Oil and Gas Investor

MARCH 2019

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Oil and Gas Investor

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From the Digital News Group

HARTENERGY.COM: We're In This Together

Meet the team that is building the most comprehensive energy news and information site in the industry. And, you're on it.

By Len Vermillion, *Group Managing Editor*

From the Associated Press to the *Houston Chronicle* to FOX and NBC news affiliates, Hart Energy's Digital News Group editors bring decades of collective journalism experience to the new HartEnergy.com, which launched Feb. 4. This core group of energy industry journalists will bring you the daily industry news and happenings, exclusive executive interviews and energy sector trends each and every day on a variety of platforms including articles, columns, videos, infographics and photography that you won't find anywhere else.

But they aren't alone. They are supported by a worldwide network of experienced energy correspondents in shale plays across the U.S. and in offshore regions such as the North Sea, Gulf of Mexico and South America. HartEnergy.com contributors also are stationed in the Middle East, Asia, North Africa and Australia. And this network is growing rapidly.

The Digital News Group editors and contributors bring a wealth of knowledge and connections to our coverage having extensively covered the oil and gas industry, both onshore and offshore, and they use that access to cover a vast array of topics including acquisitions and divestitures, exploration activity, midstream, production technology, policy and regulatory matters and renewable energy, to name a few.

Columnists come from a variety of sectors and many are well-known to industry insiders. We've recently welcomed veteran energy industry journalist Jeff Share, the former longtime editor of *Pipeline & Gas Journal*, into our collection of columnists.

We're upgrading our video capabilities to boot. So expect to hear directly from more top executives and analysts in the oil and gas and renewable energy sectors as we move forward.

Among the new offerings you'll find is a daily news and interview program in the mold of the popular television programs "Closing Bell" and "Squawk Box." The program airs Tuesday through Friday exclusively on HartEnergy.com and is hosted by veteran television news anchor Jessica Morales. It also regularly features exclusive interviews with newsmakers, energy executives, analysts and politicians discussing big picture topics within the industry. The program is available via podcast as well.

But that's just the tip of the iceberg. HartEnergy.com is your place to find everything you need to know, every day, about the energy industry. To make that happen we need your input. We're always on the look-out for new ideas for features and videos, and we want you to let us know what you want us to cover. My inbox is always open at lvermillion@hartenergy.com.

Our editors, too, welcome your comments, story pitches and questions. To make it easy, I've listed the contact information for the editors in charge of each of HartEnergy.com's vertical categories (see below).

Don't just tell us what you want to read and watch; let us know how you can contribute. Maybe you'd like to be part of our contributor network? Maybe you have something to say and would like to be part of our executive video interview series? Perhaps you can offer commentary on stories and trends?

HartEnergy.com is a site built to be our site—you, me and everyone else in the industry—and we want all of us to be part of making it the most comprehensive and useful site for energy professionals available. ■

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ABOUT THE COVER: This rig was drilling for Encino Acquisition Partners in Ohio's Utica play last fall. Photo by Ashley Unbehagen.

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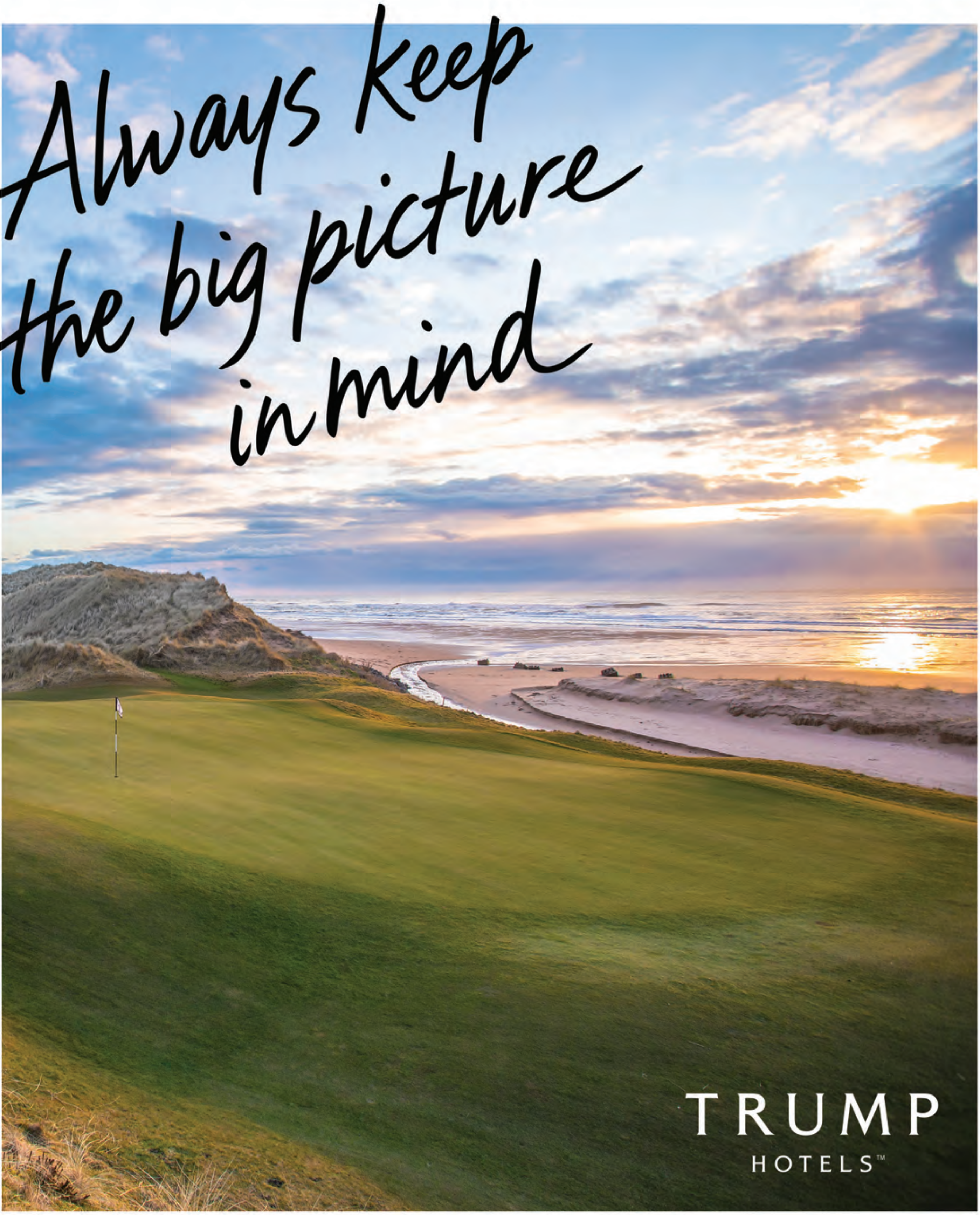
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VALUING ROCKS AND STOCKS

STEVE TOON,
EDITOR-IN-CHIEF

Why would Concho Resources Inc. pay $9.5 billion for RSP Permian Inc. last year? "Because we had a thicker pile of crappy rocks than the next guy," joked Mike Grimm, immediate past chairman of RSP Permian and president of Rising Star Petroleum. Turns out, these 95,000 acres of crappy rock were at the epicenter of the world's most-desired onshore oil play.

Grimm spoke to an audience at NAPE's Global Business Summit in February, and said he gets asked often about what made his little Permian start-up eight years prior such a consolidation sweetheart.

As Grimm tripped through memory lane offering his observations on the biggest deals of the past year, he lingered on the second largest, noting, "I'm a little familiar with that one."

With an early start in the movement to horizontal drilling in the Permian Basin, Grimm said RSP Permian focused on acreage in the deepest parts of both the Midland and Delaware basins, building blocky positions conducive for long laterals. The company subsequently went public and grew to be one of the leaders in the unconventional Permian.

But even though public, the urge to exit became imminent, he said. He recognized the company either had to grow through the drillbit or grow through a corporate acquisition, neither of which seemed desirable at the time.

"We were always private guys—get in, build it, get out and go on to the next deal," Grimm confessed. "We were eight years into a public company deal and, the fact of the matter is, hell, we were getting old and worn out. It was time to move on." The problem? Considering RSP Permian's sizeable valuation combined with a skittish public market, any deal would likely require either all or almost all stock to transact. So short of pocketing all cash, whose stock did they want to own?

"It boiled down to about five companies we were interested in whose currency we would like to own. And the larger that we grew, the smaller the universe of buyers." Concho, of course, won the bid with its all-stock offer and the hearts of RSP's shareholders.

But what happened next was both surprising and illustrative of a key theme playing out last year: Concho's stock plunged by 11% in the days following the announcement. Similar phenomena occurred on announcements of Diamondback Energy Inc. acquiring Energen Corp., Encana Corp. buying Newfield Exploration Co., and Denbury Resources Inc. purchasing Penn Virginia Corp.

"Investors were calling for consolidation, but they disliked most of the larger deals," he said. Now, "all companies are nervous about doing a large transaction because they're scared to death their stock is going to get creamed."

Thankfully, and particularly for RSP Permian stakeholders, Concho shares recovered within 90 days and continued to grow to a 52-week high into the fourth quarter. Alas, a turbulent fourth quarter trimmed some 30% to 40% off all oil and gas company valuations.

Grimm sees the shift in the E&P sector from a growth sector to a value sector as the most significant event from the past year, and takes it personally that the sector lagged. "E&Ps relative performance in the S&P in 2017 and 2018 were horrible," he said. "We got creamed by entities like Netflix, Amazon, Facebook and Google. I mean, Netflix? C'mon!"

He referenced a private speech by an unnamed New York investment fund manager the night before, who said, "'All shale companies are doomed unless they are working on net cash flow,'" the banker revealed. "'And if they're making a 10% return, 5% needs to go into company coffers, and the other 5% needs to go into dividends or share buybacks for the investors.' So major change."

As for acquisitions, "if the purchasing company of another company paid more than a 10% to 15% premium, they were going to penalize that company for paying too much. The Wall Street boys are pushing us for consolidation, but they're also penalizing the hell out of us.

"Right now, it's all about living within cash flow—regardless of size," he said. "I hope the capital markets will come back with higher hydrocarbon prices, and not penalize us for stretching on good, common sense projects."

That said, Grimm is bullish on supply and demand dynamics, laying out a long and detailed argument for why Saudi Arabian and Russian production is peaking, and why other non-OPEC conventional production will fall short of demand. But we'll dig into that another day. For now, "I feel pretty good about what we've got going on here in the U.S.," he said. "We've got the cheapest oil in the world."

And his opinion of foreign entities that would try to put shale producers out of business? "When we pull together, [they] underestimate American ingenuity. They can't outsmart us, they can't outwork us, nor will they whip us.

"The majority of global growth lies here in U.S. hands."

VOLATILITY CRUSHES CONFIDENCE

CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

Recent reports by Citi have warned of a period of commodity volatility, especially in crude markets. That has proven true, particularly in light of geopolitical events in Venezuela, Iran, Libya, China trade, etc. "Whatever OPEC's response, volatility is here to stay," said Citi.

Well, that's only part of the story, as volatility in energy equities has recently more than matched that of the commodity. After a one-way ride down in the fourth quarter of last year, the roller coaster ride in energy equities staged a rebound early this year—only to be derailed again by concerns over U.S.-China trade talks in early February.

Market sentiment in the energy sector seems, moreover, to act like the tail end of the proverbial whip.

As a general rule, investors have emphasized the need for E&Ps to spend within cash flow and prioritize returns, and E&Ps have made tangible progress in meeting these goals. Even smaller mid-cap E&Ps, typically fighting steeper production declines, are easing back on growth to offer early returns.

What's disheartening for investors is to see commodity swings being amplified into outsized moves in equity prices, even after E&Ps have moderated growth and improved capital efficiency.

An example is WPX Energy Inc., which cut its capital budget for 2019 by 23% at the mid-point in early February, while lowering prior production guidance by only 6%. With two less rigs, WPX projects it can still grow production by 5% to 10% from fourth-quarter 2018 to fourth-quarter 2019.

"We've worked hard over the past few years to position the company to spend within cash flow in a $50 world and still deliver nice growth," said CEO Rick Muncrief.

The move by WPX "sends a strong positive feedback loop to investors and E&Ps," said a Barclays report, noting WPX outperformed the XOP (S&P Oil & Gas Exploration & Production) ETF by 5% over the next couple of days. E&Ps' search for "sustainable free cash flow with growth continues to be the Holy Grail in E&P," commented Barclays in an earlier sector report.

As yet, however, strides by E&Ps toward such goals have often won only fleeting recognition in the market in absolute terms. More often, stock gains have been swept away in the next wave of volatility.

Although WPX's stock gained ground initially, it was down 4.7% over the week of the revised budget release, ending Feb. 8, and was off 8.3% from its close on announcement. For the same week, the XOP was down 7.6%, while West Texas Intermediate was down 4.6% and Brent slipped 1%.

One of the earlier E&Ps to report, Anadarko Petroleum Corp., saw its stock fall, much more so, as it released what several analysts described as "negative" or "disappointing" fourth-quarter results.

Cash flow per share came in below Street estimates by a mid- to high-teens percent, largely due to weaker than expected NGL prices and initial start-up issues with a gas processing plant. In addition, first-quarter output was guided 3% to 4% below Street expectations. However, earlier full-year 2019 capex and production guidance, based on $50-per-barrel oil, was kept unchanged.

Anadarko's stock fell 7.4% on the day of the call, and it was then swept down a further 7.9% during the next two days. From reporting to week end, the stock was down about 14.7%.

A 14.7% retracement for a quarterly miss?

Other factors were certainly at work, but some analysts focused on funding needed by Anadarko as it is about to make a final investment decision on its Mozambique LNG project this year. Net of its share of project financing (ca. two-thirds of the project), Anadarko has indicated annual capex of $400- to $500 million, funded largely from cash flow and, as needed, sales of Western Gas stock.

Although long in the making, the Mozambique LNG project apparently raised questions as to how free cash flow would be affected. Last year, Anadarko bought back $3.75 billion of its shares, lowered debt by $600 million and paid an annualized dividend of around $600 million, making it among the top E&Ps in terms of investor returns.

According to a Bernstein report, investors can expect a 5% cash-flow yield in 2019 through 2020. Thereafter, there will be "a pause of two years as Mozambique capital peaks, (and) then decades of low decline cash flow from a project with roughly $6/boe finding and development costs." A steady stream of free cash flow may be desirable, but "that's difficult when mixed with large lumpy LNG projects."

In today's volatile markets, that typifies, in Bernstein's words, "the battle of now vs. tomorrow."


Some horses are not
meant to be tamed

BUCK ROGERS VS. MICHAEL CORLEONE

DARREN BARBEE,
SENIOR EDITOR

The first full week of February brought a sense of just how off-kilter 2019 is setting out to be.

Activist investors tore into two oil and gas companies. Two others explored sales. The market remained skittish. The Green New Deal was introduced in Congress, more political than practical. And on Twitter, Elon Musk and Mars began flirting.

On Feb. 8, a Twitter account belonging to Mars (@4thFromOurStar) proclaimed it wanted "only Elon."

"I want you too baby," Musk replied. Musk has said he would consider moving to Mars.

Musk tweeted toward the end of the day, taking time away from his chores leading rocket-ship maker SpaceX, as well as Tesla and Neuralink, a company which is working on brain-machine interfaces.

"When are you coming over babe?" Mars asked.

A good question, Musk's investors may be thinking.

Here on Earth, firmly in the oil and gas ground, the chatter is less lively but the prospects just as distant. Sure, potential deals are stirring conversation—particularly with so few actual deals to distract the gossips.

But a strong current of disaffection is brewing. Activist investors have griped about bad management, poor returns and the use of private aircraft. They've called for action, including selling off companies and removing executives.

During a Feb. 5 conference call/public coup attempt, two of Rice Energy Inc.'s founders, Toby and Derek, held a conference call to explain why their $8.2-billion deal with EQT Corp. had flopped. Short version: They aren't in charge of EQT. Yet.

The Rices' ire is understandable given that about 80% of the $6.7-billion compensation Rice Energy received was tied to EQT's equity.

Toby Rice told investors and analysts that, "What we are specifically offering is a qualified management team, including myself as the new CEO, and depending on the need, up to 15 leaders from Rice Energy who know what the evolved state of an industry leading, efficient, technology-driven E&P company looks like."

He added, as casually as Michael Corleone might have, "This is not a personal attack on the current management team, but they simply do not possess the necessary experience or track record to navigate this path forward."

EQT is reportedly planning to buy stock and shore up for a fight back with the Rices.

Halcón Resources Corp. was similarly torched on Feb. 4. Halcón has built an impressive Permian Basin presence at generally low acquisition costs. But little of the company's other actions are sitting well with activist investor Fir Tree Capital Management LP. Fir Tree called for company to sell itself, cut excessive overhead costs and, somewhere along the way, replace the company's management team.

Fir Tree owns 7.2% of Halcón's stock, which has fallen by more than half since October. The company hasn't delivered on commitments to de-lever its balance sheet, cut expenses or sell off asset, wrote Evan Lederman and David Proman, managing directors and partners at Fir Tree.

"No tangible progress has been made," they wrote. The firm was particularly distressed by G&A costs of $40 million, which Fir Tree said are on par with much larger companies such as Centennial Resource Development Inc. and Jagged Peak Energy Inc. CEO Floyd Wilson's compensation and use of a private jet for travel as sparked rage, particularly given jet costs were $800,000.

Halcón did not respond to an *Investor* request for comment.

Other companies are rolling ahead with plans to sell off assets.

With QEP Resources Inc.'s $735-million Haynesville Shale divestiture closed, the company has reportedly engaged Evercore Inc. to explore a sale following a surprise takeover bid by activist investor Elliott Management Corp. in early January for $2 billion. QEP still has $1.7 billion Williston Basin sale to close.

And Permian underdog Abraxas Corp. said in late January it had hired Petrie Partners LLC to help identify options for its Bakken holdings, which loosely translates into "help the company sell it." Abraxas would become a tempting Delaware Basin target with a Bakken divestiture, particularly given its 56,934 net acres in the Delaware.

Musk's Twitter conversation with the Red Planet fell to sophomoric jokes, requests for "hot pics" of Mars and a probably inappropriate emoji.

It was weirdly entertaining. As astronauts in one film say, "No bucks, no Buck Rogers." With market values, oil prices and A&D activity suffering, the industry could use such diversions. There's always time later to take the cannoli.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
Energy Capital Conference	**March 4-5**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
OOGA Annual Meeting	March 6-8	Columbus, Ohio	Hilton Columbus at Easton	ooga.org
CERAWeek by IHS Markit	March 11-15	Houston	Hilton Americas	ceraweek.com
LOGA Annual Meeting	March 20-22	Lake Charles, La.	Golden Nugget Casino Resort	loga.la
TAEP Expo & Annual Meeting	April 2-3	Irving, Texas	Irving Convention Center	texasalliance.org
OGIS New York	April 8-10	New York	Sheraton Times Square	ipaa.org
PIOGA Spring Meeting	April 10	Pittsburgh	River Casino	pioga.org
DUG Permian Basin	**April 15-17**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
Offshore Technology Conference	May 6-9	Houston	NRG Park	2019.otcnet.org
DUG Rockies	**May 14-15**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
AAPG Annual Conv. & Exhibition	May 19-22	San Antonio	Henry B. Gonzalez Conv. Center	aapg.org
Midstream Texas	**June 5-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
CIPA Annual Meeting	June 6-9	Lake Tahoe, Calif.	TBA	cipa.org
IPAA Midyear Meeting	June 24-26	Colorado Springs, Colo.	The Broadmoor	ipaa.org
DUG EAST	**June 18-20**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Unconventional Resources Tech. Con.	July 22-24	Denver	Colorado Convention Center	urtec.org/2019
EnerCom The Oil & Gas Conference	Aug. 11-14	Denver	Westin Denver Downtown	theoilandgasconference.com
The Energy Summit	Aug. 20-22	Denver	Colorado Convention Center	theenergysummit.org
Summer NAPE	Aug. 21-22	Houston	George R. Brown Conv. Center	napeexpo.com
DUG Eagle Ford	**Sept. 24-26**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.com**
A&D Strategies and Opportunities	**Oct. 22-23**	**Dallas**	**The Omni Dallas**	**adstrategies.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Rockies	Quarterly	Denver	University Club	adamrockies.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.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
SPE GCS Business Development	Monthly	Houston	Four Seasons	spegcs.org

Email details of your event to Brandy Fidler, bfidler@hartenergy.com.

For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com.


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VACA MUERTA: POISED FOR LIFTOFF

STEPHEN G. BECK,
SENIOR DIRECTOR,
UPSTREAM

In 2018, oil production in Argentina reached nearly 500,000 barrels per day (bbl/d), up 2% from 2017 and halting a multiyear decline. Approximately 15% of the 2018 production was from unconventional sources.

So far, except for a couple of wells drilled in the San Jorge Basin in the D-129 shale formation, the majority of shale exploration and development has centered on the Neuquén Basin, specifically in the Vaca Muerta shale formation. Recent announcements from YPF, Petronas and Shell indicate moves toward full-scale development. Additional announcements from Chevron Corp. and YPF on investments totaling $800 million to drill 20 wells in the Vaca Muerta in 2019 further support the play's prospects for growth.

Longer term, Stratas Advisors estimates production could ramp to more than 600,000 barrels of oil equivalent per day (boe/d), up from 97,000 boe/d in 2017. Incentives to invest and develop the Vaca Muerta to support the "New Gas Plan" and an agreement with the Provincial Government for reduced labor costs underpin this growth outlook. Plans to reduce import tariffs on facilities for oil field exploration and production and efforts to contain and reduce costs provide additional tailwinds for operators. Total well counts are expected to climb to about 5,800 by 2030.

The Vaca Muerta shale formation is the primary hydrocarbon source rock in the Neuquén Basin in Argentina.

The play spans 7.4 million acres in the basin and was formed in a deepwater marine environment containing Type-II kerogen, mainly stratified black and dark grey shale, with lithographic lime-mudstone from the late Jurassic to early Cretaceous.

The formation is productive for gas and gas condensate in the deeper basin areas and oil around the shallower basin margins. The Vaca Muerta has average total organic carbon content of 5%, but it spikes to 12% in areas of the northern basin and ranges from 1% to 8% in areas of the south basin. Average vitrinite reflectance value (Ro) of the formation is 1.17%. Notably, the play is characterized with a range of thermal maturities, including immature areas near the margins of the oil window to less than 0.6% Ro to wet gas.

There is a small area of dry gas with 2% Ro in the basin center on the western edge. Numerous wells have been drilled to test the Vaca Muerta since 2009.

Well data indicates that the formation is anisotropic and highly overpressured throughout, with pressure gradients ranging from 0.67 to 0.97 psi per foot.

YPF is the largest producer in the play with about 110,000 boe/d. The company is projected to accelerate production during the coming years, reaching 365,000 boe/d by 2030. Total play level production at that time is estimated at 620,000 boe/d. During the next five years, YPF is targeting a 150% growth in unconventional oil and gas production with plans for more than 1,700 wells using an average of 18 operated rigs.

At present, roughly 14 major operators are involved in the Vaca Muerta. YPF controls 42% of the acreage; Gas y Petroleo, a state company of Neuquén, about 12%, and the remaining 46% of acreage is distributed among other companies, including Chevron, Equinor, Total, ExxonMobil Corp., Pan American Energy, Petronas, GrowMax Resources, Pampa Energia, Pluspetrol, Shell, Tecpetrol and Wintershall.

