Oil and Gas Investor

APRIL 2020

E&P consolidators learn to shine amidst M&A storm clouds.

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1616 S. Voss Rd., Suite 1000
Houston, TX 77057
1.713.260.6400 Fax: 1.713.840-8585
HartEnergy.com

Editor-in-Chief
Steve Toon
stoon@hartenergy.com

Editorial Director
Len Vermillion
lvermillion@hartenergy.com

Executive Editor-at-Large
Leslie Haines
lhaines@hartenergy.com

Senior Financial Analyst Chris Sheehan, CFA
csheehan@hartenergy.com

Senior Editor Darren Barbee
dbarbee@hartenergy.com

Senior Editor Blake Wright
bwright@hartenergy.com

Chief Technical Director, Upstream Richard Mason
rmason@hartenergy.com

Midstream Editor-at-Large Paul Hart
pdhart@hartenergy.com

Activity Editor Larry Prado
lprado@hartenergy.com

Associate Managing Editor Brandy Fidler
bfidler@hartenergy.com

Assistant Managing Editor Bill Walter
bwalter@hartenergy.com

Contributing Editors
Velda Addison, Susan Klann,
Joseph Markman, Emily Patsy, Faiza Rizvi

Editor-at-Large Nissa Darbonne
ndarbonne@hartenergy.com

Corporate Creative Director
Alexa Sanders
asanders@hartenergy.com

Art Director Robert D. Avila
ravila@hartenergy.com

Senior Marketing Manager Tamara Murphy

Vice President, Marketing Greg Salerno

Publisher
Kevin C. Holmes
kholmes@hartenergy.com • 713.260.4639

Vice President, Sales Darrin West
dwest@hartenergy.com • 713.260.6449

Director, Business Development Chantal Hagen
chagen@hartenergy.com • 713-260-5204

Business Development Representative Kelli Muhl
kmuhl@hartenergy.com 713-260-6450

Ad Materials Coordinator Carol Nunez
cnunez@hartenergy.com

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Vice President, Content
Peggy Williams

Chief Financial Officer
Chris Arndt

Chief Executive Officer
Richard A. Eichler

COLUMNS

DEPARTMENTS

ABOUT THE COVER: Helmerich & Payne Inc.'s drilling rigs at night at Parsley Energy Inc.'s operations southwest of Midland, Texas. Photo by James L. Durbin

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ONLINE CONTENT | APRIL 2020 | Subscribe at HartEnergy.com/subscribe

LATEST CONTENT

Oil Price Collapse Sours $320 Million Deal For Alta Mesa Resources
A court-ordered sale of one-time shale high-flyer Alta Mesa Resources fell through due to a lack of financing on March 9, a day when oil prices and shares of U.S. oil producers plummeted.

Devon, Apache, Murphy Oil Join Growing Number Of Producers Slashing Budgets
North American oil and gas producers have slashed their capital spending by about 30% on average after crude prices crashed in early March, according to data compiled by Reuters.

Permian Operator Matador Resources To Cut Rig Count In Half
Matador Resources CEO Joseph Wm. Foran said he also voluntarily agreed to reduce his base salary by 25% as the Permian Basin operator responds to a slump in oil prices.

Pioneer Natural Resources Chops Spending By 45%, Cuts Rig Count
The Dallas-headquartered Permian Basin player said March 16 it is lowering this year's drilling, completion and facilities capital budget to between $1.6 billion and $1.8 billion.

The ESG Evolution In Oil And Gas: Clearing Up Misconceptions
The oil and gas industry has made strides in beginning to report on environmental, social and governance initiatives, but there's still a lot more work yet to be done.

Oil, Gas Industry Players Talk Diversity, Building From Within
Diversity in the workforce is being championed to not only help bring in more qualified workers but also bring diverse perspectives and voices to the oil and gas industry.

ONLINE EXCLUSIVES

Empowering Women In The Oil And Gas Industry
Female executives in the oil and gas industry are challenging norms and inspiring young professionals to follow their footsteps.

Midstream Oil & Gas Outlook Leaves Bitter Taste
Weak prices, overproduction, uncertainty over COVID-19's impact on the markets and the global economy … it's a lot of bad news to digest.

Will Stock Market Shock Lead To An Oil Industry Shakeout?
Oil and gas stocks lead the market's plunge, with debt-ridden companies struggling with a commodities crash as well.

Videos

Executive Q&A: Hess' Bakken Outlook
Dougie McMichael, director of Bakken well factory planning and execution at Hess Corp., discusses the company's productivity and the technology drivers in the play.

www.HartEnergy.com/videos

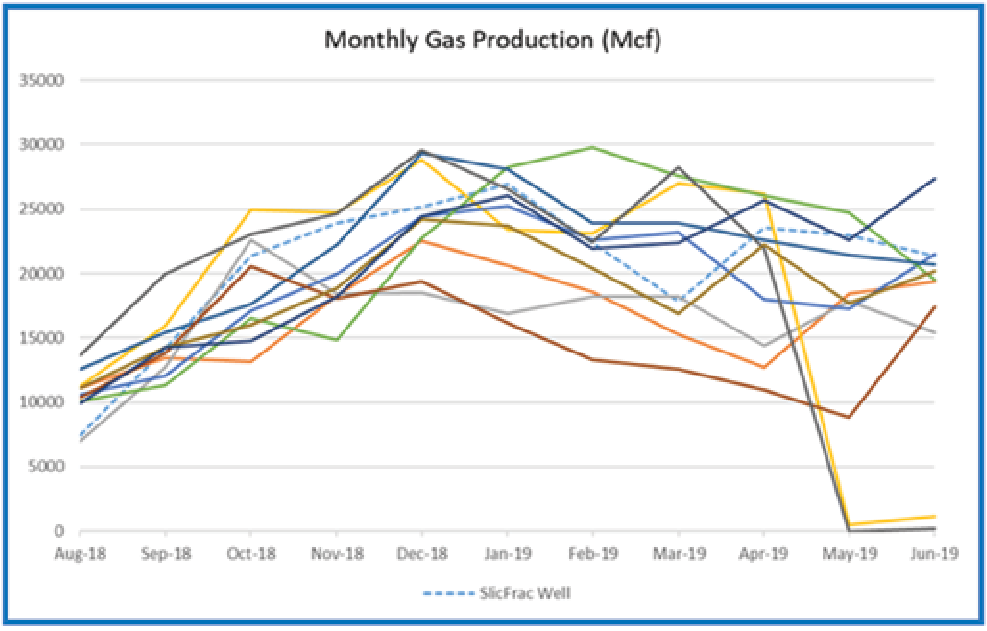
What's Trending

1. Post-Meltdown: Expect Surge Of Shale Bankruptcies, Experts Say
2. Occidental Petroleum To Slash Dividend, Spending As Oil Prices Crash
3. Saudis Escalate Price War, Pressuring Oil
4. Oil Shock Threatens To Take Wind Out Of Sails For Renewables Shift
5. Marathon Joins Growing Number Of Shale Producers Slashing Spending

Replace Frac Plugs with **SlicFrac**

Incorporating Perf PODs as an alternative to frac plugs for zonal isolation allowed the operator to complete the wellbore as designed, despite casing limitations.

Due to multiple casing ID restrictions, a customer in the DJ Basin required an alternative solution to isolate intervals and effectively stimulate the entire lateral.



The customer replaced all frac plugs with **SlicFrac** Perf PODs, deployed between each frac stimulation to isolate and divert the flow to the next interval of perforations. By isolating each perforation the customer was able to efficiently stimulate the entire lateral; attaining more reservoir contact with improved perf cluster efficiency. **SlicFrac** Perf PODs were deployed to divert fluid from the dominant perforations and provide breakdown of the less dominant or under-stimulated perf clusters within each interval.

For this 55 stage completion, degradable Perf PODs were deployed from surface maintaining isolation for the entirety of the 10 day frac stimulation. **TTS'** Standard Milling BHA was used post frac to cleanout residual sand and circulate the wellbore clean before putting the well onto production.

By replacing frac plugs with **SlicFrac** Diversion, the customer was able to effectively stimulate the entire wellbore as designed, while reducing overall completion costs and eliminating the risks associated with setting and removing reduced OD plugs. The chart above shows production of the well where **SlicFrac** was used in comparison to other wells in the field; the production is higher than many of the wells and continuing to trend upward.

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Although the oilfield services and equipment sector has been hit exceptionally hard by recent geopolitical events and the short-term impacts of COVID-19, this sector is the energy industry's technological engine and employs a significant portion of its workforce. We will continue to operate safely, drive efficiencies, provide the technologies that keep the U.S. and our allies from relying on foreign sources of energy, and deliver a lower-carbon future to the world while returning shareholder value.

PESA represents more than 500,000 men and women in the OFS sector and remains a steadfast resource for developing the adaptability required to navigate difficult times.

"The OFS sector is a critical part of the world's energy picture, and the sector stands ready to provide the world the energy it needs for years to come, regardless of market volatility," said PESA President Leslie Beyer.

EMERGENCY RESPONSE

STEVE TOON,
EDITOR-IN-CHIEF

One analyst dubbed it "OPEC-aggedon." Another a crash of historic proportions. Others: disaster; and, low-cost producer deathmatch. A Raymond James March 9 report summed it up: "When it rains, it pours."

The U.S. oil and gas sector was already struggling through a protracted capital starvation period and tepid commodity prices, but black swan events cannot be predicted, only responded to. When the three-year Saudi Arabia-Russia production-cut marriage ended acrimoniously on March 6, with each not only disagreeing on new cuts, but threatening to ramp up production to spite the other, the oil and gas world as we know it ended. For now.

The WTI price plummeted to near $30/bbl. That's a drop from $45 the week before the OPEC-plus-Russia meeting and as high as $63 in January. The last time we saw oil prices this low was in February 2016, at $26. Here we go again.

The breakup between the Saudis and Ruskies shouldn't be a surprise. They sit on opposite sides of the political aisle regarding Syria and Iran and were only in this shotgun matrimony to prop up global oil prices. We should have thanked them for these years of relatively stable prices, but we didn't. We grabbed their lost market share as long as we could. It was bound to end.

At the tail end of a beginning-of-year earnings season in which U.S. independents promised disciplined capex with measured growth and certainly free cash flow, that all blew up. Now—suddenly—it's all about survival. Precious few plays are economic at $35 oil. So, assuming this price shock has staying power, that raises the question: What actions must you take to survive?

A handful of producers responded proactively right out of the gate. Parsley Energy Inc. immediately dropped two frac crews and three rigs. Marathon Oil Corp. trimmed its 2020 budget by 20%, including all drilling and completion activity in Oklahoma and some in the Delaware Basin. Diamondback Energy Inc. slashed three completion crews and two rigs. San Andres conventional player Ring Energy Inc. suspended all activity to concentrate on liquidity preservation. Even King Occidental Petroleum Corp. haircut capex by 32% and slashed its precious dividend by a let's-get-serious-now 85%.

More—a lot more—are sure to follow.

Because as much as we hope that OPEC and Russia will hug and say "psych" by the end of March when the existing production cut agreement ends, that's unlikely, said Morgan Stanley global oil strategist and head of European energy research Martijn Rats, in a conference call March 9. "It still looks a little frosty," he surmised.

Rats noted that it took a year to put the OPEC+ partnership together, and once the genie is out of the bottle, putting it back in again "is nigh impossible in the short run."

Russia exited the ill-fated meeting by taking all production limits off of its producers, and Saudi Arabia responded by promising to hike output by 2.6 MMbbl/d, to 13 MMbbl/d. This threatened supply war rages in the face of a worldwide coronavirus-induced demand slump.

"Oil markets are now facing an unprecedented double shock … that will likely push crude prices to multidecade lows," said IHS Markit vice president of financial services Roger Diwan, in a report released shortly after the price drop. Multidecade lows? How low?

"Markets are now facing a supply battle amid a demand crisis. The last time this occurred was in 1998 during the Asian financial crisis, when Venezuela's aggressive production growth triggered a price war and pushed oil prices into the single digits. … U.S. E&Ps will very much be at the receiving end of a price collapse."

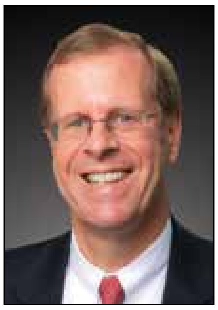
While less-than $10 oil sounds alarmist, no one seems to think this tiff between the oil-producing big daddies will be a passing blip, including Diwan. "It's not 'if' (crude) stocks will build significantly, it's by how much," he said. How much fortitude do they have to willingly flood the markets? If the overbuild is "manageably oversupplied," the markets will take one to two quarters to unwind, he said. If "catastrophically oversupplied," then buckle in for four to six quarters.

The negative impact of the price war is clearly unfolding in the U.S. On the Morgan Stanley call, Rystad Energy's Artem Abramov said he expects U.S. shale capex to drop in 2020 to $76 billion from $105 billion as guided in earnings calls. If prices hang in the $30s through this year, capex could drop to $45 billion next year.

"Thirty-five dollars just does not work for activity going forward. We'll see significant declines in production from the U.S. if the price environment doesn't improve."

Perhaps this will prove a bad dream by the time you read this, but the prognosis is for a protracted battle royale. If so, it could be a hard landing.

CRUDE AND CREDIT GET UGLY



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

Hart Energy hosted its Energy Capital Conference on March 2 amid much sober sentiment after the steepest one-day stock market drop since 2008 and a 16% plunge in WTI crude the prior week. However, the one-day conference saw a robust rebound: the Dow Jones index up over 1,200 points, a gain of over 5%, and crude up almost $2 to $46.75/bbl.

The saying is, "You take what market gives you." But energy came up empty, and far worse days lay ahead.

The E&P sector failed to participate on the day of the conference, with the S&P Oil & Gas Exploration & Production ETF (XOP) trading flat on the day and drifting down around 3.5% over the next two days. Even those short energy stocks apparently felt little urgency to cover. After all, who wanted to wager ahead of an OPEC meeting where Russia seemed to be dragging its feet in support of a key Saudi proposal?

One observer cited three potential outcomes: "very bearish, bearish and mildly bearish." He was right.

Ultimately, the Russian delegate rebuffed plans for a cut of 1.5 million barrels per day (MMbbl/d), of which core OPEC members would have cut 1 MMbbl/d and OPEC+ members the remaining balance. The proposal was aimed at offsetting a build in inventories due to the coronavirus, which had already crushed demand for crude during a seasonally weak period exacerbated further by a warm winter.

Where the meeting disintegrated into disarray was the absence of a back-up agreement, or "plan B," and then a good deal of rancor between Russia and Saudi Arabia. Having failed to reach an agreement, Saudi Arabia indicated it would boost output to 10- to 11 MMbbl/d, up from 9.7 MMbbl/d, as the prior OPEC system of quotas expired on April 1 with nothing to replace it.

Saudi Arabia swiftly cut official selling prices (OSP) for its benchmark Arab Light grade by $6/bbl—said to be its largest monthly cut in records going as far back as 2003—to Asian customers that make up about two-thirds of its exports. The Arab Light OSP for Northwest Europe was cut by $8/bbl to a $10.25 discount to Brent, while U.S. buyers saw at $7/bbl cut to a $3.75 discount to the Arhus Sour Crude Index.

In the first day of U.S. trading after the failed deal, WTI settled down $10.15 at $31.13/bbl, while Brent was down $10.91 at $34.36/bbl. Analysts expect prices to hover around these levels, with Goldman Sachs forecasting Brent to average $35/bbl for the second and third quarters, with possible dips to $20/bbl. Morgan Stanley predicted WTI at $30/bbl in the second quarter and $35 to $40 in the second half.

Bernstein analyst Neil Beveridge predicted the U.S. E&P sector would see a "wave of bankruptcies" in the wake of Saudi Arabia's switch away from what was a policy of supporting oil prices to one focused on a "battle for market share." In addition, the impact on the oilfield service sector would be "devastating."

More leveraged E&Ps, especially those facing maturities in an already highly dislocated high-yield market, are obviously most at risk if crude prices stay at sharply depressed levels. But entire economies may also be under stress. Saudi Arabia has a fiscal breakeven $83.60/bbl, while Libya and Algeria have breakevens of around $100/bbl and Iran over $190/bbl, according to Credit Suisse data.

The largely unexpected Saudi-Russian schism drove a steep drop in equity markets. The Dow fell by over 2,000 points, marking anew its worst day since 2008. E&P stocks were crushed, with the XOP down over 35%. With the lower oil prices, U.S. drilling and completion capex for 2020 is forecast to be down 35%, according to Tudor, Pickering, Holt & Co.

Reasons for Russian intransigence on further production cuts are not fully clear. Some pointed to possible attempts by Russia to impair U.S. shale production in a retaliatory move. Earlier, the U.S. had blacklisted the trading arm of Russia's Rosneft in its moves to export Venezuelan crude. In addition, the U.S. worked to prevent the completion of the Nord Stream 2 Pipeline.

Bernstein pointed to major costs for Russian producers being denominated in rubles, whereas revenues are generally generated in dollars. This makes Russia "effectively vaccinated against low oil prices," it said.

Importantly, Russia is reported to have a fiscal budget based on a $42/bbl Brent breakeven price.

Whatever the reason, the risks are clear: Brace yourself for another ongoing market share war.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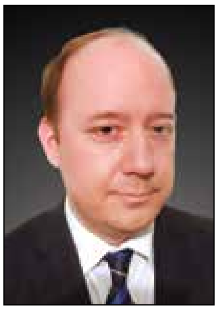
MONEY TROUBLE



DARREN BARBEE, SENIOR EDITOR

Randall L. Osterberg sat with his back to the escalator at the Hilton Americas hotel, nursing a cup of Starbucks' finest fully synthetic and ruminating on M&A in the time of the coronavirus.

Osterberg, managing director at Opportune LLP, has had time to consider the bad bounce the industry has taken since his banker days arranging credit facilities for Aubrey McClendon and Chesapeake Energy Corp., Continental Resources Inc. and HollyFrontier Corp.

Osterberg blames the unending buffet of money for the folly that's befallen the industry's deal making. Like the housing market's subprime mortgage crisis in the previous decade, lenders signed up credit-damaged borrowers who couldn't pay.

Many E&Ps turned out to be unworthy, too.

"All the money needed a home," he said. "So, they create this stuff. The industry had some bad investments just because the money was there."

In the McClendon days, most people chased the companies. Osterberg chased private equity. "The big theory—what it's always been—is you chased the money. Where is the money?"

The Chesapeake portfolio grew large, from multimillion-dollar loans to billions and then more billions. Osterberg sees the company as the spark behind the pre-downturn M&A market, with assets flipping to McClendon or one of the always-acquiring MLPs that seemed to buy anything in their path.

Osterberg recalled visiting the smaller, private-equity teams to discuss how the teams planned to exit.

"What's your exit strategy?" he would ask.

In many cases, the companies had a single offramp in mind: "Sell to Chesapeake," they would say.

But that was a long time ago. The days of flipping assets long gone. The old ways of proving up an asset over time and great effort have returned while the quick paydays have vanished like reserve-based lending values.

"I mean it's not sexy. They're just doing [it] the old way again," he said.

Lately, M&A is a mess. Market dysfunction swirls as buyers hunt for PDP assets with discounts of PV-20 or higher on their minds.

"You've got these guys who see blood in the water," he said. Elsewhere, there are still operators coming to terms with the idea that no one will pay for upside.

"A healthy M&A market is what we're all looking for," he said. "But you can't get there because the bid and the ask are too wide."

Among the hinderances to buyers and sellers is the basic disagreement on asset value, with sellers maintaining a higher value for leasehold than can be reasonably justified, in Osterberg's view. Even when potential buyers offer prices in line with market values, the distance between buyer and seller remains far too wide.

After reviewing one deal, Osterberg found no equity value in the assets, the bank was under water and most of the management team's equity was wiped out.

"There are people who just need to capitulate," he said.

But Osterberg, as a former banker, said the more fundamental question is how close lenders are to giving up.

A day will come, perhaps sooner than later, that a bank holding a foundering upstream company's debt chooses to simply foreclose rather than running another iteration of forgiveness that produces the same result.

"The banks are going to say [they] want to liquidate my assets in this market, which is a crummy M&A," he said. "Can I extend the runway by working with the current management team and keeping the assets?"

E&Ps that continue to operate and at least maintain production live to fight another day.

Osterberg is already seeing the emergence of contract operators—old private-equity teams that are still together but displaced from a failed private-equity venture. A faltering company could give them an opportunity restart.

Banks haven't made the move yet.

But, "we all feel like that first time when the bank actually forecloses the assets, then everyone can point to it. 'It's been done. Here we go.'"

Until then, equity is continuing to get wiped out. Banks are under water. And management teams still operate, "because they're at least still getting a paycheck."

"This is the worst time I can ever remember where banks have limited optionality," he said.

After about an hour, Starbucks untouched, Osterberg recalled a conversation with a former boss, a banker who couldn't believe his institution was losing money in oil and gas. Historically, "you don't lose money on oil and gas. You just don't do it," he said.

"Of course, we do it pretty regularly now," he said.

EVENTS CALENDAR

The following events present investment and networking opportunities for industry executives and financiers. These dates are effective as of March 17 and many are changing due to the impact of the coronavirus.

EVENT	DATE	CITY	VENUE	CONTACT
2020				
PIOGA Spring Meeting	Postponed	Pittsburgh	Rivers Casino	pioga.org
KIOGA Annual Midyear Meeting	Postponed	Garden City, Kan.	Clarion Inn and Convention Center	kioga.org
OGIS New York	Pending: April 20-22	New York	Sheraton New York Times Square	ipaa.org
Texas Energy Alliance Annual Meeting	Postponed	Wichita Falls, Texas	MPEC Convention Center	texasalliance.org
Offshore Technology Conference	Postponed	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
Petroleum Alliance of Okla. Annual Meeting	June 4-7	Las Colinas, Texas	Four Seasons	thepetroleumalliance.com
AAPG Annual Conv. & Exhibition	June 7-10	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
DUG East/Marcellus-Utica Midstream	**June 16-18**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
IPAA Annual Meeting	June 29	Newport Beach, Calif.	Pelican Hill	ipaa.org
Unconventional Resources Tech. Con.	July 20-22	Austin, Texas	TBA	urtec.org/2020
Mineral & Royalty Conference	Aug. 10-11	Houston	Post Oak Hotel	mineralconference.com
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
The Energy Summit	Aug. 17-19	Denver	Sheraton Downtown Denver	coga.org
Energy ESG Conference	**Sept. 1**	**Houston, TX**	**The Omni – Galleria**	**energyesgconference.com**
DUG Permian Basin/DUG Eagle Ford	**Sept. 8-10**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugpermian.com**
DUG Midcontinent	**Sept. 22-24**	**Oklahoma City**	**Cox Convention Center**	**dugmidcontinent.com**
A&D Strategies and Opportunities	**Oct. 27-28**	**Dallas**	**Farmont Hotel**	**adstrategiesconference.com**
Executive Oil Conference	**Nov. 3-4**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
PrivCap Energy Game Change	Dec. 1-2	Houston	Houstonian Hotel	energygamechange.com
Veterans In Energy Luncheon	**Dec. 3**	**Houston**	**TBA**	**impactfulveteransinenergy.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.

2020 Hart Energy Events:

CONFERENCE & EXHIBITION
DUG
BAKKEN AND ROCKIES
Feb. 18-19
Denver, CO
Colorado Convention Center
20 Years in the Bakken

energy capital CONFERENCE
March 2
Dallas, TX
Fairmont Hotel – Dallas

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

CONFERENCE & EXHIBITION
DUG
HAYNESVILLE
May 19-20
Shreveport, LA
Shreveport Convention Center

NEW IN 2020
Energy ESG CONFERENCE
Sept. 1
Houston, TX
The Omni – Galleria

CONFERENCE & EXHIBITION
DUG
PERMIAN BASIN
CONFERENCE & EXHIBITION
DUG
EAGLE FORD
Sept. 8-10
San Antonio, TX
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DUG
MIDCONTINENT
Sept. 22-24
Oklahoma City, OK
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NewsWell

Expect surge of shale bankruptcies, experts say

Upshot of the March 9 markets meltdown for the U.S. shale industry? Survival of the fittest.

"We already had a number of U.S. shale producers that were very challenged because they didn't have great balance sheets and were struggling," Pearce W. Hammond, managing director for midstream equity research at Simmons Energy, told Hart Energy.com. "This just accelerates this process. It likely means several companies will go bankrupt."

Michael Hurst, an oil and gas litigator and partner with Lynn Pinker Cox & Hurst LLP law firm in Dallas, sees it, too.

"I think it will be early in the second quarter where we will see companies that are holding on for dear life and finally letting go," he said. "As much as we'd like to say this will be over in a matter of a few weeks, it doesn't look like that's going to happen.

"I do expect to see a great deal of insolvencies and bankruptcies in the energy sector in all aspects—upstream, midstream, downstream and everything associated with oilfield services," Hurst said.

Concerns over the spread of the coronavirus, now in more than 100 countries, had been weighing on the equity markets for weeks. They fed worries about the global economy and its demand for oil.

On March 9, the International Energy Agency (IEA) revised its global demand forecast for 2020 downward, expecting a 90,000 barrel per day (bbl/d) reduction in demand. It would be the first decline in consumption since 2009.

Hurst also expects a wave of M&A activity.

"I would expect to see quite a bit of merger activity," he said. "I think you'll see some of the bigger companies that are better capitalized and better able to financially weather the storms swallowing up some of the smaller, less-capitalized companies."

On March 6, Russia rejected a call by Saudi Arabia and other OPEC members to further reduce crude production by 1.5 MMbbl. The subsequent realization that the previous round of cuts was no longer in place sent global commodities markets reeling.

The Trump administration responded with a statement that "attempts by state actors to manipulate and shock oil markets reinforce the importance of the role of the United States as a reliable energy supplier to partners and allies around the world."

But Joe F. Flack III, partner with Jackson Walker LLP in Houston, told Hart Energy that, as bad as things got on March 9, it was likely a temporary situation.

"We expect Saudi Arabia and Russia eventually to end their game of economic 'chicken' and come to an agreement on future production cuts," Flack said. "We also expect oil prices to rebound to levels supported by existing demand once the panic over the coronavirus settles [hopefully by summer]."

Then again, maybe not. If OPEC does not strike a deal in the near future, he said, continued extreme low oil prices will almost certainly result in serious geopolitical consequences. Consequences include:

- Domestic oil and gas producers and their investors, lenders and service companies will face increasing financial pressure;
- Stock markets will be roiled;
- Domestic oil and gas drilling and production will decline;
- Distressed oil and gas financings will increase; and
- As Hammond and Hurst said, more oil and gas-related bankruptcies.

The rebound on the morning of March 10 that pushed both WTI and Brent up more than 8% won't be enough, Hammond said.

"The energy markets are obviously very volatile and they certainly are capable of bouncing around," he said. "But it doesn't change the core thesis that OPEC+ is gone. The longer [the low prices go on], the more pain for the U.S. industry."

If there is a bright spot in this, he said, it's that consumers will pay less for fuel.

If access to capital was difficult before the meltdown, some companies may now be in crisis.

"Capital was already challenging before this for U.S. shale because of the poor returns and investors are frustrated, plus more marginalization on the whole environmental, social, governance issues," Hammond said.

Now it's even tougher.

"It's just going to separate those companies that are well-capitalized and have good liquidity and good assets from those that don't," he said.

Which means that, for some, opportunities will abound, Hurst said.

"There are opportunities that might ensue from this," he said, particularly for investors who are flush with capital. Those players may be able to acquire companies, either from an equity standpoint or at a very cheap price. They might also potentially pick up assets cheaply from companies that are liquidating.

It also means that a lot of the fallout will end up in the courts.

"I think you will see a big uptick in litigation," he said. "Probably in all the financial services litigation, you will see a rise in lender liability complaints. In the oil and gas industry, particularly, you'll see a lot of contract-related litigation."

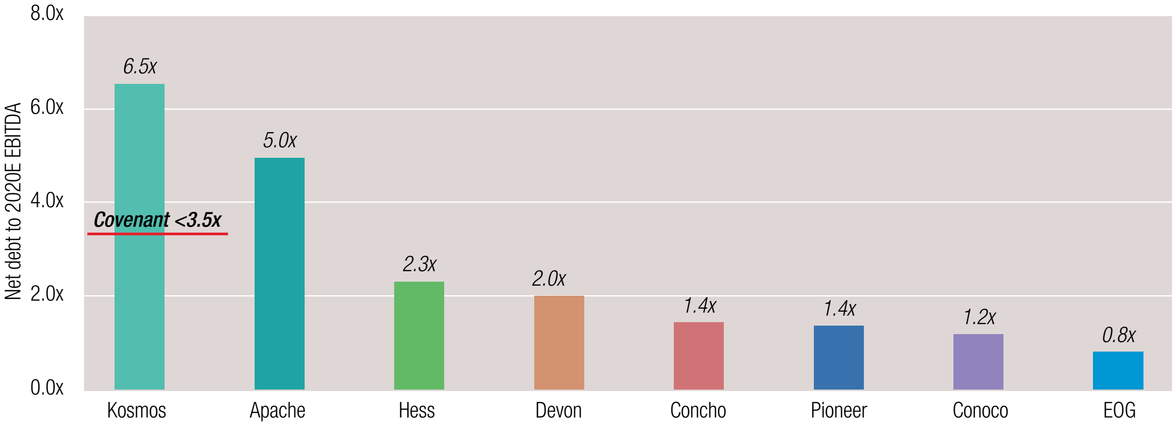
—Joseph Markman

Analyst looks at E&Ps with debt coming due soon

In light of the oil price swoon in March, analyst Bob Brackett of Bernstein Research looked at his coverage universe to gauge the pain that some E&Ps might endure as their debt payments come due throughout this year and 2021.

He said first, global oil inventories build, U.S. capital spending gets deferred, the number of DUCs (drilled but uncompleted wells) rises, and finally, production gets deferred or shut in.

"Bankruptcy is a real risk for the sector and is one of the curative mechanisms no doubt in the minds of those that chose to flood the market. It is real and coming for the broader sector," he wrote in a research note.



Source: Bloomberg, Bernstein analysis

He looked at debt covenants for his coverage group under a scenario where WTI averages near cash costs at $30/bbl for the rest of 2020 and natural gas at $2.44 per thousand cubic feet. "We think this is a realistic downside stress test," he said.

Kosmos Energy screened as most likely to violate its covenants as far as debt to capital ratio in the current commodity environment. Its stock was hammered on March 9, after Saudi-Russian negotiations broke down at the latest OPEC+ meeting, causing oil to fall by about $10/bbl. However, according to his research, Kosmos has no debt maturing before 2026.

Bracket said Apache Corp. and Hess Corp. have elevated debt metrics "but their covenants are based on debt-to-cap ratio and are well below the thresholds" required by their banks. Apache has $293 million maturing in February 2021 and another $463 million in April 2022, he said. Hess has nothing maturing until 2024.

While EOG Resources Inc. has the largest tranche of debt coming due this year, $1 billion, it has twice that amount of cash on the balance sheet, he said. The company has another $750 million maturing in 2021.

"We believe our basket of 'outperforms' are amongst the highest quality E&Ps in the space, and would point investors to Hess (well hedged at 80%). We ultimately think the pain will be felt outside of our outperforms first."

Among his stock picks designated as outperform, Pioneer Natural Resources Co. has $500 million due in January 2021 and another $600 million in 2022. ConocoPhillips Co. has $829 million due in 2022. Concho Resources Inc. has $485 million due in 2025.

—Leslie Haines

Oil industry faces rising ESG pressures this election year

Both public and private oil and gas investors are ramping up their scrutiny of environmental, social and governance (ESG) issues, and in an election year, don't expect the pressure to ease.

"There will be a whole new section in all the new loan agreements that will address compliance with ESG," warned Jim Finley, CEO and owner of Finley Resources Inc., at the recent NAPE Global Business Conference. "There'll be a huge amount of checklists you'll have to do for your banking groups. All capital providers have this high on their agenda. You'd better be prepared internally with policies that come into compliance with what the industry expects."

But capital is just one tile in an existential game of dominoes for the oil and gas industry.

"Permitting is getting significantly more challenged," said Brian Frederick, former president of DCP Midstream LP, at NAPE. "Whether it's for right-of-way, whether it's for plants, whether it's for wells, I think that is a big, big concern and that will be a governor on activity if we don't get that solved and create a set of rules that work."

In a short-term, practical sense, the permitting delays are exacerbating the sense of uncertainty over project completion in both the upstream and midstream sectors, said Tom Lloyd, director of marketing and midstream for Marathon Oil Corp.

"If there's going to be a permit change, we need to know that in advance so we can communicate with our midstream so we can probably build out," Lloyd said. "We don't build out where we shouldn't either because capacity would be a mismatch."

The end result of that mismatch creates another environmental headache. "We didn't get the infrastructure buildout, [that's] what causes flaring," Frederick said. "I would foresee in the next handful of years that it will stop, that the regulations will totally change. We better get aligned between E&P and the midstream because you won't be able to go up to North Dakota and light up the night sky every night. Five years from now, I don't think that will exist. The whole world is changing."

That change is driven by public perceptions of climate change, which is in many cases fueled by societal polarization and an election year. Steven Russo, shareholder with Greenberg Traurig LLP and a former chief legal officer of the New York State Department of Environmental Conservation, noted the harsh shift in rhetoric on climate change during recent Democratic presidential debates compared to debates during the 2016 campaign. Two leading candidates—Sen. Bernie Sanders, D-Vt., and Sen. Elizabeth Warren, D-Mass.—have pledged to ban hydraulic fracturing on federal lands.

"The advocates used to be OK with natural gas as a bridge fuel, and really just trying to take on coal and still get improvements in fossil fuel emissions from natural gas," he said during a roundtable at the Marcellus-Utica Midstream conference (MUM) in December in Pittsburgh. "They have now decided: no fossil fuels. Fossil fuels need to go, and they need to go quickly."

It's not an attitude confined to the presidential election nor is it primarily a New York state issue pushed by Gov. Andrew Cuomo, despite the obstacles his administration has placed in front of pipeline projects.

"As a New York lawyer, I'm sorry for some of the nonsense that's happened in my state," Russo said. "I think it's regrettable the attitude with regard to major oil and gas projects in the state, but I don't think it's going to be unique to New York. I think we have to look at New York and think, this is potentially the future for many states, especially where they're controlled by the Democratic Party. I think you're seeing it in California; you're seeing it in other states."

Mark Mathis, founder of the Clear Energy Alliance, agreed.

"The rhetoric has gotten more extreme and ramped up," he said at MUM. "Interestingly, what's happening in New York is happening in other states. It's happening in California, it's happening in Texas. We've got politicians, regulators who have fully embraced what I call energy fantasy. These fantasies are manifesting themselves in regulations, and everybody's just going along with it."

A number of speakers at the conferences confessed that the public perception is something of a gut punch, given how safety and environmental protection have been drummed into them since their first day on the job. And it creates a recruiting challenge.

"Our ability to hire, retain, to create that pride and culture within your company, this is a very important thing, and it's something we've been doing all of our careers; we care about it, but we have done a terrible job of communicating what we do," Finley said. "We have to understand who our stakeholders are and communicate what we're doing."

Frederick agreed, and he admitted that the industry has pretty much lost the public relations battle for the past 20 years.

"People want to work for a company they're proud of, that runs a good operation, that doesn't harm the environment, that, if you have a spill, you clean it up the right way," he said. "They want to be proud of who they work for. How do you attract people to this industry? You've got to change the public perception of what we do. I'm incredibly proud of this industry, I'm incredibly proud of what we do."

—Joe Markman

U.S. shale producers prepare to adjust amid volatility, coronavirus

Continued fears about the coronavirus, demand uncertainty and

OPEC moves are adding to a growing list of challenges for U.S. shale players.

Already under investor pressure to deliver higher returns and free cash flow, most oil and gas companies are in a “wait-and-see” mode, sticking to lower spending and drilling programs in place as they await price rebounds and higher oil demand, analysts said on a recent webinar.

A couple, however, have already made moves.

“Everybody has come out and said that if a prolonged period of low prices exists, they will take that into consideration, and they will decrease activity,” Sar Ozkan, director of energy analytics and crude market efforts for Enverus, said on a joint webinar with RS Energy Group on March 5. “They’re not afraid to decline. That’s just the world that we live in now—where free cash flow is king.”

An oil price rebound and higher oil demand remained elusive on March 9 as the market endured one of its worst days in recent history.

Continued fears about the coronavirus and demand uncertainty added to a growing list of challenges for U.S. shale players that include improving finances, focusing on ESG issues and producing within cash flow. Further complicating matters was a collapsed deal between OPEC and its allies, with Saudi Arabia and Russia pledging to increase production despite weak global demand.

Crude futures fell about 20% on March 9.

Recent commodity price volatility led Permian players Diamondback Energy Inc. and Parsley Energy Inc. to scale back drilling.

Diamondback said March 9 it will cut its nine completion crews to six and drop two drilling rigs in April and another later in the second quarter. The company also plans to further reduce its capital budget for the year.

“While this decision is expected to result in lower 2020 oil production than originally forecast, we will maintain positive cash flow and protect our balance sheet and dividend,” Diamondback CEO Travis Stice said in a news release. “We have made these decisions before, and they are driven by the goal of protecting shareholder returns over the long term.”

Parsley revised its baseline capital budget assumption from a $50 WTI oil price to between $30 and $35 WTI for the rest of the year. The company, which is now targeting at least $85 million of free cash flow—down from at least $200 million—is planning to drop its operated rig count by three to 12 and on March 6 dropped its five frac spreads to three.

“There’s no specific guidance on where capex and production will ultimately shake out given limited visibility into the duration and magnitude of pricing weakness to come,” Tudor, Pickering, Holt & Co. said of Diamondback’s announcement in a note to clients, “but less oil growth than originally targeted will be more than offset by balance sheet and dividend protection if the company maintains positive cash flow as planned. Looking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for other coverage companies to follow suit."

While Diamondback and Parsley were the first two to announce changes, others have already put the writing on the wall, looking at oil demand and the impact of the coronavirus.

"Exxon [is] actually going to be taking their expected [production] growth number for the last two years down 10% just because [it is] not happy with the prices … in the market although they are keeping their longer-term plan of almost tripling production in the Permian Basin intact," Ozkan said. "We saw Centennial saying that [it's] going to be prioritizing balance sheet preservation over production growth. We saw Continental saying that with demand impacts on the coronavirus, [it's] going to be moderating near-term growth and waiting for that pent-up demand … to show back up."

He added that Occidental Petroleum Corp. said it would remain flexible, saying it could lower growth or let production decline a bit.

Some oilfield service companies, Ozkan continued, are already seeing some rigs being returned due to reduced drilling programs in light of oil price changes.

The moves will impact supply.

"If we do see demand start to come back in the second quarter, we expect that a lot of the plans that operators had in place are likely to continue and even maybe pick up steam later on in the year as prices recover," Ozkan said. "However, even before we got to the impact of the coronavirus on demand, we already had all of these operators collectively shedding about 15%, or $8.8 billion of capex, from 2019 levels, and they were open to further activity reductions should prices deteriorate."

The International Energy Agency (IEA) cut its 2020 base case global oil demand forecast by 1.1 million barrels per day (MMbbl/d). It expects demand will fall year-over-year by 90,000 bbl/d

"In 1Q20, China's demand falls by 1.8 MMbbl/d year-over-year with global demand down 2.5 MMbbl/d," the IEA said in its March 2020 Oil Market Report. "We assume that oil demand returns to close to normal in second-half 2020."

The coronavirus is playing a role globally and in China, the epicenter of the virus.

"We think that Chinese oil demand is easily shedding over a million barrels a day in the current quarter," RS Energy Group vice president Al Salazar said on the webinar.

The situation appears to be improving in China, according to Salazar, who noted some cities in China have lifted lockdown restrictions, port congestion has fallen and traffic is starting to return to normal.

His comments were based on analysis of data from GPS manufacturer Tom Tom's Traffic Congestion Index, which assessed traffic in Wuhan and other provinces, and rising gasoline and power consumption.

"But looking beyond China—now, this is the important thing—we estimate total world oil demand this year may grow a modest 600,000 barrels a day because of the impact of the coronavirus," Salazar said. "This estimate is based on the loss of 1 percentage point in global GDP growth this year compared to the precoronavirus case."

The greatest source of uncertainty, he added, is the global impact on demand, economic activity and the spread of the disease.

—Velda Addison

NAPE crowds 'resilient' through tough A&D times

Known as the event where deals happen, the exhibit floor at the 2020 NAPE Summit buzzed with what Will Cullen, vice president of LongPoint Minerals LLC, described as a "resilient spirit" despite the fog of tough A&D times for upstream dealmakers.

Cullen, who spoke with Hart Energy at LongPoint's booth on the NAPE show floor in Houston, said he noticed a shift toward problem-solving among this year's conference attendees, which ended up totaling more than 11,000 oil and gas professionals.

"Certainly, there's a tempered enthusiasm with the current backdrop of limited capital and down commodity, but folks are still trying to figure things out," he said of the event held annually in February at the George R. Brown Convention Center.

With this year's tagline of "Find Your Focus" on purple signs every few hundred feet, thoroughfares thick with foot traffic led to roughly 700 exhibitor booths. Attendees took pathways to the latest software offerings, auction houses, E&Ps, mineral buyers and, of course, sporting clay clubs.

Some came to pitch prospects, others to promote their companies, and some hunted deals.

Tucked into a NAPE nook, BoomTown Oil LLC competed with its own "Oilfield Mafia" stickers and a poster board showing the company's assets in the Eagle Ford Shale and Denver-Julesburg Basin.

As he touted BoomTown's Wyoming acreage, Christian Walters, vice president of land and business development, said a lot had changed since he first attended the annual gathering.

Today, it's more formal and workmanlike than when he first began attending.

"My first NAPE was 2006," he said. "Back when it started, we had a lot of stuff to do. A lot of stuff to enjoy."

Fourteen years and four children later, Walters said the rowdy years of the past had given way to "the better, upscale executive" conference, he said, laughing.

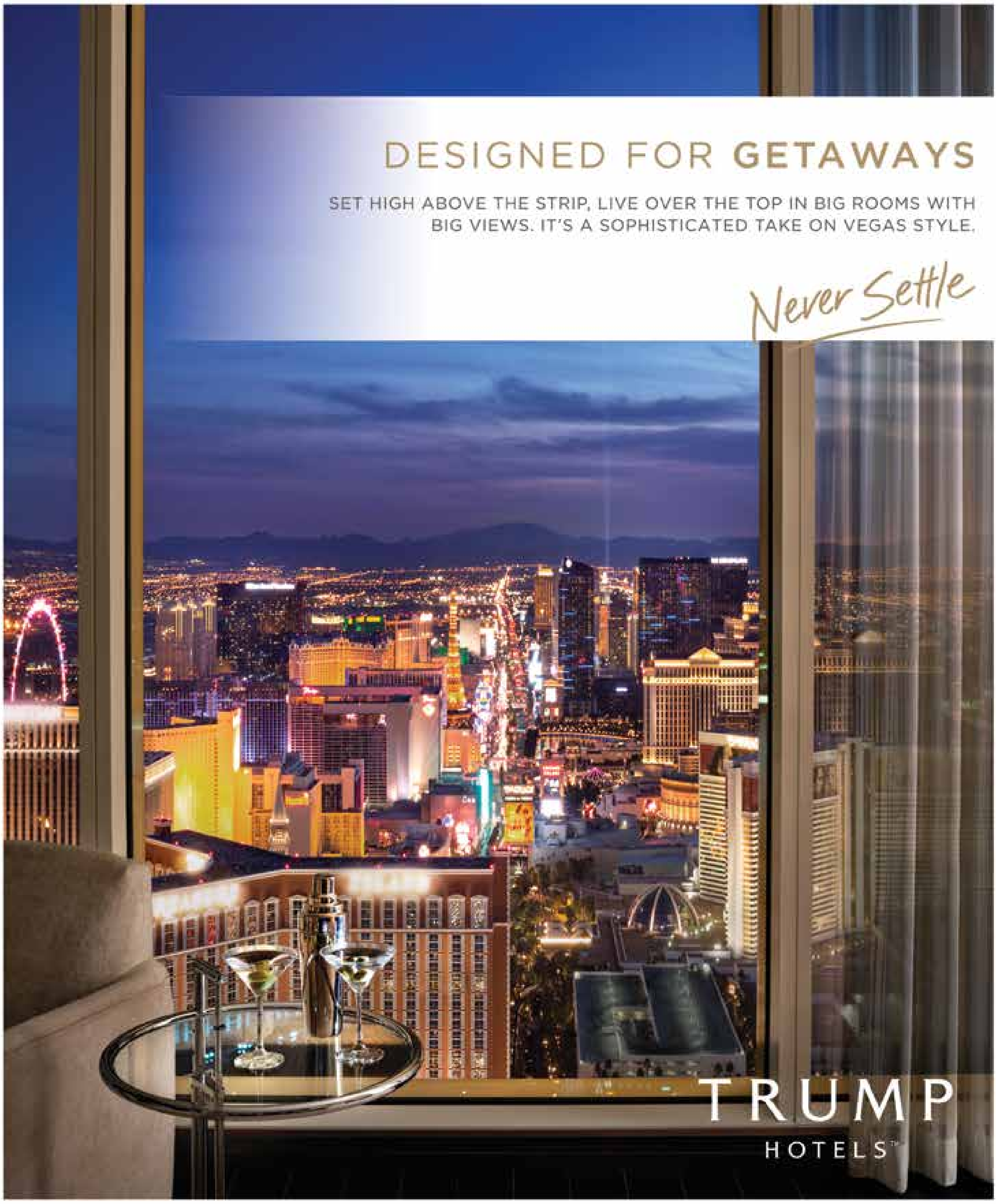
"It's been a great thing to enjoy," he said.

Coming off a slow year of A&D activity, deal making for the upstream oil and gas industry in 2020 has been projected to more or less stay the same with a few bright spots.

In an interview at NAPE, Andrew Dittmar, senior M&A analyst Enverus, told Hart Energy he sees A&D to continue to be challenging for the year ahead, citing the continued lack of capital and investor enthusiasm for acquisitions.

However, sellers have readjusted their expectations on some pricing, which might improve the bid/ask spread, he said.

"At least compared to past years, prices in some pretty premier areas look relatively moderate," he said. Using the Delaware Basin as an example, he added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that he is seeing core acreage transacting for half or a third of what was paid for in 2017.

"If you are a buyer out there, I think there's some opportunities available provided you can get capital to take advantage of them," he said.

Denna Arias, vice president of corporate development for EnergyNet, told Hart Energy she's heard hopefulness among attendees that transactions will pick up.

She added that EnergyNet has also started preparing for a potential ramp up in A&D in 2020.

"We are going to be ready to increase, just to keep growing up market and increase our technical abilities and what we can offer our clients both on the buy- and sell-side," she said.

One trend Cullen said LongPoint Minerals started to see take shape near the end of 2019 is larger mineral packages being brought to market.

"We're going to start to see more of these bigger packages either by somebody who aggregated it a while ago or just large mineral owners [or] landowners that no longer can just sit on the sidelines," he said.

Cullen said this year LongPoint Minerals is looking to expand into the Eagle Ford Shale. The Denver-based company, founded by the management team of privately held FourPoint Energy, currently focuses in two primary basins: the eastern Anadarko and Permian.

"We've done a lot of technical work there," he said of the Eagle Ford. "We haven't done a deal there yet, but I think that's going to be a place we're going to target and try to get after this year."

PetroValues Inc., an online oil and gas marketplace based in Denver, is also seeing an increase in minerals and royalties transactions.

"What we're seeing is a lot of nonoperated working interest investors are shifting toward investing in minerals and royalties because there's less risk," Eric Thompson, vice president of business development at PetroValues, told Hart Energy during NAPE.

For the first time ever, one-fourth of the total asset deal value in 2019 U.S. M&A came from royalty or joint development agreements, according to a recent report by Deloitte LLP.

