp A, Wolfcamp B and the overlying Spraberry. In western Martin County, it is appraising Jo Mill, which is a sub-member of the lower Spraberry Sands, as well as the middle Spraberry, "so up to five benches of development," Robertson said.

At a higher oil price, it likes pockets of others as well, such as appraising Wolfcamp D, which is also known as Cline.

"We're testing those benches for full development. We would like to add them on a consistent basis," Robertson said. "I don't think we're quite there yet, but we're very encouraged by the early results."

In some areas of the basin, it also sees potential from the Wolfcamp C, "and there are even some shallower horizons that have traditionally been overlooked [that have] a substantial amount of oil," he said.

Longer term, Endeavor might look at Clearfork overlying the Spraberry. "At a different oil price, it could be very attractive," he said.

Strawn, a conventional formation that has been developed vertically, might take a horizontal tap, he added, in some structural traps.

All of this leaves much more to possibly move into the "future inventory" column one day. "I would love to fully understand all of those other horizons today, but we've got such a tremendous inventory of high-value, low-risk wells in the Wolfcamp A and B and the lower Spraberry—and, increasingly, Jo Mill, middle Spraberry and Wolfcamp D.

"It's just going to take us a while to get through all of it. We're really blessed in a lot of ways."

Tulsa, Okla.-based Laredo Petroleum Inc. CEO Jason Pigott told *Investor* it is looking at Cline again; a year ago, its thinking was that it wasn't economic. Privately held, Fort Worth, Texas-based DoublePoint Energy LLC was expecting at press time to add a fifth rig and, in addition to the Wolfcamp, Spraberry and Jo Mill, it is interested in the Cline, the company told *Investor*.

Henry Resources is landing in the Wolfcamp and Spraberry, about 50:50, Bledsoe said. "In many areas, it depends on what rights you own and, obviously, what benches are technically better. But we drill equally in the Spraberry and Wolfcamp."

In some of its leasehold, "there are Spraberry benches that are kind of skinny at $55 oil that people like us would put at the end of their drilling inventory," Bledsoe said. In

Select Private Midland Operator Recent Results

Operator	Well	County	Formation	% Oil	IP-24 boe/1,000 Lateral Ft.
Surge Operating LLC	Shroyer-Wilson Unit B 23-14 8Ah	Howard	Wolfcamp	91%	248
Endeavor Energy Resources LP	Cypert H 57-51 281	Martin	Wolfcamp	89%	179
Guidon Energy LLC	Amoco-Holt 19LI	Martin	Spraberry	93%	187
CrownQuest Operating LLC	Sycamore 2Ha	Howard	Wolfcamp	87%	56
Endeavor Energy Resources LP	Cypert F 57-51 262	Martin	Mississippian	89%	113
Endeavor Energy Resources LP	Cypert E 57-51 251	Martin	Wolfcamp	82%	112
Surge Operating LLC	Shroyer-Wilson Unit B 23-14 7Sh	Howard	Spraberry	90%	134
Endeavor Energy Resources LP	Cypert E 57-51 152	Martin	Wolfcamp	90%	46

Source: J.P. Morgan Securities LLC

addition, "there have been known to be some Clearfork benches in some areas, but those won't work until there's, probably, $100 oil or better."

Outside of that, "we haven't seen a lot that interests us above the Spraberry," he said.

The same ROR

In the southern Midland Basin, Sequitur is focused primarily on the Wolfcamp. It has looked at data on other benches, such as the lower Spraberry, which it believes prospective across much of its leasehold.

"But we're generally not in much of a risk-taking mode right now," Josey said, "so we'll watch and evaluate the performance by other operators in those formations."

The basin gets gassier while moving southeast into Sequitur's Irion County leasehold. Meanwhile, the Wolfcamp is at a deeper depth in Reagan and Upton counties and is very oily.

Third-quarter production was some 35,000 boe/d, about 70% liquids, more than half of that oil, from more than 280 horizontals, 100% operated, with working interest averaging 89%.

From the top of the lower Spraberry to the bottom of the Wolfcamp is about 3,500 feet in the southern Midland. That thickness is an attribute that also drew Denver-based Tracker Resource Development III LLC's attention. Tracker had been a part of Henry Resources' successful vertical Wolfberry play in Sweetie Peck Field in northern Upton in 2004. It moved into the Bakken from there, selling that portfolio to Hess Corp. in 2010.

Returning to the Midland Basin, Tracker III has 26,000 acres in Irion; it estimates its Wolfcamp to contain more than 200 million barrels per day (MMbbl) of oil per 2 square miles. As of late 2019, it had 28 horizontals in the formation.

Sequitur's Josey said that, in addition to thickness, Wolfcamp is at a shallower depth in the south than in the north. Its wells in Irion start out oily, but GOR increases fairly quickly. The net effect is that they're cheaper to drill because of the shallower depth and cheaper to operate because they're gassy.

"As we move into our assets in Reagan and Upton counties, they are deeper and oilier. You need an extra string of pipe, and it costs more to operate," Josey said.

Thus, in terms of rates of return, the wells in Irion vs. Reagan are not materially different.

"The southern Midland Basin gets somewhat of an undeserved, poor reputation, and that is mainly because several companies have had financial struggles, probably more to do with heavy debt loads than with the rock," Josey said.

The rock is good in much of the southern Midland; Sequitur is looking to add more. "We like the area. We believe that the full-cycle economics are very good where we are."

Among neighbors' wells in the area recently, Sable Permian completed 17 in Reagan and three in Irion with IP-24s averaging 1,661 boe/d, 87% liquids, according to an early-December summary by J.P. Morgan's Jarayam and Glick.

Meanwhile, Pioneer reported 15 wells in Midland and Reagan counties that had IP-24s averaging 1,552 boe/d, 84% liquids, Jarayam and Glick added. And Parsley Energy Inc. reported two Reagan wells that had IP-24s averaging 1,779 boe/d, 84% liquids.

Getting on the grid

Formed in 2011, Sequitur entered the southern Midland in 2016 with an acquisition from EOG Resources Inc. In 2019, it picked up 11,085 net acres in Reagan and Upton from Callon Petroleum Corp., along with some minority interests, for $265 million.

Of its 90,000 net acres, about two-thirds are on University Lands; most of the balance, on large ranches. "We have significant infrastructure in place, much of which we inherited when we did the [EOG] transaction."

That includes gas-gathering, water-gathering, source-water wells, disposal wells, water recycling, ponds and connections to multiple processing plants.

A worker maneuvers pipe at the Henry Resources LLC drillsite.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LOWER BARNETT TO WOLFCAMP

Houston-based Zarvona Energy LLC is evaluating potential for Wolfcamp development in producing leasehold it recently added in the southern Midland Basin. Meanwhile, its primary focus in the Permian has been in Andrews County, targeting the lower Barnett.

The overall portfolio includes operations in West Texas, East Texas, Oklahoma and western Louisiana. Of more than $200 million in capital projects since 2016, more than half of the spend has been on the lower Barnett program, making more than 20 horizontals to date.

"We will continue to be active in our Andrews area [in 2020], although at a slower pace than the past two years," said Matt Jurgens, Zarvona COO. The position, which is on University Lands in southern Andrews, is about 90% developed, "so we will be wrapping that project up [this] year."

Meanwhile, it is evaluating the lower Barnett in a new property in Ector County. This past fall, it was drilling a second well there.

"Our main focus will be understanding that play more, as it is about 20 miles south of our Andrews activity," Jurgens said. "We are in the early stages of appraisal on that property."

While the lower Barnett laterals have been 2 miles or less, Zarvona's looking to try some of more than 2.5 miles up to 3 miles. It hasn't made these yet "mostly because our acreage position in many cases doesn't have three sections lined up in the right direction," Jurgens said. "In a majority of cases, we have two sections lined up."

Zarvona is also interested in other benches, such as the economic potential for Woodford. Marathon Oil Corp. reported this past fall that it has 60,000 net acres prospective for Woodford and Meramec. The project area is in the Delaware Basin and straddles southern Winkler and northern Ward counties, southwest of Zarvona's development in the lower Barnett.

But, Jurgens said, the Marathon findings are interesting. One Woodford test had an IP-30 of 365 barrels of oil equivalent per day (boe/d) per 1,000 lateral feet, 78% oil; a second test, 240 boe/d per 1,000 feet, 48% oil.

Jurgens said, "We have long felt the Woodford could be prospective in the right areas. We also feel the Atoka could be a good target in certain areas as well."

Meanwhile, the environment for margin of return this past year has been "pretty tough for operators and service companies alike." Rigs were released as oil hovered in the $50s and natgas and NGL prices plummeted.

"North Dakota is a good example," he said. "Operators there reported receiving $20/bbl [per barrel] for their NGL and $1 an Mcf [thousand cubic feet] in 2018. In the third quarter of 2019, they received almost zero for natural gas and $3/bbl for their NGL."

Overleaf, Latshaw Drilling Co.'s 2,000-HP walking Rig #16 drills for Midland-based Permian Deep Rock Oil Co. LLC alongside I-20 across from the Permian Basin Petroleum Museum and the VisitMidland tourist center.

Sequitur added an oil-gathering and centralized gas-lift system in Reagan this year, eliminating oil trucking and numerous individual wellhead compressors. And it's gotten rid of nearly all rod pumps.

In addition, it renegotiated its processing agreements and electricity contract.

Endeavor's Robertson said getting electricity in the field can be a challenge in West Texas. Rather than takeaway, "if there is a constraint today, I think power distribution is at the top of the list."

There isn't a shortage on the big Texas grid, but regional distribution hasn't kept up with field demand.

"In some areas, we've taken on the need to generate our own power and be our own distributor until power distributors can keep up," Robertson said. "It isn't an impediment, but it causes us to have to take on additional work."

In Borden County, Surge Energy's Webb said it's reducing its generator use. "We've worked to get on grid." How? "We kind of jumped the queue in 2018 and committed to build our own substation."

By December, it was completed. "We're not just waiting [for the power company]. We were very proactive a year ago," Webb said.

Surge expected the power problem when entering the county. "To give you a relative scale," Webb said, "there are only a few hundred people in that county. We knew we would be using more electricity than was the norm, so we worked out a solution."

'Point-0s'

With five rigs drilling for it in early December, Surge started out in 2015 with about 6,500 boe/d; at the end of third-quarter 2019, it was producing 56,712 boe/d, 83% oil, all from Wolfcamp A, B and Spraberry. Net leasehold is about 86,000 acres with high working interest.

"One of our core values has always been to be innovative," Welch said. In addition to building a substation, it began using regional sand in late 2017 and built produced-water-treatment facilities, so it's using 100% recycled in fracs, leaving roughly 50 MMbbl of freshwater in the aquifer.

It has eliminated controllable flaring and implemented a leak detection and repair program.

Subsurface, its punch list includes effective fracture-stimulation near wellbore; for that, it's finding success with mechanical diverters.

"We're actively testing and working with multiple vendors on the diversion front," Webb said. "You start really revolutionizing how you think about completions again."

Is this a 6.0 update? "Well, there are so many point-0s. I don't use that; I just ask, 'What are we actually doing?'"

The work is helping with the risk and cost profile of the extra-extended laterals, he believes. "If you can lower your risk—the mechanical number of times you have to go into your well—you give yourself a better chance of having a mechanically successful well during the completion and drill-out phase."

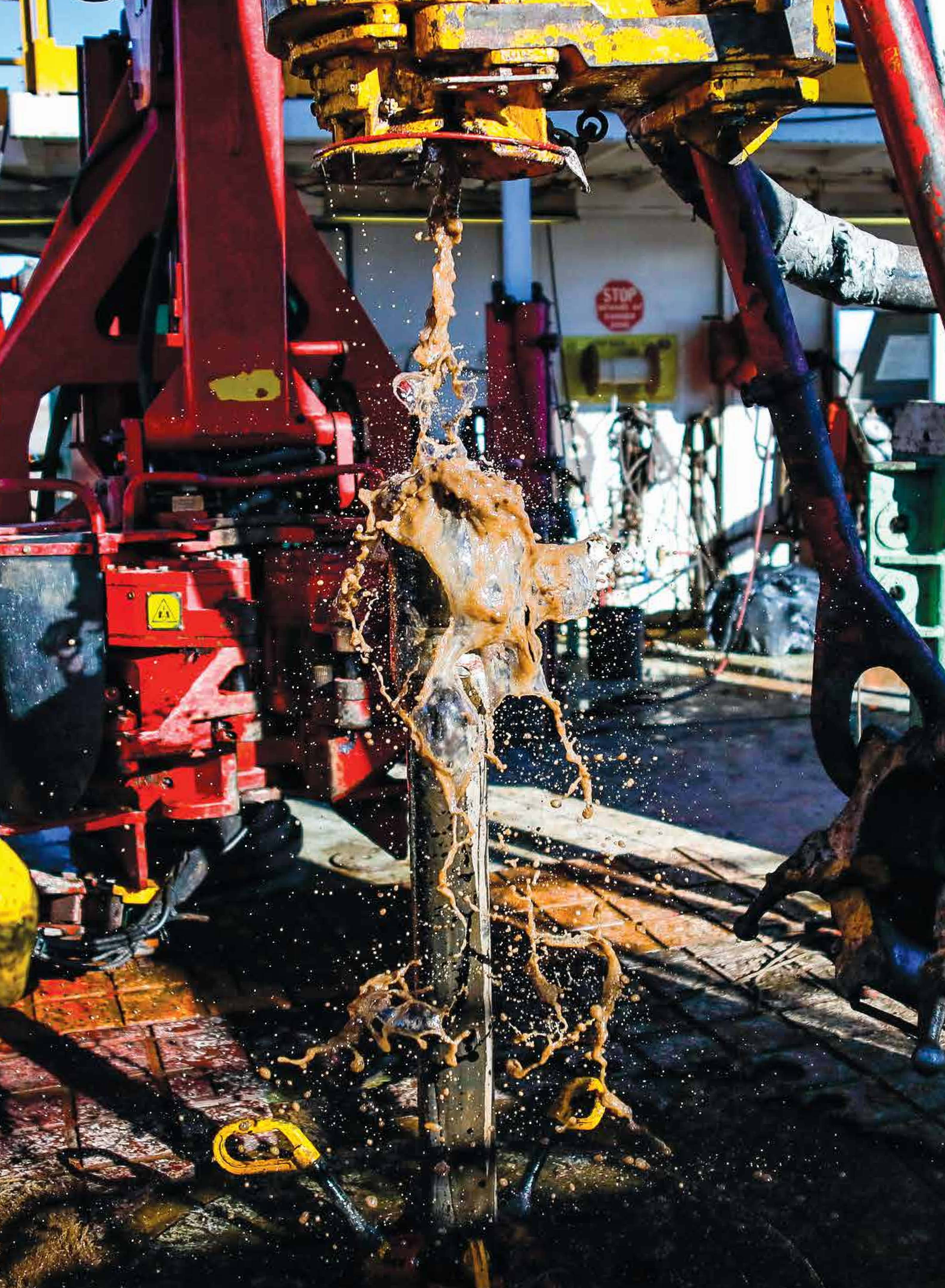
He expects it could also help with child wells. "Better production from the child well is one of the theses. It's not to say it's proven, but we're not discouraged."

Regardless, the cost savings alone help. "It's not that you're going to get this huge change in production, but you're really getting a good cost-savings on the completion side."

Parent-child

Endeavor has encountered a few primary-infill well issues; otherwise, it's mostly only

Anthony Longoria, head lease operator for Sequitur Energy Resources LLC, looks over a manifold at a Sequitur facility near Big Lake, Texas, in Reagan County. Facing page, the bottomhole assembly is being tested at the Henry Resources LLC drillsite in Midland County.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Select Private Midland Operators' Results, First Three Full Months Gross Production*

Operator	Avg. Oil %	# Wells	Avg. Gross Revenues Per Lateral Ft.
Zarvona Energy LLC	73%	5	$418
CrownQuest Operating LLC	83%	56	$391
Tracker Resource Development III LLC	84%	8	$317
Endeavor Energy Resources LP	85%	133	$332
DE3 Operating LLC	88%	22	$355
Henry Resources LLC	88%	18	$377
Sabalo Energy LLC	94%	22	$349
Lario Oil & Gas Co.	87%	26	$358
Fasken Oil & Ranch Ltd.	84%	11	$325
Summit Petroleum LLC	84%	15	$297
Guidon Energy LLC	88%	5	$351
Grenadier Energy Partners LLC	92%	8	$269
Surge Operating LLC	90%	92	$279
Sequitur Energy Resources LLC	74%	41	$241

*Wells completed May 2018 to April 2019.
Source: R.W. Baird & Co. Inc.

drilled parent wells. The most it's put in a DSU to date are 16. "And we put all of those in at one time, so those are all, in our view, primary wells," Robertson said.

"There were no infill wells, so we haven't seen any issues with that."

A unit at Endeavor is usually a half-mile wide by 2 miles long, totaling 640 acres. The most that can be put in a DSU might not be a concern, Robertson said.

"If you have the right stimulation design and the right spacing, you could have 20 or 30 wells in a unit and all of them perform very well."

The Endeavor tack is to place the highest-value, lowest-risk wells in its DSUs "the first time we show up," Robertson said. "What that does is long-term minimize the number of infill wells and any potential issues around that."

By the time it returns with infill drilling in some prospects, industry may have solved the issue, he added. "Completion efficacy has risen tremendously. I have full confidence the industry will figure out how to mitigate primary-infill well impacts much as we solve other issues in the industry over time."

Endeavor commenced horizontal development with best practices in hand from other operators' years of trial and error. "We're on our fifth generation of stimulation design," Robertson said. "And we're currently testing parts and pieces of what we hope will be our sixth generation."

It has more than 9,000 gross horizontal locations identified. "We've drilled about 5% of our total inventory of horizontals that we understand today—not including all the [potential] ones we talked about earlier," Robertson said.

"We've just barely scratched the surface of our resource base. We're optimistic about what our future looks like."

Taking partners

Henry Resources' Bledsoe said most of the work on the best completion recipe has been done, "but there are always going to be a few things [to adjust], especially area-specific, because one size doesn't fit all."

Overall, completion has reached 70% or 80% of its fullest potential, he estimates. "There's still room left to get better."

A family operation, Henry isn't private-equity backed, although about 10% of its portfolio is in a partnership with a private-equity group. In that, Post Oak Capital LP made a $200 million commitment in 2017 to Moriah Henry Partners LLC to acquire and drill in the Midland Basin.

In the rest of its portfolio, Henry Resources does take working-interest partners in everything it does. "We can never really afford 100% of everything we generate; it's just too much capital commitment," Bledsoe said.

Secondly, "Mr. Henry has always been a big proponent of taking partners in everything you do because they make you better."

Taking partners diversifies the portfolio, and they "make you better technically because you're meeting with them and brainstorming with them."

The result also means Henry Resources has a piece of a lot of others' wells and a lot of others have a piece of Henry's wells—mostly other small independents. "We do a lot of data-sharing," Bledsoe said. "We do a lot of data-trading, especially with offset operators where we need to know their frac schedules and they need to know ours.

"We're all testing the same benches, so we're cooperating with and learning from each other. There is a lot of synergy out there from co-ownership and offset operations."

As for trading acreage to accommodate longer laterals, that remains difficult, although operators keep trying. "Everybody values their own acreage a little bit differently," Bledsoe said. "But everyone realizes, for the most part, that's what needs to happen."

'Oil fraction'

Is it nice to be a private—rather than a public—E&P right now? Bledsoe said, "I think [private] is a much better environment to be working in, where Wall Street's not telling you what to do."

Robertson said a private operator has the same goal as a public: delivering the best possible cash return to the owner. "In our case, we have one owner." But, he added, in the public space, "investors want something different than what they wanted in the past."

Sequitur's Josey, who took Mariner Energy Inc. public in 2006, said, "There are pros and cons to both being private vs. being public."

If public, even in a challenging market, "at least you have access to capital," Josey said. "However, the market may push you to do some things that you might not do otherwise."

The focus on "oil fraction" is an example; it's being used as a proxy for rate of return. "Should a producer's percentage of oil in the production stream decline even a percent in a quarter, the stock may get punished," Josey said.

Meanwhile, it may have only declined between completing new DSUs. "There are also a number of oily companies struggling financially," he said.

Sequitur's oil fraction declined from some 40% to 35% this past year as it stopped drilling in April and focused on integrating the package from Callon. It used excess cash flow to pay down its bank debt, which had increased to just under $600 million at the Callon closing.

It expects resuming an active drilling program will increase its oil fraction to around 50%.

"A public company might not have the ability to pause drilling as we were able to do as a private company because of the focus on oil fraction and quarterly growth," Josey said.

Sequitur was also concerned in 2019 about the potential for lower oil prices and lower netbacks on natural gas.

"With the uncertainty in commodity prices, takeaway capacity and geopolitical events," Josey said, "we made the decision in late 2018 to just address our contractual obligations in 2019, sit back and let the market get more clarity, which is another benefit of being a private company."

When seeking an answer on whether to drill or not drill, Sequitur primarily consults rate of return. "Rate of return incorporates everything—whether it's oil fraction, operating costs, capex, royalty rate [or] commodity prices.

"If you just focus on oil fraction, you might not get it right."

Able to try

Surge Energy is a subsidiary of a public company based in China, but its board is focused on building a long-term, sustainable oil and gas company, Webb said, rather than building to exit. It expects to be cash-flow neutral by the end of [2020] and positive after that.

"We've taken a very conservative leverage profile and financial philosophy, keeping a strong balance sheet," Welch said. Its debt-EBITDA ratio is under 2.0, for example. "Not everyone in the basin is doing that."

The parent company has allowed Surge to have an innovative culture. From the start, Welch said, "we weren't going to necessarily just do it the way everyone else has done it."

It's helped Surge attract personnel who want to be a part of being able to "take a few chances here and there," he said. "When they're successful, you have significant results. That's proven in our long laterals and our completions."

Meanwhile, he added, "if you make one mistake in the public arena, you have to make a press release and talk about that." □

A digital sign in downtown Midland displays the U.S. rig count, along with oil and gas prices.

CRUISING ALTITUDE

Fresh off of a multibillion-dollar sale of its midstream interests, natural gas producer Indigo Natural Resources is flying high above the storm clouds.

INTERVIEW BY
STEVE TOON

In the past three years, Indigo Natural Resources LLC net production grew at an astonishing 80% per year, from 160 million cubic feet of gas per day (MMcf/d) in 2016 to approximately 1 billion cubic feet per day (Bcf/d) presently, becoming the fourth largest private producer in the U.S. in the process. The ramp up was led by CEO Frank Tsuru, who joined the company in 2016 as it made a transition from a single-horizon focus—the Cotton Valley—to targeting multiple pay zones: the Haynesville Shale, Bossier and Holly Vaughn.

Houston-based Indigo was one of several private-equity-backed E&Ps that took advantage of the "second wave" of the Haynesville renaissance following a sell-off by many of the earlier prominent public players. But it wasn't a new entrant to the region. First formed in 2006 by Bill Pritchard, currently chairman, to exploit the Cotton Valley, Hosston and Austin Chalk, that iteration was sold to Encana Corp. and Chesapeake Energy Corp. for a combined $611 million in 2009, a year after the Haynesville Shale made its debut.

By 2016 the company had re-established a sizeable position in North Louisiana. It was then that it received a $375 million recapitalization infusion in conjunction with the acquisition of Bridas Energy USA's Haynesville position, when Pritchard came calling Tsuru.

Pritchard and Tsuru had been partners for 13 years by then through Momentum Midstream, which they co-founded in 2004. Tsuru was CEO of Momentum, and Pritchard needed a CEO and CFO to run Indigo at the time.

"He and I were talking about potential candidates," Tsuru recounted, "and Bill says, 'Who better do I trust than my two partners (including Momentum CFO George Francisco) that I've worked with all these years? Do you guys want to run both? Can you run both?' We said, 'Sure, let's do it.'"

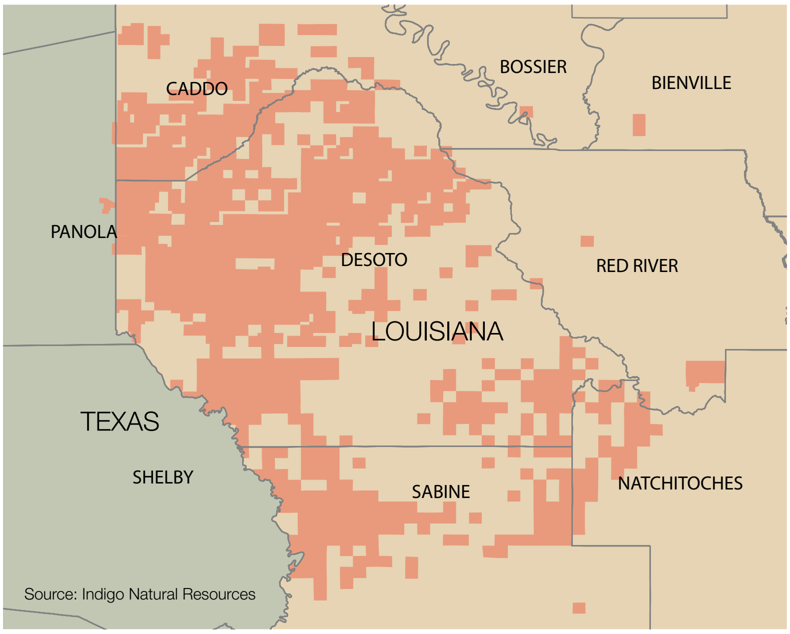
A few months later Indigo announced a $450 million acquisition of Haynesville assets from Chesapeake, and it was off to the races. The company queued up to IPO in 2017 before the market fell away.

With the shared management teams, it's not a surprise that Indigo and Momentum partnered on a joint-venture midstream infrastructure build-out on Indigo's position. In December, M5 Louisiana Gathering LLC, the 50:50 JV entity, sold to DTE Midstream for $2.65 billion, with half of those proceeds falling to Indigo.

The $2.65 billion midstream sale "was very, very good for Indigo. It was transformational for the company. It took us to a point where it allows us to withstand this terrible gas price environment."

—Frank Tsuru,
Indigo Natural Resources

Indigo Acreage Map



Indigo Natural Resources, first formed in 2006, currently holds some 237,000 net acres in North Louisiana with production approaching 1 billion cubic feet per day, making it the fourth largest private U.S. independent by volume.

Today Indigo, with 180 employees, holds some 237,000 net acres primarily in DeSoto, Caddo and Sabine parishes in Louisiana, or 450,000 "net effective" acres considering its three targeted horizons. Proved reserves are 4.7 trillion cubic feet equivalent. The company touts in excess of 1,700 core horizontal locations.

Indigo is backed by a basket of sponsors including Yorktown Partners, Ridgemont Equity Partners, GSO and Trilantic Capital Management, along with family-owned Martin Companies and Bridas Energy, an Argentinian company.

Tsuru graduated from the University of Kansas with a degree in petroleum engineering in 1982. He also serves as the president of the National Eagle Scout Association, and is himself an Eagle Scout.

Investor Why did you decide to sell the midstream interests now?

Tsuru We decided to sell the midstream because of where it was in its development. We felt it was the right time. The midstream system buildout was largely complete and the system was approaching capacity, driven by Indigo's strong production growth over the past few years. Given these factors, we felt we could present a compelling story to potential buyers based on actual throughput and cash flow. The asset was relatively mature, and the buyers wouldn't have to rely on a huge prospective volume ramp to get their return.

And it actually was very, very good for Indigo. It was transformational for the company.

Investor How did the sale impact Indigo?

Tsuru Indigo will receive $1.1 billion of proceeds from the sale with the majority of the proceeds already received in December of 2019 and a portion to be received in the second half of 2020. We used the proceeds received to date to reduce leverage and strengthen our balance sheet and plan to do the same with the deferred portion in 2020. Pro forma for the asset sale, we expect our leverage ratio to be below 1.5x throughout 2020, which is among the lowest leverage relative to our public natural gas peers. That is a big reason why we did that sale. This positions us for success in today's challenging natural gas price environment.

Investor As a private-equity-sponsored company, did you feel an urgency to have a monetization?

Tsuru No, we didn't. We have a very patient investor base—our early investors made a strong return in the asset sales in the first wave of the Haynesville and our more recent investors are early in their investment horizon. They also participated on this midstream sale and did very well.

Investor Did you have a need to monetize related to the debt? Were there near-term maturities?

Tsuru We were fine even without it. We had no near-term maturity issues—the earliest maturity of our debt at the time of midstream sale was in 2024. In addition, we had relatively low leverage at the time of the sale—around two times—so we were not driven by a need to reduce overinflated debt levels.

But it did make our balance sheet very strong. It made the company durable. We have zero balance on our reserve-based loan. We've got plenty of liquidity. We are in a much better position today following the sale with a stronger balance sheet and reduced interest expense. It took us to a point where it allows us to withstand this terrible gas price environment.

Investor How has Indigo's overall strategy changed considering the depressed gas price environment? Or has it changed?

Tsuru In 2016, when we began aggregating Haynesville acreage, our strategy was to grow at a huge clip—80% per year—and create a company with substantial scale. And we have achieved this. Since 2016, we've gone from 160 MMcf/d of net volume to 1 Bcf/d.

We decided that we're at a good place scalewise, and we're going to level off our growth. Our company looks at three things right now very carefully: conserve capital, reduce our costs as much as possible, and focus on free cash flow. Also part of that is to moderate growth. We're going to look at a growth rate of around 10% to 15%.

Investor Why did that change?

Tsuru Because right now in this environment it's not wise to continue to grow at 80%. We're going to be growing at a very moderate rate, and I think that provides a clear window to free cash flow—if I watch my costs and watch my capital.

Investor Public companies talk a lot about being free-cash-flow positive with their investor base these days. As a private company, how important is it to be free-cash-flow positive?

Tsuru Like public investors, our investors prefer a moderate pace with predictable cash flow on an annual basis. And so that's our plan. If gas were $3 or $4 an MMBtu [million British thermal units], we'd probably be doing something different than at $2.20.

Free cash flow is very difficult to attain at $2.20. Very difficult. We work hard to be free-cash-flow positive, but at this point in time it's harder. That's a very important target on the wall that we are always focused on.

Investor How are you then achieving that at $2 gas?

Tsuru Our wells are strong: We bring on 30-million-cubic-feet-a-day wells—choked back at 5 to 10 psi pressure drop per day. We're reducing our costs all the time. In the Lower 48, the slowdown is resulting in reduced rig costs, reduced services, reduced pressure pumping, all those. Similarly, we're looking at reducing costs internally within our wells.

Investor What does a well cost now?

Tsuru Across our field, from the more shallow to the northwest to the deepest in the southeast, it's $10.5 million in the shallowest, up to $13-plus million in the deeper parts, and the deeper parts are where we have temperature issues.

Investor With all the gas coming from the Northeast and all the associated Permian gas, can the Haynesville be economically competitive then?

Tsuru The Haynesville is the most economically competitive natural gas basin in the whole of the United States due in large part to the proximity to LNG and petchem demand along the Gulf Coast. While it can cost 50 cents to a dollar for Northeast gas to access the Gulf Coast market, it only costs us 25 cents. And that makes it the most profitable right off the bat. The cost to transport gas to market is cheaper than anything from the Northeast, the Permian or the Midcontinent. Nothing can be compared to the Haynesville.

Investor Are you just putting your gas into a pipe and selling it at the wellhead, or do you have contracts with LNG or other end users?

Tsuru We have a very thoughtful forward sales program where we pair transport with forward contracts with buyers at various pricing points. Right now we send our gas to different markets—to Perryville near the LNG corridor and to Carthage in South Texas among others. And in each case, we have a market already supported by forward sales contracts. We don't just dump our gas off at Perryville or Carthage.

When our gathering line gets down to Gillis, La., in the fourth quarter of this year, our gas will be going directly to the LNG markets. We have forward sales contracts in place for these volumes with certain LNG producers.

Investor What's your average realized price?

Tsuru It's different because we've got a very strong hedging program. Seventy-five percent of our 2020 volume is hedged and about 50% of 2021—at a very attractive number that I'd rather not say. That's why I'm breathing a little easier than maybe someone else that's not hedged at 75% of their 2020 gas volumes.

Investor Do you only hedge at high numbers, or do you hedge consistently regardless of price?

Tsuru Historically, we've consistently and dispassionately layered on hedges. Our wells are economic down to the low $2 range, which gives us a lot of flexibility. However, adding hedges in today's market is a little tough given the current low natural gas tape. We will opportunistically hedge and layer on some more when prices spike a little bit. But we are mindful not to hedge ourselves into mediocrity. Luckily, we have a strong hedge book with a high percentage of near-term volumes hedged.

Investor What is your view on natural gas demand and pricing going forward? Is there upside hope?

Tsuru I really think there is. I really do. I think what's happening right now gives us upside.

"Free cash flow is very difficult to attain at $2.20. Very difficult. That's a very important target on the wall that we are always focused on."

PHOTO COURTESY INDIGO NATURAL RESOURCES

Nabors' X-33 and X-07 rigs on the four-well Hesser pad, drilling for Indigo, targeting stacked Haynesville and Bossier targets in DeSoto Parish, La.

PHOTO COURTESY INDIGO NATURAL RESOURCES

In the foreground, Indigo's ROM CP compressor station for Cotton Valley operations in DeSoto Parish, La., next to the Longstreet processing plant built by partner Momentum Midstream, now owned by DTE Energy.

There are three components to natural gas price we think are important.

On the supply side, what's the best thing to do to get out of low prices? Low prices. Operators stop drilling. The capital's not there. Drilling rigs get laid down, and the supply starts reducing. Low gas prices paired with restricted access to capital, and the industry's focus on free cash flow, are all putting pressure on producers to reduce rig count.

And it's happening. We are seeing a tremendous number of rigs being laid down in the Northeast and throughout the U.S. We expect this will start putting some downward pressure on supply growth. I always say that the best thing for low prices is low prices. It's going to show.

On the demand side, you have petchem and LNG coming on, and we are well-positioned in the Haynesville to benefit from these trends along the Gulf Coast.

Finally, you have weather, which is less predictable and has not shown up in a positive way recently. We have not had a winter, and I think this may be masking the supply drop.

Investor I've heard that mantra for a while that low prices cure low prices, from $7, to $5, to $3—and now we're pushing $2.

Tsuru Yeah, but those are not low prices. You're economic at five bucks and three bucks, very economic. Very few companies are economic where we are now. We're okay because we've proactively protected ourselves, and we're closest to the takeaway point.

Investor Is it your mission to be a long-term producer, or do you need or desire an exit eventually?

Tsuru As a private-equity-backed company, we would like to see an exit. Given our substantial scale, deep inventory of economic locations, strong balance sheet and move to free cash flow this year, we think we will be an attractive candidate in the right market to a buyer or to the public markets.

In addition, ESG is a big deal now, and major companies are looking to reduce their carbon footprint, to reduce their oil production as compared to natural gas. And so we might be a good target for a company to increase its dry natural gas portfolio.

Investor Would you look for a merger opportunity?

Tsuru If the opportunity is right. We're a good target for a merger because we have such a low debt level. Our metrics are good.

Someone may want to enter the Haynesville or consolidate gas assets, and we are one of the big producers. So that might be another way to exit. But it's not a goal.

Investor Are you still considering an IPO as an exit?

Tsuru Right now we're not pursuing an IPO, but again, if the markets come around and decide that the multiples of our EBITDA are better than they have been, then we would consider the public route, but we'll let the capital markets tell us which way we'll go.

Investor Are you looking to be the consolidator of assets?

Tsuru We don't really see ourselves as aggregators. We've spent a lot of time and effort with our current acreage and balance sheet to position us to the best ability to weather this storm—we've been careful not to extend ourselves, keep our debt down, keep our volumes steady, maintain our hedge book, watch costs and target free cash flow.

We are very satisfied with what we have right now. We've got decades of drilling inventory in the core and we just don't think we need to add anything or do anything to make our story better.

However, if there is an especially compelling opportunity that fits us like a glove and allows us to maintain our strong balance sheet, we would definitely look at it.

Investor What's your operational plan going into 2020?

Tsuru To continue drilling with four to six drilling rigs, and one to two completion crews. We expect to drill upward of 48 to 52 wells for 2020 with growth of 10% to 15% over 2019.

Investor In 2018, you were running eight rigs. Are you purposefully slowing down?

Tsuru In 2018, we brought online 52 wells, and in 2020, we plan to bring online 48 to 52 wells, so we are maintaining a fairly consistent pace. We're seeing some areas of greater efficiency, so the number of rigs, really, doesn't equate to activity levels.

One has to be careful counting the number of rigs, the number of wells turned in line, as to what you perceive as the company's cadence or growth. That's not always the same. We're growing at a modest rate, just not at a clip that we had before.

Investor What are your primary targets? At what percent?

Tsuru Haynesville and Bossier are our primarily targets and where 95% of our 2020 capital will be spent.

Haynesville and Bossier wells are very similar. They are only 200 to 250 feet apart. Sometimes Bossier is a little bit more challenging because the Bossier has some difficult zones. Haynesville's a little bit deeper, so you've got more temperature. Both targets make great wells. In some areas we drill stacked Haynesville and Bossier targets.