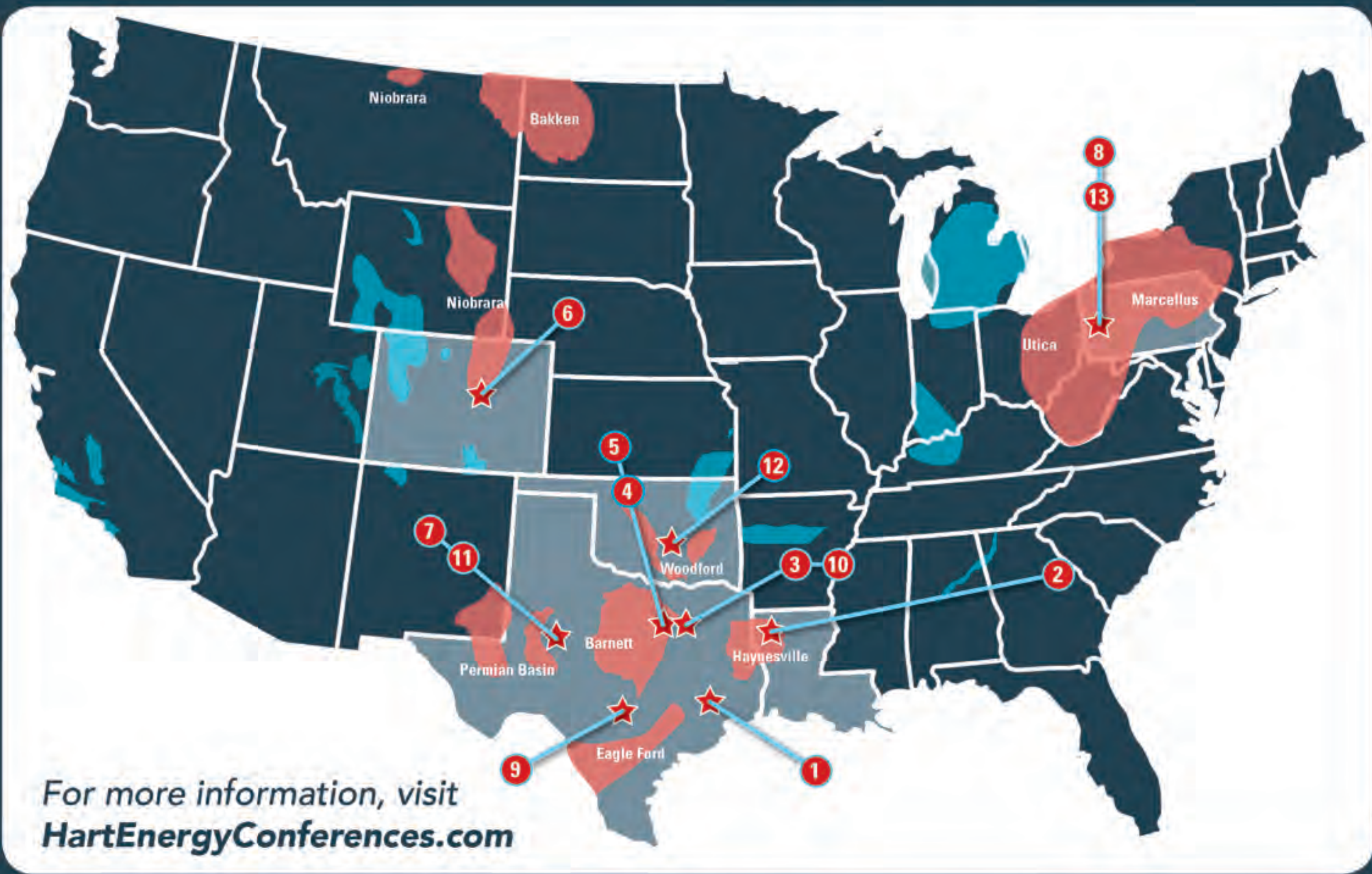
New technologies are reducing costs and improving results. Completed well costs (CWC) fell to US$8.2 million in mid-2017 from US$16.2 million in 2013 as new approaches to drilling and completion reduced drilling times and improved production. Current estimates indicate CWC is about US$7.5 million. For reference, drilling times improved by about 50%. Shifts in pad drilling have unleashed time savings in rigging up and rigging down, decreasing costs and increasing rig efficiencies. At the Loma Campana block, it now takes 20 to 22 days to reach the Vaca Muerta, a substantial improvement from just a few years ago.

Since 2015, YPF has collaborated with Schlumberger Ltd., applying a dynamic unconventional fracture model to optimize hydraulic fracture stimulation design. The optimized stimulation design is based on a hybrid treatment from inputs using four clusters per stage and a slickwater design using eight clusters per stage. This stimulation result shows higher flow rates than slickwater-only treatments.

With advanced technology and optimized fracture models, YPF is leading the charge to slash drilling and completion costs to about US$11/boe from US$29/boe in 2015. Development costs are expected to drop to $8/boe by 2023. Opex fell to US$7/boe in 2017 from $16/boe in 2015. Future operating costs are estimated to reach US$6/boe by 2023.

Well productivity has improved continuously in the past three years. Moreover, EUR increased 35% from 660,000 boe to 900,000 boe in 2018.

2019 Hart Energy Events



For more information, visit
HartEnergyConferences.com

1. **25 Influential Women in Energy** — **Feb. 12**, Houston, TX
2. **Conference & Exhibition DUG Haynesville** — **Feb. 19 – 20**, Shreveport, LA
3. **energycapital Conference** — **March 5**, Dallas, TX
4. **DUG Sand and Water** — **April 15**, Fort Worth, TX
5. **Conference & Exhibition DUG Permian Basin** — **April 15 – 17**, Fort Worth, TX
6. **Conference & Exhibition DUG Rockies** — **May 14 – 15**, Denver, CO
7. **Conference & Exhibition Midstream Texas** — **June 5 – 6**, Midland, TX
8. **Conference & Exhibition DUG East** — **June 18 – 20**, Pittsburgh, PA
9. **Conference & Exhibition DUG Eagle Ford** — **Sept. 24 – 26**, San Antonio, TX
10. **A&D Strategies and Opportunities Conference & Workshop** — **Oct. 22 – 23**, Dallas, TX
11. **Executive Oil Conference & Exhibition** — **Nov. 4 – 6**, Midland, TX
12. **Conference & Exhibition DUG Midcontinent** — **Nov. 19 – 21**, Oklahoma City, OK
13. NEW DATES **Marcellus-Utica Midstream Conference & Exhibition** — **Dec. 3 – 5**, Pittsburgh, PA

HARTENERGY
Conferences

NewsWell

E&P tightrope: preserving free cash flow

Free cash flow continues to absorb the interest of many E&P investors, particularly as commodity prices have come off the higher levels seen at certain points this past year. Though, if the drilling pace must accommodate slower growth in demand, what E&P is likely to be able to generate free cash flow in the New Year under a "maintenance capex?"

A maintenance capex, as defined by analysts with Seaport Global Securities LLC, is a budget that "keeps fourth-quarter 2018 production levels flat throughout 2019."

The Seaport analysts, led by Mike Kelly, summed up the performance of E&Ps in the firm's universe in a recent report using its fiscal-year 2019 price deck of $55 oil and $3.18 natural gas, and leaving out hedging gains to further level the playing field. To lend context to the analysis, the Seaport team looked back at a similar report the firm generated in 2015—also an "ugly period for E&P investing."

In 2015, the average E&P was expected to fall far short—43% below—the level needed to fund maintenance capex (unhedged). Today, the outlook is far rosier for many E&Ps, however.

"We expect that the average company will generate significant positive free cash flow—we see cash flow from operations that are 24% higher than maintenance capex," the analysts said.

Efficiency and productivity gains, as wells as Saudi Arabia's production cuts, have combined to set oil and gas producers up for health in a $50-plus West Texas Intermediate (WTI) world, according to the Seaport Global report.

In the Seaport universe, those having the highest free cash flow as a percentage of maintenance capex include Cabot Oil & Gas Corp., Northern Oil & Gas Inc., Goodrich Petroleum Corp., Marathon Oil Corp., Lonestar Resources Inc., Anadarko Petroleum Corp., Abraxas Petroleum Corp., Concho Resources Inc., Continental Resources Inc. and Gulfport Energy Corp.

By the firm's other measure—top stocks on maintenance free cash flow yield on enterprise value, the companies include Goodrich, Abraxas, Northern Oil & Gas, Lonestar, Gulfport, Marathon, Cabot, Anadarko, HighPoint Resources Corp. and Whiting Petroleum Corp. Seaport Global notes that there are other companies that could join these groups but likely won't due to "more aggressive development programs."

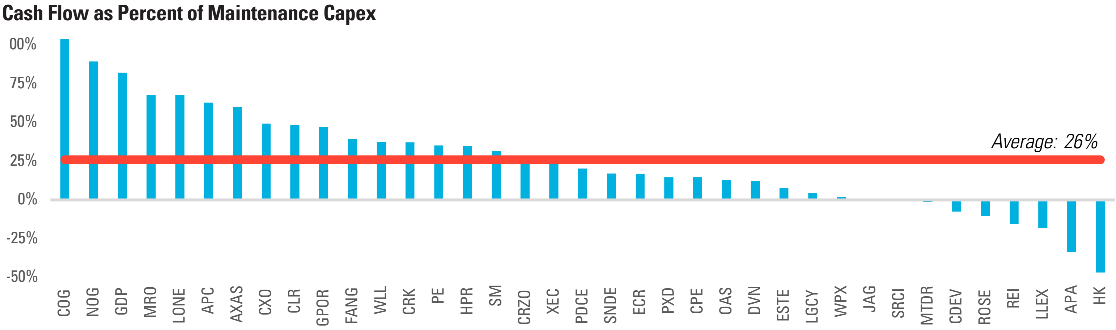
This teeter-totter of achieving a balance of spending that allows free cash flow is top of mind with investors. A recent analyst note from Tudor, Pickering, Holt & Co. (TPH) said that demand concerns aside, "the rampant U.S. supply growth in 2018—TPH estimates oil up 1.75 million barrels per day (MMbbl/d) exit to exit, total liquids up 2.25 MMbbl/d—needs to be reined in under most reasonable scenarios."

For investors to structurally invest in the industry, the TPH analysts said U.S. oil production growth will likely need to be closer to 1 MMbbl/d. "In our view, this means budgeting between $50 to $55 WTI over the near, medium, and long term while flexing down activity ... and capping activity levels above $55 with excess cash flow siphoned off towards shareholder returns."

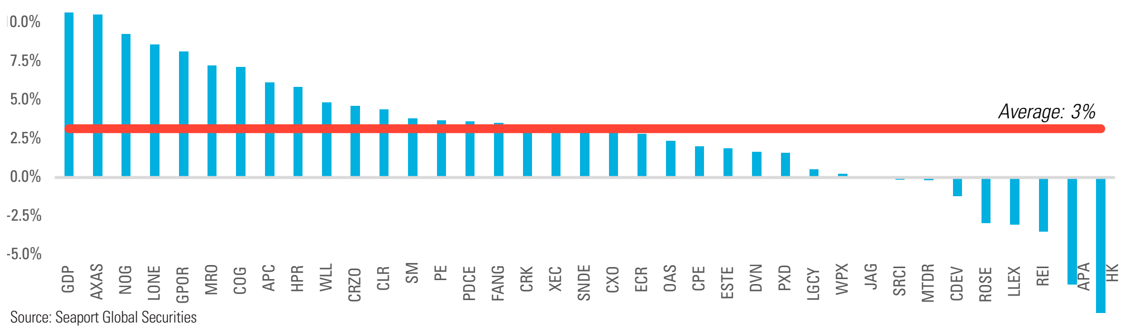
—Susan Klann

Ranking Free Cash Flow Yield

Cash Flow as Percent of Maintenance Capex



Cash Flow Yield By EV



Source: Seaport Global Securities

Permian operators look to standardize techniques, measures

Permian Basin drillers have begun to standardize drilling and completion programs that maximize production while keeping costs reasonable, according to the CEO of Dallas-based Haas Engineering, a reserve evaluation firm.

"We're not seeing as much experimentation now," Thad Toups told attendees at a Petroleum Engineer's Club of Dallas luncheon in January. While "proppant is a driver in recovery," Toups added as one example, "3,000 pounds [per foot] in my eyes isn't any better than 2,500 pounds. Unless there is some sort of price change, I think we're going to be dealing with 2,500 pounds" as something of a Permian standard.

Likewise, programs seem to be moving toward consensus on lateral length, well spacing and other factors, he added, as experimentation during a decade of drilling the Permian Basin's multiple unconventional shales has found diminishing returns with some combinations. Engineers have tried out various ideas to try and generate the highest internal rate of return (IRR) per well for the lowest drilling and completion costs.

Well variables can be enormous, he noted, and that makes cost and reserve projections difficult. Studying the results of completed wells can vary further as operators put wells on with open chokes, or choked back by various amounts. Further production and financial numbers can vary according to differing gas-oil ratios and prices for crude, NGL or gas, as well as when a completed well gets turned on.

"Delaying sales by six months can lower IRR by 10%," Toups added.

He noted ethane prices, in particular, swung wildly last year, from 25 cents/gallon as the year began to double that at 50 cents in September. "Then Mont Belvieu closed" to additional production and prices dropped.

Likewise, growing associated gas production from the Delaware Basin, a Permian sub-basin, hit limited capacity at the Waha Hub and gas prices fell to zero.

The shale plays are viewed as homogenous but they can still vary widely, he said. The Delaware, for example, varies from "oil in the east to gas in the west and everything in between." Pore spacing also varies.

Toups described an extensive study Haas Engineering did of EOG Resources Inc. wells in the Delaware Basin to gain a feel for consistency, based on what one major operator has learned works best. "That makes it easier to see what wells will be like" given more predictable plans developed by one operator.

Looking at the multitude of variables, Toups said it's easy to understand why operators are beginning to move toward benchmarking a program by return on revenue rather than proved reserves.

For 2019, Toups predicted the decline in drilling and completion costs that occurred last year will continue. He noted the Permian Basin may have 5,000 drilled but uncompleted wells "and we won't see that number dwindle soon" as producers await new pipeline capacity out of the region.

—Paul Hart

More unconventional potential in Simpson, Anadarko Basin

The Scoop and Stack plays of Oklahoma's Anadarko Basin may be the area's claim to fame lately, but the unconventional potential of the long-producing conventional Simpson Group could enter the spotlight next.

IHS Markit called the Simpson shale formation "one of the biggest yet-to-be-developed shale plays in the United States." The sentiment was shared as part of a report in which the London-based global information provider raised unconventional reserves estimates for the basin to 16 billion barrels (Bbbl) of oil and more than 200 trillion cubic feet (Tcf) of gas.

The higher estimate—which is more than pre-shale boom assessment of 495 MMbbl of oil, 27.5 Tcf of gas and 410 MMbbl of NGL from the U.S. Geological Survey—was the result of an 18-month-long IHS project that modeled and interpreted the Anadarko Basin's geologic characteristics and its 41 stacked plays. The firm analyzed historical well and production data from more than 320,000 wells and proprietary software that IHS said allows analysts to use formation tops data to identify formations of completion intervals on wells.

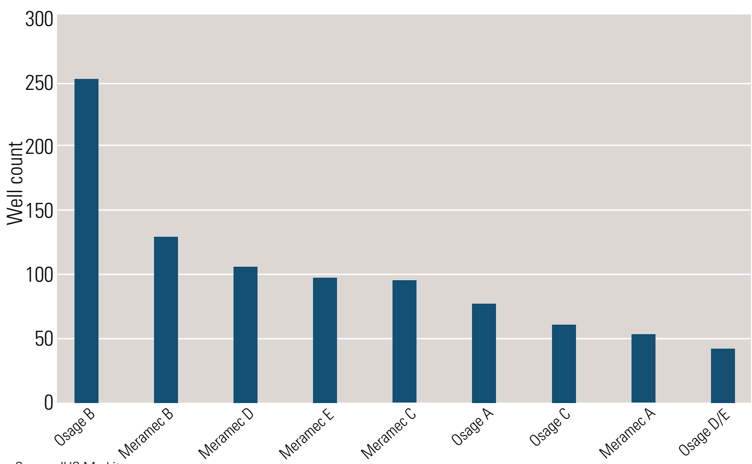
John Roberts, executive director of global subsurface operations for IHS Markit, co-authored the Anadarko Basin research with Prithiraj Chungkham, director of unconventional resources at IHS Markit. Roberts said the view of the basin can be changed with more granularity and accuracy about producing formations. He compared it to having a "more powerful microscope."

The Simpson shale is an example.

"We always like to have a couple of diamonds in the rough in here and we certainly did with the Simpson," Roberts told Hart Energy. "We see it as the biggest potential in the whole Stack play."

The Simpson, which is also present in the Permian Basin but is considered less significant because

Producing Stack Reservoirs



Source: IHS Markit

of nonproductivity as horizontal drilling targets, is believed to be a much more prolific generator of hydrocarbons, Roberts said. IHS puts the remaining technically recoverable resources for the Simpson Shale at an estimated 3.5 Bbbl of oil and 75 Tcf of gas.

Unlike the Permian Basin, which has 11 oil source shales, the Anadarko Basin has only four—including the Simpson, which Roberts said is the biggest followed by the Woodford, which has about 3 Bbbl or so of technically recoverable oil.

Located at depths between 7,500 feet and 11,000 feet with a gross thickness between 250 feet and 1,000 feet, the Stack play targets the Meramec and underlying Osage formations of the middle to lower Mississippian, Roberts said. The firm's research also shows that individual bench subdivisions can be productive targets as thin as 30 feet in the Meramec and as thick as at least 400 feet in parts of the Osage unit.

"Both petrophysical and reservoir properties vary greatly across the play and from bench to bench," Roberts added.

However, not much is known about the unconventional reservoir characteristics of the Simpson as more core and rock petrophysical data is needed. The underlying Simpson is older with Ordovician-age rock that is several hundred million years old.

About 190 MMbbl of oil and 2.5 Tcf of gas are produced in the Anadarko Basin annually—80% of which is unconventional, according to IHS.

The basin continues to attract oil and gas players for its economics and potential. Only about 20% of the basin's Stack sweet-spot locations are drilled or developed, Roberts said, adding in a news release that IHS envisions 4,000 to 5,000 more horizontal wells drilled.

Oil and gas players have taken notice. Calgary, Alberta-based Encana Corp., for example, is adding acreage in the oil-rich Stack and Scoop shale plays with its $5.5 billion merger with Newfield Exploration Co.

The Anadarko is attractive for several reasons. "First, the Anadarko Basin's costs to acquire acreage have yet to approach the exorbitant levels seen in her Permian Basin cousin to the south. Second, the plays are still in the boundary limit phase of development; so much is still unknown regarding play extents," Roberts said. "Lastly, the Stack breakeven prices have now improved to the point where they are tracking with the Permian's Midland Basin, lower Spraberry and Wolfcamp A as well as the Delaware Basin second and third Bone Spring sands and Wolfcamp A," in the mid-$30-per-barrel range.

But the basin is still considered complex, given its depth, high gas cuts and faults.

"There are places where you'll see an entire field drilled on pretty decent spacing and literally every well in that little field is in a different fault block," Roberts said. "That increases the cost because with some of these plays, you have to have 3-D seismic to accurately know where to land your horizontal well."

Yet the basin's 41 plays mean there are a lot of opportunities, he added.

"That just increases your odds when you roll the dice," Roberts said.

—Velda Addison

Select producers poised to shine amidst shifting industry variables

As the E&P sector set up for fourth-quarter results and 2019 plans recently, analysts looked for oil and gas shale producers in the U.S. to organize around some common themes.

A recent analyst report by the Williams Capital Group LP predicts these themes could include: lower 2019 budgets reactive to strip price shifts; production growth within cash flow possibly resulting in flat or lower production growth; infill drilling and spacing outcomes; and resets to lower commodity price realities and expectations.

"We believe current stock prices and market sentiment already reflect these lower expectations even though they are not reflected in the current stale consensus estimates," noted Gabriele Sorbara, senior equity analyst with The Williams Capital Group, in the January report.

Based on expectations for fourth-quarter results and recent guidance, Sorbara's top picks in the E&P space are Diamondback Energy Inc., Pioneer Natural Resources Co., WPX Energy Inc., Concho Resources Inc., Callon Petroleum Co. and SM Energy Inc.

In particular, Diamondback distinguished itself this past year, he said, because of its $9.2-billion acquisition of Energen Corp. The merger between the Permian Basin shale producers, which closed in November, is expected to contribute 38,500 barrels of oil equivalent per day (boe/d) for a total 177,600 boe/d for the fourth quarter, above "the stale consensus of 164,600 boe/d," Sorbara said.

Diamondback's total 2019 capex is modeled at between $2.7 billion and $3.1 billion for production of 275,000 to 290,000 boe/d with 18 to 22 rigs at work. The company expects to have eight completion crews working to complete 280 to 320 gross wells.

Sorbara highlighted Diamondback's cost savings from acquisition synergies and drilling and completion enhancements that could pare as much as $200 per lateral foot from costs. Additionally, the analyst likes the premium valuation potential in the E&P's desired IPO of its Rattler Midstream Partners LP affiliate and upside from dropdowns to Viper Energy Partners LP plus future asset sales.

On the other hand, fellow Permian E&P, Pioneer Natural Resources Co., gained a positive ranking from having "the strongest balance sheet in the sector," which Sorbara said can sustain the company through weaker oil prices. The company's stock is also supported by a significant, $2-billion buyback program.

Sorbara said Pioneer has indicated between $3.8 billion and $3.9 billion for a baseline capex program for this year, which could result in a $300-million outspend. The analyst believes the company's Midland Basin production could ratchet up by 20% this year.

With core positions in the Permian and Williston basins, WPX Energy was expected to announce a production beat and to align its 2019 outlook with internally generated cash flow, according to Sorbara.

For 2019, WPX management is anticipating budgeting at $50 WTI, which could prompt it to drop several rigs from its prior 10-rig plan. Significant savings could flow from completion design shifts.

The Williams Capital Group, which recently launched coverage of WPX, also expects the company to keep proceeds from the sale of midstream equity interests on the books, with a capex budget for this year of $1.16 billion and 21.8% growth in production, Sorbara said.

Concho Resources, which operates in the Permian Basin and also made its own blockbuster acquisition last year, anticipated beating production when it announced fourth-quarter results in late February. Sorbara called the company an ongoing top pick because of Concho's expected "continued execution, large free-cash-flow potential in 2020-plus and further differentiation from peers."

Likewise, Callon Petroleum was forecast to exceed production estimates for the fourth quarter of 2018, and Sorbara noted the independent's management ability to execute. The company's operations are focused across more than 83,000 net acres in the Midland and Delaware sub-basins of the Permian.

Modeling a fourth-quarter production beat of 3.9% for SM Energy, Sorbara lauded the company's "Midland Basin execution, discounted valuation and manageable 2019 outspend" ($180.3 million expected at strip). SM Energy's capex is modeled at $1.2 billion for this year for a production boost of 27.6%, he said.

As for commodities, Sorbara sees a relatively stable outlook for pricing. He said Williams is maintaining its price assumption for WTI crude futures at $56/bbl in 2019 and $60/bbl in 2020. The long-term outlook for crude is $65/bbl. For natural gas, the firm's full-year assumption is $2.98—down from $3.05 per thousand cubic feet—dropping further in 2020 to $2.85 and $2.75 for 2021.

—*Susan Klann*

EIA: Net export status coming sooner than thought

The U.S. will leap into the ranks of world energy net exporters in 2020—two years earlier than projected last year—the U.S. Energy Information Administration (EIA) said Jan. 24 in its "Annual Energy Outlook 2019."

Significant production growth in crude oil, natural gas and NGL, combined with slow growth in consumption, has changed the import/export paradigm that's been in place since 1953.

"The headline is that the United States produces approximately 10.9 million barrels per day [MMbbl/d] of crude oil in 2018, passing the 10 million barrel mark for the first time and surpassing the 1970 record of 9.6 MMbbl/d," said EIA administrator Linda Capuano.

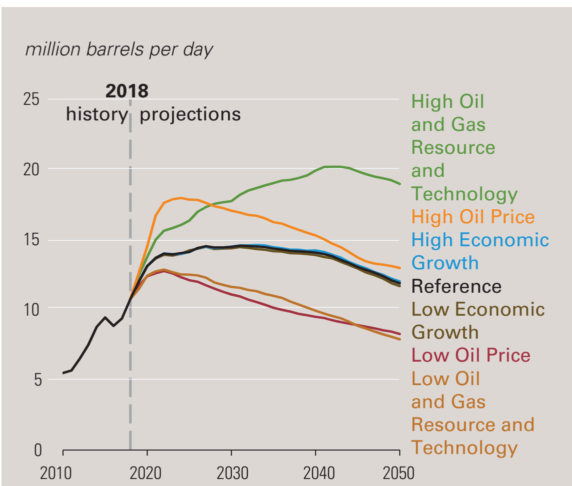
But the outlook's reference case goes further, showing peak U.S. crude production of about 14 MMbbl/d in 2027 and remaining at that level through 2040 before showing a relatively slow decline to 2050. The reference case assumes 1.9% compound annual growth in U.S. GDP and a crude oil price of $108/bbl in 2050. The 2018 Outlook projected net exporter status in 2022 and the 2017 Outlook projected that status in 2026.

Natural gas production is coming off a record year of 30 Tcf, with exports averaging 3.3 billion cubic feet per day (Bcf/d) and outpacing imports. The EIA expects gas prices to remain low in the study's time frame to 2050 as solar and wind power gain share in the relatively flat U.S. electricity market.

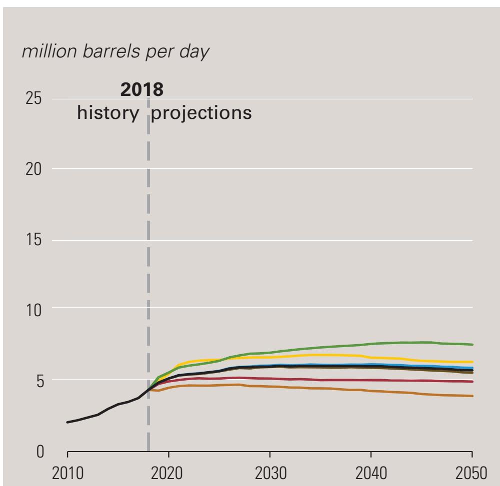
NGL production benefits from the growth in crude oil output and rises to 6 MMbbl/d in 2029 in the reference case, more than double 2018's output. In the high oil price case, NGL and crude production decline when cost increases kick in following the spike in drilling and resources become less easily accessible.