Enverus' Dittmar described minerals as one of the brightest spots of the oil and gas industry.

"Minerals show they can deliver in terms of cash flow so I think there's a lot of positivity around that piece of the industry," he said.

Unlike the E&P asset market, the minerals acquisition space is drawing interest from several buyers, according to Dittmar, ranging from royalty public companies, private-equity-backed companies, E&Ps and institutional capital.

"You've got a very diversified group of buyers in that space so capital is coming in from other areas where money is still available," he said.

After a tough year in A&D, Arias said the oil and gas industry is naturally finding its way in a turbulent market.

"Of course, everyone is kind of uncertain of pricing," she said. "But they're hopeful with the New Year, new decade that things are coming to market."

—Darren Barbee and Emily Patsy

Exxon Mobil Corp. lifts capex but other majors cut

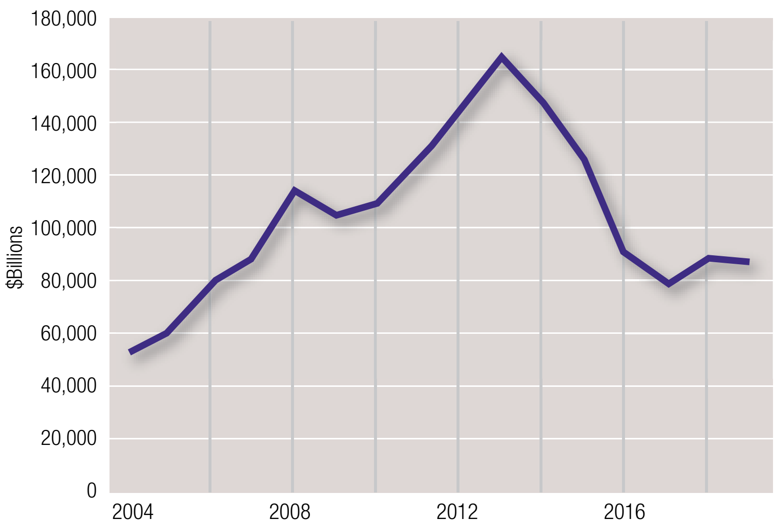
Capex budgets for the five major integrated oil companies are historically a harbinger of the energy industry's future. A Feb. 26 briefing note from the Institute for Energy Economics and Financial Analysis (IEEFA) has found that the majors' capital spending in 2019—a total of $88.7 billion—is the lowest amount since 2007. Exxon Mobil Corp., Chevron Corp., Total SA, BP Plc and Royal Dutch Shell Plc spent just half of what they did in 2013, when their operations distributed $165.9 billion worldwide. The institute said its findings signaled "a mature industry in decline."

"Diminishing capex should worry investors and serve as a warning that the oil and gas industry is not the cash cow it used to be," said IEEFA energy financial analyst and lead author of the note, Kathy Hipple. "Traditional businesses, like oil and gas exploration and production, refining and petrochemicals are all showing signs of stress."

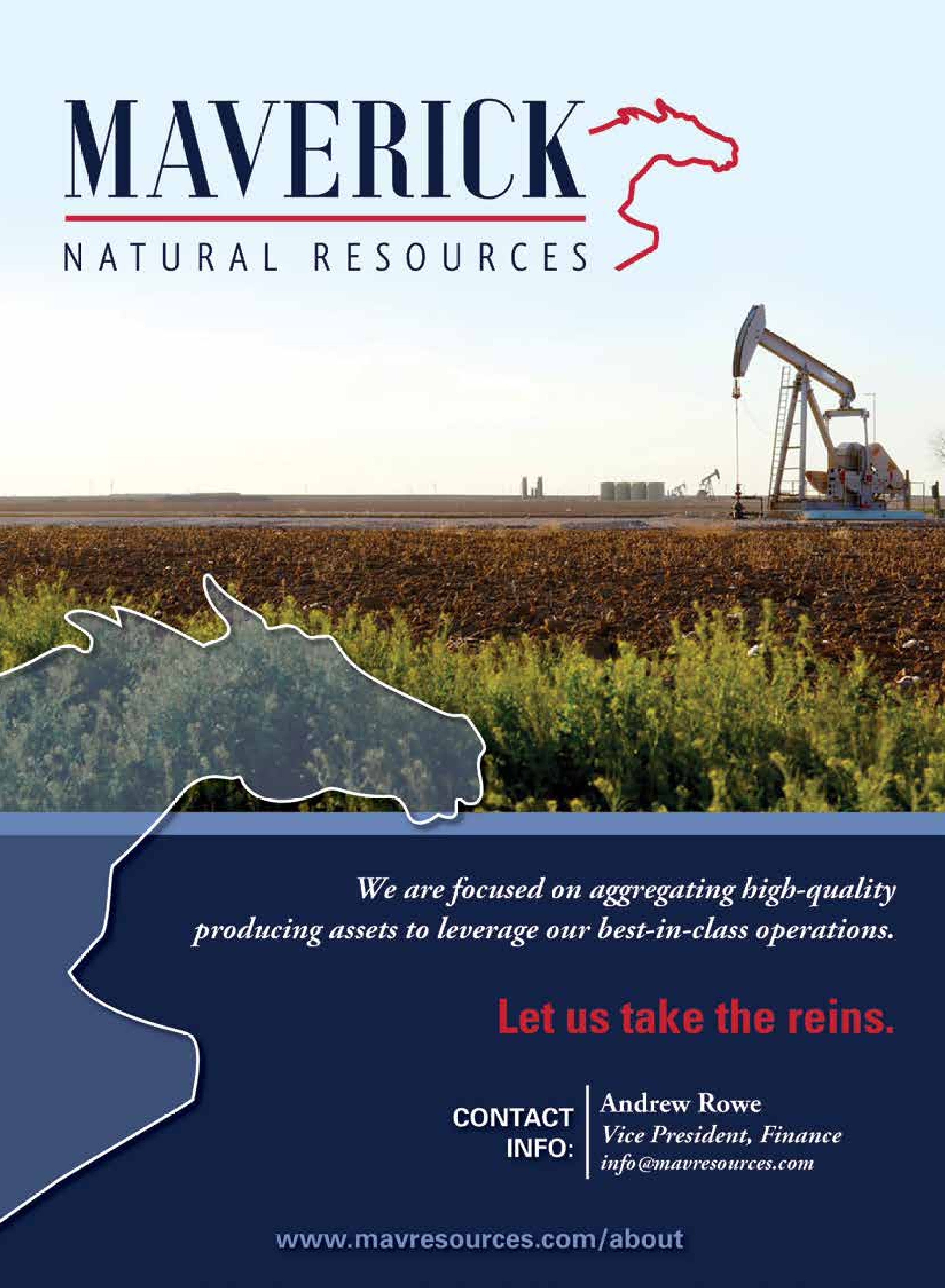
Not all the majors reacted with sharp capex cuts, however. Exxon Mobil's budget in 2019 was 93% of its 10-year average of $26.1 billion, while Chevron's was $14.1 billion, about 60% of its decade average; and Total's fell to just over half its 10-year average. After dropping sharply in 2014, Exxon Mobil's spending has been rising, in fact, with $24.4 billion invested last year. According to the institute, the company plans to expand capex this year to more than $30 billion, "in what has been described as a counter-cyclical strategy."

Commodity prices are the determining factor for oil and gas companies' spending and health regardless of whether they are majors or small independents. The report noted that the industry is still

Capital Expenditures For Five Supermajors: 2004-2019



Source: IEEFA, company sources, Morningstar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attempting to recover from the fall in oil prices from more than $100/bbl in 2014 to $29/bbl in 2016. Gas prices at $3/MMBtu are in even worse shape. These factors mean the universe of profitable projects shrinks significantly.

"The industry claims it is motivated by capital discipline and higher levels of diligence, but another explanation is a lack of viable investment prospects," Hipple said. "The decline in capex indicates an industry with lower production levels going forward and a smaller return on capital invested."

The note also cautioned that the petrochemicals industry, which used to protect the integrateds to some extent, can no longer be counted on as a buffer. Chemical margins fell in 2019, and the financial outlook worldwide is "at best, mixed."

"The days of consistent, long-term 20% returns are behind them, and unlikely to return," the authors said. Further, investors are no longer focused on reserve replacement but rather on cash flow and profits. "Free cash flow has become the crucial metric."

The note's authors also discussed the effects of renewables and climate change pressures on the fossil fuel industry. "The capital markets are shifting toward two energy economies," they said—one based on fossil fuels and the other, renewables. The majors' talk about investing in renewables does not always match their walk.

"Investments in renewable energy have been minimal," the authors said, "even among the European oil majors—Shell, BP and Total—that have made public announcements about their efforts to embrace new energy initiatives. One of the stumbling blocks is the 6% to 12% returns on investment typical in renewable energy vs. the 20%-plus ROIs for oil and gas in days gone by."

—Susan Klann

EnerCom Dallas: ESG is here to stay for energy

Many energy executives struggle with the growing emphasis on ESG issues. And well they should, speakers at the recent EnerCom Dallas conference cautioned.

Meanwhile, another trend grows: Investors want value—returns on their capital—not growth, they added.

"ESG is not a flash in the pan," James Wicklund, managing director with Stephens Inc., said in his presentation. "The goal is to be the best there is" in an industry focused on producing out-of-favor, carbon-based fuels. A producer can't compete environmentally with an office-bound information technology firm, for example, but that producer can work to keep its environmental impact less than that of similar-sized peers.

He added that "the midstream is the only segment that still works," for environmentally sensitive investors. "It's also the only one that is sustainable. The Holy Grail is all things digital and intelligence."

Kenneth Wonstolen, senior vice president and general counsel for Denver-based HighPoint Resources Corp., discussed Colorado's "challenging environment" for oil and gas producers. He reviewed the firm's ESG efforts centered on an active corporate responsibility program.

He noted that getting credit for corporate ESG efforts depends to a large part on learning to speak the right jargon.

"One of the first things to know about ESG is if you don't say it, you don't get credit, even if you're doing it," Wonstolen said. For example, he said companies should not have an environmental "practice" but a "policy."

Why the persnickety emphasis on language?

He said the monitoring agencies that rank firms' ESG efforts must rely on web crawlers that search through a blizzard of corporate responsibility reports, proxies and other documents to establish ratings. "They simply don't have the manpower" that would allow staff to manually read thousands of documents.

The crawlers have key words to find. If the words are there, fine. If not, investors and the public won't know.

HighPoint Resources operates in the Denver-Julesburg Basin, with more than 155,000 net acres under lease, centered on Weld County, Colo.

Charlie Riedl, executive director of the Center for Liquefied Natural Gas, said in a luncheon keynote that the industry does have a good story—natural gas—to tell on environmental issues.

"Gas de-risks renewables," Riedl said. But he cautioned that Russia, and perhaps other energy producers, have a vested interest in boosting U.S. environmentalism at the expense of the domestic oil and gas industry.

"There is a strong effort to undermine our efforts," he said, adding Russia wants to emphasize the perceived risks of hydraulic fracturing but "is not forthcoming about its own environmental risks."

He also cautioned the conference's energy-friendly audience not to assume regional support of the industry. Riedl described a recent survey of energy industry issues that found similar, and generally negative, views about oil and gas among Houston-area respondents. Their comments differed little from people questioned in Seattle.

Natural gas does have a more positive view with the public than oil, he added, due to its use in sustaining renewable energy when the wind stops and the sun doesn't shine.

Decoupling oil and gas could be an important move as many in the general public now mentally link gas with renewables, and oil with coal. "Thinking of the two together can be a dealbreaker for gas," he added.

Wicklund noted the environmental part of ESG continues to loom as a prime, worldwide issue. He noted BP Plc announced plans in February to be a net-zero carbon company by 2050.

"Companies like BP and Exxon Mobil don't change their emphasis on a CEO's whim," he noted. Such supermajor announcements come only after considerable research and consideration.

Several speakers spoke to another significant trend: investors' view of energy stocks as a value play rather than a growth play. Some cautioned the current downturn in prices could linger as efficient production from unconventional plays exceeds demand.

Wicklund also said BP has decided to emphasize "value or volume" because "investors want to be paid a return on their capital."

The Williston Basin could be one play that gains from that value emphasis. Nicholas Noppinger, CFO of Flatirons Field Services LLC, reviewed the firm's North Dakota operations for conference attendees.

"The Williston is a true mining operation," Noppinger said, due to its predictable geology, which keeps costs low. However, the region faces the prospect of more crude-by-rail shipping as slowing production growth won't merit new pipeline capacity.

Elaborating on value, Wicklund closed his presentation by saying, "The question is profitability, whatever the [commodity] prices are."

—Paul Hart

Eagle Ford shale productivity falters in 2019

The effects of persistent lower oil prices are increasingly leaving their mark across the U.S. shale plays and now being felt in the core of one the most mature unconventional plays—the Eagle Ford Shale.

A Feb. 13 report from Bernstein Research highlighted what the firm termed the first significant production weakness in the most productive and heavily drilled areas of the Eagle Ford Shale.

"And 2019 marks the first year in the past eight years [nearly the entirety of the Eagle Ford's life] that wells in most-intensely drilled sections have become less productive," the Bernstein analyst team led by Bob Brackett said.

The analysts noted that producers always drill the most profitable locations first, and Bernstein's heat maps show the expected overlap between highest well counts and IP rates. "The 'reddest' sections (i.e., those with the highest count of drilled wells) are squarely in the oily 'sweet spots,'" the analyst team said.

To confirm the deterioration in oil peak rates in heavily drilled Eagle Ford sections, the analysts looked at peak rates for three groups—high density, medium and low—of 2-mile-by-2-mile sections. The high-density group includes sections where 16 or more wells had been drilled, medium had eight to 16 wells and low included less than eight wells.

Bernstein analysts found that the average peak rates in the high-density sections fell 12% in 2019 versus 2018. They found "a similar trend on the basis of first six-month oil." Oil peak rates also dropped off in sections with tighter spacing.

As expected, operators are drilling fewer wells in these highest density sections. After a peak of 1,939 wells drilled in such sections in 2014, the count fell to 802 in 2016. Wells drilled rebounded slightly to 1,038 in 2018 and then declined last year to 931. In the medium-density sections, well count held relatively steady from 2018 to 2019, and the low-density sections saw a slight climb from 140 to 165 wells. Thus, for 2019 versus 2018, the high-density count fell 10% and medium dropped 6%. Meanwhile, the well count in the low-density section rose 18%.

Because producers focus on returns, "most locations with low breakeven prices [i.e., most productive ones] have already been drilled," the Bernstein analysts said. "For instance, while 53% of all the locations with breakevens below $50 have been exploited, less than 30% of wells with breakeven of $55 to $60 have been brought online."

The analysts discerned about 7,800 locations in the money with WTI at $55/bbl. "That covers only the next five years of production under our supply model and assumes optimistically that no other hiccups occur," the firm said.

Plenty of Eagle Ford locations exist—but only at higher crude oil prices.

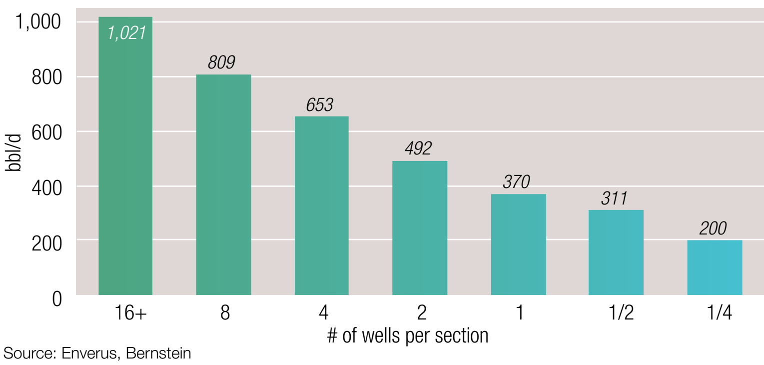
Based on the "significant inflection in production across U.S. shale," and given the need for higher crude prices to support shale growth, the team asked: "Is [this] the beginning of the end for the great bear market in oil?"

Bernstein's U.S. supply model calls for about 15,600 wells over the next 11 years, but the analysts note that sub-$60/bbl oil won't support this outlook.

The analysts also discussed the Eagle Ford production rates for 2019 of some of the companies in its coverage. For example, EOG Resources Inc.'s cumulative production fell by 6%. Chesapeake Energy Corp.'s also declined by 12% and Devon Energy Corp.'s by 29%.

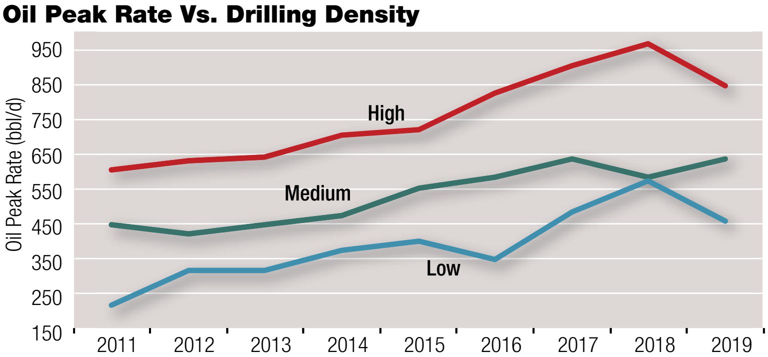
However, Bernstein said the negative effect is felt less by companies such as EOG that have broader portfolios. "While an aging Eagle Ford is good for oil prices [and thus net positive for non-Eagle Ford producers],

Eagle Ford Oil Peak Rate As A Function Of Wells Per Section



Source: Enverus, Bernstein

Oil Peak Rate Vs. Drilling Density



Source: Enverus, Bernstein

it's likely bad for Eagle Ford pure plays," the analysts added.

—*Susan Klann*

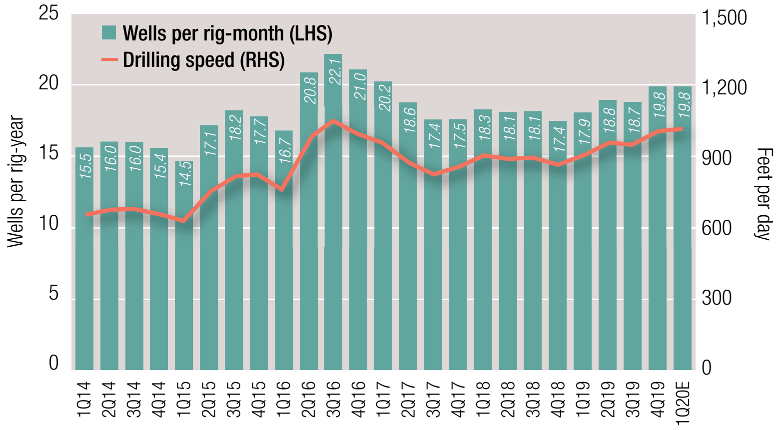
U.S. shale trends focus on operational efficiency

Record low Henry Hub gas prices, the coronavirus' unexpected hit on global oil demand and persistent pressures from shareholders show the year is off to another rocky start for U.S. shale producers.

Rig counts have fallen along with completions activity in just about all U.S. land basins, except the Permian Basin, an implication of weaker frac activity, according to Artem Abramov, head of shale research, Rystad Energy.

In a February webinar, he noted the number of active horizontal oil rigs fell by 25% last year with some liquid-rich basins laying down more rigs than others. Oklahoma, home of the Scoop/Stack play, has seen its horizontal rig count fall by about 50% since August. However, he said, the Bakken, Denver-Julesburg and Eagle Ford "activity remains relatively close to the historical record levels."

U.S. Average Horizontal Drilling Efficiency By Quarter



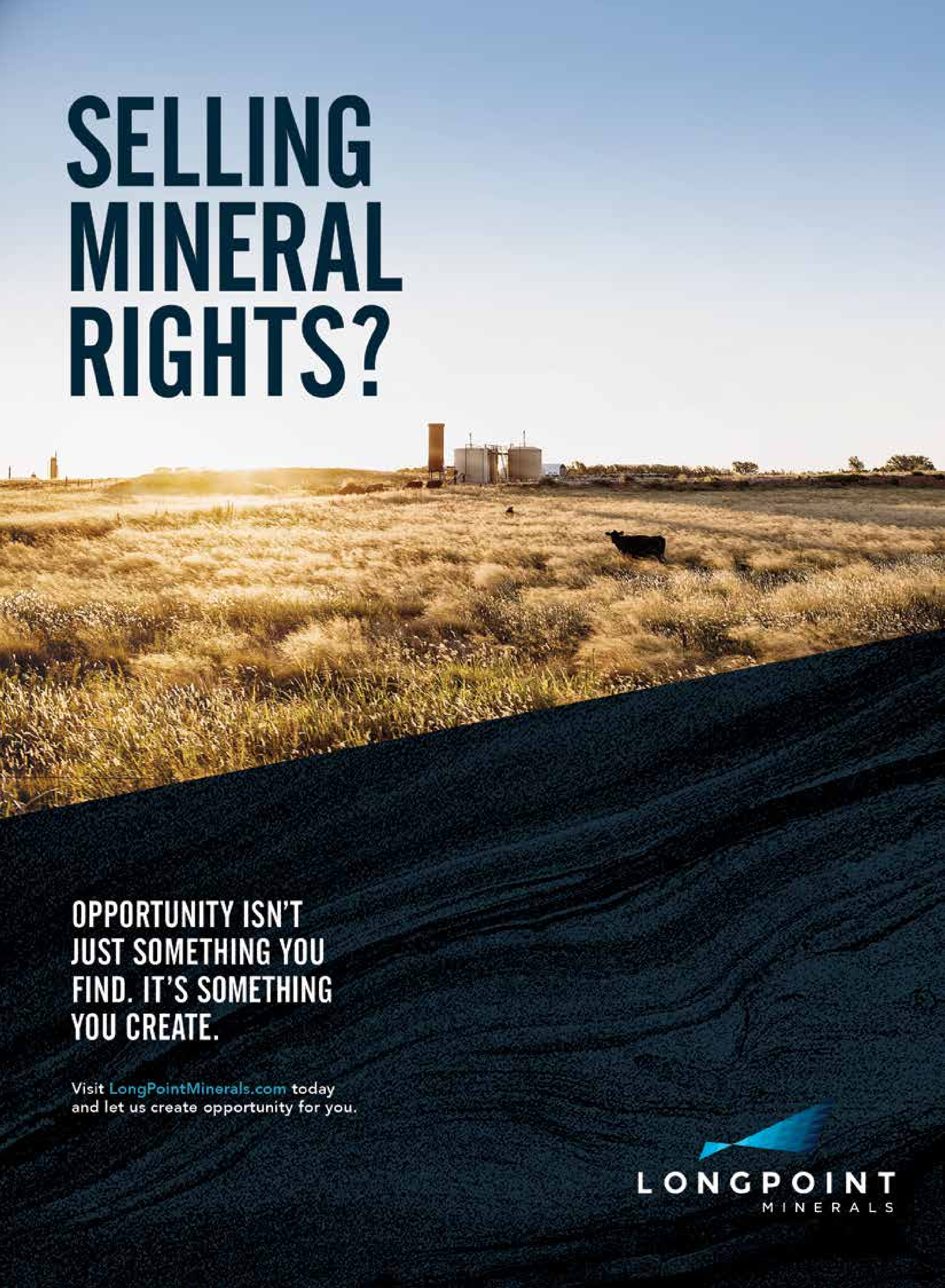
Source: Rystad Energy

This comes as activity in the Permian sees capital flow into the oilier northern Midland and Delaware New Mexico instead of the gassier southern Midland and western Delaware on the Texas side of the basin.

"We think 2020 will be quite a challenging year for the industry," Abramov said. "There is a lot of uncertainty about what kind of activity guidance [and] capital guidance we'll see from the companies. Despite that fact we believe that one thing is quite certain, this year will see continued focus of the industry on operational efficiency not necessarily productivity gains."

Here's a look at some of the trends Rystad Energy is seeing:

- Improved drilling efficiency with an average 1,000 feet being drilled per day in all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basins, which reduces the number of rigs needed to drill the same number of wells for the same footage.

- More horizontal wells per pad as the Permian catches up to other basins. "Our expectation is we will see an increase in share of large-scale projects," Abramov said. "One of the drivers behind this fundamental improvement in the drilling efficiency is continued increase in the share of pad drilling and also the increase in average pad size, average project size."
- Preference for pure slickwater jobs over hybrid and gel-based continues to grow, accounting for nearly 70% as of late 2019. That's up from 53% in fourth-quarter 2018.
- Zipper fracture stimulation dominance, representing more than 80% of the market.

However, Abramov said simultaneous fracs (simul-frac) could drive further completion efficiency this year. Stimulation via simultaneous operations allows frac fluid to be redirected with little downtime between a new wellbore and one that has just been fractured, he explained.

Early pioneers of simul-frac are "quoting average frac speeds exceeding 3,000 feet of lateral per day even with very intensive completions," he said. "In many cases, they are able to pump fluids downhole [at] a rate of 140 to 160 barrels per minute and almost without downtime."

QEP Resources Inc. is among the companies using the technique and seeing benefits in the Northern Midland Basin. The company averaged 4.2 million pounds of frac sand per day in 2018 to 2019 with an average completion speed of 2,583 lateral feet per day, he said, compared to a couple of other operators with 1,378 and 1,130 lateral feet per day, respectively. QEP's average D&C cost per perforated lateral foot was $641, which Rystad said was the lowest in the Midland sub-basin.

"It is a big gain," Abramov said. "Ultimately, all of these things lead to capital efficiency because you're able on a per well basis you are able to achieve lower cost per foot."

—Velda Addison

Differing approaches to optimizing Permian well spacing

After years of downspacing, E&P companies in the Permian Basin have started to pursue wider well spacing to resolve certain operational issues and boost returns.

Operators in the Midland Basin, in particular, have adopted various practices and wider well spacing developments to focus on free cash flow generation over the past 18 months, engineering analysts with Enverus said during a recent webinar focused on calculating optimal well spacing.

Many operators adopt the traditional midpoint distance calculation or sampling method to find the optimal distance between two wellbores, both of which do not provide a 3-D view or accurate representation of how far the wells are spaced, said Brendan Nealon, engineering analyst for Enverus.

He noted that Enverus' patent-pending Well Spacing approach analyzes factors that affect parent/child well relationships and the impact of spacing on well productivity across basins. It creates segment-wise analytical distances and wells, treating wellbores as polylines for bore-to-bore calculations.

Citing an example of the accuracy of this method compared to the traditional mid-point method, Nealon said the latter underestimated middle Bakken formation spacing by 10% across the Williston Basin.

In the Midland Basin, spacing strategies have varied over the years based on the formation, Nealon said.

Nealon compared well spacing strategies of major operators including Pioneer Natural Resources Co., Exxon Mobil Corp., Ovintiv Inc., Diamondback Energy Inc. and Concho Resources Inc. in the two most targeted formations of the Midland Basin—Wolfcamp A and Wolfcamp B.

During the past two years, he said wider spacing with variability in spacing strategies has been observed in Wofcamp A, while a convergence of five to six wells per section with about 900 feet to 1,000 feet of average horizontal spacing has been observed in Wolfcamp B.

Between 2012 and 2016, a significant increase in production was observed in both Wolcamp A and B, with operators downspacing their wells. Advanced completion technologies contributed to optimized production, despite tightly spaced wells. However, between 2016 and 2018, with further downspacing of wells, productivity growth slowed down. In 2019, operators slightly upspaced their wells, which resulted in a jump in productivity.

Tyler Krolczyk, asset evaluation engineer at Enverus, also discussed operators' spacing development strategies via a gun-barrel view. He showed a comparison between Exxon Mobil, Parsley Energy Inc. and Pioneer, their spacing strategies, production and economics.

While Pioneer and Exxon Mobil showed consistency in their true spacing, Krolczyk said it was interesting to note that Parsley's well spacing in 2015 was 1,200 feet on an average. Three years later in 2018, the company had cut spacing in half at 600 feet with slight upspacing in 2019. With this spacing strategy, he said Parsley jumped from the 10th to the second-largest Midland Basin operator among publicly traded Permian pure-play companies during this period.

The case study also showed that stacked laterals and fully- bounded wells in Wolfcamp A and B resulted in poor productivity.

"Development orientations and how do you place these different wells is an extremely important engineering consideration and there is more to space than just frac design, frac size and the fleet," Krolczyk said. "If you just have a horizontal distance, you're missing out on the vertical complexity to development."

Using the gun-barrel view, Enervus also concluded that Parsley's transition from a stacked lateral development to a wider spacing and larger frac size, doubled its internal rate of return (IRR). Meanwhile, Pioneer has been consistent with its staggered development approach and has steadily increased its EUR per section and single well IRR over time, according to the Enverus analysts.

Pioneer has co-completed its wells, while increasing frac size and mitigating "parent-child" well risk.

—Faiza Rizvi


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M&A GONE MILD

In a market environment where buyers and sellers are at odds over price and the public market is openly hostile to deals, E&P shoppers may sit out an uncertain 2020.

Southwest of Midland, Texas, Parsley Energy Inc.'s $2.3 billion purchase of Jagged Peak Energy Inc. illustrated that a smart, all-stock transaction with a low price premium could survive Wall Street's otherwise withering reaction to deals.

ARTICLE BY
DARREN BARBEE

PHOTOGRAPHY BY
JAMES DURBIN

"The M&A outlook for the year is shaped by the tug of war between the logic of consolidation and benefits of scale on one hand and the worsening conditions in the commodity and capital markets on the other," said Art Krasny, managing director and head of A&D for Wells Fargo Securities.

It was wild, like a first date, first oil, the first million-dollar check deposited in the bank. M&A lit the shale revolution like the pilot light of a great furnace that seemed capable of burning on forever.

And like a flame, it was wild, and then it wasn't.

Shalepalooza is gone, and there's no going back. But transaction advisers see a way forward. Tricky and treacherous, but forward.

"No question, it's a tough environment," said Art Krasny, managing director and head of A&D for Wells Fargo Securities.

Welcome to 2020 A&D, the sequel to a year that tore down any lingering hype over oil and gas asset values.

Even in the Delaware Basin, where two years ago leasehold cost $95,000 per acre, the bubble for acreage prices appeared to have burst. WPX Energy Inc.'s $2.5 billion purchase of Felix Energy II's position averaged $6,700 per acre, according to Enverus. Likewise, Marathon Oil Corp. paid an average of $2,600 per acre in Ward and Winkler counties, Texas.

The market faces the push and pull of competing forces, Krasny told *Investor*.

"As we sit here in late February," he said, "with natural gas prompt prices at $1.80 per MMBtu and $52 per barrel of oil and the global economic outlook shaken by the spread of coronavirus, the M&A outlook for the year is shaped by the tug of war between the logic of consolidation and benefits of scale on one hand and the worsening conditions in the commodity and capital markets on the other."

The fourth quarter of 2019 ended with a clunk for asset deals, but investors lit a signal fire for future mergers: when in doubt, underpay.

Over the course of the year, oil and gas deals racked up roughly 200 deals totaling roughly $100 billion, according to Enverus. But the dollar figure was somewhat illusory, with Enverus calculating that about 60% of total deal value was propped up by a single transaction—Occidental Petroleum Corp.'s purchase of Anadarko Petroleum Corp.

Overall, the largest deals centered on corporate consolidations as asset transactions dwindled.

Advisers expect the remainder of 2020 to tick by in the same fashion, with the Permian Basin still the center of attention but the deals there looking as they did in the fourth quarter, when the top three mergers were corporate consolidations. However, they also caution that it's time to learn to live with uncertainty. The threat of the economy stalling, a pandemic and the abysmal performance of commodity prices leave M&A up in the air.

Asset transactions, in particular, hit a wall in 2019, with many deals left on the table, said Bruce Cox, managing director for A&D at Citi Global Energy Group.

"Only about 30% of public … asset deals were completed in 2019 versus the typical 75%," Cox said.

Likewise, Mark Nelson, executive director of A&D at CIBC Griffis & Small, saw a grim marketplace that will probably carry on throughout 2020.

"The reality is that Lower 48 asset sales in 2019 were about one-fifth of the 10-year average, both in deal count and total transaction value," Nelson said. "We see a similar activity level in 2020 and expect public M&A to increase as the year unfolds."

Increasingly, words like "shift," "adjust," "recalibrate" and "reset" are being used to describe how buyers and sellers are trying to work in a market environment in which sellers and buyers are at odds over price and the public markets are openly hostile to deals.

"Buyer and seller expectations are still trying to recalibrate to the current market. In deals that don't transact, buyers are being overly conservative, and sellers are being overly optimistic about asset values or the reality of the assets," Nelson said.

The market remains replete with obstacles. Company executives want to remain in control rather than step away from businesses. In a down market, bid/ask spreads may widen while producers that are intent on a sale will face hurdles over their commodity mix and general price uncertainty, Cox said.

Cox expects to see more M&A in 2020 but said that transactions "could face headwinds and be delayed until the second half of 2020 [by] the coronavirus and market instability."

"Any potential transactions will run into headwinds originating from coronavirus issues associated with reduced oil demand and lower commodity prices," he said. "Uncertainty, regardless of the source, [is] always a limiting factor in deal flow, which will need to work its way out of the market into 2020."

Top 10 Deals Of 2019

Date	Buyers	Sellers	Value ($MM)	Type	Play/Region
April	Occidental Petroleum Corp.	Anadarko Petroleum Corp.	$57,000	Corporate	Delaware/D-J/GoM
August	Hilcorp Energy Co.	BP Plc	$5,600	Property	Conventional (Alaska)
July	Callon Petroleum Co.	Carrizo Oil & Gas Inc.	$2,740	Corporate	Delaware/Eagle Ford
December	WPX Energy Inc.	Felix Energy II	$2,500	Corporate	Delaware
October	Parsley Energy Inc.	Jagged Peak Energy Inc.	$2,270	Corporate	Delaware
June	Comstock Resources Inc.	Covey Park Energy	$2,185	Corporate	Haynesville
August	PDC Energy Inc.	SRC Energy Inc.	$1,700	Corporate	Niobrara
November	Pure Acquisition	HighPeak; Grenadier II	$1,575	Corporate	Midland
July	Ecopetrol	Occidental Petroleum Corp.	$1,500	JV	Midland
April	Murphy Oil Corp.	LLOG Bluewater	$1,375	Property	Conventional (GoM)

Source: Enverus

A Parsley Energy Inc. employee surveys newly acquired terrain being drilled by a Helmerich & Payne rig. Parsley closed on Jagged Peak Energy's West Texas leasehold in January.

After a ragged year for M&A in the Permian, Parsley Energy Inc.'s deal with Jagged Peak Energy Inc. was part of a trio of large, fourth-quarter consolidation transactions in the basin totaling more than $6.3 billion.

Merger of equals

The color spectrum outside of Monahans, Texas, seems to narrow into bands of grays and browns that blend at the horizon. But the land in Monahans in March, pocked with mud puddles and holding up a few derricks under overcast skies, represents something new, at last, in the Delaware Basin of Texas—synergy.

In October, Parsley Energy Inc. announced it would purchase Jagged Peak Energy Inc. for $2.3 billion.

In the past two years similar deals have resulted in upstream companies' stock undergoing a public evisceration on Wall Street.

But Parsley's deal and others that emerged in the fourth quarter of 2019 weren't flogged.

The long campaign for consolidation has clearly won the hearts, and now the minds, of E&P executives and investors. The push E&Ps needed: the bottom of the market.

E&Ps have performed worse than any other sector of the market over the past decade and represent less than 4% of the S&P 500 Index, an all-time low, according to Kimmeridge Energy Management Co. LLC.

"We really just have entirely too many E&P companies with duplicated overhead infrastructure and everything else," said Andrew Dittmar, senior M&A analyst at Enverus.

But the particulars of how mergers are structured and paid will continue to be vitally important for successful mergers this year. That lesson was made clear during and after Occidental Petroleum Corp.'s bidding war to buy Anadarko Petroleum Corp. Chevron Corp. made an initial offer for Anadarko in April, offering $65 per share—a 39% premium on Anadarko's stock price at the time.

Occidental countered at $76 per share, a staggering 62% premium on Anadarko's market value.

Since announcing the deal, Occidental's share price has taken a massive hit, and its value vaporized by $20 billion.

By contrast, successful deals in the latter half of 2019 centered on all-stock mergers offering low or no premiums between neighboring companies, Dittmar said.

"The playbook is pretty well-established from 2019," he said, adding that companies also have to "lay out a very solid case on how does this accelerate the runway … how does this accelerate positive free cash flow?"

Merger of equals began to pick up momentum in late 2019, led by PDC Energy Inc.'s acquisition of SRC Energy Inc. in an all-stock merger worth about $1.7 billion, including debt. PDC paid no premium on SRC's stock. In contrast to other deals that have been whipsawed by market negativity in recent months, PDC stock rose 17% on the announcement.

Likewise, Parsley's acquisition of Jagged Peak was an all-stock transaction that offered a 1.5% premium. Parsley was buffeted up and down by the market but otherwise didn't appear to suffer directly from the deal.

Both the Parsley and PDC deals closed in January.

THE ACTIVISM BIBLE

Kimmeridge Energy Management Co. LLC is looking to put the E&P sector into a kind of business reform school.

In a recent white paper, the activist firm said the U.S. E&P industry is in a time of crisis that has caused capital to flee the space. Kimmeridge, which agitated for PDC Energy Inc. to deliver sustainable cash flow prior to its merger with SRC Energy Inc., plans to persuade, cajole and, if necessary, fight to focus on equity underperformance in the public E&P space.

In February, the firm said Mark Viviano would join the firm as head of public equities to lead the effort. Viviano will lead a team focused on public market investing within the energy sector.

"The good thing about trying to be an activist in the sector is there's no shortage of opportunities out there when you think about underperforming companies," he said. "This is not about day one trying to go into proxy battles with a specific company. The idea is to own a concentrated portfolio of public energy equities where you think you have the ability to affect change."

Overall, Kimmeridge sees public E&Ps as enterprises that have suffered from mismanagement and held on to a production growth mindset long after the notion of oil and gas scarcity was played out. The firm largely sees E&Ps as companies that should seek to return capital to investors through sustainable dividends and share buybacks.

"Change is really focused around capital allocation decisions and management incentives, and we think we're uniquely positioned to launch a strategy that's going to help reform the sector," he said.

Viviano said that activism is more about persuasion and winning over shareholders to better alternatives.

With relationships spanning 15 years, he said he arguably has "as many battle scars as anyone else in the public energy sector. And that carries a certain degree of credibility when you're talking about what needs to change within the industry."

Viviano said the firm is exploring different options to invest within the energy sector with an ace up its sleeve: experience on the buy side, sell side and in operations.

"The key differentiator for Kimmeridge is having the in-house technical and geological expertise. That's a big advantage that not many other activists in the space [have]," he said.

Kimmeridge's operational and technical team, based in Denver, gives the firm the ability to understand the assets and discuss with management teams what the assets are expected to deliver and how "we would be running them differently."

"There's just a lot more credibility when you're sitting down having those discussions as opposed to somebody who's a generalist coming into the sector because they see an opportunity of a discounted valuation," he said.

Kimmeridge sees the path toward regaining investor trust as a series of to-dos for upstream companies with these necessary steps:

- Providing visibility to return all enterprise value to shareholders through dividends and buybacks in 10 years;
- Eventually reinvesting less than 70% of cash flow and a maximum of 80% depending on pricing;
- Reducing balance sheet leverage targets to 1.0x of less; and
- Making capital allocation decisions with an understanding of environmental impact.

The firm also wants to compensate executives with less base pay and more equity ownership, with bonuses paid for absolute share price performance and payments that reward selling and consolidation.

"We think in a mature sector like this where you can't count on higher commodity prices in the future, those incentives need to change," Viviano said.

In cases where the premium didn't sit right with investors, they rebelled.

The eventual merger between Callon Petroleum Co. and Carrizo Oil & Gas Inc. was stalled after Callon shareholder Paulson & Co. objected to the "unjustifiable" 25% premium the offer placed on Carrizo. A revamped proposal lowered Carrizo's premium to roughly

Bruce Cox, managing director for A&D at Citi Global Energy Group, said his clients are being more cautious about what they buy while the typical early year rush to get to market has decreased significantly as sellers hesitate.

7% and brought the deal's final price down to $2.7 billion from $3.2 billion.

In a different test case, WPX Energy Inc. said on Dec. 16 it would purchase Denver's Felix Energy II for $2.5 billion in a deal that was 64% stock. Dittmar said that after learning of the deal, he expected WPX's stock to plummet like many other Permian Basin buyers.

Instead, WPX closed out the week nearly 12% higher.

WPX "showed you could go out and do a deal if the asset quality was high enough and the price was right," he said. "And investors wouldn't sell [a company's stock] just because they saw the headline scroll across."

The push by investors to reward operations with size and scale is historically tied to the premise that, combined, they deliver on total shareholder value, free cash flow and growth, Cox said.

"M&A is the pathway needed to consolidate companies, achieve efficiencies and eliminate G&A [general and administrative]" expense, Cox said.

"Consolidation will continue," provided combinations feature low premiums, clearly defined strategic rationales, a clear-cut execution plan and operational efficiencies.

Opportunities also exist for private companies to buy other private E&Ps in roll-up transactions, particularly where private-equity sponsors have several companies in the same basin or area.

"While there have been discussions around this concept, roll-up sales may occur this year," he said.

The headline grabbing deals of 2018 and 2019 will also lead to divestitures this year, particularly as strategic decisions are made on the focus of company portfolios, according to a February report on M&A by Deloitte.

Occidental's Anadarko deal resulted in the sale of its newly acquired Africa assets for $8.8 billion. Occidental also entered into a $1.5 billion joint-venture agreement with Columbia's Ecopetrol and is exploring a sale of its Utah assets.

"Increased rate of divestments to generate cash could go hand in hand with prioritizing projects in its expanded footprints in West Texas, Colorado and the Gulf of Mexico," Deloitte said.

The potential hiccup is that companies are hunting for bargain basement prices that sellers simply cannot afford.

Fast and spurious

A mindboggling amount of money fueled the rise of the shale revolution. Since 2010, M&A has cost $567 billion, including about $140 billion coming from the Midland and Delaware basins, Enverus said.

That's enough money to buy 43 of the U.S.' most advanced aircraft carriers, plus tax, or

fund the entire military budget of the U.K.—for each of the past 10 years.

Investors remain deeply skeptical of shale oil and gas, particularly upstream companies they view as debauched spendthrifts.

Already in a financial hole, investors are resistant to addition deals. Mark Viviano, head of public equities at Kimmeridge, sees little value in pursuing more.

"We don't think the answer to the chronic over-investment within the industry is to put more capital at risk," Viviano said. "The fundamental problem with a lot of these companies that are making acquisitions is they don't have a premium valuation that can make it accretive. All they're doing is amplifying the execution risk without a clear valuation arbitrage."

To put a finer point on it, many deals haven't led to greater returns for shareholders, which is often the pitch made to Wall Street, Viviano said.

"There's just countless examples over the last few years where you're not seeing the benefits of the acquisitions that were promised to investors," he said. "There's a reason that the market is skeptical and treating these companies the way that they are when they announce these deals. The value creation proposition is not clear."

New inventory also amplifies execution risks, which have resulted in a number of companies "stumbling operationally coming out of deals."

"We don't think the answer is putting more capital into the business. It is taking capital out of the business and returning it to shareholders," he said.

But rhythm of deal making in 2020 will likely take its cues from 2019 with fewer but higher-value transactions that hinge on PDP assets.

As U.S. shales continue to mature, a clear shift is underway toward corporate M&A and away from land deals. Last year was another

Deals By Commodity Type 2018-19 ($B)

	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19
Oil	$16.2	$4.7	$16.9	$6.2	$0.6	$3.1	$10.1	$7.4
Oil+Gas	$4.5	$1.9	$14.7	$11.5	$1.3	$60.1	$5.4	$2.4
Gas	$1.8	$2.6	$2.8	$1.3	$0.5	$2.5	$1.9	$1.0
Total	**$22.5**	**$9.2**	**$34.3**	**$19.0**	**$2.4**	**$65.7**	**$17.4**	**$10.7**
Oil	72%	51%	49%	33%	27%	5%	58%	69%
Oil+Gas	20%	21%	43%	61%	54%	91%	31%	22%
Gas	8%	28%	8%	7%	19%	4%	11%	9%
Total	100%	100%	100%	100%	100%	100%	100%	100%

Source: Enverus

Under a patchy blue and white sky, Parsley Energy Inc. operates a separation station and tank battery near a wellpad in development. In the Permian, transactions will likely be driven by oil majors and independents further securing scalable positions.


Jagged
Peak
ENERGY

step down, as asset transactions totaled about $25 billion—a 40% drop from 2018, Krasny said.

"Based on deal count, market velocity [for deals] collapsed by over 60% in 2019 year-over-year," Krasny said. "We expect these conditions to continue in 2020 and could potentially see an even softer market."

E&Ps appear reluctant, or at least pickier, as they shop for deals. The Permian remains the most attractive multibasin play, particularly as valuations have decreased and enhanced the potential to transact, Cox said.

Nelson said CIBC tries to help its clients as well as buyers see values and opportunities more realistically. But in basins such as the Delaware, comparable transactions, to some extent, have lost their meaning. "It's a real challenge, and past transactions no longer serve as good indicators of current asset prices," Nelson said. "Each deal and each asset is now being evaluated on its own merits."

Deals By Quarter 2019 ($MM)

Play	1Q19	2Q19	3Q19	4Q19	Total
Delaware	$200	$100	$200	$4,800	$5,300
Midland	$0	$500	$2,600	$1,800	$4,900
SCOOP/STACK	$300	$100	$100	$1,400	$1,900
Conventional	$800	$4,400	$6,300	$1,000	$12,500
Barnett	$0	$0	$100	$800	$900
Eagle Ford	$100	$200	$0	$500	$800
Multiple	$200	$57,500	$3,000	$200	$60,900
Marcellus	$400	$100	$600	$200	$1,300
Niobrara	$0	$0	$1,700	$100	$1,800
Utica	$0	$0	$100	$0	$100
Bakken	$0	$400	$100	$0	$500
Other	$300	$2,400	$2,700	$0	$5,400
Total	$2,400	$65,700	$17,400	$10,700	$96,200

Source: Enverus

Krasny said he's tuning into three M&A "frequencies" where he thinks the deals could keep coming.

In the Permian, transactions look to be driven by oil majors and independents further securing scalable positions. Despite the diversification of deals in other basins, Krasny said that the activity remains substantially centered there.

"Everything in M&A begins and ends in the Permian," he said.

Thematically, however, corporate deals and consolidation via M&A remain important, if complicated by the market's reluctance to fund deals.

"Single well productivity is no longer the driver behind value creation and attention has switched to operational scale and efficiencies, pursuit of G&A and operational synergies and deployment of best practices across larger asset portfolios," he said.

CIBC's clients are generally interested in pursuing transactions, Nelson said. But as they weigh whether to take assets to market, they're taking a more thoughtful approach to what is marketable now and how a transaction would help meet corporate objectives.

"Some groups are holding back and taking a wait-and-see approach to the market," he said. Despite a souring of commodity prices, buyers are closely following where the bid/ask spread stands.

Cox said that his clients are also being more cautious about what they buy. The typical early year rush to get to market has decreased significantly, and sellers are largely waiting in the wings, he said.

DEAL GUIDE 2020

Over the past two years, it's been something of an act of faith for companies to engage in transactions and brace for the moderate to severe backlash from Wall Street. Advisers seem to have divined at least part of what investors want to see.

Bruce Cox, managing director for A&D at Citi Global Energy Group, said a clear pathway to value creation is essential. Simply jamming two injured companies together without synergies can lead to negative reactions. However, jamming two healthily companies together with clear synergies has also proven unpopular.

However, combinations are generally favored because of the recognition that consolidation is needed.

"But, there is a lack of clean exit options for privates due to publics largely exiting as participating, active buyers," Cox said.

However, successful mergers, in the eyes of the market, need to meet a Tinder profile worth of do's and don'ts before investors will even consider them.