While a smaller part of our capital budget, we also drill the Holly Vaughn, a Cotton Valley target with 2.1 Bcfe EURs per 1,000 feet, which has lower capex and has liquids with it. It's very competitive with Haynesville and Bossier wells, and that's what we love about it. We have three horizons that we can produce and tap, and that's what gives us such a huge inventory.

Investor How long are your laterals going these days?

Tsuru We're drilling between 6,500 and 10,000 feet. The sweet spot is probably 7,500 feet.

Investor You're not drilling super laterals?

Tsuru No, we don't. We see that cost/risk-reward of going out to 10,000 or 15,000 feet as very, very limited. That last 5,000 feet is the cheapest that you can drill, but it's very hard to get a work string to drill out plugs. You've got to pump plugs all the way down, and then if you sand out, coiled tubing is almost impossible to get down to that depth. We just don't see it.

Also, 7,500-foot laterals are more efficient—the rigs do not become a monument onsite drilling super laterals for months and months.

Investor What does a typical Indigo completion look like today?

Tsuru Typically, we will frac wells with five to seven clusters spaced 140 to 100 feet. Sand intensity will be roughly 3,800 pounds per foot, going in with 100 mesh and 40/70 at a 50:50 blend.

Investor Can you talk about your refracking program and what you're doing there?

Tsuru We have found that standalone refracs, although they're economic—they have a positive return—they're just not the return that we see with our other dollars going into a well.

We are focused primarily on what we call protective refracs, or a refrac of a legacy parent well offset to modern wells we are completing. These protective refracs generally provide the same return on investment as our drilling program. Parent wells that were producing 100 Mcf per day or 150 come on at 10 or 15 million a day. What you see is repressurization of that hole and fracking new reservoir.

In addition, we see better results on the modern child wells with protective refracs—increasing the pressure in the parent well prevents a pressure sink and ensures the modern frac job is focused in the right place around the modern child well.

We have a couple of protective refracs planned in 2020, both offset to modern completions in our drilling program.

Investor What's next for Momentum?

"The Haynesville is the most economically competitive natural gas basin in the whole of the United States due in large part to the proximity to LNG and petchem demand along the Gulf Coast. Nothing can be compared to the Haynesville."

Tsuru Momentum is working hard right now to find the next new project. We've got an exceptional business development team. There have been five iterations, and Momentum 6 is going to be successful too. At this point in time we have $500 million committed.

Investor What words of wisdom might you have for other natural gas operators in today's environment?

Tsuru Get your balance sheet in a good position and focus on free cash flow. Capital is precious—use it very wisely.

Investor What is the significance to you of being an Eagle Scout?

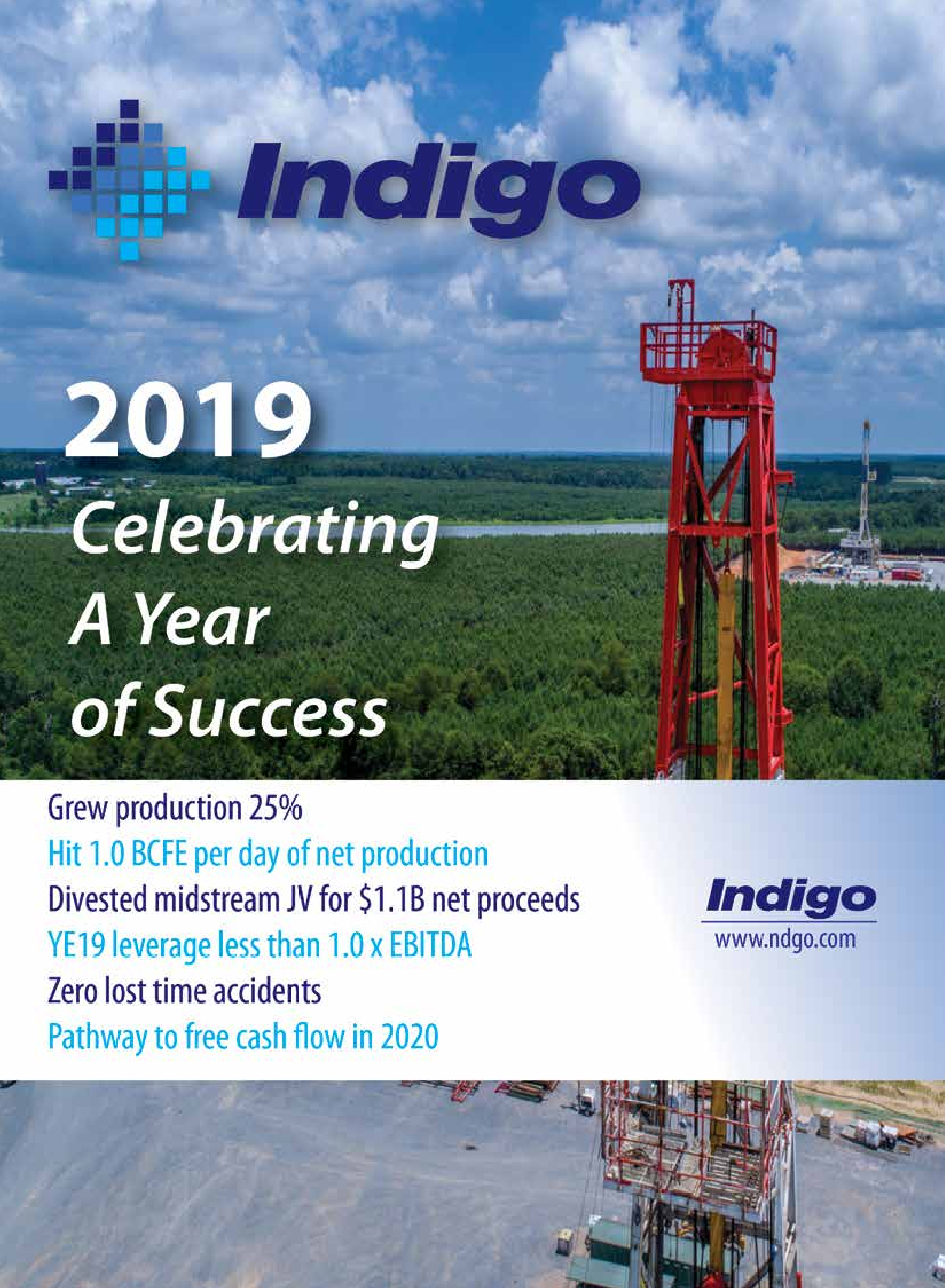
Tsuru Not only did I get to establish lifelong friendships, but the architecture of scouting molds boys into our future leaders. It completely prepared me for the leadership and problem-solving skills I use today.

I landed my first job as a petroleum engineer because of my Eagle Scout award. Of the several entry-level petroleum engineers being considered, I was the only candidate that was an Eagle Scout—and that is why I got the job. I have a framed display of scouting patches, given to me by my parents at graduation, which has followed me all over the oil patch. It now hangs prominently in my office on the 56th floor of the tallest building in Texas. I keep it to remind me of how I got my start in the industry.

Without a doubt, I have a great passion for the BSA organization. □

Big E Rig 2 on the RCHSN Haynesville two-well pad and Nabors X-07 on the three-well WLCX Haynesville pad (background) drill for operator Indigo in DeSoto Parish, La.

PHOTO COURTESY INDIGO NATURAL RESOURCES


Indigo
2019
Celebrating
A Year
of Success
Grew production 25%
Hit 1.0 BCFE per day of net production
Divested midstream JV for $1.1B net proceeds
YE19 leverage less than 1.0 x EBITDA
Zero lost time accidents
Pathway to free cash flow in 2020
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A NEW GATEKEEPER

Free cash flow is in vogue as a key metric, but much may depend on the maturity level of the producer.

ARTICLE BY
CHRIS SHEEHAN, CFA

"In a perfect world, if you were highly free-cash-flow generative and growing, you'd probably get credit," said David Deckelbaum, CFA, senior analyst at Cowen. "But, at this point, a stock is going to be much more highly rewarded by FCF than growth."

Free cash flow (FCF) is often viewed as a destination akin to the Promised Land. Once a certain inflection point has been crossed, the hope is for a growing wedge of FCF as output moves higher, commodity prices stay constant and economies of scale kick in to keep costs down. But the world doesn't always work that way. And much can depend on where an E&P is on the path to the Promised Land.

A recent heightened focus on FCF reflects the unease among some investors with the host of underlying inputs used to value E&Ps historically. E&P analysis has at times focused on net asset value (NAV), enterprise value-to-EBITDA (EV-to-EBITDA) and debt-adjusted cash flow per share growth, to name a few. In turn, these relied on other variables: rig counts, production growth, commodity prices, etc.

As investors, and especially generalist investors, have sought to bring clarity to E&P performance, some have turned to the basic elements of FCF as a minimalist marker.

"If an E&P is able to hold production flat year-over-year and—all other things being equal—generate a certain amount of operating FCF, then a generalist investor can say the E&P created value," explained one industry observer, who termed FCF the "metric of last resort."

FCF a pre-requisite?

Moreover, for an industry that has underperformed the broader market for most of the decade, it is free cash flow that has in some cases become a first check—or potentially even a pre-requisite—for reviewing investments in energy. But analysts caution against FCF being used in isolation. Rather, FCF can often be of greater use when employed with other metrics to round out the overall picture of an E&P.

While FCF may be in vogue, that's no reason to play down the importance of other industry metrics, such as NAV, EV-to-EBITDA, return on equity (ROE) or invested capital (ROIC), according to David Deckelbaum, CFA, senior analyst at Cowen covering the E&P sector. For one thing, it's not as if free-cash-flow yields are currently the primary valuation metric on which the E&P sector trades, he said.

"Currently, I wouldn't say the stocks necessarily trade on FCF yields," Deckelbaum said. "First, FCF is not being generated in substantial amounts by the E&P sector. And, second, I think there are other attributes that are important to the oil and gas investment story. FCF yield is more of a coincidental metric. It can be more of a pre-requisite before considering other metrics."

NAV still important

"I think NAV is still important—certainly as it relates to developed booked reserves, if not undeveloped resource," continued Deckelbaum. "Also, I think EV-to-EBITDA multiples are still relevant. And other return metrics, such as ROE and ROIC, can end up being important ways for E&P names to distinguish themselves. You'd rather have a unique story if you're not generating FCF."

With West Texas Intermediate (WTI) prices in the low to mid-$50s per barrel (bbl) range, "probably 60% or more of the investable universe is capable of generating FCF in 2020," estimated Deckelbaum. "And that number could potentially be skewed higher if companies go toward maintenance mode. But most E&Ps are already in or near maintenance mode, so it would be unlikely to move materially higher."

Not surprisingly, large-cap E&Ps have a lead in attaining FCF generation. At Cowen's $54/bbl crude price forecast for 2020, roughly 80% of Deckelbaum's large-cap coverage is projected to be FCF generative. Including small- and mid-cap (SMID) names covered by Cowen senior analyst Gabe Daoud, a total of 22 of 31 names, or roughly 70% of all coverage, are projected to generate FCF in 2020.

Cowen's underlying assumptions are that its large-cap names under its coverage spend just 90% of cash flow in 2020, contributing to a year-over-year decline in industry capex of about 13%. Small-cap names are expected to both outspend and underspend cash flow but on average spend in line with cash flow. Industry analysts generally point to a deceleration in U.S. production growth due to lower 2020 capex.

E&P Free-Cash-Flow Yield, ROCE, Oil Growth (2019-2021 Avg.)

Company	FCF Yield	ROCE	Oil Prod. Growth
EOG Resources Inc.	3%	11%	12%
Occidental Petroleum Corp.	7%	4%	23%
Pioneer Natural Resources Co.	2%	10%	11%
Concho Resources Inc.	0%	3%	13%
Diamondback Energy Inc.	4%	8%	40%
Continental Resources Inc.	4%	9%	13%
Noble Energy Inc.	1%	1%	6%
Marathon Oil Corp.	6%	4%	7%
Devon Energy Corp.	4%	7%	-9%
Apache Corp.	4%	6%	1%
Encana Corp.	4%	5%	30%
Cimarex Energy Co.	4%	10%	13%
Parsley Energy Inc. Class A	8%	9%	17%
WPX Energy Inc.	2%	6%	14%
Viper Energy Partners LP	10%	11%	25%
Magnolia Oil & Gas Corp. Class A	11%	5%	11%
EQT Corp.	14%	2%	10%
Matador Resources Co.	-5%	9%	19%
Jagged Peak Energy Inc.	-5%	11%	17%
Chesapeake Energy Corp.	-17%	2%	14%
Enerplus Corp.	3%	11%	10%
PDC Energy Inc.	8%	7%	27%
CNX Resources Corp.	-3%	5%	-31%
Centennial Resource Development Inc. Class A	-16%	3%	11%
Brigham Minerals Inc. Class A	9%	8%	NA
Range Resources Corp.	4%	3%	-2%
Callon Petroleum Co.	2%	8%	63%
Sundance Energy Inc.	0%	6%	19%
SRC Energy Inc.	2%	7%	8%
Oasis Petroleum Inc.	-14%	2%	-1%
QEP Resources Inc.	8%	5%	-2%
Kimbell Royalty Partners LP	10%	3%	31%
Northern Oil & Gas Inc.	16%	14%	23%
Antero Resources Corp.	-51%	0%	10%
Carrizo Oil & Gas Inc.	12%	10%	7%
Falcon Minerals Corp. Class A	12%	19%	34%
Whiting Petroleum Corp.	18%	2%	-1%
Gulfport Energy Corp.	1%	4%	-12%
Bonanza Creek Energy Inc.	-16%	10%	17%
Earthstone Energy Inc. Class A	-7%	6%	18%
HighPoint Resources Corp.	-30%	1%	13%
Extraction Oil & Gas Inc.	7%	1%	3%
Ring Energy Inc.	-11%	7%	28%
Goodrich Petroleum Corp.	7%	13%	-12%
SilverBow Resources Inc.	-18%	12%	55%
Lonestar Resources US Inc. Class A	-30%	6%	6%
Unit Corp.	-136%	-2%	9%
Rosehill Resources Inc. Class A	-29%	12%	9%

*Includes unadjusted impact of acquisitions and/or divestitures.

Source: SunTrust Robinson Humphrey Research, company data, Factset

With investor sentiment so depressed late last year, "I think you have a better chance of being rewarded right now for a respectable FCF yield vs. trying to achieve some measure of production growth," said Deckelbaum. "In a perfect world, if you were highly FCF generative and growing, you'd probably get credit. But, at this point, a stock is going to be much more highly rewarded by FCF than growth."

FCF as part of a balance

So, with seemingly few investors clamoring for growth, is free cash flow alone—rather than some sort of balance—now the key objective of energy investors? After all, for at least a temporary period of time, FCF can typically be attained by simply cutting capex and letting existing wells flow to bring in cash. But, in an industry deeply characterized by depletion, such a strategy is quick to take its toll.

Deckelbaum points to a three-pronged strategy for E&Ps, which would likely comprise 5% repeatable production growth, a 5% FCF yield and a 0.5 turn, or a little higher, in terms of EBITDA-to-net debt.

If the leverage metric seems austere, he said, the reason is that "if an E&P has credit coming due in the near term, there's skepticism in the market that you're going to be able to refinance it elegantly."

Of course, not all E&Ps are at a more mature stage of their life cycle where they can balance out growth, FCF and debt maturities. Through no fault of their own, the growth of some E&Ps may have been disrupted from what was planned to be an expansion to critical mass and, in time, FCF. One such E&P caught out by market moves was Centennial Resource Development Inc., noted Daoud.

"Centennial used to trade at a premium to other midcap names," he recalled. "The company wanted to get to critical mass, to reach an appropriate scale of over 60,000 barrels per day at that time. Typically, an E&P needs to grow to a certain level and then over time see its base decline rate become more moderate. From there, an E&P can potentially start thinking about throwing off some free cash flow."

'No man's land'

"In late 2018, when oil went from over $60/bbl to roughly $46/bbl, Centennial made a decision to rein in capital and steer away from a heavy growth ramp," continued Daoud. "But it's still trying to play catch-up and narrow its cash outspend despite not growing its oil production as fast as it was a couple of years ago. Investors view the company as being in a 'no man's land' type of bucket, with no growth or free cash flow."

E&P Free Cash Flow Yield Sensitivity

	2020 Estimated Free Cash Flow ($MM)				2020E Free-Cash-Flow Yield			
	Mkt Cap ($MM)	$45 WTI	$55 WTI	$65 WTI	Mkt Cap ($MM)	$45 WTI	$55 WTI	$65 WTI
Bakken								
CLR	$11,545	($480)	$189	$857	$11,599	-4%	2%	7%
ERF	$1,465	$57	$18	$153	$1,491	4%	1%	10%
NOG	$822	($18)	$98	$214	$829	-2%	12%	26%
OAS	$940	($295)	($187)	($41)	$988	-30%	-19%	-4%
WLL	$608	($125)	$76	$284	$625	-20%	12%	45%
Diversified								
APA	$8,820	($12)	$350	$711	$8,969	0%	4%	8%
CHK	$266	($657)	($357)	($57)	$1,408	-47%	-25%	-4%
DVN	$8,184	($178)	$244	$711	$8,954	-2%	3%	8%
ECA	$1,673	($399)	($16)	$516	$5,814	-7%	0%	9%
EOG	$42,315	($585)	$935	$1,427	$42,528	-1%	2%	3%
MRO	$9,543	($188)	$375	$1,044	$9,590	-2%	4%	11%
NBL	$10,088	($55)	$344	$776	$10,156	-1%	3%	8%
OXY	$34,122	($198)	$3,338	$3,947	$34,122	-1%	10%	12%
UNT	$54	($82)	($49)	($16)	$73	-112%	-67%	-22%
D-J Basin								
BCEI	$397	($50)	($27)	$4	$407	-12%	-7%	1%
HPR	$275	($75)	($44)	($13)	$284	-26%	-15%	-4%
PDCE	$1,568	($64)	$121	$343	$2,571	-3%	5%	13%
SRCI	$965	($77)	$8	$92	$990	-8%	1%	9%
XOG	$260	$34	$46	$122	$321	10%	14%	38%
Eagle Ford								
CHK	$1,379	($657)	($357)	($57)	$1,408	-47%	-25%	-4%
CRZO	$719	$10	$73	$210	$741	1%	10%	28%
LONE	$110	($15)	($16)	($17)	$113	-13%	-14%	-15%
MGY	$3,020	$183	$332	$480	$3,036	6%	11%	16%
SBOW	$131	$6	($5)	($17)	$139	5%	-4%	-12%
SNDE	$70	$13	$27	$49	$71	18%	38%	69%
Gas Weighted								
AR	$727	($284)	($245)	($206)	$754	-38%	-32%	-27%
CNX	$1,563	$179	$179	$179	$1,582	11%	11%	11%
EQT	$2,657	$342	$351	$360	$2,679	13%	13%	13%
GDP	$136	$9	$9	$10	$143	6%	7%	7%
GPOR	$511	$20	$24	$21	$519	4%	5%	4%
RRC	$1,058	$45	$57	$68	$1,114	4%	5%	6%
Permian								
CDEV	$918	($305)	($163)	($20)	$960	-32%	-17%	-2%
CPE	$1,021	($222)	($22)	$226	$1,910	-12%	-1%	12%
CRZO	$719	$10	$73	$210	$741	1%	10%	28%
CXO	$14,550	($189)	$44	$278	$14,642	-1%	0%	2%
ESTE	$365	($35)	($28)	($21)	$377	-9%	-7%	-5%
FANG	$12,416	$36	$736	$1,436	$12,445	0%	6%	12%
JAG	$1,564	($107)	($59)	($11)	$1,586	-7%	-4%	-1%
MTDR	$1,678	($236)	($116)	$20	$1,694	-14%	-7%	1%
PE	$4,546	$191	$202	$290	$4,569	4%	4%	6%
PXD	$22,313	($235)	$558	$1,352	$22,386	-1%	2%	6%
QEP	$843	$36	$94	$152	$863	4%	11%	18%
SM	$1,044	($240)	($155)	($22)	$1,066	-23%	-15%	-2%
REI	$153	($43)	($12)	$23	$159	-27%	-7%	14%
ROSE	$81	($12)	$10	$48	$87	-14%	11%	56%
WPX	$4,317	($59)	$81	$234	$4,362	-1%	2%	5%
XEC	$4,663	($110)	$143	$425	$4,682	-2%	3%	9%
Minerals								
FLMN	$554	$53	$64	$75	$556	10%	12%	13%
KRP	$659	$65	$73	$82	$697	9%	11%	12%
MNRL	$1,019	$75	$92	$108	$1,027	7%	9%	11%
VNOM	$3,685	$322	$392	$461	$3,813	8%	10%	12%

Source: SunTrust Robinson Humphrey

Parsley Energy's acquisition of Jagged Peak Energy has set the stage for a markedly improved free-cash-flow profile, according to Gabe Daoud, senior analyst with Cowen. The combined company is forecast to generate some $100- to $200 million of FCF, up substantially from a standalone $50- to $100 million in 2020, he said.

"I'm more apt to play those [E&Ps] that are past an inflection point—say, Parsley, WPX and Noble Energy," said Neal Dingmann, managing director, E&P research, at SunTrust Robinson Humphrey. "They'll not only continue to generate FCF in a lower commodity price environment, but, in addition, they'll offer greater upside to crude prices if the commodity does go up."

In Cowen's view, who stands out as recent winners in delivering the FCF desired by many investors?

Deckelbaum points to Noble Energy Inc. and Diamondback Energy Inc., while Daoud favors Parsley Energy Inc. and WPX Energy Inc.

"Noble Energy offers a high single-digit FCF yield in 2020 and 2021," said Deckelbaum. "It has world-class assets that it's expanding at Leviathan and other projects offshore Israel that are highly FCF generative. We think FCF continues to grow in 2022. It's a unique FCF story that checks a lot of the boxes for investors. Noble's differentiated asset base in the Eastern Med sets up a repeatable FCF stream.

"In the Permian, Diamondback has the capacity to sustain a high single-digit compound annual growth rate of production over the next five years, while making moves to sustain a 2% dividend yield, assuming an increase this year," according to Deckelbaum. "This would make the stock competitive with the broader S&P 500," given a dividend raise, a 6% FCF yield in 2020 and a pristine balance sheet.

A "merger of equals" among SMID-cap names is one way some E&Ps may generate attractive FCF in the near term, according to Daoud. The Cowen analyst cited Parsley Energy, his top pick, as an example.

In Parsley's case, its acquisition of Jagged Peak Energy has set the stage for a markedly improved FCF profile, said Daoud. Plans are to slow down activity and reduce well costs at the former Jagged Peak operations, freeing up cash. With other synergies, the combined company is forecast to generate some $100- to $200 million of FCF, up substantially from a standalone $50- to $100 million in 2020, he said.

Bottom line: A FCF wedge for Parsley of about 2% in 2020 rises to roughly 4% in 2021, as oil production grows by over 10% this year and 5% to 10% in 2021, and a recently initiated dividend is increased.

Daoud's price target for Parsley is $29 per share. His other most favored stock, WPX Energy, recently made a $2.5 billion acquisition of Felix Energy. His WPX target price is $18 per share.

'Compelling' valuation

Similar to Parsley's ability to augment free cash flow by acquiring Jagged Peak, Daoud also pointed to the merger of PDC Energy Inc. and SRC Energy Inc. in Wattenberg Field in Colorado. PDC plans, he said, call for "a slowing down of activity on SRC acreage and taking out lots of costs, largely in general and administrative expenses. Pro forma, PDC should generate over $200 million in FCF next year on our numbers."

Bottom line: PDC offers a 10% FCF yield, based on a $200 million FCF estimate for 2020, which is likely to "only grow in 2021 and beyond." At an EV-to-2020 EBITDA multiple of around 2.5x, the PDC valuation is "compelling," even allowing for a typical Wattenberg discount.

Daoud struck a note of caution as to some smaller E&Ps with higher debt levels, such as QEP Resources Inc.

"QEP is expected to generate FCF in 2020, which on its market cap is a pretty attractive FCF yield. But relative to its enterprise value, it's not that attractive. That's the problem with some smaller names. The FCF they're generating is not enough to make a dent in upcoming debt maturities. QEP's first maturity is a $400 million note coming due in 2021."

To provide context for investors, analysts at SunTrust Robinson Humphrey show FCF projections with accompanying data on the individual E&Ps' return on capital employed and oil production growth. "Any of these E&Ps can be temporarily FCF generative; the question is whether you can do it on a sustainable basis," observed Neal Dingmann, managing director, E&P research.

SunTrust E&P analyst Dingmann and managing director Welles Fitzpatrick project some 30 out of 49 E&Ps under their coverage generate free cash flow at a WTI price of $55/bbl. However, FCF is sensitive to variations in commodity prices (plus critical production levels), and at a WTI price of $45/bbl, the number of E&Ps generating FCF falls to roughly half of that at $55/bbl.

Conversely, if crude prices can be sustained at $55/bbl or higher, the often "range-bound" results of E&Ps recently may turn to delivering FCF in line with investor demands, said Dingmann. "Investors are demanding FCF. For a while we heard it, but they weren't demanding it like they are now. Most of our coverage can deliver FCF and some growth if the 12-month strip is $52.50 or above."

'Extreme fatigue' on energy

The increasing use of free cash flow as a key metric partially reflects "extreme fatigue" among remaining buy-side energy players, as well as an attempt to reach out to generalist investors, according to Fitzpatrick. If trying to schedule E&P meetings with institutional investors in New York or Boston, and an E&P is not yet generating FCF, the meetings "may not even be under consideration," he said.

"Investors don't necessarily trust slides showing internal rates of return [IRR], and everyone knows you can play with NAVs," he said. "But if you can hold production flat, throw off a high single-digit FCF and demonstrate a decade of running room, that symbolizes a real company to a generalist investor. It's a short cut. It cuts through much of the fog."

What is problematic is a tendency to apply similar standards to both early stage E&Ps and more mature large cap names—say, for instance, Bonanza Creek Energy and Diamondback Energy Inc. "FCF is being thrown out as if it was almost a 'universal rule,' regardless of the portion of the life cycle that an E&P may be in, which can be a little frustrating," commented Fitzpatrick.

"The problem is that the size, and where they are in the life cycle of an E&P, can make it very challenging for some E&Ps," added Dingmann. "For example, Centennial Development has great acreage, but the stock has traded way down because it's been outspending. If it could have had an extra year or two under its belt right now, I think it would be a much different story."

Ultimately, "commodity price and timing are two of the bigger factors E&Ps are facing," he commented.

Fine-tuning factors

As investor priorities evolve, E&Ps have tried to fine-tune the mix of factors driving stock performance.

Dingmann cited Matt Gallagher, CEO of Parsley Energy, whose strategy has been to combine a number of factors that in aggregate offer returns to investors of around 15%. In varying amounts, the 15% may be made up of shareholder returns (dividends and share buybacks), a free-cash-flow yield and production growth. For instance, the mix could be 3% to 4% shareholder returns, 5% FCF yield and 7% to 8% growth.

"Whatever the combination ends up being, it will add up to 15%," said Dingmann. "They're doing that without being too specific and painting themselves into a corner."

Parsley Energy and WPX Energy were both held out by Dingmann as having crossed an inflection point where, due to scale, generating FCF tends to become less arduous. Other smaller E&Ps, "because of where they are in the cycle, probably need to outspend for another two years to get to that inflection point. But they may not get the opportunity if they have to keep close to cash flow neutrality."

How do you rate the risk-reward of playing an E&P with FCF on the rise vs. a proven player, like, ConocoPhillips Co., which has the visibility of shareholder returns for many years to come?

"I'm more apt to play those that are past an inflection point—say, Parsley, WPX and Noble Energy—because they give me comfort they'll not only continue to generate FCF in an lower commodity price environment, but, in addition, they'll offer greater upside to crude prices if the commodity does go up," said Dingmann. "Every dollar above $52 to $53 per barrel drops right to the bottom line."

With market conditions reflecting more macro- and catalyst-driven events, fundamentals have been less of a factor, creating opportunities to pick up top stocks at cheap values, observed Fitzpatrick.

More macro-driven events

"It's been such a catalyst-oriented, hedge fund-dominated market that E&Ps you think should outperform aren't being priced as they should on fundamentals," he said. "You have so few people with books built on fundamentals that all these names have become jumbled up. You can buy high-quality names with low debt and high FCF for roughly the same valuation as an average E&P."

Fitzpatrick pointed to PDC Energy as having a valuation that is "crazy, trading at a high single-digit FCF yield, low double-digit cash flow per share growth on a year-over-year basis and just 2.5x EV-to-2020 EBITDA. It's a fantastic company. And there are other high-quality names that don't have you stepping that far out on the risk curve that are on sale with other E&Ps with more severe debt issues."

Market trends over the past few years have created a backdrop "where stock picking has enjoyed the most target-rich environment it has had in some time," said Fitzpatrick.

For Dingmann, favored names are Diamondback Energy, Continental Resources Inc. and Parsley Energy. Fitzpatrick favors PDC Energy and Brigham Minerals Inc., a play on minerals. "It has world-class acreage. If you have a long-term, positive view of U.S. shale, Brigham is the easiest way to sleep at night," said Fitzpatrick.

Resisting FCF calls

Not all E&Ps have tried chasing the herd, however, in terms of free cash flow generation. Some E&Ps have preserved earlier strategies rather than bow to premature calls to generate FCF, said Dingmann.

"Matador Resources Co. is very upfront about it. They will tell you, 'We won't be FCF positive until about January of 2022,'" he said. "They say that to maximize returns of their investments—comprising not only an upstream investment, but also a material midstream investment named San Mateo—they need to outspend cash flow. They don't make any bones about it. They're being very honest."

Likewise, in a December "meet and greet" in New York, large-cap EOG Resources Inc. "did not succumb to analyst-investor pressure for high near-term FCF yield and shareholder returns, including stock buybacks, given its belief it is too early in its operations cycle," noted Dingmann. "We believe many long-only investors remain on the sidelines until higher FCF and shareholder returns are seen."

Other analysts have discussed how to balance the advantages of maintenance, growth and returns. For example, a Bernstein report estimated that, by moving to a maintenance capex level set to keep production flat, EOG would generate as much as $17 billion of incremental FCF over the next six years.

Reasons offered by Bernstein as to why EOG would continue to prioritize growth included: a different long-term view of the industry, including greater emphasis on NAV or incremental IRR; a desire by EOG to keep its organization intact, given its unique culture, technology, etc.; and an observation that "those companies transitioning to lower growth/buybacks haven't been massively rewarded."

Topic du jour

"FCF has become the topic du jour in the E&P space," said Mike Kelly, CFA, the former head of E&P research at Seaport Global Securities LLC. "I think it's important for a couple

"It's been such a catalyst-oriented, hedge fund-dominated market that E&Ps you think should outperform aren't being priced as they should on fundamentals," said Welles Fitzpatrick, managing director, with SunTrust Robinson Humphrey. "You can buy high-quality names with low debt and high FCF for roughly the same valuation as an average E&P."

"Free cash flow has become the topic du jour in the E&P space," said Mike Kelly, CFA. "Capital markets are now nowhere as constructive as they have been in the past. And, second, investors are coming to the realization that industry has to be able to self-source."

FELIX ACQUISTION ADDS FCF

Tulsa, Okla.-based WPX Energy Inc. announced a $2.5 billion purchase of Felix Energy in a deal described as being "accretive on all important metrics." These included earnings per share, cash flow per share, net asset value and return on capital employed. Importantly, WPX also disclosed initiation of a dividend and pointed analysts to data supporting significant free-cash-flow (FCF) growth.

The purchase involved production from Felix in the Delaware Basin that is expected to grow to 60,000 barrels of oil equivalent per day (boe/d) at closing. The transaction will add some 1,500 locations, raising total Permian locations to more than 4,900 locations. Assuming $30,000 per flowing boe for the 60,000 boe/d, the transaction values the undeveloped acreage at less than $12,000 per acre.

Cowen senior analyst Gabe Daoud estimated that the pro forma company would generate almost $180 million in FCF in 2020, well above the nearly $60 million it would generate on a standalone basis. Free cash flow in 2021 was forecast to rise to just under $525 million, representing a 9% FCF yield on a Dec. 12, 2019, closing price of $10.91 per share, as compared to a standalone FCF estimate of under $140 million.

In addition, WPX stated it would pay a 10 cents per share dividend on an annualized basis upon initiation.

Others were similarly upbeat. In Credit Suisse's recent report, "Uncovering a Hidden Gem," E&P research analyst Betty Jiang forecast FCF generated by the combined company would double from $200 million to roughly $400 million in 2021 at $55/bbl. This would support "WPX's vision of delivering both sustainable shareholder returns and growth," according to the report.

Credit Suisse said the resultant 7% to 10% FCF yield was notable in that this milestone would be achieved in late 2021 with the Felix acquisition vs. what had been a projected standalone timetable of 2024. In similar manner, the Felix transaction was expected to allow WPX to attain a double-digit return on capital metric more than two years earlier than the prior target of 2024.

Also of interest was that the "slowback" choke management strategy used by Felix led to wells having lower IP rates but outperforming over the longer term through maximizing reservoir pressure. This is now expected to result in a 30% or lower base decline rate by year-end 2023, some six to 12 months ahead of prior expectations.

The Felix transaction price consists of $900 million in cash and $1.6 billion in WPX stock issued to the seller, subject to closing adjustments. WPX plans to fund the cash portion through issuance of $900 million of senior notes on an opportunistic basis. WPX has a commitment from Barclays in connection with the transaction and has full access to a $1.5 billion revolving credit facility.

WPX expects to add two members from EnCap Investments LP, who founded Felix Energy, to its board.

of reasons. One, the capital markets are now nowhere as constructive as they have been in the past. And, second, investors are coming to the realization that industry has to be able to self-source at this point."

After years of rapidly growing U.S. supply—and outspending cash flow on the part of E&Ps—it's unrealistic to think "you can just go out there and plug any outspend by raising money on Wall Street," he continued. "That's no longer the case. Investors are insisting, 'I need to know today—not two years out—that you have a FCF yield."

Admittedly, the industry faces a tradeoff between having high growth rates and lofty levels of FCF, said Kelly. "It's hard to do both. One of the things we've done is to see who has above-average levels of both FCF and growth. That's where you want to be. You can't just look at FCF in a vacuum. FCF may not be the most important variable, but I think it ranks among the top three."

Different paradigm

If free-cash-flow economics swing within a $10/bbl band—with relative few E&Ps generating FCF at sub-$50 levels, but almost all FCF positive at $60/bbl—do E&Ps add rigs if crude reaches the top end of the range?

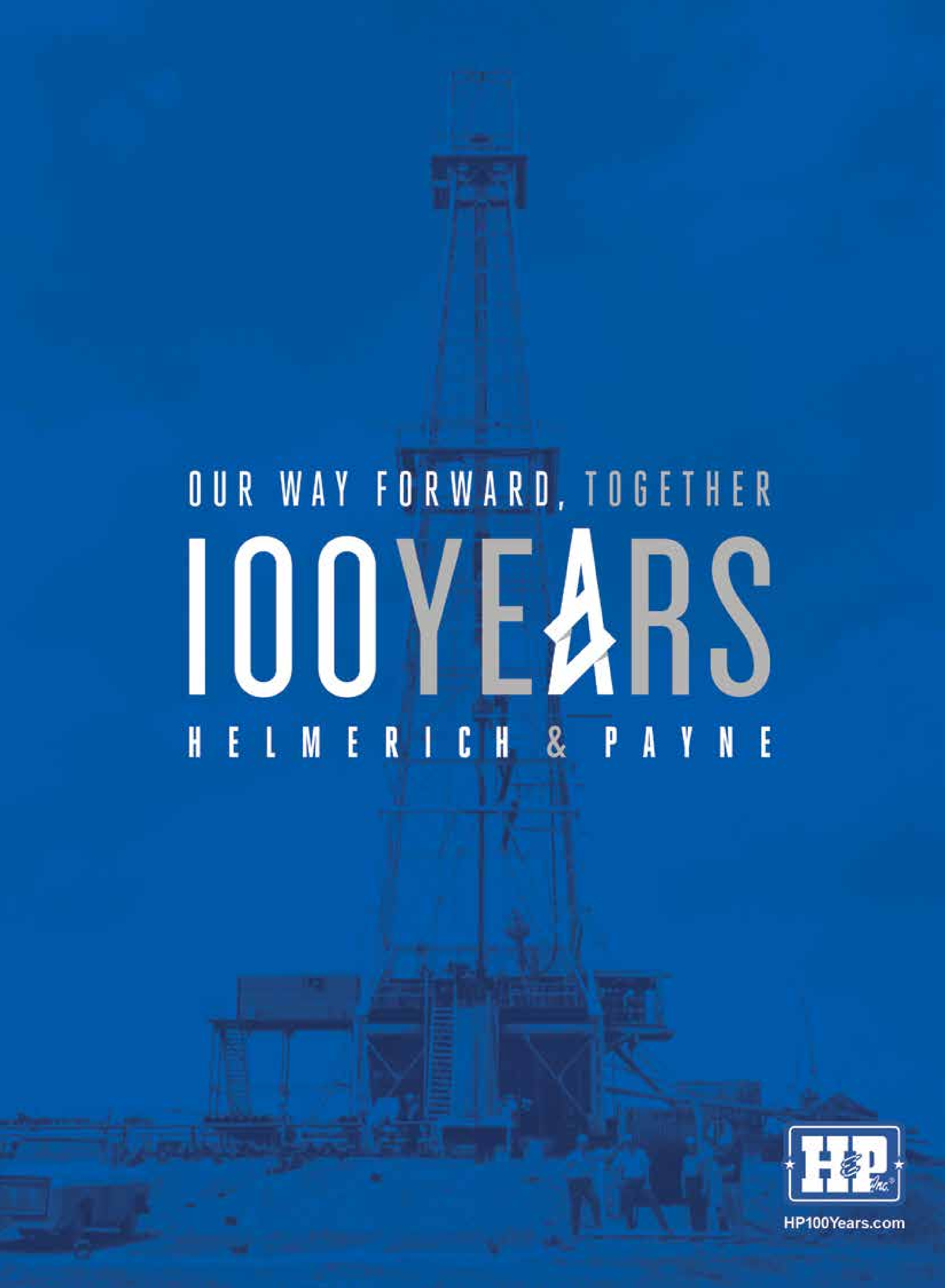
"I do think the industry is now operating on a different paradigm," observed Kelly. "I don't think E&Ps are going to be eager to add rigs to the equation. People are beginning to compete on FCF yield. And if that's the metric, you hurt yourself on that yardstick if you add a rig back. They're more likely to issue dividends, or buy back stock or pay down their debt."