Much of the growth in natural gas production is actually a function of LNG exports, the EIA said. The global price of LNG is linked to oil, even though that link is fading over time. When the price of oil is high, the U.S. is very competitive on the global market because the higher price allows shippers to cover the cost of transporting crude and maintain margins. Increased drilling for oil results in increased production of associated natural gas.

U.S. Crude Oil Production Scenarios



U.S. Natural Gas Plant Liquids Production



U.S. Energy Information Administration

When oil prices are low, U.S. LNG loses its competitive edge.

"Essentially, global market trends are more important than domestic fuel replacement," said Katie Dyl, the EIA's natural gas markets expert.

While EIA restricts itself to projections and stays away from predictions or comments, panelists at a discussion following the announcement at the Bipartisan Policy Center in Washington, D.C., were not as reticent.

"I have no problem whatsoever with gas trending the way it does," said Colette Honorable, a former Federal Energy Regulatory Commission member. "Given the very strong onslaught of renewables that we will see, we need that gas so that's very encouraging to me."

Arshad Mansoor, senior vice president for research and development at the Electric Power Research Institute, lauded the EIA's projections but noted that the study was not intended to include disruptive factors such as a rapid ramp-up of electric vehicles (EVs). Battery costs for EVs were about $800 per kilowatt hour (kWh) several years ago but are now down to the range of $100 to $150. There is every reason to think engineering innovation will lead to $50 a kilowatt hour, he said, leading to a future where energy efficiency is a driver of GDP growth.

"We will be an energy exporter but we do that with a lower cost to customers," Mansoor said. "It seems too good to be true, but that's what electrification provides to customers."

Other takeaways from the study:

- Natural gas and NGL have the highest production growth among fossil fuels, with NGL accounting for almost one-third of liquids production during the time frame of the study;
- Natural gas and intermittent renewables will increase their share of power generation as less-economic coal and nuclear plants retire;
- Flat energy consumption will be the result of increasing energy efficiency;
- The U.S. will continue to import and export energy throughout the time period to 2050 and will return to its role as a net energy importer near the end of the period;
- The U.S. will continue to be a net exporter of coal but exports will not increase because of competition from other global suppliers.

—Joseph Markman

Oil and gas industry kicks IoT into gear

The Internet of Things (IoT) has been a quiet, but solid, storm sourcing new value across the industry for giants like Shell and Spain's Repsol.

That is what case studies conducted by Florida-based financial services firm Raymond James showed in its industry brief on IoT released in January.

In the report "Energy Stat: When Thinking About Barrels, Don't Overlook Bytes—The Internet of Things Is Making Waves in the Energy Sector," analysts found that, surprisingly, the energy sector accounts for 10% of worldwide IoT deployments.

"I think because most of us don't think about information technology through the same lens as the energy industry the intersection of IT and energy is something that tends to be below the radar from the standpoint of most investors," Pavel Molchanov, senior vice president and equity research analyst at Raymond James, said.

Particularly, oil and gas leaders have seen the engine run smoother and the technological path appear brighter through the commencement of IoT. From hyper-efficient data collection in the upstream sector to predictive monitoring via sensors in midstream and refining—IoT has created a new value chain.

Best described by Deloitte Insights, IoT is a specific way of stitching together a suite of new and existing technologies to turn almost any object into a source of information.

For instance, in Raymond James' first case study, Shell saw an exponential return—10 times to be exact—on its investment in random phase multiple access (RPMA) monitoring technology. The RPMA technology has allowed Shell to weather rough climate conditions at its wellheads and flow stations through alerts from its automated sensors.

According to the report, the technology awarded Shell an outsized return of $1 million in the first year of deployment with the initial investment being $87,000 of Shell's annual $1 billion in spending on research and development.

"If [management of energy companies] only thinks about the upfront costs, that would be a harmful hurdle to making that investment," Molchanov said. "The costs are upfront, but the benefits show up over time, so management needs to think about those long-term economic benefits."

Another compelling case study from the report that concerns the midstream space is DCP Midstream's DCP 2.0 initiative. The IoT program essentially gathers and links operational data like SCADA, key performance indicators from sensors and theoretical margins from the company's processing plants to the system.

After breaking even in 2017 from an initial $20-million investment when the tech was first deployed, the report said DCP saw $40 million in margin enhancement from the $20-million-partnered investment in 2018. From this success, Raymond James' analysts predict DCP will uncover $35 million a year of incremental EBITDA.

While including IoT can source new revenue for a company, analysts warn there is protocol to follow in order to reap the benefits.

"The way to [incorporate IT] is by deploying it on a limited scale as a pilot project at first and if the small-scale deployment proves to be successful in the sense of increasing revenue, reducing costs or making operations more efficient, then what companies can do is scale up more broadly," Molchanov said.

In Deloitte Insights' "Transforming oil and gas strategies with the Internet of Things" report, analysts said investing in the applications is just one aspect of IoT's future in the industry. They added that IoT applications need to be linked with business priorities to extend their reach because just deploying IoT won't create economic value.

"By reinforcing the importance of information for all aspects of the business and elevating information to the boardroom agenda, a company can fundamentally change how it does business rather than just optimizing what it has always done," Deloitte analysts wrote in the report.

Both groups of analysts go on to insist that the survival of IoT catalyzes in the boardroom. For IoT to thrive long term, both analytics show that there has to be prioritization and support from higher level executives.

Only after that will companies gain insight into previously invisible aspects of operations where they can integrate IoT, thus driving monetization.

"When oil prices are under pressure and energy companies have to learn to be more efficient, one of the ways in which they can manifest this greater efficiency is by learning to use IoT in more comprehensive ways therefore becoming more efficient than the process," Molchanov said.

—Mary Holcomb

Gulf Coast proximity keeps the Haynesville Shale play attractive

The Haynesville Shale's location is helping keep interest in the play high. Stretching across East Texas and North Louisiana, the primarily dry-gas play offers players shorter access to Gulf Coast ports. The rise of U.S. LNG and gas exports has made the Haynesville attractive with its proximity to hubs in South Louisiana and Texas, according to Drillinginfo Inc.

In the decade or so since the opening of the Haynesville Shale play by Chesapeake Energy Corp., the region's fortunes have peaked, troughed and are now ascending again.

Gas production for the fourth quarter of 2018 was forecast to hit about 7.8 Bcf/d according to Drillinginfo, up from about 6 Bcf/d in the fourth quarter of 2016. Production for year-end 2019 is forecast at about 8 Bcf/d.

In an exclusive report provided to Hart Energy, Drillinginfo noted that more than 7,000 horizontal wells had been spudded in the Haynesville Shale during the past decade.

Spudding activity declined from 2010 to 2016 but has rebounded in recent years. Wells coming online in 2017 and 2018 are reaching 24-month cumulative values that were higher than EURs for wells completed before 2016, according to the market analysis firm.

Drastic improvements in well performance have helped grow production since the start of 2017. Renewed interest and improved designs in completions in 2016 are cited in the report as having brought about the step change in well performance and consistent growth. Proppant intensity has greatly increased in the Cotton Valley Sands and Haynesville and Bossier shales, the report noted, with lateral lengths reaching about 1.5 miles long.

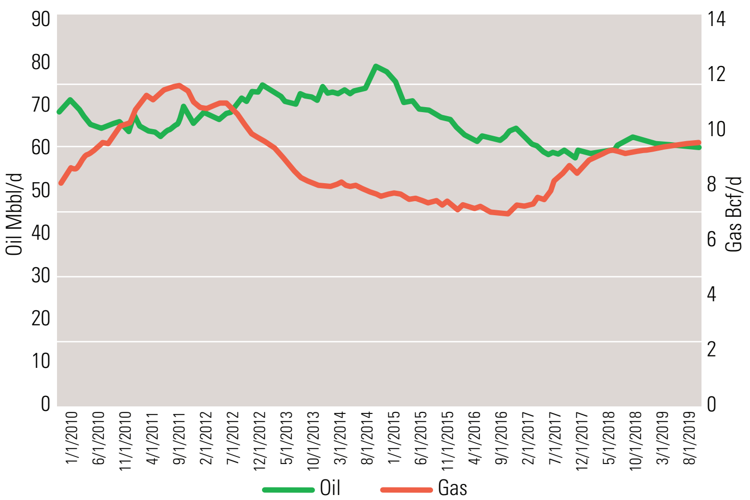
Operators in the region have time to continue making improvements in well performance as the proposed Haynesville Global Access Pipeline (HGAP) is set for in-service beginning in 2023.

"HGAP will connect the Haynesville Shale with growing markets in Southwest Louisiana, where natural gas demand is expected to triple, reaching approximately 12 Bcf/d by 2025," said Tellurian Inc. president and CEO Meg Gentle in a press release. "HGAP will improve the connection between North and Southwest Louisiana, debottlenecking existing pipeline routes and providing shippers access to expanding markets."

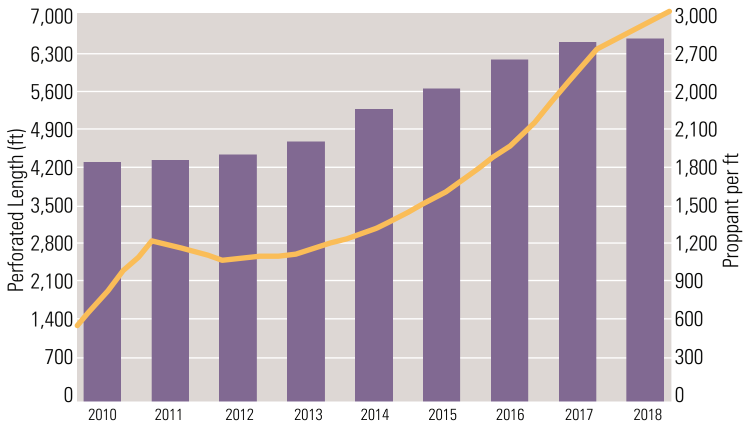
News of the construction, ownership and operatorship of the $1.4-billion, 42-inch diameter pipeline was announced by HGAP LLC, a subsidiary of Tellurian, in early 2018. The pipeline will stretch about 200 miles from northern Louisiana south toward Gillis, La., and will have a delivery capacity of about 3.7 Bcf/d of natural gas from the Haynesville/Bossier shale area, according to HGAP.

—Jennifer Presley

Haynesville Play Production



Haynesville Completion Practices Over Time*



* Includes Haynesville and Bossier shales and Cotton Valley Sands.
Source: Drillinginfo Inc.

Continued stability forecast for oil, gas M&A

After several years of remaining on near life-support, the oil and gas M&A market slowly began to show signs of increased recovery in 2018 with oil prices finally trending higher though some volatility crept back toward the end of the year.

The Permian Basin remained king for M&A activity and led the way with consolidation and forcing noncore asset sales.

Concho Resources Inc. kicked off the year with its acquisition of smaller Permian rival, RSP Permian. Diamondback Energy Corp. was soon to follow with the Energen Corp. merger as well as its purchase of Ajax Resources, both building out Diamondback's position in the prolific basin.

However, Michael Darden, partner of Gibson, Dunn & Crutcher and chair of the firm's oil and gas practice group, noted other basins were active last year as well.

The Eagle Ford, for example, remained lively, "probably more so than expected with the Chesapeake Energy/WildHorse transaction," Darden said during a recent presentation, as well as Denbury Resources Inc.'s proposed deal for Penn Virginia Corp.

The Scoop/Stack also percolated through Encana Corp.'s planned takeout of Newfield Exploration Co. The Appalachian Basin saw the mergers of Penn-Energy Resources LLC and Rex Energy, plus the pending merger of Eclipse Resources Corp. and Blue Mountain Resources Inc.

The surprise entrant into the sweepstakes, though, was the Gulf of Mexico, Darden said, which saw not one but four mergers last year.

"All-in-all, 2018 was an active year for consolidation," Darden said.

But what is in store for the state of oil and gas M&A as we begin 2019? Attorneys Justin Stolte and Darden both worked to answer that question during Gibson Dunn's 50-minute webinar, "The Current (and Future) State of Oil and Gas M&A," in January.

While neither made promises, both men predicted stability for the industry despite a rather volatile oil and gas market and during a time when OPEC and its members have agreed to cut back production in hopes of stopping a freefall on prices. There are also other variables to consider such as the continued U.S. sanctions on Iran and now Venezuela.

"There is going to be volatility but it's going to be volatility within our range now of $45 to $65 per barrel oil price on the oil side, and then hovering around $3 per Mcf on the natural gas side," said Stolte, who is a partner at Gibson Dunn's Houston office and member of the firm's M&A and energy and infrastructure practice groups. "What's going to be really interesting to see is whether or not the sanctions on Iran are continued."

The U.S. renewed sanctions

on Iran last year with hopes of bringing Iranian oil exports to zero. However, the Trump administration also granted exemptions to certain customers temporarily allowing them to keep buying crude from the Islamic Republic, which are set to expire in the coming months.

"If they do expire and they are not extended, then you could have a bunch of Iranian oil coming off the market and, at the same time, have OPEC curtailments coming into effect, which could serve as a tailwind to oil prices," Stolte said.

But he warned a headwind could be coming, as well. The global economy is slowing, plus there is uncertainty in Washington D.C. with continued tariffs on China. Those issues could adversely affect the oil and gas industry, making investors hesitant while slowing down deals for M&A in booming basins such as the Permian and Eagle Ford.

"Those types of things create uncertainty, which leads to volatile price environments," Stolte said.

Though, he pointed out that the cure for low prices is low prices.

"Once things hit a certain level you will start to see activity in the Permian, Eagle Ford and other unconventional basins decelerate," he said. "And if prices get too high, you will see production come along quickly. There are still a number of drilled but uncompleted wells in the U.S. that can quickly come online in the event that prices justify them coming online."

While uncertainty does loom, the potential for positives seem to outweigh the potential for another setback.

When looking at what will drive M&A activity in 2019, Stolte said the continued lack of public capital and continued pressure on public companies to perform will force smaller midstream and upstream companies to be absorbed by bigger, more efficient companies with cash flow.

"I think that a lot of the M&A activity and the upstream activity will be driven by our old friends scaling up and aggregating and consolidating," he said.

Stolte also believes the New Year will bring a lot of small acreage trades and swaps, but there will be some big ones, as well.

"As one client says, it's all about blocking it up," he said, noting contiguous, blocked acreage leads to longer laterals, which leads to more frack stages and more production.

On the consolidation side, Stolte said it would be extremely difficult, though not impossible, to establish an acreage position organically given the stage of the game in most basins.

"Thus, getting into a basin and significantly improving one's position in a basin requires acquiring an acreage position via buying out an existing company or public company merger," he said. "I think these needs will drive a lot of consolidation."

—Terrance Harris

APPALACHIAN BUYERS BUILDUP

Acquisitive E&Ps backed by powerful private equity seek more production, and more profits.

ARTICLE BY
LESLIE HAINES

PHOTOGRAPHY BY
GLENN KULBAKO

Just as out of acorns do mighty oaks grow, one phone call can jumpstart a multibillion-dollar E&P business. The phenomenon is certainly at work in the Marcellus and Utica plays, where private-equity leaders such as the Canada Pension Plan Investment Board (CPPIB), EnCap Investments LP, Quantum Energy Partners and The Energy & Minerals Group are backing some of the most growth-oriented E&Ps.

Such was the case for Hardy Murchison, CEO of Encino Energy LLC, which he formed in 2011. The Houston company had made a few smaller acquisitions and reduced costs on those properties. But in June 2017, Encino went bigger, much bigger, forming Encino Acquisition Partners with the CPPIB, which committed up to US$1 billion for doing onshore U.S. deals. Like most observers, Murchison fully expects to see further consolidation in the Appalachian region.

"As our chairman likes to say, acquisition is our middle name," he said with a laugh. Encino's executive chairman is legendary company-builder John Pinkerton, previously executive vice president of Snyder Oil Corp. and then chairman, CEO and president of Range Resources Corp., where Murchison once worked as vice president of corporate development.

After forming Encino Acquisition Partners in 2017 with CPPIB, in October 2018 EAP closed its first major deal, paying $2 billion in cash for Chesapeake Energy Corp.'s Ohio Utica assets. With more than 1,000 Utica locations identified that can yield an internal rate of return of at least 20%, with $2 gas and $50 oil, Encino is well on its way now, running two rigs this year and evaluating whether to add a third. It has the luxury of flexibility, because almost all the acreage is HBP (held by production), and the company can live within cash flow, Murchison said. One completion crew is working and Encino is adding another, he added.

Previously with private-equity firm First Reserve Corp. for 10 years, Murchison has helped establish several E&Ps in his career and always wanted to start his own one day, since working for Pinkerton at Range in the late 1990s. The EAP vision was simple: use long-term capital to build a large-scale E&P company, and exploit long-lived, low-cost assets held by production, but with a lot of running room. That description fits the Utica package to a T.

What's more, Encino has assembled an experienced Appalachian dream team: in addition to Pinkerton, Tim Parker joined as chief technology officer. He had been COO of Dominion E&P Co. and executive vice president of exploration at Santa Fe Snyder Corp. as well. Recently, retired Range Resources COO Ray Walker joined Encino in the same role. Walker built Range's Marcellus business, running up to 13 horizontal rigs at its peak. Michael Magilton, CFO, was previously with First Reserve Corp., Quantum Resources and Sabine Oil & Gas.

During the 2014 to 2015 downturn, Encino found competition to buy small asset packages surprisingly intense; that was when Pinkerton and Murchison pivoted to a much bolder vision.

"All we needed to do was raise a billion dollars, so I called Toronto," Murchison said. The Canadian Pension Plan Investment Board, to be exact. Encino had started with a methodical process by talking to dozens of possible investors, figuring it needed a group because of how much capital it was targeting, but then CPPIB turned out to be a perfect fit.

It sounds casual, but the backstory is what made it feasible. "Naturally there is a lot of due diligence when you're asking for a billion dollars, but at the end of the day, it was relationships and a shared vision that made the difference," Murchison explained. "I had longstanding relationships with CPPIB managing directors Mike Hill and Avik Dey; Avik and I worked together at First Reserve, and Mike, who was at Deutsche Bank for much of that time, called on us quite actively."

Because Encino sought small deals before 2016, CPPIB was not a fit then, "but when we decided on a strategic shift, suddenly the fit was there. And, it turned out to be a very opportune time in the business cycle," said Murchison. "For one thing, we knew that among many sellers of big asset packages, Chesapeake Energy Corp. wanted to exit the Ohio Utica.

"With CPPIB we crafted a strategy—everyone was trending toward a single-basin focus and short-term investments. We decided that instead of raising shorter-term money or going public with a SPAC [special purpose acquisition company], we could use long-term capital and build a large company, somewhat in the mold of what John had done at Range or Tim had done at Dominion. They built multibasin asset portfolios through acquisitions, developed world-class technical teams and operations around them, and allocated capital rigorously between the assets. Both companies either paid dividends or lived within cash flow for long periods of time—their shareholders fared very well."

Murchison said the Chesapeake Utica deal is only the first of what he hopes will be many.

Select Private Equity Investments In Appalachia

Company	PE Firm	$ Invested
Ascent Resources LLC	First Reserve Corp./EMG	$1.5B-plus
Blue Racer Midstream (50%)	First Reserve Corp.	$1.5B
EdgeMarc Energy Holdings LLC	Ontario Teachers, Goldman Sachs	$750MM
Encino Acquisition Partners	Canada Pension Plan Investment Bd.	$1B
Huntley & Huntley	Blackstone Group	$250MM
PennEnergy Resources LLC	EnCap Investments LP, et al	$749MM
Rover Pipeline (32%)	Blackstone Group	$1.5B
Tug Hill, Stone Hill Minerals	Quantum Energy Partners	$1B

Source: Oil and Gas Investor, company websites

Preceding page, a view of a Patterson-UTI rig drilling for PennEnergy LLC in Butler County, Pa., near the town of Cabot north of Pittsburgh. Facing page, a floorhand retrieving the drill pipe screen to send to a derrickman during a connection.


N21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DRAWWORKS OVERRIDE
PARKING BRAKE

His vision for Encino is to operate in multiple basins with several large assets and the latest technology. "We have seen that model of combining top-notch technical and operating teams with rigorous capital allocation work," he told *Investor*.

This last downturn teed up the buying opportunity, Murchison admitted. But before the public markets began clamoring for free cash flow and returns, "we never changed from late 2016 when we started discussions with CPPIB—we always focused on full-cycle margins and return on capital employed."

The team looked at the Permian and several other plays and at some of the largest asset packages marketed in the past two years. "This Utica asset kept rising to the top—it had large-scale production, low costs, cash flow and decades of development drilling ahead of it. It was well-delineated by a couple thousand horizontal wells and was almost all HBP.

"Think of 900 as a key number: we bought 900,000 acres, producing nearly 900 million cubic feet equivalent per day (MMcfe/d) from almost 900 horizontal wells. Chesapeake did an excellent job building this asset, but it just wasn't capitalized to optimize it. They'd built a first-rate team in Ohio, but then couldn't turn them loose to fully exploit the properties, so that's our opportunity. We're going in and applying longer laterals and a dedicated technical team, and we can make continuous improvements for years," Murchison said. "Look at companies like Ascent Resources: they've clearly demonstrated that bigger completion volumes and longer laterals work in the Utica. Chesapeake experimented with these things, but we'll take the asset to the next level …"

As chief technical officer, Parker "has explicitly adopted the philosophy that we'll be as strong technically as an independent can be, and he's building the team for that. We also had a blank slate with which to adopt the newest technologies and processes," Murchison said.

"An example is type curves—we developed an in-house, multivariable regression tool that allows us to look at every factor, from geology to rock and fluid properties to landing points, completion parameters and any other variables that affect well productivity.

"Instead of applying half a dozen type curves in the Utica, we can forecast every location uniquely. It is a single-well forecast of hydrocarbons, fluid properties, reservoir parameters—everything for which there is data."

Encino will incorporate commodity prices, capital, operating and other costs into its analysis, then map individual well returns across the play, Murchison said. "We believe this approach to big data enables us to make better investment decisions."

Encino has a long time horizon given its partnership with CPPIB, but Murchison said the E&P is building something "that could be extremely attractive in the public markets or for buyers. CPPIB's appetite is larger than what we've done so far, so if we execute well,

There is a lot of due diligence when asking for a billion dollars, said Hardy Murchison, CEO, Encino Acquisition Partners LLC.

Pipeline contractors beveling pipe and preparing to make a weld. Facing page, a driller directing his crew during a connection.

"If a pad has both Marcellus and Upper Devonian targets, we could ultimately see 18 to 20 wells on the same pad," said Greg Muse, PennEnergy Resources LLC president and COO.

we have the opportunity to build a large onshore E&P company."

By the time the deal closed, Encino operated some 865 producing horizontal Utica wells, most with high net revenue interest. It's 70% gas by volume but about 50% liquids by revenue.

"What we bought is an array of acreage that spans the hydrocarbon windows, with exposure to crude and liquids. What had not been done consistently was applying longer laterals from multiwell pads, using slickwater fracks and high pump rates, so that's what we're doing," Murchison said. "Recent results on our acreage are very encouraging. We'll drill and complete between 40 and 50 wells this year."

Encino has pipeline contracts to move all that it can produce to Dawn, Ontario, or to the Gulf Coast. While its marketers have the flexibility to take advantage of local price spikes that come with events like the polar vortex, the company can sell all its gas outside of Appalachia.

Murchison said he expects Encino to grow net production by 30% to 40% given its active development program. "Then assuming no growth through new pipeline outlets, we can hold production flat for two decades while generating strong free cash flow. That's the beauty of a large, high-margin asset like this."

And, he said the Utica remains ripe for further consolidation, and Encino has access to more capital. "We could reasonably expect to triple the size of the business through acquisitions."

PennEnergy's growth

In 2010, Atlas Energy Resources LLC CEO Rich Weber lured a 28-year Marathon Oil Corp. veteran, Greg Muse, to join him at Atlas as COO. (Muse had first come to Pittsburgh to oversee Marathon's Marcellus activity.) The pair engineered a $1.7-billion joint venture between Atlas and India's Reliance Industries as the Marcellus began to boom—but later, Chevron Corp. came calling and bought Atlas. After that sale, Weber and Muse wanted to do it all again; the pair had overseen the drilling of more than 100 horizontal Marcellus wells.

At the same time, Weber connected with EnCap Investments, where he had met partner Jason DeLorenzo more than a decade earlier. In a familiar private-equity practice, EnCap's team rightly figured that after having sold to a larger entity, these Atlas executives might want to have another shot on goal.