Cox said that in the current market, successful deals will:

- Maintain or improve corporate-level returns and visibility of free cash flow generation;
- Feature low to zero premiums in which value grows through a merger;
- Complement one another in the same basin or provide entry into superior basin;
- Offer solid production and enough cash to fund development;
- Maintain or improve the balance sheet;
- Generate superior inventory returns at current pricing; and
- Result in accretive growth.

Opposite page, Jagged Peak Energy Inc.'s flag still flies over Parsley Energy Inc.'s landscape, a reminder of how quickly change happens in the Permian Basin. Despite declining acreage prices, transaction advisers expect M&A activity to be up here as buyers look for bargains.

"We really just have entirely too many E&P companies with duplicated overhead infrastructure and everything else," said Andrew Dittmar, senior M&A analyst at Enverus.

Selected Acreage Valuations, July 2018-December 2019

Date	Buyer	Seller	U.S. Play	Value ($MM)	$/Daily BOE	$/Acre
December-19	WPX Energy	Felix Energy II	Delaware	$2,500	$35,100	$6,735
November-19	Pure Acquisition	HighPeak; Grenadier II	Midland	$1,575	$39,210	$15,130
October-19	Parsley Energy Inc.	Jagged Peak Energy Inc.	Delaware	$2,270	$37,275	$10,819
July-19	Ecopetrol	Occidental Petroleum Corp.	Midland	$1,500		$31,559
July-19	Osaka Gas	Sabine Oil & Gas	Haynesville	$610	$13,500	$2,059
July-19	Callon Petroleum Co.	Carrizo Oil & Gas Inc.	Multiple	$2,740	$33,755	$7,389
June-19	Comstock Resources Inc.	Covey Park Energy	Haynesville	$2,185	$13,500	$2,907
May-19	Sabinal; Undisclosed	Diamondback Energy Inc.	Conv./Midland	$322	$41,196	$3,629
April-19	Occidental Petroleum Corp.	Anadarko Petroleum Corp.	Delaware/D-J/GoM	$57,000	$30,293	$58,293
April-19	Northern Oil & Gas	Flywheel Bakken	Bakken	$310	$38,700	$3,048
April-19	Sequitur Energy	Callon Petroleum Co.	Midland	$260	$29,880	$14,262
February-19	Ring Energy	Wishbone Energy	San Andres	$300	$39,545	$1,686
November-18	Cimarex Energy Co.	Resolute Energy	Delaware	$1,616	$31,715	$24,352
November-18	Aethon Energy	QEP Resources	Haynesville	$735	$13,500	$1,343
November-18	Diamondback Energy Inc.	ExL; EnergyQuest II	Midland	$313	$44,509	$42,984
November-18	Encana Corp.	Newfield Exploration	SCOOP/STACK	$7,700	$28,565	$5,599
October-18	Casillas Petroleum	Sheridan Production	SCOOP/STACK	$260	$24,304	$6,074
October-18	Chesapeake Energy Corp.	WildHorse	Eagle Ford	$3,977	$41,120	$4,916
October-18	DJR Energy	Encana Corp.	Powder River	$480	$34,850	$1,603
August-18	Diamondback Energy Inc.	Energen Resources	Delaware/Midland	$9,200	$36,109	$54,977
August-18	Diamondback Energy Inc.	Ajax Resources	Midland	$1,245	$45,620	$33,008
July-18	BP Plc	BHP	Delaware/EF/Hayn.	$10,500	$26,799	$30,400

Source: Enverus

"Sellers are willing to 'soft shop' the market, but they're unwilling to run a process to avoid a potential failed deal," he said. Instead of relying on sale processes, buyers and sellers are reaching out to "targets or buyers of choice to strategically pair companies."

But deals are still missing one basic ingredient: capital.

Shelter in place

The fast money is gone from shale, racing like a jetliner's shadow over landscapes and the half-scuttled fleets of drilling rigs, leaving E&Ps nowhere to hide. Capital is often given jaunty characteristics—patient, public, private, long or short—but it has forsaken the oil and gas world and taken on a new and surly identity: frustrated.

As 2019 ended, $16 billion in debt uncertainty hung over just 11 companies in the oil and gas industry.

By March, one of those companies, oilfield service provider Pioneer Energy Services Corp., filed for bankruptcy, prompting Eric Rosenthal, Fitch Ratings senior director, to offer a dire prognosis. As of early March, the default rate for high-yield energy debt during the past 12 months was about 10% compared to the overall rate of 3%. That rate, Rosenthal said, could hit 13% in 2020.

As the first quarter came to a close, pressure from debts, activist investors and souring commodity prices would seem to make the year ripe for distressed asset sales and further consolidation.

Large public companies are keen to reduce leverage and address reserved-base lending shortfalls by selling noncore assets, transactions advisers said.

But A&D doesn't work without money, and the market and lenders have stubbornly tightened their money belts.

The A&D market that's emerged is stressed, Cox said. An oversupply of sellers are faced with finicky buyers. Public companies in particular may prefer to shelter in place, eschewing land deals in favor of building operations into free-cash-flowing businesses.

Public companies are "highly reluctant to sell assets," Cox said, particularly as they're offered "reduced valuations when their cost of capital is lower than asset valuations being offered."

As Krasny noted, when leverage levels rise above 3x debt to EBITDA, it becomes increasingly difficult to sell at a price that allows the owner to reduce leverage.

In the current market, valuations are driven less by price per acre and more by net asset value, Cox said.

The historical cycle of public-private asset deals is also out of sync.

"Private equity is looking to persevere by holding on for longer and recognizing the need for a more established production history that de-risks inventory," he said.

Faceing page, a mallard drifts in an artificial pond near Parsley Energy Inc.'s new operations in the Delaware Basin. With fears rising of oil trade wars and a pandemic, the Delaware remains a prime spot.

Public companies are resistant to make purchases, since value is more and more difficult to show, even with economic, delineated inventory, Cox said.

Nelson said that public companies are looking to make strategic moves to divest noncore assets just as the bid/ask spread begins to narrow.

"More important to the climate for deals is capital availability, which we all know is brutally low and difficult to navigate for buyers," Nelson said. "This is not only on the equity side but also with securing debt."

Shifts in the M&A market that occurred in 2019 persist in 2020. Most of them, however, aren't good.

"It's a seemingly endless list of negative commentary around the market," Nelson said.

Public E&Ps sat out on the buy side. Private-equity funds seemingly came to terms with the reality of the new A&D market and pulled back, and their limited partnerships were less supportive of new fundraising efforts.

Commercial banks continued to tighten their underwriting standards for reserve-based lending. Bankruptcies, too, seemed destined to continue marching on in 2020, which could further drag down transaction values, he said.

"The positive in all this … is an absolute lack of high-quality asset acquisition opportunities," he said. "For our clients, it has created tremendous interest for their assets and given them the opportunity to transact with financially capable buyers are attractive values."

A system-wide crash in capital availability is also possible. As capital markets keep up their resistance to providing E&Ps funding, Krasny said an expected contraction of the syndicated loan markets is unfolding. Loan syndication allows large amounts of money to be borrowed by breaking up the amount over groups of lenders to lessen exposure.

"The contraction is already underway," Krasny said.

That also means that as E&Ps file for bankruptcy, banks are facing limited ways to recover senior secured debt.

"Profound disruptions in capital markets, from syndicated loans to bonds to equity, create headwinds to M&A, particularly, as prices continue to soften and leverage levels escalate," he said. "These losses are likely to cause further contraction of the capital supply available to E&Ps, [which is] expected to result in further downward pressure on asset values. The degree of [that] is challenging to predict."

And while potential defaults would seem like a leg up for buyers, it's just another complication to deals, Krasny said.

"When equity markets are shut, bond markets are available only to a select few, and the bank market is increasingly poised for a pull back, asset monetizations emerge as a remaining source of accessing capital," he said.

"Beyond certain levels of distress, the menu of strategic alternatives shrinks markedly and ultimate restructuring through bankruptcy remains the only alternative placing a firm into a state of 'strategic paralysis' until the ultimate restructuring takes place," he said.

Bankruptcy sales require an investment of human and capital resources in order to walk away with a winning bid. The playbook for hunting for distressed assets is technical, complex and requires special expertise and stomach for particular kinds of risks.

"However, with the right team, capital and adviser, it could certainly be a potent and successful strategy."

For the disciplined, well-capitalized buyers, however, the market offers an opportunity to hunt for the right asset at the right price. Buyers know the assets must sell in order to help keep the seller afloat, Cox said.

"Companies are thinking ahead regarding high-yield maturities and the need to get ahead of liquidity crunch," he added.

Cox said that A&D could improve alongside the market across the next nine to 18 months.

"Asset sales can be impactful to companies undergoing financial issues, if material enough and divested early enough, to reduce leverage and help reposition the company," he said. "Distressed asset sales will unfortunately continue. In recent months, several injured, challenged companies have been acquired at extremely low valuations compared to NAV [net asset value] and historical public valuation multiples."

As 2020 speeds along, dealmakers offered a similar prediction for what would surprise them most this year: an A&D market returned to normal. □

Buyers and sellers are still adjusting their expectations, with transactions stuck where buyers are overly conservative or sellers too optimistic regarding asset values, said Mark Nelson, executive director of A&D at CIBC Griffis & Small.

PARSLEY PAVES THE WAY

Fresh off of a $2.27 billion merger with Jagged Peak Energy, Permian producer Parsley Energy is raising its profile on Wall Street—and raising awareness of ESG issues. Is it the new model for independent producers?

INTERVIEW BY STEVE TOON

Parsley Energy Inc. CEO Matt Gallagher is the epitome of a next generation oil and gas company executive. He's young—shy of 40, sports a hipster beard and is attuned to the concerns of climate change. He's reserved a red 2021 Ford Mustang Mach-E, the first Ford Motor Co. all-electric vehicle, for delivery later this year. He lives in Austin, Texas, which may not be an oil and gas headquartering trend but speaks to Gallagher's environmental tastes.

But most importantly he heads a 12-year-old, $7 billion market cap company operating in the Permian Basin that is on the rise. Gallagher, who joined Parsley in 2010, took over as CEO in January 2019 and spent the past year transforming the company strategy from a growth model (which it had mastered) to a returns model as market sentiment for E&Ps underwent a polar shift. That revamp is now complete, with free cash flow achieved and a shareholder friendly dividend implemented in August.

In January, Parsley completed a $2.27 billion, all-stock merger with Jagged Peak Energy Inc., a contiguous neighbor in the Delaware Basin in West Texas, which demonstrated the type of combination many in the investment community say they want to see more of. The Jagged Peak assets bolster Parsley's 120,000-net-acre, pro forma position in the southern Delaware Basin, complementing its 146,000 net acres in the Midland Basin. Pre-deal, the company produced an average 140 million barrels of oil equivalent per day (Mboe/d) in 2019, with guidance to achieve 200 Mboe/d in 2020.

Gallagher, who holds a petroleum engineering degree from Colorado School of Mines, is leading by example to be an environmentally and socially conscious producer. The company established a board-directed ESG (environmental, social and governance) committee last year and released its first sustainability report in December. Parsley in 2019 reduced its flaring rate to less than 3%, a highly visible and publicized topic, and is committed to lowering flare rates on the Jagged Peak assets from near 30% to 5% by year-end.

Gallagher spoke with Investor *Feb. 21, a month after closing the Jagged Peak acquisition.*

"The logic made a lot of sense and we didn't over promise on the synergies. All of those things combined left a pretty palpable deal for people to understand."

—Matt Gallagher, Parsley Energy Inc.

Investor You came into this deal at a period in time where many mergers were being punished in the marketplace. Why did this one work?

Gallagher It was at the bottom of sentiment coming off of two [mergers] that weren't received favorably. It just constrained the deal structure box in early 2019. We had to look to

"If we want to bring back generalist investors, we have to commit to a baseline return through a dividend. We have to commit to free cash that competes against multiple industries."

accretive valuations that had to fit within the model of accretive cash flow immediately in the next 12 months. People didn't want step outs into other basins; they wanted known operating areas.

We were able to come to agreement on a deal that checked all of those boxes. The first [trading] day was a little bit of a shock, but it recovered nicely in the rest of that first week and after that it solidified. The logic made a lot of sense, and we didn't over promise on the synergies. All of those things combined left a pretty palpable deal for people to understand. They didn't have to take a giant leap to get to the strategic justification.

Investor What was your motivation to acquire at this time?

Gallagher We were looking at our internal operations and allocating capital based on our rate of return approach across our portfolio, and we saw a rate of change improvement occurring on our Delaware Basin operations. We saw it move from the third quartile into the upper portion of the second quartile in our inventory stack. The teams had jelled on a new approach in lowering the cost structure, not to mention sourcing in-basin sand, which addressed one of the key cost pressures of 2018.

Any time you can increase the top half of portfolio returns, you should evaluate it. That was the catalyst for us. So we looked across the landscape of what could potentially make sense, and the Jagged Peak deal clearly made the most sense for us.

Investor Was raising your market cap a motivator?

Gallagher I wouldn't say it was the primary motivator, but when you have all of the other things going on, I would venture to say that it helped the other side come to the discussion table. Clearly, you've seen a divergence in multiples between large caps and small caps, and we sit in kind of a bubble area. For small caps, an opportunity to team up and get larger has quite a bit of potential improvements. I do think it helps facilitate the discussion.

Investor How do you convince a company like Jagged Peak to be acquired with little to no premium if they have to lose their jobs for this so-called G&A synergy?

Gallagher That's probably the most sensitive point in the possibilities of mergers in the future. It's been the case throughout history in multiple industries, and it's no different here. Given large [insider] ownership in Jagged Peak, there's an ability to see the benefits. The board's fiduciary responsibility is to the shareholder, and they could see the benefits of the combination when we approached the board.

The sentiment was that it's a challenged time. We're in a time of long supply currently, and so they had to evaluate it as a fiduciary, and that was the starting point.

But it's a huge challenge. You need to be cognizant of the value everybody's brought to the table, the hard work and the families involved. So as this industry looks forward to M&A over the next two or three years, that key point is probably one of the barriers to open discussions.

Investor Do you feel you need to gain further scale via consolidation, or are you where you want to be?

Gallagher Our focus is on good operations and good returning properties. You see properties in the larger market cap size that have higher multiples given similar value drivers such as inventory length, margins and cash returns. So the math is still out there, but I don't think that alone is going to drive any M&A decisions.

Investor Is it an option?

Gallagher We've been acquisitive since our inception, but we need to demonstrate a lock tight integration process and get through that.

Investor Oil and gas companies represent a pretty small percent on Wall Street today. What can you do to attract investor capital today?

Gallagher First we have to deliver quantifiable and steady profits. When you do that, then you can have a separate conversation about which companies are doing it the right way and in the right manner. If you look back over a decade, we have not been generating a profit as an industry. It's been very challenging.

We found a truly world-changing resource in the U.S. oil shales, primarily in the Permian. The acreage grab was so large and so enduring, and not many people have much to show for it from an investor standpoint. So you have the outside world saying, "They found the best thing that they could have found, and they can't generate a profit. Why am I investing in this sector?" And, in the meantime, they've been getting 20%-plus returns in the tech sector.

You're starting to see in 2020 a true inflection year where companies are demonstrating what the shale model can deliver. At least the top 10 companies are showing healthy free cash flow, healthy growth and demonstrable cost controls. So we just have to stick to it. We can't get caught as in January when oil was running up north to $65; nobody was reactivating their programs, everybody was staying steady because that helps drive a consistent cost structure.

It's going to be a big challenge for everybody to stay steady over the next couple years because we will see upside shoots again, and that will be the real test. I think if we stay steady, we will draw our investors back.

Investor Specifically, in your direct conversations with investors, what are they saying they want to see before they reengage?

Gallagher They're saying, "When I see four quarters of financials that I can pitch to my generalist portfolio manager, they can hang their hat on the backwards data." And we say, "You don't see the value in it now? Look how undervalued it is." They say, "We will gladly miss the bottom to confirm that you can deliver on results." They're not looking to just scalp the absolute bottom; they want to see consistent results for four quarters.

Investor When you shifted from a growth strategy to a sustainable free-cash-flow mindset, how did you change your approach to be able to execute on that?

Facing page, Ensign Rig T223 drills on Parsley Energy Inc.'s Trees Ranch property in Pecos County, Texas, near Coyanosa.

PHOTO COURTESY OF PARSLEY ENERGY INC.

Gallagher As an industry, we are built from the bottom up to recover resource. That's been the game plan for multiple decades. We were resource-short since the late '70s with declining oil production in the U.S. It was hard to talk about this rate of return mindset when you're not growing as fast as the resource would allow and you're not recovering the quantum of resource that would be possible, but you're actually generating a better profit. So project NPV [net present value] versus project rate of return, which one generates a better asset NAV [net asset value], and a risked NAV too?

First, we went through about six months of model analysis and sensitivity from our technical teams. We had competing teams in technical jam sessions on, "What is everybody worried about? Let's run through this analysis and see." We had a hunch, but we wanted the teams to go through their local development areas and try some things out.

The No. 1 concern was that we were going to lose physical inventory count. Okay, so let's show why that's okay and how over a decade it still plays out nicely. And I think once the numbers got printed on the screen, it was kind of black and white, especially if you just use modest risk factors on these volatile shocks. Then the teams didn't want to go back to the other way. We could put in the corporate strategy of the free cash flow, rate of return focus, and we had a lot of great buy-in across the organization. In early 2019, we came out with an updated inventory range that showed the impact of the up space. And it was received well because it was explained well and showed improving results—the icing on the cake.

Investor You are one of the early operators to instill a dividend thus far. Why is that important?

Gallagher A dividend is important because it's a prudent, disciplined approach to capital discipline. It's kind of the canary [in the coal mine], where if you start seeing signs that your dividend is not coming out of free cash flow, then you really need to look at the rest of your capital program and see if you need to adjust activity levels. It's really hard when you're in outspend mode and growing to the tune of 50%-plus a year to justify that dividend, but the time was right for the company as we are committed to the free-cash-flow approach.

Investor To be competitive in the larger market, where does your dividend need to be?

Gallagher A lot of people are looking at that 2% in the S&P 500. If we want to bring back generalist investors, we have to commit to a baseline return through a dividend. We have to commit to free cash that competes against multiple industries, get a stable program going that you can grow organically and then that allows something that investors can hang their hats on.

Investor With your capex set at $50 WTI and oil perilously close to that thus far this year, will you be able to defend the dividend if oil trends below $50 for a sustained period?

Gallagher We would be able to. About 30% of the free cash flow at $50 goes to the dividend, so we have quite a bit of cushion there. But in the low $40s, we would need to look at activity adjustments to keep a sufficient cushion for the dividend. *[Editor's note: In mid-March,*

Parsley Energy Inc. drilled Tree State 17-18-4303H, later renamed Pecan State Unit 4303JH, targeting lower Wolfcamp in Pecos County, Texas.

following the drop of WTI to near $25, Parsley announced it would slash its 2020 capex by 40% and executive salaries by 50%.]

Investor What will Parsley do with any free-cash-flow surplus if prices average above expectations?

Gallagher Hopefully, we have that challenge. When we look out over a five-year period, you can see billions of dollars of potential free cash. We're working on these gated measures of where to deploy the free cash. There would be cash on the balance sheet to prepare for debt reductions over time. There'd be modest activity increases, just pro rata to keep a steady production growth, not an accelerated production growth. At that point there's quite a bit left over and you're able to evaluate additional shareholder friendly activities and also opportunistic acquisitions for other companies that aren't able to have that type of business model.

Investor If oil prices actually trended upward sustainably, would you consider accelerating activity beyond that targeted 10% growth rate?

Gallagher No, we don't see anything beyond that 10% to 15% growth rate.

Investor Why not a lower growth rate? Why not just go flat and make everybody happy with more free cash flow, more dividends and less supply on the market?

Gallagher We're in a returns focused strategy, but no doubt it's a dynamic environment. I'm assuming when I mentioned all of these that our project returns are healthy. What goes into that is the capital structure and then the oil price on the other side. If you see degrading project returns, you're exactly right, you shouldn't stick to the growth at all costs measures and you should moderate until you can regain your return profile.

We have a large enough data set behind us now that we know these uniform areas; we know what the return profile should be over a stabilized environment. And if we're seeing those cash returns and we're able to deliver our targets, then we're perfectly comfortable meeting these types of growth rates. The higher-cost players would be bumped out of the growth equation.

Investor Climate change is a dominant topic in America and globally these days. How should independent oil and gas companies be responding to this pushback on fossil fuel production and usage?

Gallagher Step one is we should be proactive on levering up on our operations regarding pollution. It's all of our emissions, and one of the most visible is obviously flaring. We also have general methane leaks and greenhouse gas intensity, and we have liquid leaks that we need to monitor and reduce. And our safety component. So let's start as a community to agree to be worldwide leaders on these fronts.

Separately, we have a perception issue. We don't have advertising groups in our companies. For 20 years or even longer, we've been behind on engaging with consumers. We've never had to do it in the past. We think we're in a commodity business and that commodities don't have substitutes, but today we have substitutes. They're much more costly, and they have their own trade-offs, but those substitutes have plenty of advertising and engagement with the consumer. We need to engage with the consumer and say what the benefits of our product are.

So I think being proactive and not knocking new technologies and new alternative competition and renewables [is important]. We need all of this in the energy equation.

Imagine if, eight years ago, a horizontal well in the Permian didn't yield good results. What do we think oil prices would be right now? And do we think there'd be enough oil to sustain the world's energy growth? I think there are really good reasons to continue to look at energy substitutes, but we have a great product; the U.S. producer is uniquely advantaged to deliver that product and we need to refine and promote our message.

"We have a perception issue. … We need to engage with the consumer and say what the benefits of our product are."

Investor Do you think the industry is losing the messaging battle?

Gallagher I don't even think it's a question. It's a shut out right now, and we've got to put the pads on and get on the playing field.

Investor What should the message be?

Gallagher The message should be that American energy is doing things the right way at the highest employment standards, social standards and operational standards with the lowest impact possible. But we've got to make sure that's true. So all companies need to look inward and demand that amongst our employees and amongst our planning teams that that becomes true. I do believe American innovation is second to none. When tested with a challenge, we always rally.

Then the next point is, where are you getting your energy from? Not only the source such as coal, natural gas, solar or wind, but where's the origin and what is the full-cycle impact? Origin matters, based on human rights conditions. If you're already top of line operationally with lower relative greenhouse gas, then you're protecting hundreds of thousands of jobs across the country. We're displacing foreign oil from governments that may or may not be friendly to our way of life.

Investor How important is ESG from an investor's perspective?

Gallagher It used to be that they would check operations first and your profitability, and then they would check where you stand on the ESG component. We've been hearing about this growing now for probably 24 months, but in the last six months the screening has changed to "Where are you on ESG? And only if you meet my requirements will I then look at your operational business."

Investor Do you think capital will dry up if E&Ps don't focus on this?

Gallagher Yes, and I think rightfully so. There are going to be people out there that we're never going to be able to appease, and they just want a full shut off. That's the dangerous approach to it. That doesn't capture full consequences and the benefits of what our product can deliver. So that's probably

"As far as really making improvements on the ESG measures, that's something very important that I think is the right call from the investment community to be pushing on these fronts."

not the most productive area to have a conversation around. But as far as really making improvements on the ESG measures, that's something very important that I think is the right call from the investment community to be pushing on these fronts.

Investor What is Parsley doing to address ESG concerns?

Gallagher We've enhanced the focus on it from the top level. We have a dedicated ESG committee on our board. We have an internal dedicated committee that is employee based, run by our COO. We've outreached to multiple stakeholders to put a framework together for what's important to all stakeholders. We've set baseline measurements in our initial corporate responsibility report, but that's only a baseline; it's going to grow from here. We've taken a leadership position on this.

A good example is flaring. You look across multiple operators in the basin and there's anywhere from 1% flaring to 30% flaring. There's no reason for that high of a flaring percentage when there are technical solutions to solve this.

We are aggressively going to get that down below two and a half percent by the end of this year. But we're working on all measures at the same time. We're working on reducing greenhouse gas intensity through the possibility of dual fuel engines on a lot of our frack fleets. We're looking at air actuated control valves. Our real time monitoring systems are really improving [leak] response times. It's across the board, and it takes a lot of focus.

Also, I think through the ESG efforts, we are going to come up with some out-of-the-box solutions that actually help economics and productivity along the way too.

Investor Flaring has been a routine and accepted practice of doing business, and particularly in Texas where you are, there are not really any regulations that are constraining you from doing it as needed in your business. Does the industry need to change its thinking even though it's not required to shut down flares?

Gallagher Yes. I think this is a great example of a place where the industry and the operators need to get out in front of a baseline requirement. There are operational conditions and test areas where you don't know the proper sizing, so you need to look at this pragmatically, but we have to get our arms around this in a much more aggressive manner. We need to collaborate with the regulatory bodies and help them come up with a potentially better system, but we don't need to wait for them to reduce this effort.

Investor What's the solution to that problem then?

Gallagher Money. There are businesses on the other side that build these pipelines and gathering networks, but these are multibillion-dollar projects. It makes the economics very difficult for these standalone businesses if the product is being sold at a very low price. Then you have to look at things in a more integrated manner. You have to modify contracts, and you have to share expenses.

For example, we've already modified about 94 gas gathering contracts proactively to a minimum margin contract. That's a financial hit to us in low prices, and that was intentional to give the processors an ability to build out through multiple price cycles.

Investor Do you think the world is approaching a point of peak demand due to an energy transition?

Gallagher I don't see it happening in the next decade. It just depends on the worldwide GDP growth, I believe. You continue to see India or Southeast Asia or Africa come up the poverty curve, and there's going to be a huge demand for energy. That right now cannot be overtaken fast enough by renewables to send hydrocarbons into decline.

Investor With all the pressure to decarbonize, do you think the industry will be in a position to actually meet future demand?

Gallagher It's something I'm very worried about for the first time in my professional career. We're looking at no replacement to the Permian, and with the Permian slowing its growth. I also don't think that there are major productivity improvements coming in the Permian per well. So now we've got ourselves in a potential pickle, where you're really constraining opportunity for billions of people and low-cost energy may not be as abundant as it has been in the last decade.

I think we'll be able to meet demand for decades to come, but the cost structure would be much different when you have to go back offshore and go back to international environments that take a lot longer to develop with a lot more regulatory challenges.

Investor Why did you choose to go into the industry?

Gallagher I was born into it. I am a third generation oil man. Both my father and grandfather were petroleum engineers, but when I was deciding what to do in the late '90s my dad sat me down at the kitchen table and he said, "Matt, whatever you do, don't become a petroleum engineer." That was 1998, almost at the bottom at that point for the industry. 1999 was much worse. That broke a lot of operators' backs. My family had to sell all of their rigs in '99. But what he was trying to do was protect against the volatility he had seen in his career, the highs and lows, the ups and downs. He didn't want me to have to go through them.

Well, I actually loved what he did, and I've been told I'm a little hardheaded at times so, of course, I did exactly what he told me not to do. It's worked out.

And what a great industry. I'm truly proud to be part of this industry. I know it can seem tough at times in our stocks. We have activists that push against our industry. The media is constantly pushing against our industry. But I do love this industry, even though there are some challenges that we're facing. Perception is a long-term problem. Let's reduce our emissions and our spills and our injury rates. Let's turn a profit this year. No excuses. □

M&A'ING WITH CROSS PUNCHES

Increasingly, E&P mergers are drawing shareholder pushback—unless for a low or no premium.

ARTICLE BY
NISSA DARBONNE

ILLUSTRATION BY
ROBERT D. AVILA

Leo Mariani, managing director and equity analyst for KeyBanc Capital Markets Inc., concluded that, from the response to the Carrizo-Callon deal, "the lesson is that, in this type of market, investors don't want to see any kind of significant premiums."

Offering a 25% premium made sense at the time. Occidental Petroleum Corp. had just paid a hefty kicker for Anadarko Petroleum Corp.—nearly all in cash. Deals leading up to July 15, 2019, had come with premiums.

But times were changing—fast—as Callon Petroleum Co.'s offer for Carrizo Oil & Gas Inc. was in draft.

Dating back to July of 2018, the Callon board had Carrizo, a fellow Delaware Basin operator, on a short list of potential merger candidates when regularly discussing M&A prospects, particularly as Callon had shifted to the goal of generating free cash flow rather than growth.

The deal was announced before markets opened on July 15. An all-stock transaction, its value was $3.2 billion. The 2.05 Callon shares offered were worth $13.12 before markets opened.

Trading response was disappointing, though; Callon shares tumbled 16% that day, while the S&P E&P Index fell about 3%.

Until the deal was recast down to a 6.7% premium in November—based on the pre-deal share values; it was 1.1% based on Nov. 13 share prices—the journey was arduous.

And it was bruising, with a series of blows in rapid succession: a surprise punch from an activist shareholder that appeared from nowhere and disappeared before year-end, followed by cross punches by other major shareholders, finally closing with one-two uppercuts from Institutional Shareholder Services and Glass Lewis & Co.

In a summary of industry conditions last fall, a Seaport Global Securities LLC analyst reported, "Let's get real about the state of the E&P space. Time to face the facts: The 2020 oil macro setup is a mess.

"Non-OPEC growth [in daily production] is pegged at 2.2 MMbbl by the [International Energy Agency], while oil-demand growth is expected [of] 1.3 MMbbl—and we'll take the under on that."

Additional observations included that share prices will be pressured until "operator pain is palpable" and a view that discounted E&P stocks have a "scarlet letter hung around their neck."

He concluded, "What's the route for [these] names? MOE [merger of equals]."

Activism in E&P

Just days ahead of the Callon-Carrizo announcement in July, a group led by EQT Corp. shareholder Toby Rice won a vote to take over the EQT board. Earlier in the year, the Denbury Resources Inc. merger with Penn Virginia Corp. failed upon dissent by shareholder Mangrove Partners Master Fund Ltd.

After the Rice win at EQT, QEP Resources Inc. satt down with activist shareholder Elliott Management Corp., agreeing to add two independent board members. Texas Pacific Land Trust, owner of more than 900,000 West Texas acres, came to terms with Horizon Kinetics Asset Management LLC, reviewing and then deciding to convert to a C-corp.

Until then, shareholder activism in E&P was vocal but mostly unsuccessful. In May of 2019, Kimmeridge Energy Management Co. LLC failed in its bid to win three PDC Energy Inc. board seats. Kimmeridge had made a case beginning in 2018 for zero-premium mergers among E&Ps.

However, on Aug. 26, 2019, PDC announced a low-premium MOE with SRC Energy Inc. That day, PDC Energy Inc. shares rose 17%; the deal closed in January.

Meanwhile, other deals hadn't closed due to the price of WTI. In December of 2018, Earthstone Energy Inc. had to cancel a purchase from Sabalo Energy Inc. as futures plummeted in a matter of weeks.

Soon after, Vantage Energy Acquisition Corp. was unable to close on a $1.65-billion deal struck pre-plummet for QEP's Williston Basin portfolio. Vantage had to release from escrow back to shareholders its SPAC funding when a 24-month deadline to deploy expired in April of 2019.

As buyers of E&P assets became fewer, private-equity firms began talking publicly in 2019 of looking at intra-portfolio combinations and the even greater challenge of inter-portfolio deals.

Did the Rice-EQT outcome drive more boards to the table?

Leo Mariani, managing director and equity analyst for KeyBanc Capital Markets Inc., told *Investor* in February, "In general, it's always hard to know what any given management team or board of directors is thinking.

"But we have certainly seen some pretty significant successes on the activist side—maybe not in

Mergers among smaller-cap E&Ps are "likely one of the only ways most [of these] can create value at this point," said Gabe Daoud, managing director and equity analyst for Cowen & Co.

terms of stock-price appreciation but certainly in getting some agendas to bear."

Icahn versus Oxy

He expects E&Ps "are going to be taking activists more seriously these days than they might have a few years back. Obviously, you've got the major one brewing right now between Carl Icahn and Oxy.

"It will be interesting to see how that plays out over the next few months."

Icahn, taking issue with what Oxy bid for Anadarko last May and the lack of a shareholder vote on it, has called it the "OxyDarko Disaster." He and the funds he manages held 32 million Oxy shares before the deal and 87 million at press time.

Gabe Daoud, managing director and equity analyst for Cowen & Co., told *Investor* that the Toby Rice-EQT situation was unique in that Rice had great familiarity with the EQT assets, having contributed to them in a corporate sale of Rice Energy Inc. in 2017.

With activist shareholder Paulson & Co. Inc. in the Callon-Carrizo deal, it was "an outsider who had no true inside knowledge of daily operations."

But "there was some credence to what Paulson was arguing," Daoud added. "I think investors would prefer to see deals executed at low- or no-premium terms versus Callon's initial 25% premium for Carrizo.

"Callon did hear that message and ultimately revised the terms, making it more favorable," he said.

It made for a better deal for Callon and Carrizo going forward, he said, in "ability to generate free cash flow over the next couple of years."

MOEs for now

In late 2019, the WPX Energy Inc. deal for Felix Energy that closed in March "looked like a much cheaper price relative to what people were paying back in 2018," KeyBanc's Mariani said.

The WPX-Felix announcement has been "clearly the most successful E&P deal we've had in a number of years." WPX shares rose after the news.

Another success has been the MOE of PDC and SCR that was announced after the Callon-Carrizo deal news as well as the Parsley Energy Inc.-Jagged Peak Energy Inc. combination announced in October, Mariani added. "In both of those, we saw minimum premiums."

Seeing market reception of these three deals, "I would think other E&Ps that would potentially consolidate or sell themselves are likely going to be giving a lot of credence to the MOE framework."

He added that he doesn't think it will just be small and mid-caps (SMID) taking notes. "It's possible we could see that in someone a little larger as well."

Daoud said, "The E&P business has migrated to moderating growth and, ultimately, generating sustainable free cash flow that can pay down debt and be returned to shareholders.

"Perhaps the only way this can be achieved for some of the smaller-cap names is to merge with peers to enhance scale, take costs out of the equation, particularly on the G&A [general and administrative] side, and slow down operations to augment free cash generation.

"It's likely one of the only ways most SMID-caps can create value at this point."

Pre-sale

Is more consolidation—and among the largest E&Ps as well—needed to make picking up an independent worth a major bothering with the paperwork?

Daoud said, "You need to be pretty close to generating free cash flow if you're not already. Majors are also quickly drilling through Permian inventory over the next several years; thus, one could argue they will need to replenish at some point."

Mariani said, "If you're a major, you certainly want a deal that's really going to move the needle. You don't want to spend tons of time and effort on some crumbs if you can go after the cake."

There are some independents that could begin to move the needle.

"If you listen carefully to what Parsley management had to say about their Jagged Peak acquisition, it's just that: They view Jagged Peak as a sort of interim setup [with] the right dance partner," Mariani said.

Over time, "as they've gotten larger—and that deal was pure-play Delaware—that would make them more attractive as a takeout to a larger operator."

Signing MOEs gets tricky, though, particularly the part about which management team will survive, he noted. Among SMID-caps, Mariani said, "some of the most natural fits have already happened, so there aren't as many other really good fits out there."

But if this downward investment environment persists, "it could force incremental consolidation in the next year or two."

Daoud concurred that consolidation and free-cash-flow generation may reverse investor apathy toward the E&P space. "It's a tough environment. That's where we stand today."

Mariani concluded that, from the response to the Carrizo-Callon deal, "the lesson is that, in this type of market, investors don't want to see any kind of significant premiums."

In February, as operators reported fourth-quarter earnings, Tudor, Pickering, Holt & Co. analysts wrote that production growth "isn't wanted or needed."

After an E&P's earnings call in February, a SeekingAlpha member wrote in the comments, "With the release of these great numbers, combined with pursuing overall debt reduction, I don`t understand the reason for the exceptionally low [price-to-earnings] ratio.

"Can anyone explain this?"

One member replied: "Investors don't want to be in oil anymore." □

DO M&A SYNERGIES MATERIALIZE?

There's a debate on the degree of synergies realized in M&A. Commodity volatility hasn't helped.

ARTICLE BY
CHRIS SHEEHAN, CFA

It's not hard to recall times when we've heard predictions of an upturn in M&A activity, only to see the next couple of quarters go by with little M&A of substance. In 2019, setting aside Occidental Petroleum Corp.'s purchase of Anadarko Petroleum Corp., M&A activity came to just half of the average M&A total of the past 10 years, according to Enverus data.

Energy's performance in the broader market hasn't helped. The energy sector weighting in the S&P 500 has fallen below 5%, and energy has been the worst performing sector in five of the past six years. But many observers have cited the need for greater scale in order for producers to compete, especially when energy investors increasingly prioritize returns and stock buybacks over growth.

What's tough to determine is the track record of M&A activity as regards the delivery of synergies that are expected to accrue to a transaction over time and help make mergers more attractive for investors.

Some have strongly argued that projected synergies fail to materialize, making shareholders shy away from stocks involved in M&A. Others point to synergies coming in close to, or above, projected levels, typically tilted to cuts in general and administrative (G&A) expenses in the first year of a merger, followed by operational synergies as the two parties fully integrate their practices.

A study by another industry observer shows a split of roughly 50:50 in terms of those mergers that did and those that did not deliver on the synergies that investors expected at the time of the merger.

Exceeding initial estimates

Steve Trauber, head of global energy investment banking at Citi, is adamant that the trend is in favor of synergies meeting or exceeding levels announced at the time of a merger.

"Synergies are ending up being larger than when they were announced," he said. "Diamondback Energy [Inc.] exceeded its projected synergies in its merger with Energen. And

Recent Deals Focused On Synergies In G&A And Capital Productivity

Date	Buyer	Seller	Transaction Size, $B	Synergies, $MM[1]	Observed Annual Synergies, $MM	Planned Synergy Drivers, $MM	Observed Synergy Drivers, $MM	Total Synergy Capture
Nov-18	Encana Corp.	Newfield Exploration Co.	$7.7	$250	$253	$125 – G&A $125 – Capital	$120 – G&A $133 – Capital	
Oct-18	Chesapeake Energy Corp.	WildHorse Resource Development Corp.	$4.9	$200-$280	$236	$50-$80 – Non-Capital $150-$200 – Capital	$57 – G&A $179 – Capital	
Aug-18	Diamondback Energy Inc.	Energen	$9.2	$200-$300	$240	$30-$40 – G&A $200 – Capital & Operational	$29 – G&A & Financing $210 – Capital & Operational	
Mar-18	Concho Resources Inc.	RSP Permian	$9.6	$200	$111	$60 – G&A, LOE & Financing $200 – Capital	$49 – G&A, LOE & Financing $62 – Capital	
Jun-17	EQT Corp.	Rice Energy Inc.	$8.2	$450 (2019-2027)	$83	$350 – Capital Efficiencies $100 – G&A	$11 – Capital Efficiencies $72 – G&A	

Source: AlixPartners
1) Annual synergy estimated based on 10% cost of capital and perpetual synergies.

"Synergies are ending up being larger than when they were first announced," said Steve Trauber, head of global energy investment banking, Citi.

at the end of the day, the Occidental-Anadarko merger will deliver more synergies than they announced. More recently, the Parsley Energy [Inc.] merger with Jagged Peak [Inc.] will also exceed its projected cost savings."

Lengthening the list to include other recent combinations—PDC Energy Inc. with SRC Energy Inc. and WPX Energy Inc. with Felix Energy II—"I'll bet that those will also exceed their synergy numbers," he added. "I've been in there to talk to them. I've heard it straight from the CEOs' mouths. They're doing a really good job to get rid of costs. They have to; that's what these deals are all about."

Trauber attributed the likelihood of finding more synergies than when a deal was first announced to a couple of factors. "Some of it could be a desire to underpromise and overdeliver," he said. "Maybe they also recognize that there's likely to be a few hiccups along the way. But they want to be able to tell the market at the end of the day that they'll be able to exceed their goal."

Also, in a weaker commodity environment, he continued, "you're able to take out more costs. But you often need a catalyst to do it. There are a number of upstream companies today that would privately admit they have significant costs they could still take out. There's nothing like a deal to have to examine and take out your own costs. And so they end up having more synergies than they thought."

Trauber pointed to the line-by-line detail employed by Diamondback to provide transparency in progress being made on synergies in its merger with Energen. (Citi acted as exclusive advisor to Diamondback on the deal.) Synergies were achieved on a larger scale and at a faster timetable than expected on announcement of the deal, he said. "They're achieving them, plus some."

As for the timing of synergies, most of the G&A savings occur in the first year, but these are offset in part by severance and possibly relocation costs, "so you don't get the full-year benefit in year one," said Trauber. Operational synergies occur more slowly than with G&A, but they generally materialize to the tune of 80% to 100% in the second year after an acquisition, he estimated.

In terms of the capital efficiency of its corporate structure, Trauber pointed to Diamondback having "put together a really interesting organization. They've got a midstream business, they've got a royalty business and, of course, the E&P business. They have a lot of ways to make acquisitions and to move the assets around to achieve the highest valuation for their assets."

Generally, potential synergies can typically be captured by increasing volumes through existing midstream assets or through water handling and water disposal assets, said Trauber.

In addition, cost savings can be expected from greater scale in negotiating drilling rig contracts and pressure pumping services. "And greater scale should give you more flexibility to move rigs and crews around."

In particular, greater scale in terms of contiguous acreage should allow for drilling with longer laterals, typically translating into greater efficiencies in drilling operations, said Trauber.

'Less than clear' synergies

Others offer a degree of skepticism surrounding synergies realized historically in mergers. Often, the degree to which expected synergies materialized "has generally been less than clear, maybe because companies haven't been hitting their numbers," said one seasoned energy investment banker that agreed to speak anonymously. "The companies have typically been fairly opaque on that."

On the part of the investment community, "there's a general thesis that a lot of the so-called synergies that they've heard over the past several years from E&P companies have really not come to fruition," he said. In specific areas, such as operational synergies, the "buy-side" has viewed E&Ps' track record of delivering synergies projected at the time of announcement as "overly optimistic."

As a result, he said, the "buy-side is generally willing to give companies immediate, hard dollar synergies at closing, which are made up mainly of G&A savings. There have also been projected synergies related to operating costs, greater efficiencies, longer laterals, procurement of services, lower supply chain costs, etc., but the market has pretty much dismissed those expected savings."

Their attitude is, "I'll believe it when I see it. I've heard that story too many times," recounted the energy investment banker.

In the case of a significant premium being paid by the acquirer, G&A savings are likely to justify part of the takeover premium but remain "far, far shy of accounting for the entire premium paid," he continued. "And the other synergies that the acquirer used to justify payment of a big premium are assumed to in large part never come to fruition. That's the general view out there."

Outsized claims related to synergies in one high-profile merger may have contributed to the recent argument in favor of very low premium, or zero premium, mergers, according to the banker. In that vein, he pointed to what was generally applauded as a zero premium merger between two Denver-Julesburg Basin players, in which PDC Energy acquired SRC Energy.

In addition, the energy investment banker highlighted the success of Diamondback in attaining its projected synergies as well as its accompanying transparency in tracking them for investors. "They've done an excellent job—as good as anyone," he commented.

Financial versus operational synergies

"The challenge with synergies is that it's a very large bucket that encompasses a number of variables," said Mark Viviano, head of public-equity investing at Kimmeridge Energy Management Co. "Where the synergies have clearly materialized in a number of deals is in the area of financial synergies, particularly around corporate G&A and reducing head count."

Synergies in the above areas are "both identifiable and trackable" over time, according to Viviano, and these synergies "have largely materialized and in some cases been even better than expected." On the other hand, investors have struggled with most operational synergies, which "are not very transparent and not very trackable within reported financial statements."

The latter lack of transparency has, in part, helped create a "perception that the level of synergies has been disappointing," he continued. In addition, he cited a number of instances in which high-profile acquirers have run into post-acquisition "operational challenges," leading to results that fall short of company guidance or sell-side consensus expectations.

"If you look at high-profile deals done over the past two years, particularly in the Permian Basin, some of the acquirers ended up disappointing," said Viviano. That has led to a "perception that the acquisitions themselves elevated operational risk. And the elevation of operational risk can come from potentially not understanding the asset base being acquired or a struggle in organizational integration."

Concho Resources Inc. was cited by Viviano as one Permian producer that had to revise its operational strategy from what it had previously communicated to investors.

Concho's management team had been "touting the merits of the deal based on moving to larger pad completions," he said. "And, a year later, they were dialing back the size of the projects. Of course, we're talking about subsurface, where there are a lot of unknowns and management doesn't have all the information. But when something like that happens, it's damaging to the credibility of the industry."

In turn, any synergies laid out by companies at the time of the merger "become a moving target, because you're changing the way that you're developing the assets," Viviano said. "And going back to the earlier point, there are no variables you can track; there are no reported numbers in the financial statements. And unlike G&A, this creates an opaque view of what actually happened post-acquisition."

While G&A savings may be fully recognized within 12 months, operational synergies are "very case-specific," according to Viviano. Operational synergies may vary depending on supply chain inputs, for example, or on a specific methodology that is used to drill wells. Increases in efficiencies in these areas may be implemented in the first six to 12 months, he said.

"However, some synergies, such as those involved in the strategy around developing an asset, including changes in the size of a pad, can take longer. And it's less clear to the market how effective

CUTTING COSTS AT DIAMONDBACK

Diamondback Energy Inc. has provided periodic updates on its integration with Energen Corp. in an effort to shake off a suspicion that synergies would not materialize. For example, in a PowerPoint presentation accompanying its third-quarter 2019 earnings release, Diamondback compared its execution on synergies as of November of 2019 against the savings it targeted as of its August 2018 acquisition of Energen.

In terms of drilling and completion (D&C) costs incurred for wells in the Midland Basin, Diamondback had projected cost savings of $223 per foot at the time of the acquisition. Cost savings were projected against a benchmark of $999 per foot for Energen in second-quarter 2018. In its November 2019 update, Diamondback estimated D&C costs at $760 per foot for the full-year 2019.

The $760 per-foot update represented a drop in D&C costs of $239, an improvement over the original $223 per-foot estimate. In a subsequent February 2020 presentation, Diamondback lowered its D&C cost estimate again to a 2020 mid-point of $735 per foot, for a further $25 per foot in projected cost savings. Diamondback estimated 2020 cost savings at $160 million to $180 million before the two updates.

In the Delaware Basin, against a second-quarter benchmark of $1,171 D&C costs for Energen, there has similarly been a two-step drop in costs and increase in savings. Combined, the two represent a drop in costs to a 2020 midpoint of $1,100 per foot, for savings of $171 per foot. Once described as an estimated $25 million to $50 million in "secondary" synergies, these are now viewed as "primary" synergies.

Other factors are easier to track. By early 2020, Diamondback expected to bring down G&A expenses by $30 million to $40 million. By November 2019, the company had surpassed the $40 million mark. Savings on interest payments have progressed toward a goal of $25 million to $50 million in annual savings, as the company's credit rating was upgraded to investment grade, and it was subsequently able to refinance its debt in late 2019. Diamondback had achieved $5 million of interest savings through November 2019.

Diamondback's Energen Acquisition Synergy Scorecard (Q3 2019)

Synergy	Targeted Savings Presented August 2018	Execution As Of November 2019
Midland Basin Well Costs	$223/ft in D&C well cost savings by 2020 $150MM-$220MM in annual savings Timeline: begins 1Q19, fully achieved by early 2020	>$260/ft in D&C well cost savings by 2020[1] 2020 D,C&E/ft midpoint of $735/ft., down ~$264/ft vs. Energen's 2Q18 2020 savings: $160MM-$180MM+ (>650k ft)
Delaware Basin Well Costs	Up to $50/ft in D&C savings long term	~$70/ft in D&C savings in 2020[1] 2020 D,C&E/ft midpoint of $1,100/ft, down ~$71/ft vs. Energen's 2Q18 2020 savings: $25MM-$50MM+ (~535k ft)
G&A Expenses	$30MM-$40MM in annual savings Timeline: begins early 2019, fully achieved by early 2020	>$40MM savings in 2019
Interest/Cost of Capital	$25MM-$50MM in annual savings Timeline: begins 2019, continues as debt becomes callable and/or matures	~$5.5MM in 2019 savings 75 bps tighter yield in Sept. $750MM tack on Initiated IG by Fitch in December 2018 Added "fall away" provisions to credit facility[2]
Secondary/ Other Synergies	Incremental midstream capacity "Grow and prune" strategy VNOM mineral dropdown	$322MM in asset sales; closed by 7/1/2019 $720MM in net proceeds from RTLR IPO in May; contributed EGN oil gathering/SWD assets $740MM mineral drop down to VNOM; closed 10/1/2019 ($190MM cash)

[1]Based on FANG's 2020 capital plan and guidance ranges for net wells completed, D,C&E well costs per completed lateral foot and average lateral length; assumes 40% of net lateral footage completed in 2020 attributed to EGN properties (~55% Midland Basin/~45% Delaware Basin).
[2]Effective upon receiving two investment grade ratings.
Source: Diamondback Energy Inc.