In terms of favored stocks, "I still think it makes sense to own the E&Ps that are going to get there in a couple of years in a meaningful way, and still have really great growth profiles and great economics," commented Kelly. "To me, Diamondback Energy, Parsley Energy and WPX Energy fit that mold. I'd prefer owning them over those with slower growth and a stronger FCF yield today."

Obviously, most strategies involve some "give-and-take," said Kelly. "If you want to isolate FCF, you can do that. But you may be doing that at the expense of growth, and you may be doing that at the expense of building out your inventory or attaining other goals. There are consequences of focusing solely on FCF. You can't score highly on all fronts at the same time."

But for the moment, FCF is "in vogue," and it may be the necessary lure to attract generalist investors.

"The energy industry has to make sense to a generalist," said Kelly, who is moving to Northern Oil & Gas Inc., which owns nonop properties mainly in the Williston Basin. "Energy has to make itself more comparable to other industries. For a few years it got a pass, and had its own set of rules, but now they're being re-written to make the industry accountable to the same rules as other sectors." □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POLAR REGRESS

Even with giant deals, massive oil discoveries and a move west of its legacy fields, Alaska begins 2020 looking to pick up the slack from production declines, debt and the threat of higher taxes.

ARTICLE BY
DARREN BARBEE

Alaska, the giant oven mitt-shaped state of ice, fortitude and darkness, is not known for its heat waves—the average temperature in 2019 was a freezing 32.2 degrees. But that doesn't mean the state never burns anyone.

The summer of 2019, while still not swimming weather, saw Alaska record its hottest July, averaging 58.1 degrees, about 5.4 degrees above normal, according to federal data. Scientists also published papers suggesting Alaskan glaciers were melting at a rate 100 times greater than previously thought.

The oil and gas industry, a central pillar of the state's economy, faced its own scorcher. Some voters in the "Land of the Midnight Sun" began agitating to raise taxes on Alaska's largest oil producing fields—even as the state finds itself hundreds of millions of dollars in arrears to E&Ps. Alaska lease sales and exploration have been up and down. And like its cousins in the continental U.S., consolidation is rising with recent deals concentrating 72% of production in the hands of just two companies: ConocoPhillips Co. and Hilcorp Energy Co.

Among those burned by Alaska is Jim Musselman, who still has not made peace with dueling emotions—awe and anger—that the state evokes. In two deals struck in January and June, Musselman's Caelus Natural Resources

Jim Musselman, founder of Caelus Natural Resources, describes himself as fascinated by Alaska's potential but wary of its politics. "We got treated very poorly up there, unfortunately, which is too bad because we put together a really nice company," he said.

PHOTO COURTESY CONOCOPHILLIPS CO.

ConocoPhillips Co., Alaska's largest oil producer, transports oil from the 800-mile, $8 billion Trans-Alaska Pipeline to the Valdez Marine Terminal. Built to handle a peak throughput of about 2.1 million barrels per day (bbl/d), the pipeline moved less than 510,000 bbl/d in 2018.

Kara Moriarty, president and CEO of the Alaska Oil and Gas Association, said new exploration plans in Alaska hold promise, but she acknowledged the state's most recent dustup over production taxes is looming.

sold interests in Oooguruk Field to Italian major Eni S.p.A and its 21,000-acre Nuna discovery to ConocoPhillips for undisclosed sums.

"I'm fascinated by Alaska," Musselman told *Investor*. "We got treated very poorly up there, unfortunately, which is too bad because we put together a really nice company."

Caelus was among several companies that had taken up on an offer by Alaska to find oil in the frontier areas outside of the state's large legacy fields as Alaska sought to turn around its sagging production. In exchange, E&Ps were to receive tax credits for their wells. But after oil prices tanked in 2015, the state was unable to make good on promised payments. Musselman said Caelus is still owed about $160 million.

"We had good assets, but we just could not get any capital to go up there because the state had this tax credit scheme that really jumped us," he said. "And then they just ghosted. They said, 'We will pay you, but we can't pay you now because we're broke.' And it was a true statement. They were broke at the time."

Yet Musselman, who serves as chairman of blank-check company Alussa Energy Acquisition Corp., which closed a $287 million IPO in November, said the public company might consider acquiring assets in Alaska.

"Absolutely. We've depicted our search as an international search, but I've always kind of dinged Alaska as international," he said. "It's certainly different than the Lower 48 states in many respects."

Alaska operators generally grapple with the same dilemmas as the industry writ large: money, politics and consolidation. Musselman found his private-equity partners unwilling to commit more money to his project.

Some of Alaska's financial woes are coming from the inside out.

"We do have this looming, potential ballot initiative hanging over our heads" that would raise severance taxes, Kara Moriarty, president and CEO of the Alaska Oil and Gas Association told *Investor*. "We've got everything in place to have a strong energy sector for the next decade. As long as the fiscal stability regime remains" in place.

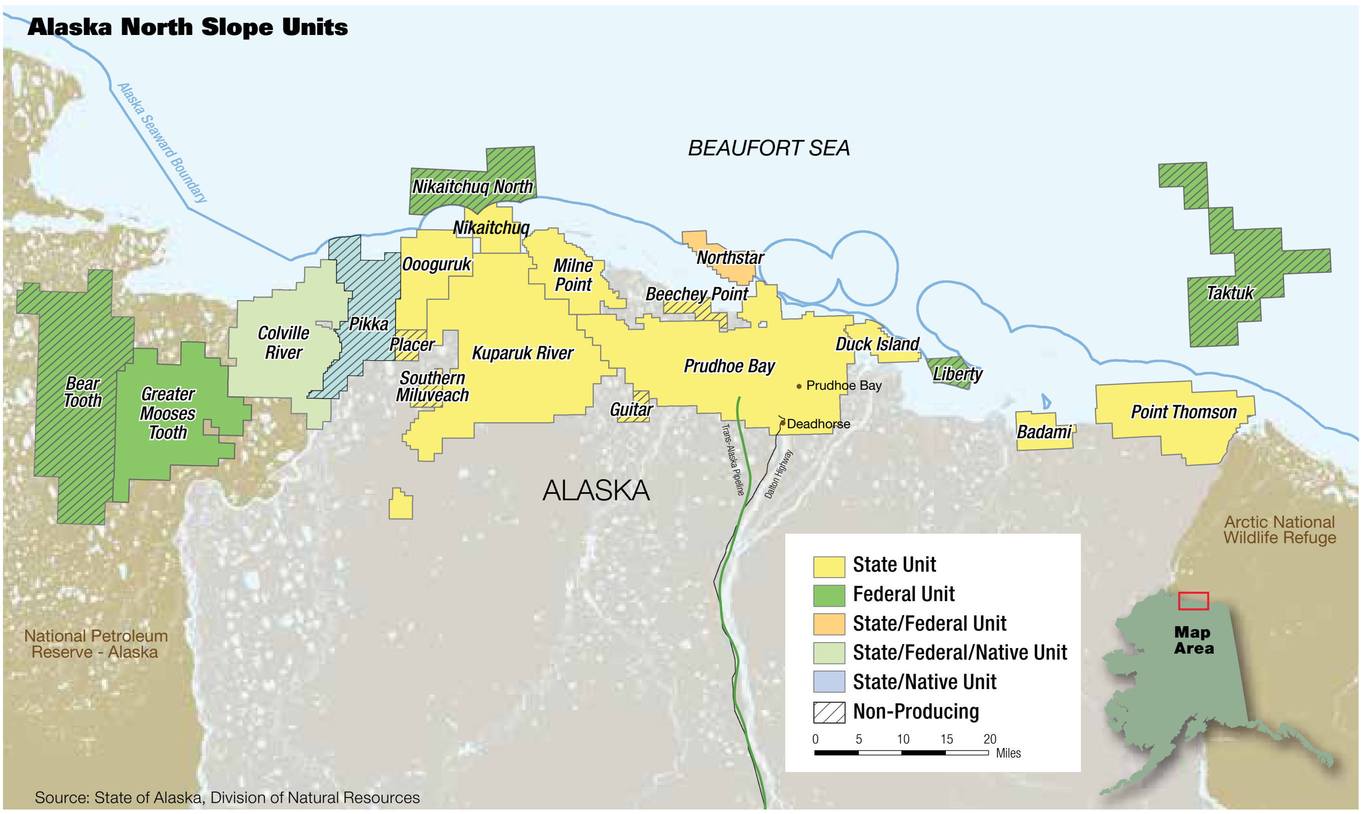
Like other oil producing states, most prominently Colorado, Alaska faced environmental ballot measures. Voters defeated a 2018 initiative that would have established new permitting rules for areas near waters used by salmon, steelhead or other fish that swim upstream from the ocean to spawn.

But a group of Alaskans want to increase taxes on production companies through an initiative called the Fair Share Act. The measure is so far not on the ballot.

Alaska does not allow the voters to amend its constitution through initiatives. However, voters may submit legislation to introduce and enact as law.

Fair Share supporters say the state is "giving away" up to $2 billion annual in tax breaks for large and profitable legacy fields. In 2015, Alaska spent more per capita on any other state and, at nearly $20,000, twice the national average, according to the Texas Policy Center. In 2019, Alaska residents' annual state dividend was $1,606, according to the Alaska Permanent Fund.

Habitual fights over how to tax oil and gas



The CD5 drillsite, part of Alpine Field, was ConocoPhillips Co.'s first commercial oil development of Alaska Native lands within the boundaries of the National Petroleum Reserve-Alaska. In 2020, the company will take delivery of a new extended-reach drilling rig that is able to drill horizontal wells of up to 7 miles.

companies have given Alaska a name for being fiscally fickle, Moriarty said.

"We just have this reputation that we like to change taxes on a constant basis," she said. In the past 14 years, the fiscal regime has been tweaked or changed substantially seven to eight times, she said.

"We've got yet another situation," she said. "That is the challenge. Are we truly a stable fiscal environment? And in this fiscal environment, companies are, under our current system, investing billions of dollars in the state."

Executives at ConocoPhillips, which plans to invest $25 billion in 10 years in Alaska and about as much again on operations, fired a not-so-subtle shot across the bow of the proposal.

ConocoPhillips COO Matt Fox said during a November analyst and investor meeting that if the measure makes it on the 2020 ballot, Alaskans will understand "the lifeblood of the state's economy" is at stake.

"Our sense is that once the dust has settled, then everybody understands what's at stake. Alaskans will understand that short-term revenue gain is a risky proposition if you're going to give up all this long-term potential," he said. "Because our investment plans would need to change if there was a change in the fiscal regime."

Beating the slump

Musselman and his exploration team were enthralled by Alaska after he founded Caelus in 2011.

"My explorers have been all over the world, but after our initial look up there we thought, 'Man, this is the oiliest place in the world.' And that's still the case," he said. "But it's expensive and it's difficult and it's a harsh environment."

By 2017, the company had invested $2.2 billion in the state. The heartbreak awaiting Caelus was that after discovering 150 million barrels (bbl) of proved and probable reserves it could not get money to drill it.

"The geology and the availability of good rocks were high with the difficulty of getting it out was maybe a little higher," he said.

Despite efforts to encourage exploration and investment, Alaska production continues to flag. Since peaking in 1988, oil production has fallen 76%, according to U.S. Energy Information Administration (EIA) data. From 2000 to 2018, Alaska oil production slumped by an average of nearly 495,000 barrels per day (bbl/d).

Alaska is often described in terms of its length and breadth. The state could squeeze in Texas, California and Montana within its borders with enough room left over for an Idaho-sized parking lot.

But the size and scale of "The Last Frontier" masks its continuing fight to turn back its dwindling production, which has largely seen limited success.

Among oil producing states, Alaska was sixth in 2018—toward the back of a middling pack that includes New Mexico, Oklahoma, Colorado and California. Put another way, in 2018, Texas pumped enough crude to match Alaska's total annual oil output roughly every 39 days.

For smaller, independent companies, the barriers of entry are sometimes hard to surmount, said Edward Hirs, an energy economist and a BDO Natural Resources fellow.

Because of the capital, equipment and manpower necessary to explore, drill, produce and transport oil and gas, costs tend to be overwhelming for E&Ps.

"Alaska is not overrun by independents,"

While the Lower 48 offers a chance for a small team with an equity commitment to lease shale acreage, "Alaska is just different," said Ed Hirs with BDO Natural Resources. "It's a big boy's game."

"Alaska, the North Slope in particular, has been experiencing a renaissance over the past 10 years, which seems to be accelerating," said David Wall, managing director of Australia's 88 Energy Ltd.

Hirs said. "It's a big boy's game."

While the Lower 48 offers a chance for a team of "five guys and $100 million" to lease acreage in the Permian Basin, "Alaska is just different," he said.

Without permanent infrastructure to transport equipment and supplies, Alaska operators often build ice roads to drilling locations. The roads alone cost between $300,000 and $400,000 per mile, according to a Bureau of Land Management (BLM) report. When temperatures or snowfall are inadequate, operators may use gravel roads that cost up to $1 million per mile to construct. Even if an ice road was built once every three years, costs to construct it would exceed building a permanent road within nine years, according to BLM's report.

In 2018, ConocoPhillips reported building about 140 miles of ice roads and 161 acres of ice pads to support the second season of exploration in the Greater Mooses Tooth Unit.

Costs to operate in Alaska are so expensive that development is more akin to deepwater projects, with returns expected years out. ConocoPhillips uses megaproject vernacular for its operations there, describing its plans for Nuna Field in 2019 as awaiting a "financial investment decision."

With seismic data shot across Alaska, producers have a good idea of where hydrocarbons are and access to markets in California, Japan or China. Alaska North Slope crude also trades at a premium to West Texas Intermediate.

"If you're successful with your exploratory well, then development becomes a very profitable enterprise," Hirs said.

To address those hurdles, in 2013, Alaska took action to lure in smaller, exploration-oriented companies with a tax credit for exploration outside the state's major legacy fields. The credit ultimately backfired as oil prices swooned. By 2018, the state owed producers roughly $1 billion, according to analytics company GlobalData.

The legality of a potential bond issuance to pay companies is before Alaska's Supreme Court. If the state receives a favorable ruling, the Alaska Revenue Department said it would appropriate $700 million to pay explorers.

Musselman, one of the five founders of deepwater company Kosmos Energy, is no stranger to risk. But his experience with the state and Caelus-backer Apollo Global Management LLC may serve as a cautionary tale for would-be explorers in Alaska.

Still convinced of Alaska's opportunities, Musselman continues to work with a company in Alaska on Caelus' former leasehold. But he's not sure smaller, private-equity-backed companies are eager to embrace the state.

"As far as creating a company like Caelus, [like we] did with Apollo, starting from scratch there and buying the assets, I think that's pretty hard to do," he said. "And some of that is prob-

The Polar Enterprise, owned by ConocoPhillips Co. subsidiary Polar Tankers, is part of the Trans-Alaskan Pipeline system that moves oil from Valdez, Alaska, to the U.S. West Coast.

PHOTO COURTESY CONOCOPHILLIPS CO.

ably because of our experience. I think people were forewarned by our experience just [of] the state not being terribly welcoming."

In early December, Michael A. Barnhill, the acting commissioner for the Alaska Department of Revenue, projected further declines in oil production in 2020 and 2021.

"New fields offer tremendous potential to increase production later in the 2020s, but these developments are still contingent on final investment decisions and commitment of billions of dollars of new investments on the part of oil and gas producers," Barnhill said in a letter to the governor.

West of North Slope

In February, the Nordic-Calista No. 3 rig, winterized to operate in arctic climes, sent plumes of exhaust white as snow into the night sky.

Like other pioneers in Alaska, Australian company 88 Energy Ltd. is pushing out into new territory. The company is targeting horizontal drilling on 225,000 net acres in an area dubbed Icewine. It began the New Year embarking on a campaign that first involves a 30-mile ice road to the south of the community of Deadhorse, about 5 miles inland from the Beaufort Sea in Prudhoe Bay.

The company planned to begin construction of the ice road in January as it makes its way to the drillsite for the Charlie-1 appraisal well, which is expected to be drilled in February. It's taken roughly four years for 88 Energy to get to this point, after the company first acquired 2-D seismic in 2016, followed by 3-D seismic in 2018.

"Alaska, the North Slope in particular, has been experiencing a renaissance over the past 10 years, which seems to be accelerating," David Wall, managing director of 88 Energy, told *Investor*.

That renaissance is largely focused on discovery. In 2019, the state enjoyed one of its best exploration seasons in decades. This year, ConocoPhillips is launching its largest-ever exploration and appraisal program, with four wells planned for prospects in its Willow discovery in the Bear Tooth Unit in addition to three exploration wells in the Harpoon prospect. The company plans to invest about $25 billion in Alaska over the next decade.

"On the exploration front for Alaska, 2019 was one of the busiest exploration seasons we've had in almost 20 years, and 2020 is shaping up to be another really strong exploration year for Alaska," Moriarty said.

Hilcorp, Eni and Oil Search are planning projects and investments totaling billions that could generate several hundred thousand barrels of oil per day, Moriarty said.

Wall also noted several deals that have transacted. Among the more jarring M&A in 2019, BP Plc ended six decades of operations in the North Slope, after selling its operations, pipelines and other assets to Hilcorp for $5.6 billion. ConocoPhillips also plans to sell a 25% farm-down of its working interests.

Wood Mackenzie analyst Rowena Gunn said in August that the BP deals stood out, in particular, for the importance of BP's 48% interest in the Trans-Alaska Pipeline.

"Growth is coming westward from ConocoPhillips and Oil Search-operated projects. But all North Slope barrels rely on the infrastructure established at Prudhoe Bay," Gunn said, adding "this will not be the last deal in the region. ExxonMobil [Corp.] may be next to follow BP, Anadarko [Petroleum Corp.], Pioneer [Natural Resources Co.] and Marathon [Oil Corp.] in the list of companies having sold out of Alaska."

Wall said such deals were made on "the back of over 4 billion barrels of oil discovered on the Slope in the past six years."

He also noted substantial participation in lease sales as well as seismic acquisition and drilling activity—exploration, appraisal and development. Lease sales have been hit or miss

PHOTO COURTESY CONOCOPHILLIPS CO.

Since 2015, ConocoPhillips Co. has expanded operations in the Greater Mooses Tooth Unit project—the first field entirely within the 22.1-million-acre National Petroleum Reserve-Alaska.

in Alaska. In May 2019, about 10 million net acres offered by the state drew only three bids. A BLM lease sale fared better, with 92 bids, although by only three companies. “There is a lot going on,” he said.

Wall said the state’s production estimates are appropriately conservative, which “has not always been the case, historically.” Further exploration should help reverse the production declines in Alaska, he said.

Projects in Pikka and Willow to drill discoveries should add 200,000 bbl/d of oil by 2024 or 2025, he said. In 2017, Spain’s Repsol SA and partner Armstrong Energy announced what they called the largest U.S. onshore oil discovery in 30 years with a 1.2 Bbbl find in Alaska’s North Slope.

“Production at Prudhoe has also plateaued in recent years, and the decline forecast of circa 50,000 barrels per day over the next four years will be more than offset by the new production,” Wall said, adding that will be upscaled over time as more oil is discovered or commercialized. “Including by us, hopefully,” he said.

ConocoPhillips’ exploration efforts, by necessity, will be far more widespread than anything undertaken in the Lower 48.

While shale producers routinely drill 5,000-foot laterals—and Basic Energy Services Inc. and Surge Energy Inc. drilled a record 17,935-foot horizontal well in New Mexico in July 2019—wells in Alaska tend to be an order of magnitude longer.

ConocoPhillips has drilled the 10 longest wells in Alaska, with the longest at 32,000 feet, Michael Hatfield, president of ConocoPhillips’ Alaska, Canada and Europe operations, told analysts in December. But it is gearing up to reach out even farther.

“We expect to push the records even further because next year we’ll take delivery of a new-build extended reach drilling rig [ERD],” he said.

The ERD rig will be capable of drilling more than 7 miles from a pad site, he said, and has three times the subsurface coverage of existing rigs. The rig’s reach is so great that if centered in Lower Manhattan, it could reach “the other four boroughs covering an area greater than 150 square miles.”

Despite a provision of the 2017 tax law signed by President Donald Trump opening the Arctic National Wildlife Refuge to exploration, Musselman said prospecting continues to push out from North America’s second largest oil field, Kuparuk, 40 miles west of Prudhoe Bay. He said little science has been down east of Prudhoe Bay, and there’s generally more interest in following the path of Armstrong and Oil Search.

“Those developments extend the frontier by another 8 or 10 or 20 miles to the west,” he said. “I think there’s going to be a stepping out to the West and in Alaska and the North Slope.” □

PHOTO COURTESY 88 ENERGY LTD.

In February 2019, 88 Energy Ltd.’s Winx-1 well in Prudhoe Bay highlighted the drilling risks in Alaska. In development since June 2018, the company’s portion of the well cost $15 million, which required construction of an ice road but ultimately did not produce enough oil to be commercial.

A U.S. Well Services Clean Fleet e-frac fleet on location at an undisclosed well site.

PHOTO COURTESY U.S. WELL SERVICES

POWER PLAY

While barriers to entry are high, electricity is positioning to be the future of fracturing.

ARTICLE BY BLAKE WRIGHT

The majority of hydraulic fracturing fleets across the Lower 48 are idle, combating pricing pressures, an overall softening in demand as well as budget belt-tightening by clients. The outlook for 2020 is at best uncertain, but most agree there is little light to be seen at the end of this particular tunnel.

The current state of the market does not sound like the best time for an expensive, new spin on a proven technology to make inroads, but that is the exact position where contractors of electrically driven fracturing or e-frac fleets find themselves.

Operators would tend to push toward conventional and readily available diesel-based or even dual-fuel units for their fracturing requirements, but these are interesting times and things are not so cut and dry.

While investors are pressuring operators to live within cash flow and be more cash-conscious in general, there is also a movement toward increased environmental and social awareness that is gaining momentum. Some of the same equity backers that are demanding returns are pushing the ESG (environment, social and corporate governance) agenda, and operators are responding by looking at ways to reduce their carbon footprints and generally be better stewards of the environment. The movement is serious.

According to one vendor, some operators have even gone as far as to tie executive bonus structures directly to the amount of annual carbon reduction achieved by the efforts at the field level, financially incentivizing the use of technology like e-frac.

"Given multiple benefits, we foresee e-frac continuing to take share in the years ahead," said Scott Gruber, analyst with Citi Research in a mid-2019 note to clients. "However, this is unlikely to be a surge as in prior cycles, rather a steady investment stream over time given capital discipline demands, but nonetheless a free-cash-flow moderator."

There are more than 500 frac fleets across North America totaling around 20 million horsepower, the majority of which are powered by trailer-mounted diesel engines. Each fleet can consume up to 7 million gallons of diesel annually, emit 70,000 metric tons of CO_2 and require around 700 tanker truckloads of diesel to be supplied to site.

The draw of e-frac is obvious in a place like the Permian Basin, where natural gas is often a byproduct of crude oil production to be flared if there is no takeaway capacity available. Operators can put that gas to work to generate electricity for completion operations. Electric systems also run more quietly than conventional diesel spreads, offering an additional safety or nuisance consideration for both workers at the field site and any neighboring populace.

COMING CLEAN

For operators in the most remote locations of popular unconventional oil and gas basins around the world, turning on a light—much less a frac pump—isn't as easy as a flick of a switch. That power needs to come from somewhere, and the isolation of the infrastructure-poor regions of the Permian Basin of West Texas, for example, can make that normally simple task a challenge.

If the operators are too far away from a tapable power grid, then the historic solution has been running diesel turbines on site to supply the needed juice.

Today, eco-minded operators are looking more to the sky for their required electricity. Both wind and solar are being employed more by producers in multiple locations to power oilfield operations.

In the fourth quarter of 2019, supermajor Chevron Corp. signed a deal with Silicon Valley-based solar specialist SunPower Corp. to build a new 35-megawatt DC solar array to supply power to the operator's Lost Hills project in Kern County, Calif. Once completed in 2020, the project is expected to provide around 80% of the total production, processing and office power needs of the 40-year old field. It is the only oilfield solar project that the provider currently has under construction.

"Companies across industries are looking for solutions to a low carbon footprint, and the Chevron project is one example of how organizations are moving the world toward a new energy future," said Nathan Griset, SunPower senior director of commercial solar.

"The nonprofit CDP [Carbon Disclosure Project] has ranked 24 of the largest and highest-impact publicly listed oil and gas companies on business readiness for a low-carbon transition, estimating that low-carbon projects account for just 1.3% of their spending. One might see this as an opportunity to increase solar adoption. There's undeniably room for growth."

Last October, operator Occidental Petroleum Corp. started up its Goldsmith Field solar facility—a 120-acre, 16-megawatt solar array in Ector County near Odessa, Texas. The operator will use the facility to directly power an enhanced oilfield recovery (EOR) operation in the Permian Basin.

Occidental also signed a 12-year power purchase agreement with a joint venture of Macquarie's Green Investment Group and Core Solar LLC to source additional solar energy for its Permian operations.

Deals like these followed supermajor ExxonMobil Corp.'s announcement in late 2018 that it locked in a power purchase agreement with Lincoln Clean Energy, a subsidiary of Denmark's Orsted, for 500 megawatts of wind and solar power for use in its Texas operations. And there are likely more coming.

But why is Big Oil looking to renewables to assist with oilfield power generation in the first place? The answer is twofold.

First, the current streak of environmental, safety and governance consciousness sweeping across the industry appears to be more than just a phase. Companies are seeing that sensible environmental stewardship is the way forward and that can start with lowering emissions across their respective asset bases. Second is just simple economics.

"We frequently evaluate opportunities to diversify our power supply and ensure competitive costs," explained ExxonMobil spokesperson Julie King.

In these instances, use of renewable power is not only more environmentally friendly; it is also more pocket book friendly. Government incentives and tax credits, both of which are due to phase out soon barring extensions, have made it attractive for developers to punch their renewables ticket now.

While power generation from natural gas and diesel works well in scale, the economics skew as the projects get smaller. With green field renewables, operators can simply start small—a few solar panels or wind turbines—and scale up as needed, or simply purchase green power from existing low-cost providers.

"As part of our onshore operating principles, we're working to reduce the operational footprint of our assets in the Permian," said Curtis Smith, a spokesperson for Royal Dutch Shell Plc.

"This year, we've piloted the use of solar energy to power parts of our operations in the region, and we're continually exploring ways to improve the energy efficiency of our existing facilities."

That is not to say that the renewables route isn't without its own pitfalls. California-based Aera Energy, a joint venture between subsidiaries of Shell and ExxonMobil, was due to have California's largest solar energy project—the Belridge solar plant—under construction during the first half of 2019 and online in 2020.

Aera's plan is to use the power to create steam for its regional EOR projects. However, Belridge has suffered setbacks, including the financial trouble and management changes at project partner GlassPoint Solar. As a result, the planned 770-acre, 850-megawatt project has yet to move forward.

"Companies across industries are looking for solutions to a low carbon footprint, and the Chevron project is one example of how organizations are moving the world toward a new energy future," Nathan Griset, SunPower senior director of commercial solar.

PHOTO COURTESY SUNPOWER CORP.


PHOTO COURTESY EVOLUTION WELL SERVICES

An Evolution Well Services electric fracking spread operating in the field. The company recently delivered its sixth e-frac fleet under a contract with supermajor Shell.

Entry into the e-frac market for the interested contractor is an expensive proposition. While none of the current crop of providers involved in the market are speaking too candidly about the overall cost, pundits place the price tag of a new e-frac system at upward of $60 million. That's about double the cost of a conventional diesel spread.

The win-win

E-frac pure-player Evolution Well Services started up in 2011 as a Canadian concern. Later, the company moved to the U.S. and spent a few years engineering its e-frac unit, which came to market in 2016. The company currently has six e-frac fleets currently pumping and a seventh that will be deployed during the first quarter of 2020. The contractor's active fleet is operating in the Permian, Eagle Ford and Marcellus-Utica basins.

"As a company, the timing for when we're rolling out our electric technology has been a perfect fit," said Nicholas Ruppelt, director of sales for Evolution. "Before when we rolled out the technology it was all about the fuel savings. Currently, it is still one of the top two reasons that people go electric, but now we are seeing the ESG focus coming into play, and investors are pushing oil companies to go this way. It has been a huge factor in why people are choosing electric frac as well."

The bulk of the price for an e-frac unit lies with the gas turbine required to generate the electricity. E-frac units can utilize standard gas turbine systems; however, the size and composition can make them challenging to mobilize.

"We started with an off-the-shelf turbine package, and it worked great," said Ruppelt. "It is just as reliable, but it is made for industries like hospitals or if there was a natural disaster where the power plant goes down and you'd need to deploy something in seven days, and that is literally how long it can take to move them. When we had that, our move times didn't meet the standards of the North American frac market. So we spent quite a bit of money, time and engineering to come up with our own package. That's what our sister company Dynamis Power Solutions is making for us."

Evolution uses one large turbine that it manufactures itself, in partnership with GE Aviation. The engine is a GE LM2500+G4 aero-derivative gas turbine used by GE in aircraft and ships. Evolution Well Services and Dynamis Power Solutions package these engines into ultra-mobile, built for purpose, hydraulic fracturing power generation units. Due to its size and modular design, it can move quicker, competing with conventional fleets on mobilization time.

"That is one of the biggest differentiators between us and those trying to get into the space right now," said Ruppelt.

While expensive for contractors, the lure of e-frac units for operators is real, and there are savings to be had over diesel units. Pundits have estimated that use of an electrically driven frac unit could shave around $300,000 in cost off of a $6- to $8 million shale well.

The power of efficiency

Demand for e-frac units is robust, according to the contractors in the space. U.S. Well Ser-

"We are seeing all of the ESG funds coming into play, and investors are pushing oil companies to go this way. It has been a huge factor in why people are choosing electric frac as well," said Nicholas Ruppelt, director of sales, Evolution Well Services.

"They are saving as much as $250,000 per well by going with electric, as well as reaping the ESG benefits and emissions reductions," said Jared Oehring, chief technology officer with U.S. Well Services.

vices, which is currently preparing to take delivery of its fifth electric fleet, or Clean Fleet, across a handful of unconventional basins, is in active dialog with customers regarding new build fleet opportunities.

With both fuel savings and ESG benefits playing in its favor, the company is not shying away from expanding its horsepower footprint in the e-frac market if the deal is right. Earlier this year, the company deployed its latest fleet in the Permian Basin for supermajor Royal Dutch Shell Plc.

"We began designing the Clean Fleet in 2012, and after more than five years of operating experience with the technology, we have been able to optimize the design of the equipment to reduce our upfront cost and still deliver fuel savings, emissions reductions and best-in-class performance for our customers," said Joel Broussard, U.S. Well Services' CEO.

"We took delivery of three new fleets in 2019 and will take delivery of a fourth early in 2020," said Jared Oehring, chief technology officer with U.S. Well Services. "We are increasing our electric frac horsepower to meet the demands of our customers. They are saving as much as $250,000 per well by going with electric, as well as reaping the ESG benefits and emissions reductions."

The new additional fleet brings U.S. Well Services' e-frac portfolio to five active fleets. The company has built six fleets overall but combined the first and second into a single fleet as leading edge jobs have commanded higher horsepower fleets over time.

U.S. Well Services has been consciously working with its supply chain network to drive down its own cost per fleet to assist with improving economics on the vendor side of the equation. The company has a partnership and exclusivity agreement with PW Power Systems, which packages a Pratt & Whitney turbine for use in its fleets—the 30-megawatt FT8 MOBILEPAC aero-derivative gas turbine. The contractor has also moved to reduce its footprint per fleet, and that has had a positive effect on mobilization times.

"We have also worked with our turbine packaging partner to make the turbines more mobile," said Oehring. "Maybe it does take slightly longer to move, but are you willing to take half-a-day longer to save $250,000 per well?"

The company's latest fleet design it will deploy for Shell is a testament to the strides being made in the space to reign in the overall footprint of e-frac spreads. U.S. Well's initial fleets consisted of over 100 power cables, with 18 cables per pump. The latest generation has only one cable into the pump trailer. The trailers themselves have shrunk from around 45 feet down to 35 feet. They have also rolled out an all-electric blender. The company's first generation blender was electric over hydraulic.

"We are aggressively evaluating our supply chain in order to reduce costs," Oehring said. "We've been able to build an electric pump for less than it would cost to build a conventional diesel pump. Contractors that are just starting in the space don't have those supply chain efficiencies and partnerships that we've been able to achieve. These will serve as a competitive advantage for U.S. Well Services and help us continue to build cost-efficient, long-lived frac equipment."

A bet with upside

Baker Hughes sold its pressure pumping fleet in 2016 to help recreate BJ Services, so it is not a contractor in the domestic space; however, it is a player in e-frac via the supply of the gas turbines required to power these systems. The company was the first to successfully deploy gas turbines for e-frac applications and remains a leading provider of gas turbine technology for the e-frac market offering customizable options in power ranges from 5.6 megawatts up to 38 megawatts. An early client was Evolution Well Services, which utilized Baker's TM2500 turnkey gas turbine generator package. Additionally, Baker Hughes is working with packagers like Dragon, which chose the contractor's Nova LT5 and Nova LT16 for its power packages in the Permian.

U.S. Well Services is currently preparing to take delivery of its fifth electric fleet, or Clean Fleet. Here is one of the company's Clean Fleet electric pumping units.

PHOTO COURTESY U.S. WELL SERVICES

PHOTO COURTESY BAKER HUGHES

A digital rendering of Baker Hughes' TM2500 RT mobile aero-derivative natural gas turbine.

"We continue to see a lot of potential for our turbomachinery and process solutions business in the e-frac space," said Steve Goldstein, Baker Hughes Turbomachinery and Process Solutions unconventional platform manager. "We have received several e-frac contracts from customers this year and are continuing to generate interest from others."

Baker Hughes is leveraging its oilfield service relationships across the Permian and other unconventional plays in the U.S. to draw interest in its gas turbine offerings. Even though additional infrastructure is required, Baker Hughes views e-frac as a compelling economic solution that is safer, cleaner and more efficient for people and the planet. It addresses remote power access, saves on fuel costs, streamlines logistics and operational footprint, reduces maintenance cycles and minimizes noise pollution.

"As a result, e-frac fleets are being added, while some conventional fleets are being stacked," added Goldstein. "And, since we are not exposed to the pressure pumping market in North America like some of our competitors, the e-frac market is all upside for us."

The bullishness on the e-frac market starts at the top for Baker Hughes. Speaking to investors in early 2019, chairman, president and CEO Lorenzo Simonelli called e-frac and the company's range of carbon-competitive products a "great example of a new solution" addressing "some of our customers' toughest challenges such as logistics, power and reducing flare gas emissions."

Integration hesitation

Larger oilfield service companies in the space have made recent investments in the conventional fracturing market and show little sign of taking the e-frac plunge.

In late 2017, Schlumberger Ltd. paid $430 million for Weatherford's pressure pumping business, while Halliburton CEO Jeff Miller told attendees at a recent Barclays conference that the contractor had tested the technology but held no current desire to pursue the market. Miller added that the cost of converting the industry's 500-plus diesel systems to electric could run upward of $30 billion.

Others with assets in pressure pumping have made similar overtures. Patterson-UTI manufactures electric control systems used for e-frac spreads but does not own any electric frac fleets.