Sure enough, relationships propelled the discussions forward. Weber and Muse formed PennEnergy Resources LLC in 2011 and EnCap came in to the tune of a $300-million initial commitment. PennEnergy was to focus on three counties north of Pittsburgh.

Fast forward to August 2018, when PennEnergy made another significant deal, paying nearly $571 million (after collateralized cash disbursement) to acquire the Pennsylvania assets of Rex Energy Corp. out of the latter's bankruptcy. It took over operatorship of the assets (on mostly contiguous acreage) last October, and assumed all of Rex's back office functions this past January.

PennEnergy plans to turn in line 41 Marcellus Shale wells in 2019. Facing page, workers opening the valve on a frack tank.

"The acquisition was an ideal fit for us with numerous opportunities for synergies and significant reduction of overhead. We have fully integrated the assets, and it has gone very smoothly," president and COO Muse told *Investor*, "due to planning on both sides and full cooperation from the team at Rex."

Post-close, PennEnergy is producing close to 530 MMcf/d gross of natural gas and 3,900 barrels per day (bbl/d) of condensate from approximately 350 wells. By the time wet gas is processed, total equivalent production is about 700 MMcfe/d gross from the combined assets. The company is operating two rigs this year (one horizontal fluid rig, the other an air drilling rig that opens up the first 2,000 vertical feet), and may pick up another horizontal in the second half, depending on gas and NGL prices. It expects to turn in line 41 wells this year and thus bring the total to 390 wells on production, Muse said.

"We have plans underway to be ready to pick up another horizontal rig, including the building of new pad locations. But right now our primary focus is on cash flow and maintaining a strong balance sheet," Muse said.

The air rig is currently drilling on legacy wet-gas assets in Beaver County north of Pittsburgh and the horizontal rig is drilling in the dry gas area in Butler County. If a second horizontal rig is picked up, it will deploy on Rex's Butler County acreage, he said. About 34% of production is NGL. With the newly added Rex acreage, the company's production will be a bit more weighted to wet gas than dry on the whole, he said.

"We have very good economics in the dry gas area, and with oil and NGL prices having come down, the dry gas areas are competitive with the wet gas economics. Our three-year average finding and development cost is just 36 cents per Mcfe," he said.

The company has a fair amount of stacked Upper Devonian upside above the Marcellus on its Beaver County acreage which is material, he said, even though it is not nearly as pervasive as the Marcellus is, basinwide.

"We think completing six wells per pad is optimal for us, considering capital spend cycle times, with laterals of 7,000 to 8,000 feet being the sweet spot, although PennEnergy has drilled laterals as long as 10,000 feet. We do have some future laterals planned as long as 13,000 feet," Muse said.

"If a pad has both Marcellus and Upper Devonian targets, then we could ultimately see 18 to 20 wells on the same pad, but not drilled all at one time. We'd plan to spread out the development over time such that we won't have to come back to the pad for five or six years. We want to manage the total investment on one location, because the cycle time is so long already going in—to drill and complete as many as 18 wells at one time, you'd be well in excess of one year on the same pad. It would take several months just for the fracking."

To minimize the parent-child effect on future reserve recoveries, PennEnergy leaves large areas open between developed wells such that future wells can be developed without significant negative impact to ultimate recovery.

The PennEnergy team keeps a close eye on technology; while not cutting edge, it likes to be fast followers that employ new technology once it has demonstrated success.

"We believe in the value of a lot of detailed planning—we are planning for our 2020 wells and beyond already," Muse said. "Where mar-

Ascent Resources LLC CEO Jeff Fisher loves the Utica; Ascent's 210 wells are producing close to 2 Bcfe/d.

gins could be low, planning and capital efficiency are all the more important, and that includes everything across all disciplines, such as better water management."

PennEnergy has dramatically reduced water costs by between $500,000 and $600,000 per completed well since it laid a 5-mile line from the Ohio River to its Beaver County acreage and installed a central impoundment to cost-effectively pump water to multiple pads.

A further backstop is that the company has hedged 85% of its 2019 output and 50% of 2020's anticipated production, he added.

"The capital outlay is massive but the capital efficiency is great," said Michael G. Radler, Tug Hill Inc. CEO, describing multiwell pads in the Marcellus.

Keeping the pipes full

Privately held Tug Hill Inc., based in Fort Worth, Texas, has drilled or participated in more than 1,000 Marcellus wells, the bulk of them in northeast Pennsylvania through a partnership operated by Trevor Rees-Jones' Chief Oil & Gas. They jointly own about 230,000 acres in the northeast corner of the state, with production of about 1 Bcfe/d gross, 110 MMcfe net to Tug Hill. Chief operates the asset and does all the gas marketing.

"Much of the gas is now flowing on our FT (firm transport) on Atlantic Sunrise. I believe any producers who have FT on Atlantic Sunrise are happy. We're very excited because, going forward, basis will not be as big an issue," said Michael Radler, CEO of Tug Hill.

Atlantic Sunrise Pipeline, operated by Williams, has capacity to move 1.7 Bcf/d, with Cabot Oil & Gas holding 700 MMcf/d of that. Prices at Leidy, Pa., rose to more than $4 recently, more than double what they were before the new 183-mile line opened for business in October. It moves gas from northeast Pennsylvania to Dominion's Cove Point LNG facility and other markets further south.

"The Northeast producers have learned their lesson—you drill to produce only as much as you have to, to supply your FT and nothing material beyond that," Radler told *Investor*.

"That goes for every operator you speak to. There's no need to over-drill. The days of telling the equity markets to look at production growth, while ignoring returns, are gone. If a public company is spending outside its free cash flow, it gets beat up and its stock price reflects that. I think this has helped level the playing field for privately held companies," Radler said.

"There are very few DUCs anymore, because in 2018 we saw a flurry of AFEs anticipating Sunrise going into service. But that has fallen off; if it's a DUC [drilled but uncompleted well] today, it's probably going to be a DUC forever unless it's in an area with no midstream or access to markets."

In the Ohio Utica, almost all of Encino Energy LLC's acreage is held by production, with some 1,000 locations ahead.

PHOTO BY ASHLEY UNBEHAGEN/COURTESY ENCINO ENERGY LLC

Radler said most operators in northeast Pennsylvania have settled on well spacing of 1,000 feet, with most wells drilled to the Lower Marcellus.

In 2011, Tug Hill and Chief sold the majority of their acreage in southwest Pennsylvania and West Virginia to Chevron. In 2014, Tug Hill established a new partnership with Quantum Energy Partners focused on southwest Appalachia. Today, they have three platforms (upstream, minerals and midstream) with a combined equity commitment of about $1 billion.

"I've known Wil [Quantum CEO Wil VanLoh] for quite some time; we're friends. The energy business is a small fraternity," Radler said. "When the decision was made to go with private equity, I went to Wil for advice on the various options and said, 'Tell me who's good and who's bad,' and he walked me through it. But he also said, 'Before you decide, let Quantum have a shot at it.'"

Three-dimensional chess

The first of the three platforms, THQ Appalachia, is operated by Tug Hill. It has a consolidated block of over 50,000 net surface acres, 94,000 net formation acres, in Marshall and Wetzel counties, W.Va., where it's pad drilling to the Marcellus and Utica/Point Pleasant with four rigs. It plans 16 Utica and 74 Marcellus wells there by year-end.

Current production of about 93 MMcf/d will rise to 450 MMcf/d by year-end and exit 2020 around 770 MMcf/d, Radler said. "We're drilling both zones on pads in West Virginia and have been for quite some time due to the complexity of the topography. It's proven to be the most efficient way to go and creates the highest EURs and economic returns."

In addition to dealing with the topography, pad locations are limited due to area coal mines. THQ has to position its wells in a manner that allows drilling through the coal pillars to access the target reservoirs.

"We think of it like three-dimensional chess," Radler said. "A tremendous amount of front-end planning and well design goes into it. It's very complex with a lot of logistics.

"For example, the biggest pad we're drilling now has 20 wells on it, and we've planned one that will have 28 wells. The directional plan for each well becomes critical and in some ways, it's like drilling offshore. We've reduced D&C costs to what we believe are the best in the basin, and we've approached this in a very technical way, with sim-ops [simultaneous operations, that is, drilling, fracking and flowing production at the same time on the same pad]."

Radler said if not done this way, due to limited surface area for pads, there's a likelihood the company could miss the opportunity to complete future wells in the Utica, due to poor pad design and directional well planning.

"Many operators don't understand the Utica/Point Pleasant because early well costs have been so high. Our full-cycle returns in the Utica are over 40% using strip pricing, and that's including land costs, G&A and everything. We have cracked the code on completing these

Encino Energy LLC's rig in Ohio. Facing page, a mural near the Butler County, Pa., courthouse on South Main Street, paying homage to Butler's history.

wells in West Virginia, and we're generating returns superior to Tier-1 dry Marcellus."

Some THQ wells have laterals as long as 16,000 feet, but the average range is 8,000 to 11,000 feet, depending on the terrain, geology and lease lines. Optimum Utica well spacing is 1,250 feet.

Some operators have tried tighter spacing in southwest Appalachia, but Radler said he thinks 750 to 1,000 feet is the optimum for the Marcellus. Zipper fracks help retain the pay zone's energy and yield a higher EUR, he said. "We know that if you really want to get the greatest recoveries by well, pad drilling and completions are the right answer to avoid depletion issues that have been seen in other basins from parent-child relationships, when returning to a pad at a later date.

"The capital outlay is massive, but the capital efficiency is great," Radler said. "A lot of capital goes out the door, but in the end it pays off on many different levels."

The second Tug Hill-Quantum platform is Stone Hill Minerals LLC, with has 25,000 net fee mineral acres in West Virginia and Pennsylvania, 25,000 net overriding royalty acres in Ohio and 59,000 net fee mineral acres in the Permian. These minerals have been strategically acquired in the most prolific areas of these basins and ahead of the drillbit.

Finally, there is XcL Midstream LLC, a rich- and dry-gas gathering and transportation system in Marshall and Wetzel counties, with extensions into Ohio and Pennsylvania planned in the near future.

Throughput is about 600 MMcf/d on the rich-gas side and 2.5 Bcf/d on the dry-gas side. It consists of two 24-inch pipes and various laterals that service THQ and third-party gas producers. "It interconnects to every major long-haul pipeline—Dominion, Columbia, Texas Eastern, Energy Transfer, etc., in southwest Appalachia. It's the backbone for us—we can flow production to all these different points, which allows us to take advantage of the best gas markets and pricing," Radler said.

Ascent's latest

The Energy & Minerals Group and First Reserve Corp. are the private-equity players backing Ascent Resources LLC, which has grown through a series of acquisitions, most recently the $1.5 -billion purchase of Utica Shale assets when Hess Corp. and CNX Resources Corp. exited Ohio. Since the company was formed in 2013 it has become the largest pure play in the Utica. (For more, see "Ascent in the Utica," *Oil and Gas Investor*, August 2018.) It has 310,000 net acres and has identified nearly 2,300 locations.

It's in some of the best rock, where the play strengthens and is overpressured to the south with better permeability and somewhat higher porosity, CEO Jeff Fisher said, in Belmont, Monroe, southern Jefferson and Guernsey counties. Some 210 wells are producing.

In January, Fisher made the decision to reduce the number of operated rigs from seven to six "with plans to level out there, subject to significant shifts in commodity prices."

In light of those changing prices for oil, gas and NGL, has the production mix shifted for Ascent? "No shifts, as we will maintain exposure to all phases, where our returns are robust and comparable. We will be leveraging our mineral ownership on a significant portion of our 2019 plan," he told *Investor*.

Last summer Ascent acquired Utica Minerals Development and assets from another undisclosed seller at the same time the Hess and CNX deals came to fruition. That added 60,000 net fee mineral acres, always a boon to economics. Achieving cash-flow neutrality is a priority for 2019 and Fisher thinks the company will succeed as it has "a strong line of sight given our execution and hedge book. We will start throwing off significant free cash flow in 2020 and beyond."

All in, Ascent ended 2018 producing 1.8 Bcfe/d, right on target with projections, Fisher said. According to the Ohio Department of Natural Resources, in fourth-quarter 2017, the company had 17 of the top 20 gas wells in Ohio—and it had this same track record per third-quarter 2018 ODNR data. "Our top-producing well averaged a choke-managed 32.5 MMcf/d, and we had 34 wells that averaged over 20 MMcf/d. We also were the top oil producer in the Utica at 20,000 bbl/d," he said.

Good technology follows good rock, and since many of Ascent's employees were formerly with Chesapeake Energy, technology is a focus.

"We see the rhetoric on optimized well spacing playing out with some of our peers, but from the start, we designed for 1,000-foot inter-lateral well spacing in the dry gas and 750 feet in the liquids-rich phases of the Utica," Fisher said. "Our data continues to confirm these parameters. One operator in the Marcellus has recently stated they are moving from 750 feet toward 1,000 feet in the dry gas … we are already there.

"We continue to make positive strides on continuously improving our completion efficiency along every foot of the lateral using advanced techniques, including new core analysis and fiber optic technology."

Fortunately given the rise in Ohio production, all major infrastructure that Ascent needs is in place, he said, with the company being an anchor shipper on the Rex and Rover pipeline systems. "We will look to further enhance connectivity within the basin amongst all of our takeaway pipelines to increase market optionality," he added.

"We love the Utica. We're focused on our program and repeatability, but we're hitting on all cylinders." □

AFTER SUNRISE

Over the past 15 months, a massive 10 billion cubic feet per day (Bcf/d) of new takeaway capacity has started up in the Marcellus-Utica plays, bringing the total to 33 Bcf/d. Production is around 31 Bcf/d, according to the latest data from the Energy Information Administration. It is a startling increase since 2010, when area production was 20 Bcf/d.

"We think there is still 6 Bcf/d of room before bumping up on capacity/differential problems in the southwest Marcellus-Utica," wrote analyst Jean Ann Salisbury, in a recent Bernstein Research report.

In the northeast part of the play, however, the arrival of Williams' Atlantic Sunrise Pipeline, which came on in October, is making all the difference, adding 1.7 Bcf/d of additional takeaway capacity. Cabot Oil & Gas Corp., Chesapeake Energy Corp., Southwestern Energy Co. and Chief Oil & Gas are the largest Marcellus producers there.

But despite the good news, Salisbury thinks that by the end of 2019, this pipe could be full, with other pipeline projects being challenged to add more capacity due to delays and cost overruns inherent in this region. All in, she thinks slower production growth lies ahead, which may be a stabilizing influence on gas prices.

In November 2018, Energy Secretary Rick Perry and the Department of Energy (DOE) reported to Congress that the Appalachian Basin should be the site of a new NGL hub similar to Mont Belvieu, Texas, or Conway, Kan. Within a 300-mile radius of Pittsburgh, demand is great, as nearly one-third of U.S. petrochemical activity takes place via 7,500 business establishments such as chemical plants, paint, plastics and other manufacturing. In addition, the ethane supply from the Marcellus and Utica will be enough to support as many as four ethane crackers, the report said.

"From 2018 to 2025, total U.S. ethane value chain productive capacity is estimated to increase more than 51%, or by 42 million metric tons (two-thirds in Texas-Louisiana and 17% in Appalachia)," the DOE said.

TRANSFORMING DJR

A D-J Basin veteran's start-up will apply horizontal drilling to the Mancos Shale on assets acquired from Encana Corp. in the San Juan Basin.

INTERVIEW BY LESLIE HAINES

Two days after Christmas, during vacation days that are often marked by a year-end rush to conclude business, Denver-based DJR Energy LLC closed on its acquisition of Encana Oil & Gas (USA) Inc.'s San Juan Basin assets in New Mexico. It paid US$480 million, or as calculated by a Jefferies analyst, $35,000 per flowing barrel of oil equivalent (boe).

The deal included approximately 182,000 net acres. In 2017, these assets produced about 5,400 boe/d, including 3,900 boe/d of liquids, according to Encana.

The package has transformed DJR, which already owned 800 vertical wells on 170,000 net acres in the area that it had acquired from Elm Ridge Exploration Co. LLC a year earlier, before making the Encana bid.

DJR Energy LLC is eager to apply horizontal lessons from its successes in the D-J Basin to its newly acquired assets in the San Juan, said CEO David Lehman.

The privately held DJR was formed in April 2017 by Dave Lehman, a 40-year industry veteran and former executive with ExxonMobil Corp. who had been with the oil major for 27 years. He was manager of worldwide new business opportunities for Exxon Exploration Co., among many other job titles, until taking early retirement in 2012.

After leaving ExxonMobil, the geologist helmed two Denver-Julesburg Basin-focused companies that he built and sold successfully. Assets of the first, DJ Resources LP, went to 10 different buyers, including EOG Resources Inc., Marathon Oil Corp. and Whiting Petroleum Corp., making a 10-times return. In the second transaction, DJ Resources LLC was sold in July 2014 to Bonanza Creek Energy Inc., for a 7-times return.

The key DJR team members bring a wealth of experience to the new company. They include Jerry Austin, vice president of production operations, who used to be area operations manager for BP's Rockies region; and Chuck Mallary, vice president of drilling and completions, who was with BP, ConocoPhillips Co., EOG Resources and Noble Energy Inc., and is the author of four Society of Petroleum Engineers papers on wellbore construction.

Backing Lehman's new company is a private equity trio of Trilantic Capital Management LP, Waveland Energy Partners and Global Energy Capital. Between these and management, in excess of $500 million of equity capital was committed to DJR, although further details on exact terms were not disclosed.

To get started, DJR's team evaluated many areas in the Rockies but ultimately chose as its first target the San Juan Basin, specifically the Mancos Shale oil window in the southern part of the basin. There, the Gallup Formation is similar in geology and economics to the Turner Sand in the Powder River Basin and, more importantly, to the Codell Sand in the D-J Basin, where Lehman had had success before. The area is comprised primarily of federal and state leases. (For more, see "San Juan Rising," Oil and Gas Investor, *January 2018.)*

It's fairly early in the life of the play, with about 200 Gallup horizontal wells drilled to date, but Lehman said he sees the potential for economic improvement by drilling 2-mile laterals on pads, not to mention adding improved infrastructure and further reducing D&C costs. He likens it to the qualities he saw during his experience in the D-J Basin of Colorado.

We spoke to Lehman less than a month after he closed on the Encana transaction, to see what his 2019 plans are for the developing play.

Investor Dave, what was your thinking on making a pivot to the San Juan, given that you'd been so successfully involved in the D-J Basin?

Lehman We sold our last D-J company in July 2014. At that time, we felt the basin was getting a bit too crowded and too expensive, and it was also getting difficult to put enough acreage together. So this time around, when we started DJR, we started looking at other Rockies plays, and we liked the San Juan. We see a lot of parallels.

Investor What sort of parallels do you draw between the two?

Lehman The rocks there are the same age, Cretaceous, and we felt the fracking and economics would be very good; in fact, just as good. In 2015, we began looking for assets, and we purchased some vertical wells from Elm Ridge in 2017. These sort of bookended the Encana assets, so when those came up for sale, we were very pleased to be able to make a bid to Encana. Now we're the dominant player on the Mancos Shale oil rim in the southern part of the basin. We think it has significant potential.

Investor What are your immediate plans since you closed in December?

Lehman We certainly purchased these assets with the concept of putting a rig or rigs to work, so we'd anticipate activity starting by midyear. We just closed on this on Dec. 27, and it's winter there, of course, so we're still getting our arms around the asset, although we know what we want to do. But we have some more things we want to study first.

Investor Which sort of factors are you still looking at?

Lehman The geology work is done; we've already done an extensive study on the oil in place in the Mancos. These wells will be about 70% oil, and the rest natural gas and liquids. Now we're working on some operations things, such as getting the pads ready for drilling, getting completion equipment ready and bringing in frack tanks and so forth prior to starting drilling. We feel fairly confident in being able to get a rig, as there are some in the basin that are not working right now.

Investor What is the initial plan?

Lehman We plan wells that are 5,000 or 6,000 feet TVD (total vertical depth), and then laterally we'll go out a mile and a half or 2 miles, depending on the acreage situation.

In addition to its existing production seen here, DJR Energy plans new horizontal wells in the San Juan Basin this year.

PHOTO COURTESY DJR ENERGY LLC

We prefer five to eight wells per pad, as we think that will be the most efficient way to develop the Encana assets. We anticipate piping the water and frack fluids and produced oil, gas and fluids, to minimize truck traffic.

Investor Can you discuss in more detail the parallels do you draw between your D-J experience and the San Juan Basin?

Lehman There are some uncanny parallels and you can start with the geology. As I've said, they have the same age rock from a Cretaceous seaway. The frackability and economics are very comparable. The San Juan reservoir is shallower, but the EURs and even the quality of the crude are comparable. In the D-J, people are going to multiwell pads and longer laterals, but both basins started out with vertical wells. Now, in the D-J, they've all gone to 2-mile laterals, and we hope to see the same thing develop in the San Juan.

Investor What about any differences?

Lehman We see a couple of significant ones. In the D-J Basin, 3-D was required because of the numerous small faults there, but here in the San Juan, no. In the San Juan the frack orientation is from northeast to southwest, but generally the frack designs will be very comparable, although in the San Juan we'll be using a nitrogen foam frack, whereas in the D-J they use slickwater fracks.

Investor What stage would you say the San Juan is at in terms of new horizontal activity in the Mancos?

Lehman The industry is starting to find its way in the San Juan and gain momentum, so I think it's about five to seven years behind the D-J. Keep in mind that when we first started in the D-J in 2003 there were no horizontal rigs drilling; now there are 15 or 20 rigs running in Wattenberg Field. In the San Juan there is only one running right now that's drilling on the Mancos oil rim. I don't necessarily think we'll get to the same rig count as the D-J, but we will see more rigs running.

Investor Once you get started by midyear, how many wells will you drill in 2019?

Lehman At this point I can't be too definitive, but once we pick up a rig, we hope to keep it working all year. One of the biggest challenges will be the regulatory environment and if we can get the APDs (application for permit to drill) in a timely manner and get our midstream efforts approved. DJR has access to over 50 APDs filed by the previous operator, and it plans to file for an additional 80 APDs during 2019.

The differential between WTI and the local price has been as high as $12/bbl—but this is another remarkable similarity with the D-J, in that there it got to as high as $15 until enough infrastructure was put in place, and then the differential came back down. I'd expect and hope to see a similar effect in the San Juan over time.

Investor Do you plan to go back into the vertical wells you acquired from Elm Ridge and complete them horizontally?

Lehman That is always the first question we get asked. Yes, there is always a temptation to do that, but based on what our folks have studied, we think it is going to be more economic to drill new horizontal wells. From the Elm Ridge deal, we have 800 verticals making about 1,400 boe/d, mostly gas but some oil—but they are cash-flow positive, and what's even more significant, they hold the acreage, so we'll continue to produce most of them, although we'll high-grade them and may sell off a few.

We like the geology, we like the economics, and we think we're in early, so we're really pleased with the Encana acquisition. □

> "The industry is starting to find its way in the San Juan and gain momentum; I think it's about five to seven years behind the D-J."

SAN JUAN TURNS OVER

In November 2017, Logos Resources II, backed by ArcLight Capital Partners, bought San Juan gas production and undeveloped acreage that WPX Energy Inc. divested for $169 million. Some 900 producing wells were included, along with 200 undeveloped horizontal locations. The package was spread over Rio Arriba and San Juan counties, N.M.; and Archuleta and La Plata counties, Colo.

In February 2018, WPX left the basin's Gallup oil play after reaching an agreement to sell about 105,000 net acres in Rio Arriba, San Juan and Sandoval counties, N.M., for $700 million.

Although WPX didn't disclose the buyer in its initial announcement, regulatory filings later identified it as Enduring Resources IV LLC, a private Denver company helmed by industry veteran Barth Witham. The Gallup oil play had previously been a part of WPX's plans and was producing 10,800 barrels of oil per day (boe/d) in third-quarter 2017.

Several other buyers have entered the San Juan Basin or added to their position, most notably Houston-based and privately held Hilcorp Energy Co., which produces about 1 billion cubic feet per day (Bcf/d) in the San Juan, one of the largest gas producers in the basin. Its subsidiary, Harvest Midstream, paid $1.1 billion in July 2018 to take up Williams' San Juan midstream system. That deal entailed more than 3,700 miles of pipeline, two gas processing plants and one carbon dioxide treatment facility in an area stretching from New Mexico's San Juan and Rio Arriba counties to La Plata County in southern Colorado. The pipeline system includes gathering capacity of 1.8 Bcf/d.

This past November, despite opposition from the newly elected governor and environmentalists, Hilcorp received approval from the New Mexico Oil Conservation Commission to revise legacy spacing rules, to allow eight wells per 320-acre drilling unit instead of four, above the Blanco-Mesaverde gas formation. The move had engendered controversy in the state for several months prior to the final decision.

IN SEARCH OF SUPERIOR WELLS

Today's non-ops go the extra mile to ensure the latest data for investing in wells and future inventory.