Some of the acquirers in high-profile deals, particularly in the Permian Basin, "ended up disappointing," said Mark Viviano, head of public equity investing, Kimmeridge Energy Management, leading to a "perception that the acquisitions themselves elevated operational risk."

"The deal has to make strategic sense," said Andy Rapp, co-founder, Petrie Partners. That said, "you can look at the synergies as a real component as to why a transaction might make sense."

that is over time due to the lack of trackable data," said Viviano.

While energy stock prices have factored in some linkage between synergies delivered by a company as compared to prior market expectations, other market forces are also at work, noted Viviano. "A lot of it is the market's overall view of energy and the E&P sector specifically. It's always hard to disaggregate how much is company specific versus sector specific under performance," he added. "I think the template going forward for successful acquisitions is going to be deals that enhance the free-cash-flow profiles of the companies and the measurable return of capital to shareholders," said Viviano. "Ultimately, the litmus test for a business is how much cash is returned to the investor. And we haven't seen a deal in shale that has materially changed the cash return to investors."

According to Kimmeridge, the industry goal should be to strive toward a capital allocation framework of spending about 70% of cash flow in a given year and returning the balance to investors via dividends and stock buybacks. "The industry has to provide visibility as to how it will get to those types of re-investment to attract shareholders back to the sector," said Viviano.

Strategic sense

Andy Rapp, co-founder of energy investment bank Petrie Partners, underscored the important role that synergies may play in a merger but cited strategic rationale as the critical factor in making mergers successful over the long term in today's tough energy environment. "The deal has to make strategic sense," according to Rapp. "You don't want to have to rely on the synergies to carry the deal. That said, in this challenging environment where every penny of improved margin counts, you can look at the synergies as a real component as to why a transaction might make sense, why it may provide substantial savings and be a material improvement in the economics of the combined entity."

G&A and operating expense synergies have "always been something that we've tracked and modeled in transactions," he said, adding that the net present value (NPV) of the asserted capex has also become a focus and can be viewed as having a certain asset value.

"Unfortunately, if all of a sudden you get into an environment where there is limited capital for development and the economics are challenged, and you end up running three rigs instead of four, everything gets delayed, and the NPV gets pushed out," said Rapp. "The $1 million to $2 million you were going to save per location aren't as impactful. I think that scenario playing out in prior deals has led to some skepticism on synergies from investors."

"In this kind of environment, no one is given the benefit of the doubt, especially in these large acquisitions," commented Rapp.

Looking back at the combination between Cimarex Energy Co. and Resolute Energy Corp., Cimarex had "the luxury that everybody pretty much understood and embraced the strategic fit when they did the transaction. The asset fit was so hand-in-glove," said Rapp. "Cimarex's stock has come down with the market, but that's not because it's not realizing anticipated synergies or efficiency targets."

In a recent M&A study, AlixPartners LLP analyzed more than 240 asset and corporate transactions made by publicly traded energy companies over the period 2006 to 2018. The analysis compared the total equity value of the acquiring company and the target prior to announcing the merger against the two parties' combined equity value at intervals of one year and two years after the transaction.

While commodity prices played a large part in E&Ps' revenues and profitability, even transactions that were conducted at a time of relatively stable commodity prices showed that M&A was "no panacea," according to the study. In terms of equity value, there was a roughly 50:50 split between transactions that were value accretive and value destructive, after both one and two years post-deal closing.

In a more recent study, focusing on a subset of five mergers announced in 2017 to 2018, the findings were somewhat similar, according to Bill Ebanks, managing director in AlixPartners' energy practice. "We went back and tried to track what companies were planning to do in terms of projected synergies and what it appeared they were doing in terms of delivering on their synergies," said Ebanks. "Our findings indicated three of the five look to be on track to deliver in a range of expected synergies they announced, while two looked like they were trailing their targeted synergies."

The three mergers that looked like they were "in the ballpark" as regards expected synergies were: Encana Corp. and Newfield Exploration Co.; Chesapeake Energy Corp. and WildHorse Resource Development Corp.; and Diamondback Energy and Energen Corp. The two that looked like they were may be more challenging were: Concho Resources Inc. and RSP Permian Inc.; and EQT Corp. and Rice Energy Inc.

In its deeper dive into the five E&Ps, AlixPartners sought whatever assumptions were available on "activity levels that drive the synergies that you may be able to capture, including how much capital you deploy, how many rigs you run, how much footage you drill, etc.," said Ebanks. "If those things don't materialize as expected, it's hard to deliver the synergies that you promised."

In instances where E&Ps provided projected synergies over several years, the study translated the targets into annual dollars for purposes of comparability. Present values assumed a 10% cost of capital.

Captured synergies

"If you look at what was planned versus what was actually captured, most of the operators appear to have captured their G&A synergy," said Matt McCauley, director in AlixPartners' energy practice.

For example, Encana-Newfield had a target of $125 million and, based on its most recent

10-Q, has an annual run-rate of $120 million of savings, which "seems in line with what the company projected its G&A synergy to be," said McCauley. As for Chesapeake-WildHorse, the company provided guidance of $50 million to $80 million, and based on the most recent financial statements is at a run rate of $57 million of G&A savings, he added.

"Most of the time, G&A is a very near-time item that companies control and can usually take action on quickly as they integrate the organizations," said Ebanks. "We would expect the full run rate of a G&A target to be achieved within the first year post-transaction. If we're involved in the merger integration activity following an M&A transaction, we'd aspire to lock in the organizational synergies in first six to nine months, if not sooner, so we're at a full run rate benefit by the end of year one."

On operational synergies, or the "capital efficiency" side, results were more varied. Mergers consummated by Encana, Chesapeake and Diamondback all appear to be on track to achieve their targets, the study indicated. However, those led by Concho and EQT appear to have had annualized capital savings targets of $200 million and $350 million, respectively, "and in both cases it is difficult to see those results being achieved at this point," said McCauley.

Parent-child issues related to working out optimum spacing of wells "may have caused Concho to pause, take a step back and slow down its capital investment last year in order to eventually optimize its financial results," said Ebanks. "Concho may not deploy as much capital as it probably thought when it first bought RSP," he continued. "And it's hard to achieve the synergies or capital efficiency if you're not going to spend as much capital in the first place."

"When you're talking about a present value benefit of as much as $2 billion, so much of that benefit comes in the first two or three years," said McCauley. "If you decelerate your capital plan, or if you aren't able to operationalize the capital plan, that has a material impact on the PV [present value]. That may be a factor in what we're seeing in the instances of Concho and EQT."

Setting targets

One of the takeaways from the study, according to Ebanks, is that "those companies that are clearly setting targets and measuring themselves consistently against those targets over the course of the following year or two, post-transaction, seem to be the ones that also are clearly showing the benefits they got from these transactions."

Those companies reaping benefits from synergies appear to be doing it through one of two main ways, said Ebanks.

One is building "local scale, which allows them to enjoy purchasing power from suppliers and to leverage the expertise on the acreage they already own, and to then apply it to the offset acreage that they pick up," he said. "Another is being fundamentally better operators. They have an advantaged capability they can apply to someone else's acreage and drill and complete wells better than others."

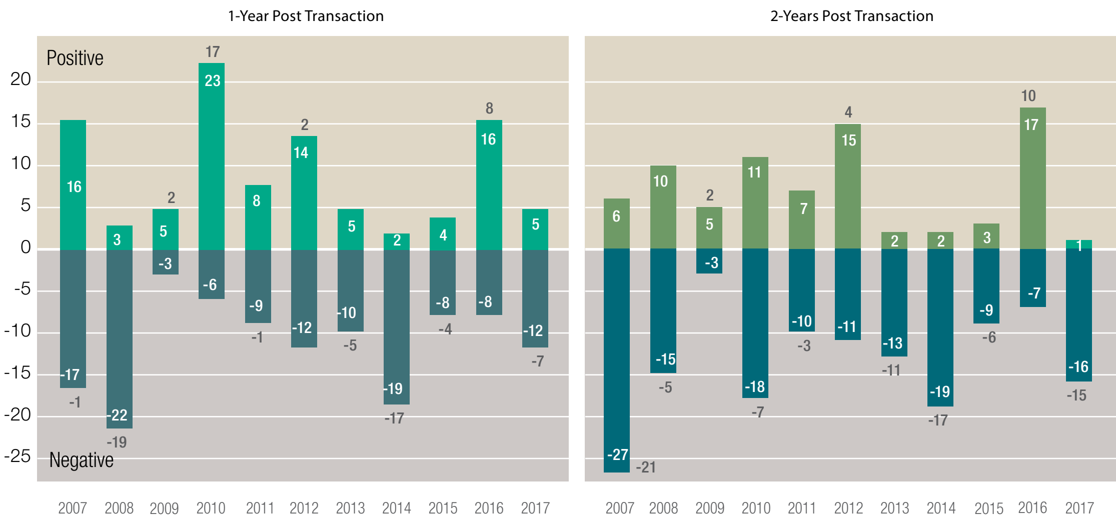
In looking at the premiums paid in the five mergers in 2017 to 2018, acquirers paid a range of premiums of 20% to 35%, said McCauley. Since then, premiums have been declining, even as "some of the healthier companies are interested in acquiring—but on a value basis of maybe closer to 20% or, in some instances, a zero premium in the case of distressed companies."

The obstacle to transacting mergers could in part be due to the continued volatility in the commodity prices, according to McCauley.

Takeover premiums in energy are markedly lower than in the broader market, he said, "and part of the reason could be due to the volatility in prices," he added. "If you don't know that you'll be able to capture the synergies because of the uncertainty as to commodity price and/or pace of development, then the premium is going to be correspondingly lower." ☐

"If you decelerate your capital plan, or if you aren't able to operationalize the capital plan, that has a material impact on the present value [of synergies]," said Matt McCauley, director, AlixPartners.

Count Of Positive And Negative Equity Performances Post-M&A Transaction



Source: AlixPartners

Only about half of companies engaged in M&A show an increase in shareholder value post-transaction.

M&A FANTASIES

E&P analysts weigh in on what makes a dream combo and whether the majors will play.

ARTICLE BY
LESLIE HAINES

One of the most popular parlor games played by CEOs, investment bankers, analysts and investors is like charades—a real guessing game. We're talking about lively discussions that put one E&P company with another and consider which companies would be choice merger targets—or put another way, the most vulnerable.

Sliding oil and gas prices in first-quarter 2020 turned up the pressure cooker where E&P companies already found themselves stewing, many in a pungent sauce of high debt. The downturn and uncertainty will push some companies on the margin to consider selling, in hopes of taking a buyer's stock for some upside.

Opportunities abound. Many private-equity-backed E&P firms have reached their sell-by date of three to five years since inception. If they are in the Permian Basin, they are all the more ripe for consolidation. After all, doesn't everyone want more Permian acreage?

It's anybody's guess as to when the M&A game will begin. Will we see another blockbuster deal between giants like Occidental Petroleum Corp.'s combination with Anadarko Petroleum Corp., or a marriage between two large independents such as Concho Resources Inc.'s hookup with RSP Permian Inc. for $9.5 billion—all in stock?

We asked analysts to ponder the combinations that could make sense. Any and all E&P companies are targets at the right price, but, given that, M&A is no longer an investment thesis that would woo anybody back to the sector. The focus now on the part of companies and investors is to spend on maintenance mode, repair balance sheets and get that free cash flow going. If a deal is done, it has to be accretive, and the pro forma company that results has to have low leverage.

"Acquisitions are like picking up hand grenades—a misstep (i.e. using equity!) can end poorly," said Bob Brackett, Bernstein research analyst, in a January note. In general, companies that are likely to be acquired include those with high costs but rapidly growing production and cheap stock valuations, he said.

But will investors applaud a deal in this environment?

"I think M&A is mostly a distraction now," said Gabriele Sorbara, managing director and equity research analyst for Siebert Williams Shank & Co.—itself the product of a recent merger of investment banks. "As an analyst I've shifted to other themes because we've seen that M&A is not going to create value. It's just not a theme for investors like it was maybe five years ago. It's not a call I can make for clients," he told *Investor*.

Nevertheless, Sorbara said, high-quality Permian pure plays with a lot of inventory could be good targets. "I do think managements know now what makes a good deal, and they are not in any hurry to buy," he added.

Majors to act?

Much of the deal speculation centers on which majors or international oil companies with the most firepower could make a big move, such as when Exxon Mobil Corp. acquired Bopco LP (the Bass family entities), or before that, XTO Energy Inc. It's not clear that they should make such a move or would be rewarded if they did. But sellers like to accept stock in a major, thinking that could be rewarding compensation in the long term.

"I think what everybody wants to see is the majors coming in, but they tend to buy at the wrong times, when prices are higher," said Sorbara. "Plus, their commentary on the recent conference calls is that they plan to be shrewd and protect their balance sheets, and no one is in a hurry," he said.

Several observers echoed Sorbara's theme of the majors seemingly reluctant to enter the M&A arena. Looking within his coverage group at Bernstein, Brackett said Concho Resources and Pioneer Natural Resources Co. "are the obvious meals for mega-majors (but like pythons, majors can last a long time without a meal)." He might be prescient: His top candidate to be acquired, as mentioned in a report two years ago, was Resolute Energy Corp., which was acquired by Cimarex Energy Co. in March 2019 for $1.6 billion.

In a recent research note from Cowen & Co., analyst Jason Gabelman, who covers the majors, estimated "Chevron [Corp.] would likely show flat Permian production from its current portfolio before accounting for potential Permian growth beyond plan, which is a 2023 goal, new projects, exploration success and M&A."

A buyer has to have money and motivation. Sorbara considered the case of Marathon Oil Corp., which has about 10 years of drilling inventory and yet some concerns as its Eagle Ford position matures—that could be motivation. It has the checkbook, too: $3 billion on a fully undrawn borrowing base. However, he noted that company management has said on conference calls that it is not looking to do a deal, preferring instead to expand inventory internally, such as with its Austin Chalk play in Louisiana, under the rubric of its so-called "Rex" (resource expansion) plan. He also noted there have been rumors of Marathon merging with an equal like Devon Energy Corp., which he said could be logical.

Most analysts hesitate to name names on the record, but of course privately, plenty of fantasy combos are emerging in what-if scenarios. But Mizuho Securities USA managing director Paul Sankey did some speculating in his research note issued just before the analyst days that were scheduled in early March by Chevron and Exxon Mobil. He noted Exxon Mobil's stock trades at a 15-year low.

"One mega-move into environmental/emission friendliness would be for either [Chevron or Exxon Mobil] to buy Occidental … which has some of the world's largest CO_2 sequestration operations. We only see this as a friendly deal, and [with] Oxy CEO Vicki Hollub in control, our view is that the Oxy dividend is safe."

Gabelman said he doubts Shell will do anything big in the near term, although its name frequently comes up as a Permian buyer. "They have a large capex plan of $24 billion to $29 billion this year that includes $5 billion that could be used for M&A. After this year, their annual capex budget excludes M&A, which could give them capacity to execute a larger transaction. However, we believe they have other financial priorities that could limit interest in M&A such as the buyback and the debt.

"Total has stated many times that it's not interested in acquiring any U.S. shale. BP [Plc] is digesting what they acquired from BHP, so I don't see them doing anything this year."

Many are skeptical about any major deciding to do a deal, because so many of the big acquisitions they've made in the past few years have caused a lot of indigestion. Huge reserve write-downs have plagued these buyers.

"It's historically been horrific. In general, majors buying independents has not worked out, so they'll need to be picky," said Leo Mariani, an E&P analyst for KeyBanc Capital Markets.

He cited the Exxon Mobil-XTO Energy deal, ConocoPhillips' buy of Burlington Resources Inc. and Chevron's acquisition of Atlas Resources' assets in Appalachia. Each deal was weighted heavily to natural gas, but then the price of gas tanked, wreaking havoc across the U.S.

"What surprises me is if a buyer who's in good shape buys a company that's not giving them operational efficiencies, but it's celebrated if what they've bought is on the verge of generating free cash flow," said Subash Chandra, managing director of E&P at Guggenheim Securities.

"I think M&A is mostly a distraction now," said Gabriele Sorbara, managing director, Siebert Williams Shank & Co.

Possible Buyers Or Sellers

Buyer	Seller
Exxon Mobil Corp.	Cimarex Energy Co.
Chevron Corp.	Pioneer Natural Resources Co.
Marathon Oil Corp.	Concho Resource Inc.
Devon Energy Corp.	Occidental Petroleum Corp.
Cimarex Energy Co.	Callon Petroleum Co.
	Centennial Resources Development Inc.
	Parsley Energy Inc.
	Any private Permian company

Analysts speculated on these possible dealmakers but without any specific signs that a deal will happen. Some E&Ps appeared on both lists.

Concho Resources and Pioneer Natural Resources "are the obvious meals for mega-majors, but like pythons, majors can last a long time without a meal," said Bob Brackett, Bernstein Research.

MOEs or survival pacts

Mergers of equals (MOEs) are a tactic some analysts advocate, especially in the small- and mid-cap space, although others take a cautionary stance because value depends on the quality of the equals. Two weak sisters hanging onto each other to stand up is not a pretty picture.

Sorbara calls these "survival pacts" that won't work if the pro forma result has too much debt.

"You just end up with a larger pile of debt. Now the Parsley-Jagged Peak deal was a good combination because it created a pro forma company with low leverage and high margins. But I don't think a major comes in and buys a Callon Petroleum [Co.]—that doesn't move the needle. "Maybe you could see Cimarex [Energy Co.] targeted by Chevron since they already are in a JV [joint venture] in Culberson County. But I am not making a call on any of these," he emphasized.

It may be that the most likely crew of buyers is motivated to gain scale and add to their drilling inventory, and reduce overhead, but when will they act and what can they pay?

"A lot of the obvious combinations have already happened, but I do think more of the Permian companies could get bought out," Mariani said.

The Permian Basin remains the only region that's consistently most attractive to buyers. There's plenty of fish in that pond. According to data supplied by Enverus, there are almost 140 private E&Ps in the Delaware and Midland basins, excluding mineral and royalty companies. Of the 400 private-equity-backed E&Ps it identified in the U.S., nearly 65% were funded in 2016 or prior years, meaning the time to monetize is nigh.

Seeking inventory

Before E&Ps can even think about matching up, they have to get their house in order, analysts say. It's like reentering the dating scene after a long hiatus: First, they have to lose some weight, color their hair or rewrite their online profile.

A company without enough drilling inventory is like a person with no date next Saturday night, the lack of it being a strong motivator to take action. There is no strong rule of thumb as to how much inventory a company should have—it's subjective—but The Street generally begins to understand who's short and who's long, Chandra said, with short being three to five years of visibility.

"I think the industry thinks high-quality drilling inventory is becoming more limited," Mariani said. "Most companies are in pretty good shape for the next three to five years or so on that score. And if they do make a deal, it takes time, by the time you negotiate it, close and then begin drilling on that. Certainly if you step down in [acreage] quality, you can extend that inventory life."

There are two types of buyers, observed Chandra. The first is an over-levered company that's heading toward cash-flow neutrality that needs more production. The second is inventory-short but with debt metrics that are reasonable. Their acquisition has to make sense at the asset level, like entering a new basin or buying adjacent acreage to support longer lateral wells.

"The dream combo is going to be a free-cash-flowing acquisition with inventory less meaningful," Chandra told *Investor*. "The one thing you cannot buy is an over-levered, outspending company, no matter what. But I do think the market is a lot shorter of inventory than companies like to admit. Once you get past 2021, you have to get pretty creative about the runway.

"I don't see a lot of companies with a lot of 'un-mowed grass' so I think acquisitions are going to be important."

Should investors applaud a significant deal that brings the buyer diversity into another play or applaud a buyer that bulks up its one-basin strategy? "I don't think basin diversity is bad … but it's secondary to valuation. It all depends on the valuation and the price one pays," Chandra said. "It's neutral to your outlook for free cash flow."

Analysts said that the list of attractive places to buy inventory has narrowed. The Bakken and Eagle Ford plays are very mature with less drilling inventory left to attract a buyer other than in noncore areas. The Utica is less economic. The Denver-Julesburg Basin has well-known regulatory challenges. "Nobody's touching Appalachia," said one.

"The challenge associated with larger-scale acquisitions in more mature basins such as the Eagle Ford and Williston will continue to be remaining Tier 1 inventory, which we believe to be few and far between," said analyst Neal Dingmann of SunTrust Robinson Humphrey in a report.

"What you have left is a cheaper exploration play somewhere, or the Permian, but that's not novel anymore," Sorbara said. "Maybe on the small-cap side you have some of the gassy names that might try to do something transformative, like the EQTs and Ranges. Maybe Cabot Oil & Gas could buy an oily company—they're the only name that has a good enough stock price to issue equity. But I don't see any reason a major would get involved."

Mariani agreed that the right target has to be seen as a low-cost player holding a good bit of drilling inventory. No one is interested in buying pure production without enough inventory ahead, he said. "Someone with seven to 10 years of inventory is top of the list. Secondarily, buyers look for a company with free cash flow but which has large capital needs that go beyond their cash flow. And oil—we haven't seen much activity on the gas side. Gas players just have too much leverage."

That leads to another desired characteristic, which is, of course, a reasonably healthy balance sheet. But not necessarily a pristine one, he said. "Debt is prohibitive for most purchasers. Yes, you could see some bankruptcies among the gas players where a buyer can come in and get the assets, but not have to take on the seller's debt."

With these traits in mind, Mariani lists oil-weighted Cimarex Energy, WPX Energy Inc., Centennial Resource Development Inc. and Parsley Energy Inc. as possible targets. "I'd be surprised if one of these doesn't get bought in the next few years. But if the majors eventually decide to step up, they'd probably go for the larger targets like a Concho or a Pioneer," he added.

Premiums or not?

In the slow M&A atmosphere we've seen for the past two years, the base price and premiums are not heading skyward anymore. In general, a low-premium model prevails now, coupled with most buyers offering some of their equity, with the seller hoping for stock appreciation.

"I just don't think the majors will pay very large premiums in the near term, and besides, several of them already have a decent U.S. footprint," Mariani said. "When we see smaller players, you aren't going to see high premiums. The Concho-RSP deal had a large premium, and it was punished by the market, while the WPX Energy-Felix Energy deal was very positive. That deal was the type the market will embrace, that is, a smaller premium with a good-sized stock component."

Guggenheim's Chandra recently hiked his price target on WPX to $19 per share from $17, saying, "Our price target change is mainly due to a working capital surplus in 2020 as the Felix acquisition enhances the company's FCF [free cash flow] profile."

Naming names

SunTrust's Dingmann issued an intriguing report in December 2019 that listed potential deals that would make sense based on geography, free-cash-flow effects and other criteria. He also cited the positive market reaction to the WPX-Felix merger as a guide to what investors would accept: a large PDP component and relatively inexpensive valuation on the part of Felix as seller and a strong balance sheet with less than 1.5 times leverage on the part of WPX, the buyer.

"We believe potential buyers could include Marathon, Devon Energy, Cimarex Energy, Enerplus [Corp.], Diamondback [Energy Inc.] and Noble Energy [Inc.], while we believe notable potential public sellers could include Oxy, Pioneer, WPX and Callon. We believe notable private sellers could include DoublePoint [Energy LLC], Encore [Energy Inc.], Ameredev [II LLC], Bruin, Camino, Venado [Oil & Gas LLC], Verdad, Vine, Indigo [Natural Resources] and Ascent (all private)."

To display his reasoning, he spoke of some potential hookups. Regarding DoublePoint Energy LLC, for example, whose core is the Midland Basin, he said, "According to a Reuters article in February 2019, the company was believed to be exploring a sale for as much as $5 billion. The company is currently running four rigs throughout its Midland position and is estimated to have drilled about 70 gross wells since its formation in June 2018. Given that the company has five different private-equity partners, we see potential for increased difficulty in negotiation given the number of parties that need to reach a consensus.

"Given the scale of the asset and breadth of the asset, we believe only larger Midland operators with a historical Midland Basin focus would be likely candidates for an acquisition of DoublePoint, including Concho, Apache [Corp.] and Pioneer."

In a Delaware example, Dingmann mentioned Ameredev II. "We believe that given the contiguous nature of the position and sought after state-line geology, Ameredev could be attractive to a number of operators with a northern Delaware position, ample size and strong balance sheet including Marathon or Devon."

Viewing the Denver-Julesburg Basin in Colorado, Dingmann cited Verdad Resources, founded in 2017 with private-equity backing.

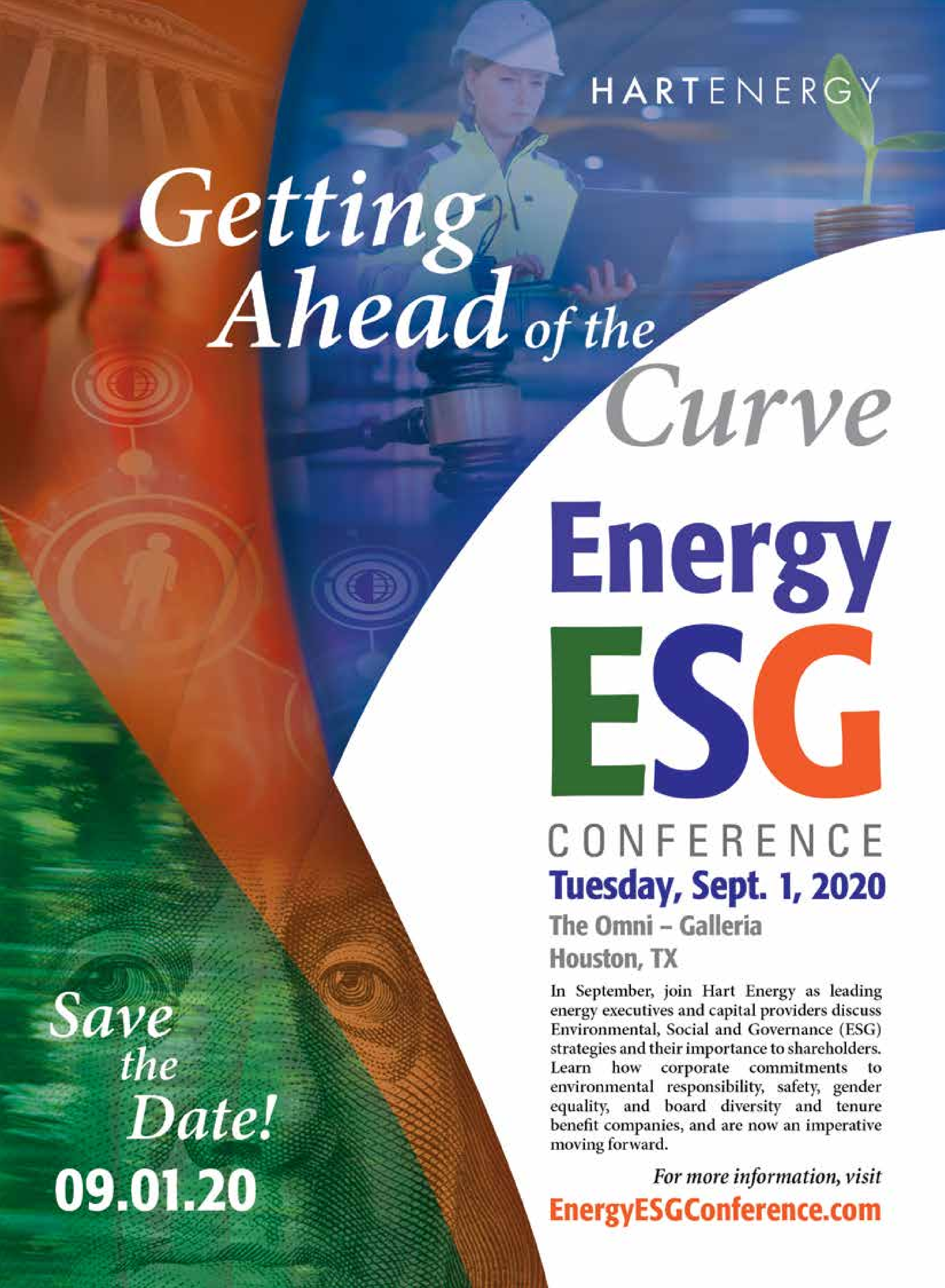
"The company has a massive acreage position; however, with the Wattenberg group trading at 2.7 times, a significant premium for the acreage is unlikely as it would be hard for the acquirer to justify. Verdad could be attractive to HighPoint Resources or Bonanza Creek (BCEI), perhaps best with BCEI given its RMI midstream asset that Verdad could feed into. That being said, as BCEI trades near PDP, it is hard to see a near-term deal unless Verdad decided to 'participate in the upside' via the stock," he wrote.

Dingmann also speculated about Bakken-focused Bruin E&P Partners LLC, which was founded in 2015 and is backed by private-equity firm ArcLight Capital. The company has built over 170,000 net acres, is running one rig in the basin and has drilled about 170 wells, according to Enverus. Activity is focused in McKenzie, Dunn and Mountrail counties, N.D. "Given the appetite for additional Williston acreage, we believe that the company could be attractive to Marathon, WPX or Enerplus," Dingmann wrote.

Regardless of basin, the deal-making blueprint is clear: merge an inventory-rich, free-cash-flow machine with a larger company that has capital to drill but can't seem to replace reserves. Any players with contiguous acreage should get together for coffee. It's cheaper to buy reserves than to drill for them, given that valuations are down by half or more. A deal has to be done without much of a premium, and the pro forma company that comes out of it has to have low leverage.

In the end, deal metrics and the commodity price outlook may not matter: "All the names are targets at the right price," said every analyst. "If I was a seller, I'd probably not pick this time to sell," said Chandra. "When you look at the reception most M&A deals have gotten, it's been awful. You'd think that would scare away the buyers, but I think deals happen because the buyer is trying to solve bigger long-term problems than the Street sees." □

"The dream combo is going to be a free-cash-flowing acquisition with inventory less meaningful," said Subash Chandra, managing director of E&P at Guggenheim Securities.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SERVICE SECTOR RESHUFFLE

Amidst a volatile price environment and depressed share valuations, the prospect for oilfield service consolidation remains murky. But one thing is certain—it needs to happen.

ARTICLE BY
BLAKE WRIGHT

"I think it is going to be like-for-like companies, small to mid-sized, stock-for-stock deals most likely with little to no premium," said James West, senior managing director, oilfield services, Evercore ISI.

Merger appetites in the oilfield service space mirrored a wasteland of inopportunity for most of last year, and the outlook for 2020 remains mired in a bog of challenging fiscal patterns and heightened levels of uncertainty. Translation? It's ugly out there.

Budget cuts, lower activity levels and fresh waves of right-sizing rule the day as operators look to survive in the new world order of living within cash flow.

All the financial maneuvering by E&Ps has trickled down and impacted service providers' bottom lines. Less money and less activity by their client base means leaner times ahead for contractors that supply the tools to produce oil and gas. The stress has tempered deal making, according to a report by Deloitte.

There were fewer larger deals in the sector during 2019—only 10 worth more than $500 million and four worth over $1 billion worldwide. Previous years have seen a healthy tranche of deals between companies in the offshore drilling and the engineering, procurement and construction spaces.

While Deloitte expects to see some smaller deals made in 2020, overall M&A activity is expected to be muted. One driver the firm points to as a potential jumpstart to more deals is the restructuring wave that is expected as companies look to secure better financial footing.

"I think the industry is sitting here today at a crossroads," said James West, senior managing director, oilfield services, for Evercore ISI. "I think we have a distinct part of the industry—the North American land part of oilfield services—where we massively over capitalized the business both with existing companies and also with plenty of new start-up companies to attack what we now know was a massively over capitalized E&P industry that was going after shale oil."

As of mid-February 2020, the shares of service giant Schlumberger Ltd. were down 30% over the company's 52-week high of almost $49. Similarly, rival Halliburton Co. shares have slumped by a third over its peak during the past 12 months. Others are in worse shape.

> "You can consolidate at your current stock prices, you can consolidate when prices are lower or we can consolidate you in a Delaware court room after you've filed Chapter 11. I think the urgency is improving."
>
> —James West,
> Evercore ISI

Global offshore driller Noble Corp. has seen its stock price erode to below $1 per share. Other offshore rig contractors—Transocean Ltd., Diamond Offshore Drilling Inc. and Valaris Plc—all have stock prices in the $4 to $5 range.

"I think everybody would generally agree there needs to be consolidation, but I think for two public companies to come together, there will have to be a meeting of the minds where the teams agree that being together versus separate is the best thing for their shareholders and for the business as a whole," said Dean Price, managing director of energy at Opportune LLP. "I think that rationalization is still trying to work itself out. I think if everybody could see some stabilization in commodity prices in the $55 to $60 per barrel range for oil with the belief the forward look price will remain in that range, it is possible upstream companies could increase their budgets. It might give a little nudge to the consolidation notion."

With the massive growth cycle for shale oil winding down, investors are looking for returns. E&P companies are slashing capex in a bid to live within cash flow. The strain of lower investment dollars and the fact that many upstream companies have been effectively cut off from capital markets have negatively impacted the service industry.

Pundits are pointing to consolidation as a tool to reconcentrate the industry, but underperforming stocks have made the process to defragment the service side a slow one. No

"There are going to be people who are running short on runway and don't want to continue funding the business unless they see a sign of improvement in demand for their services," said David Smith, senior vice president, Mercer Capital.

one, neither management nor their boards, is too keen on stepping up and consolidating at lower valuations than they believe their companies are worth.

"We've told them, 'You can consolidate at your current stock prices, you can consolidate when prices are lower or we can consolidate you in a Delaware court room after you've filed Chapter 11,'" said West. "I think the urgency is improving. But we are still at a bid/ask spread point where things aren't aligning just yet. We're starting to see things. You have Era buying Bristow on a reverse merger out of bankruptcy. I think you'll see more going forward especially in the more fragmented product lines."

Several forces, both internal and external, can drive consolidation. There are geopolitical factors that could prompt more activity. A leadership change in the U.S. could also affect M&A levels, especially if that leadership were to target the domestic oil and gas business for a regulatory reshuffle.

"Until the current conditions change, you're not going see the necessary dynamics for potential transactions or see the number of potential transactions increase," said David Smith, senior vice president at valuations firm Mercer Capital. "It's a muddy way of looking at it, but to an extent that's true. We've been sitting on the current conditions, without material change for a while now, and that doesn't happen in the energy industry for very long.

"To an extent we're kind of due for something to happen. But it's not within our crystal ball clarity level to know what it's going to be and when it's going to happen. It just kind of seems like we've been sitting where we are for quite a while, and we're due," Smith said.

Whether the nudge that sets the industry on a change of course is imminent is anybody's guess; however, most don't believe the larger, integrated companies are where any merger activity will start. It will likely be the smaller, more fragmented segments that will take the leap first.

"I think the large, diversified service companies right now are more focused on culling their own businesses, so looking internally at underperforming product lines and in some cases jettisoning those, or in some cases, shutting them down," said West. "You can see just from Schlumberger's last quarter [when] they announced they had shut down coiled tubing in the U.S. They also announced a major restructuring of their U.S. operations. As did Halliburton, as they are pivoting from a growth focus to a returns focus. I think it is going to be like-for-like companies, small to mid-sized, stock-for-stock deals most likely with little to no premium."

Deals like the 2019 merger between pressure pumpers C&J Energy Services and Keane Group is a good example. Both companies entered the shale solutions space and grew rapidly. The deal was an all-stock, merger-of-equals to create NexTier Oilfield Solutions, a larger, more diverse oilfield service company that has a combined enterprise value of $1.8 billion. Similar deals in the shale space could follow

Recent Top 20 Oilfield Service Deals

Date Announced	Buyer	Seller	Value ($MM)	Segment
Dec-19	Apergy Corp.	Ecolab Inc.	$4,387	Integrated
Sep-19	Public, Baker Hughes, a GE company	GE Oil & Gas	$3,098	Integrated
Jul-19	DP World Plc	Renaissance Services SAOG, Standard Chartered Private Equity	$1,079	Integrated
Jun-19	Keane Group Inc.	C&J Energy Services	$723	Drilling and Completion
May-19	Brookfield Business Partners	Teekay Offshore Partners LP	$965	Integrated
Mar-19	Yinson Holdings Berhad	Ezion Holdings Ltd.	$916	Production Operations
Mar-19	Tenaris SA	PAO TMK	$1,209	Drilling and Completion
Oct-18	Sentinel Energy Services Inc.	Strike Capital LLC	$854	Production Operations
Oct-18	Ensco Plc	Rowan Companies Plc	$4,153	Drilling and Completion
Sep-18	Transocean Ltd.	Ocean Rig UDW Inc.	$2,717	Drilling and Completion
Aug-18	Ensign Energy Services Inc.	Trinidad Drilling Ltd.	$720	Drilling and Completion
Mar-18	US Silica Holdings Inc.	EP Minerals	$750	Production Operations
Dec-17	McDermott International Inc.	CB&I	$3,745	Information Services
Nov-17	National Energy Services Reunited Corp.	Gulf Energy SAOC, National Petroleum Services	$1,100	Integrated
Aug-17	Transocean Ltd.	Asia Research & Capital Management, York Capital Management, Songa Offshore	$3,400	Drilling and Completion
Aug-17	Jacobs Engineering Group Inc.	CH2M Hill Inc.	$3,266	Information Services
Jul-17	Brookfield Business Partners LP	Teekay Offshore Partners LP	$2,393	Integrated
May-17	Ensco Plc	Atwood Oceanics Inc.	$1,726	Drilling and Completion
Apr-17	SNC-Lavalin Group	Atkins	$2,672	Information Services
Mar-17	John Wood Group Plc	Amec Foster Wheeler Plc	$3,946	Information Services

Source: Enverus

PHOTO COURTESY OF NEXTIER OILFIELD SOLUTIONS

given the current barometer for activity in the near term.

Usually M&A is fueled by companies attracted to a new technology or an additive piece of business not already in their portfolio. However, deals in the current climate may stray more toward the necessity of joining forces with a rival in order to reset financial stability.

The oilfield service industry is a broad one dotted with companies with high-fixed cost structures, low-fixed cost structures and those that can lay off employees and bring them back when things improve. However, some don't have that sort of flexibility.

"It really depends on their particular position or niche, whether they're more exposed to the extended mediocre oil price or whether they can weather that much more easily than others," said Smith. "And it depends on how deep their bank account is right now. Those are all the factors that are going to come into play.

It's really a case by case, or a niche by niche, and even a company by company, and a depth of bank account that determines at what point do they cry 'uncle' and say, 'Call the investment bankers and tell them to find me a buyer; I'm not going to continue funding this.' There are going to be people who are running short on runway and don't want to continue funding the business unless they see a sign of improvement in demand for their services."

During the shale boom of the last decade, new money entered the space from the private-equity side of the equation. Not only funding start-up E&Ps driven by the attractiveness of a drill-and-flip style entry and exit strategy, but on the service side as well. Firms like Riverstone Holdings pumped cash into contractors like Liberty Oilfield Services and Proserv among others. The exit strategy from these types of deals isn't as cut-and-dried as it was previously. Many private funds are having to retrench and remain engaged. Consolidation could offer an exit from these investments. Additionally, private-equity groups might look to build the attractiveness to outside parties by pairing comparable companies within their portfolios.

"With private-equity investors, we've seen a little bit of consolidation in their portfolio companies," said Price. "You might have two or three companies within your portfolio that are compatible or maybe have compatible services. We thought we were going to see more of that, and that doesn't seem to be happening as quickly."

Deal-making motivations can vary between companies, but it appears clear that most see 2020 as a year that could see an uptick in oilfield service marriages. The climate for mergers in the space during the past 12 month has been weak at best. As there are factors that lie ahead that could spur new deals, things could occur that may well extend the M&A slump through the rest of the year and beyond.

"If we see an oil price spike, that would kill it pretty fast," said West. "A lot of this is forced consolidation. It's not companies looking for new product lines or embracing new technology. It is really about trying to get the G&A [general and administrative] out of the system, trying to right the ship for a resized market that is smaller than what they built for. If the oil price were to go up substantially and E&P's started spending a little more, that could prolong that lack of serious M&A." □

"With private-equity investors, we've seen a little bit of consolidation in their portfolio companies," said Dean Price, managing director of energy, Opportune LLP.

PURCHASERS PREFER PIPES

Private-equity acquirers boosted midstream transactions to the fore last year, but has that till been depleted? An active midstream M&A climate looks to continue in 2020, say pundits, with water-related deals most attractive.

ARTICLE BY
BLAKE WRIGHT

Blackstone Infrastructure Partners LP bought Tallgrass Energy LP in August for nearly $5.5 billion.

Dealmakers in the midstream sector had a busy 2019, and there are indications that the trend could continue this year. Like the E&P sector, midstream companies have increasingly faced headwinds from the investment community due to perceived lop-sidedness in the risk/reward equation. This squeeze, paired with other financial factors such as limited interest from the debt markets, has resulted in depleted coffers that have partially hamstrung growth prospects. As a result, private money has moved into the sector and may fuel additional deals going forward.

According to S&P Global, midstream acquisition deal values almost doubled to $27.8 billion in the first five months of 2019 compared to the same period the previous year. The movers in the space were mostly private-equity concerns looking to secure positions in the less-volatile infrastructure plays required to move record amounts of production out of places like the Permian and Eagle Ford basins in Texas.

Blackstone Infrastructure Partners LP's multibillion-dollar pursuit of Tallgrass Energy LP netted the company's private portfolio a growth-oriented midstream energy company specializing in moving oil and gas from the Rocky Mountains and the upper Midwestern and Appalachian regions into major demand markets. Stonepeak Infrastructure Partners, an infrastructure-focused, private-equity firm with over $15 billion of assets under management, snapped up Oryx Midstream Services LLC for $3.6 billion. The deal covered a robust pipeline network in the Permian.

PHOTO COURTESY OF TALLGRASS ENERGY LP

"I think midstream M&A has to be viewed in the context of the infrastructure build cycle," said David Amoss, midstream research analyst with Heikkinen Energy Advisors LLC. "We're sort of on the down slope of that cycle now. If you went back a couple of years, you had significant capital spending ahead of the industry to unlock the Permian growth, to change the routes from other regions to new delivery points, specifically to move to a more export-driven delivery. That money has now largely been spent.

"We were pretty tight—there was a high utilization of midstream assets even in '18 and '19. A lot of those 'tight' situations are being unlocked now. Long-haul crude pipe, long-haul NGL pipe, fractionation, processing—all of those asset classes are moving into a situation with less average utilization and more excess capacity," Amoss said. "I think that really changes the dynamic of how M&A will occur in the future, but I do think this year and next year will be robust M&A years in the midstream sector."

Eight weeks into 2020, there had already been a quintet of deals in the midstream sector valued at over $1.3 billion, including Kinder Morgan Inc.'s decision to sell its entire stake in Pembina Pipeline and Phillips 66 Partners' buy-in of Liberty Pipeline—a $1.6 billion project to transport Rockies and Bakken crude oil production to Oklahoma's Cushing hub.

"From our conversations, midstream is the overwhelming preference for investors as opposed to upstream," said Brendan Matthews, director with PJ Solomon. "Financial sponsors are hearing the same refrain from LPs that public companies are hearing from investors as they look to fundraise—capital is no longer there, or limited, until we receive something from our previous investments in return.

"Private-equity midstream activity has been constrained in large part due to its close association with its upstream counterparts. Upstream activity has been nonexistent, and some sponsors have been forced to bring their midstream assets to market in order to return capital to investors and help with current fundraising efforts," he continued.

"Many of these midstream assets are a bit premature and would historically be billion-dollar enterprises. Where these midstream assets currently stand is a fraction of that because they don't have the growth once associated with them—the funds will not commit to a drilling program on the upstream side in order to maximize value for the midstream asset. I think it's interesting that you're seeing the same pressure applied to the private side is on the public side."

Strategic drivers

For 2020, midstream M&A is positioned to be more strategic in nature. Going back to the middle of the last decade, companies raised a lot of private-equity capital in the energy space. This capital formation was then put to work in what became a very competitive environment.

PHOTO COURTESY OF TALLGRASS ENERGY LP

Tubulars on site at a Tallgrass facility.

In areas like the Permian, which saw a large amount of investment, contractual support for the assets that were created was weaker than it had been historically. That has made it difficult for private-equity companies to find their exit, as a lot of those assets and funds cannot currently achieve the returns their investors and sponsors once thought possible.

"Private-equity capital that was deployed during that period now has two options," said Amoss. "One is you wait out the cycle; you wait for a period of time where you're not selling into an underutilized asset market. And in many cases the private-equity assets are more underutilized than the public assets are. You wait out that cycle or, secondly, you just take a lower return than you used to originally underwrite your fund. I don't think either of those are particularly great options, but I do think there's enough assets that are in that category that some of them will be forced to move here."

A traditional driver of midstream M&A has been upstream companies selling off midstream assets to raise capital; however, many of those deals have already been done and not a lot of strategic offerings exist beyond those controlled by the larger, integrated companies that don't react to shorter-term cycles the same way that smaller operators do. Exxon Mobil Corp., Chevron Corp. and the like would not fall into the class of 'forced' sellers. They typically do not sell off assets just to fund other projects.

"Your forced sellers of assets who need to raise capital, and currently do not have other options, are going to get less than they would prefer or have grown to expect," Amoss continued. "Historical M&A values won't hold up for these assets. Those upstream companies are going to continue to market their remaining midstream assets, and they'll just get bids that are lower than they expected. Then it's up to their discretion or their specific situation whether or not they execute. I think a lot

"We are already seeing intra-fund private equity consolidation, but would expect to see a bit more collaboration and cooperation inter-fund going forward," said Brendan Matthews, director with PJ Solomon.

"All indications are we're probably going to start seeing some transactions on the water side of things," said David Smith, senior vice president of Mercer Capital.

of higher-dollar transactions will be driven by buyers that are larger, diversified midstream companies that have existing systems that can bolt on in a strategic fashion.

"We saw a deal recently from Plains All American, which has a great oil transportation system, and they bought a gathering system in the Permian to feed that system. The economics of that system on its own probably doesn't support a deal like that, but Plains can move those volumes through their long-haul pipelines and into their downstream network. They can make a higher return because of the system they already have. That's the type of M&A I'd expect to see really heat up here. That will be driven by large diversified companies like Kinder [Morgan], Enterprise, Plains [and] Magellan."

Any lack of midstream deal activity may have as much to do with the current health of the upstream sector. In years past, deals in areas such as the Permian were done when a buyer saw a climbing rig count, capital dollars being spent, type curves were being exceeded on a consistent, repeatable basis and returns were achieved. That is not the world we live in today.

"Across the board, capital budgets are falling, rig counts are dropping and companies are now required to do more with less," said Matthews. "This shift in operator focus will have a dramatic impact on many of those in the market as they look for potential solutions, particularly those on the private-equity side.

"From our conversations, midstream is the overwhelming preference for investors as opposed to upstream."

—Brendan Matthews, PJ Solomon

"We are already seeing intra-fund private-equity consolidation (Jamco/Smashco), but would expect to see a bit more collaboration and cooperation inter-fund going forward.