At the same Barclays conference, Patterson-UTI president and CEO Anthony Hendricks told attendees that the numbers made it difficult to move forward with phasing in e-frac fleets, alluding to the current oversupply of under-utilized diesel spreads.

That oversupply and lack of demand has even forced some conventional hydraulic fracturing companies out of the business completely. Basic Energy Services said in December it would divest of its pumping services assets (not inclusive of coiled tubing) in multiple transactions with expected proceeds of around $30- to $45 million. The contractor pointed to the difficult pricing and activity environment for the move.

Around the same time, Superior Energy Services Inc. said it would shutter its hydraulic fracturing unit. The company said it was cutting 112 Pumpco jobs in West Texas and anticipated a $45 million pre-tax charge to earnings from a reduction in the value of its assets.

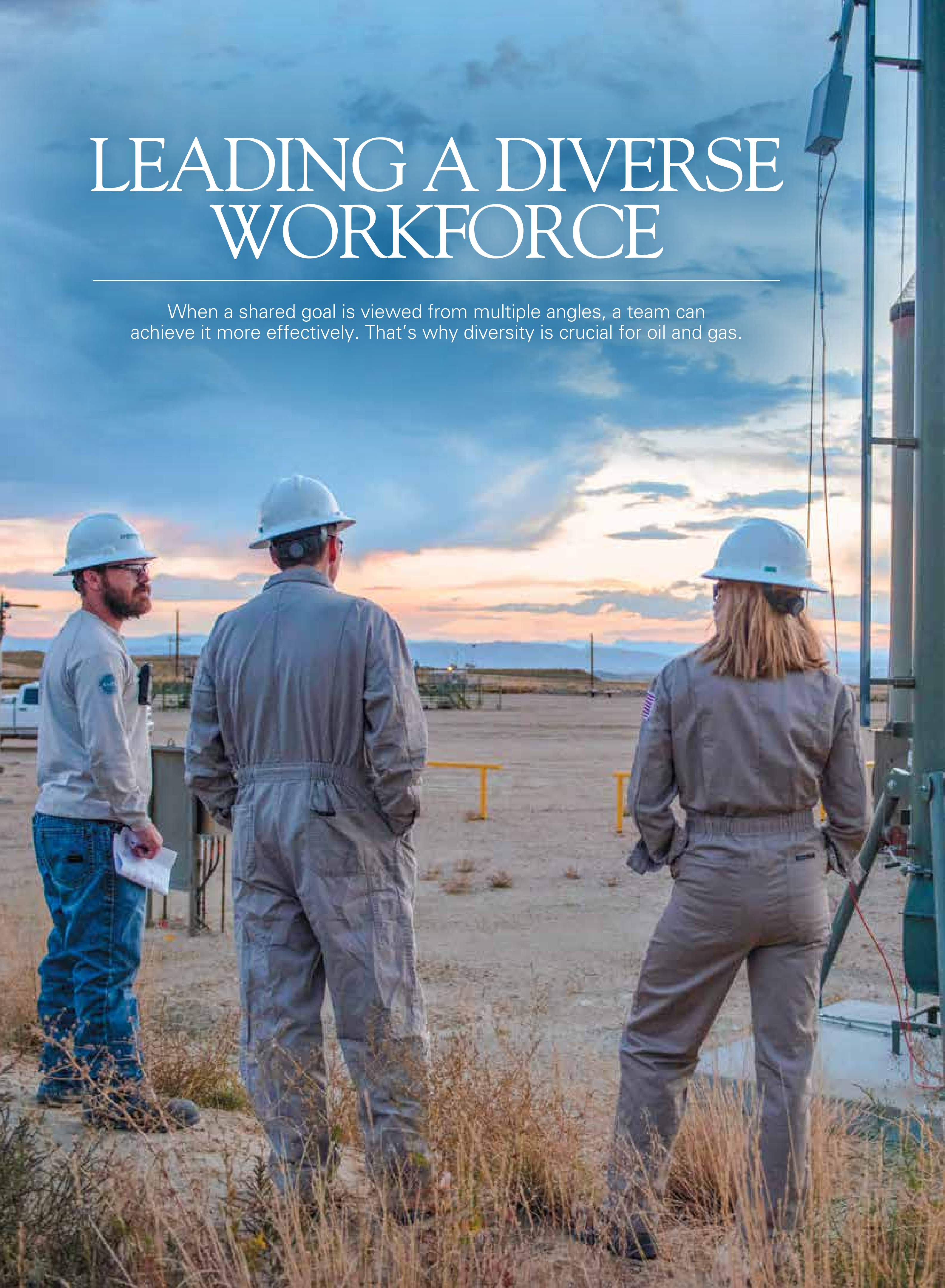
According to estimates by investment bank Tudor, Pickering, Holt & Co., e-frac accounts for about 3% of active fleets and could reach between 25% and 33% in the next five years.

"Ultimately the customer is going to decide what technology is going to win in the market, and we have found that the demand is there for our products and services," said Ruppelt. "We see that the demand is there due to the cost savings, efficiencies and environmental benefits. Markets change and costs improve as technology advances." ☐

Baker Hughes president and CEO Lorenzo Simonelli said e-frac addresses operator challenges related to logistics, power and flare gas emissions.

LEADING A DIVERSE WORKFORCE

When a shared goal is viewed from multiple angles, a team can achieve it more effectively. That's why diversity is crucial for oil and gas.



ARTICLE BY
CASEY NIKOLORIC
AND
TRACI AYER

PHOTO BY
MIEKO MAHI

When thinking about corporate culture today, diversity is a word that is sure to come to mind. From creating high-level positions to weaving the term into a mission statement or list of core values, organizations large and small are developing strategies and tactics to ensure they recruit and nurture a diverse workforce. According to Google, approximately 20% of Fortune 500 companies now employ diversity officers.

Simply put, a diverse workforce includes people with different characteristics. These differences may be generational, cultural, gender-based or racial. They are sometimes based on spiritual or religious beliefs, or they may be based on previous work and world experiences. The concept of diversity itself is, well, diverse.

Oil and gas and diversity

According to a recent study from The Wall Street Journal, when it comes to diversity, the energy sector is underperforming. In its October 2019 report, "The Business Case for More Diversity," WSJ research analysts ranked individual companies in the S&P 500 index to see which sectors fared the best in terms of diversity and inclusion. The ranking was based on 10 metrics including the representation of women, age and ethnic diversity, and whether the company has diversity programs in place. The study found that the financial industry performed best while the energy and materials sectors brought up the rear.

While that report card is underwhelming, when it comes to gender diversity, the industry is making progress. The percentage of women on boards of oil and gas companies has doubled since 2009, reaching 14% in 2019, according to a recent S&P Global report. Progress is slow but trending in a positive direction.

WSJ Diversity And Inclusion Rankings By Sector

Financials	50.4
Communication services	49.5
Consumer staples	48.8
Consumer discretionary	45.8
Healthcare	44.3
Information technology	44.1
Industrial	41.3
Real estate	40.9
Utilities	40.5
Energy	40.0
Materials	40.0
S&P 500	44.2

Source: The Wall Street Journal

The Wall Street Journal diversity and inclusion ranking of companies in the S&P 500 is based on 10 metrics including the representation of women, age and ethnic diversity, and whether the company has diversity programs in place. Scored on a scale of 0-100.

The benefits of workforce diversity

While inclusion in the energy sector is improving, savvy business leaders and hiring managers who recognize the advantages of diversity and proactively seek better balance stand to profit. The benefits are well documented. An article in the Harvard Business Review from November of 2016, "Why Diverse Teams are Smarter," identified three specific areas in which diverse teams are stronger:

- **They focus more on facts.** Diverse teams are more likely to constantly reexamine facts and remain objective. They often encourage greater scrutiny of each member's actions, keeping their joint cognitive resources sharp and vigilant.
- **They process those facts more carefully.** Scientists believe that diverse teams may outperform homogenous teams in decision-making because they process information more carefully and consider the perspectives of outsiders.
- **They are more innovative.** Hiring individuals who do not think, look or talk like you can allow you to dodge the costly pitfalls of conformity, which discourages innovative thinking.

Interestingly, these benefits map particularly well to the needs of energy companies. Oil and gas is a data-dependent industry, and employees who can empirically analyze facts and figures through a variety of lenses or filters are increasingly valuable. Further, as the industry grapples with commodity pricing challenges and a constrained capital market, innovative thinking and original ideas will be critical.

Building a more diverse workforce

Energy executives recognize they can gain competitive advantages by building more diverse organizations, and many are actively seeking to do so.

"The industry sees the value in a diverse workforce, from entry level to the boardroom. The data is there, and it is appreciated more than ever," said Laura Preng of Preng & Associates, a leading global energy search firm.

In particular, Preng has noticed a change when it comes to board searches. "As they endeavor to fill board seats, our clients want to see a diverse slate of candidates as they work to balance skill sets, perspectives and worldviews. They know this balance boosts performance and mitigates risk."

Jen Fontenot and Emily Baker have felt the positive returns of a diverse executive team first hand. As two of the three founding partners of Lotus Midstream LLC, an independent energy company backed by EnCap Flatrock Midstream, they have seen their organization grow through acquisition from start-up to more than 300 employees in less than a year.

"Our company grew extremely fast, so as a leadership team, we needed to develop policies

BUILDING INCLUSIVE TALENT

Here are strategies oil and gas companies can use to attract a more diverse workforce.

- Seek a more diverse board. In addition to the benefit of more perspectives, when younger workers see role models resembling themselves, a positive cycle of diversity is created.
- Create diverse interview panels. Incorporating diversity in the firm's mission and values is positive, but a diverse interview panel shows good candidates that your firm is walking the walk.
- Make mentorship a priority. Establishing a robust mentorship program can be powerful because it affords opportunities for candid top-down and bottom-up conversations about inclusion in the workplace.

and procedures that weren't necessary when we were a small firm. Emily and I brought a different perspective to many of the conversations. From our maternity policy to our accommodations for new parents, we naturally knew what works for working mothers," said Fontenot, COO.

Fontenot and Baker recognize the rarity of a majority female-led company in the industry, and they take the responsibility seriously. "While neither Emily nor I give much thought to 'being a woman in the industry' on a day-to-day level, we know it is atypical for females to have role models in executive positions in our field. We feel strongly this enables Lotus to build more diverse teams at all levels, and we know that makes our organization stronger," Fontenot said.

Managing a more diverse workforce

The business case for diversity is unquestionable, and energy firms are striving for more inclusivity across all functions and at every level. As these shifts take root, those in the C-suite also need to be thoughtful and deliberate as they calibrate their approach to their teams.

As Solaris Water Midstream COO and chief commercial officer Amanda Brock put it, "The corporate dynamic is fundamentally changing, so management styles must change too."

Brock believes leaders need to be aware that diverse groups of people often value different things. This can manifest itself in many ways in working relationships. Communication styles, incentive structures and feedback mechanisms should all be examined to ensure they are not counterproductive for different groups.

Working to refine the organization's approach to these areas is critical. A one-size-fits-all mindset may result in the kind of homogeneity that can lead to inertia.

"The issue is there will be stagnation, lack of continued innovation and a workforce that is not fully engaged or participating," Amanda says. "If we lose that input, the corporation itself will suffer and ultimately be less competitive in its sector."

Luis Rodriguez, CEO of Raisa Energy, has very purposefully built a firm where diversity of thought is considered a fundamental driver of success. Rodriguez believes varied perspectives are positive for the growth of the business, but he recognizes they can also create what he calls "constructive heat."

"Vetting out differences of opinion is essential to developing new ideas and continuously improving, but it can also create anxiety for those involved. At Raisa we do a lot of things to build trust and a common basis of understanding amongst different constituencies," Rodriguez said.

In addition to providing leaders with tools like executive coaching and mandating communication vehicles like regular one-on-one meetings with all teams, Rodriguez believes strongly in the importance of language when it comes to harnessing constructive heat.

"Diversity of opinion and challenging each other is a way of generating more powerful solutions," Rodriguez said. "But we can create a language to improve those interactions. For example, reacting to a colleague by saying 'you don't want to discuss this' assumes you know your colleague's motives. Alternatively, if you say 'I feel like you don't want to discuss this' you are clarifying your own emotions allowing both parties to move forward from a more neutral place.

"It may be as simple as knowing that very few things are black and white, knowing we all see things through our own lens and express our views differently. If we can share a common language of understanding that allows us to both express and contextualize our emotions, it lowers the barriers to debate and enables more productive conversations," Rodriguez continued.

Moving the industry forward

The need to diversify isn't merely about competitive advantage, but it may also be about survival.

A February 2019 article from Forbes.com suggests that failing to manage toward a more diverse workforce will result in a talent shortage because more than half of the energy workforce will be retiring in the next seven years. But as noted, strong leaders in the energy space are already meeting the challenges and reaping the rewards of more diverse workplaces.

Over time, these shifts and changes will accrue to benefit the industry as a whole. □

Casey Nikoloric founded the TEN|10 Group in 2008. She leads the firm as its managing principal, spearheading strategic efforts for TEN|10's clients. Traci Ayer, a seasoned consultant with the TEN|10 Group, has expertise in brand management, marketing strategy and communications. She serves as the editor of the TEN|10 blog.

SPECIAL SECTION:

EXECUTIVE ENERGY GRADUATE PROGRAMS

STUDYING FOR THE C-SUITE

Higher education in energy, through graduate business and technical degree programs, offers new opportunities for executives to diversify their skills and accelerate their career paths.

ARTICLE BY
BILL WALTER

For executives in a transitioning industry like energy, graduate education can be critical, said Dipankar Ghosh, executive director of The University of Oklahoma Executive MBA in Energy program.

As February begins, all oil and gas executives find themselves immersed in first-quarter operations, but a smaller, though growing, number of them also manage a separate set of tasks and challenges: the coursework for specialized graduate degrees, such as an Executive MBA in Energy or MS in Energy Management. Programs offering such degrees have lately surged in popularity for myriad reasons, with many students citing their flexible, hybrid course formats and emphasis on specific knowledge that can be applied directly to an already existing career.

Though these programs vary widely, their directors and alumni have consistently found that completing one of these specialized programs, or an MBA track that caters to energy, can tangibly improve an executive's career trajectory. In fact, the unique characteristics of the oil and gas industry make it possible for the industry's executives to more extensively benefit from these specialized degree programs.

Dipankar Ghosh, executive director of The University of Oklahoma's Energy Institute and founder of its Executive MBA in Energy program, explained, "While all executive MBA [EMBA] programs have their benefits, those students coming from industries undergoing changes are the ones who are most likely to benefit from a specialized EMBA by providing a more specialized management skill set and preparing them to be leaders through the transitional years. Energy is an example of such an industry. It is also a particularly complex and unique industry. Thus, a specialized EMBA to train professionals working in energy to take on the mantle of leadership in that industry makes a lot of sense."

These programs dispel the myth that academia exists solely within an ivory tower, that universities cannot keep pace with the rapidity of business. Because of their small size and industry-staffed advisory boards, they can regularly review and redesign their curriculum to address shifting markets, technologies and social conditions; some of them, such as the University of Colorado Denver MS in Global Energy Management (GEM) program, allow executives to sit in on classes at any point post-graduation to remain up to date.

Sarah Derdowski, executive director of CU Denver's GEM program, said, "Energy changes literally quarter to quarter, so if students want to come back, we offer lifelong learning. The industry is going to change, but we're here for you."

A false dichotomy

Regardless of the degree offered, be it an MBA or a technical master's degree, all of these programs bring experienced individuals from varied energy disciplines—engineering, finance, information systems, you name it—into collaborative learning environments designed with input from senior industry personnel (and sometimes taught by them) to create microcosms of the industry at large. They allow students to share real issues drawn from their present work experiences and leave the classroom with new solutions to test in the office or field. This facilitates crosstalk that bridges the oft-described dichotomy between studying and working, theory and practice.

Stephen Molina, director of the MS in Energy Management program at The University of Texas at Dallas, illustrated this learning environment with an example from an energy economics course, in which he brought in senior executives to discuss project funding. "I told them, 'dust off the last presentation you made to lenders in the Northeast, and I want you to give the exact same presentation you gave. I want you to sell yourself, your company and your project to the students. Make the pitch to them, just like they're your investors. You'll be surprised at the questions you get.'"

The energy courses in Molina's curriculum draw their material entirely from actual energy contracts and agreements, many of them international. "We took a really practical approach," Molina said. "I'm not a professional professor, I like to remind the students; I don't have a Ph.D., and I haven't read a lot of books about this. I've actually done it. I like to tell

PHOTO COURTESY PRICE COLLEGE OF BUSINESS

The OU EMBA in Energy program welcomes its 10th class of students. Since 2014, the program has graduated several cohorts of executive students.

students that I'm bringing in speakers that the books were written about."

More so than in a typical MBA program, the ability to evaluate actual business situations is necessary for these programs to engage students, as many cohort members have a decade or more of industry experience, with some already in executive roles.

"Executives, they're opinionated. They want to hear the war stories," Derdowski said. "You [an instructor] can't just say 'I'm the expert, this is how it is.' That doesn't work anymore. Professors don't immediately have credibility like they used to, and students want to know what you did, when you did it, how it affected the industry, and then maybe they'll trust you and think you have something to provide for them."

Derdowski typically hires adjunct faculty who have the ability to remain involved beyond academia. "Tenure-track faculty are obviously still important on the research side," she said. "But people want more applied learning, and so you're seeing more part-time faculty [and] instructors still working in the industry to stay in tune with the industry." Other programs, such as Molina's and Ghosh's, follow a similar path, balancing instructors with academic and industry-specific backgrounds.

PHOTO COURTESY CU DENVER BUSINESS SCHOOL

University of Colorado Denver MS in Global Energy Management program students engage each other in class. Strong relationships among cohort members are critical to graduate education in energy.

Think of the big picture

However, when practical education is pushed too far, you run the risk of missing the forest for the trees, and that is why these programs cultivate a holistic understanding of the industry. Rather than diving into the weeds of a specific sector, topic-specific courses, such as energy finance or strategic decision-making, draw examples from myriad sectors to illustrate the overarching strategic factors, thought processes and behavioral patterns that executives must consider in any business environment. For example, a case study of a midstream deal may be used to illustrate how to evaluate an acquisition in the upstream, or vice versa.

Explaining how the EMBA program maintains a big-picture awareness, Ghosh said the classes largely break down into "tool classes and concept classes." The tool classes tend be more specialized and skillset focused, such as electric utility fundamentals, while the concept classes are more abstract and synthetic, such as global perspectives in energy. The latter classes synthesize ideas from across disciplines and the globe, which Ghosh considers essential to developing a holistic understanding. Together, the tool classes and concept classes, the applied and abstract, create an intellectual approach to the business of energy.

Derdowski said that the CU Denver GEM program requires its students to complete some technical energy science classes, taught by faculty from the school of engineering, and explained this is part of the balancing act of specialized and big-picture knowledge in the GEM program's curriculum. "We tend to pull out pieces that are more specialized, and a lot of other schools do to, to focus on business acumen and managerial expertise. However, we highlight the importance of things such as data analytics or AI [artificial intelligence]. We show that this is one of your tools in your tool chest.

"I think that would speak to the broader executive energy education," she continued. "We want students to be flexible, nimble, to oversee multiple departments and have the skillset to ask the right questions or know who their go-to people are in each key area."

Breaking down silos

Oil and gas has traditionally been a highly siloed industry. Those involved in technical efforts such as geology or engineering typically do not enter the world of finance or business development. However, these programs encourage the simultaneous advancement of technical and nontechnical skillsets.

Ghosh said, "A VP of engineering … can benefit from a better understanding of finance, valuation, organizational behavior, strategy, etc. On the other hand, a CFO will know all the nuances of accounting and finance, but to be an effective decision-maker at the organizational level, a broader perspective about the industry and the company would be beneficial via topics such as strategy, use of big data, legal, policy and so on. And both can benefit from developing a global mindset, which we address via our international module in Amsterdam and London."

The ability to understand both sides of the industry improves executives' competitiveness in these volatile times, and with the transitions ahead for the industry, the need for such an edge will only become more acute, making "a platform for life-long learning … a must for all," Ghosh said.

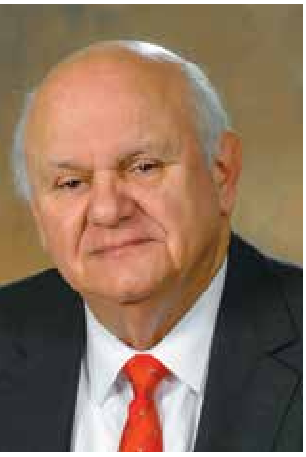
For executives on management teams at smaller or leaner companies, the interdisciplinary nature of these graduate programs is especially pertinent. Limits to human resources and fewer obstacles to career development often encourage individuals who can effectively communicate and strategize across multiple disciplines to attain greater responsibilities.

Seen here at a graduation, Sarah Derdowski, executive director of the University of Colorado Denver MS in Global Energy Management program, said graduate programs help executives become more interdisciplinary.

Executive Energy Graduate Programs Key Stats

SCHOOL	DEGREE PROGRAM	PROGRAM DURATION	PROGRAM COST ($)
Arizona State University	Certificate in Oil and Gas Management	12 modules, 2 hrs. per module	2,300
Boston University	Executive MBA	22 mos.	115,000
Duke University	Weekend Executive MBA in Energy & Environment	19 mos.	140,400 + fee for concentration
Duke University	Global Executive MBA in Energy & Environment	18 mos.	148,000 + fee for concentration
Duke University	MBA concentration in Energy Finance	Follows Duke Daytime MBA schedule	4,000
Duke University	MBA concentration in Energy & Environment	Follows Duke Global EMBA schedule	4,000
New York Institute of Technology	MS in Energy Management	1 year	39,600
Northeastern University	MS in Energy Systems	18-24 mos.	51,700
Oklahoma City University	MS in Energy Management	2 yrs.	23,500
Oklahoma City University	MS in Energy Legal Studies	2 yrs.	23,500
Penn State University	Master of Professional Studies: Renewable Energy and Sustainability Systems	32 credits	29,000
Rice University	PMBA with Energy Concentration	22 mos.	108,000-113,000
Southern Methodist University	Executive MBA	21 mos.	121,825
Southern Methodist University	Online Energy MBA	27 months	90, 740
Southern Methodist University	PMBA	2 yrs. part time	93,696
Stanford University	MS in Energy Resources Engineering | MS in Petroleum Engineering	1+ yrs.	
Texas A&M University	Executive MBA	2 yrs.	99,500
Texas A&M University Texarkana	MBA in Energy Leadership	1.5-2 yrs.	10,000-12,000
Texas A&M University	MS in Energy	10 mos.	30,000-40,000
Texas Christian University	Energy MBA	12-22 mos.	58,000-75,000
Tulane University	Master of Management in Energy	10 mos.	66,600
UNC Chapel Hill	Full-Time MBA in Energy	2 yrs.	51,202 resident/66,324 nonresident
UNC Chapel Hill	Online MBA in Energy	18-36 mos.	125, 589
UNC Chapel Hill	Evening Executive MBA in Energy	24 mos.	88,608
UNC Chapel Hill	Weekend Executive MBA in Energy	20 mos.	119,305
University of California, Berkeley	MA/MS in Energy and Resources	2 yrs.	~17,000 per year
University of California, Berkeley	MBA in Energy & Clean Technology	2 yrs.	99,000-102,000
University of Colorado-Denver	MS in Global Energy Management	18 mos.	54,000
University of Connecticut	Master of Energy and Environmental Management	30 credits (9 required + 3 internships)	~25,000
University of Delaware	Master of Energy and Environmental Policy	36 credits (21 core + 15 elective)	~68,000
University of Denver	MS in Environmental Policy and Management, concentration in Energy and Sustainability	18 mos.	34,224
University of Georgia	Executive MBA	16 courses, 18 mos.	77,000
University of Houston	Global Energy Executive MBA	22 mos.	74,000
University of Houston	MS in Global Energy Management	23 mos.	34,000
University of Oklahoma	Executive MBA in Energy	15 mos.	77,400
University of Oklahoma	Energy Executive Management Program (EEMP)	3-7 days	4,500-13,500
University of Phoenix	MBA in Energy Management	18 mos.	~26,000
University of Pittsburgh	Executive MBA	18 mos.	80,000
University of San Francisco	MS in Energy Systems Management	18 mos. full time/2 yrs. part time	~49,000
University of Texas	Weekend MBA	2 yrs.	110,460
University of Texas	Full-Time MBA	2 yrs.	99,068 in-state/108,848 out-of-state
University of Texas	Energy Certificate	6 days	7,350
University of Texas Dallas	MS in Energy Management	1-2 yrs.	32,203 resident/62,004 nonresident
University of Tulsa	Master of Energy Business	2.5 yrs.	45,000
University of Wyoming	Energy Management MBA	21 mos.	

GRADUATION RATE	ACCREDITATION	COURSE FORMAT	CAPSTONE REQUIRED	GLOBAL FOCUS/ INTERNATIONAL STUDY OPPORTUNITIES	AVERAGE STUDENT YEARS OF INDUSTRY EXPERIENCE	AVERAGE STUDENT AGE AT ENTRY	STUDENTS WITH COMPANY SUPPORT
		Online					
	AACSB	Online, with residencies		••	15		
	SACSCOC	Online, with residencies		••	5-30	25-60	
	SACSCOC	Online, with residencies		••	5-28	26-52	
	SACSCOC	In person			6	28	
	SACSCOC	Online, with residencies			5-30	25-60	
95%	MSCHE	In person and online tracks available	••	••	1-2	30	25%
	ABET, SACSCOC	Online					
61%	AACSB, AAPL	Online, with residencies	•		2+	38	75%
61%	AACSB, AAPL	Online, with residencies	•		2+	38	75%
	MSCHE	Online	•				
	AACSB	In person	•	•			
	AACSB	In person	•	••	15	38	
	AACSB	Online	•	••	5+		
	AACSB	In person		••	6	28	
	WASC		•	•			
94%	AACSB	In person	•	••	16	40	25%
~100%	AACSB, ABET	Online	•	••	1-2	36	
	SACSCOC	In person and online tracks available	•			26	
90%	AACSB, TCU Energy Institute	In person and online tracks available	••	••	3-5	32	50%
	AACSB	In person	•			25	
94%	AACSB	In person	•	••	0	28	25%
	AACSB	Online, with residencies		••			
	AACSB	In person once per week		••	11	35	
	AACSB	In person Fri-Sat classes every three weeks		••	12	36	
	AACSB	In person	•				
	AACSB	In person	•	••	5		
86%	AACSB	Hybrid	•	••	3-5	34	25%
	NEASC	Online	•				
	MSCHE	In person	•	••			
	Higher Learning Commission	In person evenings or online	•				
	AACSB	Hybrid	••	••	16	40	
	AACSB	In person		••	12	31	
	AACSB	In person		••	0	28	25%
95%	AACSB	Online	•	•	8+	37	50%
	IPAA	In person				34	75%
	ACBSP	Hybrid					
	MSCHE	In person	••	••		38	
	WASC	In person	•				
	AACSB	In person		••	3-11	25-36	
	AACSB	In person		•	6	29	
	AACSB	In person		•			
90%	AACSB, SACSCOC	Hybrid		•	0	30	0%
90%	AACSB, AAPL	Online		•	1-2	30	75%
	AACSB	In person	• •				



Stephen Molina, director of The University of Texas Dallas MS in Energy Management program, built his energy curriculum around actual industry contracts and materials.

This has certainly been the case with John Argo, vice president of business development at Continental Resources Inc. and one of the first graduates of The University of Oklahoma's EMBA program.

With a bachelor's degree in petroleum engineering, Argo quickly moved through various engineering roles in the industry, all with progressively increasing responsibilities. By the time Argo was 27, he was in his first management role at HighMount E&P, a small independent oil and gas producer. At HighMount, he noticed that those on his senior leadership team with both technical and financial experience contributed most effectively to the overall company vision, strategy and success. This observation proved critical to Argo's leadership path.

"At each level of my career, I have never wanted to be held back by limits to my own knowledge or understanding. This was a major reason why I thought an MBA would be a critical complement to my technical background. I believe you have to be familiar with all aspects of your business in order to effectively lead a successful organization," Argo said.

After aiding HighMount's divestiture process in the fall of 2014, Argo joined Continental Resources as engineering manager of business development. "I was excited to join a best-in-class operator but also to take a position that accelerated my professional growth. Business development was not my background, but I had enjoyed my role in HighMount's divestiture and was getting my MBA at the time," he said. "The combination of Continental leadership's financial and strategic knowledge along with the projects I worked provided me with relevant, real-time experience with the concepts, classwork and discussions we were having. This all helped me accelerate the leverage of the EMBA program to my career."

Executive Q&A

Even so, it's reasonable for any executive to ask: "Is this really for me?" Advantages in curriculum content and approach, in course format and quality of peers, all of these perks aside, there's no denying these programs are difficult—and executives deal with plenty of challenges already in any given business day.

Before enrolling in CU Denver's GEM program, Mike Wracher, CEO of Beacon West Energy Group LLC, a California-based oil and gas asset management company, wrestled with that very question, wondering if the program was a good fit or worth the possible costs.

At that time, Wracher had just been promoted to vice president at Venoco Inc., an E&P that operated in California's Monterey Formation, and he felt he had his hands full. He wondered, "How is this going to help me in my career? I've gotten to where I wanted to be, as VP of an exploration company. Is [this program] going to take away from my focus on my new job?'"

Similar concerns kept Argo from enrolling in a traditional MBA program, which "required two and half years away from work. I didn't want to lose two and a half years of my career path," he said. So as Argo evaluated the various specialized degree programs that existed, none were as compelling to him as The University of Oklahoma program, which began in 2014.

Program directors are keenly aware of these questions, too. As Derdowski said, "the ROI [return on investment] demand of students is pretty strong." Or Molina, "Graduate students are serious about it. They have their eye on the ball, their career, they're aggressive, am-

PHOTO COURTESY PRICE COLLEGE OF BUSINESS

The University of Oklahoma Executive MBA in Energy students visit BP Plc's London office as part of the program's international module. Understanding the industry's global dimension is crucial to graduate education in energy.

bitious and they work very, very hard," and that means they will not settle for programs that leave few options to accommodate their career development.

The hybrid education model of many of these programs has been critical to helping students maintain their career paths. In these models, students may take many, if not all, of their classes online, via recorded lectures, live digital learning environments and myriad other web resources. These features allow students to work from anywhere in the world, often at their own pace and on their own time.

The hybrid format's flexibility helped Argo, with three young children at the time, when HighMount's parent company elected to market the subsidiary shortly after he began the EMBA program. "My job went from 60 hours a week to, at times, over 20 hours a day. It was very intense, from April through August, when we ultimately signed the PSA [purchase and sale agreement]," he said. "The flexibility of the online environment was an important aspect that allowed me to continue the program during an arduous time."

And though students often communicate via digital means during these programs, the small cohort size and frequent team-based learning objectives create strong relationships that mutually develop students.

"When you end up in a cohort, you're with people from all different parts of the oil and gas business, and you get perspectives from all these people outside the sweet spot of your career. It makes everything more human," Wracher said. "You have a great group of colleagues you can discuss issues with."

The ROI of higher ed in energy

All told, Wracher and Argo consider graduate education in energy to have been a valuable addition to their careers, well worth the initial investment of material and mental resources.

Though he'd already been in management for some time before earning his graduate degree, Wracher said that the "GEM program broadened my horizons quite a bit. It filled in and buttressed my more than 20 years in the industry. It gave me more confidence in managing the disparate pieces of the business."

The acumen gained through CU Denver's GEM program in part helped Wracher, along with his partners, successfully start his present company after Venoco's bankruptcy, as he now manages assets that Venoco formerly owned, having won the bids for the company's operations thanks, in part, to a reputation for efficient and safe leadership.

Argo also affirmed his education, "Bottom line, [the EMBA program] allowed me to take a more macro and strategic perspective."

He also added an important qualification: "You shouldn't expect incremental responsibility and opportunities because you've done this, you are more likely to receive incremental responsibility because you have demonstrated that you can handle it.

"If people have the right motivation [when completing these programs] for self-improvement, I think those other benefits will come in time," he said. □

John Argo, vice president of business development at Continental Resources Inc., said the The University of Oklahoma Executive MBA in Energy program grew his strategic understanding.

PHOTO COURTESY CU DENVER BUSINESS SCHOOL

The University of Colorado Denver MS in Global Energy Management program headquarters at night. The program, like many others, offers much of its curriculum online.

The University of Colorado Denver MS in Global Energy Management program helped Mike Wracher, CEO of Beacon West Energy Group LLC, better manage disparate parts of the oil and gas business.

A BIG-PICTURE EXECUTIVE EDUCATION

The University of Oklahoma Executive MBA in Energy program offers an innovative curriculum that looks forward to prepare leaders in an industry in rapid transition.

> *"To understand the industry holistically … You must be able to think not just about specific tools but also abstractly about concepts. You also must have a global perspective."*
>
> *—Dipankar Ghosh, executive director, OU Executive MBA in Energy program*

To ensure that the Executive MBA in Energy program (EMBA) at The University of Oklahoma, which started in 2014, could develop both practical tools and conceptual thinking in its students, Dipankar Ghosh, executive director, asked university alumni and energy, "If I want to build a successful specialization in energy, what topics should I cover?" He received enthusiastic answers. "From 40 pages of notes," he said, "came the first seven courses."

Deep industry knowledge is ingrained in the EMBA's 15-month, 22-course curriculum, most of which is online but includes three face-to-face residencies, two in Oklahoma and one in Europe (split between Amsterdam and London). "Having knowledge of the industry is crucial," Ghosh said. "That's how the executive part of the program came into play."

The average EMBA student has a minimum eight years of industry experience, and you must have at least three years in the energy industry to be admitted; some students are already vice presidents or one step below. "After seven or eight years of experience, you generally know a person's trajectory, and that's how the eight-year requirement came into being," Ghosh said.

"Of my 23 instructors, 10 of them are from the industry," he continued. "A vast majority of those 10 have C-suite backgrounds."

The program's high-level discussion addresses the entire energy value chain, not just a particular sector. "To understand the industry holistically," Ghosh said, "you must see all aspects of it. You must be able to think not just about specific tools but also abstractly about concepts."

In addition, he said, "You also must have a global perspective; hence, we not only have one of the modules delivered internationally, we have a course which is very heavy in international perspective, and international topics are scattered throughout the program."

He described a recent guest speaker to illustrate this approach: "They were from one of the top boutique M&A advisory firms in the U.K., with billions of dollars in business in the last five years; my question to them was, 'When you advise your clients, what are the factors you look at, and why do you look at them?' I want to understand the thought process, not just the mechanics that they practice, anybody can do that."

The program also critically assesses new developments in energy. "The Amsterdam part of the international residency was added only in 2018, because the Netherlands is going through the energy transition, trying to decarbonize their environment. So what is the government doing, what are the policies there, what are companies doing to adapt? These are things that people in the U.S., even people in the hydrocarbon industry, need to be cognizant of."

Ultimately, the EMBA is entirely energy-specific. Unlike many MBA programs, which offer energy concentrations via electives, "there are no energy electives," Ghosh said. "All of the courses you take are only for the energy program, and everyone in the classroom is only from this particular energy program." It truly is all energy, all of the time. ■

TOP 15 ENERGY GRADUATE PROGRAMS

Offering a mixture of technical and nontechnical degrees, these 15 graduate energy programs can help materially advance executives' careers.

ARTICLE BY FAIZA RIZVI

RESEARCH AND RANKINGS BY HOLLY KEILY, PH.D.

With priorities ranging from discovering fresh resources in tricky geological formations to analyzing financial data to close a deal, it's little wonder that executives have limited time to evaluate the individual merits of the many targeted graduate degree and certificate programs in the U.S. That's where the below list, researched and presented by *Oil and Gas Investor*, comes in, offering busy professionals a listing of the top 15 energy graduate programs in the country.

With information drawn from publicly available data and survey responses received from a number of programs, we developed a weighting system to account for differences in program-specific nuances to narrow down our selections.

Though the programs are diverse, these 15 consistently value direct student engagement with energy initiatives and leaders, careful attention to the global nature of the energy industry and flexible course formats that keep students' coursework from conflicting with their careers.

Ultimately, our hope is that this list, along with the rest of this special report, will help professionals looking to advance their careers through higher education by introducing them to the programs that are truly the best in class.

Methodology: The "Best In Class" program research was conducted in fall 2019 and targeted U.S.-based graduate degrees and certificate programs that help professional students advance their careers in the energy industry. All qualifying programs were invited to participate. The overall survey had a 29.1% response rate with 100% completion and a margin of error of 3.8%. Weighted scores were calculated for each program including student and faculty composition, average student experience, globalization and post-graduate support.

1 THE UNIVERSITY OF OKLAHOMA EXECUTIVE MBA IN ENERGY

Program Highlight: The majority of OU's EMBA students are senior energy professionals, creating an environment of intensive collaboration and networking.