ARTICLE BY
CHRIS SHEEHAN, CFA

"We have to make an election on an AFE, just like the operator does," said Mark Clemans, CEO of Carrier Energy Partners. "You can take that lightly or not, and we take it seriously."

If running a non-op business sounds like you're just along for the ride—a so-called "armchair operator"—then you haven't met the professionals. True, it is the operator that makes major drilling decisions. But non-ops exercise control in key areas: choice of basin, selection of E&P partners, opting in or out of wells and, in today's data-rich environment, constantly searching for the best wells in the best basins.

In addition, non-op strategies have fulfilled a variety of goals in the past. Want to pursue a play ahead of forming a new E&P team? Then entrust the task to a non-op that is able to swiftly sift through well data and acquire non-op interests in the requisite play. Or, want an inventory of opportunities to develop over an extended period? A non-op can identify Tier 1 acreage and build key inventory in specific areas.

Another economic edge enjoyed by some non-ops relates to extended billing cycles. Authorizations for expenditure (AFEs) are typically sent out by operators only as wells are spudded and call for payment in a further 60 days. This means that early well costs may be in large part paid from non-op funds, but a significant portion of the well costs may later be paid from revenues generated by the well.

"Everybody's got a different strategy," observed Mark Clemans, CEO of Carrier Energy Partners, a Houston-based non-op. "Do you want to have 2.5% or 3% working interests in hundreds or thousands of wells, so you can be diversified? That's one way to do it. Another is to be concentrated in good areas, with good operators, with greater exposure, like we are."

Non-op companies face a variety of challenges in the normal course of business, according to Clemans.

"Of course, we're trying to make good decisions all the time," he said. "We have to make an election on an AFE, just like the operator does.

You can take that lightly or not, and we take it seriously. We look at every AFE, which means you have to have good data. Some of that is available publicly, but some depends on having a good relationship with the operator."

For example, Carrier offers to share its type curves for wells with the operator whenever practical.

"We do a lot of work, and we just want to make sure we're not missing something, to make sure that we're aligned," explained Clemans. "We're willing to share our type curves with the operators and tell them what we think; they don't have to share their type curves with us. What we expect in return is good data and good communications. You have to find that person who's willing to help you."

Clemans formed Carrier in 2009, bringing with him 20 years of industry experience from positions at ExxonMobil Corp., Netherland Sewell & Associates, Sproule and Goldman Sachs E&P Capital.

With initial backing from a Houston-based Fortune 200 waste disposal firm, Carrier completed a series of non-op, working interest (WI) acquisitions with combined production of over 5,000 barrels of oil equivalent per day (boe/d). The acquisitions were aimed at providing a stream of cash flow that would serve as a natural hedge against rising diesel costs. The investor held onto the non-op holdings until last year.

'Pivot' to new plays

As interest built in U.S. shale plays in 2013, Carrier Energy Partners LP (Carrier I) was formed with funding from Riverstone Holdings LLC.

"We convinced Riverstone we could 'pivot,'" recalled Clemans. "There was a lot of money to put to work in the industry, and it was tough to form new teams quickly for all the different plays. If Riverstone needed time to evaluate the Utica and Marcellus, for example, we could still move forward in the play with the task of finding a good operator and doing our due diligence in the interim."

Relationships with multiple operators were already in place, explained the Carrier CEO. "Then it's just a matter of finding an opportunity to buy a working interest and make sure they're aligned with us."

Carrier I was able to attract funding of up to $300 million from Riverstone based in large part on work that Clemans had led at Goldman Sachs. This included "rigorous analysis" covering elements of geology, reservoir engineering, a financial analysis of the structure of the deal and the quality of the assets being acquired, according to Clemans. "That's what my team brought to the table that they liked."

Working with Riverstone partner Robert Tichio, Carrier Energy Partners II LLC (Carrier II) secured a second tranche of funding of $100 million in 2015. This was subsequently expanded to $400 million.

Initial Permian investments

The first investment by Carrier I was a joint-venture agreement with Panther Energy II LLC. The agreement called for the two companies to develop 15,000 acres, mainly in Culberson and Reeves counties, in the Delaware Basin. Terms of the agreement provided Carrier I the right to participate through a 49% WI in wells drilled by Panther.

In early 2017, Carrier I closed the sale of its 49% WI in Culberson County to a private buyer. In addition, it sold its 49% WI in Reeves County as part of a previously disclosed $775 acquisition by WPX Energy Inc., which also included acreage and production in Loving, Ward and Winkler counties.

Investments alongside Marathon Oil Corp. in the Eagle Ford Shale make up by far the largest part of Carrier Energy Partner's current production, accounting for over 80% of total output of about 7,700 boe/d.

PHOTO BY TOM FOX

"The thesis Gerrity had going into the Bakken was that the play would get deeper, denser, cheaper, better," said Brian Cree, CFO, Vitesse Energy LLC.

Prior to the Panther asset sales, Carrier I and Carrier II had engaged in a number of key acquisitions. For example, Carrier II purchased an approximate 30% WI in a joint venture with PT Petroleum LLC, based in Plano, Texas, and Midland-based Henry Resources in the Midland Basin. It also acquired an approximate 13% WI in the Sugar Loaf area of mutual interest (AMI) operated by Marathon Oil Corp.

Operated by PT Petroleum, the former project involves roughly 65,000 acres in Reagan, Upton and Crockett counties. Carrier II was brought into the project in light of a significant drilling commitment on what are largely university lands. Drilling and delineation operations have been "active" over the last couple of years, with primary targets in Wolfcamp A, B and C horizons.

80% output in Eagle Ford

Investments alongside Marathon Oil in the Eagle Ford make up by far the largest part of Carrier's current production, accounting for over 80% of total output of about 7,700 boe/d. Carrier II entered the play by buying assets in the Eagle Ford held by two Australian E&Ps, Empyrean Energy Plc and AWE Ltd. Of the two transactions, the latter was much larger, carrying a $190-million price tag.

"Riverstone didn't have an operating team in the Eagle Ford, so this was a good way for them to get into the play," recalled Clemans. "Plus, they liked having Marathon as the operator."

With a staff of just seven people—and general and administrative (G&A) costs spread over 7,700 boe/d of production—Carrier is not carrying a lot of overhead on a per-barrel basis. Its staff includes a core group of engineers and financial analysts, noted Clemans, while accounting and land are largely outsourced. Consultants are used for some geology and reserve-based work for reports to the banks.

However, Clemans downplayed the likelihood of light G&A expenses providing a meaningful advantage for a non-op vs. an operating strategy. "If you're in good rock and you have good performance from your drilling, the G&A component should not be a 'make or break' factor, unless you've built an empire," he observed. "And you need to pay good people well whether they're operating or nonoperating."

As of mid-January, Carrier II still had dry powder to fund future investments. Carrier continues to see more attractive opportunities in oil than natural gas—even with oil pulling back into the $50s—and leans toward further investments in the Permian and Eagle Ford. However, Tier 1 acreage is tougher to secure, especially in the Permian, where much of the acreage is locked up.

Potential emerging plays

Clemans pointed to the Louisiana Austin Chalk as a potential emerging play, where entry costs would be lower.

"We've looked at a couple of projects in the Louisiana Austin Chalk," he said. "We're just risk-averse enough to wait for a few more wells to be drilled there—by anybody—before we can probably latch onto the play. It may cost us more to get in then, if it's de-risked a little further, but we look to get exposure to plays like that. It's certainly intriguing."

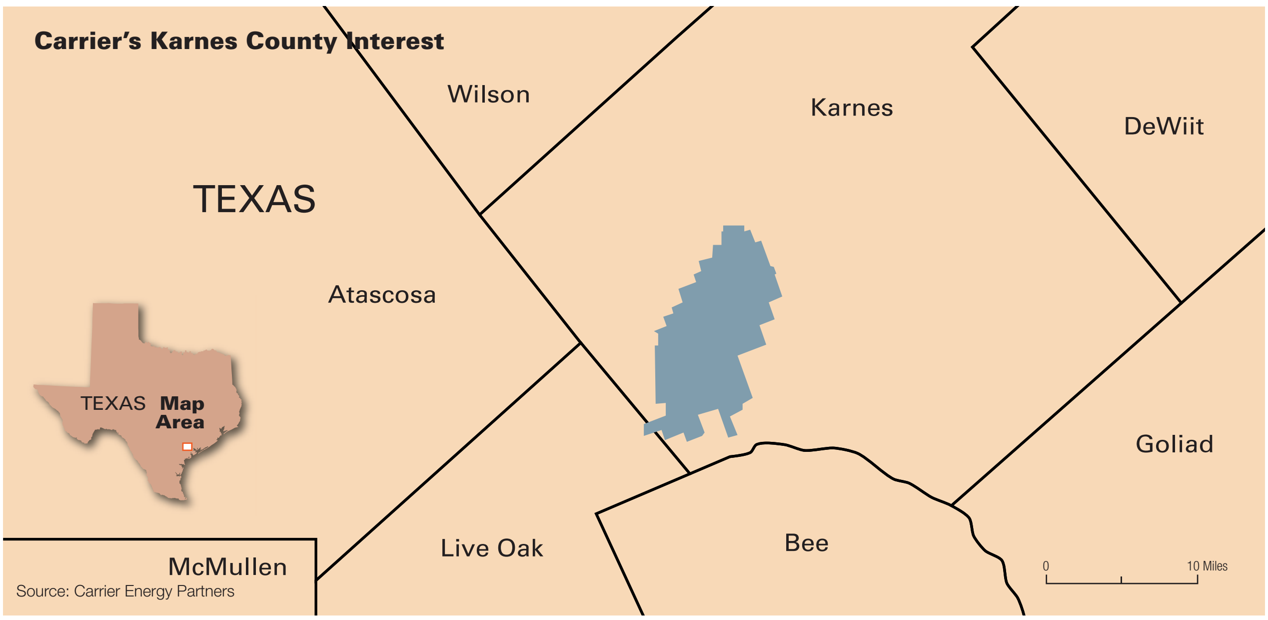
While acknowledging the severe slowdown in the acquisition and divestiture market may have dampened expectations for near-term growth by non-ops, Clemans was optimistic about the track record compiled by Carrier with Riverstone.

"Riverstone has been a really good investment partner, and we've made efficient decisions together," commented Clemans. "Our role is to do a good job in evaluating the data and putting our conclusions in front of them.

"We can get on the phone and make good, quick decisions," he continued. "And we've sent a whole lot of money back to Riverstone."

Interests in Bakken wells

As with Carrier, Vitesse Energy LLC's



Source: Carrier Energy Partners

partners, Bob Gerrity, CEO, and Brian Cree, CFO, dispel the notion that non-op "is easy, because it's like 'mailbox money' with minerals." Far from it, their business has been woven together from a mix of deep industry knowledge of the Bakken play, long-standing relationships with key basin operators, and a painstaking study of massive data on wells in the basin.

The results have been in many ways remarkable. At a West Texas Intermediate (WTI) price of $45 per barrel (bbl), and without hedging, Vitesse is able to generate earnings on a GAAP (generally accepted accounting principles) basis. This might imply a very mature asset with a heavily depreciated cost basis, but only about 10% of Vitesse's reserves are in fact producing, with the remaining 90% of reserves yet to be developed.

Another eye-opener is the degree of Vitesse's participation in recent drilling activity. While Vitesse has held only about 1% of the acreage in the Bakken in North Dakota, it has participated in between one-quarter and one-third of all wells drilled in the Bakken over the last several years, according to CEO Gerrity. "We picked our acreage well," he commented.

Gerrity and Cree worked together earlier at Denver-Julesburg (D-J) E&P Gerrity Oil and Gas Corp. They have run 15 rigs at a time, drilled some 2,000 wells and operated 5,000 wells in their careers.

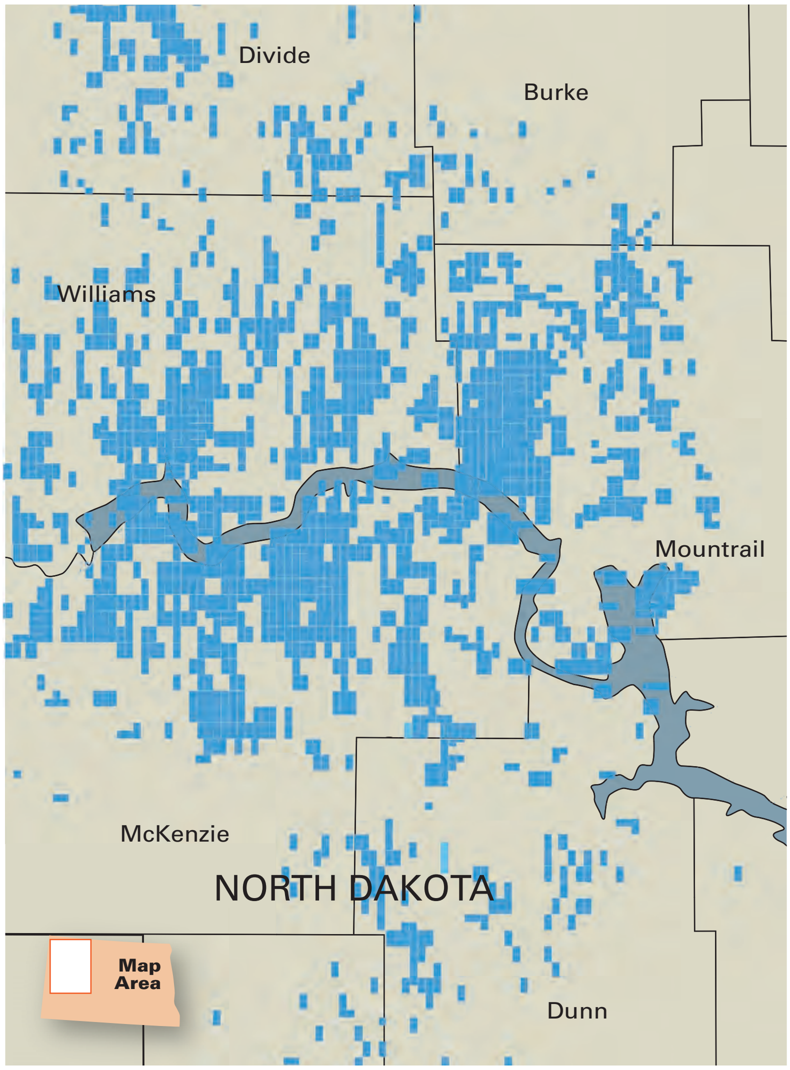
"Our competitive advantage is that we understand the operating side of the business," said Gerrity. "We understand what operators have to go through. Most consider it a real hassle having to deal with their non-ops. But we develop relationships, work with them hand-in-hand and try to make their jobs easier."

Internally, Vitesse views itself as a "financial company," with eight current or past CPAs in a total staff of 30, according to Cree. The CPAs work with the land department to do "forensic work," which entails calculating what the Vitesse WI should be in a well and what Vitesse should get paid. "We do the work along with the operator, and then we let the operator have the benefit of our work," he said.

Vitesse has interests in 5,000 wells in the Bakken, with an average 3% to 4% WI in each well, and keeps a decline curve "on every well in the Bakken—not just ours, but every well," according to Gerrity. "We have an advantage in that we can see what every operator is doing. We can see which operators have better costs and more effective fracks. We have to know the Bakken as well as anybody."

The history of Vitesse began in 2013, when Jefferies Capital Partners funded Vitesse Oil LLC with roughly $50 million. Shortly thereafter, Leucadia National Corp. (now named Jefferies Financial Group) acquired Jefferies. Vitesse Energy LLC was formed with a commitment of $300 million from Leucadia. An additional $150 million from Leucadia was committed in 2018 to help finance an acquisition.

Vitesse Bakken Acreage Map



Source: Vitesse Energy LLC

Starting a non-op business focused on the Bakken was not an overnight idea, but rather an outgrowth of a multiyear, meticulous analysis of well data in the Bakken undertaken by Gerrity and his wife. This was in turn supplemented by learnings from developing acreage in the D-J Basin at Gerrity Oil and Gas.

"At the time, no one did non-op. Everyone thought that 'non-op sucks, you can't control anything.' But what you can control is what you invest in," said Gerrity.

'Deeper, denser, cheaper, better'

"The thesis Gerrity had going into the Bakken was that the play would get deeper, denser, cheaper, better," recalled Cree. "When we originally got into the basin, the spacing was only four to six wells per DSU [drilling spacing unit]. This assumed just the Bakken and the first bench of the Three Forks.

"But based on what we learned from the D-J, we believed that over time there would be more wells per DSU, that there would be additional benches, that the EURs [estimated ultimate recoveries] would increase, and the operations would get cheaper as drilling and

PHOTO COURTESY HESS CORP.

Vitesse Energy LLC's well interest in Hess Corp. is in the Bakken Shale.

frack technology improved," he continued. "The play got better, and that's really why we did so well."

As an example of improving technology over time, Gerrity cited the parent-child well relationship in the play. The typical parent well would have had an EUR of 600,000 boe in 2013 to 2014, he noted. By comparison, child wells today are likely to come in at an EUR of more than 1 MMboe, even though the spacing has become tighter in the interim, he said.

Vitesse has an estimated inventory of some 15,000 gross locations left to be drilled in the Bakken. This very substantial inventory is part of a "vision" the company implemented in deliberately focusing its investments on undeveloped acreage and, ideally, undeveloped core, Tier 1 acreage.

"This is the vision Gerrity brought to the Bakken," said Cree. "When we talk about being undeveloped, we didn't just fall into that; that was part of that vision. The vision was that it was better to be in an undeveloped play than in a developed play. If you think things are going to get better, with new wells drilled in the future, then focus your acquisition opportunities on undeveloped acreage."

'Vision' set on undeveloped acreage

The emphasis on undeveloped acreage—now standing at more than 47,000 net acres—actually helped protect Vitesse when WTI went sub-$30/bbl in early 2016, according to Cree.

"The beauty of Vitesse is that almost all the money we invested went into undeveloped acreage," he said. "Yes, some of our PDP [proved developed producing] properties lost value. But our undeveloped assets really didn't lose value, because during the timeframe that oil prices dropped, all the operators figured out how to get their EURs up and how to get their costs down.

"By the time they started drilling again, our undeveloped acreage was more valuable at $40/bbl than it had been at $100/bbl because of all the advances in operations. That's how we survived," he said. "Now, we can replace production and, at $45 to $55/bbl, still generate free cash flow because our wells are getting better and better."

As little as roughly 10% of the Vitesse reserves are categorized as PDP, that is, producing, and even without the benefits of its hedge book, it generates net income at $45/bbl. The company estimates that at an average $50/bbl for 2019, it will generate about $40 million of free cash flow that can be either redeployed or distributed to Jefferies.

Vitesse is also attentive to G&A, although low G&A "is not what makes a winning company," according to Cree. "Having lower G&A is a byproduct of having a well-run, non-op company. But not every non-op is going to have low G&A. You have to have that critical mass, too."

Importance of scale

As it has sought to attain greater scale in operations, Vitesse has on occasion turned to parent Jefferies.

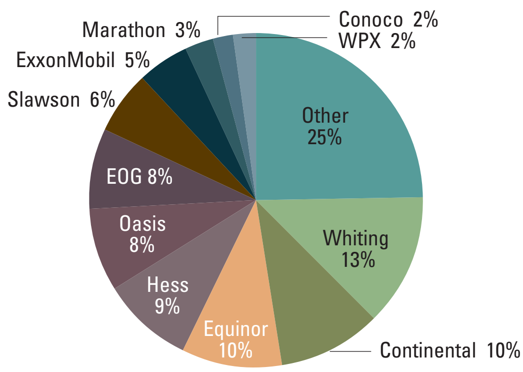
During the course of two years, Vitesse engaged in arduous, on-and-off negotiations that eventually led to the purchase of a package of non-op Bakken assets from an institutional seller in April of 2018. The purchase price was $190 million, of which $145 million was funded by Jefferies, with the balance being drawn under Vitesse's credit line.

The assets being acquired were well-known to the Vitesse team and involved 4,200 boe/d of flowing production and 23,000 net acres. The purchase essentially doubled the size of assets owned by Vitesse in the core of the Bakken, in many cases simply raising existing WIs already owned in the play. More than 85% of the assets in the acquisition were undeveloped.

With an asset that clearly has long-term growth prospects, does the Vitesse team have a next milestone in mind?

"We have a wonderful long-term investor, who has allowed us to build a company for the long-term," said Gerrity. "Scale is important; you do need scale. If we weren't producing over 9,000 boe/d, we wouldn't have the kind of net income that we have. We have a great company now, but we're going to look to double our company again in 2019." □

Vitesse's Well Interest



Source: Vitesse Energy LLC

M&A'S UNFINISHED SYMPHONY

Splashy mergers worth billions dominated the talk, but many companies spent the year playing it safe as E&P executives fretted over trade, interest rates, demand for oil, how to please investors and how long better times would last.

ARTICLE BY
DARREN BARBEE

ILLUSTRATION BY
RICK CORRIGAN

"It opened like a lion and ended with a thud," William A. Marko, managing director, Jefferies LLC, said of 2018, adding that the fourth quarter was "simply awful."

As 2018 unfolded, buyers bargained and sellers were willing to entertain offers. The backlog for A&D was deep. Oil prices flirted with $75 per barrel (bbl). Yet something was off.

Victor Barcot, managing director at Houlihan Lokey, calls 2018 "the missed upcycle." Even as oil prices escalated and deals were discussed, "We were kind of looking at each other across the table and saying, 'Yeah, but this sure feels like a $40 environment,'" Barcot told *Investor.*

Measured by value, 2018 was easy to see as a return to form for M&A, with overall deal value up 26% compared to 2017, according to the January report, "Unrealized Potential," by Deloitte. Multibillion-dollar deals and mergers uniting big-name, independent oil and gas companies flourished. But the large deals obscured a slowdown in closings for smaller and mid-size deals.

On June 27, a barrel of West Texas Intermediate (WTI) crude reached its highest spot price in three years, seven months and 17 days at $77.41/bbl, according to U.S. Energy Information Administration (EIA) data. Spot prices spent more than one-fifth of the year's trading days above $70.

"It ended up being somewhat of a disappointing year from a transactional standpoint," Barcot said. "To sum it up, no one really felt like it was sustainable.

"No one benefitted from it. The clients didn't benefit from it."

Across all sectors, the oil and gas industry spent more than $300 billion on deals, the highest value since 2014, according to a January presentation by PwC. However, about $120 billion of those transactions were restructurings and simplifications of midstream MLPs, which converted to C corp business structures.

In the upstream, M&A values soared—on paper, and specifically share certificates. Megadeals of at least $1 billion powered the overall U.S. upstream deal market to an $80-billion year. But for independent E&Ps, the currency of choice was common stock.

The top 10 largest upstream deals by value, strewn along the year from February to November, totaled $49.6 billion, or more than half of all the year's upstream deal value, according to *Investor* data. Major oil company BP Plc's purchase of BHP Billiton Ltd.'s U.S. assets led all upstream deals at $10.5 billion in cash.

However, public companies such as Concho Resources Inc. and RSP Permian Inc., and Diamondback Energy Inc. and Energen Corp., merged companies in the Permian Basin by putting virtually zero cash on the table. Among U.S. independent E&Ps and excluding BP, the 10 largest upstream deals totaled about $42 billion, roughly 81% of which was paid using stock, according to *Investor* analysis.

However, the overall rate of 2018 transactions fell 16%, or by 35 deals, compared with 2017, PwC said.

"When you look at 2018 on a deal volume basis, the 186 deals were well below our average of about 200 deals over the last nine or 10 years," said Joe Dunleavy, PwC's U.S. deals leader, in a January web presentation.

Mid-sized and smaller deals sometimes didn't get done or did so at a slackened pace from years past.

Fourth-quarter blues

For an industry that prides itself on optimism, the end of the year was a fog of pessimism.

With gallows humor, William A. Marko, managing director at Jefferies LLC, joked to a colleague, "Well, at least up to now, we've had a decade-long run.

"The year took a bad turn," Marko said, citing falling oil prices, the continued volatility

Victor Barcot, managing director, Houlihan Lokey, calls 2018 "the missed upcycle," noting that even as the oil price environment recovered, "no one benefited from it."

of the general stock market, the unknowns of tariffs and trade wars. Interest rates also rose, and with a "malaise in the public capital equity markets for energy, it's hard to do deals at this moment," he said in January.

"It opened like a lion and ended with a thud," Marko said of 2018. "The fourth quarter was awful."

The first nine months of 2018 saw a seesawing of deal activity—the second quarter was miserable, the third quarter fabulous—and the usual basins being haggled over.

The Permian Basin led all basins both in value and volume with 33 deals tallying $36 billion, followed by the Bakken at $21 billion, PwC said.

Deloitte added that, "in any given quarter, the weighted average dollar per acre paid by companies for Permian assets is two to five times higher than prices for acreage in other basins."

In the Eagle Ford, about $8 billion in deal value opened up and $10 billion in the Scoop/Stack, Deloitte said.

But in the M&A trenches, advisers and business development professionals saw the year close in stark contrast to the megamergers and hearty third quarter.