"This has historically been a social impossibility, but the stance that we've seen some take is, 'Hey, I probably can't make it alone. Long term, you probably can't make it alone. Perhaps if we get together, we have a better shot of getting us out of where we are today.'"

The bid/ask spread on many current deals is wide, but expected to narrow over time. The gap is expected to close because the ask comes down, not because the bid goes up. A litany of factors is aligning to impact the oil and gas

Recent Top Midstream Deals

Date Announced	Buyer	Seller	Value ($MM)
Oct-19	Hess Midstream Partners LP	Hess Infrastructure Partners LP	$6,194
Sep-19	Energy Transfer Partners LP	SemGroup Corp.	$4,977
Aug-19	Blackstone Group	Tallgrass Energy LP	$5,484
May-19	MPLX LP	Andeavor Logistics LP	$14,010
Apr-19	Stonepeak Infrastructure Partners	Oryx Midstream Services LLC	$3,600
Jan-19	Blackstone Group, GIC, Enagas	Tallgrass Energy LP	$4,775
Nov-19	EQM Midstream Partners LP	Equitrans Midstream Corp	$4,388
Nov-18	Western Gas Equity Partners LP	Western Gas Partners LP	$8,465
Oct-18	EnLink Midstream LLC	EnLink Midstream Partners LP	$7,954
Oct-18	Antero Midstream GP LP	Antero Midstream Partners LP	$7,508
Aug-18	Energy Transfer Equity LP	Energy Transfer Partners LP	$59,697
Jun-18	Loews Corp.	Boardwalk Pipeline Partners LP	$3,359
Jun-18	Global Infrastructure Partners	EnLink Midstream LLC, EnLink Midstream Partners LP	$3,125
May-18	Enbridge Inc.	Spectra Energy Partners LP	$4,756
May-18	Williams	Williams Partners LP	$14,832
May-18	Enbridge Inc.	Enbridge Energy Partners LP	$6,947
May-18	Enbridge Inc.	Enbridge Income Fund Holdings Inc.	$4,351
Mar-18	Tallgrass Energy GP LP	Tallgrass Energy Partners LP	$3,140
Jan-18	Enbridge Inc.	Spectra Energy Partners LP	$7,200
Dec-17	Marathon Petroleum Corp.	MPLX LP	$10,100

Source: Enverus

PHOTO COURTESY OF TALLGRASS ENERGY LP

industry in 2020—closed bank markets, the rise of environmental, social and governance requirements, global economic health (China and coronavirus) and the upcoming presidential election to name a few.

Water transactions

One area expected to emerge as a robust M&A target for 2020 is the water sector. In West Texas, for example, the growing water industry is highly fragmented consisting of several mid- to small players. Consolidation in that market is expected over the coming months.

"We have effectively witnessed a modern day land-grab arms race on the water side of the midstream sector," said Matthews. "What was once a niche part of the business and market has become a major influencer in how operators do business. We are able to highlight our abilities relating to recycling, treatment, etc., in order to attract a new pool of investors to the space."

"All indications are we're probably going to start seeing some transactions on the water side of things, whether it's supplying water to the site or the disposal business," added David Smith, senior vice president at valuations firm Mercer Capital. "That's the one area that has had rumblings of transactions due to a natural economics-driven consolidation, because it's been so fragmented up to this point. It's a newer area. It's scattered. It's due for consolidation and in West Texas with both a lack of water and all the fracking going on that uses a heck of a lot of water, it is ripe for that type of consolidation." □

Private-equity players secured multi-billion-dollar acquisitions in less-volatile infrastructure plays last year, a trend that has continued this year.

TRENDS IN U.S. LAND PRICES

This play-by-play takes a deep look into pricing trends across six key basin areas, including the two most active gas plays and the Gulf of Mexico.

ARTICLE BY
ANDREW DITTMAR

Author's Note: This review of acreage prices was written prior to the recent collapse in crude prices and market volatility. Its primary goal is to provide historical prospective on pricing in key plays. Any forward-looking statements should be read in context of current market conditions.

PHOTO BY RICARDO MERENDONI

The past year was a pivotal time for U.S. upstream deal markets and the broader industry. Investors who funded the shale revolution over the past decade became increasingly vocal in advocating for payouts and to cut back on providing new capital. That flowed through to limited M&A and a challenging reaction to deals for much of the year.

While Enverus tracked $96 billion of U.S. oil and gas M&A in 2019, the annual total was substantially skewed by Occidental Petroleum Corp.'s $57 billion acquisition of Anadarko Petroleum Corp. in May. 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 over the past 10 years.

Occidental's acquisition of Anadarko highlighted 2019's consolidation in the shale patch. The deal is in the ballpark of Exxon Mobil Corp.'s 2009 acquisition of XTO Energy Inc. as the most spent on shale in a deal. Occidental saw 75% of Anadarko's value in shale, including the Permian Basin. After allocating value across Anadarko's portfolio, Enverus estimated the Delaware acreage price at $58,300 per acre, in line with top-tier Permian corporate sales in past years.

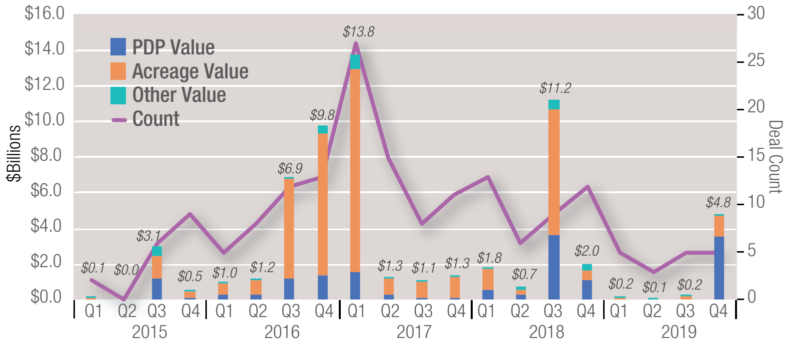
Most of 2019's other marquee deals also focused on the Permian but came in the back half of the year as sellers seemed to adjust pricing expectations on acreage downward. After the Occidental/Anadarko deal, 2019's largest corporate deals were Callon Petroleum Co.'s $2.7 billion merger with Carrizo Oil & Gas Inc., WPX Energy Inc.'s $2.5 billion buy of private Felix Energy II and Parsley Energy Inc.'s $2.3 billion acquisition of Jagged Peak Energy Inc. These deals ranged from $6,700 to $10,800 per acre for Permian leasehold.

Buyer demand for undeveloped land outside of the Permian was limited, and few deals saw a substantial payment over production value. The highest priced non-Permian deal was a $185 million acquisition by Marathon Oil Corp. in the Eagle Ford valued at $4,200 per acre. The Williston Basin and the Haynesville Shale saw a number of deals priced in the $2,000 to $3,000 range. In other plays like the Scoop/Stack, buyers proved largely unwilling to pay for undeveloped land.

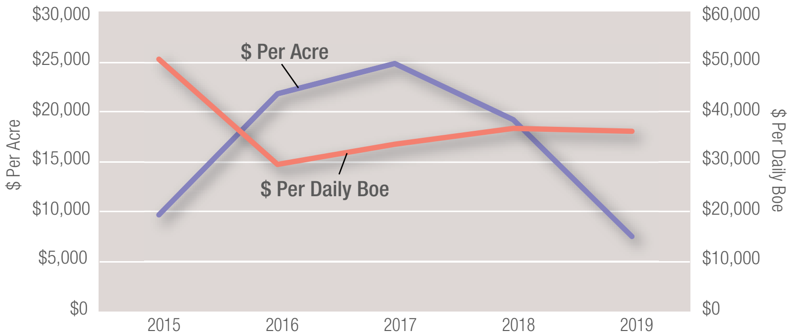
Overall, all the plays that were surveyed reached their highest average acreage prices between 2016 and 2018 and showed a noticeable drop in 2019. Land valuations in the past year looked similar to where deals were pricing in 2015. As of late February, 2020 has usurped 2019 as the slowest start for upstream deals since 2009. The year has currently recorded less than $1 billion in upstream transactions versus a $9 billion average from 2010 to 2019. With limited buyer appetite, particularly when it comes to paying for upside, acreage values look poised to remain beneath recent 2016 to 2018 highs.

Here is a play-by-play look at pricing across six key unconventional liquids-focused areas, the two most active gas plays plus the Gulf of Mexico. All acreage prices are adjusted for PDP value using flowing production multiples, and averages are based on deals with a disclosed value greater than $50 million.

Delaware Basin Deal Value And Count



Delaware Basin $/Acre And Daily Boe



Source: Enverus

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
07/15/19	Callon Petroleum Co.	Carrizo Oil & Gas Inc.*	$2,740	Corporate	$33,755	$7,389
12/16/19	WPX Energy Inc.	Felix Energy II	$2,500	Corporate	$35,100	$6,735
10/14/19	Parsley Energy Inc.	Jagged Peak Energy Inc.	$2,270	Corporate	$37,275	$10,819
09/30/19	Marathon Oil Corp.	Undisclosed Seller	$144	Acreage	-	$2,400
02/19/19	Tall City Exploration III	Noble Energy Inc.	$132	Acreage	-	$10,154
		Total	**$7,786**	**Average**	**$35,377**	**$7,499**

*Also held assets in the Eagle Ford. $/acre is for Delaware acreage.

PHOTO BY TOM FOX

Delaware Basin 2019 M&A review

The Delaware Basin has been a leading play for deal activity, particularly with a land-buying boom that peaked in early first-quarter 2017, when nearly $14 billion in assets changed hands. Leasehold pricing also peaked in 2017 at an average of $25,000 per acre with numerous deals in 2016 to 2018 pricing at $30,000 per acre or more.

Early in 2019 would-be sellers appeared to hold onto past years' acreage valuations, leading to a high bid/ask spread and trouble negotiating deals. A very notable exception was Occidental Petroleum Corp.'s acquisition of Anadarko Petroleum Corp. for $57 billion in May. While Anadarko held a diversified global portfolio, the Delaware leasehold was among the crown jewels. After adjusting for other assets, Enverus estimates Occidental paid about $58,000 per acre in the Delaware, comparative to top-tier pricing in past Permian corporate deals.

By the back half of the year, seller expectations seem to have moderated, and public buyers began to make acquisitions. Callon Petroleum Co. made an offer for Carrizo Oil & Gas (which also held Eagle Ford assets) although the deal met substantial pushback from Callon shareholders and ultimately required a reworking of deal terms implying a Permian land valuation of $7,400 per acre. Additionally, Parsley Energy Inc. bulked up its position in the Delaware with the acquisition of pure-play Jagged Peak Energy Inc. in a deal valued at $10,800 per acre.

To close the year, WPX Energy Inc. bought EnCap Investments-sponsored Felix Energy II for $2.5 billion, or $6,700 per acre. Excepting the price, the deal had shades of the 2016 to 2018 land-buying boom as a public E&P bought out a premier private-equity operator. Encouragingly, investors cheered the deal with a boost in WPX's stock as they considered the acreage quality and a moderate price. Delaware leasehold overall averaged $7,500 per acre in 2019, a significant discount from past years and possibly a price that will spur additional deal activity.

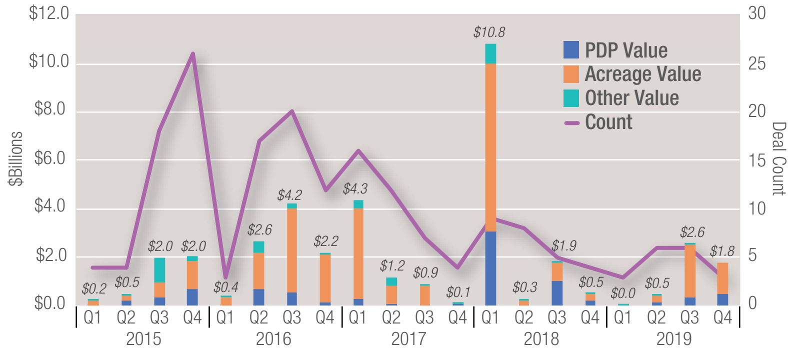
Midland Basin 2019 M&A review

The Midland Basin, along with the Delaware, has accounted for the bulk of the Permian's rise to the top of U.S. shale regions. The transaction market trajectory of the Midland Basin is slightly less dramatic than its counterpart to the southwest though. With an earlier start to unconventional drilling, Midland Basin leasehold was averaging $15,000 per acre in 2013, at a time when Delaware positions could still be had for a few thousand dollars per acre. Its corresponding rise when Permian land buying kicked off in earnest in 2016 was therefore less dramatic, although average acreage prices did double from $17,800 per acre in 2015 to $34,600 per acre in 2018.

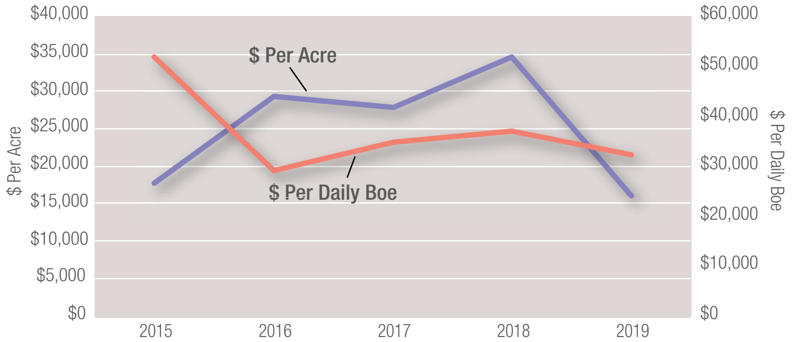
In 2019, Midland deal activity slowed substantially from an average $10 billion per year in 2016 to 2018 to $4.8 billion. In a fairly unique deal, Occidental was able to bring in Colombia's Ecopetrol as a joint-venture partner for $1.5 billion or $31,600 per acre, fully in line with past Midland pricing. A shrinking buyer pool seems to have taken effect on prices late in the year with HighPeak Energy forming a new northern Midland Basin pure play in a series of combinations implying $15,100 per acre.

Overall, acreage in the Midland Basin averaged $16,000 per acre in 2019 or 50% off the 2018 highs. Prices in the northern and central portions of the basin were on average higher than in the southern Midland. Although the Midland has consistently shown a higher dollar per acre average than the Delaware, that may be primarily a function of fewer transactions, particularly in Tier 2 or 3 areas. It is likely Tier 1 positions in either basin would draw comparable valuations. Acreage prices at this level could spark additional buyer interest. The Midland has a handful of select consolidation targets including some significant private companies, although fewer than in the Delaware.

Midland Basin Deal Value And Count



Midland Basin $/Acre And Daily Boe

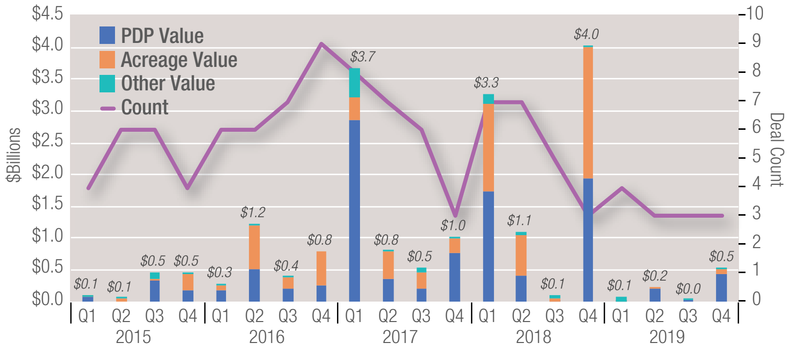


Source: Enverus

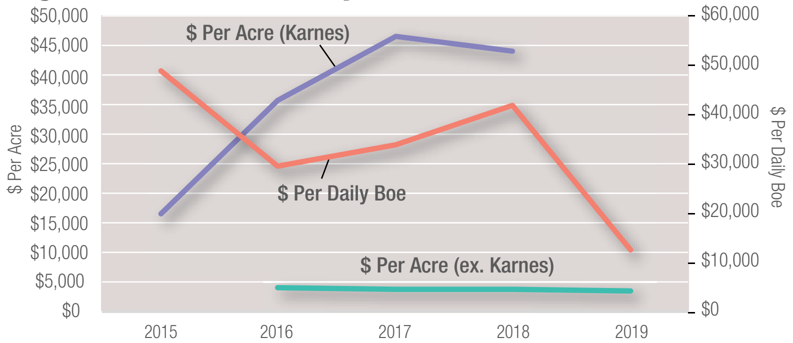
Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
11/27/19	Pure Acquisition	HighPeak; Grenadier II	$1,575	Corporate	$39,210	$15,130
07/31/19	Ecopetrol	Occidental Petroleum Corp.	$1,500	JV	-	$31,559
07/30/19	Viper Energy Partners	Diamondback Energy Inc.	$700	Royalty	-	-
04/08/19	Sequitur Energy Resources	Callon Petroleum Co.; Undisclosed Seller	$265	Property	$27,360	$11,618
09/30/19	Viper Energy Partners	Undisclosed Seller	$168	Royalty	-	-
		Total	**$4,208**	**Average**	**$33,285**	**$19,436**

PHOTO BY JAMES L. DURBIN

Eagle Ford Deal Value And Count



Eagle Ford $/Acre And Daily Boe



Source: Enverus

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
11/07/19	Repsol	Equinor	$325	Property	$9,559	-
05/06/19	Ensign Natural Resources	Pioneer Natutal Resources Co.	$213	Property	$14,792	-
11/06/19	Marathon Oil Corp.	Rocky Creek Resources; Delago Resources	$185	Property	$12,857	$4,167
05/06/19	Magnolia Oil & Gas	Titanium Exploration	$77	Property	-	-
02/14/19	Undisclosed Buyer	Harvest Oil & Gas	$52	Corporate	-	-
		Total	**$851**	**Average**	**$12,403**	**$4,167**

Eagle Ford 2019 M&A review

Deal activity and pricing in the Eagle Ford consists of several subportions of the play tied together by a few overarching themes. The most active years of Eagle Ford M&A were largely in the first half of the past decade, with 66% of total value and 74% of land value paid prior to 2015.

The Karnes Trough area primarily in Karnes County plus portions of Gonzales and DeWitt counties stand out as unique among Eagle Ford areas on pricing. With well economics competitive with the best, core acreage in this narrow area averaged $42,000 per acre 2016 to 2018. This is not indicative of prices in the remainder of the play, however. Additionally, being a core position for a number of large operators, this area rarely trades and had no significant deals in 2019.

Excluding Karnes Trough, prices have remained consistent around $4,500 per acre since 2015 with most deals targeting a section of the black oil or condensate windows. Marathon's $185 million acquisition from Rocky Creek Resources and Delago Resources in November 2019 was representative at $4,200 per acre. Moving into the thinner areas of the black oil window, acreage values have generally averaged $1,000 to $2,000 per acre with little appetite among buyers in 2019. The gassy portions of the Eagle Ford have particularly struggled with a weak commodity price environment.

Like other plays, the Eagle Ford has recently struggled with a lack of a buyers. Two public stalwarts, Pioneer Natural Resources Co. and Equinor, worked hard to find exits in 2019 and ultimately ended up with what look to be production value only deals. In the past few years, private equity was an active buyer but looks to have pulled back on challenging exit options. The Eagle Ford still plays a key role for big operators including EOG Resources Inc. and ConocoPhillips Co. that rarely participate in M&A.

PHOTO BY TOM FOX

Williston Basin 2019 M&A review

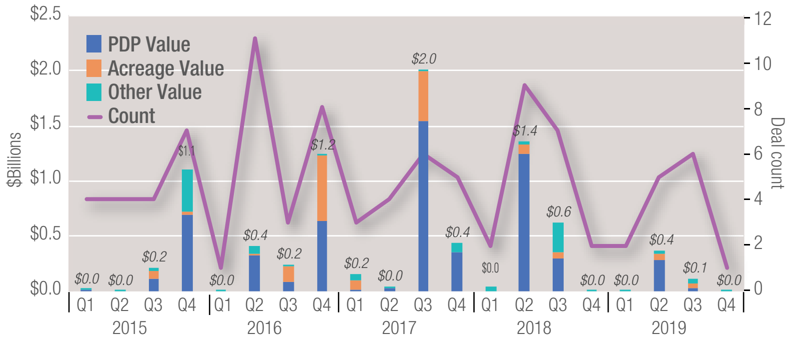
There were limited transactions targeting the Bakken and Three Forks in the Williston Basin during 2019 with just over $500 million in deals, down 66% from the $1.5 billion worth of assets that traded hands in 2018. Along with the Eagle Ford, the Williston Basin constitutes one of the more mature shale plays that had a larger role in deal markets during prior years. Nearly 80% of reported Bakken/Three Forks M&A took place prior to 2015 and 87% of the value paid for land transacted prior to 2015.

Williston Basin acreage values have ceded ground in recent years. The play reached a peak for land valuations in 2015 and 2016 at $14,900 and $12,600 per acre, respectively, before a sharp drop to an average of $5,000 per acre in 2017 and 2018. In 2019, prices further declined to an average of $3,400 per acre.

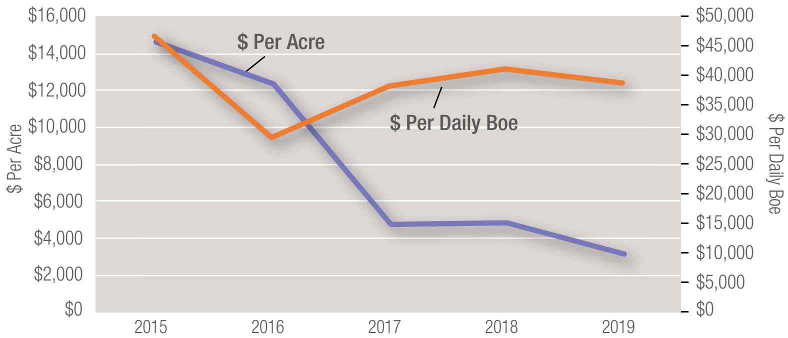
The bulk of 2019 value came from one transaction, the acquisition of a nonoperated stake by Northern Oil & Gas Inc. from Flywheel Bakken for $310 million, or an adjusted $3,050 per acre. The second-largest deal of 2019 was also comprised of a nonoperated interest with Whiting Petroleum Corp. selling a position for $53 million, or $3,800 per acre.

Reasons for the decline in Williston valuations likely include more attention on the Permian, oil price differentials and relatively high development of the core. Available positions may have less remaining inventory or be located towards the fringier areas. The highest acreage values appear to have been paid in the east-central portion of the Williston, consisting mostly of parts of Dunn, McKenzie, Mountrail and Williams counties, N.D. Like in the Eagle Ford, the Williston remains a key position for a number of large operators that actively drill their core areas but rarely participate in deal markets.

Williston Basin Deal Value And Count



Williston Basin $/Acre And Daily Boe

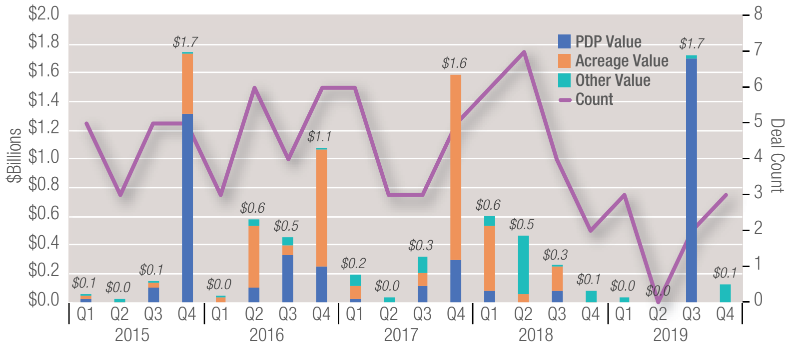


Source: Enverus

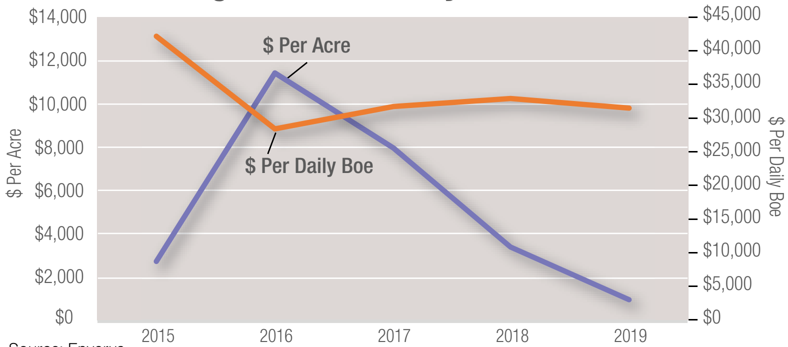
Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
04/22/19	Northern Oil & Gas Inc.	Flywheel Energy	$310	Property	$38,700	$3,048
07/02/19	Undisclosed Buyer	Whiting Petroleum Corp.	$53	Property	$38,700	$3,793
09/30/19	Undisclosed Buyer	Oasis Petroleum Inc.	$41	Property	-	-
06/30/19	Undisclosed Buyer	QEP Resources Inc.	$38	Property	-	-
05/06/19	Undisclosed Buyer	Abraxas Petroleum Corp.	$16	Property	$44,286	-
		Total	**$457**	**Average**	**$40,562**	**$3,421**

PHOTO BY STEPHEN COLLECTOR

D-J & PRB Deal Value And Count



D-J & PRB Average $/Acre And Daily Boe



Source: Enverus

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
08/26/19	PDC Energy Inc.	SRC Energy Inc.	$1,700	Corporate	$27,961	-
11/26/19	Crestone Peak	ConocoPhillips Co.	$380	Property	$36,427	$842
12/09/19	YTEF Drilling Capital	Bayswater E&P	$125	JV	-	-
01/31/19	Undisclosed Buyer	Extraction Oil & Gas	$22	Property	-	-
01/22/19	Grizzly Petroleum	PetroShare Corp.	$17	Property	-	-
		Total	**$2,244**	**Average**	**$32,194**	**$842**

PHOTO BY STEPHEN COLLECTOR

Rocky Mountain 2019 M&A review

In the Rocky Mountain region, the Denver-Julesburg (D-J) Basin and the Powder River Basin have emerged as the two most consistently active unconventional plays with some similar trends in valuations and deal activity and are the focus of this analysis.

Between the two areas, the D-J Basin has the longer history and has historically been more active for deals. Acreage values in the D-J Basin rose rapidly from $3,000 per acre in 2015 to $11,500 per acre in 2016. Pricing slipped a bit in 2017 to an average of $8,000 per acre, and then land buying evaporated in 2018 with no significant acquisitions. That trend carried over into 2019, with only one transaction specifically focused on the D-J Basin with an implied acreage value. That deal was Crestone Peak Resources' $380 million acquisition from ConocoPhillips, which implied $842 per acre.

While the D-J Basin lost deal momentum in 2018, the Powder River Basin recorded its most active market ever with nearly $1 billion in transactions and an average price of $3,400 per acre. Leading the way was Northwood's $500 million buy from SM Energy Co. However, the deal momentum failed to carry through into 2019 with no significant deals.

The largest development of 2019 in the D-J Basin was long-standing operator Anadarko's acquisition by Occidental for $57 billion. Also, PDC Energy Inc. acquired D-J pure-play SRC Energy Inc. for $1.7 billion. Investors cheered the deal with a boost in stock prices, likely on the low premium, all-equity consideration and sensible in-basin consolidation. Given the weakness in SRC's stock price, the deal implied $28,000 per flowing barrels of oil equivalent (boe) with no value allocated for acreage.

Additional corporate consolidation seems like the most likely route forward for deals in the D-J, while the Powder River Basin has a few significant operators that could consider a bolt-on deal at the right price.

Scoop/Stack/Merge 2019 M&A review

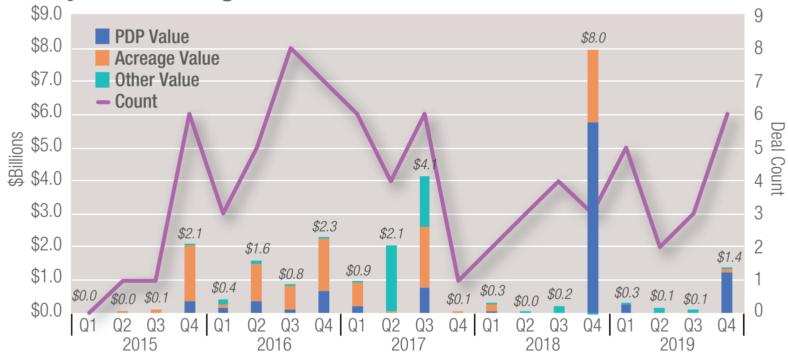
The Scoop/Stack/Merge has had a fairly dramatic trajectory for M&A during the past few years. It began to gain some traction in M&A markets in 2015 and became a major target in 2016 to 2018, averaging $6.9 billion transacted per year. Acreage values rose slightly from an average $9,300 per acre in 2015 and 2016 to a high of $11,800 per acre in 2017. M&A began to slacken off a bit in the play in 2018, but the year ended with Newfield's $7.7 billion acquisition by Encana Corp. (Ovintiv) in a deal largely focused on the Stack that valued the land at $5,600 per acre.

In 2019, significant challenges emerged, including producers struggling to rein in capex, a sharp drop in gas and NGL pricing and some inconsistent well results. All this amounted to a near-complete lack of appetite for paying up for acreage in the play during 2019.

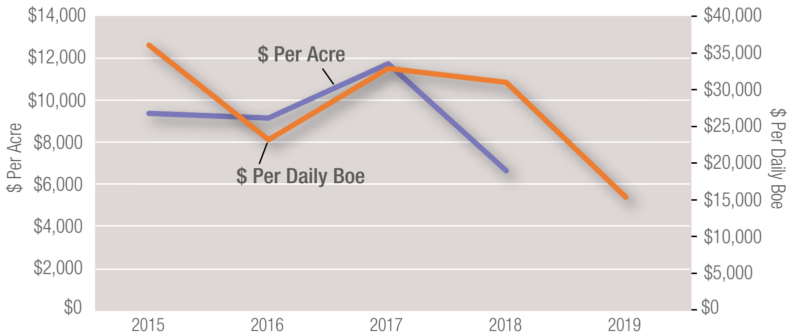
The year was mostly notable for the exit of public companies into private ownership, all in production value-only deals. In the largest deal of the year, Roan Resources was acquired by Warburg Pincus-backed Citizen Energy for $1.01 billion or $19,964 per boe/d after a brief run in public markets. Jones Energy II was similarly taken private by Revolution Resources (sponsored by Mountain Capital Management) for $202 million, or $9,416 per boe/d after it emerged from Chapter 11.

To end the year, Alta Mesa and its subsidiary Kingfisher Midstream received a stalking horse bid in Chapter 11 from a joint venture between Tom Ward's Mach Resources and Bayou City Energy. The offer was approved in 2020 for $320 million including $232 million, or $7,733 per boe/d for the upstream assets, ending Alta Mesa's public market run that started with a special purpose acquisition company deal in 2017. The outlook for valuations in the Scoop/Stack/Merge remains challenging with current commodity prices.

Scoop/Stack/Merge Deal Value And Count



Scoop/Stack/Merge $/Acre And Daily Boe



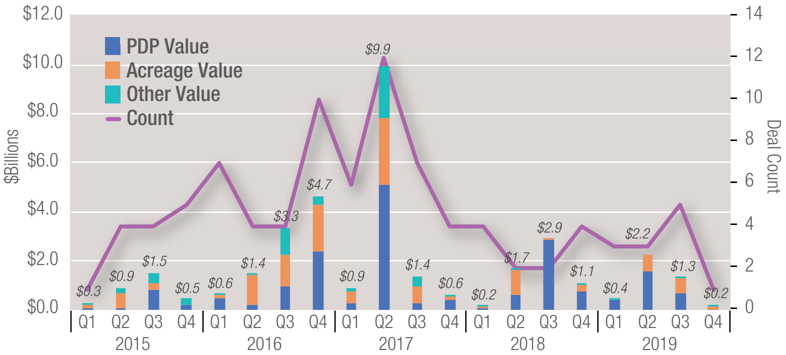
Source: Enverus

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
10/01/19	Citizen Energy	Roan Resources Inc.	$1,014	Corporate	$19,964	-
03/31/19	Red Wolf Natural Resources	Apache Corp.	$245	Property	$18,421	-
12/31/19	BCE-Mach II	Alta Mesa Resources Inc.	$232	Property	$7,733	-
12/06/19	Revolution Resources Inc.*	Jones Energy II	$202	Corporate	$9,416	-
12/10/19	Dow	Devon Energy Corp.	$100	JV	-	-
		Total	**$1,793**	**Average**	**$13,884**	**-**

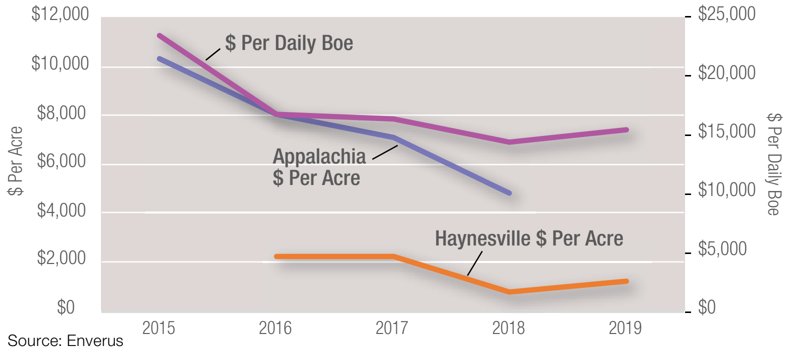
*Also included western Anadarko Basin assets.

PHOTO BY EDWARD DeCROCE

Appalachia/Haynesville Deal Value And Count



Appalachia/Haynesville $/Acre And Daily Boe



Source: Enverus

Appalachia/Haynesville 2019 M&A review

Lower 48 gas producers have been challenged by persistently low prices for several years. That has scaled back deal activity to the most economic areas. Outside of the occasional Barnett exit or Rocky Mountain legacy area deal, gas-focused M&A has mostly been in Appalachia and the Haynesville.

Appalachian M&A was fairly active in 2016 to 2018 at an average $7.9 billion per year. Acreage prices however showed a significant and persistent decline, falling from $10,335 per acre in 2015 to an average $4,800 per acre in 2018. Deals in 2018 shifted toward wet-gas areas including the Utica in Ohio to take advantage of favorable NGL pricing relative to gas. However, the 2019 decline in NGL prices looks to have closed that window as well.

The cumulative effects of low gas prices and corresponding financial troubles for producers ground the market for Appalachian acreage to a standstill in 2019 with no significant deals for working interest acreage. Deals have shifted primarily to production value, including Diversified Gas & Oil Plc buying legacy assets from HG Energy II for $3,200 per thousand cubic feet equivalent daily.

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
06/10/19	Comstock Resources Inc.	Covey Park Energy LLC	$2,185	Corporate	$13,500	$2,907
07/29/19	Osaka Gas Group	Sabine Oil & Gas Corp.	$610	Property	$13,500	$2,059
07/19/19	Franco Nevada; Lime Rock Resources	Range Resources Corp.	$600	Royalty	-	-
03/27/19	Diversified Gas & Oil Plc	HG Energy II	$400	Property	$19,364	-
10/21/19	Heritage Resources	Range Resources Corp.	$150	Royalty	-	-
		Total	**$3,945**	**Average**	**$15,455**	**$2,483**

PHOTO BY EDWARD DeCROCE

The Haynesville has been a more recent M&A target after private equity led a resurgence starting in 2016. However, similar to other areas exits for these operators have proven challenging. Dallas Cowboys owner Jerry Jones has become a major backer of the play via his controlling interest in Comstock Resources Inc. In 2019, he merged with Denham Capital's Covey Park Energy LLC in a $2.2 billion deal valued at $2,900 per acre.

The Haynesville's favorable positioning for Gulf Coast LNG export has also drawn the attention of Asian buyers, including Osaka Gas' $610 million acquisition from Sabine Oil & Gas at $2,100 per acre. After averaging $4,600 per acre in 2016 and 2017, Haynesville prices have declined to an average $2,000 per acre the past two years.

Gulf of Mexico 2019 M&A review

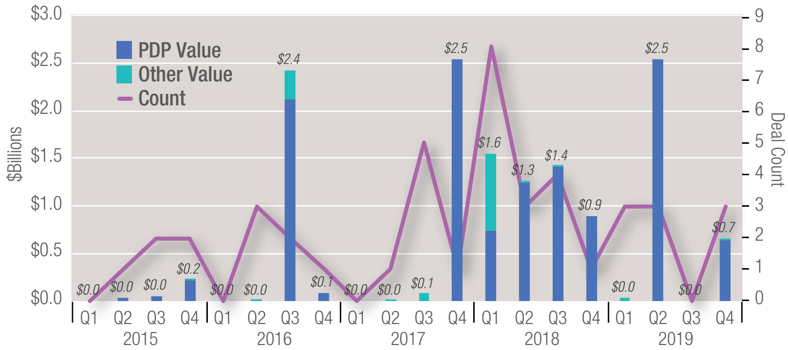
The late 2014 fall in crude prices hit Gulf of Mexico M&A particularly hard. In the years that followed, U.S. independent producers were particularly enthusiastic about the growth prospects for shale and invested significant capital to snap up leasehold while pulling back from offshore operations.

This led to a moribund Gulf of Mexico (GoM) M&A market that saw few deals and, when a deal did occur, low valuations. The most notable deal during this stretch was Anadarko's acquisition of the deepwater GoM assets of Freeport-McMoRan for $2 billion, implying $21,500 per boe/d (80%-plus oil) or 1.5x EBITDA.

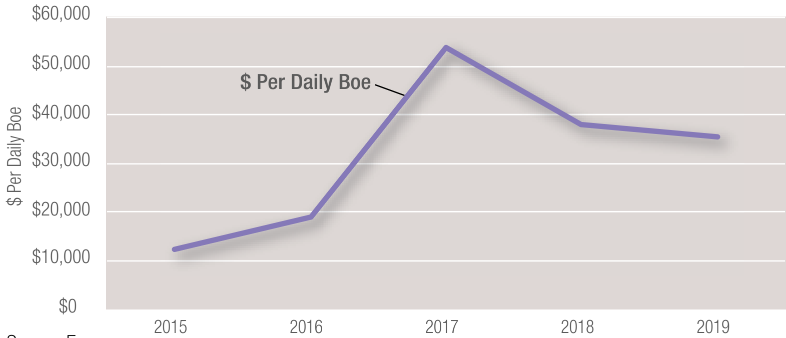
The GoM M&A market began a moderate resurgence in late 2017, when Talos Energy Inc. went public via a $2.5 billion combination with Stone Energy that valued the combined enterprise at $54,000 per boe/d. Since fourth-quarter 2017, GoM M&A has averaged $1.1 billion per quarter versus only $200 million from first-quarter 2015 to third-quarter 2017. Valuations for production (mostly oil-focused deals) have held relatively steady at $38,000 per boe/d and $35,600 per boe/d in 2018 and 2019, respectively.

Even with the rebound, the GoM M&A market remains fairly challenged. Valuations on production and cash flow are moderate, and deals seem to have been priced on production value only with little paid for prospects or discoveries. The buyer pool for offshore assets remains shallow. The majors and large international companies are active in the Gulf but largely focused on an exploration-driven model. Murphy Oil Corp. stands out as a unique U.S. independent that has looked to grow its offshore business in recent years including a $1.4 billion acquisition from LLOG Bluewater in 2019 valued at $36,200 per boe/d or 2.1x EBITDA. That has left mostly the two public GoM pure plays (Talos and W&T) as the primary buyers. □

Gulf of Mexico Deal Value And Count



Gulf Of Mexico $/Daily Boe



Source: Enverus

Date	Buyer	Seller	Value ($MM)	Deal Type	$/Daily Boe	$/Acre
04/23/19	Murphy Oil Corp.	LLOG Bluewater	$1,375	Property	$36,184	-
05/13/19	Equinor	Shell	$965	Property	$62,463	-
12/10/19	Talos Energy Inc.	ILX; Castex; Venari	$640	Property	$33,684	-
06/27/19	W&T Offshore	Exxon Mobil Corp.	$200	Property	$10,101	-
01/16/19	Talos Energy Inc.	Samson Energy Co.	$30	Property	$17,939	-
		Total	**$3,210**	**Average**	**$32,074**	**-**

PHOTO BY STEVE TOON

Andrew Dittmar is a senior M&A analyst at Enverus and focuses on deal analysis and market trends. He has a Bachelor of Business Administration in finance from Texas A&M University and a JD from The University of Texas at Austin.

U.S. E&P ACQUISITIONS & DIVESTITURES

Deals closed from July 1-Dec. 31, 2019. Deals closed in first-half 2019 were listed in the September 2019 issue. All deals, updated in real time, are now available at HartEnergy.com/ad-transactions.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
1	57,000	Occidental Petroleum Corp.	Anadarko Petroleum Corp.	8	Acquired The Woodlands, TX-based independent producer with a portfolio of international assets including 600,000 gross acres in the Permian's Delaware Basin; stock-and-cash transaction includes assumption of debt.
2	2,700	Callon Petroleum Co.	Carrizo Oil & Gas Inc.	12	Acquired Houston-based Carrizo, which has Permian Basin and Eagle Ford oil-weighted positions, in an all-stock transaction with assumption of $1.96B net debt and preferred stock; companies amended terms on Nov. 14, 2019.
3	2,200	Comstock Resources Inc.	Covey Park Energy LLC; Denham Capital Management LP	7	Acquired the Dallas-based privately held independent backed by Denham Capital with properties in the Haynesville and Bossier shale plays of N LA and E TX; includes assumption of debt and retirement of preferred units.
4	1,500	Ecopetrol SA	Occidental Petroleum Corp.	11	Formed JV to develop 97,000 net acres within the Permian's Midland Basin in W TX; Ecopetrol purchased a 49% stake for $750MM cash plus $750MM of carried capital.
5	1,000	Citizen Energy LLC; Warburg Pincus LLC	Roan Resources Inc.	12	Purchased the Oklahoma City-based company focused in the Merge, Scoop and Stack plays of the Anadarko Basin in OK; includes about 182,000 net acres and 50,800 boe/d net production.
6	965	Equinor ASA	Royal Dutch Shell Plc; Shell Offshore Inc.	7	Acquired, through an exercise of preferential rights, an additional 22.45% interest in the Caesar Tonga deepwater U.S. GoM field within the Green Canyon area; boosts Equinor's interest to 46% from 23.55%.
7	925	Spur Energy Partners LLC; KKR & Co. Inc.	Concho Resources Inc.	11	Acquired Concho's NM Shelf position in the Permian Basin; includes roughly 100,000 gross acres and about 25,000 boe/d of current production.
8	740.2	Viper Energy Partners LP	Diamondback Energy Inc.	10	Acquired through a dropdown 5,490 net royalty acres across the Permian's Midland and Delaware basins, over 95% of which is Diamondback-operated.
9	610	Osaka Gas Co. Ltd.	Sabine Oil & Gas Corp.	12	Acquired Houston-based Sabine, which has a 175,000 net-acre position in the Haynesville and Cotton Vally shale plays across E TX; production is 210 MMcfe/d.
10	525	Finley Resources Inc.	Crescent Point Energy Corp.	10	Purchased Crescent Point's Uinta Basin asset in UT; includes about 350 net sections of undeveloped land, 123.1 MMboe of 2P reserves and 29.5 MMboe of PDP reserves.
11	512	Amplify Energy Corp.	Midstates Petroleum Co. Inc.	8	Acquired Midstates through a merger; combined company portfolio includes CA, E TX/N LA, S TX's Eagle Ford and OK's Mississippian Lime.
12	500	Colony HB2 Energy; Colony Capital Inc.	California Resources Corp.	7	Formed JV to develop Elk Hills Field located within the San Joaquin Basin in Kern County, CA; initially commitment of $320MM could be increased to $500MM, subject to mutual agreement.
13	450	Oil Search Ltd.	Armstrong Oil & Gas Inc.; GMT Exploration Co. LLC	8	Bought the companies remaining interest in the Pikka Unit and Horseshoe Block plus other AK North Slope exploration leases as an option to a previous transaction.
14	367	Presidio Petroleum LLC; Morgan Stanley Energy Partners	Apache Corp.	7	Purchased western Anadarko Basin assets in KS, OK and TX representing a basin-exit for Apache.
15	325	Repsol SA	Equinor ASA	11	Bought Equinor's 63% interest in its Eagle Ford JV with Repsol, covering 69,000 net acres in S TX; includes operatorship.
16	310.4	Northern Oil and Gas Inc.	Flywheel Energy LLC; Kayne Anderson Capital Advisors LP	7	Bought Williston Basin properties consisting of nonop interest in 86.9 net producing wells expected to produce 6,600 boe/d during 2H 2019; includes roughly 18,000 net acres (100% HBP).
17	300	Franco-Nevada Inc.	Range Resources Corp.	7	Bought a 2% proportionately reduced ORRI in 350,000 net surface acres in SW Appalachia and applies to existing for future Marcellus, Utica and Upper Devonian development; Franco-Nevada is one of two buyers.
18	300	Lime Rock Resources LP	Range Resources Corp.	7	Bought a 2% proportionately reduced ORRI in 350,000 net surface acres in SW Appalachia and applies to existing for future Marcellus, Utica and Upper Devonian development; Franco-Nevada is one of two buyers.
19	295	Scout Energy Partners	Riviera Resources Inc.	11	Bought Riviera's remaining Hugoton Basin assets located in SW KS; includes upstream and midstream properties comprising of about 4,000 wells producing 104 MMcfe/d plus natgas processing plants.