Web Address: www.ou.edu/price/mba/embainenergy

PHOTO COURTESY PRICE COLLEGE OF BUSINESS

Great minds think alike, and that's why experienced industry leaders can enroll in OU's EMBA program to learn from senior industry experts, faculty and peers. Working in conjunction with industry personnel, the program faculty designed their curriculum so that every course focuses on the energy industry and delivers outcomes which are expected in energy companies' current and future leaders.

The 15-month program includes three in-person residency weeks delivering energy-focused courses, many of which are delivered by senior energy professionals. The program also includes an international module in Amsterdam and London to broaden students' perspectives about the global energy industry as well as provide them with an experiential learning opportunity that pertains to the energy industry in transition, which is more prevalent in Europe. The trip also includes prominent guest speakers from the energy industry, corporate visits to both local and international headquarters of companies associated with energy, and cultural tours of iconic places.

The program is carefully designed to provide students with the exact tools they need to advance. Students on average have 10 years of experience in the energy industry, and 56% are a director or above.

2 TEXAS CHRISTIAN UNIVERSITY ENERGY MBA

Program Highlight: Flexible course formats allow for working professionals to still obtain the resources of TCU's top-ranked MBA program.
Web Address: www.neeley.tcu.edu/energymba/

Professional life doesn't have to stop for students at the Texas Christian University (TCU) Energy MBA program, which grants a global perspective and tools for success in the energy industry. The average duration of the program is between 15 and 22 months, and its cost ranges from $58,000 to $75,000. The program is governed by the Energy MBA Advisory Board, updating the curriculum and focus as the industry changes. TCU Energy MBA students can take on-campus or virtual courses designed for working professionals.

The Energy MBA also includes a 10-day course in an international destination that takes students to an energy-rich region for first-hand knowledge of crucial international issues and access to senior executives at global energy companies. By connecting with experienced classmates from top energy firms plus a variety of other fields, students can learn from each other and form powerful relationships that last long after graduation.

Educational resources include a mix of university faculty and industry experts who demonstrate business practices and strategies for managing the risks and opportunities in the industry. The TCU Energy MBA allows students to combine the integrated, broad business perspective of an MBA with industry specific practices and tools pertinent to the energy industry, broadly defined to include alternative energy sources. An Energy MBA is comprised of 75% general MBA core courses and 25% energy MBA-specific courses.

3 UNIVERSITY OF COLORADO DENVER MS IN GLOBAL ENERGY MANAGEMENT

Program Highlight: GEM program students consistently earn salary increases or promotions upon graduation.
Web Address: www.business.ucdenver.edu/ms/global-energy-management

At the cutting edge of the energy conversation, the University of Colorado Denver Global Energy Management (CU Denver GEM) degree focuses on the global aspect of energy commoditization, looks at applied business practices and considers all types of energy resources. The program's advisory board updates the design to stay current with industry trends. With their Executive in Residence program, students have access to three C-level executives for personal discussions, lunches and lectures. Early career students can take advantage of the hybrid online structure of the program that allows them to continue working full time and from anywhere in the world.

Although all students enrolled in the program work full time, statistics show that 55% of them received a pay increase or promotion upon completion of the program. The program administration and faculty are entirely student-focused and operate with a boutique mentality, which allows the program to be more nimble to industry changes and student needs.

PHOTO COURTESY CU DENVER BUSINESS SCHOOL

The CU Denver GEM Program has its own alumni board and events supported by the program. It hosts a summer event, webinars and a portal to keep everyone connected virtually and professionally. Alumni are also welcome to sit in and audit any previously completed course free of charge to ensure they are up to date on course material.

4 TEXAS A&M EXECUTIVE MBA

Program Highlight: The resources of one of the world's largest alumni networks are at the fingertips of A&M's EMBA program.
Web Address: www.mays.tamu.edu/executive-mba/

Aggies are no strangers to hard work and success in the energy industry, and the Executive MBA (EMBA) program at Texas A&M focuses on advancing effective energy executives. With a significant number of participants from the oil and gas industry, students have the option of taking an additional energy finance course. All functional areas of business are thoroughly covered, which allows the EMBA participant a view from the CEO level of the organization.

PHOTO COURTESY MAYS BUSINESS SCHOOL

PHOTO COURTESY MEINDERS SCHOOL OF BUSINESS

The program is comprised of alternate weekend courses at the Mays Business School-CityCentre, Houston, and refines students' executive leadership skills in 21 months over a two-year period, with no summer classes. The Mays Executive MBA Program is designed for the more experienced mid-career professional who has on average 16 years of work experience. Students can share their challenges with peers and use what they learn on the job.

Built on a foundation of data-driven decision-making, the lock-step program builds on core competencies from business analytics, operations/supply chain, finance, accounting, management, communication and marketing, while also focusing on personal leadership development and executive presence. The general management overview degree offers participants the skills to advance within their organization, take on new job opportunities and start their own entrepreneurial venture. In addition, students participate in three required immersive experiences that take their learning outside the classroom.

5 NEW YORK INSTITUTE OF TECHNOLOGY MS IN ENERGY MANAGEMENT

Program Highlight: A practically inclined curriculum allows students to efficiently tackle a variety of sophisticated energy issues.
Web Address: www.nyit.edu/degrees/energy_management_ms

An appreciation for complexity, and how to pragmatically address it, grounds the New York Institute of Technology MS in Energy Management program, which helps early-career energy professionals prepare for and advance careers in energy efficiency, power generation, facilities management and renewable energy. Students normally have one to two years of industry experience.

The program costs about $39,600 and is designed to be flexible: It can be completed full time, part time, on campus or online. Moreover, the courses are more practical, rather than theoretical. With a 95% graduation rate, students spend about one year in the program, guided through practical courses covering everything from green buildings and environmental issues to power. Also, the students are required to complete a capstone project, but an internship is not required. Faculty expertise includes facilities management, smart homes, energy modeling software, solar energy systems and sustainability management.

6 & 7 OKLAHOMA CITY UNIVERSITY MS IN ENERGY MANAGEMENT AND MS IN ENERGY LEGAL STUDIES

Program Highlight: Two program specializations allow students to study areas pertinent to their careers.
Web Address: www.okcu.edu/business/graduate/energy/

Offering a compelling two-in-one possibility, both the MS in Energy Management and MS in Energy Legal Studies at Oklahoma City University are part of the Meinders School of Business, an innovative collaborative college that takes every opportunity to invite industry experts into the classroom.

Students in both programs are already industry professionals that work in a cohort to understand new material and build their networks. The programs are primarily online with two required residencies. With two options, students can hone their focus on the aspect of energy leadership that will most help their career: the core business of energy with the MS in Energy Management or legal principles that underlie the entire industry with the MS in Energy Legal Studies.

The U.S. News & World Report announced in January 2019 that Oklahoma City University has one of the best online graduate business programs in the country for the fifth year in a row. OCU's Meinders School of Business was ranked 37th in the country, which is the highest in Oklahoma in the best online business programs (non-MBA) list.

8 THE UNIVERSITY OF TEXAS DALLAS MS IN ENERGY MANAGEMENT

Program Highlight: Students receive an education grounded in real-world business documents pulled from global energy situations.
Web Address: www.jindal.utdallas.edu/finance/ms-energy-management/

In the energy industry, there's no substitute for experience with the tools of business practice, and UT Dallas' MS in Energy Management program recognizes this as it emphasizes oil, gas, coal, hydro, solar, wind and power energy asset management. The program incorporates traditional management curriculum and state of the art energy curriculum, updated and overseen by an energy industry advisory board.

The program's core classes are half MBA core classes and half energy-focused classes, such as energy joint interest accounting, energy economics, energy finance, energy law and contracts, and managing energy risk, investment and technology. Total tuition based on four semesters is $32,304 for residents and $62,004 for nonresidents.

Global perspectives are always incorporated, with more than 50% of international students. As energy industries are global, the different perspectives and contacts that students bring to the program benefit all and help prepare them for industry careers.

Full-time energy faculty in the program belong to the industry. In addition, learning is not based on textbooks, but instead it relies on actual contracts and deals from the above industries. Students are taught various AIPN-model contracts including study and bidding agreements, foreign concessions and licenses, domestic oil and gas leases, unitization agreements, gas-balancing agreements, farm-out agreements, typical lender credit facilities and so on.

9 TEXAS A&M TEXARKANA MBA IN ENERGY LEADERSHIP

Program Highlight: A&M Texarkana's all-online curriculum allows students to work full time and from across the world while completing coursework.
Web Address: www.tamut.edu/Academics/Colleges-and-Departments/CBET/Graduate-Programs/MBA-Program/Energy-Leadership.html

Flexibility in terms of time and place is central to Texas A&M Texarkana's MBA in Energy Leadership program. The program helps energy professionals broaden and deepen their managerial and leadership skills specific to the energy industry. The online program is designed for working students and takes about two years to complete. University faculty focus on the managerial and leadership skills necessary to advance a career in oil and gas, coal, wind or electric power. The program offers in-depth knowledge of accounting, finance, economics, management and the state of the industry. The average cost of the program is $10,000 to $12,000.

One of the outstanding features of the program is that it is offered online to accommodate students located throughout the world and those with restrictive work schedules. It is relatively inexpensive, and there is ease of interaction between students and faculty.

10 UNIVERSITY OF HOUSTON MS IN GLOBAL ENERGY MANAGEMENT

Program Highlight: Individuals with no previous industry work experience are given ample experiential learning opportunities at a diverse energy institute.
Web Address: www.bauer.uh.edu/graduate-studies/prospective-students/ms-gem/

In the heart of the country's energy capital, early-career students can advance their careers in energy management and tailor their education to meet their interests and needs with 20 energy-specific electives on top of the regular curriculum at the University of Houston. The goal of the MS in Global Energy Management program is to prepare graduates to advance their careers as managers in the energy industry by imparting both the knowledge of the business of energy and exposure to effective management skills. The average duration of the course is 23 months, and the total cost of the program is $34,000 for residents.

Instructor expertise includes industry experts and tenured faculty. While the tenured faculty specialize in energy strategic management and HR management, energy finance, and energy trading and markets, the adjunct faculty are experts in all aspects of the structure and economics of the energy value chains. Students who enroll in the program typically have no industry work experience. They are given an opportunity to work in the Gutierrez Energy Management Institute that provides opportunities for experiential learning, adaptive energy elective options and access to industry expertise. The program attracts international and domestic students and is highly diverse.


PHOTO COURTESY C.T. BAUER COLLEGE OF BUSINESS

11 UNIVERSITY OF NORTH CAROLINA CHAPEL HILL MBA IN ENERGY

Program Highlight: A broad perspective on the energy value chain prepares students for any industry sector.
Web Address: www.kenan-flagler.unc.edu/programs/mba/full-time-mba/academics/concentrations-electives/energy/

The full-time MBA in Energy at UNC Chapel Hill guides students looking to make entry into the energy industry by helping them see the big picture. Students gain broad understanding of the energy value chain at the UNC Kenan-Flagler Energy Center. Industry experts and some university faculty bring decades of experience to teach "the business of energy" and the keys to commercial success in the changing market. The program covers the global aspects of the industry, bringing in speakers and designing courses to ensure students are prepared for the opportunities and challenges of globalization.

The average duration of the course is two years. The energy concentration certificate requires 7.5 credit hours taken from the 12 energy courses offered. This must include energy value chain, the gateway course. Typically, earning the certificate requires taking a minimum of four elective courses on top of the required course. The average cost of the course is $51,202 for in-state students and $66,324 for out-of-state students.

One of the outstanding features of the program is that it focuses on the whole energy value chain. Rather than concentrating on one sector like renewables or oil and gas, the program offers courses across the chain and covers topics that will reshape the entire chain over time.

12 THE UNIVERSITY OF TULSA MASTER OF ENERGY BUSINESS

Program Highlight: The highly diverse student body nonetheless focuses on a specific energy niche—the oil and gas industry.
Web Address: www.business.utulsa.edu/energy-economics/masters-energy-business/

Rooted in Oklahoma's rich energy history but available anywhere in the world, this online program designed for working professionals is taught by instructors with extensive energy expertise. Over an average two and a half years, students learn from experts in energy policy and energy markets about operating in and adapting to the changing energy market. Content covers all forms of energy but focuses on oil and gas. The cost of the program is $45,000.

Students enrolled in the program are mostly professionals in the energy industry with varying academic and ethnic backgrounds encompassing vast geographic areas. According to their testimonials, students have found that this program fits their lifestyle and contains the energy content they need to succeed.

PHOTO COURTESY PRICE COLLEGE OF BUSINESS

13 THE UNIVERSITY OF OKLAHOMA ENERGY EXECUTIVE MANAGEMENT PROGRAM (EEMP)

Program Highlight: Some of the best learnings of OU's energy faculty are distilled into a few day- to week-long experience.
Web Address: www.ou.edu/price/divisions/programs/energy_exe_mgt_pro

Sometimes, brevity and intensity are best, as shown by this non-degree program at The University of Oklahoma that provides energy professionals an overview of the business side of an energy enterprise to help them be more effective managers. University faculty and industry experts explain how energy companies create value, address business issues and opportunities specific to the industry, illustrate the variety of business models in the industry and discuss how to evaluate new business opportunities.

The average duration of the program is three to seven days, depending on customization, and it costs between $4,500 and $13,500, also depending on length and customization.

This program will provide participants with deeper insight into the skills necessary to think and act with an entrepreneurial mindset in the energy industry. Participants will also develop their business acumen, strengthen their strategic decision-making skills and update/expand their management skills to lead their companies to greater success.

Currently, the university is offering a five-day program for energy professionals in Oklahoma and surrounding areas, a three-day program in New York City for financial professionals in energy and a seven-day program in Oklahoma City/Norman customized for a natural gas company from the Far East.

14 UNIVERSITY OF SAN FRANCISCO MS IN ENERGY SYSTEMS MANAGEMENT

Program Highlight: A forward-thinking mandate looks at renewables and low-carbon resources.
Web Address: www.usfca.edu/arts-sciences/graduate-programs/energy-systems-management

Scheduled for professional students, the University of San Francisco's MS in Energy Systems Management program recognizes that the future of energy waits for no professional, addressing all types of energy but offering a focus on renewables and the move to low-carbon production. A mix of faculty and industry professionals collaborate to offer research and internship opportunities. The program offers personalized attention with small class sizes and offers opportunities for research, internships and professional engagement.

PHOTO COURTESY TEXAS A&M ENERGY INSTITUTE

15 TEXAS A&M MS IN ENERGY

Program Highlight: This diverse faculty and student body synthesize the major aspects of the energy industry in the program's curriculum.
Web Address: www.energy.tamu.edu/education/master-of-science-in-energy/

The program aims to educate students/professionals with a broad spectrum of important energy issues, energy technologies based on fossil and non-fossil resources, sustainable energy technologies and their interactions with energy economics, entrepreneurship, law and policy.

Emphasis is placed on creating a new generation of energy-focused students and professionals who are broadly educated on all components of industry through quantitative analytical methods and multiscale system-based approaches.

No professional experience is required to enroll for the course. Faculty from across the university provide energy-specific expertise in the 10-month program. The A&M MS in Energy addresses U.S. and international needs, technology, trends, policies and laws. The cost of the program is between $30,000 and $40,000.

One of the outstanding features of the program is that it is targeted to both traditional students and working professionals. In addition, students are accepted with a variety of educational backgrounds and not just engineering majors. Courses are taught by instructors from eight different colleges or schools. □

PHOTO COURTESY NEELEY SCHOOL OF BUSINESS

Energy graduate programs, like Texas Christian University's Energy MBA, keep pace with the latest industry technical developments.

STAYING NIMBLE TO MEET EXECUTIVE NEEDS

A flexible academic approach and strong community help the University of Colorado Denver Global Energy Management program hone energy executives' leadership abilities.

Since recruiting its first cohort in 2008, the University of Colorado Denver MS in Global Energy Management (CU Denver GEM) program has educated executives through booms and busts in oil and gas, and it has never ceased to adapt to industry members' needs.

"I remember when I started in '08, there was a conversation about peak oil, then the shale boom, then the '14 downturn," said Sarah Derdowski, executive director of CU Denver's GEM program. "As much as our learning objectives don't change, the way we teach those objectives changes, the examples, such as technology discussed, market forces or changing business models, like the funding issues right now in oil and gas."

Designed to be completed in 18 months, GEM curriculum consists of 12 courses, divided into 24 core credit hours, nine energy elective credits and a three-hour capstone course. Intermingled with energy business acumen and leadership courses are several technical classes, a feature which distinguishes CU Denver's GEM program from EMBA programs. These courses ensure a well-rounded executive education, so that, upon graduation, a CFO, for instance, better understands the actual science that his company's geologists perform to find profitable acreage.

The curriculum is reviewed annually by faculty and an advisory council, which includes executives from leading oil and gas corporations, data analytics and alternative energy companies. In addition, each course is updated when it is offered, which occurs biannually.

"The only people looking at my curriculum are energy professionals," Derdowski said. "That makes it much more in tune with global trends."

The course format of CU Denver's GEM program is also adaptable; the program practices a hybrid model, allowing students to take classes from abroad via online resources. The hybrid format helps the program "better look at how to serve students where they are, and that means in the workforce," Derdowski explained.

"All of our students work full time," she continued. "They're all going through the same walks of life and experiences, moving, getting married, having kids, all the things you shouldn't do in a year while going to grad school." These shared experiences help glue together the 30 students that form a given academic cohort in the program.

"We want to give students the tools to be able to make solutions that work for everyone and are sustainable."

—Sarah Derdowski, executive director, CU Denver Global Energy Management program

"Many students have been hired by other students, and several have created companies with each other," Derdowski said. These connections are aided by the GEM program's exclusive alumni board and program.

Another community pillar is the Executive in Residence program, which connects students with three C-level energy executives. One-on-one conversations with these senior executives help students develop soft skills alongside the hard skills learned in class, and they grant important networking opportunities. In other words, "we bring in executives who are complementary to what we teach," Derdowski said.

The collective features of CU Denver's GEM program are critical to long-term student success. As Derdowski noted: "We want to give students the tools to be able to make solutions that work for everyone and are sustainable, as opposed to a Band-Aid fix. Strategic, actual solutions."

And clearly, graduates are proving that they can create these solutions in their companies, as 55% of CU Denver GEM alumni report a salary increase or promotion upon graduation. ■

University of Colorado Denver

Global Energy Management Program

Business School

business.ucdenver.edu/ms/global-energy-management

A&D Watch

EDITED BY
DARREN BARBEE

The Original Shale Play: Devon Exits Barnett As Kalnin Steps In

> "If you look at our strategy, it's really to buy long-term, high-quality assets that are PDP weighted ... [that] we can deliver to market."
>
> —Chris Kalnin, *Kalnin Ventures LLC*

DEVON ENERGY CORP. reached an agreement on Dec. 17 to exit the Barnett Shale for $770 million as the company regroups under its "New Devon" strategy as a high-return oil business.

The deal with **Kalnin Ventures LLC**, a gas-focused investment company backed by Thailand's **Banpu Pcl**, makes for a study in shale strategies. Devon's divestiture of the Barnett, which it had carried on its balance sheet at a value of $1.4 billion, will result in a non-cash, pre-tax charge to its earnings of between $650 million and $750 million.

The sales price was in line with analyst estimates of between $600 million and $1 billion.

Chris Kalnin, CEO of **BKV Oil & Gas Capital Partners LP**, told *Investor* he primarily sees affiliate Kalnin Ventures as a PDP management company. With operated assets in the Marcellus Shale, Kalnin evaluated assets in the Gulf Coast as the company looked to enter the LNG market.

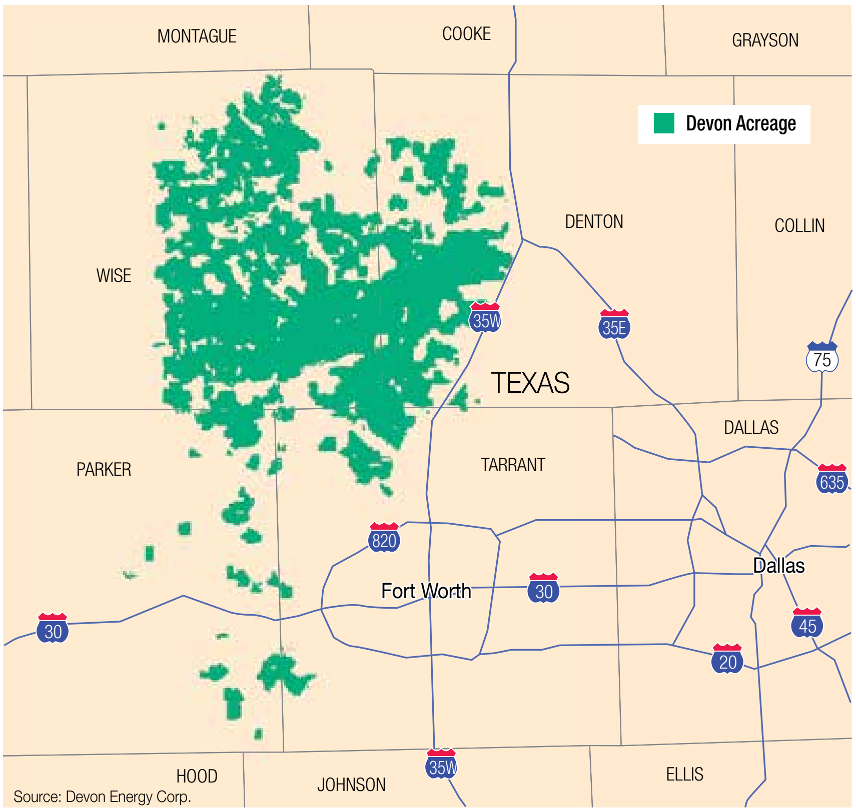
"If you look at our strategy, it's really to buy long-term, high-quality assets that are PDP weighted ... [that] we can deliver to market," he said.

The Barnett's cash flow will keep the company off a "capex treadmill" and position it to "respond to what commodity prices are telling us," he said.

"We're oversupplied," Kalnin said of the natural gas market. "We're going to hunker down and maintain our base production. The idea of a static strategy where you have one plan and barrel on, no matter what, is arcane."

Kalnin Ventures holds about 60,000 net acres in the Marcellus, which it purchased through eight deals in 2016 and 2017 totaling about $520 million.

Kalnin's Acquired Barnett Assets



Source: Devon Energy Corp.

Devon's Barnett assets include more than 320,000 gross acres and 4,200 producing wells. With 597 MMcfe/d, Kalnin Ventures will become the largest natural gas producer in the Barnett, according to a company release.

The company remains committed to Appalachia but sought out the Barnett as it looks to "diversify our gas marketing and gas basins." Its Marcellus assets supply heating and power needs in Appalachia. The company's interest in LNG had it searching along the Gulf Coast, including the Haynesville Shale.

"Rapid declines in the Haynesville were a concern," Kalnin said. "The Barnett has shallow decline rates that look like conventional rates. PDP assets where we don't have to spend cash at all are very attractive for us."

The Barnett, one of the largest natural gas fields in Texas, had historically been a cornerstone asset for Devon. After acquiring a substantial position in 2002 through its acquisition of a company founded by George P. Mitchell, largely regarded as the father of the shale revolution, Devon was the first to apply horizontal drilling techniques in the Barnett, according to the company website.

However, with its sights set on increasing returns, Devon laid out plans in February 2019 to transform into a U.S. oil growth business. This included the possible sale or spin-off of its assets in the Barnett and Canada, the latter of which the company sold to **Canadian Natural Resources Ltd.** in a multibillion-dollar transaction that closed in June.

Devon CEO Dave Hager declared Devon's transformation to a U.S. oil growth business now complete in a December news release. The company also announced a new $1 billion share-repurchase program, bringing the total repurchase authorization to $6 billion.

"The timely and tax-efficient exit from Canada and the Barnett this year has generated $3.6 billion of proceeds at accretive multiples to Devon's current valuation," Hager said. "Furthermore, these transactions accelerate efforts to focus exclusively on our resource-rich U.S. oil portfolio, where we have the ability to substantially increase returns, margins and profitability."

Following the close of the Barnett transaction, expected second-quarter 2020, Devon's business will focus on core positions in four basins: the Delaware Basin in the Permian, Oklahoma's Stack play, the Powder River Basin and the Eagle Ford Shale.

Devon initially entered the Barnett through the 2002 acquisition of Mitchell Energy & Development Corp. for $3.5 billion in cash and stock.

Jefferies and **Citi** were financial advisers to Devon on the Barnett transaction with Kalnin. **Vinson & Elkins LLP** acted as its legal adviser. **Willkie Farr & Gallagher LLP** acted as legal adviser to BKV Oil & Gas Capital Partners LP, of which Kalnin Ventures is an affiliate.

—Darren Barbee

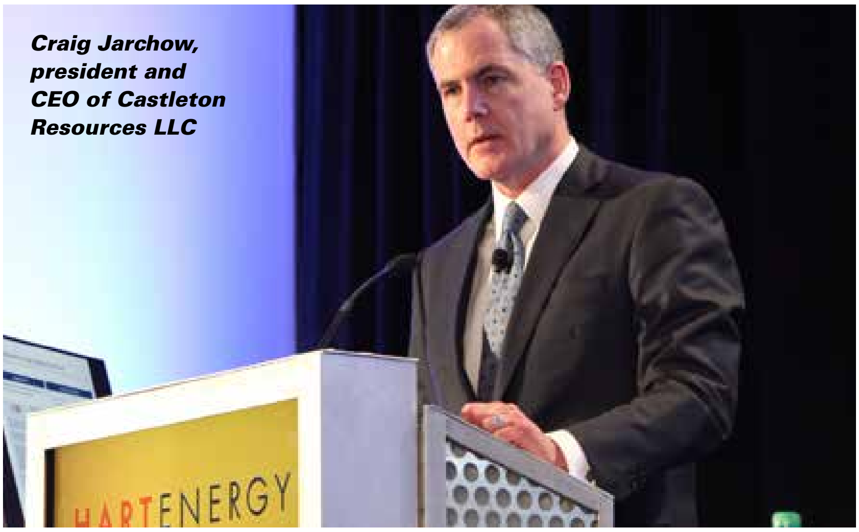
Shell Peels Off Last Haynesville Stake

ROYAL DUTCH SHELL Plc sold off its last package of Haynesville assets on Dec. 30 as the oil and gas supermajor finalizes its exit from the shale play.

The Anglo-Dutch company had previously sold off a bulk of its Haynesville assets roughly five years ago to **Vine Oil & Gas LP** and its partner **Blackstone** for $1.2 billion in cash. Shell's remaining assets in the Haynesville gas play consist of a nonoperated position, the company website said.

On Dec. 30, privately backed **Castleton Resources LLC** said it had closed on the acquisition of the East Texas and North Louisiana Haynesville Shale assets of a Shell subsidiary. Terms of the transaction weren't disclosed.

According to the company website, the acquisition with Shell increases Castleton's position in the region by nearly 40%. Pro forma for the acquisition, Castleton Resources will hold about 222,400 net acres in the region and produce approximately 334 million cubic feet equivalent per day (net), a company release said.



Craig Jarchow, president and CEO of Castleton Resources LLC

"With the help of our partners, we are well-positioned to continue building a world-class, and relatively low-decline portfolio in the Haynesville and Cotton Valley natural gas and liquids plays."
—Craig Jarchow,
Castleton Resources LLC

Castleton Resources, owned by **Castleton Commodities International LLC** (CCI) and **Tokyo Gas Co. Ltd.**, has steadily been building its position of gas assets in the region.

In particular, the company is focused on being a consolidator of E&P assets in the Ark-La-Tex region, which it said on its website has a stacked pay potential rivaling that of the Permian Basin.

Since its formation by global energy commodity merchant CCI in 2014, Castleton Resources has built its portfolio through multiple transactions. The largest of the company's transactions was its acquisition of **Anadarko Petroleum Corp.**'s Carthage upstream and midstream assets in East Texas for roughly $1 billion in 2016.

Japan-based Tokyo Gas acquired a 30% stake in Castleton Resources from CCI for an undisclosed price in 2017. Concurrent with the transaction on Dec. 30, Tokyo Gas increased its interest in Castleton Resources to about 46%.

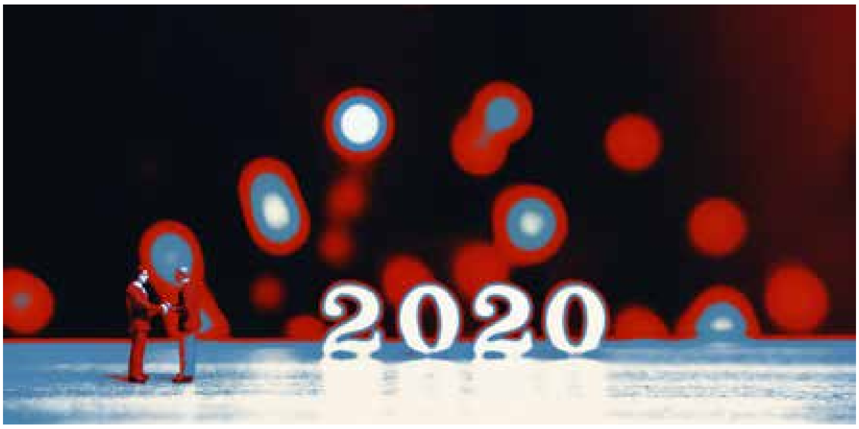
Castleton Resources will execute the acquisition from Shell with no increase in ongoing general and administrative expenses, said Craig Jarchow, the company's president and CEO.

"With the help of our partners, we are well-positioned to continue building a world-class, and relatively low-decline portfolio in the Haynesville and Cotton Valley natural gas and liquid plays," Jarchow said in a statement.

Moelis & Co. was exclusive financial adviser to Castleton Resources in the transaction. **Latham & Watkins LLP** was its legal adviser.

—Emily Patsy

Kimbell Opens New Year With 10-State Mineral Buy



KIMBELL ROYALTY PARTNERS LP added a sweeping portfolio of mineral and royalty interests to its stable on Jan. 9 with an agreement to buy interests from **Springbok Energy Partners LLC** for $175 million in cash and stock.

Nearly half of the purchase price, about $80 million, is comprised of equity in Kimbell and its affiliate, **Kimbell Royalty Operating LLC**. The remaining $95 million in cash will be paid through a combination of an underwritten public offering of common units and borrowings under Kimbell's revolving credit facility.

The Springbok acquisition is expected to further solidify Kimbell's position in the Permian Basin by adding mineral interests in the Delaware Basin and further bolster its Eagle Ford Shale, Bakken Shale, Haynesville, Stack and Denver-Julesburg Basin positions.

In particular, the Delaware Basin represents 29% of the rig activity included in the acquisition.

"Included with this acquisition is our first meaningful addition from the Delaware Basin since our initial public offering, which is an area where we are finally seeing opportunities that we believe have the right balance of existing and future drilling locations," Bob Ravnaas, chairman and CEO of Kimbell's general partner, said in a statement.

Kimbell estimates that, as of Oct. 1, the Springbok assets produced 2,533 barrels of oil equivalent per day (boe/d) and included 2,160 net royalty acres. Ravnaas added that he is optimistic about the future development of the assets for many years to come.

Upon closing, Kimbell expects to have over 13 million gross acres, 145,917 net royalty acres and a total of 93 active rigs on its properties, which represents about 12% of the total active land rigs drilling in the continental U.S., according to a company news release.

In a Jan. 9 news release, Ryan Watts, president and CEO of Springbok Investment Management LP and manager of the Springbok entities, called Kimbell "the natural acquiror" of the company's acreage.

Since its IPO in 2017, Kimbell has become a major consolidator within the oil and gas mineral and royalty space, completing over $700 million worth of transactions.

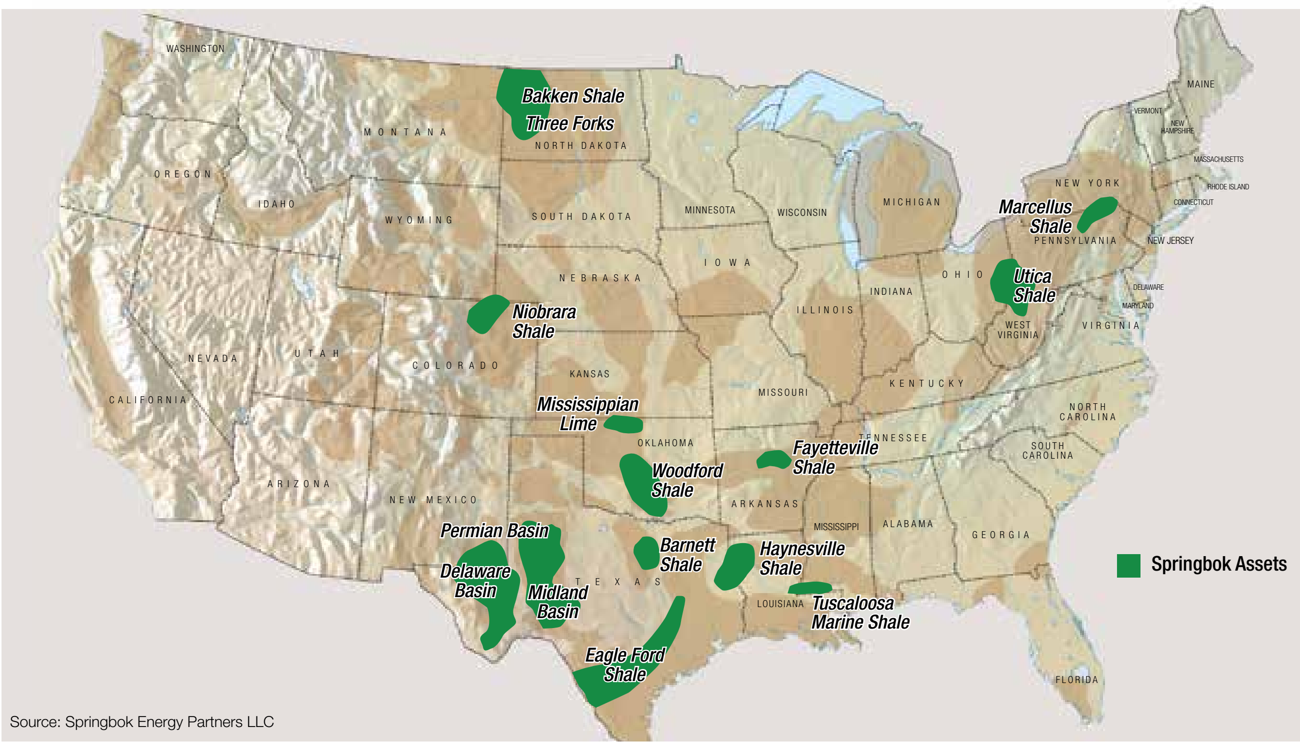
"We believe strongly in the continued future success of Kimbell as a leading consolidator in the highly fragmented national minerals market," Watts said in a statement.

The companies expect to close the transaction in the second quarter. The effective date of the acquisition is Oct. 1.

Baker Botts LLP and **Kelly Hart & Hallman LLP** provided legal counsel to Kimbell for the transaction. **Willkie Farr & Gallagher LLP** served as legal counsel to the Springbok entities with **TenOaks Energy Advisors LLC** acting as financial adviser.

—Emily Patsy

Kimbell's Acquired Mineral Interests



Source: Springbok Energy Partners LLC

Tallgrass Headed Private After Sweetened Offer

TALLGRASS ENERGY LP agreed to a sweetened take-private offer on Dec. 17 from a group led by **Blackstone Infrastructure Partners**, continuing a move by some midstream and upstream companies to retreat from the spotlight of the public markets.

The Leawood, Kan.-based midstream company said it entered a merger agreement for Blackstone together with affiliates of Spain's **Enagas SA**, **GIC Private Ltd.**, **NPS** and **USS** to acquire the shares in Tallgrass that they do not already own. Together, the group already owns nearly 44% of Tallgrass' Class A and Class B shares, according to a report by Reuters.

The transaction, expected to close second-quarter 2020, is among several midstream and upstream deals in which a public company has agreed to abandon the public market. Notably, **IFM Global Infrastructure Fund**'s took **Buckeye Partners LP** private for $6.5 billion. Among E&Ps, Oklahoma City-based E&P **Roan Resources Inc.** agreed to a similar, all-cash deal with private-equity-backed **Citizen Energy LLC** for $1 billion. And on Jan. 7, Canada's **Pengrowth Energy Corp.** was bought by privately backed **Cona Resources Ltd.**

Blackstone had made an earlier offer to Tallgrass in August. However, Reuters reported the offer triggered a dispute with investors over a provision that gave Tallgrass executives a premium of about 30% for their shares.

In the revised offer, Tallgrass shareholders will now receive $22.45 in cash from Blackstone vs. the original $19.50 per-share offer. According to Kyle May, equity research analyst with **Capital One Securities Inc.**, the revised offer represents a 23% premium to Tallgrass' prior closing price.

In addition, the new agreement approximates the LP unit amount of roughly $22.45 noted in the controversial management side letter agreement, he wrote in a Dec. 17 research note. May added that Capital One's take on the sweetened deal was positive and, as a result, the firm is increasing its price target for Tallgrass to $22.45 from $20.