From early October through the end of 2018, spot prices dropped by $30.68/bbl, ending at $44.48, the lowest price of the year. Average fourth-quarter WTI prices fell 15% compared to the third quarter's average.

Fourth-quarter deal value fell by 37% compared to the third quarter, excluding drop-down deals and related party transactions, PwC said.

Already announced but unclosed mergers may yet face additional hurdles, Marko said.

"The public mergers are under a lot of pressure at this moment," Marko said. "I think the intention by many is to try to get them closed, and we'll see how things turn out."

Evidence of that pressure surfaced in late December, as sliding oil prices and relentlessly falling stock prices played a role in Earthstone Energy Inc. nixing its $950-million deal for Sabalo Energy LLC. Denbury Resources Inc.'s $1.7-billion deal for Penn Virginia Corp. is also under fire by some investors who consider Denbury's offer too low. And Denbury's share price averaged a 46% decline from Oct. 28 through early January.

As first-quarter 2019 began, deals and larger consolidation were at risk, especially as oil prices continued to stall out and potential buyers' stock prices continue to swoon, said Austin Elam, an attorney with Haynes and Boone LLP's Oil and Gas Practice Group.

"Until prices stabilize, there is an expectation that A&D activity for oil-focused basins will slow, including a pause to increased industry consolidations," Elam told *Investor.*

Capped market

In first-quarter 2018, Houlihan Lokey had seven A&D sell-side mandates and Barcot expected them all to close, he said. Oil prices were at a healthy level. Clients expressed interest in transacting.

But as the summer neared and the second quarter began, potential buyers began to pull back, he said.

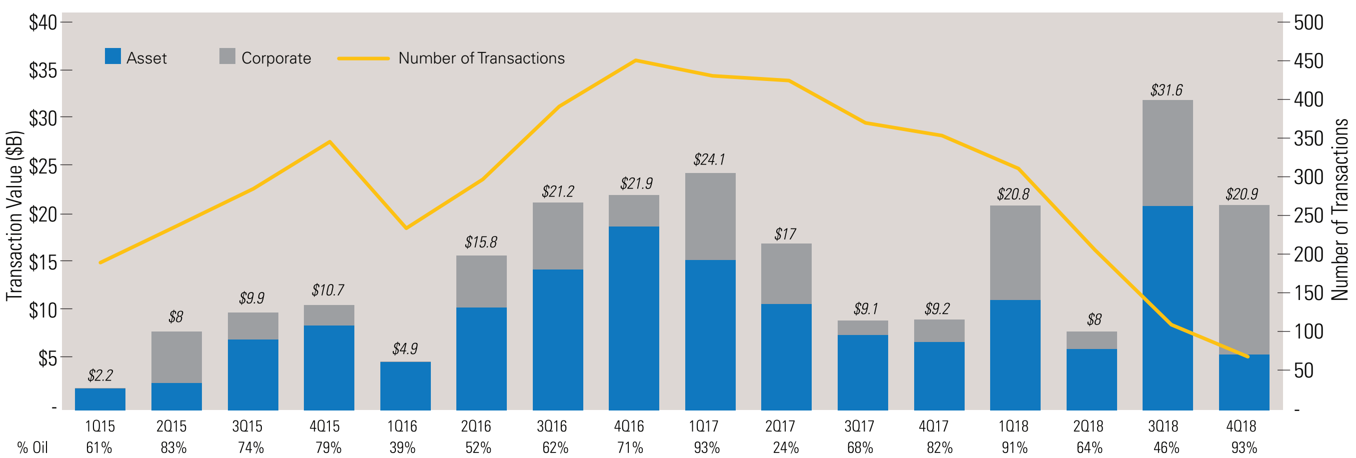
"The buyers were … falling through because of funding. Funding wasn't coming through," Barcot said. "Access to capital markets seemed to be an issue for publics."

Bolstered by epic-sized deals, M&A seemed on solid footing but hid the difficulty many public E&Ps faced. Even as companies show sustained efforts toward capital discipline, Barcot said, investors have made a fundamental shift in capital allocation away from the oil and gas space.

The hope had been that increased prices, E&Ps' restrained spending and paying down debt would lure the market investors back in 2018, Elam said. That hasn't helped E&Ps, however, which see their values continue to trail commodity price increases.

"The markets have reiterated the need for producers to demonstrate value through drilling within cash flow and to rationalize their balance sheet, relying less upon debt and equity issuances than in prior years," he said. "Until producers can demonstrate that ability, public investor appetite for the upstream industry might remain depressed, continuing trends from 2018."

Quarterly Deal Activity (Through Feb. 4)



Source: BMO Capital Markets

Last year, companies played it safe by divesting noncore assets or consolidating with other producers. Shale producers also kept busy swapping acreage to create more contiguous blocks to allow for maximum lateral wells, Elam said.

Still, as oil prices have dropped precipitously, Marko said, times have changed at oil and gas companies. In early 2017, an executive vice president at Equinor noted that in 2014, the company needed $90/bbl to make money.

"In 2018, we'll make money at $50," the executive said.

Marko said that E&Ps are prepared, should prices remain in a long-term funk.

"That's kind of a microcosm of what a lot of companies have done. They've really looked at cost structure," Marko said. He noted that ConocoPhillips Co. evaluates its portfolio by cost of supply and how low prices can get while the company still earns 10% returns at different price levels. Some of those prices are as low as $30/bbl, he said.

"They've really scrubbed the portfolio so they can live in a lower-cost environment," he said.

'The Fear Index'

With public companies hamstrung by the markets, essentially one subset group of buyers—private equity—remained. "And they all knew they were the only buyers," Barcot said.

However, private equity faces its own challenges, chief among them a path toward the exits. Partly that's due to the cold shoulder markets continue to give IPOs and follow-on offerings.

Private-equity firms still command a huge stockpile of cash and demand remains strong, but private capital appears to be behaving cautiously, Marko said.

"There are probably more than 250 management teams, so there's somebody out there looking at almost anything you could think of," he said. "So there is demand to some extent for almost anything."

Curt Karges, PwC managing director and energy leader, sees sentiment in the industry more negative than it was a year ago, despite oil at roughly the same price.

The rate of global growth, trade complexities, market volatility and rising interest rates are concerning, he said during the January presentation. "I would call that sort of the fear index," he said. "Added to that is the actual experience by investors."

Karges noted that private equity has invested in about 250 service companies, with 180 of those investments made prior to 2015 at

KEY AREAS TO WATCH:

Acreage or production? Curt Karges, PwC managing director and energy leader, said that 2019 will likely "continue to see that investors will be buying cash flow, not acreage." Companies will try to lower costs through scale, invest in technology and "balance spending money vs. monetizing prior investing."

The Permian's many remaining small- and mid-cap Permian pure plays will also be asking themselves serious questions about longevity or the ability to compete with their larger neighbors in productivity, costs and services, Greig Aitken, director, M&A research at Wood Mackenzie, said in a January report.

"How do they remain relevant to investors? We expect more combinations," Aitken said.

Aitken also said that at least two material positions appear to be piquing the interest of buyers. One is EnCap Investments-backed Felix Energy Resources LLC's Delaware Basin position. The other is Endeavor Energy Resources LLC, which holds more than 300,000 net acres in the Midland Basin.

"It is no surprise that Chevron [Corp.], ExxonMobil and Shell are rumored to have kicked Endeavor's tires," he said. "A deal in 2019 is not a foregone conclusion, but if Endeavor's backers want a near-term exit, the IPO route looks like a nonstarter under current market conditions."

QEP Resources Inc. has also engaged advisers to explore a possible sale after an activist investor offered to buy the company. Abraxas Corp., which has formally hired an adviser to sell its Bakken assets, is also a potential Permian buyout candidate.

Consolidation remains necessary in the Permian if the market is to strengthen, Barcot said.

"We have just way too many companies in the U.S. Fourteen or 15 independent companies in the Permian Basin is not sustainable," Barcot said. "If I look at the outlook and the bright side of it is that reduced capital allocation in the sector, reduced oil prices are going to force some healthy transitions."

Oil pricing will remain a key determinant in how deals flow in 2019, Karges said.

"Tell me what the oil price is going to be, and I'll tell what M&A activity is," Karges said. "Obviously, supply of oil is going to be there. The question is, what is the demand?"

Deflated oil prices will also likely mean companies will deal for low-risk, producing assets rather than undeveloped acreage, Deloitte said.

Oil demand is now more important that supply. Barcot, a former equity research analyst and CEO of a publicly traded E&P, said 2018 was the year he finally stopped looking to supply for answers to oil and gas pricing and deals.

The switchover to a demand-focused world appears to have become cemented in the minds of investors as well, he said. Even OPEC's late push in December to install quotas did little to raise prices or stir the market.

Where peak oil production once was the obsession of oil companies, Barcot said that peak demand now appears to be driving the markets. Renewable energy is also sapping an increasingly larger share of electric generation.

U.S. crude oil production is still predicted to set annual records through 2027 and to remain at more than 14 MMbbl/d through 2040, according to the EIA's 2019 energy outlook.

Barcot, however, said that demand is a fundamental question.

"We've sort of answered that we have unlimited supplies in the U.S.," he said. "We've grown to this astronomical output figure, to where now private-equity firms are fighting over export terminals and deepwater docks to export our excess hydrocarbons."

As the second half of the year came to a close, he said that "industry keeps trying to fix supply, but the reality is the investor universe, as the capital providers to this space and the buyers of the stock, they're not focused on supply. Supply was answered from 2008 to 2014. Now it's demand, peak demand."

"Until prices stabilize, there is an expectation that A&D activity for oil-focused basins will slow, including a pause to increased industry consolidations," said Austin Elam, an attorney at Haynes and Boone LLP.

relatively high valuations. Headed into 2018, many private-equity companies "believed they were going to be able to finally exit at a profit" for their older portfolio of investments.

But the industry as a whole saw "a lot of busted auctions. There's still a bid-ask spread between owners of properties and prospective owners or investors."

A scarcity of IPOs and lethargic market activity have also hampered private equity from finding the exits.

In the second half of 2018, public oil and gas companies' secondary offerings averaged $1.5 billion, down from an average $3.25 billion in the previous four quarters, according to PwC. For the nine months spanning the second, third and fourth quarters, only one IPO successfully launched, though at least 10 companies have expressed interest in going public, according to PwC.

E&Ps and particularly natural gas companies, most backed by private-equity capital, will be hard-pressed to make substantial moves in 2019, Marko said.

"You've got a number of Haynesville producers that have publicly stated 'we'd like to go public,'" he said. "There's no IPO market for energy in general and even less so for gas," he said.

Investors have also pulled up stakes in the oil and gas industry in general, Barcot said. Prior to the 2014 and 2015 downturn, large-scale investors were allocating up to 15% to 17% of the entire capital allocation to the space. Since then, "the bucket of money" devoted to the space "has shrunk to 7% to 9% and we're there permanently now," he said.

With a "flight to quality, mature companies and vertically integrated companies such as ExxonMobil [Corp.] and ConocoPhillips performed well compared to the group," he said. "Overall the sector's down and is underperforming the broader market."

2019 themes

The road to M&A in 2019 may be as treacherous and full of blind curves as it's been since the downturn.

The market volatility that began to stabilize in January will need to further settle before more megamergers or acquisitions kick off in 2019, said Kraig Grahmann, an attorney with Haynes and Boone.

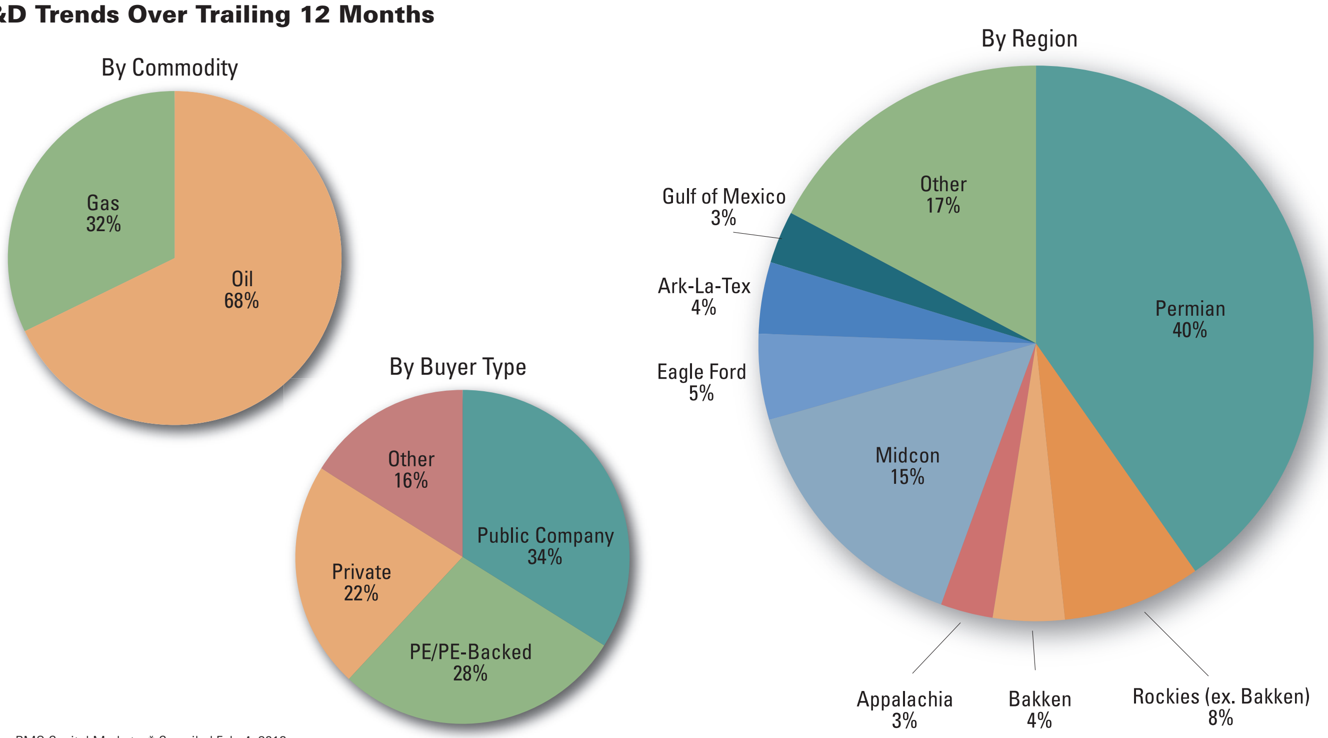
Views of M&A vary widely, with speculation over what moves international oil companies have to make in the U.S. and how oil and gas pricing might make a difference. Consolidation, particularly between large independents and small and mid-size companies, seems likely to be part of the balance of deal making. But cash flow will continue to be more of a motivator than raw acreage, deal makers and other industry observers said.

Grahmann sees 2019 M&A revolving around themes: a major or super-major making a transformative entry into a basin—or an independent E&P company exiting an asset that it acquired in a better price environment to pay down debt, return cash to shareholders or invest in its core assets.

Karges, however, said it appears that most of the majors have finished positioning in shale plays and will likely work toward lowering costs and improving drilling efficiency. While integrated companies have clearly become convinced that shale is part of their future, they also retain deepwater investments.

"They have established positions in the major shale regions, most notably the Permian," he said. □

A&D Trends Over Trailing 12 Months



Source: BMO Capital Markets * Compiled Feb. 4, 2019

U.S. E&P ACQUISITIONS & DIVESTITURES

Deals closed from July 1-Dec. 31, 2018. Deals closed in first-half 2018 were listed in the September 2018 issue. All deals, updated in real time, are now available at HartEnergy.com.

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
1	10,500	BP Plc; BP American Production Co.	BHP Billiton Ltd.; Petrohawk Energy Corp.	10	Bought 100% of the issued share capital of Petrohawk, which holds BHP's Eagle Ford, Haynesville and Permian/Delaware Basin shale assets in LA and TX; includes about 526,000 net acres which produced 58.8 MMboe in the 2018 financial year.
2	9,500	Concho Resources Inc.	RSP Permian Inc.	7	Acquired Dallas-based RSP Permian in an all-stock transaction; includes roughly 92,000 net acres in the Permian and 55.5 Mboe/d of 4Q 2017 production.
3	9,200	Diamondback Energy Inc.	Energen Corp.	11	Acquired Energen, which holds a 179,000-net-acre position across the Permian's Midland and Delaware basins; includes $830MM net debt.
4	2,660	TPG Pace Energy Holdings Corp.; Magnolia Oil & Gas Corp.	EnerVest Ltd.	7	Acquired EnerVest's S TX division, which includes 360,000 net acres and 40,000 boe/d of current net production of Eagle Ford and Austin Chalk assets, and form a new pure-play operator Magnolia Oil & Gas.
5	2,303	Flywheel Energy LLC; Kayne Private Energy Income Funds LP	Southwestern Energy Co.	12	Bought Southwestern's Fayetteville Shale business consisting of 915,000 net acres, 4,033 operated producing wells and associated midstream in the AR Arkoma Basin; includes assumption of $438MM in future contractual liabilities.
6	2,000	Encino Acquisition Partners; Canada Pension Plan Investment Board	Chesapeake Energy Corp.	10	Acquired Chesapeake's OH acreage, of which about 320,000 net acres are in the commercial window for the Utica Shale, 920 operated and nonop wells which produced an average of about 107,000 boe/d (67% natural gas, 24% NGL and 9% oil) in 2017, on a net basis, and related property and equipment.
7	1,245	Diamondback Energy Inc.	Ajax Resources LLC; Kelso & Co.	10	Purchased Ajax in a cash-and-stock transaction; includes about 25,493 net leasehold acres in the northern Midland Basin with more than 12,100 boe/d (88% oil) of production and 362 net identified potential horizontal drilling locations.
8	1,225	Kosmos Energy Ltd.	Deep Gulf Energy Co.; First Reserve Corp.	9	Acquired Houston-based Deep Gulf Energy, which has operated assets in the deepwater U.S. GoM producing about 25,000 boe/d (85% oil).
9	1,100	Murphy Oil Corp.	Petróleo Brasileiro SA (Petrobras)	12	Formed deepwater U.S. GoM JV; adds 41,000 net boe/d to Murphy's GoM production (97% oil).
10	800	Falcon Minerals Corp.; Osprey Energy Acquisition Corp.	Royal Resources Partners LP; Blackstone Energy Partners LP; Blackstone Capital Partners LP	8	Acquired Blackstone's Royal Resources, which represents the entirety of the firm's mineral interests in the Eagle Ford Shale, forming new public company Falcon Minerals.
11	775	Diversified Gas & Oil Plc	EQT Corp.	7	Purchased 92% NRI in roughly 2.5 million net acres of Huron assets across KY, VA and WV within southern Appalachia; includes about 12,000 wells with current net production of 200 MMcfe/d, midstream infrastructure and assumption of $200MM plugging/liabilities.
12	620	Comstock Resources Inc.	Arkoma Drilling LP; Williston Drilling LP	8	Acquired interests in certain oil and gas properties in ND's Bakken shale basin, currently producing 10,500 bbl/d of oil and 20 MMcf/d of natural gas.
13	620	The Carlyle Group LP	Diamondback Energy Inc.	9	Formed JV to develop San Pedro area assets in Pecos County, TX, within the southern Delaware Basin.
14	600.5	PennEnergy Resources LLC; EnCap Investments LP; Wells Fargo Energy Capital Inc.	Rex Energy Corp.	9	Bought substantially all of State College, PA-based Rex's Appalachia-focused assets and assume certain liabilities.
15	570	Callon Petroleum Co.	Cimarex Energy Co.	9	Purchased oil and gas properties in the Delaware Basin covering about 28,657 net surface acres primarily in Ward County, TX; includes 6,831 boe/d (73% oil) of production mainly from the Bone Spring Formation and 18,925 net undeveloped Wolfcamp acreage.
16	480	DJR Energy LLC; Trilantic Capital Management LP; Waveland Energy Partners; Global Energy Capital	Encana Corp.; Encana Oil & Gas (USA) Inc.	12	Purchased Encana's San Juan Basin position in N NM; includes about 182,000 net acres and average production in 2017 of 5,400 boe/d (3,900 bbl/d of liquids).
17	477	Ascent Resources LLC; Ascent Resources - Utica LLC; Ascent Utica Minerals LLC	Utica Minerals Development LLC	7	Bought certain natural gas and oil properties within the Utica Shale in the Appalachian Basin; includes royalty interests on about 69,400 fee mineral acres.
18	404	Kimbell Royalty Partners LP	Haymaker Minerals & Royalties LLC; Haymaker Resources LP; KKR & Co. LP; Kayne Anderson Capital Advisors LP	7	Acquired the mineral and royalty interests which include 5 million gross mineral acres and mineral and royalty interests in more than 35,000 producing wells across 26 states; also includes interest in the Permian Basin and Midcontinent Scoop/Stack regions.

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
19	400	Ascent Resources LLC; Ascent Resources - Utica LLC	CNX Resources Corp.	8	Purchased a 50% stake in OH Utica JV assets; includes about 39,000 net acres, of which 26,000 net acres are undeveloped, and net production for 2018 forecast to average 14,000 boe/d (70% residue gas).
20	400	Ascent Resources LLC; Ascent Resources - Utica LLC	Hess Corp.	8	Purchased a 50% stake in OH Utica JV assets; includes about 39,000 net acres, of which 26,000 net acres are undeveloped, and net production for 2018 forecast to average 14,000 boe/d (70% residue gas).
21	400	ConocoPhillips Co.	Anadarko Petroleum Corp.	6	Acquired 22% nonop interest in the AK's western N Slope assets; includes interest in the Alpine pipeline.
22	387	Matador Resources Co.	U.S. Bureau of Land Management	9	Purchased through the BLM lease sale 8,400 gross/net acres in the Delaware Basin in Lea and Eddy counties, NM.
23	322	Cox Oil Offshore LLC	Energy XXI Gulf Coast Inc.	10	Acquired Houston-based Energy XXI for $9.10 per share; includes about 26,000 boe/d of production in the GoM.
24	312.5	Diamondback Energy Inc.	ExL Petroleum Management LLC; ExL Petroleum Operating Inc.; EnergyQuest II LLC	10	Purchased 3,646 net leasehold acres and related assets in Martin and Andrews counties, TX, within the northern Midland Basin; includes roughly 3,500 boe/d of current net production.
25	300	Merit Energy Co.; MMGJ Hugoton III LLC	BHP Billiton Ltd.	9	Purchased BHP's Fayetteville assets in central N AR; includes about 268,000 net acres and 13.3 MMboe (79.9 Bcf of gas) of production in the 2018 financial year.
26	300	Undisclosed	Range Resources Corp.	10	Purchased 1% overriding royalty interest in Range's Washington County, PA, leases in the Appalachian Basin; interest applies to existing and future Marcellus, Utica and Upper Devonian development.
27	292	Northern Oil and Gas Inc.	W Energy Partners; Crestview Partners LP	10	Acquired 10,600 net acres in the core of the Williston Basin with expected production of about 6,750 boe/d.
28	230	Lime Rock Resources	ConocoPhillips Co.	11	Bought interest in about 114,000 net acres in the Barnett Shale in N TX's Fort Worth Basin; production averaged 9,000 boe/d (55% natgas, 45% NGL) for 1H 2018.
29	223	Ascent Resources LLC; Ascent Resources - Utica LLC	Salt Fork Resources LLC	8	Bought certain natural gas and oil properties within the Utica Shale in the Appalachian Basin.
30	220	Franco-Nevada Corp.	Continental Resources Inc.	8	Formed JV to acquire mineral interests in OK's Scoop and Stack shale plays; includes acquisition of a stake in Continental's newly formed minerals subsidiary.
31	204.9	Carrizo Oil & Gas Inc.	Devon Energy Corp.	10	Purchased 9,600 net acres adjacent to its Phantom area in Reeves and Ward counties, TX, in the Delaware Basin with production of about 2,500 boe/d.
32	201	Scout Energy Partners	Pioneer Natural Resources Co.	8	Bought Pioneer's West Panhandle position in TX; includes 239,500 net HBP acres, 705 operated wells and average net production during 1Q 2018 of about 6,000 boe/d.
33	191	Magnolia Oil & Gas Corp.	Harvest Oil & Gas Corp.	8	Purchased Harvest's S TX assets comprised of about 114,000 net acres in Giddings Field and 15 net core Karnes County locations; includes about 4,800 boe/d of 1H 2018 production.
34	186	Vermilion Energy Inc.	Massif Oil & Gas LLC	9	Purchased mineral land and producing assets in the Powder River Basin in Campbell County, WY; includes 96% WI in roughly 55,700 net acres and 2,500 boe/d (63% oil and NGL) of production.
35	183	Diversified Gas & Oil Plc	Core Appalachia Holding Co. LLC	10	Acquired Charleston, WV-based Core Appalachia; portfolio in KY, VA and WV includes 5,000 wells, 1.3 million net acres, 11,200 boe/d (90% gas), 4,100 miles of pipeline and 47,000 hp of compression.
36	164	Undisclosed	Parsley Energy Inc.	11	Bought about 11,850 net acres and 256 locations in the southern Midland Basin across Reagan, Upton and Howard counties, TX, as part of multiple sales and acreage trade.
37	156	Franklin Mountain Energy LLC; Franklin Mountain Capital	U.S. Bureau of Land Management	9	Bought about 4,041 acres in Lea and Eddy counties, NM, within the Permian's Delaware Basin through the BLM lease sale.
38	155	Middle Fork Energy Partners LLC; Quantum Energy Partners	QEP Resources Inc.; QEP Energy Co.	9	Purchased Uinta assets located in eastern Utah in Duchesne and Uintah counties; includes natural gas and oil producing properties, undeveloped acreage and related assets with 1Q 2018 net production of 54 MMcfe/d (23% liquids) and 605 Bcfe estimated proved reserves.
39	151.8	Northern Oil and Gas Inc.	Pivotal Petroleum Partners II LP; Tailwater Capital LLC	9	Acquired a large package of producing wells in the core of the ND Williston Basin with more than 4,100 boe/d of production.
40	144.5	Osaka Gas Co. Ltd.; OG East Texas LLC	Sabine Oil & Gas Corp.; Sabine East Texas Basin LLC	7	Acquired a 30% stake in Sabine's E TX shale gas project targeting the Cotton Valley Sand and Haynesville Shale formations; includes 450 wells producing about 45 MMcfe/d on roughly 100,000 acres, 35,000 net to Osaka.
41	132.8	Matador Resources Co.	Jetstream Oil and Gas LLC	10	Acquired 12,600 net leasehold and mineral acres in the Delaware Basin including 2,600 net mineral acres. T*his deal closed in 3Q 2018.*