Deals shown are those closed during second-half 2019, involving U.S.-based assets or companies only, and having values of approx. $20MM or more. Deals are ranked in descending estimated dollar value, when available, and then alphabetically when no value was made public or when the deal was significant but valued at less than $20MM. Deals shown as pending may have since closed. The next E&P A&D list, covering Jan. 1-June 30, 2020, will appear in the September 2020 issue. Details on all deal-making, updated in real time, are available at HartEnergy.com/ad-transactions.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
20	285	Undisclosed; Sabinal Energy LLC	Diamondback Energy Inc.	7	Purchased, in separate transactions, a package of 103,423 net acres in the Central Basin Platform, Eastern Shelf and the Northwest Shelf plus 6,589 net acres in the southern Midland Basin in Crockett and Reagan counties, TX; estimated full-year 2019 net production is about 6,500 boe/d from over 3,000 producing wells.
21	200	W&T Offshore Inc.	Exxon Mobil Corp.	9	Purchased interests in and operatorship of U.S. GoM properties and related onshore processing facilities in the Mobil Bay Area offshore AL; includes 19,800 boe/d (25% liquids) of production.
22	200	Undisclosed	Occidental Petroleum Corp.	11	Purchased select Occidental assets; further detail undisclosed.
23	193.6	Viper Energy Partners LP; Diamondback Energy Inc.	Undisclosed	10	Purchased about 1,272 net royalty acres through 25 acquisitions that closed in 3Q 2019; largest two deals were located in the Permian Basin.
24	185	Marathon Oil Corp.	Rocky Creek Resources LLC; Boomtown Oil LLC; Juniper Capital Advisors LP; Delago Resources LLC	12	Acquired 18,000 contiguous and largely undeveloped net acres adjacent to Marathon's existing NE Eagle Ford leasehold; includes 7,000 net boe/d of current production and associated midstream infrastructure.
25	165	NextEra Energy Inc.	Encana Corp.	8	Bought Arkoma Basin assets covering 140,000 net acres of leasehold in OK and 77 MMcfe/d (98% natgas) of current production.
26	150	Heritage Resources Inc.	Range Resources Corp.	9	Bought a 0.5% proportionately reduced ORRI applied to 350,000 net surface acres in SW Appalachia in PA.
27	150	Viper Energy Partners LP; Diamondback Energy Inc.	Santa Elena Minerals LP; EnCap Investments LP	10	Acquired certain Permian mineral and royalty interests from EnCap-backed Santa Elena in all-equity deal; comprises 1,358 net royalty acres primarily in Glasscock and Martin counties, TX.
28	145	Alliance Resource Partners LP	Wing Resources LLC; Natural Gas Partners LP (NGP)	8	Bought oil and gas mineral interests in the Permian Basin from Dallas-based Wing, which holds more than 200,000 gross acres with interest in over 4,000 wells throughout the Midland and Delaware basins.
29	132.5	Contango Oil & Gas Co.	White Star Petroleum LLC	11	Acquired the assets of White Star and certain affiliates comprising about 314,000 net acres in OK's Stack, Anadarko Basin and Cherokee plays with average production of 15,000 boe/d.
30	130	Laredo Petroleum Inc.	Cordero Energy Resources LLC	12	Acquired 7,360 net acres (96% operated) and 750 net royalty acres of largely undeveloped leasehold within the Midland Basin in Howard County, TX.
31	106	Marathon Oil Corp.	Multiple sellers	12	Purchased about 40,000 net acres in Ward and Winkler counties, TX, establishing a new Delaware Basin oil play in the Permian.
32	100	ConocoPhillips Co.; ConocoPhillips Alaska	Caelus Energy LLC; Caelus Natural Resources Alaska LLC	9	Acquired 100% of the Nuna discovery comprised of 11 tracts covering 21,000 acres within the AK North Slope region.
33	100	DowDuPont Inc.	Devon Energy Corp.	12	Forming drilling JV spanning 133 undrilled locations in the liquids-rich portion of Devon's Stack position in central Oklahoma; includes half of Devon's WI in the locations in exchange for a drilling carry over the next four years.
34	79.5	Continental Resources Inc.	Undisclosed	7	Acquired additional leasehold in the Scoop play adding up to 150 gross operated Woodford and Sycamore locations.
35	72	Bedrock Energy Partners LLC	Harvest Oil & Gas Corp.	9	Bought substantially all of Harvest's interests in the Barnett Shale, which comprise a roughly 28% WI in 164,276 gross (40,658 net) acres across N TX, over 90% of which is nonoperated; production in 1Q 2019 averaged 55.6 MMcfe/d.
36	65	Laredo Petroleum Inc.	Undisclosed	12	Bought 4,475 contiguous net acres (80% HBP) in Glasscock County, TX, in the Permian Basin with current net production of 1,400 boe/d (55% oil) and about 45 total gross (35 net) locations across the lower Spraberry, upper Wolfcamp and middle Wolfcamp formations.
37	54	Undisclosed	Gulfport Energy Corp.	7	Bought S LA assets with net production averaged 1,500 boe/d; Gulfport retained ORRI.
38	53	Undisclosed	Whiting Petroleum Corp.	8	Purchased, in multiple agreements, nonoperated properties comprising 6,800 net acres in the Rockies/Williston Basin and production of 703 boe/d as of April 2019.
39	50	Diversified Gas & Oil Plc	EdgeMarc Energy Holdings LLC	9	Bought through a stalking-horse bid certain OH Utica assets; include 12 gross producing unconventional Utica natural gas wells and related facilities in Monroe and Washington counties plus certain undeveloped lands containing deep Utica rights.
40	44.5	Riverside Energy Michigan LLC	Riviera Resources Inc.	7	Acquired interest in MI properties consisting of 1,400 net wells with 193 Bcfe proved developed reserves and proved developed PV-10 value of $38MM.
41	36.3	Kimbell Royalty Partners LP	Buckhorn Resources LLC	12	Acquired 86,000 gross (400 net) royalty acres, 90% of which is located in the Eagle Ford Shale in La Salle and McMullen counties, TX, with current production about 270 boe/d (83% oil, 11% natural gas and 6% NGL).

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
42	29.5	Bayshore Energy TX LLC	Sundance Energy Australia Ltd.	10	Purchased Dimmit County, TX assets comprised of 19 gross producing wells in the Eagle Ford Shale an about 6,100 net acres; averaged 1,051 boe/d sales volumes in 1Q 2019.
43	27	Black Swan Oil & Gas LLC	Pioneer Natural Resources Co.	7	Bought certain vertical wells and roughly 1,400 undeveloped net acres in Martin County, TX, within the Permian's Midland Basin.
44	23	Contango Oil & Gas Co.	Will Energy Corp.	10	Acquired 12,560 net acres in N LA and 147,312 net acres in the western Anadarko Basin located in W OK and the TX Panhandle.
45	20	W&T Offshore Inc.	ConocoPhillips Co.	12	Purchased 75% working interest in and operatorship of Magnolia Field, located in the central region of the deepwater U.S. GoM, offshore LA; includes 11,500 gross (8,600 net) acres and 2,300 boe/d (82% oil) net production.
46		BP Plc	Talos Energy Inc.	9	Acquired 75% WI and operatorship of the Puma West prospect located in Talos-owned Green Canyon Block 821 in the U.S. GoM as part of a farm-out agreement.
47		BCE-Mach II LLC; Mach Resources LLC; Bayou City Energy Management LLC	Undisclosed	9	Bought producing properties within the western Anadarko Basin across 32 OK counties and seven TX counties.
48		BCE-Mach II LLC; Mach Resources LLC; Bayou City Energy Management LLC	Undisclosed	9	Bought producing properties within the western Anadarko Basin spanning Beckham, Custer, Dewey, Roger Mills and Washita counties, OK, and Hemphill and Roberts counties, TX.
49		Castleton Resources LLC; Castleton Commodities International LLC; Tokyo Gas Co. Ltd.	Royal Dutch Shell Plc	12	Bought East Texas and North Louisiana Haynesville Shale assets comprised of about 55,000 net acres currently producing more than 100,000 cubic feet per day of natural gas.
50		Chisholm Oil and Gas LLC; Apollo Global Management LLC	Gastar Exploration LLC; Ares Management Corp.	9	Acquired Houston-based Gastar through a merger agreement; combined company to hold roughly 165,000 net acres in the OK Stack play, primarily in Kingfisher County, with net production of about 20,000 boe/d.
51		Inpex Corp.	Anadarko Petroleum Corp.	7	Bought a 40% participating interest in Keathley Canyon blocks 921/965 and Walker Ridge blocks 881/925 located in the U.S. GoM over 200 miles off the LA coast.
52		Kimmeridge Energy Management Co. LLC; Desert Peak Minerals Inc.	Desert Royalty Co. LLC	7	Acquired Delaware Basin mineral position in merger forming Desert Peak Minerals which will have over 70,000 net royalty acres on a 1/8th royalty-adjusted basis across W TX and SE NM.
53		Lime Rock Resources LP	BP Plc; BP America Production Co.	9	Bought properties in the SWOOP area of Cleveland and McClain counties, OK.
54		Repsol SA	Equinor ASA	11	Acquired a 20% nonoperated interest in the Monument prospect that Equinor is drilling in the Northwest Walker Ridge area in the U.S. GoM.
55		Talos Energy Inc.	Exxon Mobil Corp.	9	Purchased 100% WI in the Hershey prospect located on Green Canyon blocks 326, 327, 370 and 371 with no upfront payment.
56		Undisclosed	BHP Group Ltd.	9	Purchased 50% interest in the Samurai prospect in the U.S. Gulf of Mexico; BHP says buyer is an undisclosed private-equity firm.
57		Undisclosed	Samson Resources II LLC	9	Bought 8,500 noncore acres in Johnson County, WY, within the Powder River Basin.
58		Undisclosed	Samson Resources II LLC	9	Purchased Greater Green River Basin assets located in WY including in Carbon and Sweetwater counties; comprises about 48,000 net acres (63% HBP) with 5,850 boe/d (33% liquids) of current production.
59		Vermilion Cliffs Partners LLC	Undisclosed	8	Purchased a 30-well package within the Permian Basin located across NM and TX.
60		Viper Capital Partners LLC	Standard Oil Co.	9	Acquired drilling rights to over 12,000 acres of Rock Creek Oil Field in Roane County, WV, and Tanner Oil Field in Gilmer County, WV, along with 371 existing oil wells.
PENDING DEALS (AS OF JAN. 1, 2020)					
61	5,600	Hilcorp Energy Co.	BP Plc		To buy BP's entire upstream and midstream business in AK; includes 26% WI and operatorship of Prudhoe Bay plus the Trans Alaska Pipeline System.
62	2,500	WPX Energy Inc.	Felix Energy LLC; EnCap Investments LP		To acquire PE-backed Felix Energy II, which has a 58,500 net acre position in the Permian's Delaware Basin in W TX projected to be producing about 60,000 boe/d (70% oil) at time of closing.
63	2,270	Parsley Energy Inc.	Jagged Peak Energy Inc.		To acquire Denver-based Jagged Peak, a Southern Delaware Basin operator with about 78,000 net acres in Winkler, Ward, Reeves & Pecos Cos., TX and 2Q 2019 production of about 38,300 boe/d (76% oil); all-stock transaction includes assumption of $625 MM debt. *This deal closed in January.*
64	1,700	PDC Energy Inc.	SRC Energy Inc.		To acquire Denver-based SRC Energy, which holds roughly 86,000 net acres in the D-J Basin's Wattenberg Field, nearly 100% of which is located in Weld County, CO, through all-stock transaction; includes assumption of about $685 million in net debt. *This deal closed in January.*

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Comments
65	770	Kalnin Ventures LLC	Devon Energy Corp.	To acquire Devon's Barnett position, which includes over 320,000 gross acres and 4,200 producing wells in N TX that average 597 MMcfe/d of net production in 3Q 2019; proved reserves at YE 2018 were about 4 Tcfe.
66	640	Talos Energy Inc.	Castex Energy LLC; ILX Holdings LLC; Venari Resources LLC	To acquire a broad portfolio of U.S. GoM producing assets, exploration prospects and acreage including over 40 identified exploration prospects located on a total acreage footprint of roughly 700,000 gross acres; 3Q 2019 production was bout 19,000 boe/d (65% oil and over 70% liquids).
67	201.5	Revolution Resources LLC; Mountain Capital Partners LP	Jones Energy Inc.	To acquire Austin, TX-based Jones Energy, which has assets in the Anadarko Basin in OK and TX. *This deal closed in January.*
68	50	Navitas Petroleum US LLC	Denbury Resources Inc.	To buy 50% WI in four SE TX oil fields consisting of Webster, Thompson, Manvel and East Hastings.
69	34	Undisclosed	Riviera Resources Inc.	To buy Riviera's interest in Personville Field in E TX consisting of about 750 wells with average 3Q 2019 net production of roughly 28 MMcfe/d.
70	29	Undisclosed	Gulfport Energy Corp.	To purchase certain nonoperated interests in the Utica Shale.
71		HighPeak Energy Inc.; Pure Acquisition Corp.	Grenadier Energy Partners LLC; EnCap Investment LP; Kayne Anderson Capital Advisors LP	To acquire The Woodlands, TX-based Grenadier Energy through a business combination to form a pure-play Permian E&P with a 73,000 net acre position in the northern Midland Basin.

INDEX: U.S. E&P ACQUISITIONS & DIVESTITURES

THERE'S FLOODIN' DOWN IN TEXAS

The relationship between water management companies and producers is being shaped by the recent surge of water infrastructure transactions.

ARTICLE BY
DALE SMITH,
MOLLY BUTKUS,
LYTCH GUTMANN
AND
JOHN STAVINOHA

As producers seek to deliver on investor demand for free cash flow from ongoing drilling operations and the reduction of debt, the industry has seen a rapid emergence of large-scale water management companies. Further, because most producers constructed their water infrastructure assets purely to service their own production, inefficiencies and excess capacity on these systems became prevalent across the Permian Basin.

Armed with billions of dollars of non-deployed capital, private-equity-backed players have entered the water management market over the past few years to capitalize on both the increased efficiencies they could offer through the interconnection of these independent water systems and their operational expertise. The water companies' desire for assets, coupled with the producers' need for liquidity, has set the stage for the rapid emergence of a more sophisticated water management industry.

Transaction structures

In the most common (and straightforward) transaction, an upstream producer sells some or all of its water assets to a water management company for cash pursuant to a purchase and sale agreement. Simultaneously with the closing of the transaction, the producer dedicates its leasehold interests to the water management company for the provision of services related to the gathering and disposal of produced water (gathering agreement) and, if water supply assets are included in the transaction, the producer commits to acquire all of its supply water for drilling operations pursuant to a water supply agreement.

One challenge presented by an outright sale of a producer's water assets is that most producers do not build or operate their water assets as standalone systems for third-party use. As a result, special attention must be given to ensure that the necessary real property interests, permits and equipment are correctly identified and transferred.

In some transactions, the producer contributes or sells its water assets to the water management company in exchange for equity interests (or for a combination of cash and equity) in the water management company. When the producer receives equity interests as consideration, the producer will have an ongoing interest in the water management company, which can be beneficial from an economic perspective and also may provide the producer with governance rights (i.e., a board seat, a board observer position and/or approval rights on the water management company's ability to take certain actions).

The terms of the equity interests to be held by the producer will be subject to negotiation, including, among other matters, whether the equity interest is a preferred or common interest, the producer's governance and approval rights and the producer's ability to transfer its equity interests. Because the water management company may engage in transactions with competitors of the producer, the parties are often careful to limit the producer's ability to participate in board meetings or receive information relating to such competitors.

Another way for a producer to monetize its water assets while still maintaining day-to-day operational control of such assets is to bring in a limited financial partner. In such transactions, the producer transfers its water assets to a special purpose vehicle (SPV) in exchange for a controlling share of the SPV. The financial partner contributes cash to the SPV in exchange for a minority share (which cash may be immediately distributed to the producer). At closing, as with an outright sale, the producer and the SPV enter into a gathering agreement and/or supply agreement. In order to provide the services under these agreements, the SPV enters into an operating agreement with the producer whereby the producer operates and maintains the water assets on behalf of the SPV. The ultimate effect is that the producer continues to operate the water assets as it did before closing, but the financial investor is entitled to a share of the profits the SPV earns as the service provider under its long-term water contracts.

Common issues that arise in water infrastructure transactions

Perhaps the biggest issue producers face when divesting their water assets is loss of control of day-to-day operations and the related loss or reduction of firm capacity. By owning the water assets, the producer has sole and exclusive control over source water delivery and/or produced water disposal, and operations are not subject to capacity limitations. When asset ownership is relinquished, however, capacity may be provided to other producers on the system and no longer available to service the requirements of the original owner.

Another issue that typically arises in these transactions involves the transfer of the necessary land rights for the assignee to continue operating the water assets after closing. Rights-of-way and easements, for example, present a host of issues if not transferred or otherwise addressed correctly, as producers generally construct water infrastructure pursuant to their existing oil and gas leases, and such leases will be retained by the producer after the water assets are transferred. While it may be relatively straightforward to identify a produced water pipeline to be conveyed in a transaction, actually separating such pipeline from the producer's underlying real property interests must be done carefully and in accordance with the language in the granting instruments, which often do not directly address such separation or, in certain cases, specifically prohibit it.

The inability to transfer disposal permits can also result in the producer retaining disposal assets it intended to transfer. Although the transfer process for permits issued by the Railroad Commission of Texas (RRC) to operate Class II disposal wells is relatively straightforward, recent enforcement actions undertaken by the RRC have demonstrated a willingness to reassess, and in some cases significantly decrease, the permitted disposal capacity for a particular disposal well. Given this development, both producers and water management companies have increased their diligence efforts to better understand the risks that may be present in a given transaction.

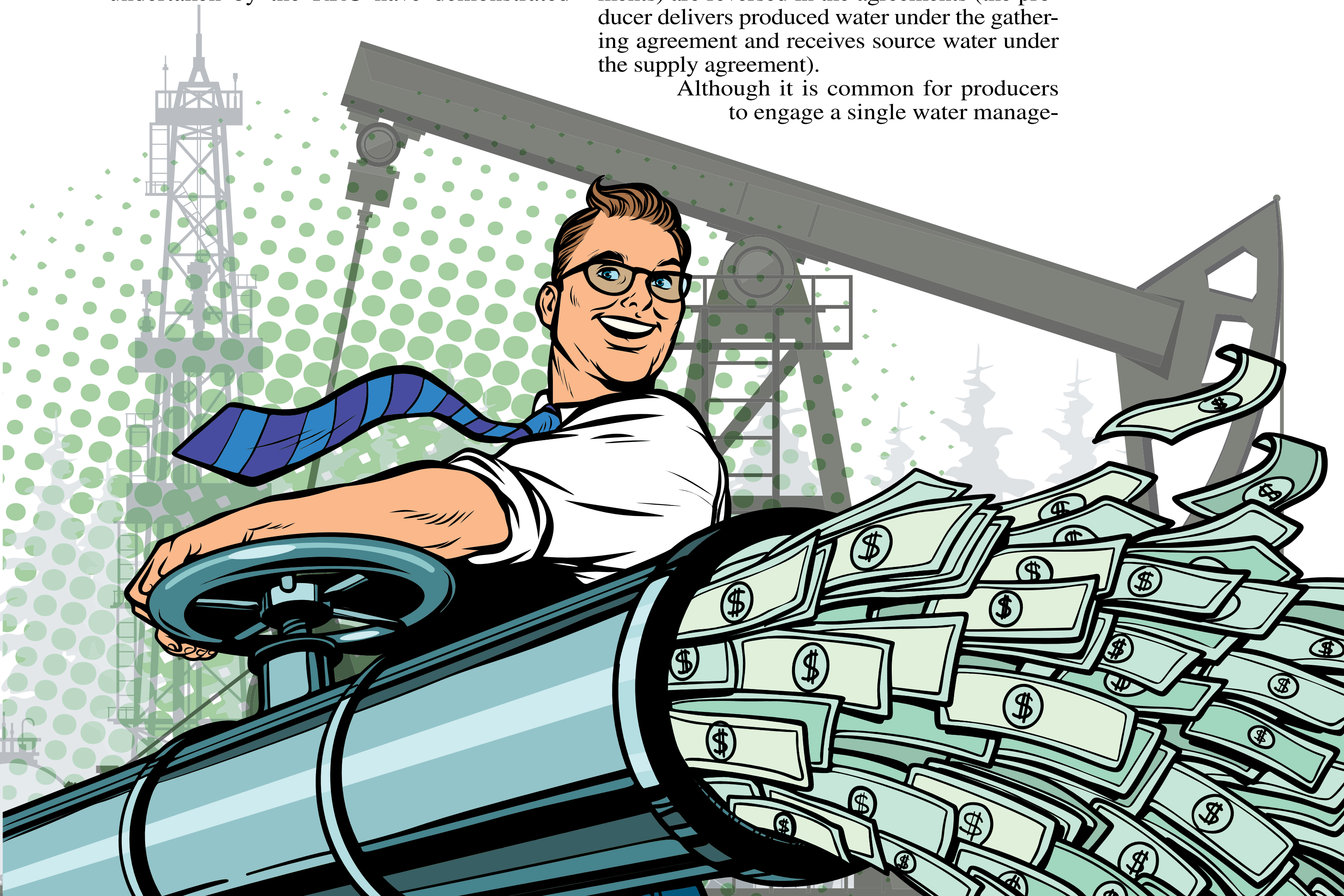
Transferring fresh water permits and registrations can also present issues, especially in the case of a transfer of such assets to an SPV or other entity that will not be directly operating the fresh water wells or an entity that will be providing fresh water supply services to third parties. Care must be taken to comply with the specific transfer requirements of the applicable groundwater conservation district.

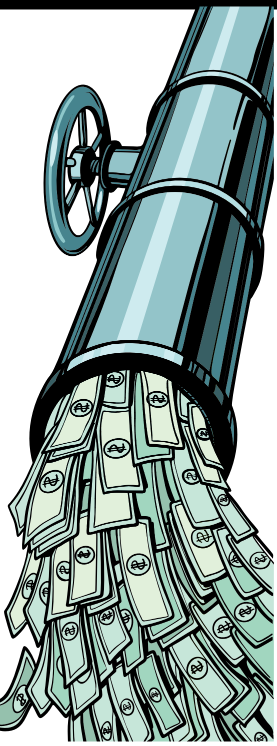
Because the water assets being transferred are usually fully integrated into the producer's ongoing operations, a comprehensive transition services agreement is usually necessary for a period of time following closing to assist the water management company with assuming full control of the system.

Water gathering and supply agreements

Two of the most common agreements in water transactions are the gathering agreement and the supply agreement. While these services are sometimes covered in a single "full-cycle water agreement," many parties prefer to execute separate standalone agreements for these distinct services, especially because the roles (and thus, the corresponding provisions in the agreements) are reversed in the agreements (the producer delivers produced water under the gathering agreement and receives source water under the supply agreement).

Although it is common for producers to engage a single water manage-





Another way for a producer to monetize its water assets while still maintaining day-to-day operational control of such assets is to bring in a limited financial partner.

ment company to handle both water disposal and water supply, occasion sometimes necessitates that a producer use separate water management companies to service its assets, even within the same area. Although there are many similarities between water agreements and the typical gas and liquids midstream agreements, special attention is required for certain aspects that are unique to water gathering, disposal and supply, a few of which are noted below.

The gathering agreement governs the relationship between the producer and water management company for the delivery, transportation and disposal of produced water. In addition to an acreage dedication made by the producer (and exceptions and reservations therefrom), a gathering agreement typically includes provisions addressing custody and control, service priority, capacity commitments, system buildout, water quality, measurement and indemnification obligations. The producer's ability to obtain more favorable terms is influenced by, among other things, (i) the size of the dedication, (ii) whether the gathering agreement is a standalone agreement or part of a larger infrastructure acquisition, (iii) development areas where zones of excess pressure are known to exist, (iv) the distance (and time) needed to make the initial receipt point connections (and any additional connections), (v) capacity constraints on the system and (vi) the producer's anticipated pace of production operations.

A producer possessing bargaining strength will likely obtain firm service priority and remedies for service delays and capacity curtailments, including make-whole reimbursement, rig down-time expense, fee reductions and/or accelerated releases of its real property interests from the acreage dedication. These remedies help to align the producer and the gatherer with respect to providing flow assurance throughout the term of the gathering agreement. Remedies for producers with less bargaining strength are typically limited to a temporary release from the dedication of the water volumes the gatherer does not or cannot accept. To the extent that a temporary release event persists for a specified amount of time, the release can become permanent in order to permit the producer to contract with another service provider.

Other typical provisions in a gathering agreement include ownership of skim oil contained in produced water, representations and warranties from the producer regarding the delivered produced water and from the gatherer regarding sufficient capacity on the gathering and disposal system to service producer's forecasted production, and rights and remedies of the parties with respect to water that fails to satisfy the quality specifications under the agreement. Additional complexity is introduced if high levels of hydrogen sulfide are present in produced water due to the expensive treatment cost and applicable state and federal environmental and safety regulations.

The supply agreement governs the relationship between the producer and the supplier for the delivery of source water for production operations. Source water may be limited to fresh water or a mix of fresh water and treated or recycled water. In addition to the reversal of roles as noted above (i.e., the water management company is the water deliverer under a supply agreement), there is usually less pipeline infrastructure required under a supply agreement because flexible surface lines that can be easily relocated between sites are often used to deliver water from the source to the drill pad.

Another key difference from a gathering agreement is that the supply agreement does not include an acreage dedication. Instead, the producer generally commits to obtain all of its water requirements for operations within a specified geographic area from the supplier. Remedies for failure to timely deliver or for the delivery of off-specification water, such as make-whole provisions and commitment releases, are usually similar to those contained in a gathering agreement.

In cases where the water management company provides both the gathering and disposal services and has the ability to treat and redeliver produced water as source water, sometimes the firm water-sourcing obligations are tied to the volume of produced water delivered by the producer under the gathering agreement.

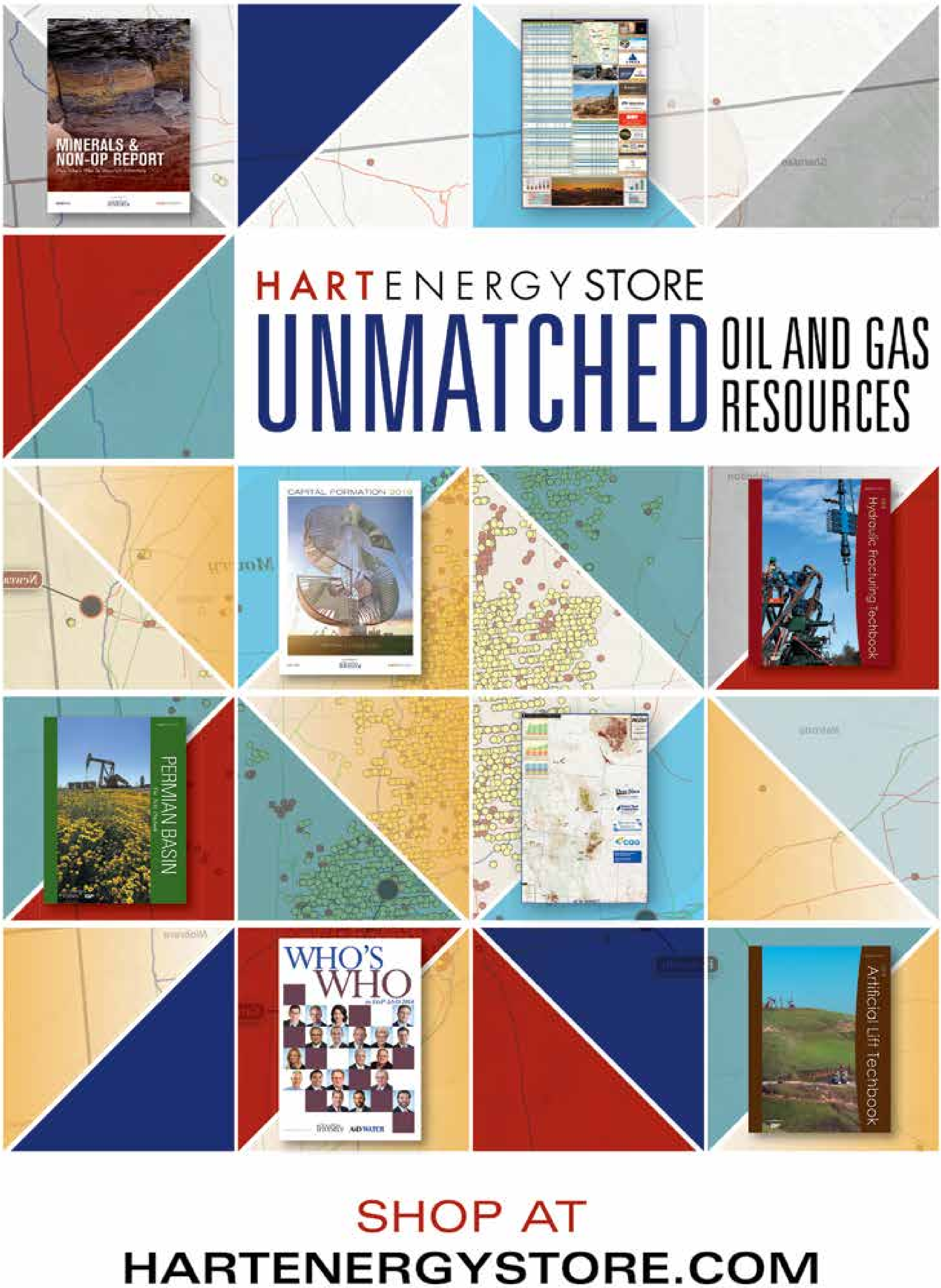
Looking forward

As producers look to strengthen their balance sheet and renew favor within the investment community, the industry should continue to see the monetization of water assets as a viable solution.

Moreover, due to the extremely large volume of water required for oil and gas fracking operations, and the resulting large volume of produced water requiring a home, new disposal well permitting and recycled and treated water options and requirements, among other issues, will continue to be critical issues for producers and water management companies.

As was, and continues to be, the case with traditional gas and liquids midstream transactions, new complexities will continue to surface within water service agreements to address evolving regulatory and environmental requirements as well as public policy considerations. □

Dale Smith is a partner in Bracewell LLP's business and regulatory group and advises clients on financing and energy transactional matters. Lytch Gutmann is a partner in the firm's corporate and securities group and represents public and private companies in a variety of corporate transactions. Molly Butkus is a partner in the firm's oil and gas projects group and represents E&Ps, midstream companies, water management companies, private equity funds, purchasers and sellers in all aspects of upstream and midstream transactions. John Stavinoha is an associate in the firm's oil and gas projects group whose practice focuses on representing E&Ps, midstream and water management companies, and private-equity funds.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GOODBYE TO CLAYTIE

Wildcatter Clayton W. Williams Jr. was larger than life, with a quick wit, a big vision and a bigger legacy.

ARTICLE BY
LESLIE HAINES

In February the oil patch lost one of the last great, colorful wildcatters, another of the legendary oilmen known simply by their first name: Claytie.

Words can hardly capture the many business and philanthropic achievements—some would say adventures—of Clayton W. Williams Jr. The founder, former chairman and president of Clayton Williams Energy Inc., passed away in Midland, Texas, at age 88, prompting an outpouring of tributes from Texas oil and gas, business and political leaders. During his 62-year career, he was a strong voice for Midland, for his beloved Texas A&M University, for the energy industry and free enterprise.

In 2018, Hart Energy presented him its Energy Industry Leadership Award. Commenting on his humble beginnings, his great business success and subsequent world travels, Williams declared the U.S. to be the best nation in the world because it provided the most freedom. He supported numerous E&P organizations as an advocate of American-produced energy.

At Williams' funeral, former Texas Gov. and former U.S. Energy Secretary Rick Perry delivered the eulogy, calling him "one of the grandest people I ever met." Speaking to the *Midland Reporter-Telegram*, Concho Resources Inc.'s chairman and CEO, Tim Leach, called Williams a mentor, legend and true wildcatter. "His enthusiasm was limitless, and he was a tireless supporter of our community and Texas A&M. He had a big vision, and he challenged me to be involved and give back to our community."

Williams never stood still—he founded some 26 companies through the years, eight of them in the oil and gas sector. Well-known for wildcat drilling throughout Texas, he also founded what was once the largest individually owned gas pipeline company in Texas, Clajon Gas Co.

The capstone of his long career was the 2017 sale of publicly held Clayton Williams Energy Inc. (CWEI) to Noble Energy Inc. for cash and stock valued at $2.7 billion ($665 million in cash). The sale was his largest and last great deal among many he forged over the years.

"It's not how many times you get knocked down. It's how many times you get back up. I'm a scrapper."

—Clayton Williams

At the time, CWEI held 171,000 net Permian Basin acres and produced 10,000 barrels of oil equivalent per day, primarily in the Delaware Basin. The deal brought to Noble 2,400 Wolfcamp drilling locations.

Williams was known for his zest for life. An award-winning, big-game hunter, he took trips to exotic places around the world with his wife, Modesta. He hosted legendary parties at his annual Brangus cattle auction, which attracted ranchers from all over the U.S. At one time he owned 10 ranches in Texas and Wyoming and ran 7,000 head of cattle. A big outdoorsman, he founded the Chihuahuan Desert Research Institute.

He loved to party and was known for his humor. Once when about to testify about the woes of the oil business and over-regulation during an industry downturn, he arrived at the Texas state capitol building on a stretcher, accompanied by nurses, to dramatize his point. When he needed to clear land at an old drive-in theatre in Midland in order to build ClayDesta office park, he brought in some of his cowhands on horseback to help tear down the old movie screen.

PHOTO BY MIEKO MAHI

Clayton Williams Energy sold its East Texas Eagle Ford assets (pictured) to Wildhorse Resource Development in 2016 for $400 million, but its big exit came when it sold the remainder of its assets in the Delaware Basin to Noble Energy in 2017 for $3.2 billion.

A lifelong resident of West Texas, Williams' story began in Pecos County, where he was born. His father graduated from Texas A&M University in 1915; Claytie followed, majoring in animal husbandry and graduating in 1954. A lifelong, passionate A&M supporter, he was named a Distinguished Alumnus in 1981, and the school's alumni center is named for him—he donated millions to the school.

Williams shared his expertise and passion for action by teaching entrepreneurship at A&M's College of Business Administration and received the Dean's Service Award for Teaching Excellence. He further showed his love for A&M with his tuxedo and corporate airplane both Aggie maroon.

Following service in the U.S. Army, Williams began his career as a lease broker and independent producer in the Permian Basin in 1957. Over the decades he made his mark, amassing a significant lease position across Texas. He founded companies in the upstream, midstream, banking, digital long distance telecom and real estate development industries.

In the 1960s and 1970s, Williams was one of the top natural gas wildcatters in Texas, and he was recognized for developing many of the first ultra-deep gas plays in far West Texas. In 1975, his Gataga No. 2 in remote Loving County came in, the biggest find of his career. This well flowed 30 million cubic feet a day once it had been brought under control, after erupting with much more gas than that and being out of control for several days. His company was also an early driller in Giddings Field and the Austin Chalk of central Texas, and in 1979, he donated overriding royalty interests in Giddings to Texas A&M.

Through the years, he endured every cycle of the oil and gas industry, from highest highs to lowest lows. At one point he was named the first Aggie billionaire, and in 1984, he landed on the Forbes 400 list of wealthiest Americans. In his 2007 biography, "Claytie," Williams said he resembled Christopher Columbus: He used other people's money but never knew where he was going or where he was once he got there. In the book, he recounted the lessons learned through his many business ventures and misadventures.

At a low point in 1991, Williams was about to file for bankruptcy protection, but at the last minute, during a flight to meet with his bankers, he changed his mind, vowing to work doubly hard to pay off all his creditors. He did, by negotiating with the banks and selling many of his assets.

"It's not how many times you get knocked down. It's how many times you get back up. I'm a scrapper," he said.

In 1993, he took his company public on NASDAQ, having rebounded from the near disaster.

His most unsuccessful, yet most publicized, effort came when he ventured into politics, running for governor of Texas in 1990 as a Republican. For much of the campaign he led in the polls, but at the last minute he was defeated by Ann Richards after he made some regrettable "locker room" comments when reporters were present and also admitted he had paid no income taxes in 1986—but it was because he was in the midst of the worst oil industry downturn at the time.

The energetic entrepreneur received many business and oil industry accolades. He was inducted into the All-American Wildcatters Association, and in 2005, the Permian Basin Petroleum Museum Hall of Fame. In 2002, he was the honoree at the Permian Basin International Oil Show.

In November 2019, he and his wife were honored as outstanding philanthropists during an event in Midland to mark National Philanthropist Day.

Through the numerous ups and downs of a wide-ranging career, he has remained one of the most enthusiastic and successful entrepreneurs ever to rise out of West Texas. Williams is survived by his wife, Modesta, their five children, nine grandchildren and five great-grandchildren. □

A&D Watch

EDITED BY
DARREN BARBEE

ConocoPhillips Closes $380 Million Niobrara Deal

CONOCOPHILLIPS CO. closed on a multimillion-dollar sale of Niobrara assets located in the southern Denver-Julesburg (D-J) Basin, marking its exit from Colorado where operators have faced regulatory uncertainty in recent years.

ConocoPhillips said an undisclosed company purchased the Niobrara asset for $380 million, plus customary adjustments, and overriding royalty interests in certain future wells.

Crestone Peak Resources LLC is believed to be the buyer of ConocoPhillips' Colorado asset, according to reports by multiple media outlets.

Houston-based ConocoPhillips held about 98,000 net acres in the Niobrara, located in northeastern Colorado, according to recent filings. Production from the divested assets was about 11,000 barrels of oil equivalent per day (boe/d) in 2019.

On March 5, the company also said it had completed the sale of its Waddell Ranch property, a conventional asset located in the Permian Basin. Full-year 2019 production associated with the Waddell Ranch asset was 4,000 boe/d. The buyer and terms of the Waddell Ranch transaction weren't disclosed.

In a Feb. 20 earnings call, ConocoPhillips CEO Ryan Lance said the company expects to close about $2 billion in divestitures in the early part of this year.

In October, the company agreed to sell its Australia-West assets, including Darwin LNG, to Australia-based **Santos Ltd.** for $1.39 billion.

"But we're not just selling," Lance said. "We're also on the lookout for opportunities to add low cost of supply resources to the portfolio, like we did last year in the Lower 48, Alaska and internationally."

Creston, formed in 2016 with backing from the **Canada Pension Plan Investment Board** and **The Broe Group**, holds acreage in Greater Wattenberg Field in Colorado's D-J Basin.

The effective date of the Niobrara transaction is June 1, 2019. The Wadell Ranch transaction had an effective date of Nov. 1.

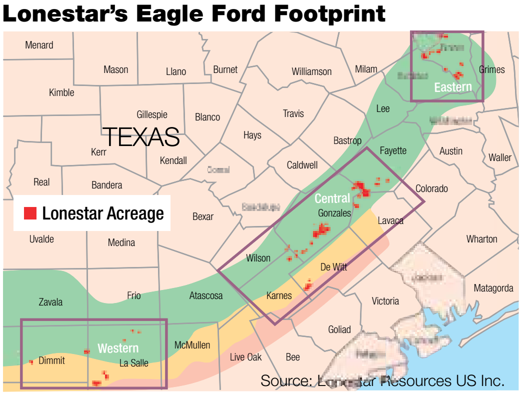
—Emily Patsy

Lonestar Resources Enters Eagle Ford JV

LONESTAR RESOURCES US Inc. formed a joint venture (JV) partnership with one of the largest producers in the Eagle Ford Shale to develop acreage in Gonzales County, Texas.

In a recent news release, the Fort Worth, Texas-based company said it had entered into a joint development agreement with the undisclosed company for an area of mutual interest (AMI) encompassing about 15,000 acres in Lonestar's Cyclone/Hawkeye area.

Lonestar's Eagle Ford Footprint



Lonestar CEO Frank D. Bracken III said the venture provides a clear path of development for the Cyclone/Hawkeye asset, which he called Lonestar's oiliest asset.

"This venture is a win-win for both parties and is illustrative of how Lonestar continues to leverage its drilling and completion prowess into new growth opportunities without upfront capital," Bracken said in a statement.

Lonestar is a pure-play Eagle Ford operator with more than 57,000 net acres in the crude oil window of the South Texas shale play. The company's position is located in 11 counties, which are divided into three distinct regions: western Eagle Ford, central Eagle Ford and eastern Eagle Ford plays.

The JV agreement requires lower levels of annual gross drilling activity than Lonestar has engaged in on its own since becoming active in Gonzales County in 2016 while also consolidating each company's respective positions into a single development plan, according to the release.

Per the agreement, Lonestar will operate a minimum of three to four Eagle Ford Shale wells annually on behalf of the two companies through 2022, intended to HBP roughly 6,000 gross acres within the AMI. Lonestar's partner has the option to participate in each well with a 50% working interest or to participate via a carried working interest that ranges from approximately 9% to 17%, depending on location.

The JV will also increase Lonestar's inventory of gross drilling locations by roughly 50% in the Hawkeye area while also maximizing lateral lengths, the release said. The locations are expected to deliver average lateral lengths of over 9,500 feet, with many locations exceeding 12,000 feet.

Lonestar's inventory will now include 72 long-lateral drilling locations that Bracken said offer "highly attractive returns at current commodity prices."

—Emily Patsy

Occidental Contemplates Giant Wyoming Sale

STATE OFFICIALS IN Wyoming are in talks to buy millions of acres of land from **Occidental Petroleum Corp.** in what lawmakers say would be the biggest land purchase since the U.S. bought Alaska from Russian tsar Alexander II.

The U.S. state is advancing bills authorizing the use of state funds to acquire the properties. People involved say the price ranges between $1 billion and $3 billion.

Oil and gas producer Occidental has put the land on the block as it pays down debt from its $55 billion acquisition of **Anadarko Petroleum Corp.** in 2019. The company is under pressure, with U.S. oil prices sliding below $50 a barrel and activist shareholder Carl Icahn agitating for change.

The land lies on either side of the Union Pacific railroad, which originally received it from the federal government during the frontier era before its sale to Anadarko.

"Opportunities like this don't come along very often," Gov. Mark Gordon and leaders of the Republican-controlled legislature wrote in a column in February. "It's likely that this would be the largest government purchase of private land since the United States purchased Alaska." Critics at first panned the 1867 U.S. purchase of Alaska as "Seward's folly," after U.S. Secretary of State William Seward who negotiated it.

Wyoming's interest in an area so large is also raising questions. The land on offer—more than 1 million acres of surface land and 4 million acres of underground mineral rights—could deepen the Wyoming economy's exposure to natural resources. State finances are deteriorating as taxes on coal and natural gas decline.

State officials view the land as a potential bonanza for oil and gas extraction, wind and solar farms, power transmission lines, soda-ash mining, livestock grazing and big-game hunting.

Houston-based Occidental has confirmed the auction for the acreage, which cuts mostly through Wyoming's arid southern tier.

"While the state has clearly communicated a lot of interest in this asset, it is a competitive process, and there's a large number of qualified participants in that," said Oscar Brown, Occidental senior vice president. "The winner of that asset will be one of the largest land and mineral owners in the United States."

Several energy-focused private-equity groups and at least two publicly listed exploration and production companies have expressed interest, according to people briefed on the sale process.

Shannon Anderson, staff attorney at the Powder River Basin Resource Council, said the Wyoming conservation group was "very concerned about the risk to our state if we spend our savings to acquire this land and minerals that Occidental can't wait to get rid of."

Gordon first discussed a potential land deal with Occidental CEO Vicki Hollub last May, at a conference on carbon capture and storage technology held in Jackson, Wyo., a state official said.

The state government owns 3.5 million acres of surface land and 3.9 million mineral acres. Leases and royalties generate almost $200 million in annual revenue for the government, according to its Office of State Lands and Investments. The U.S. federal government owns another 29 million acres of land in Wyoming, almost half the total.

—Darren Barbee

Lilis Fends Off Debtors With Asset Sale

LILIS ENERGY INC. agreed on Feb. 14 to sell a chunk of its northernmost Permian Basin acreage as the company continues to struggle with its debt payments.

In a news release, the Fort Worth, Texas-based independent said it had executed a purchase and sale agreement on Feb. 12 for the sale of about 1,185 undeveloped acres in New Mexico's Lea County. An undisclosed buyer agreed to acquire the assets for net cash proceeds of roughly $24.9 million.

Lilis said it plans to use the proceeds to fund a substantial portion of its borrowing base deficiency, initial payments of which have been extended for a third time, according to the company's press release on Feb. 14.

The initial payments to cure the company's $25 million borrowing base deficiency were originally due Jan. 24. The company's bank lending group agreed on Feb. 14 to extend the due date for the first two installment payments, totaling $12.5 million, to Feb. 18 and Feb. 29. The final two installments continue to be due on March 16 and April 14.

Last month, Lilis received a nonbinding cash take-private offer from **Värde Partners Inc.**, one of the company's major shareholders. The offer is valued at roughly $17 million, according to **BMO Capital Markets**.

In its proposal, the Minneapolis-based alternative investment firm said it would acquire the roughly 75% of outstanding shares of Lilis common stock it doesn't already own in a cash merger transaction for $0.25 per common share. The nonbinding cash offer was set to expire Feb. 17.

"The company is continuing to consider transactions to fund the repayment of the borrowing base deficiency on a timely basis. ... If the company is unable to repay the borrowing base deficiency as and when required under the revolving credit agreement, an event of default would occur under the revolving credit agreement," Lilis Energy said.

Lilis is receiving financial advice from BMO and **Barclays Capital Inc.**

—Emily Patsy

Centennial Sells Permian Water Assets

PHOTO COURTESY OF WATERBRIDGE RESOURCES LLC

CENTENNIAL RESOURCE Development Inc. agreed to divest produced water infrastructure in the Permian Basin in a $225 million sale to **WaterBridge Resources LLC**.

The divested water infrastructure assets, located in the southern Delaware Basin, currently dispose of approximately half of the company's gross produced water in Texas. Centennial has roughly 80,100 net acres in the Delaware Basin located in Reeves County, Texas, and New Mexico's Lea County.

"This transaction represents a significant premium to Centennial's current trading valuation and will essentially offset any outspend this year, assuming current prices," said Centennial CEO Mark Papa in a statement on Feb. 24. "It also significantly reduces the amount of infrastructure capex needed to maintain and grow these assets in the future."

WaterBridge, described as a long-standing partner of Centennial's in its news release, has historically disposed nearly half of the company's produced water volumes in Reeves County.

Centennial expects the combination of the divested assets with WaterBridge's broader southern Delaware system will provide significant flexibility and additional capacity to service the company's water disposal needs. The company said it will pay a market disposal rate on incremental water volumes that WaterBridge does not already gather and dispose, and these incremental costs are incorporated into Centennial's 2020 lease operating expense guidance.

The divested assets expand WaterBridge's produced water network in the southern Delaware Basin to nearly 2 million barrels per day of handling capacity, according to a separate release by WaterBridge on Feb. 25.

WaterBridge is backed by **Five Point Energy LLC**, which sold a 20% minority equity stake in the company to affiliates of Singapore's sovereign wealth fund GIC in May 2019. Though the terms of the transaction weren't disclosed, the Houston-based private-equity firm said the transaction's purchase price implied a roughly $2.8 billion enterprise value of WaterBridge.

"In 2016, Five Point Energy funded the formation of WaterBridge with a well-defined strategy of being a first mover in progressively addressing the produced water needs of the Permian Basin," said David Capobianco, CEO of Five Point and chairman of the WaterBridge board, in a statement. "With the addition of Centennial's produced water handling assets to WaterBridge's network, the company has expanded the capabilities of its system and firmly established itself as the largest pure-play water midstream company in the industry."

Upon closing of the transaction, WaterBridge will have over 600,000 acres operated by over 23 blue-chip producers under long-term dedication in the southern Delaware Basin. WaterBridge's extensive integrated water infrastructure network includes 1,140 miles of large diameter pipelines and 87 handling facilities.

Payment for Centennial's assets consists of $150 million in cash at closing and an additional $75 million payable to Centennial on a deferred basis upon meeting certain incentive thresholds. Centennial said it plans to use proceeds from the sale to repay borrowings under its revolving credit facility.

Barclays acted as exclusive financial adviser to Centennial in connection with the transaction. **Winston & Strawn LLP** served as WaterBridge's legal adviser.

—Emily Patsy

TRANSACTION HIGHLIGHTS

ROCKIES

■ **Phillips 66 Partners LP** agreed to acquire a 50% stake in the Liberty Pipeline, a $1.6 billion project to transport Rockies and Bakken crude oil production to Oklahoma's Cushing hub.

According to a Feb. 21 news release from the Houston-based company, Phillips 66 Partners will acquire the interest as part of a roughly $75 million dropdown agreement with **Phillips 66 Co**. The company plans to fund the transaction through a combination of cash on hand and its revolving credit facility.

Service on the 24-inch Liberty Pipeline is targeted to commence in first-half 2021. The cost of the pipeline is expected to be about $800 million net to Phillips 66 Partners. **Bridger Pipeline LLC** owns the other 50% interest in Liberty.

MIDSTREAM

■ **The Williams Cos Inc.** is seeking a partner to invest in a network of its pipelines in the western U.S. in a deal that could raise close to $5 billion for the Tulsa, Okla.-based company, people familiar with the matter said.

The investment would be larger than the joint venture that Williams clinched last year with the **Canada Pension Plan Investment Board** (CPPIB) in the Marcellus and Utica shale basins of Appalachia, which gave the pension fund a 35% stake in the assets for $1.33 billion.

The deal would underscore how pipeline operators are cashing out on some of their assets, so that they can pay down debt and put money into new projects, which have the potential to give them better returns.

■ **Dominion Energy Inc.** said this week it agreed to buy Southern Co.'s stake in the roughly $8 billion Atlantic Coast natural gas pipeline from West Virginia to North Carolina, which is expected to enter service in early 2022.

If approved, that will bring Dominion's share in the pipeline to 53%, up from 48%. **Duke Energy Corp.** will own the remaining 47%. Southern will remain an anchor customer of the pipe through its **Virginia Natural Gas** subsidiary.

In addition, Dominion said it agreed to buy Southern's **Pivotal LNG**, which distributes LNG for marine and road transportation. The total cost of the Atlantic Coast stake and Pivotal was about $175 million, Dominion said.