The Blackstone-led group plans to fund the purchase of the Tallgrass Class A shares with roughly $3 billion of equity, with the remainder provided by debt. A conflicts committee comprised of board members of Tallgrass' general partner have unanimously approved the transaction and determined it to be in the "best interests" of Tallgrass and its public shareholders, the company said in a release.

Citigroup Global Markets Inc. and **Credit Suisse Securities (USA) LLC** acted as Blackstone Infrastructure Partners' financial adviser and was represented by **Vinson & Elkins LLLP**. **Latham & Watkins LLP** was legal adviser to Enagas. **Sidley Austin LLP** was GIC's legal adviser.

Evercore Group LLC was financial adviser, and **Bracewell LLP** was legal adviser to the conflicts committee of Tallgrass' general partner. **Baker Botts LLP** was legal adviser to Tallgrass.

—Emily Patsy

Gulfport Boots Noncore Scoop, Utica Assets

GULFPORT ENERGY CORP. cleaned up its balance sheet on Dec. 19 through bond repurchases and the divestiture of a slew of noncore assets with proceeds totaling over $100 million.

The Oklahoma City-based company, which has faced activist investor pressure this year to improve its stock performance, agreed to divest various noncore assets including its water infrastructure assets in the Scoop play. In total, Gulfport said it expects to receive about $86 million in up-front proceeds from the divestitures plus future contingent payments in excess of $50 million.

The buyer is Oklahoma City-based **Bison**, which will pay $50 million in cash upon closing for the assets, and it also agreed to additional incentive payments in excess of $50 million during the next 15 years, subject to Gulfport's ability to meet certain thresholds.

The acquired assets include the 15-year agreements, a multi-line water gathering and delivery system, 2.3 million barrels of storage capacity, 40,000 barrels per day (bbl/d) of recycling capacity, 55,000 bbl/d of freshwater supply capacity, associated real property and a pending saltwater disposal permit.

"Today's announcement is another major milestone for our company, which has grown exponentially throughout the year and now serves over 12 E&P customers dedicated to our infrastructure under long-term agreements," Bison CEO North Whipple said in a statement.

The agreement with Bison contains no minimum volume commitments, and Gulfport said it had anticipated closing the transaction in January.

Separately, Gulfport also recently entered an agreement to divest certain nonoperated interests in the Utica Shale for about $29 million in cash. The company anticipated closing the transaction prior to year-end 2019.

In addition, the previously announced sale of certain overriding royalty interests associated with assets Gulfport held in the Bakken closed on Dec. 11. Net of purchase price adjustments, Gulfport received about $7 million of total proceeds.

Gulfport also revealed that so far during the fourth quarter it had repurchased $85.6 million aggregate principal amount of unsecured senior notes for $60.1 million in cash. This brings total debt repurchases year-to-date to $190.1 million for $140.4 million in cash representing a total discount capture of $49.6 million.

These developments are the latest in a series of moves Gulfport has made in recent months to reverse a slide in its stock price. During the past year, the company has lost more than half of its market value largely as the result of weak natural gas prices.

In November, Gulfport confirmed that it would cut jobs, change its board and end its share buybacks in an earlier bid to improve its stock price. In response, **Firefly Value Partners** urged the Gulfport board in a letter to immediately fill one of the new director vacancies with a Firefly principal as a shareholder representative that would work collaboratively with the remaining board members to select the best candidates.

Gulfport has been under pressure to implement changes from Firefly since late 2018. The hedge fund owns 9.9% of the outstanding common stock of Gulfport, making it the company's largest active stockholder, according to a Nov. 21 letter.

Scotiabank was financial adviser to Gulfport on the divestiture of its water infrastructure assets.

—Emily Patsy

ExxonMobil Buys Offshore Egypt Rights

EXXONMOBIL CORP. said Dec. 30 it had secured more than 1.7 million acres for exploration offshore Egypt, strengthening its upstream portfolio in the eastern Mediterranean.

The discovery of the giant Zohr Field in 2015 by Italy's **Eni SpA** is believed to have ignited a growing interest in exploration in Egypt. The Zohr discovery is the largest in the Mediterranean and estimated to hold about 30 trillion cubic feet of gas.

The Irving, Texas-based company, which has had a long-standing downstream presence in Egypt dating back to the beginning of the 20th century, marked its foray into gas exploration in the country in February 2019 by winning awards in one of Egypt's largest-ever oil and gas exploration tenders. Later that same month, ExxonMobil made a mammoth gas find of its own in the East Mediterranean Sea offshore Cyprus.

ExxonMobil's acquisition on Dec. 30 includes acreage in the 1.2-million North Marakia offshore block, which is located about 5 miles offshore Egypt's northern coast in the Herodotus Basin. The remaining 543,000 acres are in the North East El Amriya offshore block in the Nile Delta.

ExxonMobil will operate both blocks and hold 100% interest. Operations, including acquisition of seismic data, are scheduled to begin this year.

"ExxonMobil has been a partner in Egypt's growth for more than 115 years, and these awards reaffirm our commitment to pursuing high-quality opportunities in the country," Hesham Elamroussy, chairman and managing director of ExxonMobil Egypt, said in a statement.

Egypt also awarded oil and gas exploration concessions in the Red Sea to **Chevron Corp.**, **Royal Dutch Shell Plc** and **Mubadala** in an international tender, according to a report by Reuters on Dec. 29.

—Emily Patsy

TRANSACTION HIGHLIGHTS

SOUTH TEXAS

■ **Denbury Resources Inc.** has entered into a farm-down agreement with a subsidiary of Israel's **Navitas Petroleum** to sell half of its nearly 100% working interest position in four southeast Texas oil fields, the company said Dec. 31.

Denbury will sell assets in the Texas cities of Webster, Thompson, Manvel and eastern Hastings for $50 million in cash and a carried interest in 10 wells to be drilled by Navitas. The sale is expected to close by early March 2020 and is subject to customary closing conditions. The company anticipates using the sale proceeds to fund operations, enhance liquidity and/or reduce debt. Denbury will remain operator of the fields, but Navitas will drill and complete each of the 10 wells.

Under the agreement, Navitas is committed to funding 100% of the capital required to drill and complete an initial 10 horizontal wells across the fields, with the first of the 10 wells to be spudded within six months of closing and with all 10 wells to be completed within 18 months after closing.

HAYNESVILLE

■ **Chesapeake Energy Corp.**'s rumored sale of its Louisiana assets to **Comstock Resources Inc.** apparently snagged as the natural gas company scrambled to restructure its debt, Reuters reported. In November, Chesapeake warned it could default on its debt.

An earlier plan to cut debt through cash flow from expanding oil operations and asset sales ran headlong into a drop in commodity prices and rising investor resistance to new financing for oil and gas companies.

On Dec. 20, the shale gas pioneer completed a term-loan refinancing early with support by 99% of holders. Chesapeake also is refinancing longer-dated notes that will pare $1 billion off its about $9.7 billion in debt by paying the bond holders between 62 cents and 70 cents per dollar on the older notes.

The refinancing has sidelined a deal reportedly worth about $1 billion deal that would sell Louisiana assets to Dallas Cowboys owner Jerry Jones' **Comstock Resources Inc.**, Reuters said, citing a confidential source familiar with the discussions. Expectations for an agreement have been pushed into 2020 from December, the person said.

PERMIAN BASIN

■ **Callon Petroleum Co.** and **Carrizo Oil & Gas Inc.** said Dec. 20 the companies had completed their multibillion-dollar merger.

Under terms of the merger agreement, amended in November to placate resistant investors, Carrizo shareholders will receive 1.75 shares of Callon common stock for each share of Carrizo stock they own. This represented a reduction to the equity exchange ratio the companies had originally agreed to when the all-stock transaction was first announced in July.

Phillips Johnston, an analyst with **Capital One Securities Inc.**, estimates the amended terms lowered the total transaction value to $2.7 billion from the original $3.2 billion deal value. Callon shareholders will now also own 58% of the combined company, up from the original 54%.

EAST TEXAS

■ **Riviera Resources Inc.** signed an agreement to sell its interest in East Texas properties to an undisclosed buyer for a contract price of $34 million, subject to closing adjustments.

The properties to be sold consist of about 750 wells located in Personville Field in East Texas with average third-quarter net production of roughly 28 million cubic feet equivalent per day. Proceeds from the sale are expected to be added to cash on the company's balance sheet.

So far this year, Riviera has gradually been monetizing assets from the multibasin portfolio it inherited through its spin-off from **Linn Energy Inc.** in 2018.

"I am pleased to announce this sale not only because it generates additional proceeds that can be returned to shareholders, but our capability to resourcefully maximize value given the current market environment," David Rottino, president and CEO of Riviera, said. "In 2019, we generated over $500 million in proceeds through strategic monetizations and returned over $400 million of capital to shareholders."

NORTH SEA

■ U.K. independent oil company **Premier Oil Plc** is set to buy stakes in North Sea oil fields Andrew and Shearwater from **BP Plc** for $625 million and increase its stake in the Tolmount gas project in a deal with **Dana Petroleum Ltd.** worth $191 million, it said Jan. 7.

Premier said the deals would generate more than $1 billion in free cash flow by the end of 2023, push its output above 100,000 barrels of oil equivalent per day by next year and add 82 million barrels of reserves and resources to its portfolio.

The acquisitions, the latest in a string of deals moving North Sea assets from oil majors to smaller groups, would be funded by a $500 million equity raise, "which has been fully underwritten on a standby basis," existing cash and, if needed, a loan of $300 million.

CEO Tony Durrant told Reuters the response from major shareholders for the plans was "extremely positive" although hedge fund and Premier bondholder **Asia Research and Capital Management** said it would fight the plans. Premier said it was confident it had enough support from its other creditors to get permission for the transactions at a so-called scheme of arrangement court meeting.

GOM

■ **Contango Oil & Gas Co.** entered a joint-venture (JV) agreement on Dec. 20 to develop certain offshore exploration prospects in the U.S. Gulf of Mexico (GoM) shelf owned by **Juneau Oil & Gas LLC**.

"Our entire team could not be more excited to reconnect with our original partner, Contango Oil & Gas, which Ken Peak and I started back in 1999," Brad Juneau, president of Juneau Oil & Gas, said in a news release.

As part of the JV agreement, Contango will have the right to acquire an interest in all of Juneau's GoM prospects for aggregate consideration of $6 million, consisting of $1.69 million in cash and $4.31 million in stock.

The companies' original 1999 partnership made several notable discoveries in the GoM from inception, including the discovery of Dutch and Mary Rose Field, which Wilkie S. Colyer, Contango's president and CEO, said continues to be an important contributor to Contango's reserves and cash flow.

MIDSTREAM

■ **Occidental Petroleum Corp.** said on Jan. 6 the company would cut its majority stake in pipeline operator **Western Midstream Partners LP** to less than 50% in 2020 as it seeks to reduce debt from its acquisition of **Anadarko Petroleum Corp.**

Occidental's shares rose about 4% on the news, having lost over 30% in value since the $38 billion offer for Anadarko was made public on April 24, 2019.

The company is working to pare $40 billion of debt it took on with the Anadarko deal.

BACK TO BASICS

RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

Just when it looked so good in the Midcontinent as the Stack and Scoop promised to become the next great stacked pay play in the storied renaissance of North America's tight formation revolution, inconsistent field results and variable well economics turned the nation's most promising region in 2017 into the most hard hit area in the oil patch in 2019.

Midcontinent rig count fell by two-thirds in 2019, more than any other play in the U.S. Promises of major gains through cube development deflated into disappointment when it became evident that E&Ps were placing wells too close together.

Meanwhile, geological heterogeneity took a toll as once promising E&Ps with celebrity CEOs literally vaporized into Chapter 11 or formerly high-flying regional explorers merged into companies that emphasized free cash flow on proved developed producing holdings.

Issues that damaged Midcontinent credibility included faulty analysis on Wall Street aided and abetted by overly optimistic industry press releases. The headline well, or the parent well, was used to build economics that extrapolated the best performance of the best well across all acreage instead of the average performance of all wells. In other words, Wall Street learned that single-well economics are very different than the reality of full-field development economics.

A related issue was allocating too much benefit to short-term IP rates rather than acknowledging the conservative reality provided by examining cumulative production over an extended period (90 or 180 days), which provided a more accurate assessment of acreage potential.

Parent wells in the Stack that promised estimated ultimate recovery (EUR) of 1.7 million barrels of oil equivalent (MMboe) and rate of returns at 175% at tight downspacing on paper turned into 1.2 MMboe wells at 75% IRRs with much fewer wells per section. A post-mortem study found a 29% reduction in EUR on parent vs. infill wells—in other words the average of all wells—dropped rate of return by 79% in the case of the overpressured Stack.

Development programs that focused on 10 or more wells per section devolved into spacing of four to eight wells per section in the Meramec/Osage. That's a lot of evaporating net asset value.

Furthermore, the sins of the Midcontinent were reflected across the industry in all regions, though each region played its own role in over-hyping shale play potential. The only upside left after the 2019 hangover set in was that lower-than-forecast potential would become an important step in slowing North America's contribution to growth in an oversupplied global market.

It may come as a surprise, then, that the Midcontinent story is not over. Rather, it is in transition, and this transition says something about evolution in tight formation plays everywhere.

While the big players regroup, reassess, divest and retool, smaller E&Ps with focused management teams, technical expertise and private-equity backing are squeezing success out of smaller acreage parcels. This focus is producing better results at a lower cost.

The storyline is that management teams now view acreage as a holistic asset rather than a collection of individual wells.

Instead of high-input efforts to produce single-well metrics attractive to Wall Street, innovative E&Ps are now looking at how to make acreage profitable across the board, even if it requires more modest wells and lower inputs. Lateral length and proppant volume have not only plateaued as a well construction technique, but both inputs are being reduced in many cases as focus turns to economics first.

It also means looking at some underexplored areas of the Midcontinent where technologies such as advanced geo-steering can overcome intense local fracturing and faulting in the northwestern Arkoma Basin at the same time the area's productive potential is increased by extending completions into additional formations such as the Caney, Mayes and Woodford.

It is also reflected in Midcontinent E&Ps who are returning, for example, to the always reliable Cleveland Sands in the Anadarko Basin where wells have lower output but cost much less and, more importantly, are consistently economic.

Midcontinent particulars say something about the future of an oil and gas industry perpetually adrift in the doldrums of $55 oil or offer hope in a volatile commodity price environment where oil rallies to $65, or above, on geopolitical wild cards.

EASTERN U.S.

1 ***Ebers Drilling***, based in Chester, Ill., has scheduled a Monroe County, Ill., wildcat about 10 miles southeast of the nearest oil field. The #1-3 Frees R has a planned depth of 1,300 ft and will be in Section 3-4s-9w. The company's venture is targeting oil pays in Grand Detour. Several shallow wildcats have been drilled within 3 miles of #1-3 R. Frees, with most of the earlier tests abandoned at depths of 1,000 ft or less. One of the deeper tests in the area, #1 Au Buchan in Section 1-4s-9w, was abandoned in 1964 at 2,005 ft. In 2013, ***West Bay Exploration*** drilled an exploratory test in the county at #1-15 Gros in Section 15-3s-9w and was abandoned at 1,000 ft in Maquoketa.

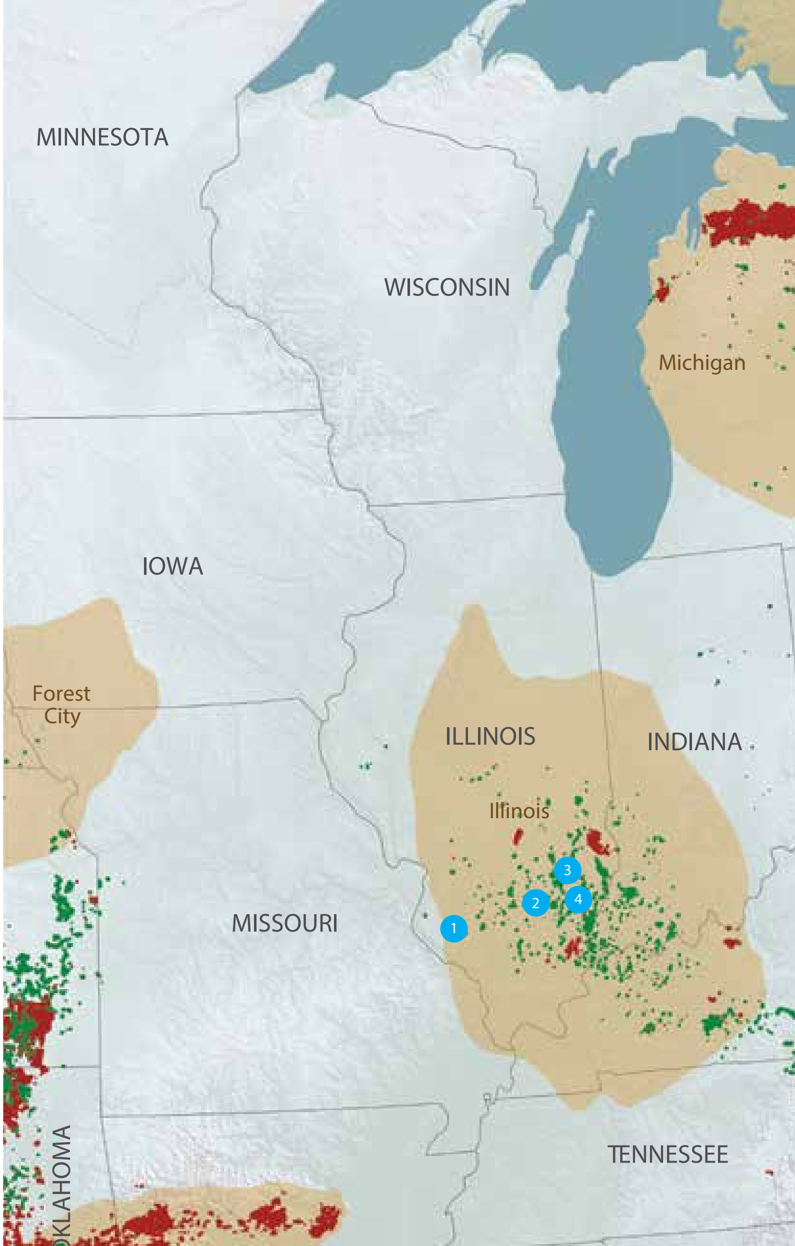
2 Mt. Vernon, Ill.-based ***Resolve Exploration Corp.*** has extended Coil West Field more than a mile to the south following the completion of a Salem Lime oil well in Jefferson County, Ill. According to IHS Markit, #1 Withrow pumped 124 bbl of crude per day from perforations at 3,364-69 ft. The well was drilled to 3,745 ft and is in Section 36-1s-4e. There had been no previous drilling in Section 36. The nearest drilling is within 1 mile to the northwest in Section 25 at #1-A Clyne M. Rapp, which was drilled in 1962 to 3,051 ft in Valmeyer.

3 An Upper St. Louis completion in Richland County, Ill., was announced by ***Tri-State Producing & Development Inc.*** The #17 Kermicle-Pottorff Unit was drilled to 3,500 ft and is in Section 31-5n-10e in Clay Consolidated Field. It produced 85 bbl of oil and 40 bbl of water per day. Production is from a perforated zone at 2,985-2,994 ft. According to IHS Markit, Clay City Consolidated Field was opened in 1937 and spans several counties in southeastern Illinois. The nearest horizontal drilling in the field is 10 miles to the southwest in the Richland County portion of the reservoir. Tri-State is based in Olney, Ill.

4 A White County, Ill., completion was announced by Carmi, Ill.-based ***Campbell Energy LLC***. The #4 Willard is in Phillipstown Consolidated Field. It was tested flowing 15 bbl of oil and 150 bbl of water per day. Production is from commingled zones in St. Louis (3,442-52 ft.), Salem Lime (3,843-4,035 ft) and Warsaw (4,066-4,116 ft). The venture is in Section 1-4s-10e.

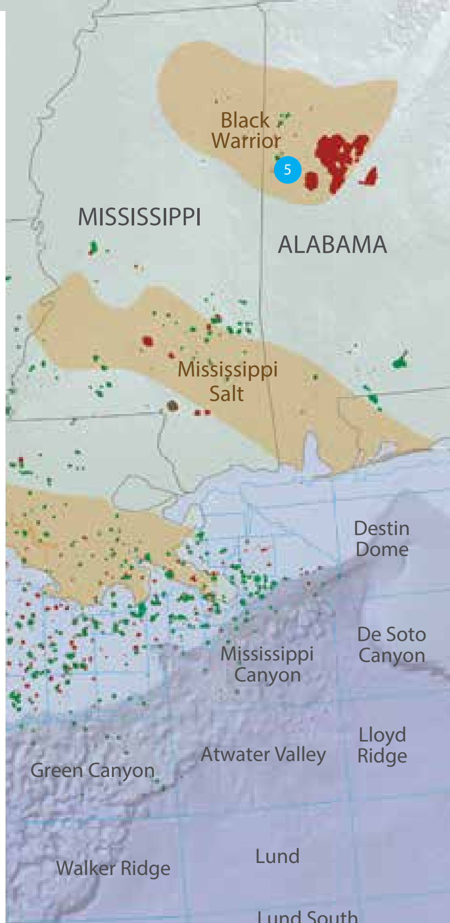
5 ***Jabsco Oil Operating LLC*** has set production casing at a Pickens County, Ala., wildcat drilled as part of the company's Black Warrior Basin program in western Alabama. The #1 Gulf States Paper Co 28-6 was re-entered to 4,041 ft with 4 1/2-in. casing set on bottom. It has been perforated in Pottsville A at 3,803-27 ft with no other details reported. The original hole was drilled in 1985 in Section 28-18s-13w, and the exploratory test was abandoned at 4,910 ft in the Tuscumbia. Nearby gas production is within 3 miles to the south-southwest of Tuscaloosa, Ala.-based Jabsco's workover at #1 Irvin 5-6. The well was tested in 2009 flowing 273 Mcf of gas daily from Lewis Sand at 5,216-32 ft.

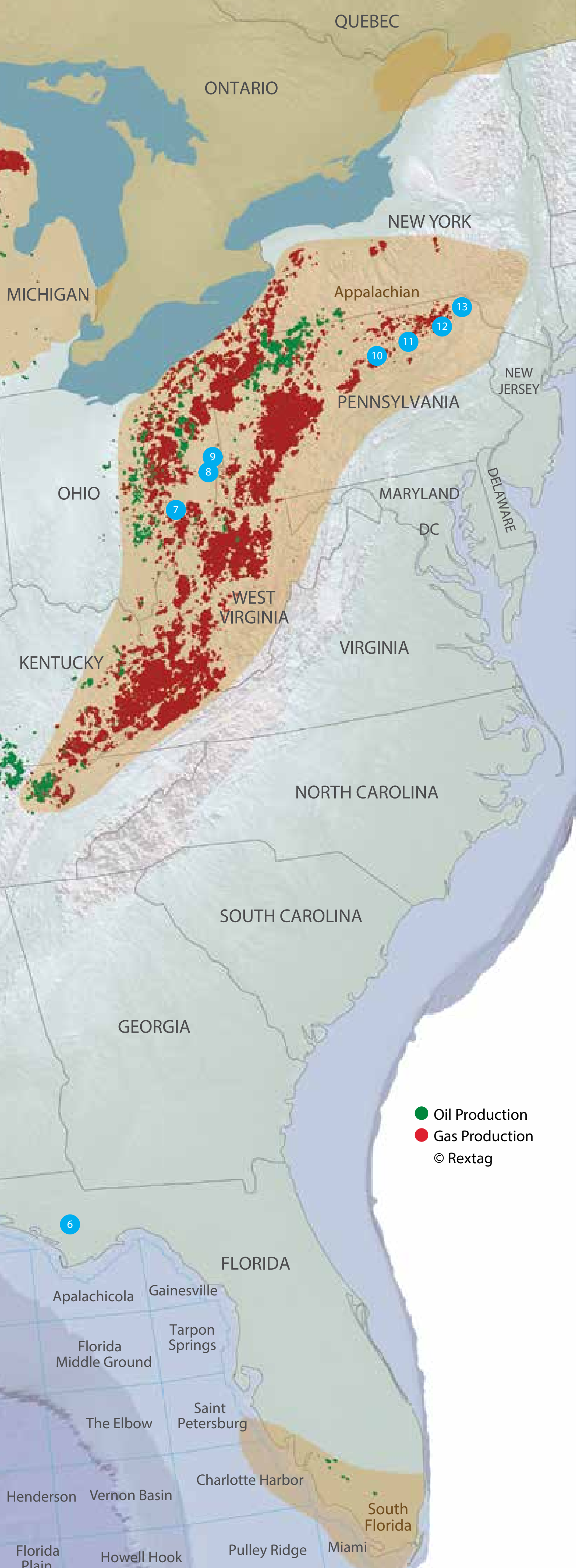
6 Six Smackover wildcats have been scheduled in a nonproducing part of the Florida Panhandle. According to IHS Markit, Dallas-based ***Cholla Petroleum***'s prospects will be in Calhoun County, and five directional tests have planned depths ranging from 14,076 ft to 14,418 ft, with true vertical depths ranging from 13,620 ft to 13,970 ft. The #25-3 NLT Royalty Partners and #26-4 NLT Royalty Partners are planned for offsetting surface locations in Section 26-2s-9w. In Section 10-3s-9w will be #10-1 NLT Royalty Partners and #10-4 NLT Royalty Partners. The fifth directional test, #4-4 NLT Royalty Partners, will be in Section 3-3s-9w. The lone vertical wildcat, #19-1 NLT Royalty Partners, will be drilled in Section 19-3s-9w, and the proposed depth is 14,300 ft. Nearby drilling occurred in 2018—Spooner Petroleum drilled #1 Hunt 7-3 in Section 7-3s-10w as a 12,228-ft exploratory test, which was abandoned in Smackover.



7 ***Antero Resources Corp.*** announced results from a Utica Shale completion in Section 30-6n-6w in Monroe County, Ohio. The #1H Harper Unit is in Creighton Consolidated Field. It produced 26.255 MMcf of gas and 714 bbl of water per day. The well was drilled to 25,470 ft, 8,967 ft true vertical, and bottomed in Section 15. It was tested after acidizing and fracturing, and it is producing from a perforated zone between 8,890 and 25,359 ft. Antero is based in Denver.

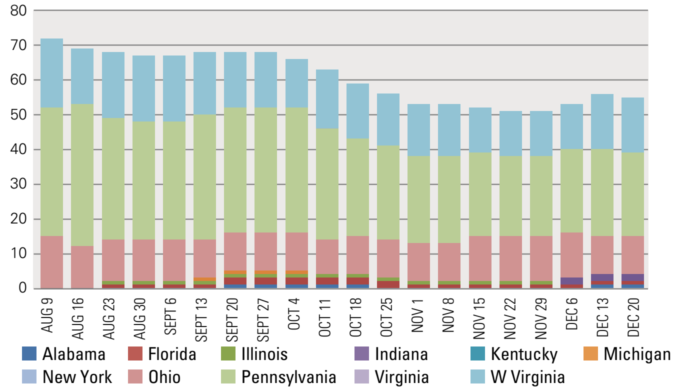
8 In Jefferson County, Ohio, ***EAP Ohio LLC*** completed a Clay Lick Field-Utica well, #205H Williamson 12-10-3. The venture was drilled to 20,819 ft, 8,787 ft true vertical, in Section 12-10n-3w, and it bottomed to the southwest. It produced 29.312 MMcf of gas and 1.076 Mbbl of water per day. Production is from a perforated and fractured zone at 9,305-20,636 ft. EAP is based in Houston.





Eastern U.S. Rig Count

Aug. 9, 2019-Dec. 20, 2019



Data compiled from Baker Hughes

9 Oklahoma City-based ***Chesapeake Operating Inc.*** announced results from two Utica Shale discoveries that were drilled from a pad in Section 6-10n-3w of Belmont County, Ohio. The #1H Old Oak Farm 6-10-3 was drilled to 21,993 ft, 8,802 ft true vertical, and flowed 30.309 MMcf of gas and 769 bbl of water per day from acidized and fractured perforations at 9,662-21,863 ft. About 20 ft to the west, #3H Old Oak Farm 6-10-3 was drilled to 21,783 ft, 8,799 ft true vertical. It produced 30.698 MMcf of gas and 665 bbl of water per day. Production is from acidized and fractured perforations at 9,452-21,653 ft.

10 ***Chief Oil & Gas LLC*** completed a Marcellus Shale well in Sullivan County, Pa. The new field discovery, #1H Hemlock Hunting Club North Unit, is in Section 6, Shunk 7.5 Quad, Elkland Township, in Sullivan County, Pa. The venture was tested flowing 23.416 MMcf of gas with a shut-in casing pressure of 2,745 psi. It was drilled to 20,453 ft with a true vertical depth of 8,303 ft, and production is from perforations at 7,865-19,890 ft. Chief's headquarters are in Dallas.

11 In Bradford County, Pa., ***Chesapeake Operating Inc.*** completed a Marcellus Shale well that produced 25.956 MMcf of gas per day with no reported water. The Herrick Field discovery, #5HC Deremer, was drilled to 17,239 ft, 7,207 ft true vertical, and was tested on an unreported choke size with a shut-in casing pressure of 3,604 psi. The completion is in Section 8 Laceyville 7.5 Quad, Tuscarora Township, and produces from perforations at 7,495-17,099 ft.

12 Two Susquehanna County, Pa., completions were announced by ***Cabot Oil & Gas***. The wells were drilled from a pad in Salladasburg Field in Section 8, Montrose East 7.5 Quad, Brooklyn Township. The #8 Williams D was tested flowing 31.526 MMcf of gas and was drilled to 16,894 ft, 7,153 ft true vertical. The #10 Williams was tested flowing 30.375 MMcf of gas and was drilled to 17,773 ft, 7,196 ft true vertical. Additional completion information was not available.

13 Two Susquehanna County, Pa., Marcellus Shale completions were reported by ***Southwestern Energy*** in Section 7 Susquehanna 7.5 Quad, Jackson Township, in Page Lake Field. The #1H Dropp was tested flowing 29.598 MMcf of gas per day with no reported water. It was drilled to 21,511 ft with a true vertical depth of 6,534 ft and was tested on an unreported choke size with a shut-in casing pressure of 2,140 psi. Production is from fractured perforations at 7,410-21,441 ft. Within one-half mile to the northeast, #3H Gremmel produced 20.596 MMcf of gas and no water from a fractured zone at 7,282-21,319 ft with a shut-in casing pressure of 1,706 psi. It was drilled to 21,392 ft, 6,948 ft true vertical. Southwestern's headquarters are in Spring, Texas.

GULF COAST

1 A Hawkville Field-Austin Chalk discovery by ***EOG Resources Inc.*** was reported in Webb County, (RRC Dist. 4), Texas. The #4H G-B Minerals was tested flowing 11.47 MMcf of gas and 80 bbl of water per day and is in Section 2034, TC RR CO Survey, A-2091. It was drilled to 18,833 ft with a true vertical depth of 12,843 ft. Gauged on a 20/64-in. choke, the flowing tubing pressure was 5,480 psi, and the shut-in tubing pressure was 7,800 psi. Production is from fractured perforations between 12,898 and 18,821 ft. EOG's headquarters are in Houston.

2 In McMullen County (RRC Dist. 1), Texas, ***Silverbow Resources*** announced results from an Eagle Ford completion in Hawkeye Field. The #31H Bracken EF C is in Section 4, Brooks & Burleson Survey, A-652. It was drilled to 20,584 ft, 13,111 ft true vertical. It was tested flowing 5.965 MMcf of gas and 1.464 Mbbl of water per day from perforations at 13,376-20,437 ft. The venture was drilled to 20,584 ft with a true vertical depth of 13,113 ft. Gauged on a 19/64-in. choke, the flowing tubing pressure was 6,222 psi. Silverbow's headquarters are in Houston.

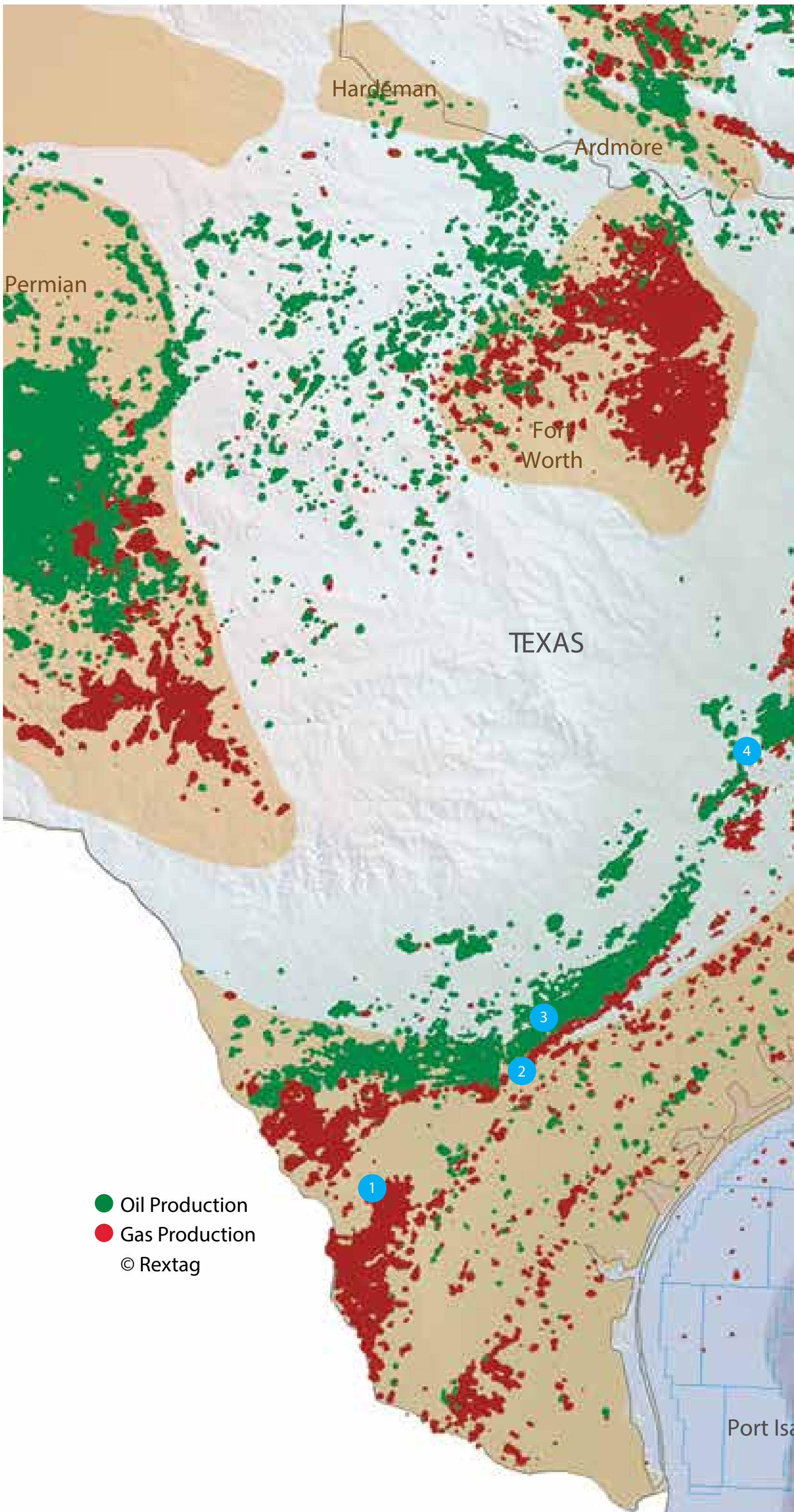
3 Four Eagle Ford Shale-Eagleville Field wells were completed in Live Oak County (RRC Dist. 2), Texas, by ***Marathon Oil Corp.*** The discoveries were drilled from a drillpad in Section 5, John Houlighan Survey, A-17. The #1H 74 Ranch-Guajillo Unit A was drilled to 18,237 ft, 10,954 ft true vertical, and bottomed in A.H. Lasater Survey, A-1340. It was tested on a 26/64-in. choke and flowing 2.858 Mbbl of oil, 1.518 MMcf of gas and 1.698 Mbbl of water per day from perforations at 11,306-18,113 ft. The #3H 74 Ranch-Guajillo Unit A was drilled to 18,174 ft, 10,965 ft true vertical, and bottomed in A.H. Lasater Survey, A-1340. It was tested on a 64/64-in. choke and produced 3.123 Mbbl of oil, 1.812 MMcf of gas and 2.152 Mbbl of water per day from perforations at 11,232-18,142 ft with a flowing tubing pressure of 2,842 psi. The #4H 74 Ranch-Guajillo Unit A was drilled to 18,240 ft, 10,992 ft true vertical, and bottomed in Berry Campbell Survey, A-64. Tested on a 30/64-in. choke, it flowed 2.018 Mbbl of oil, 1.741 MMcf of gas and 2.32 Mbbl of water per day with a flowing tubing pressure of 1,999 psi. Production is from perforations at 11,203-18,105 ft.