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
42	132	Undisclosed	Pioneer Natural Resources Co.; Newpek LLC	12	Bought Pioneer's position in Sinor Nest (Lower Wilcox) Field in Live Oak County in S TX; includes roughly 2,900 net acres and average net production of 3,100 boe/d.
43	130	Whiting Petroleum Corp.	Undisclosed	7	Acquired bolt-on of Williston Basin properties contiguous with the E Missouri Breaks and Hidden Bench areas that encompass 54,833 net acres with current production of 1,20 boe/d and estimated proven reserves of 26 MMboe.
44	117	Mission Creek Resources LLC	Bonanza Creek Energy Inc.	8	Bought a Midcontinent position covering about 11,000 net acres in Lafayette and Columbia counties, AR, primarily targeting the Cotton Valley Formation; includes associated net production during 1Q 2018 of about 3,000 boe/d (55% oil) and 12 MMboe proved reserves (100% PDP).
45	100	Rebellion Energy II LLC	Liberty Resources II LLC	9	Bought 19,000 net Powder River Basin acres.
46	97	SRC Energy Inc.	Undisclosed	9	Purchased vertical and horizontal wells in the Greeley-Crescent development area in Weld County, CO, within the D-J Basin.
47	90	Kimbell Royalty Partners LP	Undisclosed	12	Purchased package of royalty interest predominately located in the Eagle Ford Shale, Permian Basin, Appalachian Basin and Bakken; includes 16,700 net royalty acres and about 1,190 boe/d of production (6:1).
48	82.5	Energy Resources 12 Operating Co. LLC	Bruin E&P Non-Op Holdings LLC	8	Purchased interest in certain nonop oil and gas properties and related rights with in the Bakken in McKenzie, Dunn, McLean and Mountrail counties, ND.
49	79	Evergreen Natural Resources	Pioneer Natural Resources Co.	7	Purchased 165,000 net acres in the Raton Basin in southeastern Colorado.
50	77	Undisclosed	Oasis Petroleum Inc.	8	Bought 15,000 net acres Williston Basin acres.
51	75	Equinor ASA	Texegy LLC	9	Purchased exploration acreage in the LA Austin Chalk play.
52	75	Otto Energy Ltd.	Hilcorp Energy Co.	7	Formed JV to acquire a 37.5% WI in an eight-well portfolio of prospects in the onshore/near shore U.S. Gulf Coast (GoM); estimated cost to Otto is $37.5MM.
53	75	Bainbridge Energy Partners LLC	Ultra Petroleum Inc.	10	Bought all of Ultra's UT assets, which had about 2,000 boe/d of 2Q 2018 production.
54	60	Undisclosed	Vanguard Natural Resources Inc.	7	Acquired certain properties in the Permian Basin, Green River Basin and MS regions currently producing about 17 MMcfe/d; executed through four separate PSAs.
55	58	Presidio Petroleum LLC; Morgan Stanley Equity Partners	Midstates Petroleum Co.	6	Bought producing properties in the Anadarko Basin located in the TX Panhandle and western OK; includes production of about 3,900 boe/d and proved developed PV-10 value of $53 million.
56	57	Carbon Natural Gas Co.; Carbon Appalachia Co. LLC	Old Ironsides Energy LLC	12	Purchased the remaining 73.5% outstanding Class A units in Carbon Appalachian.
57	56.8	Undisclosed	W&T Offshore Inc.	9	Bought ownership in overriding royalty interests in about 25,500 net Permian Basin acres.
58	55	PetroShale Inc	Undisclosed	7	Purchased 1,981 Williston Basin acres.
59	52	Talos Energy Inc.	Whistler Energy II LLC; Apollo Global Management LLC	9	Acquired Whistler, which holds 100% WI in Green Canyon 18, Green Canyon 60 and Ewing Bank 988 blocks in the Central GoM producing about 1,500 boe/d (82% oil) year-to-date.
60	50	Undisclosed	Devon Energy Corp.	11	Acquired roughly 100,000 net acres in the Barnett Shale in Wise County, TX, with 400,000 boe/d of production.
61	45	Cobra Oil & Gas Corp.	Enduro Resource Partners LLC	6	Purchased ND waterflood assets as part of a stalking-horse bid.
62	43	WildHorse Resource Development Corp.	Undisclosed	9	Acquired in multiple agreements about 31,005 net acres in the Eagle Ford, Austin Chalk and other intervals; includes 39 boe/d of net production across Burleson, Brazos, Lee and Washington counties, TX.
63	42	Undisclosed	MCM Energy Partners LLC	12	Purchased leasehold within the Delaware Basin in Ward and Loving counties, TX.
64	40	Northern Oil and Gas Inc.	Salt Creek Oil & Gas; Deutsche Rohstoff AG	6	Bought nonop interest in producing assets and acreage in the core of the Williston Basin in ND.
65	38.7	Lonestar Resources US Inc.	Sabine Oil & Gas Corp.; Alerion Gas AXA LLC	11	Purchased 3,084 gross (2,706 net) acres of producing Eagle Ford Shale properties (95% operated) within Sugarkane Field in DeWitt County, TX; includes 800 boe/d of production from 20 wells.
66	38	SRC Energy Inc.	Undisclosed	8	Bought leasehold acreage and associated nonoperated production in the D-J Basin; included working interest in existing operations and planned wells.
67	37.4	Undisclosed	Camber Energy Inc.	9	Bought a 'substantial portion' of Camber's assets which includes holdings within the Hunton Formation in Central OK, Permian Basin's San Andres Play and TX Panhandle.

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
68	37	Comstock Oil & Gas-Louisiana LLC; Comstock Resources Inc.	Enduro Resource Partners LLC	8	Purchased Cotton Valley and Haynesville Shale assets largely in Caddo and De Soto parishes, LA, as a stalking-horse bidder.
69	37	Cuda Oil and Gas Inc.	Undisclosed	8	Bought a light oil asset in WY's Powder River Basin; includes 25,000 gross acres.
70	36	COERT Holdings I LLC	Enduro Resource Partners LLC	8	Purchased assets in the Permian Basin, East Texas and northern Louisiana
71	31	Undisclosed	Carrizo Oil & Gas	7	Bought 1,700 net Delaware Basin acres.
72	28	Undisclosed	Viking Minerals LLC	7	Purchased 1,191 net royalty acres in Karnes, DeWitt and Gonzales counties, Texas, in the Eagle Ford Shale.
73	28	Undisclosed	Chaparral Energy Inc.	7	Acquired, in three deals, noncore assets in Texas and Oklahoma.
74	26	Centennial Resource Development Inc.	Undisclosed	11	Bought about 2,100 net acres in Reeves County, TX, within the southern Delaware Basin.
75	25.1	SandRidge Energy Inc.	Undisclosed	11	Purchased certain oil and gas properties, rights and related assets in the Mississippi Lime and Northwest Stack areas of OK and KS in the Midcontinent region.
76	24.4	Southern Energy Corp.; Standard Exploration Ltd.	Gulf Pine Energy Partners LP	12	Acquired Calgary, Alberta-based Gulf Pine, which assets consist of more than 29,000 net acres of developed land and 30,000 net acres of undeveloped land in AL and MS.
77	22.9	Sanguine Gas Exploration LLC	Vanguard Natural Resources Inc.	8	Bought conventional Arkoma Basin gas assets; includes 44 active operated wells, associated compression and gathering infrastructure in Potato Hills Field in southeastern OK.
78	21	Pacific Energy Development Corp.	Hunter Oil Corp.	8	Purchased 2,300 net acres in the San Andres Formation.
79		BCE-Mach II LLC	Mach Resources LLC; Bayou City Energy Management LLC	10	Formed JV to focus on acquisition opportunities in the western Anadarko Basin across OK and TX.
80		BCE-Mach LLC; Bayou City Energy Management LLC; Mach Resources LLC	Repsol E&P USA Inc.	10	Bought producing properties in OK and KS consisting primarily of interests in wells operated by SandRidge Energy.
81		Cuda Energy Inc.; Cuda Oil and Gas Inc.	Junex Inc.	8	Acquired in a business combination forming Cuda Oil and Gas, which will have a portfolio of assets in WY's Powder River Basin and Canada within Alberta and Québec.
82		CML Exploration LLC	U.S. Energy Corp.	8	Formed JV to continue development of its existing leasehold in Zavala County, TX, targeting the Georgetown Formation.
83		ConocoPhillips Co.	BP Plc	12	Purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the AK North Slope in exchange for 16.5% interest in Clair Field in the U.K. North Sea.
84		DoublePoint Energy LLC	Double Eagle Energy Holdings LLC; FourPoint Energy LLC	6	Formed new Midland Basin pure play through the combination of Double Eagle's existing acreage and production plus recently acquired assets; includes 70,000 acres in Midland, Glasscock, Martin, Howard, Upton and Reagan counties, TX.
85		Earthstone Energy Inc.	Undisclosed	10	Purchased an average 100% WI in 3,899 net operated acres in Reagan County, TX, within the Midland Basin in exchange of 1,222 net nonop acres in Glasscock County, TX, with average WI of 39% and $27.8MM cash as part of an acreage trade.
86		Empire Petroleum Corp.; Empire Louisiana LLC	Cardinal Exploration and Production Co.; Exodus Energy Inc.	10	Purchased operated producing oil and gas assets in St. Landry and Beauregard parishes, LA; includes about 70 boe/d and about 1,555 gross acres of leasehold.
87		Eni SpA	Caelus Energy LLC; Caelus Alaska Exploration LLC	8	Purchased 100% WI in 124 exploration leases covering roughly 350,000 acres in the eastern exploration area of the AK North Slope.
88		Franklin Mountain Energy LLC; Franklin Mountain Capital	OneEnergy Partners Operating LLC; Carnelian Energy Capital Management LP	10	Bought operations and leasehold totaling about 4,280 net acres in Lea and Eddy counties, NM, within the Permian's Delaware Basin.
89		Fremont Petroleum Corp. Ltd.	Undisclosed	7	Purchased 2,702 net acres in Pathfinder Field within the D-J Basin of CO.
90		Lilis Energy Inc.	Felix Energy Holdings II LLC	8	Acquired acreage in its core Delaware Basin position through an acre-for-acre trade of about 1,500 net acres in Winkler and Loving counties, TX.
91		Lilis Energy Inc.	Ameredev II LLC	9	Acquired NM Delaware Basin properties in an acre-for-acre trade of about 750 net acres in Lea County in exchange for nonop sections with lower WI.

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
92		Murchison Oil and Gas LLC	Roxo Energy LLC; Vortus Investments LLC	10	Bought Roxo's interest in oil and gas leases and wells in Howard and Borden Counties, TX, within the northern Midland Basin; includes roughly 5,300 contiguous leasehold acres targeting the Wolfcamp and Spraberry.
93		Nostra Terra Oil and Gas Co. Plc	Tall City Exploration III LLC; Warburg Pincus LLC	10	Bought 100% operated WI in the Mesquite Prospect, which covers about 1,384 net acres in W TX with the potential for eight horizontal wells.
94		Red Emperor Resources NL; Otto Energy Ltd.; 88 Energy Ltd.	Great Bear Petroleum II LLC	7	Purchased a majority of Great Bear's WI in four leases on the western flank of the AK N Slope.
95		Riviera Resources LLC	Linn Energy Inc.; Blue Mountain Midstream LLC	8	Bought assets in spin-off forming new company operating Linn's legacy, mature, low-decline properties located in KS' Hugoton Basin, E TX, N LA, MI/IL, UT's Uinta Basin and the Midcontinent region in OK.
96		Roan Resources Inc.; Linn Energy Inc.	Citizen Energy II LLC	9	Acquired Citizen's 50% equity stake in Roan as part of a reorganization agreement.
97		Royale Energy Inc.	California Resources Corp.	10	Formed JV expanding previous development area to entire Rio Vista Field in N CA; provides Royale up to three years to drill to any formation.
98		SRC Energy Inc.	Undisclosed	9	Acquired assets through a trade of about 2,500 net acres, which further enhanced contiguous nature of SRC Energy's acreage position in the D-J Basin.
99		Undisclosed	Amelia Resources LLC	8	Purchased 40,000 net acres in the LA Austin Chalk and LA-MS Stack Play.
100		Undisclosed	Cabot Oil & Gas Corp.	7	Bought Cabot's remaining E TX assets.
101		Venado Oil & Gas LLC; KKR & Co. LLP	Texas American Resources LLC; First Reserve Corp.	7	Purchased the assets of Texas American Resources, which included a position in the Eagle Ford Shale of more than 23,000 net acres.

Deals shown are those closed during second-half 2018, 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, 2019, will appear in the September 2019 issue. Details on all deal-making, updated in real time, are available at HartEnergy.com.

PENDING DEALS (AS OF JAN. 1, 2019)

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
102	7,700	Encana Corp.	Newfield Exploration Co.		To acquire The Woodlands, TX-based Newfield in an all-stock transaction and the assumption of $2.2B net debt; includes positions in the Anadarko Basin (Stack/Scoop), Arkoma Basin, Uinta Basin and Williston Basin.
103	3,977	Chesapeake Energy Inc.	WildHorse Resource Development Corp.		To acquire Houston-based WildHorse in a cash-and-stock merger; includes roughly 420,000 net acre position in the Eagle Ford Shale and Austin Chalk formations in S TX with 47,000 boe/d of production (88% liquids/73% oil). *This deal closed in February.*
104	1,725	Vantage Energy Acquisition Corp.; Vantage Energy Inc.; NGP Energy Capital Management LLC	QEP Resources Inc.		To acquire the entirety of QEP's Williston Basin assets in ND and MT; includes more than 100,000 net acres in the core of the Bakken in the S Antelope and Fort Berthold leasehold and various mineral interests currently producing 46,000 boe/d.
105	1,700	Denbury Resources Inc.	Penn Virginia Corp.		To acquire through a cash-and-stock merger Houston-based Eagle Ford Shale operator Penn Virginia, which holds roughly 84,000 net acres across Gonzales, Lavaca and Dewitt counties, TX, with net production of 22,200 boe/d (74% oil).
106	1,600	Cimarex Energy Co.	Resolute Energy Corp.		To acquire Denver-based Resolute which controls 21,100 net acres (89% HBP) within the Delaware Basin in Reeves County, TX, with an average 79% WI (97% operated) and average production of about 34,752 boe/d during 3Q 2018.
107	735	Aethon Energy Management LLC; Ontario Teachers' Pension Plan; RedBird Capital Partners LLC	QEP Resources Inc.		To buy QEP's Haynesville/Cotton Valley business comprised of about 49,700 net acres including 137 gross operated producing wells in NW LA with production averaging 49,500 boe/d (100% dry gas) during 3Q 2018; includes midstream operations. *This deal closed in January.*
108	345	Eclipse Resources Corp.	Blue Ridge Mountain Resources Inc.		To acquire Irving, TX-based Blue Ridge Mountain through merger; creates Utica-focused operator with about 227,000 net effective undeveloped core acres across the Appalachia plus 500-560 MMcfe/d of pro forma production.
109	283	Whiting Petroleum Corp.; Riverside Energy Co. LLC	Oasis Petroleum Inc.		To buy certain Williston Basin assets covering about 65,000 net acres with an estimated 4.4 Mboe/d net production including assets in the Foreman Butte position.
110	176	Alliance Resource Partners LP	Dale Operating Co.		To buy 42,000 net royalty acres in the Anadarko, Permian, Williston and Appalachian basins.
111	100	Viking Energy Group Inc.	Multiple sellers		Acquired oil and gas wells in Texas and Louisiana producing 2,469 boe/d. *This deal closed in January.*

Deal No.	Estimated Value ($MM)	Buyer/ Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
112	68	Foundation Energy Management LLC	Riviera Resources Inc.		To buy interest in properties located in the Arkoma Basin in Oklahoma including about 37,000 net acres, 100% HBP, with 24 MMcfe/d of net production during 3Q 2018. *This deal closed in January.*
113	57.5	Summit Natural Resources LLC	Titan Energy LLC; ARP Production Co. LLC; ARP Mountaineer Production LLC		To buy Titan's CBM oil and gas properties in the Black Warrior Basin in WA and WV.
114	49	Pantheon Resources Plc	Great Bear Petroleum Operating LLC		To purchase private oil exploration company Great Bear based in Anchorage; includes 250,000 leased acres onshore North Slope of AK.
115	20.5	Comstock Resources Inc.	Shelby Shale LLC		To acquire an 88% interest in 6,124 gross (6,023 net) acres limited to Shelby's Haynesville Shale rights in Harrison and Panola counties, TX.
116		Sumitomo Corp.; Summit Discovery Resources II LLC	IOG Capital LP; Convington Equity Investments LLC; 1836 Resources LLC		To acquire 100% operated WI in a tight oil producing asset within the Eagle Ford Shale in Karnes County, TX; includes 624 acres with estimated peak production of 3,000 boe/d.

INDEX: U.S. E&P ACQUISITIONS & DIVESTITURES

AL WALKER'S VIEWS

The chairman and CEO of Anadarko Petroleum Corp. weighs in on the Permian, LNG, investor sentiment, politically motivated barrels and why he is not worried.

ARTICLE BY
LESLIE HAINES

Anadarko Petroleum Corp. chairman and CEO Al Walker remains optimistic about the industry and the company, yet advises to be prepared for continued volatility.

As head of one of the largest and most successful independents in the U.S., Anadarko Petroleum Corp. chairman and CEO Al Walker has led the pivot most independents are now making: to focus on shareholder returns as much as production growth.

To meet that goal, in 2018 the company bought back stock, reduced debt and increased its dividend from 5 cents to 30 cents per share, ending the year with $1.3 billion of cash on hand. Walker has vowed to continue to improve per-barrel margins and lower the free cash flow, breakeven oil price the company needs. In the fourth-quarter conference call in February, Walker reiterated that Anadarko will use $50 oil in planning and, moreover, all the company's main assets except the Delaware Basin are free-cash-flow positive at $50—and the Delaware will be in 2020.

The 2019 budget midpoint is $4.5 billion, equal to the 2018 spend. In the Delaware Basin this year, Anadarko will operate 10 rigs and turn to sales 150 operated wells. In the Denver-Julesburg Basin, it will operate four rigs and turn 250 operated wells to sales. In the Gulf of Mexico, one or two drillships and two platform rigs will work, and Anadarko will bring 10 deepwater wells to sales. Walker also said, "The Powder River Basin is a coming attraction." In the first half of 2019, Anadarko is expected to take a final investment decision (FID) on its Mozambique LNG export facility, for which it has already announced several contracts with Asian buyers.

Walker, a distinguished alumnus of the University of Tulsa and a former investment banker, joined Anadarko in 2005 as CFO, later serving as president and COO before becoming chairman and CEO.

"As an industry we have not reduced our optimism about the Permian from a capital standpoint; it's human capital restraints."

In January, about three weeks before releasing 2018 results, he spoke on a wide range of topics at the Houston Producer's Forum. He emphasized these opinions are his own and not necessarily the official position of the corporation. However, we provide a summary of some of his remarks on key topics of the day, providing a window into which trends he watches, and the thinking that lies behind decisions made in the corner office.

On the macros

We've seen without a doubt unprecedented volatility. When you think back to 2014 around Thanksgiving when the world started changing for all of us … it seems like with each passing year, we find new ways to increase the volatility.

And more recently, we've seen that the Saudis actually made a huge, colossal mistake trying to sweep our industry off the table. Somehow they just didn't do the math, that if you produce more volume at a lower price, the treasury gets less revenue. More recently OPEC-plus has stepped in from a supply standpoint … with the Saudis committing to a 900,000-barrel reduction in supply.

Most people seem to be concerned about global demand but since 1972, there's been only a couple of years when it didn't actually grow year-over-year. Most years it's grown by a million barrels or more. I think these China trade issues will smooth out, and so I continue to believe we'll have a very strong 1 million barrel a day (MMbbl/d) per annum increase in the demand function. But there is less investor interest in seeing growth from us. More on that later.

You hear a lot of people talking about it, but I don't worry about plateauing oil demand. They say global demand is plateauing at 100 to 110 MMbbl/d and my reaction to that is, So what?

It declines at 6% to 8% a year, so we'll still have to find 6 to 8 MMbl/d of oil, every year, to replace what we produce. We are not going out of business; we're not going to be the next Kodak camera. I don't believe electric vehicles will have enough drawdown on demand.

Unconventional (oil production) is basically the wedge and that's kind of hard to find. We're just not replacing that.

On Permian growing pains

For those of us involved in the Permian, what we've seen is nothing short of jaw-dropping, the increase in production, especially in what was not a halcyon period for oil prices. We've started to understand in ways I never imagined back in 2010 to 2011 what the Wolfcamp A could potentially become.

The emergence of the Permian, probably by the middle of the next decade, as the third-largest oil producing area in the world, would never have been on anyone's radar screen during the collapse in financial markets in '08 and '09.

When people extrapolate from the Wolfcamp A alone and question the Permian's real potential, that's a big stacked pay and not all of it is oil, there is gas too. I'm not sure all the

SEEKING PERMIAN SOLUTIONS

A new group in Midland composed of 17 E&P companies, Schlumberger Ltd., Halliburton Co. and Plains All American Pipeline LP has formed the Permian Strategic Partnership (PSP). The group includes majors such as Shell and BP Plc, and large independents such as Anadarko Petroleum Corp., Encana Corp., Occidental Petroleum Corp., XTO Energy Inc. and Cimarex Energy Co.

Former U.S. Commerce Secretary Donald Evans was named in January to head the group. He is a longtime Midland resident and former CEO of an E&P company.

As the Permian ramps up toward producing 4 million barrels a day, booming activity is pressuring local communities with power demand, traffic fatalities, school overcrowding and other issues.

Members of PSP have pledged to commit $100 million during the next several years, to improve living conditions and infrastructure in Texas and New Mexico, addressing the strains on Midland, Odessa and surrounding towns. The group intends to work closely with local governments and agencies to address concerns around affordable housing for oilfield workers, nurses and teachers; education, roads, and other problems caused by the oil boom.

In the Midland Reporter-Telegram in November 2018, the CEOs of the 17 E&Ps signed an op-ed piece that explained their efforts.

"While the oil and gas business is inherently cyclical, we are convinced that what is happening in the Permian today points to a resilience that is different from the boom and bust cycles of the past. Advances in technology and improved operating efficiencies have helped us produce safely and profitably even when prices are relatively low. We have analyzed various scenarios and believe that, even in a downturn, Permian production will continue to grow in the coming years.

"Being such a strategically important oil producing region comes with certain challenges that are stressing our communities. To start identifying these key challenges and understanding future community needs, the Partnership first listened to local organizations and surveyed thousands of our employees who live here.

"Collectively, they emphasized the need for safer roads, superior schools, quality health care, affordable housing and a trained work force. As employers, we want workers to move here with their families, build careers, and become a part of the community. The good news is that the production growth we anticipate will result in billions of dollars of state and local tax revenues that could be directed to help meet these needs.

"A number of significant charitable foundations are also doing important work in education and infrastructure, and our individual companies are already supporting many community projects. But we feel this uncommon situation requires more."