SOUTH TEXAS

■ **Enbridge Inc.** is taking ownership of a South Texas pipeline project expected to lead to over a billion dollars of future growth opportunities for the Calgary, Alberta-headquartered midstream company to support the growing LNG export market.

According to a Feb. 13 news release from Houston-based LNG developer **NextDecade Corp.**, Enbridge agreed to acquire the Rio Bravo Pipeline from NextDecade for a cash purchase price not to exceed $25 million.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AS GOES EXXON MOBIL, SO GOES THE PERMIAN

RICHARD MASON, CHIEF TECHNICAL DIRECTOR

Let's go straight to the tape. Rig count may now fall precipitously in a post-COVID-19/OPEC+ world, but the hidden narrative in the land drilling market, and for the Permian Basin in particular, involves Exxon Mobil Corp.

Exxon Mobil had been the nation's leading rig employer at 69 units on average year-to-date 2020, double the tally for EOG Resources Inc., the nation's second most active rig employer.

In the Permian, a majority of E&Ps are bunched in the 5% to 6% share of regional rig employment and have been since early 2018. In contrast, Exxon Mobil has persistently added rigs and grown regional market share beginning with a 6% share of Permian rig activity in first-quarter 2018, moving to a 9% share by first-quarter 2019, and currently holding 14% share year-to-date 2020.

On a numeric basis, Exxon Mobil increased its rig count from 25 units in the first quarter of 2018 to 56 units year-to-date 2020, more than doubling the rig employment on behalf of Diamondback Energy Inc. and Pioneer Natural Resources Co., the Permian's next two largest players. Diamondback and Pioneer each hold a 6% rig employment share in 2020, or 23 rigs each. Add Exxon Mobil, and those three public companies account for 26% of Permian rig employment.

While Exxon Mobil traditionally operates counter-cyclically to the macro environment, the company's Permian efforts stand out not just in the Permian but in contrast to every regional market in the U.S. where the the company has been the leading onshore rig employer for several years. The company's rig employment peaked during the second and third quarters of 2019 at 76 units, again roughly double EOG Resources Inc.'s second-place rig tally.

Exxon Mobil activity has migrated from a concentration in the Midland Basin in 2017 to a major focus in the northern Delaware Basin, where the size of its activity dwarfs all other players with a 25% share of rig employment.

The Permian transformation has a long history. Exxon Mobil quietly began expanding its Permian presence in 2014 in a series of transactions that initially added 135,000 operated Midland Basin acres prospective for Spraberry and Wolfcamp. The integrated giant further expanded that position across the Midland and Delaware basins with an additional 22,000 acres pre-2017 when the company and its subsidiary, XTO Energy Inc., was the seventh-largest acreage holder in the Permian. Interesting at the time, but hardly earth shaking.

Then came the $6.6 billion acquisition of the Bass family acreage in early 2017 that established a large contiguous position of 227,000 acres in the heart of New Mexico's Delaware Basin. At the time, Exxon Mobil was running 19 rigs, including 14 in the Midland Basin.

Its Bass acquisition was transformative. First, it added an estimated 6 billion barrels of oil equivalent (Bboe) in resource in place, including 3.4 Bboe in the Delaware Basin. The deal involved an upfront payment of $5.6 billion in stock, now worth about $3.6 billion if the Bass family retained all Exxon Mobil's shares, with contingent cash payments of up to $1 billion to be paid beginning in 2020.

In March 2019, Exxon Mobil debuted plans to grow Permian production by 80% to 1 MMboe by 2024 following the doubling of production in 2018. The new plan will push its production back above 4 MMboe/d following a steady depletion-related decline in the company's global upstream output.

The company's master plan in the Permian is built on an integrated approach tying Delaware Basin production via pipelines, including an agreement with Summit Midstream Partners LLC, to the Exxon Mobil petrochemical complex on the Gulf Coast. The company is pushing lateral lengths beyond 15,000 feet in the Delaware in concert with centralization in processing facilities in order to lower development costs.

Exxon Mobil's half decade-long acquisition spree has now provided the company with a net 1.8 million-acre position in the Permian. It remains one of the major narratives over the last half decade for the Permian and, indirectly, the U.S. tight formation liquids play. The company is now the leading rig employer (13) in the southern Delaware Basin and the second most active rig employer (18) in the Midland Basin.

The oil price collapse and cuts to capex and rig count will alter the scale of Permian activity. The question is whether it will change the narrative.

EASTERN U.S.

1 ***Lampley Oil Inc.*** is underway at a Franklin County, Ill., wildcat. According to IHS Markit, #21-1 Blacktop has a planned depth of 4,200 ft and is in Section 21-7s-3e with a Warsaw oil objective. Earlier in 2019, Lampley Oil scheduled a Section 21 workover within 1 mile to the east-southeast at #21-2 Blacktop. The company plans to re-enter the well at 4,200 ft, and it is also targeting Warsaw. The original hole, #21-1 Illinois Minerals, was drilled in 2015. The vertical wildcat was abandoned at 3,886 ft, with some shows of oil and gas in St. Louis at 3,175-3,206 ft. Oil production in West Frankfort Consolidated Field is about 1.5 miles west of Benton, Ill.-based Lampley Oil's drillsite. Opened in 1941, the reservoir yields crude from a range of Mississippian wells, with the deepest production coming from Salem Lime at around 3,600 ft.

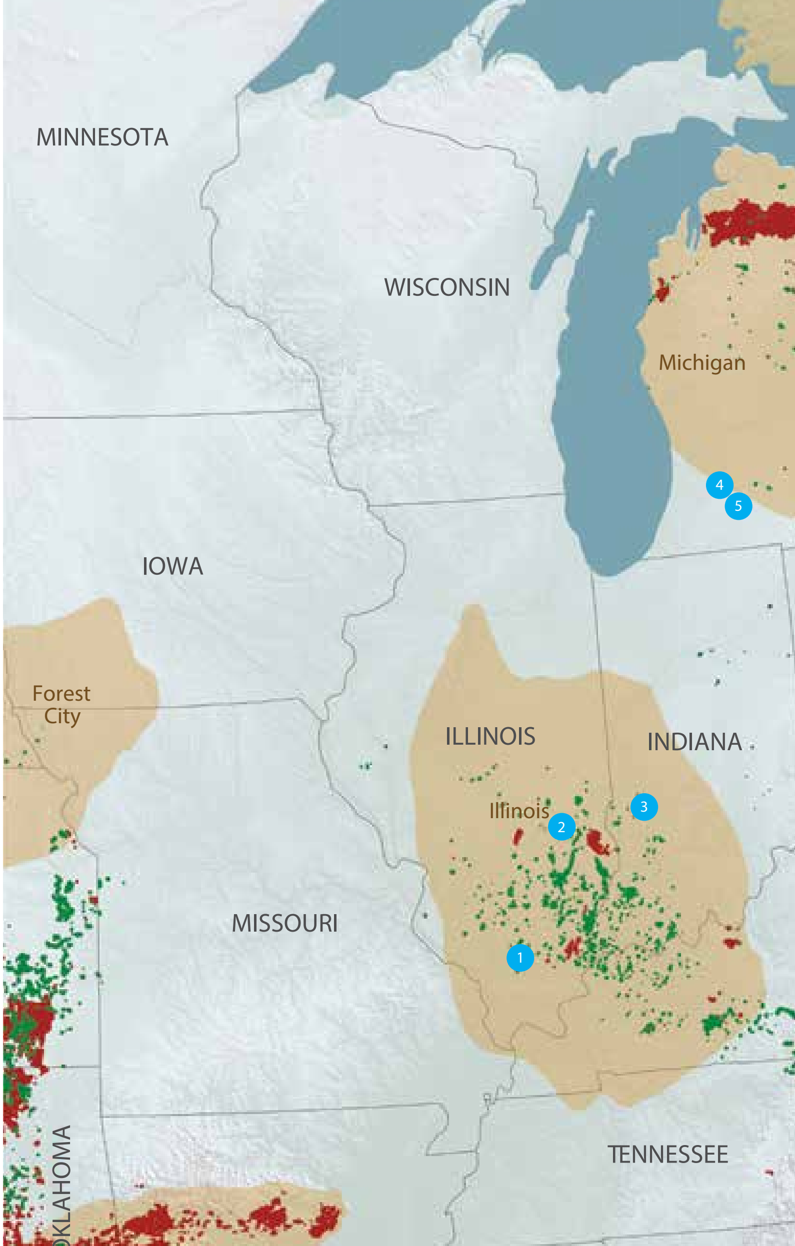
2 According to IHS Markit, ***Faithful Oil LLC*** has permitted a deeper pool exploratory test in Illinois' Bellair Field. In Crawford County, #3B Wiman has a planned depth of 5,300 ft and is targeting oil pays in Gunter Sand and will be drilled in Section 26-8n-14w. Two shallower field tests have also been scheduled by the operator in Section 26 at #1B Wiman and #4B Wiman, each with planned depths of 1,450 ft, and will test in Yankeetown. The deepest drilling in Bellair Field took place in 1985 at #1 Eugene Lockhart in Section 25-8n-14w. It was tested pumping 41 bbl of crude and 160 bbl of water per day from an openhole zone ranging from St. Louis at 1,654 ft to Carper Sand at 2,460 ft. Faithful Oil is based in Newton, Ill.

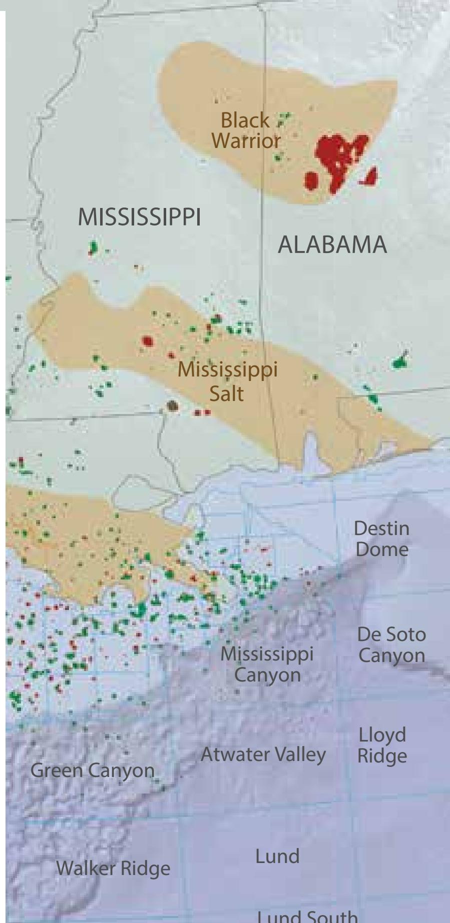
3 In Clay County, Ind., ***Sunrise Production Inc.*** completed a Bowling Green Field well in Section 23-11n-6w. The #8 Bowling Green West Community Unit produced 15 bbl of oil per day from an openhole section of Devonian Jefferson Limestone at 1,336-1,340 ft. The well was drilled to 1,340 ft. Sunrise Production is based in Terra Haute, Ind.

4 ***Wolverine Gas & Oil*** announced a Climax Field-Trenton producer in Kalamazoo County, Mich. Located in Section 8-3s-9w, #8-1 McMichael was drilled to a proposed true vertical depth of 3,997 ft. It was tested flowing 200 bbl of oil per day from an unreported Trenton interval. Additional information is not currently available from the Grand Rapids, Mich.-based company.

5 Two more tests have been added by ***Savoy Energy LP*** to the Traverse City-based company's Trenton/Black River program in Michigan's Calhoun County. The #3-3 Replogle is scheduled to be directionally drilled in Section 3-4s-8w, and the proposed true vertical depth is 3,950 ft. Within 2 miles to the east in Section 1, the proposed #1-1 Wagley is also a directional Trenton/Black River test, and it is permitted to 3,660 ft true vertical. Nearby production is at the company's 2019 discovery, #1-19 Motz in Section 19-4s-7w, which was drilled to 3,600 ft and was tested pumping 192 bbl of crude per day from acidized Trenton perforations at 3,482-98 ft.

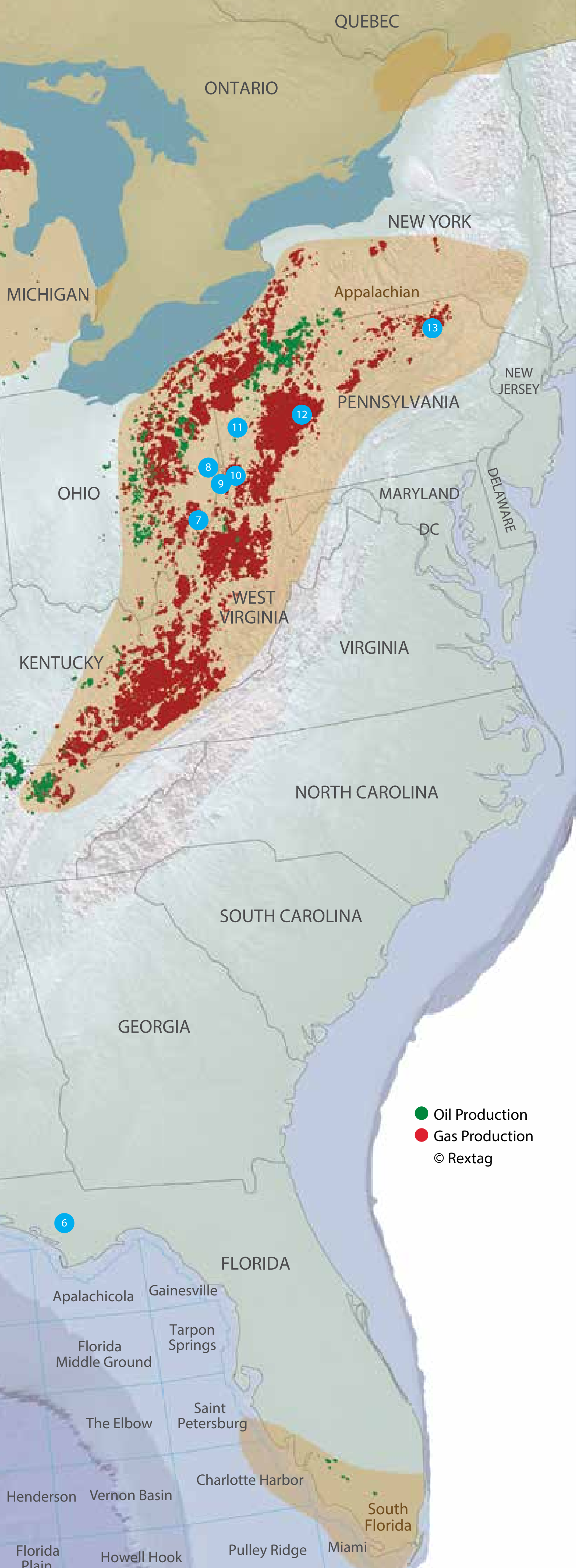
6 A second Smackover exploratory test has been planned by ***Spooner Petroleum*** on the company's acreage in the Florida panhandle. The Gulf County venture, #1 Bear Creek 34-4, will be directionally drilled to a true vertical depth of 12,900 ft, and it will be in Section 34-3s-11w. There is no production in this lightly drilled part of the panhandle. Nearby drilling is about 3 miles to the west at #30-4 International Paper, which was drilled in 1974. Spooner was last active in the area in May 2018, about 5 miles northeast of its new location. In neighboring Calhoun County, #1 Hunt 7-3 in Section 7-3s-10w was abandoned at a total depth of 12,228 ft in Smackover. Spooner is based in Ridgeland, Miss.





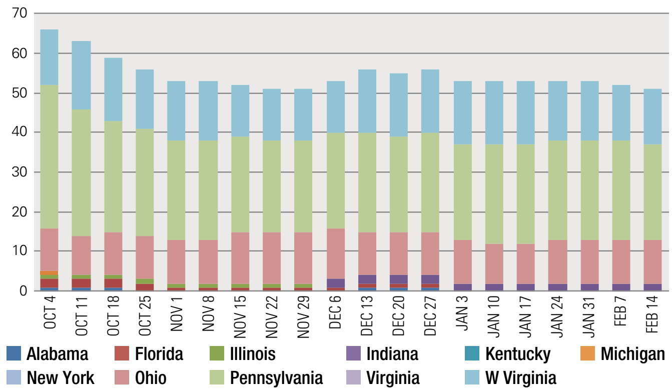
7 A Marcellus discovery in Monroe County, Ohio, was completed by ***Eclipse Resources*** at #4HM Richard Stalder F-M. The Hannibal Field well was drilled in Section 4-2n-4w to 13,230 ft, 6,323 ft true vertical, and bottomed in Section 33-1n-3w. It was tested after acidizing and fracturing flowing 195 bbl of oil, 2.61 MMcf of gas and 438 bbl of water daily. Production is from perforations at 6,759-13,080 ft.

8 ***Ascent Resources*** announced results from a Utica Shale completion in Jefferson County, Ohio. The #3H Roxy CRC JF was drilled in Section 33-6n-2W and bottomed in Section 5. The Bloomingdale Field producer initially flowed 22.03 MMcf of gas and 235 bbl of water daily. Drilled to 21,340 ft, the true vertical depth was 9,358 ft. Ascent's headquarters are in Oklahoma City.



Eastern U.S. Rig Count

Oct. 4, 2019-Feb. 14, 2020



Data compiled from Baker Hughes

9 ***Southwestern Production Co.*** completed a Marcellus Shale producer in West Virginia's Ohio County. Located in Richland Dist., Tiltonsville 7.5 Quad, #205H Edward Dremak Ohi flowed 1.044 Mbbl of oil, with 4.681 MMcf of gas and 1.195 Mbbl of water daily. The discovery was drilled to 22,313 ft, and the true vertical depth is 5,640 ft. Production is from perforations between 6,310 and 22,226 ft. Southwestern's headquarters are in Oklahoma City.

10 A Brooke County, W.Va., Marcellus Shale producer was completed by ***Southwestern Production Co***. The #1H Sandra Parr Brk is in an unnamed field in Buffalo Dist., Bethany 7.5 Quad. It produced 523 bbl of oil, 5.542 MMcf of gas and 645 bbl of water per day with a shut-in casing pressure of 1,435 psi. The well was drilled to 16,692 ft, and the true vertical depth is 6,264 ft. Production is from perforations between 7,011 and 16,347 ft.

11 An unnamed field discovery was announced by ***Range Resources Corp.*** in Beaver County, Pa. The #2H Seibel Joseph 11396 produced 14.763 MMcf of gas per day from Marcellus Shale at 6,752-21,573 ft with a shut-in casing pressure of 622 psi. The well was drilled in Section 8, Aliquippa 7.5 Quad, Independence Township, to 21,656 ft, and the true vertical depth is 6,006 ft. Range Resources is based in Fort Worth, Texas.

12 Two Marcellus Shale producers were completed in Armstrong County, Pa., by ***Snyder Brothers Inc***. The wells were drilled from a Midvale Field pad in Section 3, Freeport 7.5 Quad, Buffalo South Township. The #5H Neumann was drilled to 17,866 ft, 6,791 ft true vertical. It flowed 5.092 MMcf of gas per day from perforations at 7,645-17,774 ft. Tested on an unreported choke size, the shut-in casing pressure was 1,843 psi. The offsetting #7H Neuman was drilled to 20,372 ft, 6,772 ft true vertical. It produced 7.394 MMcf of gas per day from perforations between 7,208 and 20,278 ft with a shut-in casing pressure of 1,701 psi. Snyder Brothers is based in Kittanning, Pa.

13 ***Cabot Oil & Gas Co.*** reported a Marcellus Shale completion in Pennsylvania's Susquehanna County. The #52 Diaz M flowed 21.4 MMcf of gas per day. It is in Section 7 Hop Bottom 7.5 Quad, Springville Township. The 18,011-ft Dimock Field well has a true vertical depth of 7,463 ft. It produces from fractured perforations between 8,743 and 17,940 ft. Cabot's headquarters are in Houston.

GULF COAST

1 An Eagle Ford gas discovery by ***Comstock Oil & Gas LLC***, #3H San Roman, in Hawkville Field produced 14.943 MMcf of gas and 1.5 Mbbl of water per day after fracturing. Located in Webb County (RRC Dist. 4), Texas, the well was drilled to 19,751 ft, 11,783 ft true vertical, in Section 1883, Jane Thompson Survey, A-1824. It was tested on a 28/64-in. choke with a flowing casing pressure of 5,236 psi and a shut-in casing pressure of 7,000 psi. Production is from perforations at 11,695-19,322 ft. Comstock is based in Frisco, Texas.

2 ***Rocky Creek Resources***, according to IHS Markit, completed an Eagle Ford Shale oil well along the northeastern edge of Eagleville Field. In the northern Lavaca County (RRC Dist. 2), Texas, portion of the reservoir, #1H Young flowed 1.182 Mbbl of 48-degree-gravity crude, 1.486 MMcf of gas and 1.372 Mbbl of water daily from an acid- and fracture-treated zone at 12,309-19,843 ft. Flowing casing pressure was 4,165 psi during testing on an 18/64-in. choke. The well was drilled to 20,046 ft (12,062 ft true vertical) in Mary Lewis Survey, A-289, and bottomed within 2 miles to the south in William Taylor Survey, A-55. Rocky Creek is based in Houston.

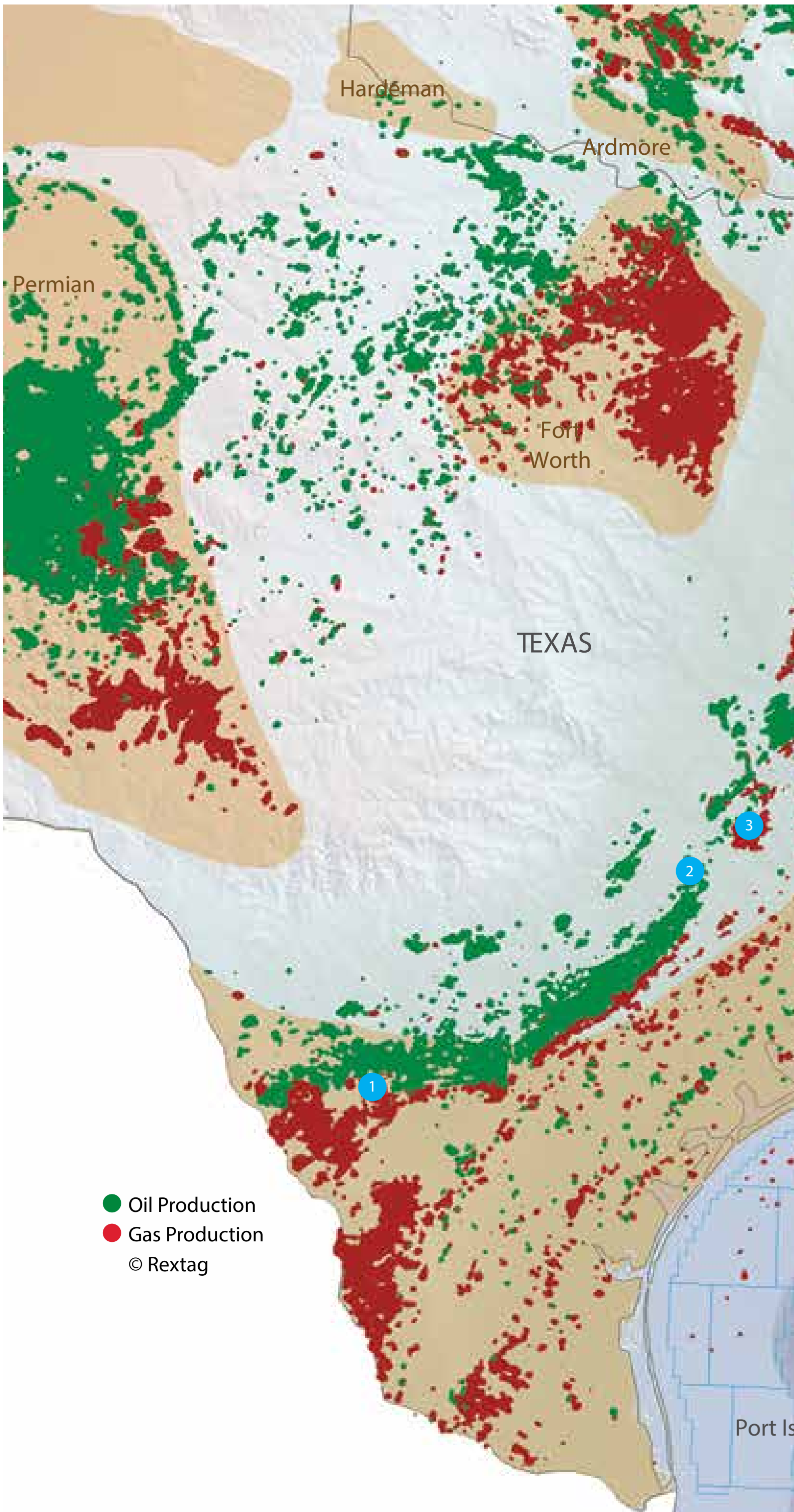
3 ***Ramtex Energy***, based in Tulsa, Okla., announced results from two Austin Chalk completions in Giddings Field. The discoveries were drilled from a pad in Fayette County (RRC Dist. 3), Texas, in William O. Burnham Survey, A-124. The #1H Hawk produced 10.434 MMcf of gas and 426 bbl of oil with 1.59 Mbbl of water per day. The 21,131-ft well has a true vertical depth of 13,885 ft. It was tested on a 7/64-in. choke with a flowing tubing pressure of 3,482 psi and a shut-in tubing pressure of 5,700 psi. Production is from perforations at 14,703-20,913 ft. The #1H Lincoln was drilled to 19,900 ft, 13,393 ft true vertical, and produced 635 bbl of oil, 13.767 MMcf of gas and 1.848 Mbbl of water per day. Production is from perforations at 14,329-19,788 ft. Gauged on a 28/64-in. choke, the flowing casing pressure was 3,979 psi, and the shut-in casing pressure was 4,407 psi.

4 In the southern Brazos County (RRC Dist. 3), Texas, portion of Giddings Field, ***Lonestar Operating*** has completed an Eagle Ford Shale oil well. The #1H SFR flowed 463 bbl of crude, 2.674 MMcf of gas and 138 bbl of water per day through fracture-treated perforations at 11,703-21,893 ft. Flowing tubing pressure was 2,675 psi on a 17/64-in. choke. It was drilled to 22,025 ft, 10,771 ft true vertical, and is on a 1,717-acre lease in Thomas Henry Survey, A-129, and bottomed 2 miles to the northwest in Jesse Bledsoe Survey, A-71. The horizontal leg of the Upper Texas Coast venture was drilled after completing an 11,550-ft vertical pilot hole. Lonestar's headquarters are in Fort Worth.

5 ***Tanos Exploration*** has completed a Cotton Valley gas well in the Panola County (RRC Dist. 6), Texas, portion of Carthage Field. The #1H Mauritzen-Vera Davis-Beckham flowed 7.339 MMcf of gas, 295 bbl of condensate and 1.3 Mbbl of water through perforations at 9,905-17,430 ft. It was drilled to 17,480 ft (9,620 ft true vertical) on a 1,654-acre lease in Harrison Davis Survey, A-157. The lateral bottomed about 1.5 miles to the north in John Coughran Survey, A-121. The shut-in casing pressure was 1,981 psi during testing on a 38/64-in. choke. Tanos is based in Tyler, Texas.

6 IHS Markit reported that ***GEP Haynesville*** has completed four high-volume, horizontal Haynesville Shale wells in the DeSoto Parish, La., portion of Caspiana Field. Two offsetting wells, #001-Alt Hall 27-34HC and #002-Alt Hall 27-34HC, were drilled from a pad in Section 27-15n-14w, bottoming about 1.5 miles to the south in Section 34. The #001-Alt Hall was tested flowing 37.266 MMcf of gas and 381 bbl of water daily from perforations at 12,132-19,578 ft. It was drilled to 19,786 ft (11,829 ft true vertical). The #002-Alt Hall flowed 35.593 MMcf of gas and 1.11 Mbbl of water per day from perforations at 12,082-19,527 ft. It was drilled to 19,745 ft (11,820 ft true vertical). Within one-half mile to the east in Section 27 are the offsetting #001-Alt J&R Family 27-34HC and #002-Alt J&R Family 27-34 HC, which both bottomed 1.5 miles to the south in Section 34. The #001-Alt J&R Family was tested flowing 36.641 MMcf of gas and 1.392 Mbbl of water daily from perforations at 12,027-19,532 ft. The #002-Alt is producing from perforations at 11,072-19,538 ft flowing 37.876 MMcf of gas and 1.265 Mbbl of water per day. GEP is based in The Woodlands, Texas.

7 Two Bossier Parish, La., Haynesville wells were completed in Elm Grove Field by ***Ensight IV Energy***

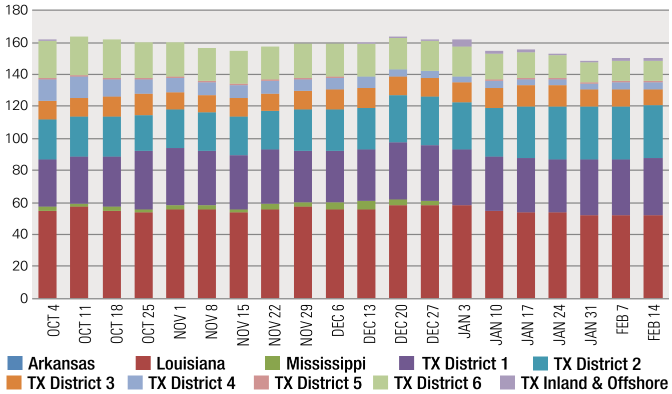


Management LLC. The discoveries were drilled from a pad in Section 19-16n-10w. The #1 Hodges Family 19H was drilled to 16,685 ft with a true vertical depth of 11,678 ft. It produced 19.97 MMcf of gas and 283 bbl of water per day. It was tested on a 24/64-in. choke with a flowing casing pressure of 7,552 psi. Production is from perforations at 11,897-16,505 ft. The #2-Alt Hodges Family 19H was drilled to 16,585 ft, 11,672 ft true vertical, and flowed 21.859 MMcf of gas with 270 bbl of water per day. Gauged on a 24/64-in. choke, the flowing casing pressure was 7,606 psi, and production is from perforations between 11,798 and 16,390 ft. Ensight IV Energy is based in Shreveport, La.

8 ***Vine Oil & Gas*** completed a horizontal Haynesville Shale well in the Red River-Bull Bayou Field portion of Red River Parish, La. Located in Section 32-12n-10w, #1-Alt Yves Lelong 32-5 HC was drilled to 23,015 ft with a true vertical depth of 12,919 ft. It flowed 25.285 Mcf of gas and 1,226 Mbbl of water per day from perforations between 13,041 and 23,010 ft. It was fractured in 29 stages and tested on a 16/64-in. choke, and the flowing casing pressure was 8,691 psi. Vine's headquarters are in Plano, Texas.

9 A Sibley Field-Haynesville Shale discovery was reported by ***Brix Operating***. The Bienville Parish, La., well, #1-Alt BFW Properties 32-29HC, was tested flowing 16.926 MMcf of gas per day from fracture-stimulated perforations at 13,912-21,995 ft. Drilled to 22,000 ft (13,885 ft true vertical), the venture is in Section 5-16n-9w, and it bottomed within 2 miles to the north in Section 32-17n-9w in Webster Parish. Gauged on a 16/64-in. choke, the flowing casing pressure was 9,604 psi. Brix is based in Houston.

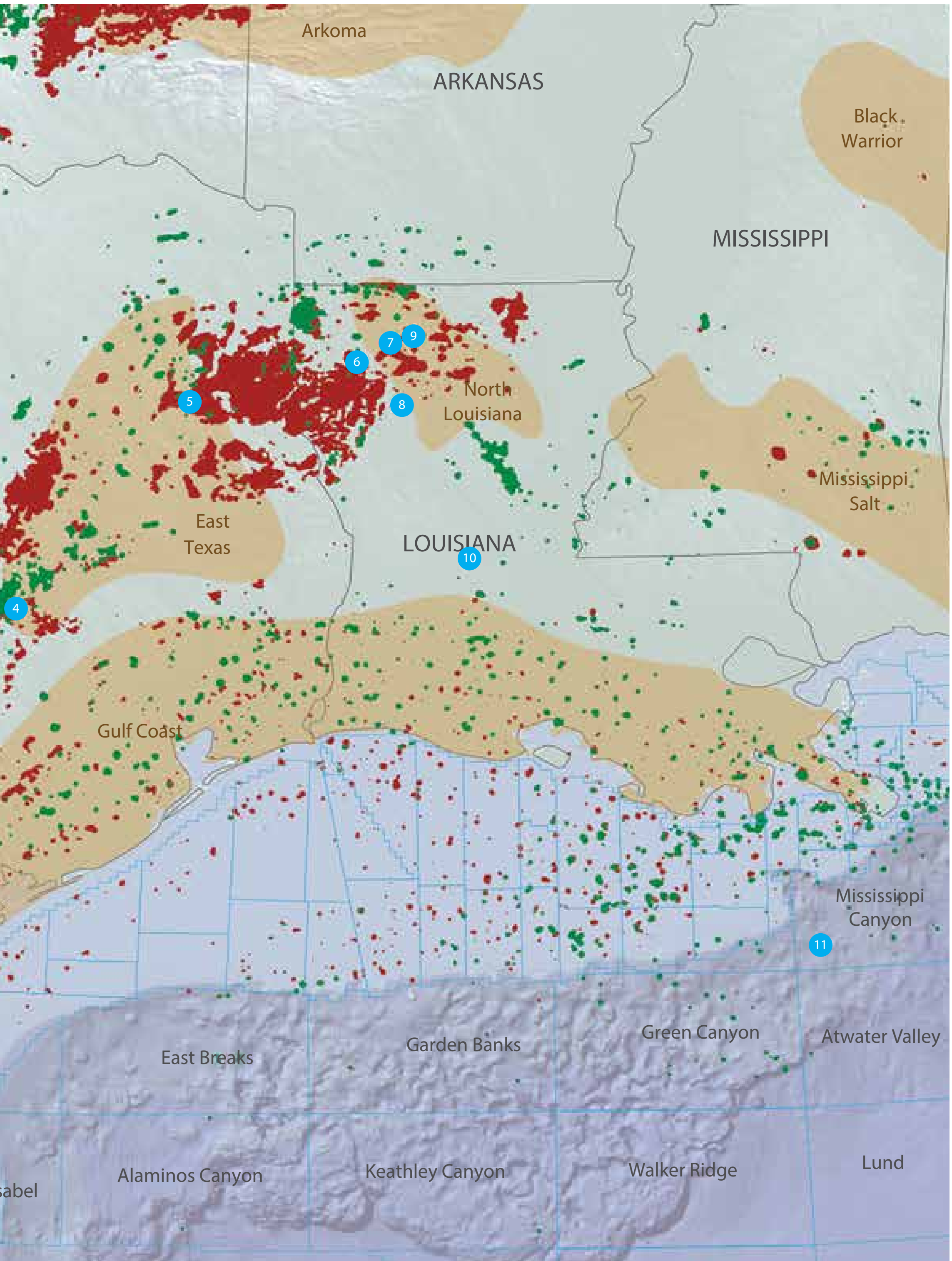
Gulf Coast Rig Count
Oct. 4, 2019-Feb. 14, 2020



Data compiled from Baker Hughes

10 ***Southwind Oil & Gas*** has completed a horizontal Austin Chalk venture in Louisiana's Rapides Parish. The #2 L.M. Crowell 30H flowed 210 bbl of crude, 1.65 MMcf of gas and 3.343 Mbbl of water through an openhole zone at 16,157-22,372 ft. It was tested on an 18/64-in. choke with a flowing tubing pressure of 8,200 psi and a flowing casing pressure of 1,300 psi. The Masters Creek Field well was drilled in Section 30-1s-1w and bottomed approximately 1.5 miles to the north in Section 18. It was drilled to 22,500 ft with a true vertical depth of 15,269 ft. Southwinds's headquarters are in Houston.

11 ***Beacon Offshore Energy*** has scheduled a development test in the Gulf of Mexico's producing Claiborne Field. The #3SS OCS G34909 will be in the northeastern portion of Mississippi Canyon Block 794—it is the first of three new tests planned for the field, according to the development plan. There are two other producing wells on the block, and additional wells will be tied back to the ***Walter Oil & Gas***-owned A platform on Ewing Bank Block 834. Water depth in the area is 1,500 ft. First production from Claiborne Field (Mississippi Canyon Block 794) was reported in 2017 from Miocene at 21,270-21,346 ft and 21,760-21,870 ft. Houston-based Beacon Offshore Energy holds a 23.4% interest in the field.



MIDCONTINENT & PERMIAN BASIN

1 ***OXY USA*** announced results from a Bone Spring discovery at #025H Length CC 6-7 Federal Com in Eddy County, N.M. The Pierce Crossing Field well is in Section 6-24s-29e. It was tested on a 48/64-in. choke flowing 3.996 Mbbl of oil, 5.645 MMcf of gas and 6.248 Mbbl of water per day. The venture was drilled to 18,800 ft, 8,514 ft true vertical, and was fractured in 52 stages. Production is from perforations between 8,327 and 18,703 ft. OXY USA is based in Houston.

2 ***EOG Resources Inc.*** completed a Triple X Field well in Lea County, N.M. Drilled in Section 32-23s-33e, #204H Yarrow 32 State initially flowed 2.955 Mbbl of oil, 4.971 MMcf of gas and 2.68 Mbbl of water per day. The venture was drilled northward to 14,481 ft, 9,608 ft true vertical, and was tested on a 64/64-in. choke with a flowing casing pressure of 707 psi. Production is from perforations at 9,883-14,481 ft. EOG's headquarters are in Houston.

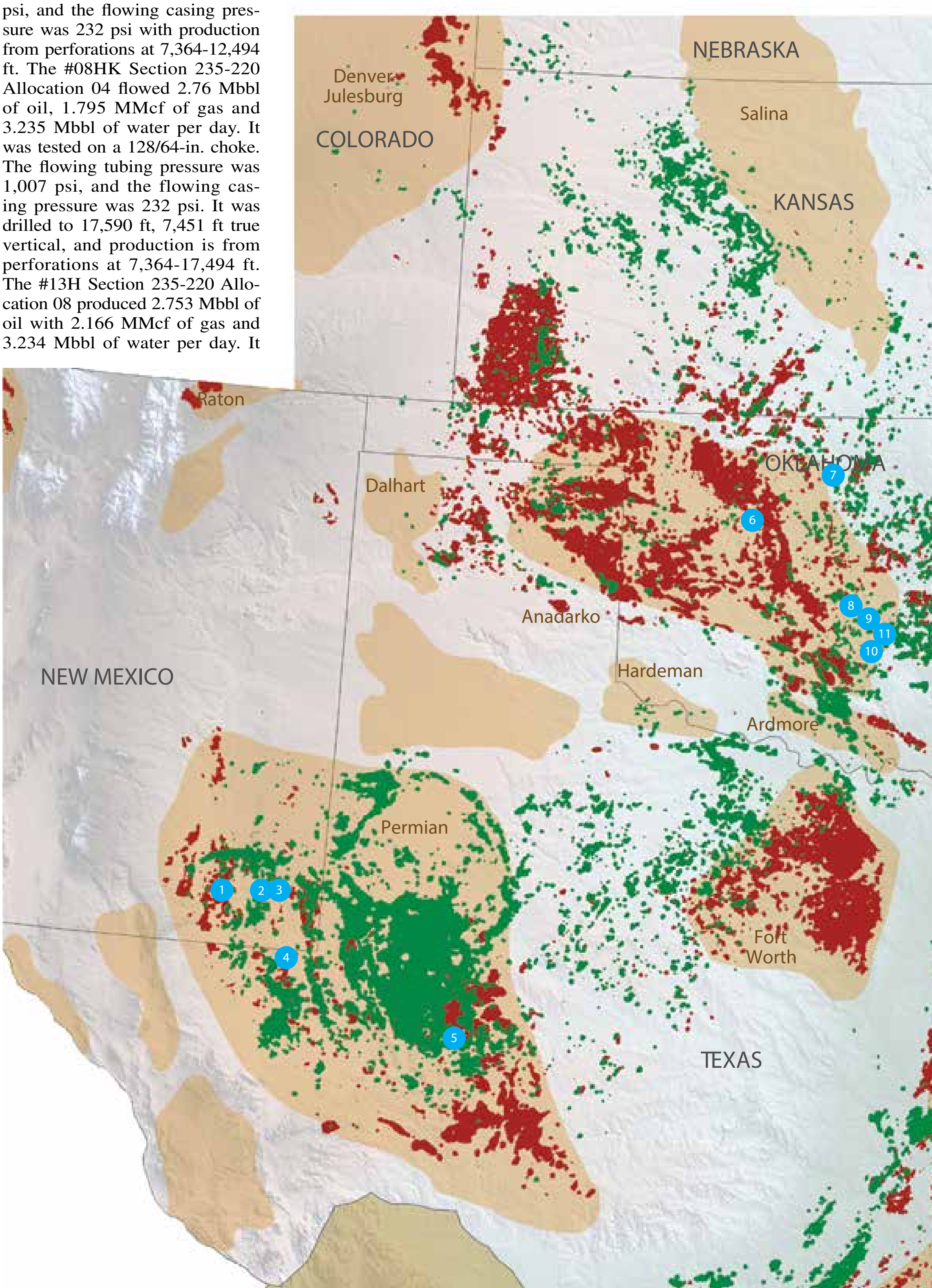
3 A Lea County, N.M., Wolfcamp completion was announced by Oklahoma City-based ***Devon Energy Corp.*** in Brinninstool West Field. The #155H Thistle Unit is in Section 33-23s-33e and bottomed in Section 28. It was tested flowing 4.166 Mbbl of oil, 8.79 MMcf of gas and 6.472 Mbbl of water per day. The well was drilled to the northwest to 22,932 ft, and the true vertical depth is 12,408. Production is from perforations between 12,853 and 22,759 ft.

4 IHS Markit reported that a record Wolfcamp producer was completed by ***EOG Resources Inc***. The Phantom Field venture is in Section 46, Block 76, PSL Survey, A-1120. The lateral bottomed almost 2 miles to the north at 21,939 ft (11,885 ft true vertical) in Section 39 in Loving County (RRC Dist. 8), Texas. The #5H McGregor D Unit flowed 11.444 Mbbl of crude, 21.771 MMcf of gas and 15.48 Mbbl of water per day from a fractured zone at 11,942-21,939 ft. Flowing casing pressure was gauged at 1,740 psi on a 104/64-in. choke. From the same pad, #8H McGregor C Unit flowed 6.161 Mbbl of oil, 10.377 MMcf of gas and 8.05 Mbbl of water per day. Production is from a fractured and perforated zone at 12,065-21,977 ft, and it was tested on a 58/64-in. choke with a flowing casing pressure of 1,741 psi. The 21,977-ft well has a true vertical depth of 11,828 ft.

5 ***Sable Permian Resources***, based in Houston, completed three Wolfcamp C-Midland Basin wells in Reagan County (RRC Dist. 7c), Texas. The Lin Field wells were drilled from a pad in Section 235, Block 1, T&P RR CO Survey, A-576. The #03HK Section 235-220 Allocation 01 produced 3.251 Mbbl of oil, 2.502 MMcf of gas and 3.167 Mbbl of water per day. It was drilled to 17,590 ft (7,451 ft true vertical). Tested on a 128/64-in. choke, the flowing tubing pressure was 1,007 psi, and the flowing casing pressure was 232 psi with production from perforations at 7,364-12,494 ft. The #08HK Section 235-220 Allocation 04 flowed 2.76 Mbbl of oil, 1.795 MMcf of gas and 3.235 Mbbl of water per day. It was tested on a 128/64-in. choke. The flowing tubing pressure was 1,007 psi, and the flowing casing pressure was 232 psi. It was drilled to 17,590 ft, 7,451 ft true vertical, and production is from perforations at 7,364-17,494 ft. The #13H Section 235-220 Allocation 08 produced 2.753 Mbbl of oil with 2.166 MMcf of gas and 3.234 Mbbl of water per day. It was drilled to 17,556 ft, 7,469 ft true vertical, and produces from perforations at 7,520-17,477 ft. Gauged on a 128/64-in. choke, the flowing tubing pressure was 931 psi, and the flowing casing pressure was 377 psi.

6 A Red Fork completion was reported by ***Unit Petroleum Co.*** in Custer County, Okla. The #1HX Saratoga 1720 was drilled to 20,751 ft, 11,034 ft true vertical, in Section 8-14n-14w. Located in Thomas Field, it produced 1.566 Mbbl of oil, with 2.68 MMcf of gas, 1.797 Mbbl of oil with 2.68 Mbbl of water per day. It was drilled to 20,571 ft (11,034 ft true vertical). Gauged on a 38/64-in. choke, the flowing tubing pressure was 1,570 psi. Production is from perforations between 11,466 and 20,751 ft. Unit's headquarters are in Tulsa, Okla.

7 ***Stone Creek Operating LLC*** completed a single-section producer in Kingfisher County, Okla., that, according to IHS Markit, has the highest initial oil production rate for a horizontal Oswego well in the county. The Oklahoma City-based company's #O5H Koopa 23 was drilled in Section 23-18n-6w and produced 1.709 Mbbl of

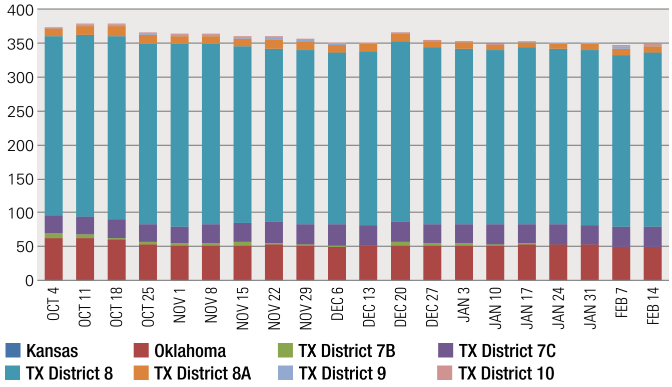


40-degree-gravity oil, 1.5 MMcf of gas and 1.666 Mbbl of water per day. It is producing from an acidized (but not fractured) interval at 6,945-11,528 ft. It was tested on a 64/64-in. choke with a flowing tubing pressure of 271 psi. It was drilled to the north to 11,671 ft, and the true vertical depth is 6,389 ft.

8 ***Gulfport Energy Corp.***, based in Oklahoma City, completed three extended-reach, horizontal producers from a Grady County, Okla., pad in Section 13-4n-6w—one producing from Woodford and two producing from commingled Woodford and Sycamore in Chitwood Field. The #5E-13X12H Dale was tested on a 38/64-in. choke initially flowing 7.25 MMcf of gas, 854 bbl of 57-degree-gravity condensate and 3.151 Mbbl of water per day from Woodford. Production is from acidized and fracture-stimulated perforations between 15,529 and 25,673 ft. The well was drilled to the north to respective measured and true vertical depths of 25,734 ft and 14,902 ft and bottomed in Section 12. About 40 ft to the west, #3-13C-12H Dale LS was tested producing from commingled Sycamore at 15,660-17,127 ft and Woodford at 17,127-22,046 ft flowing 5.48 MMcf of gas, 641 bbl of 57-degree-gravity condensate and 2.5 Mbbl of water daily after acidizing and fracturing. The venture has a parallel lateral extending to 22,128 ft, 15,124 ft true vertical, also bottoming in Section 12. The #3-13X12H Dale LS was drilled to 22,128 ft, 15,124 ft true vertical, producing 641 bbl of condensate, 5.477 MMcf of gas and 2.5 Mbbl of water per day from Sycamore at 15,660-17,127 ft and Woodford at 17,127-22,046 ft.