4 ***Treadstone Energy*** announced results from two Austin Chalk completions in Milam County (RRC Dist. 1), Texas. The Giddings Field wells were drilled from a pad in Fernando Rodriguez Survey, A-53. The #1HA Jamie was drilled to 13,876 ft, 6,181 ft true vertical. It flowed 669 bbl of oil, 374 Mcf of gas and 3.752 Mbbl of water per day from perforations at 6,362-13,700 ft. The offsetting #1HA Kristin was drilled to 13,796 ft, 6,128 ft true vertical, and it produced 869 bbl of oil, 374 Mcf of gas and 3.752 Mbbl of water per day. Production is from perforations at 6,601-13,600 ft. Treadstone's headquarters are in Houston.

5 Two Cotton Valley-Gilmer Field discoveries were announced by Houston-based ***Sabine Oil & Gas*** in Upshur County (RRC Dist. 6), Texas. The wells were drilled from offsetting surface locations in Section 231, Maria Antonio Esparcia Survey, A-149. The #1H Hill LC-Landers was tested flowing 10.869 MMcf of gas, 84 bbl of condensate and 1.075 Mbbl of water per day from an acid- and fracture-treated zone at 11,231-19,147 ft. It was tested on a 38/64-in. choke, and the flowing casing pressure 2,084 psi. It was drilled to 19,200 ft (11,015 ft true vertical) and bottomed about 1.5 miles to the southeast in Section 260, Williams Carlton Survey, A-71. The #1H Hill LC-Gilmer flowed from a fracture-stimulated zone at 11,212-19,353 ft and produced 10.465 MMcf of gas, 69 bbl of condensate and 1.299 Mbbl of water daily. Gauged on a 36/64-in. choke, the flowing casing pressure was 2,385 psi. It was drilled to 19,408 ft (11,026 ft true vertical). It bottomed in Section 231, Maria Antonio Esparcia Survey, A-149.

6 Three Haynesville Shale wells were completed by Houston-based ***Rockcliff Energy Operating*** in Harrison County (RRC Dist. 6), Texas, in Carthage Field. The wells were drilled in William Tiller Survey, A-706, and bottomed approximately 2 miles to the north in James Shandoin Survey, A-622. The #1H Abney flowed 22.978 MMcf of gas and 1.117 Mbbl of water from acid- and fracture-treated perforations at 11,454-20,501 ft. The flowing casing pressure was 6,872 psi when tested on a 28/64-in. choke. The well was drilled to 20,732 ft (10,976 ft true vertical). The offsetting #2H Abney produced from a Haynesville zone at 11,247-20,067 ft, and it produced 18.177 MMcf of gas and 1.829 Mbbl of water per day. The total depth is 20,377 ft, and the true vertical depth is 10,883 ft. The #3H Abney flowed 23.126 MMcf of gas and 1.609 Mbbl of water per day from perforations at 11,365-20,309 ft and was drilled to 20,498 ft (11,006 ft true vertical).

7 A shallow-water test on Ship Shoal Block 136 has been permitted by ***Castex Energy***. The #1 OCS G36513 will be in the southwestern portion the tract. Water depth in the area is 55 ft. According to the exploration plan, a second test could be drilled from an offsetting surface location. Under an earlier lease (OCS G03790), Ship Shoal Block 136 was part of Ship



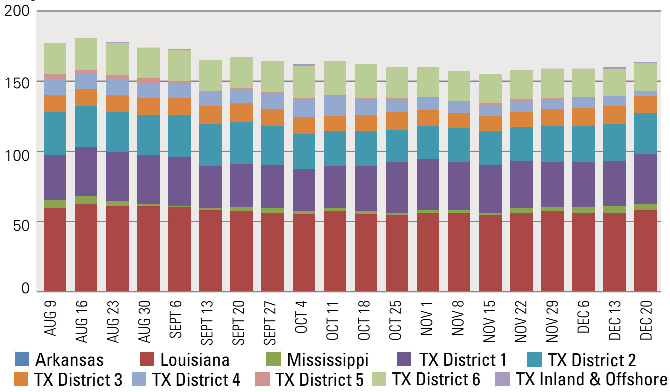
Shoal Block 113 Field. ***Murphy Oil & Gas*** previously operated three gas wells on Block 136 that produced from Pleistocene at 2,836-4,756 ft. Castex is based in Houston.

8 ***Australis Oil & Gas*** has tested two Tuscaloosa Marine Shale wells from a pad in Amite County, Miss. According to IHS Markit, #3H Quin 41-30 was tested flowing 592 bbl of 40-degree-gravity crude, 156 Mcf of gas and 598 bbl of water per day from perforations at 12,552-15,039 ft. Gauged on a 14/64-in. choke, the flowing tubing pressure was 1,264 psi, and the flowing casing pressure was 1,098 psi. The well was drilled to 15,531 ft (11,975 ft true vertical). The offsetting #2H Saxby 3-10 flowed 445 bbl of 39-degree-gravity crude, 176 Mcf of gas and 551 bbl of water from perforations at 12,550-17,379 ft. During testing on a 16/64-in. choke, the flowing tubing pressure was 1,098 psi, and the flowing casing pressure was 1,023 psi. The well was drilled to 17,562 ft (12,137 ft true vertical). Australis Oil & Gas is based in Perth.

9 ***LLOX LLC*** has tested a gas well in St. Charles Parish's Bayou Couba Field in a South Louisiana reservoir. According to IHS Markit, #003 EMC Fee produced 1.911 MMcf of gas and 52 bbl of condensate through perforations in Cibicides opima (Miocene) at 11,410-62 ft. It was tested on a 16/64-in. choke with a flowing tubing pressure of 3,096 psi. The directional well was drilled to the southeast to 11,650 ft (11,313 ft true vertical) and is in Section 2-15s-21e. LLOX is based in Houston.

Gulf Coast Rig Count

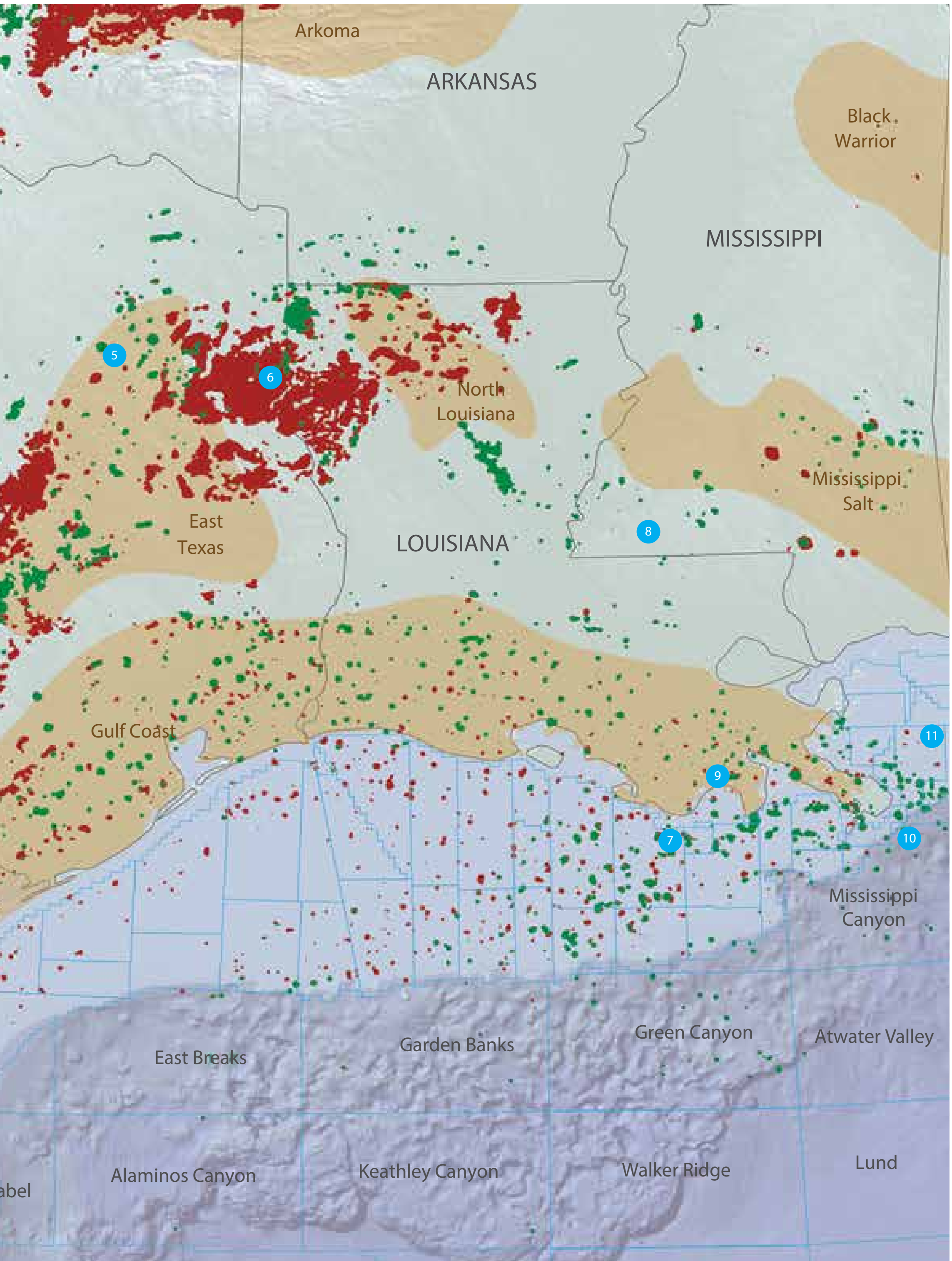
Aug. 9, 2019-Dec. 20, 2019



Data compiled from Baker Hughes

10 Houston-based ***Chevron Corp.*** has received a permit for an exploratory test on Mississippi Canyon Block 700. The Clingmans Dome prospect test, #1 OCS G33753, will be drilled in the northeastern portion of the block, and area water depth is 7,400 ft. According to the prospect's exploration plan, up to 11 tests could be drilled from various surface locations on Block 700.

11 ***BP Plc***'s first exploratory test on the company's three-block Johanna prospect is underway. The #1 OCS G36281 is in the southeastern portion of DeSoto Canyon Block 357. Water depth in the area is 7,800 ft. According to the London-based company's prospect exploration plan, as many as eight tests could be drilled on DeSoto Canyon Block 357, Block 358 (OCS G36282) and Block 401 (OCS G36284).



MIDCONTINENT & PERMIAN BASIN

1 A Culberson County (RRC Dist. 8), Texas, Wolfcamp discovery was tested flowing 1.1 Mbbl of condensate, 4.708 MMcf of gas and 3.44 Mbbl of water per day. ***Cimarex Energy Co.***'s #9H Owl Draw 12 Unit D is in Ford West Field. It is in T&P RR CO Survey, A-6999, and was drilled to 19,131 ft with a true vertical depth of 8,914 ft. Tested on a 40/64-in. choke, the flowing tubing pressure was 560 psi, and production is from perforations between 8,990 and 19,062 ft. Cimarex is based in Denver.

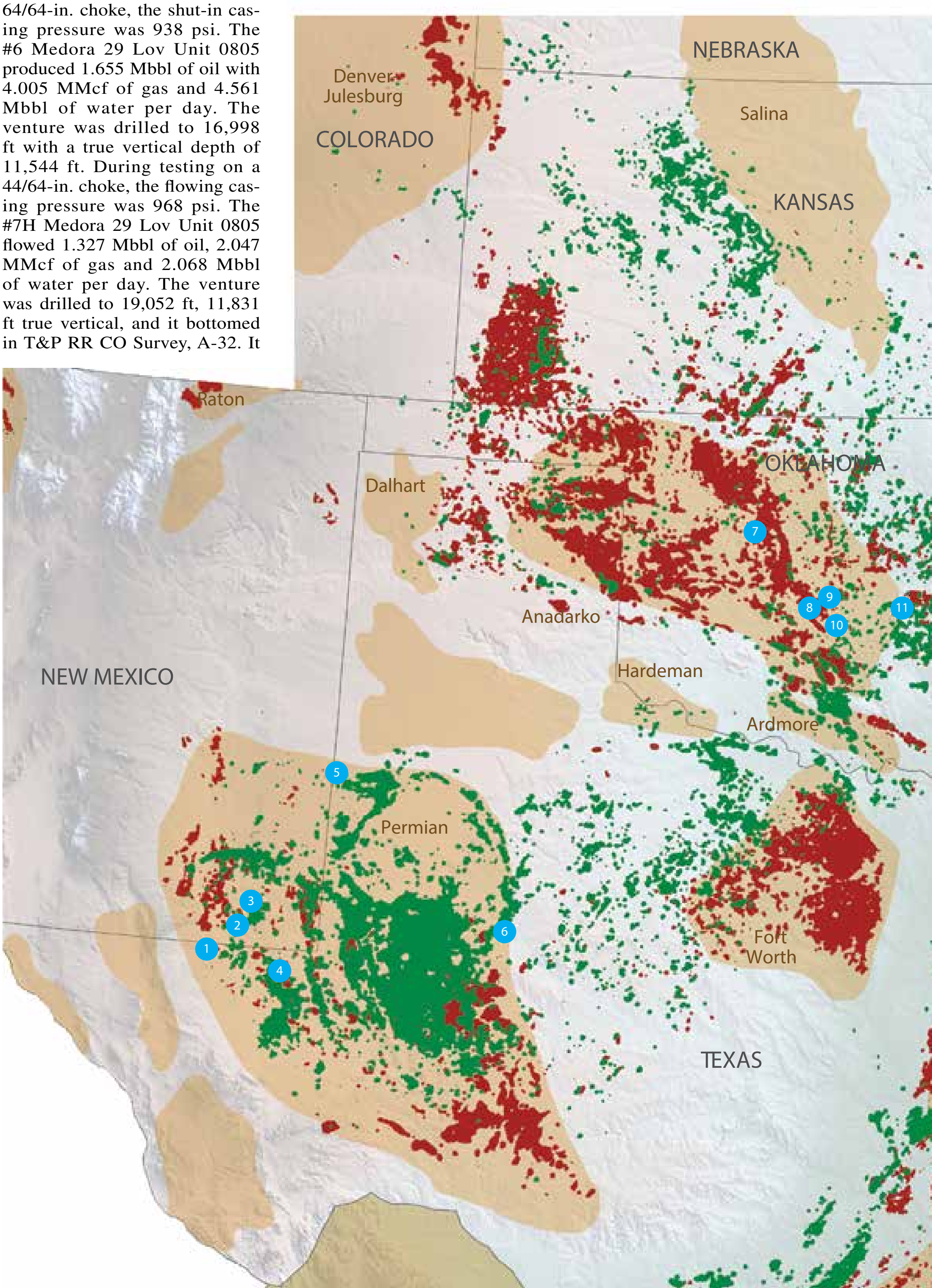
2 Houston-based ***EOG Resources Inc.*** announced results from an Eddy County, N.M., Bone Spring discovery. The #581H Quail 2 State Com is in Section 2-26s-30e, and it produced 2.584 Mbbl of oil, 7.82 MMcf of gas and 5.916 Mbbl of water per day after fracturing. It was tested on a 90/64-in. choke with a flowing casing pressure of 1,023 psi. It was drilled to the north to 15,185 ft, 10,215 ft true vertical. Production is from perforations at 10,360-15,185 ft.

3 In Lea County, N.M., ***Devon Energy Corp.*** completed a Bone Spring well, #215H Alley Cat 17-20 Fed Com, that produced 8.779 Mbbl of oil, with 10.959 MMcf of gas and 8.75 Mbbl of water per day. The Salt Lake Field well is in Section 8-23s-32e and was drilled to 21,436 ft, 10,516 ft true vertical, and it bottomed in Section 20. Devon's headquarters are in Oklahoma City.

4 In Loving County, (RRC Dist. 8), Texas, Houston-based ***Shell Oil Co.*** announced results from three Wolfcamp wells completed at a pad in Phantom Field. The pad is in T&P RR CO Survey, A-38. The #5H Medora 29 Lov Unit 0805 was drilled to the north to 16,920 ft with a true vertical depth of 11,782 ft. It produced 2.105 Mbbl of oil, 3.058 MMcf of gas and 3.255 Mbbl of water per day from perforations at 12,001-16,577 ft. Tested on a 64/64-in. choke, the shut-in casing pressure was 938 psi. The #6 Medora 29 Lov Unit 0805 produced 1.655 Mbbl of oil with 4.005 MMcf of gas and 4.561 Mbbl of water per day. The venture was drilled to 16,998 ft with a true vertical depth of 11,544 ft. During testing on a 44/64-in. choke, the flowing casing pressure was 968 psi. The #7H Medora 29 Lov Unit 0805 flowed 1.327 Mbbl of oil, 2.047 MMcf of gas and 2.068 Mbbl of water per day. The venture was drilled to 19,052 ft, 11,831 ft true vertical, and it bottomed in T&P RR CO Survey, A-32. It was tested on a 44/64-in. choke, and the flowing casing pressure was 812 psi.

5 A Marmaton completion was announced by Austin, Texas-based ***Jones Energy LLC***. The #1HX Elizabeth 746 is in Section 746, Block 43, H&TC Survey, A-617, in Ochiltree County (RRC Dist. 10), Texas. The venture produced 1.152 Mbbl of 41-degree-gravity oil, 1.74 MMcf of gas and 836 Mbbl of water per day when tested an open choke with 380-psi flowing tubing pressure. Production at the western Anadarko Basin venture is from a fracture-stimulated openhole interval at 7,413-10,715 ft. The Allen-Parker Field well was drilled to the north to a true vertical depth of 6,959 ft. It bottomed in Section 751, A-247.

6 ***CrownQuest Operating LLC***, according to IHS Markit, has completed two extended-lateral Wolfcamp producers in the Midland Basin portion of Howard County (RRC Dist. 8), Texas. The #1HD Jacuzzi produced 1.043 Mbbl of crude, 1.05 MMcf of gas and 1.265 Mbbl of water per day from acid- and fracture-treated perforations at 9,529-19,787 ft. The Spraberry Trend well was drilled to 20,030

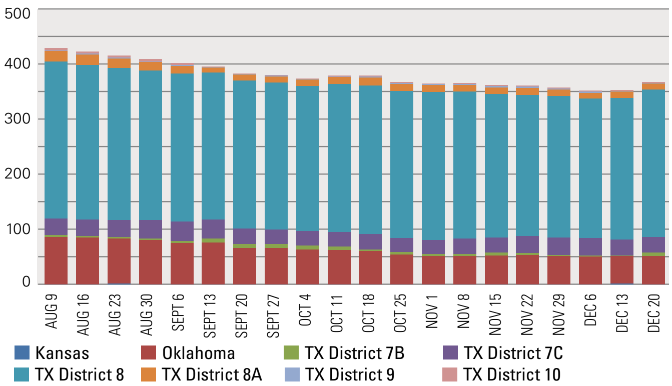


ft, 9,264 ft true vertical, and is in Section 42, Block 32 T1S, T&P RR Co Survey, A-709. It bottomed in Section 31, Block 32 T1S, T&P Survey, A-167. The flowing tubing pressure was 250 psi when tested on a 48/64-in. choke. The 2-mile lateral bottomed to the northwest. The offsetting #1HD Sink flowed 718 bbl of oil, 658 Mcf of gas and 1.132 Mbbl of water daily from acidized and fracture-stimulated perforations at 9,383-18,960 ft. It was tested on a 48/64-in. choke, and the flowing tubing pressure was 195 psi. The horizontal sidetrack was drilled to 19,120 ft (9,193 ft true vertical) and bottomed 2 miles to the southeast in Section 1, Block 32 T2S, T&P Survey, A-299. CrownQuest is based in Midland, Texas.

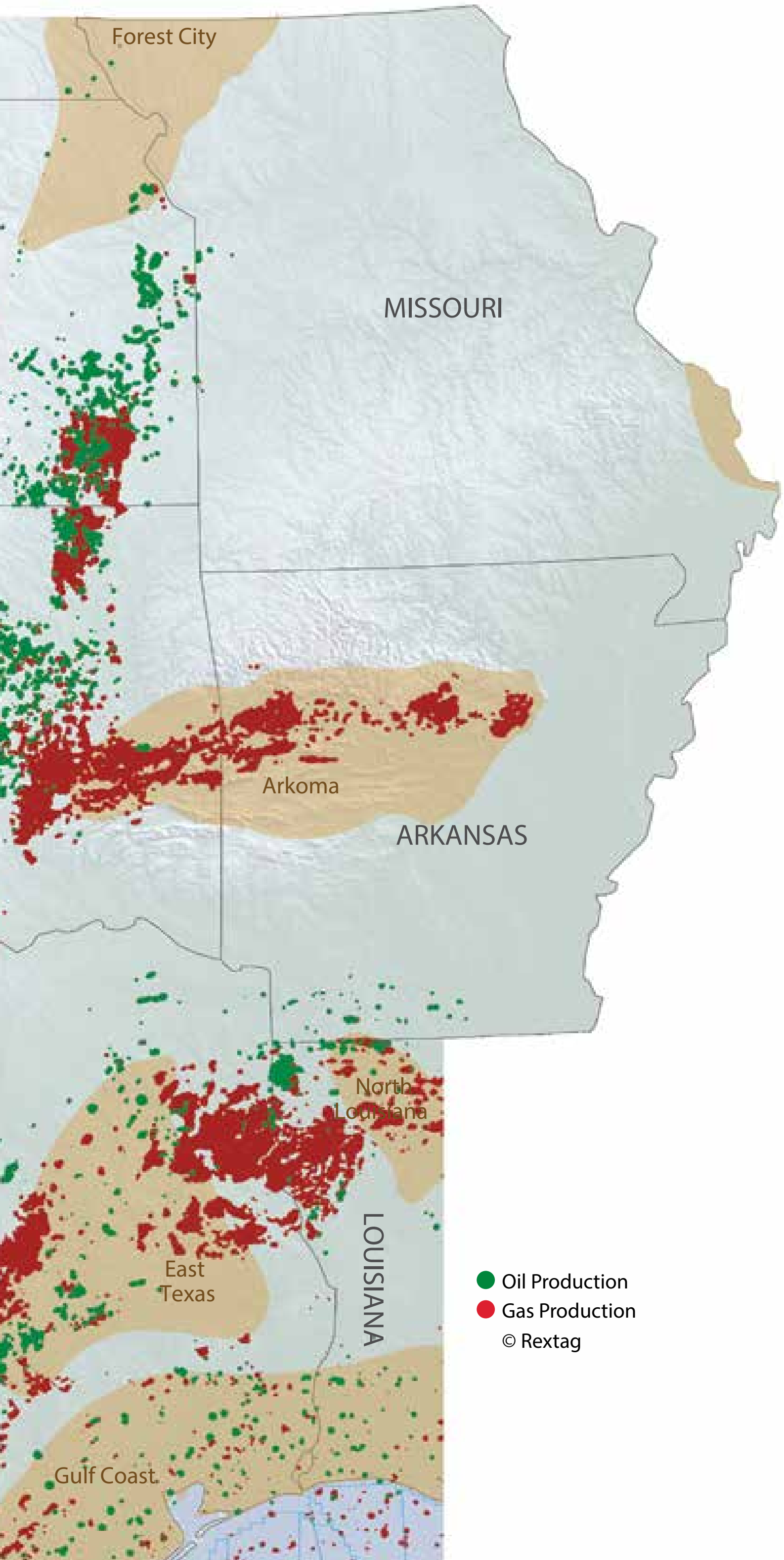
7 Two single-section horizontal Meramec wells were reported by Oklahoma City-based ***Continental Resources Inc***. The completions are in Section 13-15n-11w in Blaine County, Okla. The #3-13HM Reba Jo was tested on a 36/64-in. choke flowing 2.489 Mbbl of 48-degree-gravity oil, 7.22 MMcf of gas and 1.905 Mbbl of water daily after acidizing and fracturing at 11,285-16,183 ft. The 16,352-ft Watonga-Chickasha Trend prospect was drilled north across the section to a true vertical depth of 10,940 ft. According to IHS Markit, its oil initial production rate is the third highest reported among single-section Mississippian wells in the Anadarko Basin-Stack play. Within one-half mile to the west, #1-13H Reba Jo produced 2.095 Mbbl of oil with 5.68 MMcf of gas and 1.425 Mbbl of water per day. It was drilled to 15,960 ft, 11,564 ft true vertical, and was perforated and treated in a parallel lateral between 11,240 and 15,960 ft. It was tested on a 34/64-in. choke, and the flowing tubing pressure was 2,202 psi. The shut-in tubing pressure was 4,175 psi.

Midcontinent & Permian Basin Rig Count

Aug. 9, 2019-Dec. 20, 2019



Data compiled from Baker Hughes



8 ***Marathon Oil Corp.*** completed a Golden Trend Field-Springer Shale well in Garvin County, Okla. The Houston-based company's #2-18SH Newby 0304 was drilled in Section 18-3n-4w to 17,938 ft with a true vertical depth of 13,495 ft. The discovery produced 1.986 Mbbl of oil, 2.263 MMcf of gas and 1.14 Mbbl of water daily. It was tested on a 30/64-in. choke, and production is from a fractured zone at 13,687-17,978 ft.

9 In Garvin County, Okla., ***Marathon Oil Corp.*** completed two Springer Shale wells. The #2-7-6SXH BP 03 Starfox 0304 is in Section 6-3n-4w and flowed 2.111 Mbbl of oil, 1.54 MMcf of gas and 2.043 Mbbl of water per day. It was tested on a 50/64-in. choke, and production is from treated perforations between 13,325 and 22,896 ft. It was drilled to the south to 23,070 ft and bottomed in Section 7-3n-4w; however, little additional information was available. Almost 2 miles to the southeast, #1-5-32SXH Yoshi 0304 in Section 5-3n-4w flowed 1.547 Mbbl of oil with 1.28 MMcf of gas and 1.164 Mbbl of water per day during testing on a 96/64-in. choke. Production is from perforations at 12,287-20,208 ft after acidizing and fracturing. This 20,358-ft well was drilled to the north and bottomed in Section 32-4n-4w.

10 A horizontal Sycamore producer in Sho-Vel-Tum Field was reported by Tulsa, Okla.-based ***Casillas Operating LLC***. The #1-8-5MXH Flash is in Section 17-1s-3w of Carter County, Okla. It flowed 1.708 Mbbl of oil, 1.62 MMcf of gas and 2.201 Mbbl of water from an unreported interval with 470-psi flowing tubing pressure. Additional information has been released for the 18,890-ft prospect, which was projected northward 2 miles and bottomed in Section 5-1s-3w. Casillas' well is the first extended-reach Sycamore well in the Ardmore Basin township.

11 ***Newfield Exploration Co.***, based in Houston, announced completion details for a horizontal Woodford producer in Ashland Field. The #0311 5H-33 Brown is in Section 28-3n-11e in Coal County, Okla. The Woodford producer was perforated, acidized and fractured at 8,918-13,786 ft. It was tested flowing 7.21 MMcf of gas and 441 bbl of water per day. Gauged on a 52/64-in. choke, the flowing tubing pressure was 619 psi. The measured and true vertical depths are 13,900 ft and 8,695 ft, respectively, and it bottomed about 1 mile to the south in Section 33-3n-11e.

WESTERN U.S.

1 IHS Markit reported that Dallas-based ***Merit Energy Co.*** has completed the first of four modern horizontal tests in the Big Horn Basin in Wyoming's oldest oil field, Grass Creek Field, as Curtis oil producers. The wells are in Hot Springs County. The #3H Curtis is in Section 21-46n-98w, and it initially flowed 110 bbl of oil and 1.496 Mbbl of water per day. Production is from a lateral in Curtis drilled to the southwest to 8,019 ft (3,493 ft true vertical) and bottomed in Section 29-46n-98w. It was tested after 18-stage fracturing between 4,547 and 7,966 ft. The #2H Curtis, Section 19-46n-98w, produced an average of 149 bbl of oil, 38.1 Mcf of gas and 2.315 Mbbl of water per day. It was drilled northeastward to 7,797 ft (4,030 ft true vertical) and bottomed in Section 20-46n-98w. Completion details are not yet available. The #4H Curtis is in Section 29-46n-98w, and it initially flowed 253 bbl of oil and 1.109 Mbbl of water per day. Production is from a lateral in Curtis drilled to the southeast to 6,814 ft (3,485 ft true vertical). It was tested after 12-stage fracturing between 3,975 and 6,578 ft. The #1H Curtis is also in Section 29-46n-98w and initially pumped 169 bbl of oil and 691 bbl of water daily from a Curtis lateral drilled to the northeast to 6,090 ft (3,766 ft true vertical) and bottomed in the same section. It was tested after seven-stage fracturing between 3,875 and 6,090 ft.

2 Austin, Texas-based ***ATX Energy Partners LLC*** has reported the completion of a horizontal Mowry discovery in Johnson County, Wyo. The western Powder River Basin test, #16-2MH Tatanka, is in Section 16-46n-80w. It initially flowed 162 bbl of 43.8-degree-gravity oil, 163 Mcf of gas and 317 bbl of water per day. Production is from a lateral in Mowry extending from 11,253 ft that was drilled to the northwest to 17,690 ft (13,649 ft true vertical). It was tested on a 16/64-in. choke following 18-stage fracturing between 13,320 and 17,597 ft.

3 Oklahoma City-based ***SandRidge Exploration & Production*** has completed an extended-reach horizontal Niobrara discovery in the North Park Basin. The Jackson County, Colo., well, #1-23H2 Rabbit Ears Unit 0681, is in Section 23-6n-81w, and it flowed an average of about 225 bbl of oil, 147.838 Mcf of gas and 1.436 Mbbl of water daily in its first full month of reported production (January 2018). No additional completion details have been disclosed. It was drilled to the south to a proposed total depth of 21,876 ft and bottomed in Section 2-5n-81w. The true vertical depth was anticipated at 5,585 ft.

4 A Johnson County, Wyo., Niobrara discovery in the Powder River Basin was announced by Houston-based ***Navigation Powder River LLC***. The #30-43-77-7H Cole-Federal was drilled in Section 30-43n-77w. It produced a daily average of 749 bbl of oil in March, 588 bbl of oil in June and 225 bbl of oil in September 2019. The well was drilled southward to 21,356 ft and bottomed in Section 31-43n-77w. The planned true vertical depth was 11,381 ft, and no completion details have been disclosed. The exploration plan called for 60-stage fracturing between 11,860 and 21,286 ft.

5 Tulsa, Okla.-based ***Samson Resources*** completed a horizontal Frontier producer that produced 1.386 Mbbl of oil, 7.447 MMcf of gas and 872 bbl of water per day. The #3974-1720 2FH Bohlander Fed was drilled in Section 17-39n-74w in Converse County, Wyo. Production is from a lateral drilled to the south to 22,125 ft, 12,428 ft true vertical, and it bottomed in Section 20-39n-74w. It was tested on a 26/64-in. choke after 39-stage fracturing between 12,419 and 21,891 ft.

6 In Converse County, Wyo., ***Devon Energy Corp.*** completed two Turner Sand wells in Calamity Field. The #07-063971-CXTUH is in Section 18-39n-71w and was drilled to 21,735 ft, 10,561 true vertical, and bottomed in Section 19. It was tested on a 28/64-in. choke flowing 1.179 Mbbl of oil, 1.413 MMcf of gas and 1.906 Mbbl of water per day. Production is from a perforated zone at 11,374-21,546 ft. In nearby Section 12-39n-72w, #12-013972-CXTLH was drilled to 20,523 ft, 11,115 ft true vertical. It produced 2.07 Mbbl of oil, 2.724 MMcf of gas and 656 bbl of water per day from perforations at 11,270-20,701 ft.

7 A Codell wildcat in Laramie County, Wyo., initially produced 1.012 Mbbl of oil, with 373 Mcf of gas and 1.306 Mbbl of water daily. Denver-based ***North Silo Resources LLC***'s #17-64-E25-36-3CH Singletree Land is in Section 25-17n-64w. Production is from a lateral extending south-southeastward 18,130 ft (7,888 ft true vertical) with a bottom-hole location in Section 36-17n-64w. The Denver-Julesburg Basin venture was tested on a 38/64-in. choke following 62-stage fracturing between 8,354 and 17,983 ft.

8 ***Oasis Petroleum*** announced results from a Bakken discovery in Williams County, N.D. The #5501 43-7 5B Erickson O M is in Section 7-155n-101w. It initially flowed 1.377 Mbbl of oil, 970 Mcf of gas and 2.153 Mbbl of water per day. The Missouri Bridge venture was drilled to 21,245 ft with a true vertical depth of 10,823 ft. Gauged on a 24/64-in. choke, the flowing casing pressure was 704 psi, and production is from perforations between 11,136 and 21,181 ft. Oasis is based in Houston.

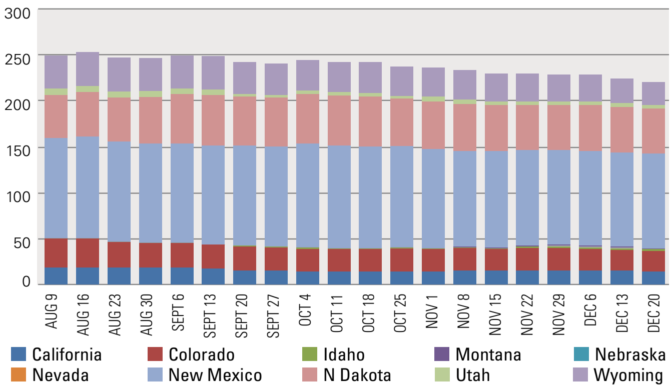
9 Two Chimney Buttes Field-Three Forks wells were completed at a pad in Section 23-146n-95w, Dunn County, N.D., by ***Marathon Oil Corp***. The #44-23TFH Ruth flowed 5.361 Mbbl of oil, 3.644 MMcf of gas and 5.438 Mbbl of water daily. It was drilled to the north to 21,350 ft, 10,492 ft true vertical, and bottomed in Section 14. It was tested on a 1-in. choke after 45-stage fracturing between 11,270 and 21,213 ft, and the flowing casing pressure was 1,400 psi. The #31-26TFH Higgins produced 4.485 Mbbl of oil, 3.076 MMcf of gas and 6.112 Mbbl of water per day. It was drilled to the southwest to 21,633 ft, 10,851 ft true vertical, and bottomed in Section 35. It was tested after 45-stage fracturing on a 1-in. choke, and the flowing casing pressure was 900 psi.

10 ***Marathon Oil Corp.***, based in Houston, announced results from three Kildeer Field completions that were drilled from a pad in Section 1-145n-95w in Dunn County, N.D. The #14-31TFH Mason was drilled to the south to 21,784 ft, 10,838 ft true vertical. It flowed 4.253 Mbbl of oil, 2.356 MMcf of gas and 8.419 Mbbl of water per day from Upper Three Forks and was tested on a 64/64-in. choke with a flowing casing pressure of 1,473 psi. Production is from perforations at 11,362-21,315 ft. The #14-31H BP01 Hayes produced 6.22 Mbbl of oil, 4.69 MMcf of gas and 8.709 Mbbl of water per day from Middle Bakken perforations at 11,955-21,094 ft. It was tested on a 64/64-in. choke, and the flowing casing pressure was 1,575 psi. The #44-36TFH Gwen initially flowed 2.795 Mbbl of oil, 1.44 Mcf of gas and 4.466 Mbbl of water per day from Upper Three Forks perforations at 11,283-21,235 ft. Gauged on a 64/64-in. choke, the flowing casing pressure was 900 psi.

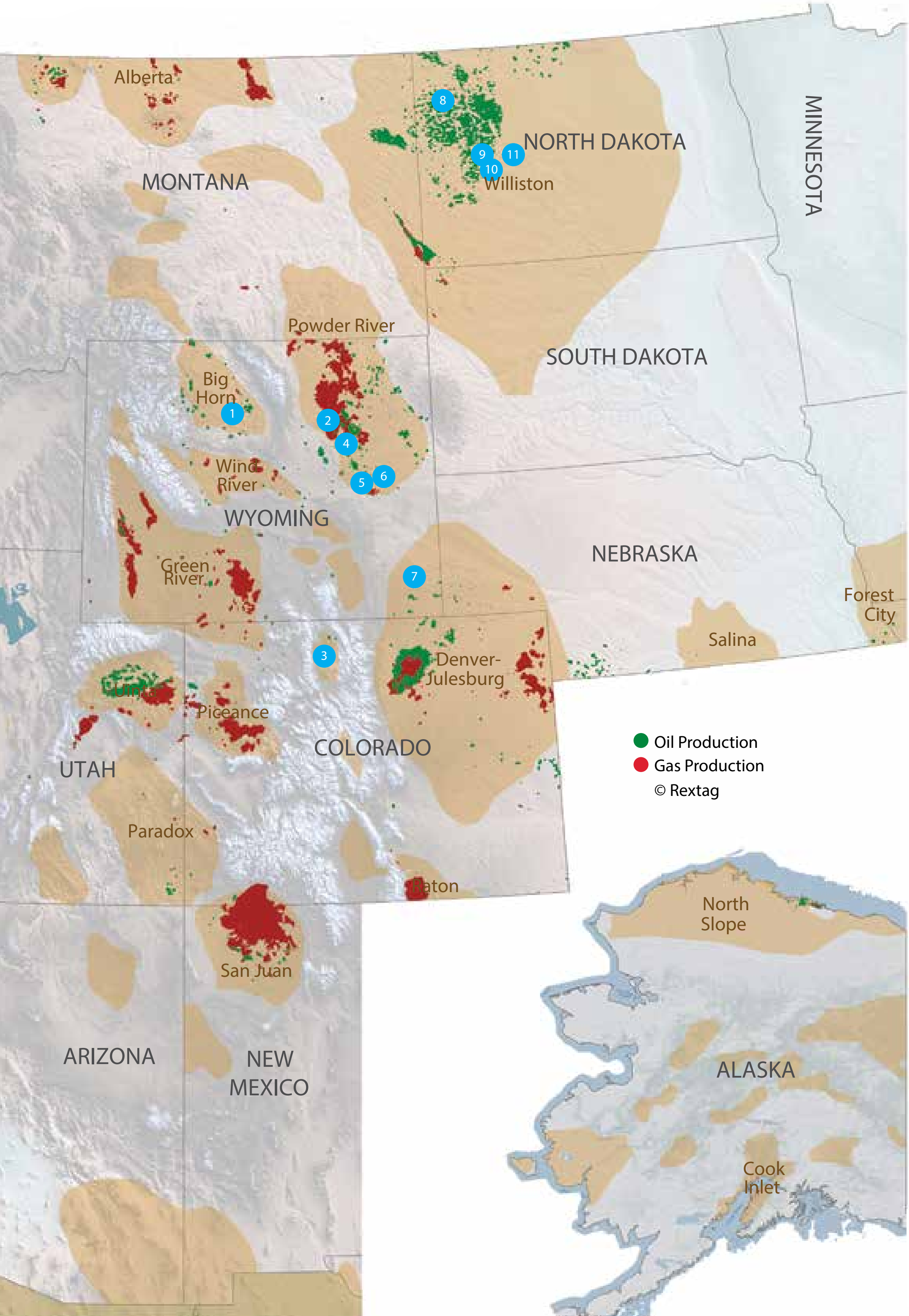
11 ***WPX Exploration & Production*** announced results from a Wolf Bay Field-Upper Three Forks discovery in Dunn County, N.D. The #28-33HY Howling Wolf flowed 2.429 Mbbl of oil, 1.134 MMcf of gas and 2.113 Mbbl of water per day. The well is in Section 21-147n-92w. It was drilled to 20,834 ft with a true vertical depth of 10,432 ft. It bottomed in Section 33. Tested on a 28/64-in. choke, the flowing casing pressure was 2,150 psi. Production is from perforations at 11,021-20,703 ft. WPX is based on Tulsa, Okla.

Western U.S. Rig Count

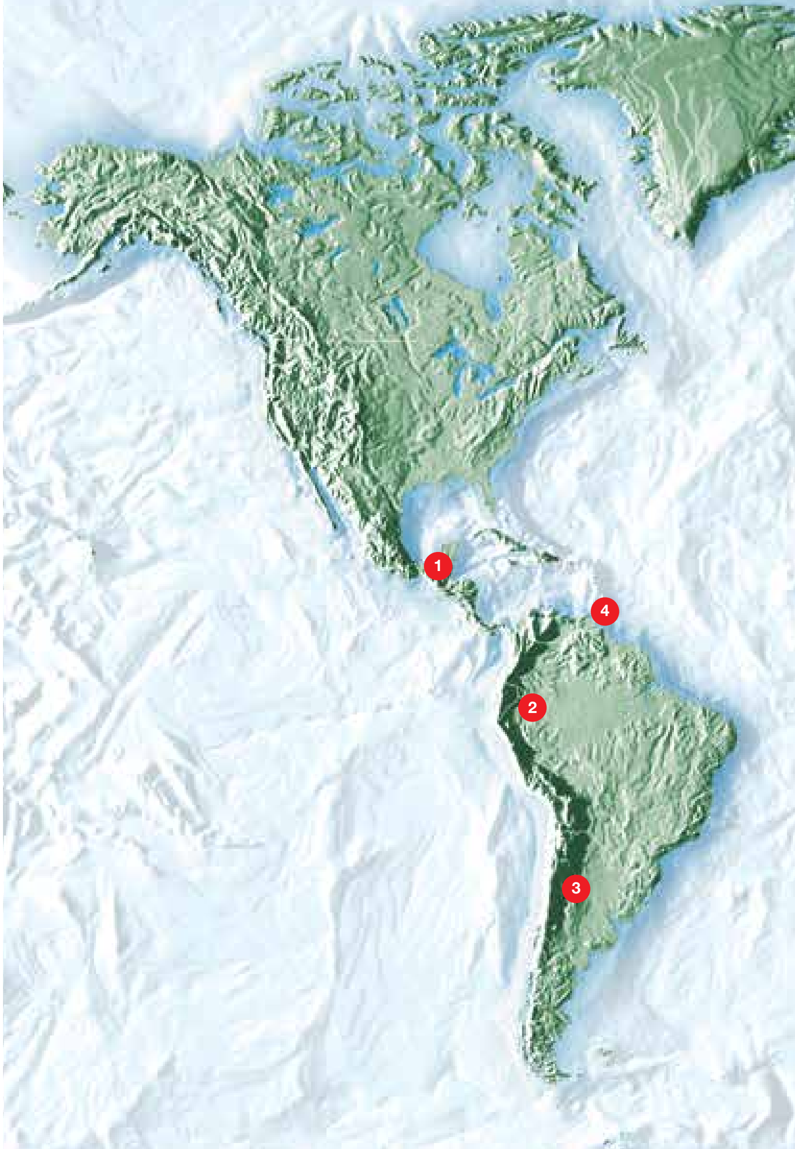
Aug. 9, 2019-Dec. 20, 2019



Data compiled from Baker Hughes



INTERNATIONAL HIGHLIGHTS



Currently, there are protests against India's amended Citizenship Act, which gives the eligibility for citizenship to illegal migrants from Afghanistan, Bangladesh and Pakistan who are Hindus, Sikhs, Buddhists, Jains, Parsis and Christians, and have entered India on or before December 2014. The act is being widely opposed in India's northeastern states, particularly Assam and Bengal, for its exclusion of Muslims. There are approximately 200 million Muslims living in India.

Protests are disrupting the operations of India's state oil companies Oil India Ltd. (OIL), Oil and Natural Gas Corp. (ONGC) and Indian Oil Corp. (IOC). The companies have been appealing to the protestors to allow them to carry out their daily operations.

Besides the loss crude oil and natural gas production, the stoppage of operations has badly hit the production of LPG and the crude oil supply to refineries and consumers.

OIL's oil production has dropped 15% to 20% due to the protests, and ONGC has reported an approximate 25% in lost production and gas supply. IOC has been forced to shut down its Digboi refinery in Assam and is operating its Guwahati unit at minimal throughput.

Drilling has stopped, and oil collection stations have been shut down by protestors with gas production down almost 90%. Assam refineries have been unable to produce more due to the stoppage of delivery tankers.

—Larry Prado

1 *Mexico*

According to Mexico City-based ***Pemex***, the company discovered a new oil field, Quesqui, in the state of Tabasco. The reserves are currently estimated at up to 700 MMboe. The first test well in license area AE-0053-3M-Mezcalapa-03 was completed in mid-2019, and it produced approximately 4.5 Mbbl of oil per day. The company has been conducting a range of studies to determine the field's viability. Current estimates of production are 110 Mbbl of oil per day. Pemex noted that the 34-sq-km field could be developed with up to 11 wells and could produce up to 69 Mbbl of oil and 300 MMcf of gas per day by 2021.

2 *Peru*

PetroTal completed a horizontal well, #5H, in Bretana Field onshore Peru in Block 95. The well reached the targeted Vivian at a true vertical depth of 2,696 m, and an 863-m horizontal section was tested in the main productive reservoir. The discovery initially flowed 8.25 Mbbl of oil per day and was drilled updip toward the crest of the structure. According to the company, the horizontal well is the longest horizontal well drilled to date in Peru. PetroTal is based in Calgary, Alberta.

3 *Argentina*

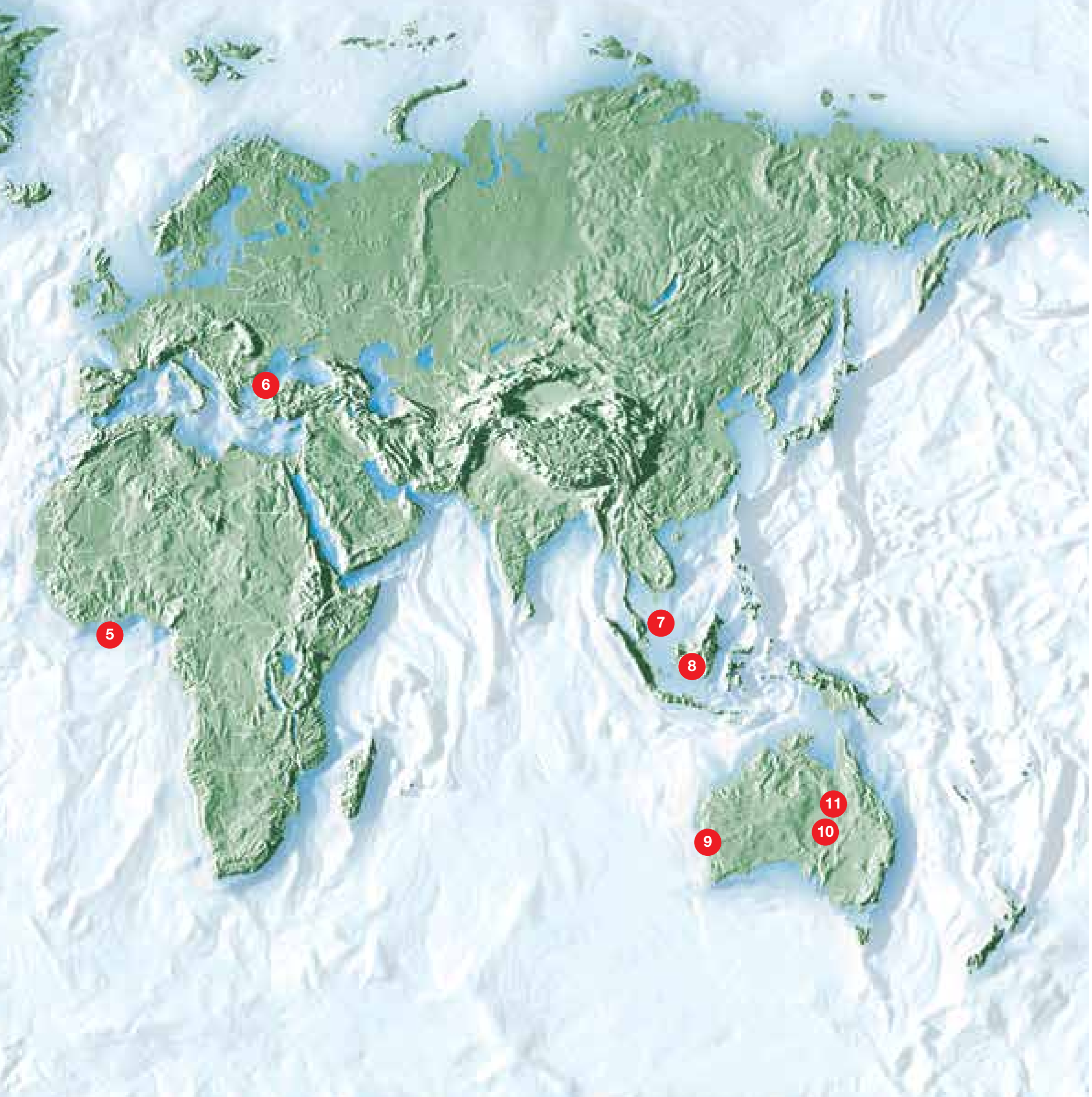
Crown Point Energy has completed two exploration wells in the Cerro de Los Leones (CLL) exploration permit area in Mendoza Province, Argentina. The Calgary, Alberta-based operator announced that the first of the wells, #1001D-SRM, was drilled to a true vertical depth of 1,333 m and was cased as a potential discovery after well log analysis indicated a potential 5-m, hydrocarbon-bearing zone in Agua de la Piedra (Middle Tertiary) at 1,021-26 m (true vertical). The well was drilled to intersect the crest of a structure, which lies beneath the Rio Malarga floodplain in the northern part of the CLL Block. The second well, #1002-SRM x, is about 1 km to the west of #1001D-SRM and is testing the Tertiary sandstones on an extension of the structure. It had a planned true vertical depth of 1,183 m.

4 *Trinidad*

According to ***Touchstone Exploration***, the company made a significant crude oil discovery at #1ST1-Cascadura in the Ortoire Block onshore the Republic of Trinidad and Tobago. Cased-hole wireline logs indicated oil pay from 1,037 ft to 1,374 ft of gross sand and that 80 net ft of oil pay was encountered in the Lower Cruse Sands at 1,030-2,134 ft. Approximately 180 net ft of oil pay was encountered in an Upper Herrera Gr7c thrust sheet at 4,198 ft and 4,994 ft, and 600 net ft of oil pay was encountered in a Middle Herrera Gr7c thrust sheet at 5,516-6,162 ft. About 177 net ft of oil pay was encountered in a Lower Herrera Gr7a thrust sheet at 6,162-6,350 ft. Another well is planned at #1ST1-Cascadura. Calgary, Alberta-based Touchstone has 80% interest in the license area in partnership with ***Heritage Petroleum***, holding the remaining 20%.

5 *Ghana*

In West Cape Three Points Block 2, ***Springfield Exploration and Production*** announced an offshore Ghana discovery of more than 1.2 Bbbl of oil, with up to 35% recoverable, at #1x-Afina. The discovery is in the Tano/Western Basin. Springfield is the operator and majority interest holder of WCTP2 with the ***Ghana National Petroleum Corp.*** holding a minority interest. Water depths range from 100 to 1,700 m. The block is flanked by the Jubilee, Sankofa and Sankofa East oil and gas fields. Additional exploration and testing is planned by the Accra, Ghana-based company.



6 ***Turkey***
Calgary, Alberta-based ***Valeura Energy*** announced results from exploration well #1-Devepinar in the Banarli licenses in Turkey's Thrace Basin. The company tested three stimulated intervals in the well and performed a production test in a 125-m section between 4,640 and 4,765 m. The average flow rate over the 11-day comingled test period was 908 Mcf of gas per day with the final 24-hour rate of 462 Mcf. According to the company, the comingled test yielded gas flow rates that may indicate that each of the three stimulations contacted a common fracture network. Future work may include long-term testing of the stimulated zone, tests shallower in the well bore and further geotechnical study. Valeura is the operator of the Banarli licenses and #1-Devepinar, with 50% interest in partnership with ***Equinor***, holding the remaining 50%.

7 ***Indonesia***
Conrad Petroleum announced results from its appraisal drilling campaign in the Duyung Production Sharing Contract in the West Natuna Basin offshore Indonesia. An exploratory well, #1-Tambak, which is about 4.5 km north of #1-Mako South, was drilled to a true vertical depth of 513 m and intersected the Intra-Muda reservoir of Mako Field. According to the company, the venture encountered an upper sandstone unit of approximately 5.2 m, a lower sandstone unit of almost 20 m with an overall gross thickness of approximately 25 m of Intra-Muda Sandstone. Pressure data indicates it is in the same pressure system as previously drilled #1-Mako South with similar gas composition. An independent assessment of the field indicated a gross 2-C resource of 276 Bcf of recoverable dry gas in the field, with gross 3-C resources of 392 Bcf of additional field upside. The JV partners are Singapore-based Conrad Petroleum (76.5%), ***Coro Energy*** (15%) and ***Empyrean Energy*** (8.5%).

8 ***Indonesia***
Interra Resources completed drilling and testing of the company's first well in the Kuala Pambuang Block, onshore Kalimantan, Indonesia. The Java Sea well, #10 KP, was drilled to 3,771 ft and tested with wireline logging, and oil shows were recorded over several zones in the primary reservoir targets. Additional testing is planned. Interra is the operator of the Kuala Pambuang Block and the exploration well with 67.5% interest in partnership with ***SKK-Migas***, holding the remaining interest.

9 ***Australia***
An exploration well in Western Australia's EP368 license area has been planned by ***Norwest Energy*** at #1-Lockyer Deep. The well site is approximately 15 km east of the Waitsia gas field and on-trend with the #2-West Erregulla gas discovery that has an estimated 2-C contingent resource of 1.19 Tcf gas. Additional potential may exist within Wagina as encountered at #2-West Erregulla; however, Norwest does include prospective resources in the current estimate. The venture will test the Permian Kingia/High Cliff conventional gas play within the combined Lockyer-North Erregulla Deep greater structure. Norwest is based in Perth.

10 ***Australia***
Beach Energy began a four-well appraisal program of the Butlers oil field at #10-Butler in the PEL 92 exploration license. The well will be targeting the Namur Sandstone, which is the primary producing reservoir in the field. The #10-Butler is about 540 m southeast of previously drilled #6-Butlers, and it will test the southeastern field boundary with a planned depth of 1,659 m. The additional wells, #11-Butlers, #12-Butlers and #13-Butlers, will be targeting the Namur Sandstone which is the primary producing reservoir in the field. The appraisal wells will enable development locations to be selected for future field development. The Butlers campaign is to be followed by two wells at the Rincon oil field. Adelaide, South Australia-based operator Beach Energy holds a 75% interest with partner ***Cooper Energy***, which holds a 25% interest in the joint venture.

11 ***Australia***
Drilling has been scheduled by ***Vintage Energy*** in Queensland, Australia's ATP 2021 license area in the Cooper/Eromanga Basin. The #1-Vali has a planned depth of 3,140 m and will be testing the Vali structure, an anticlinal closure that was identified in the 2017 Snowball 3-D seismic survey. The Vali Prospect is prospective for gas in Permian-aged reservoirs, including Patchawarra (the primary target) and Toolachee, secondary target. These reservoirs are proven as producing reservoirs on the southern flank of the Nappamerri Trough, with more than 600 Bcf of gas produced from fields within a 15 to 40 km radius of the proposed #1-Vali. Vintage, based in Adelaide, is the operator of ATP 2021 and #1-Vali with 50% interest in partnership with ***Metgasco*** (25%) and ***Bridgeport*** (25%).

THAWING IN HIGH-YIELD ENERGY

What not too long ago seemed to be a frozen market for high yield has begun to thaw, as swings in geopolitical events have caused crude prices to rise and retreat, creating short-term opportunities for debt issuance. Those taking advantage of a more receptive market include Nabors Industries Ltd. in oilfield services and WPX Energy Inc. and Range Resources Corp. in the upstream sector.

While the market's reopening to new issuance is welcomed, it comes at a price. For example, Nabors' new issues of $600 million and $400 million will push out maturities to 2026 and 2028, respectively, but they carry coupons of 7.25% and 7.5%, respectively. By comparison, proceeds from the issues will be used to fund an offer to repurchase senior notes with coupons ranging from 4.625% to 5.5%.

In the upstream sector, Range Resources placed $550 million of senior notes due 2026, upsized from an originally planned $500 million, with a coupon of 9.25%. Proceeds will fund tender offers to buy three senior notes issues with markedly lower coupons, ranging from 5% to 5.875%. The new issue will replace 2021 and 2022 maturities on the latter issues with one that is four or more years further out.

In a note, Tudor, Pickering, Holt & Co. welcomed the placement but said the yield paid by Range pointed to a "growing trend of E&Ps seeing dichotomous results in the market." E&Ps tended to divide into two camps, with larger producers with strong balance sheets able to access "plenty of cheap liquidity" at rates of around 3% to 4.5%, with levered names "settling for high rates to court investors."

In public-equity markets late last year, Brigham Minerals Inc. stood out by completing an offering of 11 million shares. The offering was priced at $18.10 each and comprised of 6 million primary shares and 5 million secondary shares. The latter were sold by existing shareholders: affiliates of Warburg Pincus LLC, Yorktown Partners LLC and Pine Brook Road Advisors.

Brigham Minerals intends to use proceeds from the offering to repay outstanding debt and to fund future acquisitions of mineral and royalty interests.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Brigham Minerals Inc.	NYSE: MNRL	Austin, Texas	$108.6 million	Announced the pricing of an underwritten public offering of 11 million shares of its Class A common stock at a price to the public at $18.10 each. The company is offering 6 million shares of its common stock, and the selling stockholders (affiliates of **Warburg Pincus LLC**, **Yorktown Partners LLC** and **Pine Brook Road Advisors LP**) are offering 5 million shares of **Brigham Minerals**' common stock. The selling stockholders have granted the underwriters a 30-day option to purchase up to an additional 1.65 million shares of Brigham Minerals' common stock. The company intends to use the net proceeds from the offering to repay outstanding indebtedness under the company's credit facility and to fund future acquisitions of mineral and royalty interests. Brigham Minerals will not receive any of the proceeds from the sale of shares of its common stock held by the selling stockholders. **Credit Suisse Securities (USA) LLC**, **Goldman Sachs & Co. LLC** and **RBC Capital Markets LLC** acted as lead book-running managers for the offering.
Kimbell Royalty Partners LP	NYSE: KRP	Fort Worth, Texas	$77.5 million	Priced a public offering of 5 million common units representing limited partner interests at a public offering price of $15.50 each. The total gross proceeds of the offering, before underwriter discounts and estimated offering expenses, will be approx. $77.5 million. Certain selling unitholders have granted the underwriters an option to purchase up to 750,000 additional common units at the public offering price less the underwriting discount and commissions. **Kimbell Royalty** intends to use the net proceeds from the offering to fund a portion of the cash purchase price for the pending acquisition of oil and natural gas mineral and royalty interests held by **Springbok Energy Partners LLC** and **Springbok Energy Partners II, LLC** and to pay fees and expenses related to the Springbok acquisition. Pending the closing of the Springbok acquisition, Kimbell intends to use the net proceeds from the offering for the repayment of outstanding borrowings under its revolving credit facility. Kimbell may use future amounts borrowed under its revolving credit facility for general partnership purposes, including a potential redemption of a portion of its outstanding 7% Series A cumulative convertible preferred units. Kimbell will not receive proceeds from the sale of common units by the selling unitholders if the underwriters' option to purchase up to 750,000 additional common units is exercised.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Laredo Petroleum Inc.	NYSE: LPI	Tulsa, Okla.	$1 billion	Priced $600 million in aggregate principal amount of 9.5% senior notes due 2025 and $400 million in aggregate principal amount of 10.125% senior notes due 2028 in a registered underwritten offering for a total of $1 billion, representing a $100 million upsize from the previously announced offering. Interest is payable on Jan. 15 and July 15 of each year. The first interest payment will be made on July 15, 2020, and will consist of interest from closing to that date. The company intends to use the net proceeds of the offering to refinance its $450 million in aggregate principal amount of 5.625% senior unsecured notes due January 2022 and $350 million in aggregate principal amount of 6.25% senior unsecured notes due March 2023 through tender offers or, if applicable, redemptions, and to pay tender premiums and fees and the fees and expenses related to the offering and for general corporate purposes, including repaying a portion of the borrowings outstanding under the company's senior secured credit facility. The new notes will be senior unsecured obligations of the company and will be guaranteed on a senior unsecured basis by its existing subsidiaries and all of its future subsidiaries, with certain exceptions. **BofA Securities**, **Wells Fargo Securities**, **BMO Capital Markets**, **Goldman Sachs & Co. LLC**, **Barclays** and **Capitol One Securities** acted as joint book-running managers for the offering.
Nabors Industries Ltd.	NYSE: NBR	Hamilton, Bermuda	$1 billion	Priced $600 million in aggregate principal amount of senior guaranteed notes due 2026 and $400 million in aggregate principal amount of senior guaranteed notes due 2028 in a private placement offering. The 2026 notes will bear interest at an annual rate of 7.25% and are being offered to investors at an initial price of 100% at par. The 2028 notes will bear interest at an annual rate of 7.5% and are being offered to investors at an initial price of 100% at par. The notes will be fully and unconditionally guaranteed by certain of Nabors' indirect wholly owned subsidiaries consisting of **Nabors Industries Inc.**, **Nabors Drilling Holdings Inc.**, **Nabors International Finance Inc.**, **Nabors Lux Finance 1**, **Nabors Global Holdings Ltd.** and **Nabors Holdings Ltd.** The sale of the notes is expected to result in approximately $986 million in net proceeds to Nabors after deducting offering commissions payable by Nabors. The notes will be senior unsecured obligations of Nabors and will rank pari passu in right of payment with all of Nabors' existing and future senior obligations. The 2026 notes will mature on Jan. 15, 2026, and the 2028 notes will mature on Jan. 15, 2028. Nabors intends to use the net proceeds from the offering to fund NII's offer to repurchase, for an aggregate purchase price of up to $800 million, NII's 5.5% senior notes due 2023, 4.625% senior notes due 2021, 5.1% senior notes due 2023 and 5% senior notes due 2020 in the previously announced tender offers and consent solicitations for such notes. It will use the remaining proceeds for general corporate purposes, including the repayment of other debt.
WPX Energy Inc.	NYSE: WPX	Tulsa, Okla.	$900 million	Priced its previously announced offering of $900 million aggregate principal amount of 4.5% senior unsecured notes due 2030. The notes were sold to the public at par. The net proceeds from the offering will be approximately $888.75 million, after deducting underwriting discounts and commissions and before estimated offering expenses payable by **WPX Energy**. The company intends to use the net proceeds to finance a portion of the cash consideration of the previously announced acquisition **of Felix Energy Holdings II LLC** and to pay related fees and expenses. The offering is not contingent upon the consummation of the acquisition of Felix, although the notes are subject to a special mandatory redemption if the Felix acquisition is not consummated. **Barclays Capital Inc.** and **Citigroup Global Markets Inc.** are acting as joint lead book-running managers for the offering.
Range Resources Corp.	NYSE: RRC	Fort Worth, Texas	$550 million	Announced it has priced at par an offering of $550 million aggregate principal amount of senior notes due 2026, which will carry an interest rate of 9.25%. **Range Resources** expects that the net proceeds from the offering will be approximately $541.6 million. The size of the offering was increased from the previously announced $500 million to $550 million. On Jan. 8, 2020, Range also commenced tender offers to purchase for cash, subject to certain conditions, up to $500 million aggregate principal amount of its outstanding 5.75% senior notes due 2021, 5.875% senior notes due 2022 and 5% senior notes due 2022. Range intends to use the net proceeds from the offering to purchase target notes in the tender offers, including fees and expenses incurred in connection therewith, with the remainder of the net proceeds to be used to repay borrowings under its bank credit facility.
Unit Corp.	NYSE: UNT	Tulsa, Okla.	N/A	Announced that it has extended the expiration date for its previously announced offer to exchange any and all of its outstanding 6.625% senior subordinated notes due 2021 for newly issued 10% senior secured notes due 2024 and 7% junior secured notes due 2025, upon the terms and conditions set forth in the prospectus relating to the exchange offer included in Amendment No. 2 to the registration statement filed with the Securities and Exchange Commission.

These deals and details on thousands more are available in real time in a searchable, sortable database at HartEnergy.com.

Hart Energy Recognizes Veterans' Influence

First-ever "25 Impactful Veterans in Energy" luncheon highlights roles in industry and veteran communities

Hart Energy's inaugural "25 Impactful Veterans in Energy" program welcomed hundreds of cheering guests to a sponsored recognition luncheon on Thursday, December 5, 2019 at Houston's Marriott Marquis hotel.

The 2019 'class' of energy-industry veterans included women and men who served in the U.S. Army, Marine Corps, Air Force and Navy as well as National Guard contingents. Their oilfield careers and experiences ranged from staff roles and field managers to executives and C-suite leaders.

An enthusiastic crowd showered appreciation on these honorees after watching a tribute video which briefly summarized each one's career and continued involvement in other military veterans' lives.

Attendees especially enjoyed lively presentations from Pete Hegseth, outspoken veterans advocate and a Fox News co-host, and from Staff Sgt. David Bellavia (U.S. Army, ret'd), the Iraq war's only living recipient of the Congressional Medal of Honor.

Nominations are being accepted now for the 2020 "25 Impactful Veterans in Energy" program. For more information, visit the web site at ImpactfulVeteransInEnergy.com

HARTENERGY

IMPACTFUL 25 VETERANS IN ENERGY

2019 HONOREES

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Tech-Fab
U.S. Army

Chris Bentley
Bellatorum Resources
U.S. Marine Corps

John Boerstler
Combined Arms
U.S. Marine Corps

Tim Butts
Continental Resources
U.S. Army

Ryan Deaderick
Greylock Energy
U.S. Army

Phillip Dunning
Enverus
U.S. Army

Patrick Finney
Chesapeake Energy
U.S. Army National Guard

Ann Fox
Nine Energy Services
U.S. Marine Corps

Mia Garcia
NextOp
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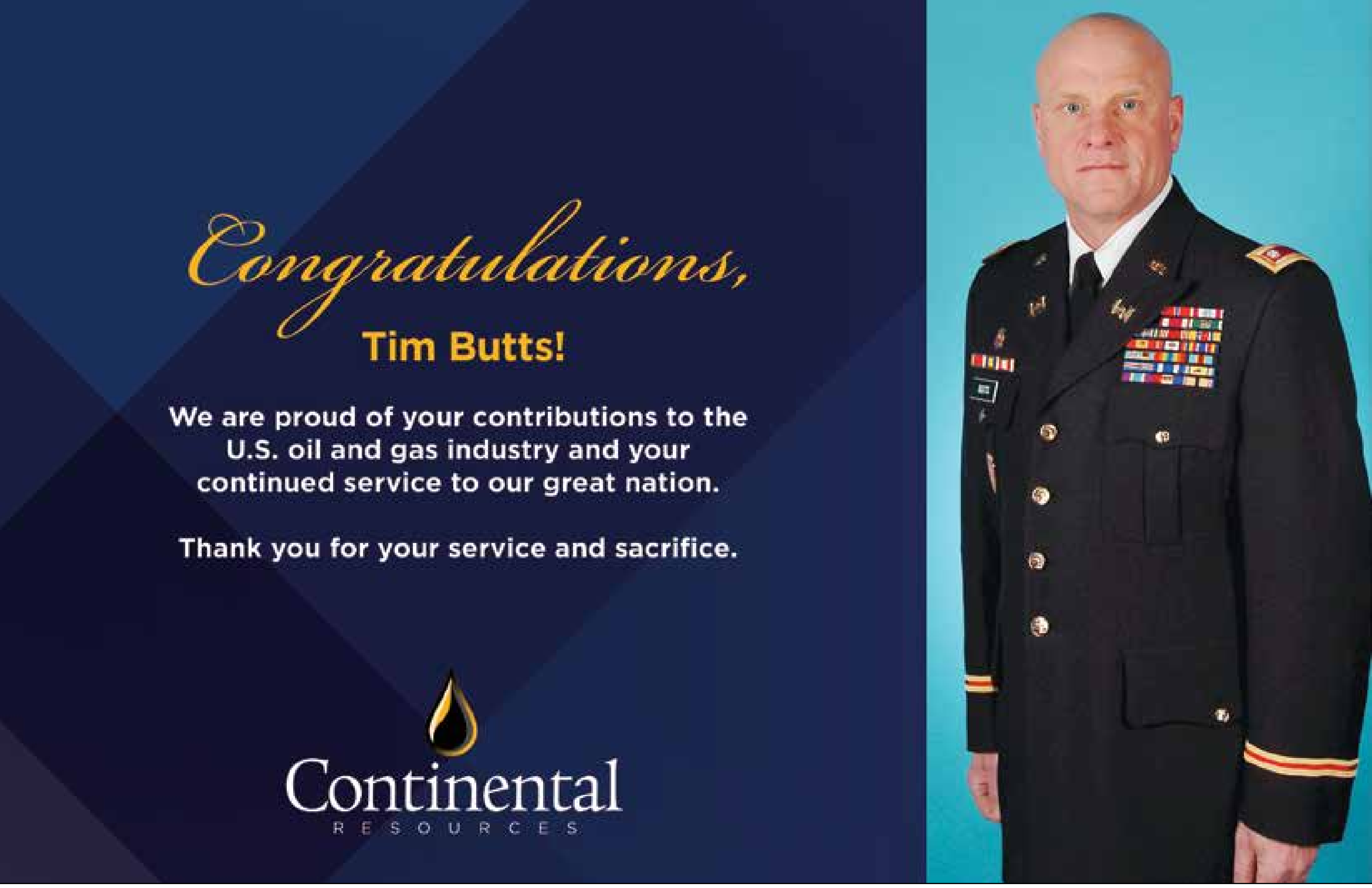
Staff Sgt. David Bellavia
U.S. Army (ret.)

Pete Hegseth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Thank you for your service and sacrifice.
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KEYNOTE
Tuesday, April 21
Thomas Petrie
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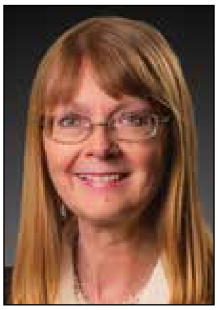
NEPA OR NOT?



LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

The year was 1970. Woodstock was barely in the rearview mirror, still generating buzz—everyone asked, "Were you there?" Meanwhile, we learned that the Cuyahoga River that flowed through Cleveland had caught fire and the eagle, a proud symbol of America, was endangered. Then as now, America was sharply divided as protests against the Vietnam War intensified, and a presidency was in peril.

The first Earth Day was celebrated that April, as the public became much more aware of the environmental degradation that was happening to our water and air. And then that president, Richard Nixon, signed into law NEPA—the National Environmental Policy Act, which required a new way of thinking about big infrastructure projects that receive federal funding. Environmentalists hailed it as a powerful new tool in their arsenal, one they could carry into court, but labor unions and the oil and gas and mining industries derided it as one more obstacle to fight in their effort to provide energy infrastructure and jobs to America.

Still standing today, NEPA requires federal agencies to weigh in on the near-term and longer-term effects on the environment of proposed pipelines, mining operations, highway and bridge construction and other such projects before they can begin. It requires the public to be given an opportunity to give its opinions during hearings as well. But over the years, NEPA became a monster of obstruction. "Nimby" landowners and environmentalists used it to delay, delay and delay. They expanded its interpretation to include studying how a project might contribute to long-term climate changes.

But now, President Donald Trump may have turned this around. He announced his aim to deliver a glancing blow to NEPA, proposing the first significant revisions and clarifications to it in 50 years. That's a long time for any law or regulation to stand without being amended, without a review of its original purpose and implementation, especially given changes in technology to mitigate threats of pollution, changes in public sentiment and changes in the environment itself.

The rollback of NEPA could give industry more hope to realistically move forward with its projects in a timelier manner. Said new Interior Secretary David Bernhardt, "This is a really, really big proposal." But if Trump succeeds, this also gives enviros and anti-fossil fuel groups despair—which in turn gives them renewed motivation to fight harder.

Critics say the feds would gut the law and give infrastructure companies free rein to destroy the land, water and air. Note that the proposed changes are more about how NEPA should be implemented than what the law actually does.

For example, Trump wants to redefine what constitutes a major federal action in order to exclude from NEPA privately financed projects, which would make it easier on pipeline companies. He also wants to speed up the process: in most cases, federal agencies would be required to complete their environmental assessments in one year and the full-bodied environmental impact statements within a two-year limit—no more dragging it out indefinitely.

Trump rightly complained about how long it can take to get any construction done, sometimes as much as 10 years. It's a serious waste of money and time that puts the U.S. infrastructure buildout behind where it needs to be.

Take the tortured case of the Constitution Pipeline that would bring enough natural gas from the Marcellus Shale to New York's southern counties above Pennsylvania to power 3 million homes. It was first proposed in 2013 by The Williams Cos. et al, and after an environmental review, FERC approved it in December 2014, stipulating certain mitigation measures to be met during construction. The route was also approved. The effect on area water quality was the biggest hurdle.

But New York Gov. Andrew Cuomo listened to the opposition and blocked it in 2016. Many courtroom hours later, in August 2019, FERC overruled the state. Long story short, Williams now says the line will go into service in 2021—that's seven years after it received federal watchdog approval.

Cuomo vows to keep fighting. He's ignoring the energy needs of 3 million people!

It is not right to reduce or short-change scrutiny of these projects. It is practical to make sure that that scrutiny occurs in a reasonably timely manner that doesn't waste money or imperil the environment.

One thing will not change, NEPA or not: Any project anywhere, of any size, can be blocked by a single person who chooses to file a suit. These proposed changes to NEPA will be fodder for arguments and briefs in courtrooms for months or years to come. Sad.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