Midcontinent & Permian Basin Rig Count

Oct. 4, 2019-Feb. 14, 2020

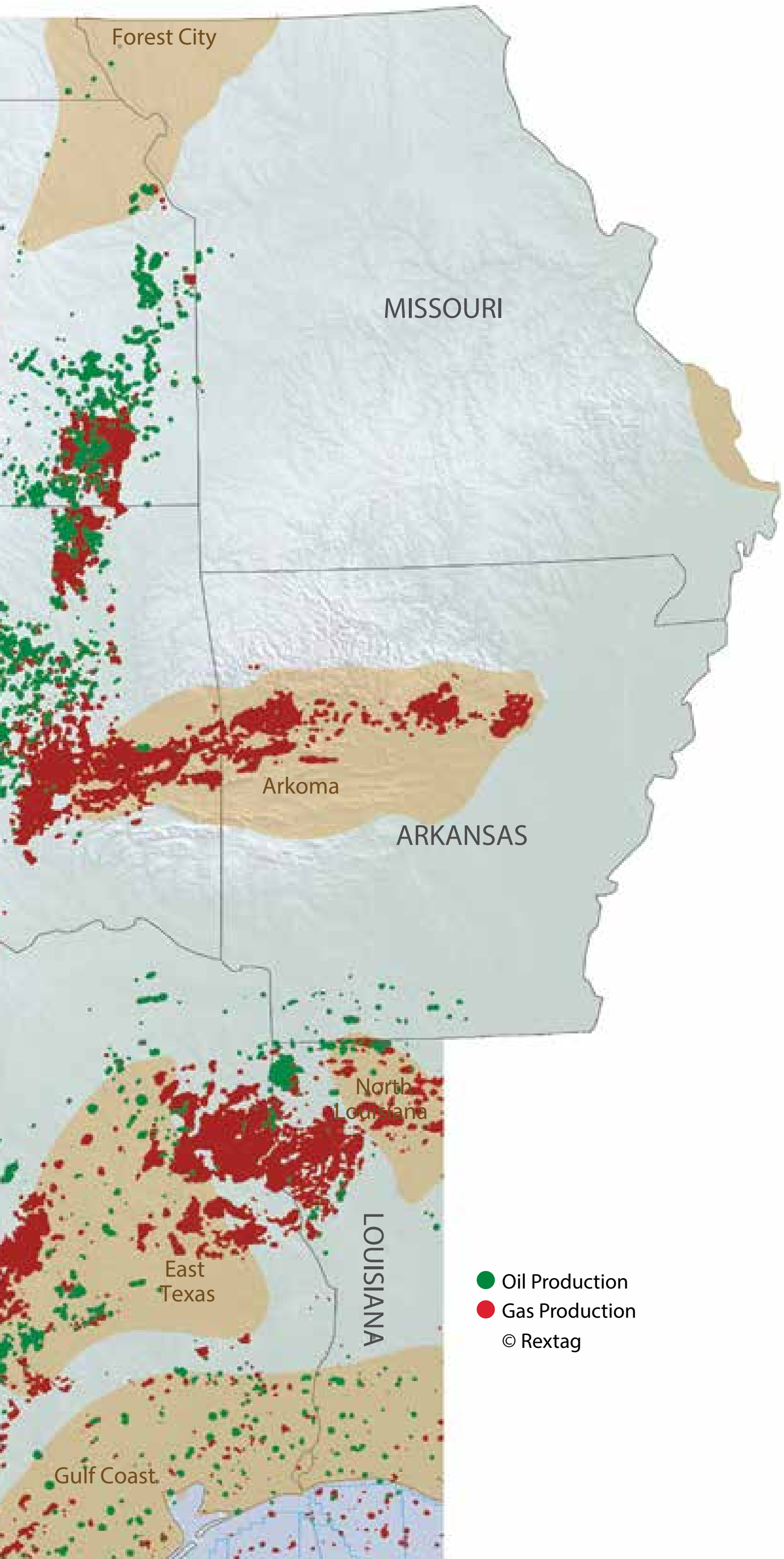


Data compiled from Baker Hughes

9 A Garvin County, Okla., venture in Oklahoma's Golden Trend Field was reported by Houston-based ***Marathon Oil Corp***. The #1-4-33SXH ST01 Jewel Bia 0304 is producing from Goddard Shale. Located in Section 4-3n-4w, it was drilled to the north to 21,198 ft, 11,355 ft true vertical. It initially flowed 1.859 Mbbl of 40-degree-gravity oil, with 1.213 MMcf of gas and 1.526 Mbbl of water per day during testing on a 30/64-in. choke from perforations between 12,741 and 21,106 ft.

10 According to IHS Markit, ***Casillas Operating*** has completed a high-volume Sycamore producer in eastern Stephens County, Okla. The #1-21-16MXH Park Place was drilled in Section 28-1n-4w to the north about 2 miles to 19,052 ft (10,655 ft true vertical). The discovery initially flowed 1.826 Mbbl of 44-degree-gravity oil, 3.31 MMcf of gas and 907 bbl of water per day. The well was tested on a 64/64-in. choke with a shut-in tubing pressure of 1,020 psi and a flowing tubing pressure of 1,515 psi. The Ardmore Basin well bottomed in Section 16 and was perforated, acidized and fractured at 9,555-18,953 ft. Casillas is based in Tulsa, Okla.

11 ***Marathon Oil Corp.*** completed a Pearl Northeast Field discovery in Stephens County, Okla. The #2-3-34SXH BP02 Papa Pump 0204 is a Springer Shale producer, and it flowed 2.008 Mbbl of oil, 1.089 MMcf of gas and 1.574 Mbbl of water daily. It is in Section 10-2n-4w and was drilled to 23,025 ft, 12,029 ft true vertical. Gauged on a 40/64-in. choke, production is from perforations at 12,715-22,900 ft.



WESTERN U.S.

1 A remote wildcat is planned in the nonproducing Gabbs Valley in Nye County, Nev., by Reno-based ***Cortez Exploration LLC***. The #41-1 Gabbs will be in Section 1-12n-34e. No objectives and/or target depth were released for the currently unpermitted well. Nearby drilling occurred at a 2003 prospect about 3 miles to the east at #1-4 Gigante, which was drilled to 7,707 ft and cased to 7,502 ft. No additional information was released.

2 ***Staroil Inc.*** has filed a permit with the BLM to drill a wildcat in Hot Springs County, Wyo. The agency did not release drilling objectives or proposed total depth for #1 Staroil No, which will be in Section 28-43n-93w and on the southern edge of the Big Horn Basin. The Red Springs Field discovery was completed on an anticlinal feature in 1957 at a workover of a 1,205-ft dry hole at #3 Government in Section 28-43n-93w. According to IHS Markit, the field opener initially pumped 28 bbl of oil daily from an acidized Madison zone at 955-75 ft. Delineation drilling in the 1960s and 1970s resulted in new pay discoveries in Phosphoria, Tensleep, Amsden and Big Horn. The field was abandoned in 2017 after producing 239 Mbbl of oil and 158 Mbbl of water from 18 wells.

3 ***South Pass Petroleum Inc.*** plans to drill a new test in the Big Horn Basin Field in Washakie County, Wyo. The Cheyenne-based operator filed for a permit for #1-26H Sand Creek-Government in Section 26-46n-91w. No objectives or proposed depth were announced; however, the project is presumed to be a horizontal test targeting bypassed Frontier reserves. The drillsite is on the northeastern edge of Sand Creek Field, a Frontier accumulation on an anticlinal structure that was discovered and developed in 1947-1949. The discovery well, #45-26 Government in Section 26-46n-91w, was completed in an untreated openhole interval of Third Frontier at 6,685-6,753 ft flowing 589 bbl of 46-degree-gravity oil and 1.4 MMcf of gas per day with no water.

4 ***Samson Resources Co.*** completed two Shannon-Bull Gulch discoveries at a Converse County, Wyo., drillpad in Section 27-40n-75w. The #21-2215 40-75SH Ogalalla Fed was tested flowing 2.475 Mbbl of 38-degree-gravity oil, 785 Mcf of gas and 1.262 Mbbl of water per day from Shannon. It was drilled to 21,154 ft with a true vertical depth of 10,696 ft. Tested on an 18/64-in. choke, the flowing casing pressure was 2,146 psi, and the shut-in casing pressure was 61 psi. Production is from perforations at 11,123-21,021 ft. The #4075-2215 2SH Ogalalla-Federal produced 1.695 Mbbl of oil, 445 Mcf of gas and 1.958 Mbbl of water per day. The Shannon lateral was drilled to the northeast to 21,002 ft (10,676 ft true vertical) and bottomed in Section 15-40n-75w. It was tested on an 18/64-in. choke following 39-stage fracturing between 11,339 and 20,887 ft. Samson is based in Tulsa, Okla.

5 A Mowry discovery by Campbell County, Wyo., was reported by Houston-based ***EOG Resources Inc***. The #870-2833H Flatbow is in Section 28-42n-73w and was tested flowing 998 bbl of oil, 5.484 MMcf of gas and 2.239 Mbbl of water per day. The well was drilled to 21,820 ft with a true vertical depth of 11,990 ft, and it bottomed in Section 33. Tested on a 34/64-in. choke, the flowing casing pressure was 2,448 psi. Production is from fractured perforations between 12,175 and 21,571 ft.

6 In Broomfield County, Colo., ***Extraction Oil & Gas Inc.*** announced results from a Wattenberg Field well. The #35N-20-8C Interchange B was drilled to 18,910 ft, and the true vertical depth is 8,068 ft. It flowed 509 bbl of oil, 1.066 MMcf and 123 bbl of water per day from commingled Codell (9,298-18,886 ft), Fort Hays (14,730-14,890 ft) and Niobrara (14,915-15,010 ft). It was drilled in Section 10-1s-68w. Extraction's headquarters are in Denver.

7 ***Bison Oil & Gas II LLC*** has completed three extended-reach horizontal Niobrara producers from a common drillpad in Section 17-8n-60w in Weld County, Colo. The wells were drilled to the north and bottomed in Section 8. The #8-60 17A-8-6 Hunt flowed 548 bbl of 36-degree-gravity oil, 368 Mcf of gas and 423 bbl of water per day. Production is from a lateral drilled to 14,019 ft (6,452 ft true vertical). It was tested on a 32/64-in. choke after 48-stage fracturing between 6,705 and 13,923 ft. The #8-60 17A-20-1 Hunt flowed 553 bbl of oil, 328 Mcf of gas and 423 bbl of water per day. Production is from a lateral drilled to 13,827 ft (6,357 ft true vertical). It was tested on a 33/64-in. choke after 47-stage fracturing between 6,755 and 13,727 ft. The #8-60 17A-8-2 Hunt flowed 514 bbl of oil, 368 Mcf of gas and 423 bbl of water per day. Production is from a lateral drilled to 13,766 ft (6,387 ft true vertical). It was tested on a 32/64-in. choke after 47-stage fracturing between 6,758 and 13,661 ft. Bison Oil & Gas is based in Denver.

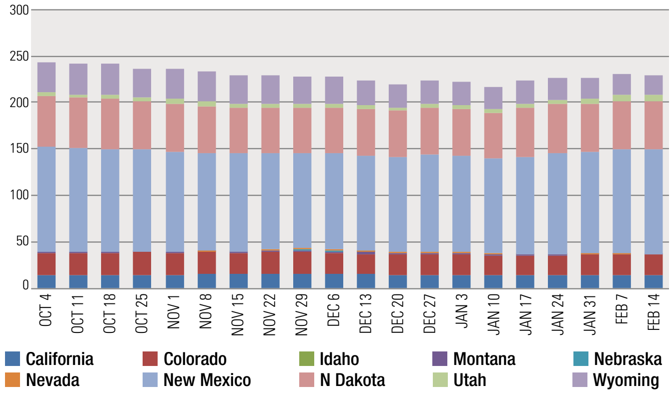
8 Two McKenzie County, N.D., Three Forks wells on the Nesson Anticline were completed by ***Hess Corp.*** in Blue Buttes Field in Section 7-150n-95w. The #150-95-0718H-6 BB-Charlie Loomer was drilled to 21,410 ft, and the true vertical depth is 10,804 ft. It produced 3.771 Mbbl of oil, 9.812 MMcf of gas and 1.488 Mbbl of water per day from perforations at 11,228-21,111 ft after

30-stage fracturing. Gauged on a 44/64-in. choke, the flowing tubing pressure was 1,790 psi. The #150-95-0718H-9 BB-Charlie Loomer was drilled to 18,781 ft, 10,720 true vertical. It flowed 4.251 Mbbl of oil, 10.298 MMcf of gas and 1.096 Mbbl of water per day from perforations at 11,228-21,111 ft after 22-stage fracturing. It was tested on a 44/64-in. choke, and the flowing tubing pressure was 1,501 psi. Hess is based in New York City.

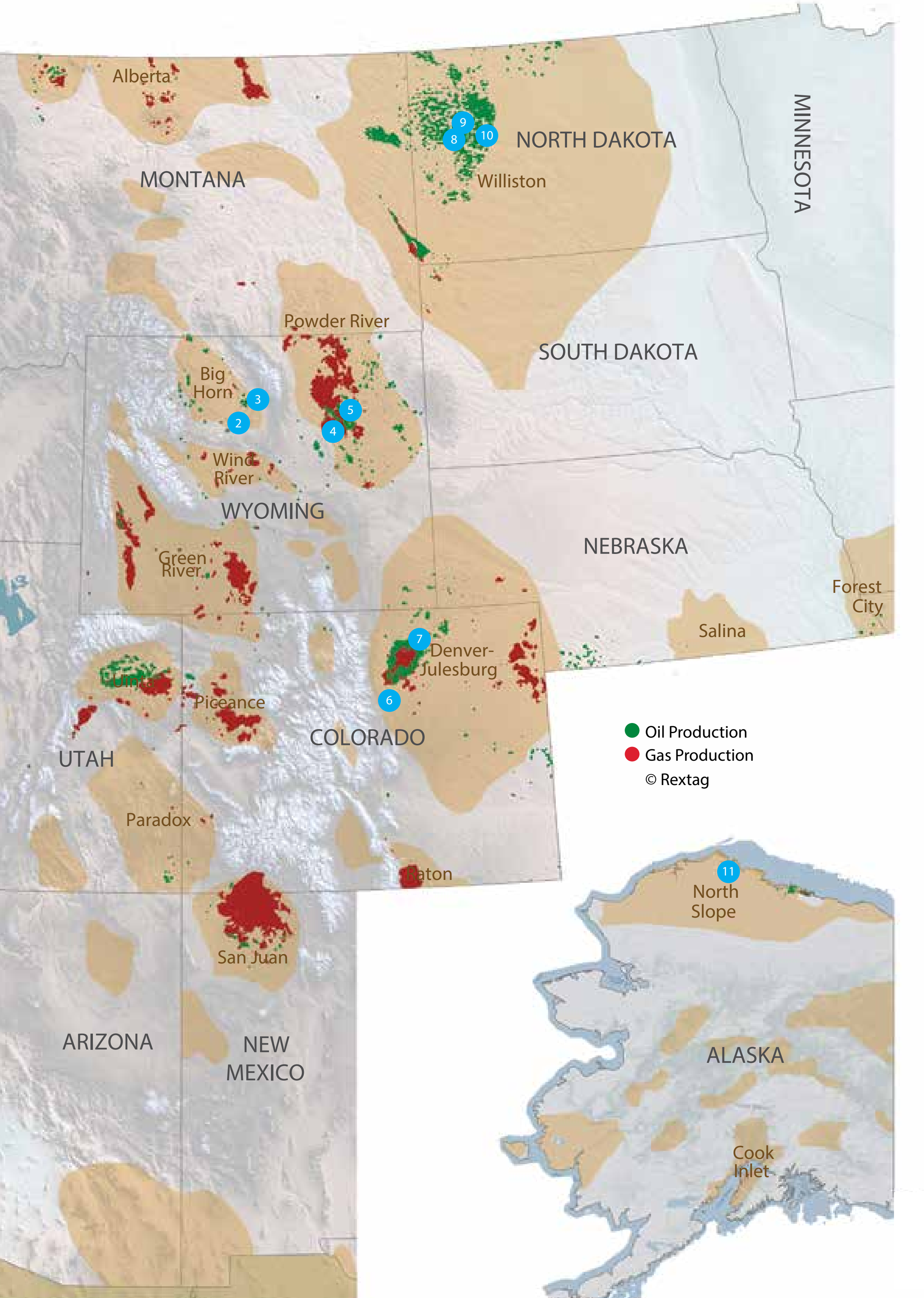
9 ***Hess Corp.*** completed two Antelope Field wells from a pad in Section 4-152n-94w in McKenzie County, N.D. The company's #152-94-0409H-3 AN-Norby was drilled to 21,899 ft (10,776 ft true vertical) and initially flowed 3.757 Mbbl of oil, 7.928 MMcf of gas and 1.771 Mbbl of water per day. Production is from Middle Bakken at 11,086-21,732 ft. The #152-94-0409H-6 AN-Norby was drilled to 22,068 ft with a true vertical depth of 10,852 ft. It produced 3.999 Mbbl of oil, 8.562 MMcf of gas and 1.876 Mbbl of water from Three Forks perforations at 11,198-21,894 ft. Both wells were tested on 46/64-in. chokes.

Western U.S. Rig Count

Oct. 4, 2019-Feb. 14, 2020



Data compiled from Baker Hughes



10 Houston-based ***Marathon Oil Corp.*** has completed two high volume horizontal Bakken/Three Forks producers on the Fort Berthold Indian Reservation in Mountrail County, N.D. According to IHS Markit, the wells were drilled from a pad in Section 2-151-93w. The #11-2TFH Dietrich-USA initially flowed 6.028 Mbbl of 41-degree-gravity oil, 5.644 MMcf of gas and 3.655 Mbbl of water per day from Three Forks. The venture was drilled to the southwest 20,765 ft (10,655 ft true vertical) and bottomed in Section 11. It was tested on a 1-in. choke following 45-stage fracturing between 11,125 ft and 20,627 ft. The #41-3H Holmgrem produced 4.041 Mbbl of oil, 4.558 MMcf of gas and 2.845 Mbbl of water per day. Production is from a southwestern lateral in Middle Bakken extending from 10,887 ft to 20,836 ft at a bottomhole location in Section 10. The 20,765-ft well has a true vertical depth is 10,533 ft. It was tested on a 1-in. choke after 45-stage fracturing at 10,995-20,697 ft.

11 The state of Alaska has granted Houston-based ***ConocoPhillips Co.*** drilling permits for two more delineation tests at the Willow development project in the northeast National Petroleum Reserve-Alaska in Umiat. The #18 Tinmiaq will be in Section 10-8n-1w and will evaluate Nanushuk oil zones. It will be directionally drilled northwestward to a proposed bottomhole location in Section 4-8n-1w. The #22 Tinmiaq will be in Section 15-11n-1w and is approximately 17 miles north of #18 Tinmiaq site. It will be vertically drilled to evaluate Nanushuk oil zones.

INTERNATIONAL HIGHLIGHTS

The Energy Information Administration (EIA) has adjusted its 2020 oil price forecast given the impact of the coronavirus.

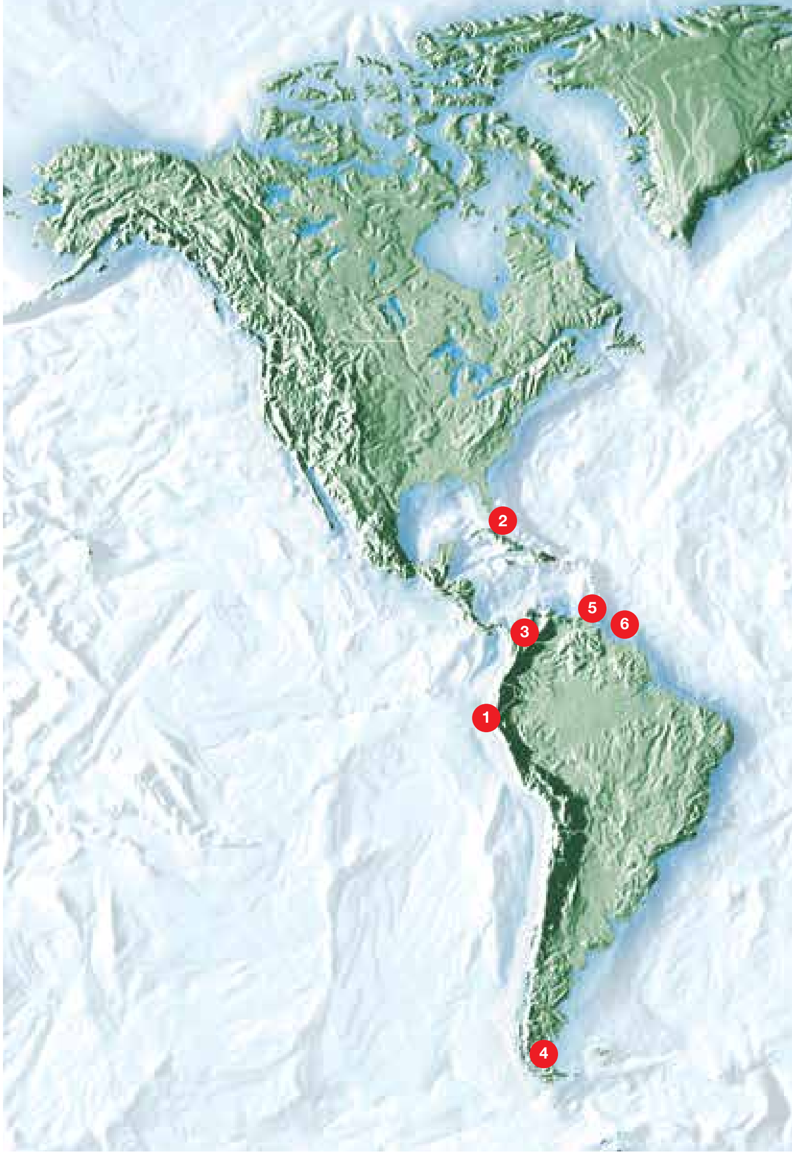
According to EIA's latest "Short-Term Energy Outlook," crude prices are now expected to average $55.71/bbl in 2020, down from the month-earlier forecast of $59.25. The agency's Brent crude oil forecast dipped to $61.25/bbl this year from $64.83.

The magnitude and duration of the coronavirus' effects remain uncertain, but the EIA is reducing its estimates for Chinese and global oil consumption for 2020 due to it. The mid-January Chinese travel restrictions are disrupting petroleum demand worldwide. The EIA expects liquid fuels consumption in China to average 14.8 million barrels per day (bbl/d) during February through April, a drop of 400,000 bbl/d from earlier forecasts.

Other price factors included reduced tension and de-escalation in the Middle East, including supply disruption, and warmer-than-normal temperatures across much of the Northern Hemisphere.

OPEC also lowered its forecast for 2020 oil growth and cited the coronavirus outbreak as the major factor in its decision. Despite the amended forecast, OPEC and non-OPEC partners, namely Russia, in March failed to agree on additional output cuts and instead ended the existing agreement, fueling an oil price shock on fears of oversupply.

–Larry Prado



1 *Peru*

Karoon Energy is underway at exploration well #1-Marina in Block Z-38 Tumbes Basin, Peru. The well has a planned depth of 3,000 m. Karoon is the operator and has a 40% net interest in Block Z-38. The Marina prospect has a gross prospective resource best estimate of 256 MMbbl of oil and comprises a large fault bounded structure with targets at multiple levels from 900 m to 3,000 m. The targets are in the Tertiary Pliocene La Cruz to Cardalitos formations. Melbourne, Victoria-based Karoon is the operator of Block Z-38 and the Marine Prospect with 40% interest in partnership with Tullow Oil, holding 35%, and ***Pitkin Petroleum*** with the remaining 25%.

2 *Bahamas*

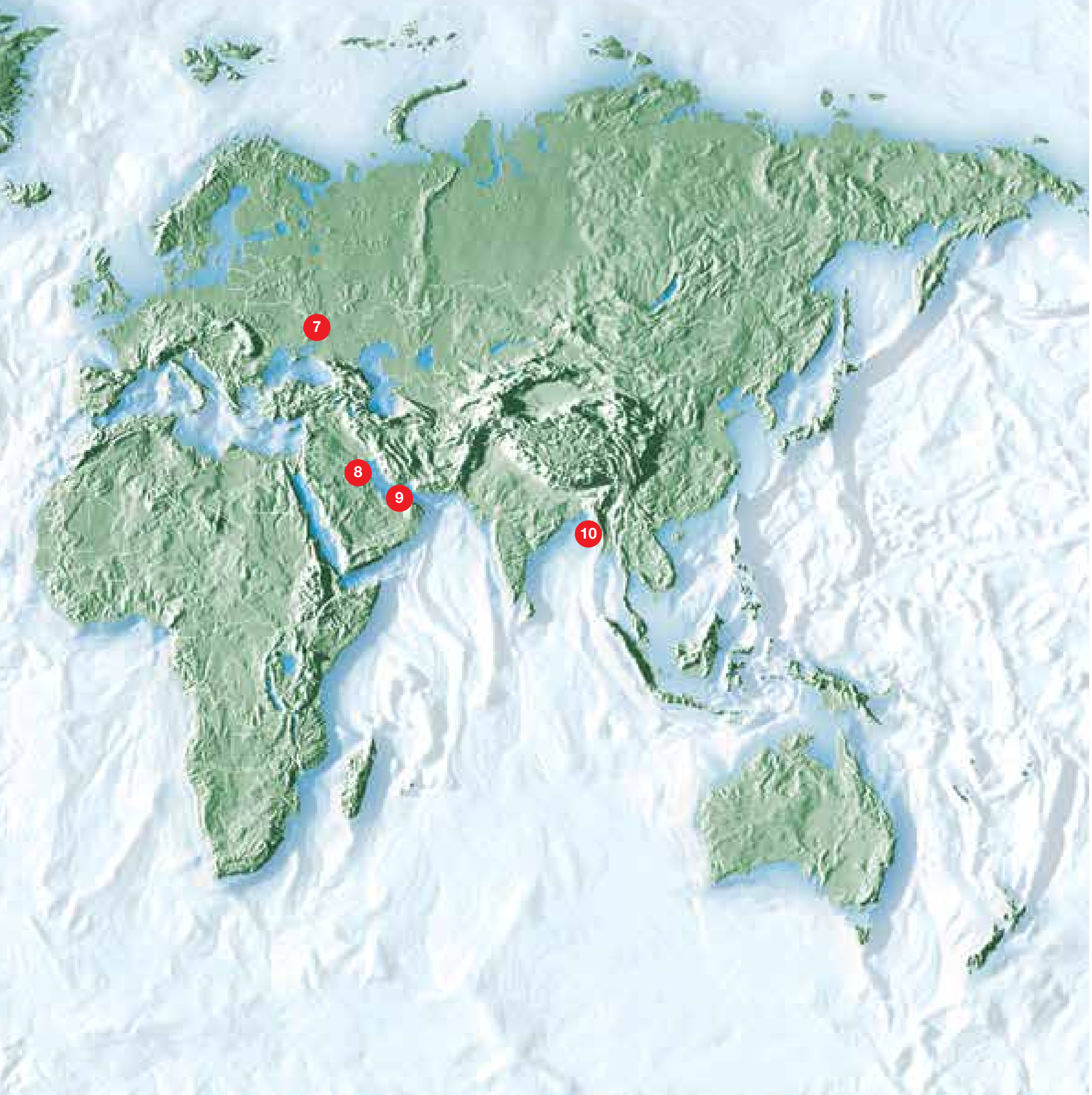
An offshore Bahamas exploration well is planned by ***Bahamas Petroleum Co.*** at #1-Perseverance. The well is targeting recoverable P50 oil resources of 77 MMbbl of oil with an upside of 1.44 Bbbl of oil in the B structure and a recoverable resource potential in excess of 2 Bbbl. The well location will be on the northern segment of the structure. Area water depth is approximately 510 m. It has a planned depth of 4,822 m with a Tertiary objective, but it will evaluate multiple reservoir horizons. The company anticipates that any discovery at this location has the potential to extend into a larger portion of the overall B structure extending to the southeast. London-based Bahamas Petroleum owns and operates the well on the northern segment of the B mega structure located near the Cuba-Bahamas maritime boundary.

3 *Colombia*

Fronterra Resources announced a Lower Magdalena Valley discovery in Colombia in the VIM-1 Block. Exploration well #1-La Belleza was drilled to 11,680 ft and encountered 179 ft of potential hydrocarbon bearing reservoir in Cienaga De Oro. It was tested flowing 2.696 Mbbl of oil, 11.8 MMcf of gas per day with an average water cut of 10%. The initial shut-in wellhead pressure was 4,700 psi. The test was limited by the on-location facilities. Bottomhole flowing pressures were at approximately 6,000 psi. The partners (Fronterra and ***Parex***) are evaluating options to drill additional delineation wells in 2020 from the existing La Belleza well pad. Parex began drilling another exploration well in the nearby Guama Block at #1-Asai and is targeting oil and gas in Porquero at approximately 12,000 ft. Fronterra and Parex are both based in Calgary.

4 *Chile*

GeoPark, based in Buenos Aries, announces the discovery of a new gas field, Jauke Oeste, in the Fell Block in Chile. Exploration well #1 Jauke Oeste was drilled to 9,596 ft. A production test in Tobifera flowed 4.4 MMcf per day of gas with 52 bbl of condensate per day. The wellhead pressure was 3,141 psi. Additional production history is required to determine stabilized flow rates of the well and the extent of the reservoir. The Jauke Oeste gas field is about 1 km north of the Jauke gas field, which is currently producing about 8 MMcf of gas per day from two wells. Jauke and Jauke Oeste gas fields are part of the large Dicky geological structure in the Fell Block. Additional testing and exploration is planned by operator GeoPark, including exploratory wells at #1 Leun in the Flamenco Block, #1 Huillin well in the Isla Norte Block and #1 Koo 1 in the Campanario block.



8 Neutral Zone (Kuwait, Saudi Arabia)

Kuwait Petroleum and ***Aramco*** have decided to resume operations in the Khafji and Wafra fields in the Neutral Zone between Saudi Arabia and Kuwait. A territorial dispute halted oil production in offshore Khafji Field and onshore Wafra Field. According to Kuwait City-based Kuwait Petroleum, production from the fields is approximately 280-300 Mbbl at Khafji and 220 Mbbl per day at Wafra, which both produce heavy, high-sulfur crude—U.S. sanctions on Iran and Venezuela have tightened the supply of heavy crude. The shutdown began in 2014 at Khafji Field due to a dispute over their territorial rights then expanded to include Wafra in 2015.

9 United Arab Emirates

A gas and condensate discovery was announced by Rome-based ***Eni*** in the Mahani exploration prospect located onshore in the Area B Concession of Sharjah (United Arab Emirates). The #1-Mahani was drilled to 14,597 ft and encountered a thick gas-bearing limestone reservoir in the Lower Cretaceous Thamama. The well was tested with flow rates up to 50 MMcf per day of gas and associated condensate. Additional appraisal drilling is planned. The new phase of exploration will be targeting complex sub-thrust Jurassic and Cretaceous plays of the Arabian carbonate platform in the inner thrust zone of the Oman Fold belt. Eni holds a 50% stake in the Concession Area B, with operator ***Sharjah National Oil Co.*** holding the remaining 50%.

5 Trinidad

Touchstone Exploration, based in Calgary, announced test results at #1ST1-Cascadura on the Ortoire Block in Trinidad. The well had a peak flowback rate of 5.736 Mboe per day, including 30.2 MMcf of gas and 710 bbl of NGL. The first stage of testing was lower-most 162 ft of a total of 777 ft of identified pay in Herrera. Analysis indicated liquids-rich gas with no hydrogen sulfide and no produced water. The well will be shut-in for a two-week pressure build-up test, and completion and testing are planned on an additional 450 ft of identified pay. A sidetrack was drilled to 6,350 ft, and wireline logs and drilling samples indicated approximately 1,037 ft of prospective hydrocarbon pay in Cruse and Herrera at depths between 1,030 and 6,350 ft. It was tested on a 40/64-in. choke, and the flowing pressure was 3,305 psi. Operator Touchstone holds an 80% working interest, and partner ***Heritage Petroleum Company Ltd.*** holds a 20% working interest.

6 Guyana

Another Guyana discovery was announced by ***Exxon Mobil Corp***. According to the Irving, Texas-based company, the new find increases its estimated recoverable resource base in offshore Guyana to more than 8 Bboe. The new well, #1-Uaru, hit about 94 ft of high-quality, oil-bearing sandstone reservoir. It was drilled in 6,342 ft of water and is about 10 miles northeast of Liza Field. The #1-Uaru adds approximately 2 Bboe to the previously estimated reserves on the block. A fifth drillship is expected to be deployed later in 2020. The Stabroek Block is 6.6 million acres. Exxon Mobil is the operator and holds 45% interest in the block along with ***Hess Corp.*** (30%) and ***China National Offshore Oil*** (25%).

7 Ukraine

Cub Energy, based in Houston, is drilling #30 Makeevskoye in eastern Ukraine. The venture has a planned depth of 1,985 m and will evaluate several prospective horizons. According to the company, it will be the first well drilled in the producing Makeevskoye Field in over three years after recent successful recompletions on the Makeevskoye and Olgovskoye fields. Cub Energy is the operator of the West Olgovskoye Block and Makeevskoye Field wells with 100% interest.

10 Myanmar

Posco International announced it discovered a new offshore gas field in Myanmar near the Shwe gas field development in the Andaman Sea, Bay of Bengal, Block A-1. The #1-Mahar discovery was made while carrying out exploratory undersea drilling for its Mahar gas project. An 18-m gas column was encountered, and currently it is estimated that it could produce 38 MMcf of gas per day. The completion is in 2,598 m of water. Posco plans to drill more appraisal wells at the site in 2021. The Shwe gas field consists of blocks A1 and A3. There are currently two existing gas fields, Shwe and Shwe Phyu, in Block A1. Posco International, based in Incheon, South Korea, has a 51% stake in the Shwe natural gas project, while ***Myanma Oil and Gas Enterprise***, ***KOGAS***, ***Oil and Natural Gas Corp.*** and ***Gail Ltd.*** hold the remaining 49%.

MIDSTREAM GAIN, HIGH-YIELD PAIN

While the entire energy sector has been roiled by the coronavirus outbreak and Saudi Arabia's surprise shift in strategy toward market share rather than price stability, a handful of midstream operators were able to tap the fixed income market before commodity, high yield and equity markets collapsed in the wake of the failed OPEC meeting.

At press time, WTI is trading around $33/bbl, down from $61.18/bbl on the first day of trading this year.

Midstream players able to tap the debt market ahead of the chaos included ONEOK Inc., Tallgrass Energy Partners LP and Holly Energy Partners.

ONEOK priced $1.65 billion senior notes in an $850 million tranche and two $400 million tranches. The former was a 3.1% senior note due 2030 priced at 99.897 to yield 3.112%. The latter two were: a $400 million issue of 2.2% senior note due 2025 priced at 99.922 to yield 2.215%; and a $400 million issue of 4.5% senior notes due 2050 priced at 99.852% to yield 4.509%.

Holly Energy Partners priced at par $500 million of 5% senior notes due 2028. The notes are guaranteed by the partnership's wholly owned subsidiaries, which operations include refined product pipelines. Tallgrass Energy Partners offered $430 million of 6% senior unsecured notes due 2027, which were priced at 98.591% to yield 6.25%.

Also able to tap the debt market just before it closed was Parsley Energy Inc., which priced at par $400 million of 4.125% senior notes due 2028. Proceeds will redeem $400 million of 6.25% notes due 2024.

In high yield, if any question remained as to it being open for business, it was swept away by the OPEC meeting disintegrating into disarray. Shortly before the meeting, the spread between U.S. Treasuries and high- yield energy stood at nearly 1,000 basis points, or 10%, versus a peak spread of around 1,300 basis points when WTI fell to $26/bbl in February 2016.

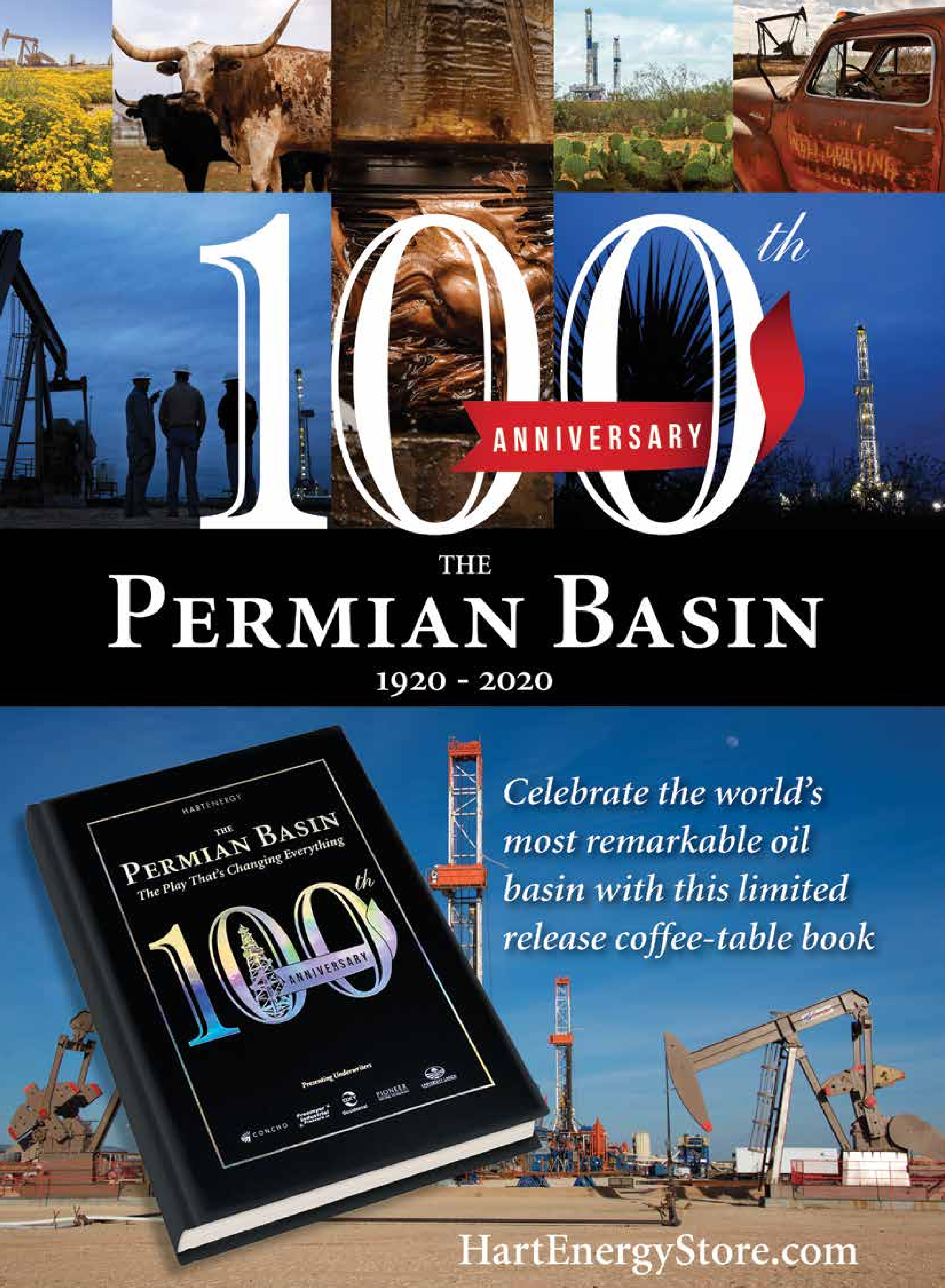
On the OPEC failure, coupled with quotas ending on April 1, the spread over U.S. Treasuries ballooned wider to match the record February 2016 level.

—Chris Sheehan, CFA

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
ONEOK Inc.	NYSE: OKE	Tulsa, Okla.	$1.65 billion	Priced an offering to sell $1.65 billion of senior notes, consisting of $400 million of five-year senior notes at a coupon of 2.2%, $850 million of 10-year senior notes at a coupon of 3.1% and $400 million of 30-year senior notes at a coupon of 4.5%. The net proceeds from the offering, after deducting underwriting discounts, commissions and offering expenses, are expected to be $1.63 billion. ONEOK expects to use the net proceeds to repay all amounts outstanding under its commercial paper program and for general corporate purposes, which may include repayment of existing indebtedness and funding of capex. Barclays Capital Inc., Deutsche Bank Securities Inc., Mizuho Securities USA LLC, TD Securities (USA) LLC, BofA Securities, Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Goldman Sachs & Co. LLC, Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., PNC Capital Markets LLC, RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SMBC Nikko Securities America Inc. and Wells Fargo Securities LLC are acting as joint book-running managers for the offering. Regions Securities LLC, SunTrust Robinson Humphrey Inc., U.S. Bancorp Investments Inc., Siebert Williams Shank & Co. LLC and Tuohy Brothers Investment Research Inc. are the co-managers for the offering.
Halliburton Co.	NYSE: HAL	Houston	$1 billion	Priced an offering of $1 billion aggregate principal amount of 2.92% senior notes due 2030. Halliburton intends to use the net proceeds of the offering, together with cash on hand, to finance concurrent cash tender offers to purchase certain series of Halliburton's outstanding senior notes. If the tender offers are not consummated or the net proceeds from the offering exceed the total consideration payable in the tender offers, Halliburton intends to use the remaining net proceeds from the offering for general corporate purposes, which may include the repayment or repurchase of other indebtedness. J.P. Morgan Securities LLC, Citigroup Global Markets Inc., HSBC Securities (USA) Inc. and Mizuho Securities USA LLC are acting as joint book-running managers.
Enbridge Inc.	NYSE: ENB	Calgary, Alberta	$750 million	Issued $750 million of floating rate senior notes due 2022. The notes are fully and unconditionally guaranteed by Enbridge Energy Partners LP and Spectra Energy Partners LP. The notes will mature on Feb. 18, 2022, and will bear interest at a rate equal to the three-month LIBOR plus 50 basis points per annum, payable quarterly in arrears on Feb.18, May 18, Aug. 18 and Nov. 18 of each year, beginning on May 19, 2020, subject to the provisions set forth under "description of the notes and the guarantees—principal and interest." The notes will not be redeemable prior to their maturity, other than, in whole, at any time, if certain changes affecting Canadian withholding taxes occur.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Holly Energy Partners LP	NYSE: HEP	Dallas	$500 million	Announced it has finalized the terms of its previously announced offering of $500 million in aggregate principal amount of 5% senior notes due 2028 in a private placement under Rule 144A. The 2028 notes will be issued at a price equal to 100% of the principal amount thereof. The 2028 notes will be fully and unconditionally guaranteed on a senior unsecured basis by the Holly's existing wholly owned subsidiaries. The company intends to use the net proceeds from the offering, together with borrowings under its revolving credit agreement, to fund the previously announced conditional redemption of all its currently outstanding 6% senior notes due 2024 and pay related expenses.
Tallgrass Energy Partners LP	NYSE: TGE	Leawood, Kan.	$430 million	Priced with **Tallgrass Energy Finance Corp.** an offering of $430 million in aggregate principal amount of 6% senior unsecured notes due 2027 at an offering price equal to 98.591% at par. Tallgrass intends to use the net proceeds of the offering to repay outstanding borrowings under its existing senior secured revolving credit facility.
Parsley Energy Inc.	NSE: PE	Austin, Texas	$400 million	Announced with its wholly owned subsidiary, **Parsley Finance Corp.**, the pricing of its previously announced private offering of $400 million in aggregate principal amount of senior unsecured notes due 2028. The 2028 notes, which are priced at par, will mature on Feb. 15, 2028, and will pay interest at an annual rate of 4.125%. Parsley will not guarantee the 2028 notes. The company intends to use the net proceeds from the notes offering and borrowings under its revolving credit facility to redeem all of the its outstanding 6.25% senior unsecured notes due 2024 at a redemption price of 104.688% plus accrued and unpaid interest to the redemption date, pursuant to the terms of the indenture relating to the 2024 notes.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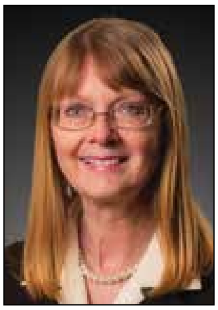

LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

By now you've read way too much about the effects of the first oil price war of the new decade—it's not going to be the last. Now that the yellow caution lights are flashing, just hit the reset button. I don't mean to be naive, but it does no good to run around with your hair on fire during an oil price shock with an unknown duration. Certainly this price rout should force every company to reset its 2020 plans, even if the price rebounds by the time you're reading this.

For 2020, stick to your core business but adjust your strategy. Keep running the numbers and analyzing the data. Continue to tweak everything to cut expenses. Hunker down and slow down.

In years past, we've seen that unexpected, disruptive price shocks do not last. The price and rig count always come back, although the timing is never clear.

This year, 2020, was never going to be that good anyway. Oil and gas prices were already wobbly; U.S. production growth was slowing down. If a $30 oil scenario holds, Lower 48 oil production will end the year more or less flat from where it started, according to Rystad Energy modeling. At press time, some producers already announced that they will lay down rigs.

Concurrently, Saudi Arabia was flooding global markets with additional oil we do not need and, what's more, offering customers much lower prices, in a bid to recoup lost market share. But the International Monetary Fund said Saudi Arabia needs $83 a barrel to balance its budget—not $30 or $40.

About a week before the OPEC-Russia battle erupted, EOG Resources Inc. CEO Bill Thomas spoke on his fourth-quarter 2019 conference call. He reiterated the company's strict standards, which should serve as a business model for all E&Ps. "Our premium well strategy dictates that a well isn't a well unless it earns at least 30% return at an oil price of $40. Requiring our hurdle rate of 30% for direct capital ensures that once full cost is applied, we earn a healthy double-digit all-in return."

The base decline rate on EOG's existing production is 32%, but it has 13 years of premium drilling inventory to offset that; the median rate of return on those locations is 58% at $40 oil, the company said.

Or if these metrics simply aren't possible, do what one guru said recently, "Don't hesitate; consolidate."

"There is only one good number [to pay attention to], and that's the oil price," declared Paul Sankey, Mizuho Securities managing director, addressing Hart Energy's Energy Capital Conference in Dallas—just two days before OPEC+ met in Vienna and all hell broke loose.

"We are at 3 MMbbl/d of oversupply in the market, so this year will be another unfortunate year, regardless of what OPEC does, and all the OPEC members are cheating," he said.

He did offer one ray of hope, however. "The next 10 years is still assuredly the decade of oil. It takes about 16 years to turn over the U.S. fleet, so if you buy only EVs now, it will take 16 years. The stock market will stabilize—where else can you put your money if you pull out: China? No. Japan? No."

In a research note on March 9, Sankey wrote, "With no price elasticity of oil demand right now because of coronavirus, price elasticity of supply is the only question. U.S. E&P is the fastest-cycle, most price-sensitive production globally, so that will be the pain point.

"*It is imperative that private oil companies cut capex to retrench to the point where debt is not rising*. On average to balance the market, we need 2 MMbbl/d to 3 MMbbl/d less U.S. oil supply, which implies at least 20% capex cuts."

Reuters calculated that $18.2 billion in corporate debt in the oil and gas sector is due to mature in the next three months, and most of the issuers were on credit watch for a downgrade.

A Wood Mackenzie analyst told Reuters, "… it will take at least six months for U.S. shale production to ease off even if capital spending is cut now. That means supply will remain elevated and the oil price could stay around $35." Yikes.

All of this should serve as an important reminder of two basic facts, wrote Sarah Ladislaw, senior vice president and director, and senior fellow of the Energy Security and Climate Change Program, at the Center for Strategic and International Studies in Washington, D.C.

"First, oil markets remain interconnected, and what happens in oil producing countries around the world still impacts the United States. So much for energy independence.

"Second, there may be an energy transition underway for which many oil-producing countries are trying to create a long-term strategy for future competitiveness. But today, oil still matters a great deal to their life and livelihood, and in the current energy arena at least two major producers have decided it's time to do battle."