For more information, see permianpartnership.org.

benches will be developed. Today, we have a 20% recovery factor in the Wolfcamp A and that might be optimistic. If we could get to 30% to 35% that's a whole new oil field. That's why you see Exxon (Mobil Corp.), Chevron (Corp.), all these majors moving in, because they know they can crack the code.

Out in Midland, we've stood up the Permian Strategic Partnership, chaired by Donnie Evans (former U.S. DOE Secretary Donald Evans) to address the problems. Donnie's done a great job. We finally came public with it a few months ago. We have raised over $100 million in commitments from the industry to create a public-private ability to improve education, roads and healthcare.

We plan to address the very significant issues we see, not the least of which is housing—it's one of the highest-rising cost environments in which you can put your people to work. We've seen, as an example, a two-bedroom apartment in Midland has gone from $1,100 a month to $2,000. There are restaurants that had to go out of business because they couldn't get people to work in the kitchen.

We as an industry have not reduced our optimism about the Permian from a capital standpoint; it's really about the human capital restraints. We all talk about all the pipes that have to be built, the rigs we need, all the gathering that has to be put in place … but one of the biggest issues is attracting enough teachers to the area and then, are they able to afford to live there.

Donnie's been successful in getting some federal money, and we've met with the governor (Texas Gov. Greg Abbott) several times and he's come around and understood the need as well, and we've gotten some separate funding for energy roads.

This was not to create new money, but to have money already set aside move to the top of the queue for infrastructure financing in the Permian. So I'm optimistic, but the huge and rapid expansion of the Permian has come with some serious growing pains.

Natural gas and LNG

Another thing we're very close to is LNG. They said the LNG business was dead and now it is not dead. Most people would say that from here to 2030 it (demand) will double and from here to 2050, it could double again.

LNG is becoming a weapon not just for our industry, but really, for our government. It can displace Russian natural gas in Europe … I think you will see our administration continue to support it for domestic use, as well as exports.

The tremendous gas supply that's coming, it's almost stunning. In many ways, gas is just a byproduct of trying to get all these liquids out; it wouldn't have been on the horizon 10 years ago.

While I think LNG can be a conduit, that comes with such a big price tag and it doesn't move quickly. If you're successful in making a final investment decision, it still takes you four years from FID to first shipment and billions of dollars. In Mozambique we anticipate taking FID on two trains, and we're looking at $20 billion for the first two, so that's a big price of admission. But it's almost easier to get your head around an LNG development (with prices set by a contract) than if you have a discovery in the Gulf of Mexico and have to decide if you'll build a spar, when you don't know what the price of oil will be when it finally comes online.

Natural gas is just never going to be valued as it should be at the wellhead; I just can't see it. So as a company we sold all our gas assets back in 2015. We had looked at all the oil production that was going to be coming out of the Permian and all the gas with it ... Natural gas at the wellhead is never going to give you a better

PHOTO COURTESY ANADARKO PETROLEUM CORP.

Walker said Anadarko is vying to be at the front of the pack for "next gen" technology incorporating artificial intelligence and machine learning. Here, Anadarko operations in the Permian Basin.

margin than oil on a boe (barrels of oil equivalent) basis. What would gas prices have to be to compete with $60 oil: $5 or $6 at the wellhead? And we don't think we'll see that again.

We just saw negative basis at Waha in December, and we'll probably see that again from time to time because gas is a byproduct. The basis is slowing shifting from the Permian to the Gulf Coast as the pipelines are building.

Capital markets and M&A

Another thing we've seen is an evolution in the way that public and private capital is formed. During the earlier part of this decade and the last, I think private equity went through a big expansion that was nothing short of remarkable in what it accomplished with many management teams, but I do think that's starting to change a bit.

I think over 80% of our trades every day are done by black box algorithms based on the macros, so very few of us have long-only investors any more. These algorithms trade off macros.

As an industry we got through a period where high IP flow rates caused the public markets to react in a certain way. But today, investors look at IRR for the integrateds and for the independents, we are still a cash-flow-based group—that is how investors look at us.

Alpha is an asset's return compared to a risk-adjusted return, and beta is a measure of volatility and how an asset does against some benchmark. I look at the volatility and our beta is going up and our ability as a company to add alpha is not keeping up; in fact it is flat to going down. That is hard to sustain.

What does that mean if you're a private company or a private-equity-backed company and you're looking at the traditional build it for three to five years and flip it? I think the halcyon period for the private-equity community may be over.

It's come as no surprise that you see very few of us public companies buying properties or entire companies today like the recent Concho-RSP deal. I'm not sure there is any large public E&P company out there today who wants to buy any Tier 2 or Tier 3 acreage, and I'm not sure they'd pay cash to buy Tier-one either. So as bigger companies, we're left with looking at acquisitions as the last thing we'd do.

I've asked the buyside and some institutional investors, why do you care if a deal is done at $70,000 an acre? If they'd paid cash, that would be a different answer. Both companies' stock go down on the day of the announcement.

Since 2014 in the public market, M&A has been discouraged—you don't see a whole lot being done. The best deal I saw last year was Concho and RSP coming together; I think that was a tremendous move for both of them, yet it took a while for the market to digest it and understand it. That's the way it goes.

Political barrels

Last year, we moved into the fall with strong fundamentals, and we thought we'd have $90 or $100 oil, only to have our president put sanctions on Iran. Then he gave eight countries an exemption from that, including China and India, and then he was asking the Saudis to overproduce going into the midterm elections.

Where we as a country do have some leverage is in terms of asking the Saudis to do

PHOTO COURTESY ANADARKO PETROLEUM CORP.

Demand for LNG will double by 2030, and double again by 2050, said Walker. Anadarko expects to FID its Mozambique LNG project, supported by its offshore Mozambique operations, shown here.

some things, but I do worry between here and 2020 that the politically motivated barrel might continue. I have no idea what will happen in May when interim sanctions end. How Venezuela factors into that I don't know. I do think we're in a better price environment for oil. We just have to recognize the events that occurred this fall will continue between now and the 2020 election.

So many things happen to our industry that we never see coming … One of our board members said it best: "Just when you think you've got it figured out, some new issue comes up" and then we're saying, "Where did that one come from?" So I'm a little cautious.

We've seen lately, at least in the public market, less investor interest in growth. I think we've probably found that $40 or $50 is the floor but I'm not sure what the ceiling is, maybe $70. But at some point in the next decade, underinvestment is going to cause a problem.

On AI, Google and more

What lies ahead in the next decade? I can tell you that as a company, we've been making tremendous investments in technology. We put in place in 2014 a technology team to look at "next gen," not improving current gen, but trying to develop next gen through AI and machine learning. When I came into my current role in 2012, I started looking around at other industries, not so much for improving our current technology but looking at what other industries are doing. I started to realize just how far behind the curve our sector was.

At Anadarko the board has talked a lot about this and so we brought in a person from the tech space—we're probably the only E&P company with a millennial on our board. But he's been not only very good in the board room, but very helpful in terms of how we set up our advanced analytics and emerging technology groups, and how we build out the systems to deliver that. We've centralized our R&D group.

It's kind of like with plumbing, where you're in trouble if you don't have a big enough gauge, so you have to have a chief technology officer and a chief systems officer that can actually deliver what the technology people develop to the various verticals we manage.

We just went public with a joint venture with Google that we've been working on for a while.

I think someone's going to take seismic from being an indicative tool to being a predictive tool—hopefully Anadarko does it. That big discovery BP just made in the Gulf of Mexico was done by making a different algorithm. We have about 80 people committed in an arrangement with engineers, geologists, petrophysicists and others to figure out our new algorithms. About a third of them have PhDs in things like applied mathematics.

Now why did we partner with Google? It knows nothing about oil and gas … but a lot of us have partnered with Silicon Valley firms before, like in our case, we use the Google cloud. Years ago we used the national labs to figure out technology questions; now we're using algorithms.

I do think in years to come we're going to see more regulation at the federal and state level and so, we're going to have to absorb that cost in some way. We think technology will allow us to offset that by lowering costs in some way. Lowering that breakeven cost is very important.

Our industry is really rich in data, but it's data-poor in how we can actually do something with it. We've got to figure out how to process it more efficiently … We know we're going to be living in some sort of volatility so having lower costs will allow us to offset that.

"I don't worry about plateauing oil demand… We are not going out of business; we are not going to be the next Kodak camera."

The future

If you think about the refining capacity at the Houston Ship Channel and Corpus Christi, and then the expectation that 5 or 6 million is coming out of the Permian, if we aren't set up to ship that for export, you're going to see LLS and GC (Gulf Coast pricing) look very different than it is today.

How does the Port of Houston address this? Larger cargoes are coming in, and the pilots union has concerns about how they move these big ships and how petroleum products are being displaced by non-petroleum products in the Ship Channel. I think Enterprise (Products Partners LP) will take a lead role on this. If we don't solve it, a lot of the oil is going to get stuck there.

Can you imagine what the price of WTI would be today if we could not export? We're going to have to solve this or there'll be a huge basis differential we don't have today as the Permian ramps up and potentially doubles.

Technology has room for a lot of improvement in ways we can't know today. We'll go into older fields and understand the recovery factor. All of us have technology groups but to move from the lab to the field, you've got to have a system. Whether you are Exxon or whomever, we're all figuring out how our systems will deal with technology and develop the next gen. People are skipping generations. For our industry the next decade will be very exciting.

I think our industry is alive and well and healthy; there is less regulation than two years ago. I think the next decade will be better than the last two years. Most of OPEC needs $80, if not $90, a barrel for operating costs and their social spending, and they are operating at a deficit today, so I think we have some good backdrop to all of this. I think the equilibrium in the next decade could be good.

I think $70 is the range we're likely to operate in this year and next. I think if you can grow at 5% and return more cash to investors than if you grew at 10%, than you should. I think you should see slower growth.

So as we look out at 2019 to 2020, I think some of the same macro factors are in place, and the price volatility will continue. But I think the under-investment we've all heard about is going to come back in some form or fashion early in the next decade, probably just not in 2019 or '20. ☐

CO-DEVELOPING THE SCOOP

Stacked-pay basins present both opportunity and challenge when evaluating the most economic variations of development. Three companies active in the Scoop play in the southern Anadarko Basin reveal their current full-field development strategies.

ARTICLE BY
VELDA ADDISON,
TERRANCE HARRIS
AND STEVE TOON

The latest results from Continental Resources Inc.'s SpringBoard project in Oklahoma's Scoop play show the stacked development is on track to boost the company's oil production by about 10% from third-quarter 2018 to this year's third quarter. And that's just from this singular project.

But this isn't a typical pad development project. With SpringBoard, Continental is testing the boundaries of achieving maximum returns from full-field development across multiple pay zones.

"There are a lot of names for full-field development," said Continental vice president of exploration Tony Barrett, speaking at Hart Energy's DUG Midcontinent conference in November. "There's the cube, there's sequence development. But we're basically talking about the same thing: What is the best way to capture all of the resource most efficiently and most economically in a drilling and spacing unit?

"In the Anadarko Basin, we're lucky in that we have multiple stacked pays, and this type of development, we believe, is going to be the future of the industry going forward."

Continental advertises that some 711,000 net "reservoir" acres across the Scoop—broken out by prospectivity per formation—have the potential for co-development.

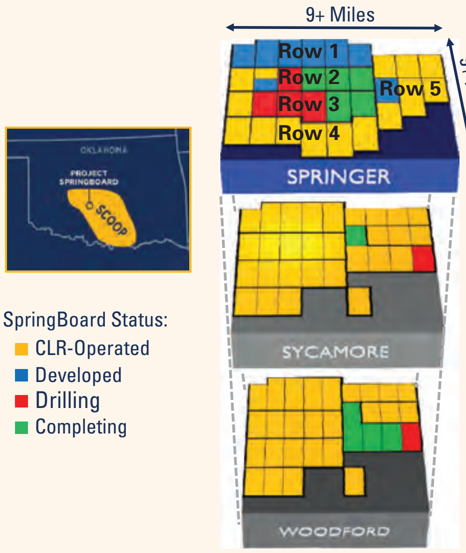
Pushing off the Springer

The SpringBoard project, specifically, focuses on co-development of the Springer, Sycamore and Woodford reservoirs and spans 73 square miles and 33,000 net acres of contiguous leasehold in Grady County. It has an unrisked resource potential of up to 400 million barrels of oil equivalent (MMboe).

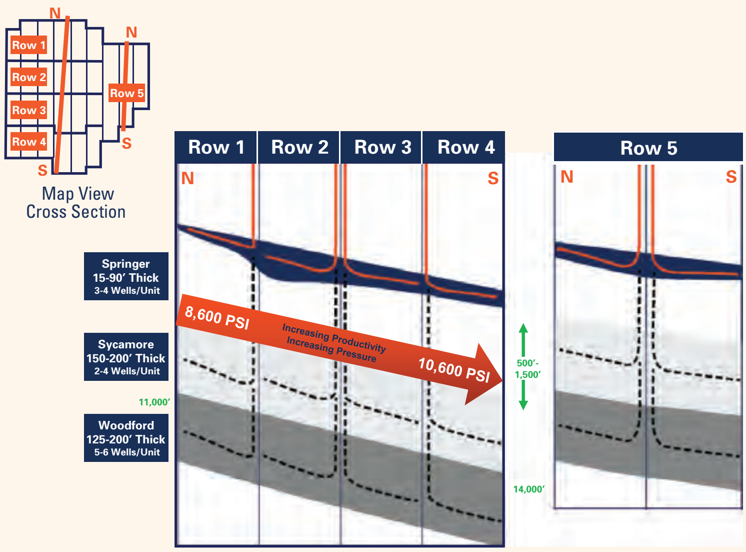
The Oklahoma-headquartered company is currently running 12 rigs as of January—down two thanks to improved efficiency—as part of the project. Seven of the rigs are in the less thick Springer reservoir with the rest in the thicker Woodford and Sycamore reservoirs. Springer has a maximum thickness of 90 feet but trends as thin as 15 feet at the edges of the project, while Sycamore and Woodford each have a maximum thickness of 200 feet, the company said.

"In general, we expect wells located in the thicker portions of the reservoir to outperform

Continental Project SpringBoard Overview



Project SpringBoard Row Development Plan



Source: Continental Resources Inc.

Continental vice president of exploration Tony Barrett said many shale companies are wrestling with multi-formation development. "We're basically talking about the same thing: What is the best way to capture all of the resource most efficiently and most economically in a drilling and spacing unit?"

our type curve and wells located in thinner portions of the reservoir to underperform the type curve," Continental president Jack Stark said during an investor update on Jan. 29.

"Our updated 1.3 million boe type curve represents the average performance expected from a 9,800-foot Springer well in SpringBoard, assuming average reservoir thickness and bottomhole pressure," Stark added. "Regardless of thickness, however, these are prolific flowing oil wells."

Row development is the name of the game in SpringBoard. The project is divided into five rows, with differing formation thickness, depths and pressures in each one—and thus various expected results. Row 1, where Continental focused its efforts in 2018, is the most updip, and thus less pressured.

Most of the Springer wells drilled last year were in Row 1. The 18 wells drilled here had a combined IP of 23,255 barrels of oil equivalent per day (boe/d), or 1,292 boe/d per well, Continental reported.

The 2018 Springer drilling program also included four wells in what the company called "Triple H," which partly lies in Row 2 and Row 3, where the reservoir is thicker. The combined IP for Triple H was 6,065 boe/d, or 1,516 boe/d per well—perhaps signaling growth ahead as the company prepares to tap into more of the thicker reservoirs.

Over 80% of the production was oil, Gary Gould, senior vice president of production and resource development for Continental, said on the investor call.

"Comparing these initial rates of the Triple H to Row 1 provides a great example of the influence of reservoir thickness on production. The Triple H unit was developed in a thicker reservoir area, which is why it resulted in a higher average IP per well," Gould said. "It is important to note that our 2019 development activities are focused on rows 2 and 3 immediately west of the Triple H and will benefit from both thicker reservoir and increasing pressures."

The results, so far, are in line with expectations, company executives said. Economics also have improved. As the lateral length rose by 30%, from 7,500 to 9,800 feet, the company reduced the cost per lateral foot by 20% and increased EUR per well by 8% to 1.3 MMboe. The declines were driven by lower drilling costs and cycle times along with an increase in frack stages completed per day.

"Combining this with the 5% increase in capex, our finding cost is improved by 3% [$9.62 per boe]," Gould added.

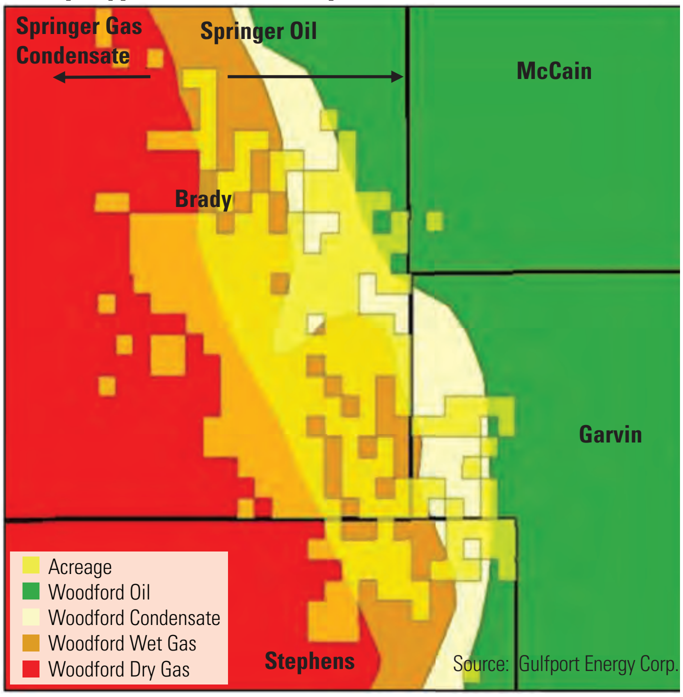
Streamlining logistics

Barrett offered one example of cost cutting at his DUG Midcon speech. "We eliminated intermediate casing, which was normally run in that area, which saved us a million dollars per well," he said. "Think of that—over the course of drilling hundreds of wells, we estimate 300 to 400 wells in SpringBoard, that's $300- to $400 million. We're talking real money."

Improved logistics also have reduced costs. "Hats off to our teams," he said. "The volume of materials and men and hardware that are moved every day with 14 drilling rigs and two to three completion crews is astronomical. We calculate that at any hour during the day, we have 400 to 450 people actively working in this very concentrated effort, so it requires a lot of logistical planning to make this work."

As part of the project, Continental streamlines material management with a centralized stockpile of equipment and supplies. "It allows us to sequence our completions and to

Scoop Type Curve Assumptions



Source: Gulfport Energy Corp.

maximize recovery," Barrett said.

"By having everything together and drilled in sequence, it allows us to tailor our completions across the entire field to maximize unit value. It's economy of scale: if you've got 14 rigs [at that time] and tons of sand and everything being delivered all day, you get a break on your costs. That affects the bottom line."

Additionally, 100% of SpringBoard's oil, gas and water is on pipe, effectively removing 230,000 trucks from the roads, he said. All water is recycled.

In its January investor call, Continental acknowledged a lower EUR per 1,000 feet of lateral than previously guided, but pointed out that this reflected maximizing NPV per section on a fully developed basis. Gould explained that the new type curve's lower IP of 1,430 boe/d was due to increased early completion load water recovery associated with unit development.

"Overall, the refined type curve well economics generates 60% to 90% rates of return based on \$50 to \$60 WTI oil prices, which today reflects one of the strongest rate of return oil plays in the entire United States," Gould said. "We continue to be on schedule to increase Continental's net oil production by 10% or more from third-quarter 2018 to third-quarter 2019 just from Project SpringBoard alone."

Springer oil volumes are expected to hit 16.9 million barrels per day (MMbbl/d) by third-quarter 2019.

"This is a massive scale project," Barrett said. "It's a very large resource potential for oil, in that we're dealing with 70% to 80% oil in this project, and it's part of our plan as a company as we move forward to continue to push our oil growth."

Winning in the Woodford

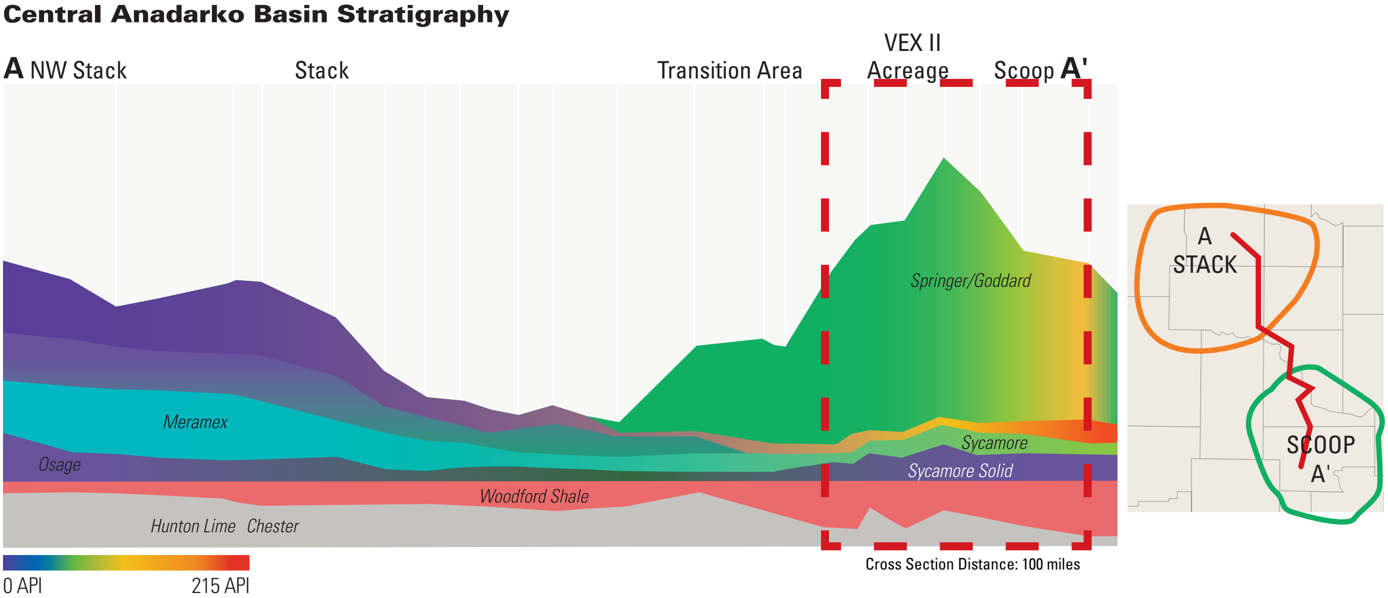
In 2016, pure-play, dry-gas Utica Shale operator Gulfport Energy Corp. strategically decided to secure acreage that had the potential for a more liquid production. Oklahoma's wet-gas Scoop play seemed a natural fit. Two years after entering the play, the Scoop appears to have been a profitable decision for Gulfport Energy: The returns on Woodford Shale wells are competitive with Gulfport's Utica asset and, in some cases, are outperforming the best Utica dry-gas wells.

"We are very confident in our ability to have repeated success both in the Woodford and the Sycamore," said Joshua Lawson, Gulfport Energy vice president of operations. "The results will bear that."

"Every dollar that we have, we are going to re-invest that in the asset that has the highest rate of return," Joshua Lawson, vice president of operations at Gulfport Energy, said during the DUG Midcontinent conference. "So there is this effort to continue to try to transition more and more of our activity into the Scoop and try to focus on the more liquids portion of the asset."

Oklahoma City-based Gulfport has 15,000 net acres in the Utica, but more than 92,000 net acres in its Scoop asset. As of the end

Central Anadarko Basin Stratigraphy



Source: Gulfport Energy Corp.

Greg Casillas, head geologist and president of Casillas Petroleum, discovered that the Sycamore Formation produces higher oil yields than the Woodford, "so we're extremely excited about that particular component."

of third-quarter 2018, Gulfport was producing more than 1.4 billion cubic feet per day companywide, including 275 million cubic feet per day (MMcf/d)—or 20%—from the Scoop. These Scoop wells produce from 10% to 30% oil, and 30% to 60% liquids when adding in NGL.

"That's what's really driving that return on investment."

Gulfport's Oklahoma drilling program targets wet-gas Woodford Shale in central Grady County, where it's completed 27 wells since entering the play. Here, the Woodford is about 200 feet thick at vertical depths ranging from 13,000 to 16,000 feet. When the company began operations in first-quarter 2017, just 54% of the laterals were being placed in zone. In 2018, 98% attributed to the use of 3-D seismic to place laterals better.

> "Every dollar that we have, we are going to re-invest that in the asset that has the highest rate of return."
>
> —Joshua Lawson, Gulfport Energy

"When you're at a 98% success rate, landing and staying within that target zone, it really does help with your efficiencies," Lawson said.

With the geosteering solved, Gulfport wasted no time upping the ante. It extended laterals from 5,000 feet to 7,500 and nearly 10,000 feet, with total measured depth extending past 25,000 feet. "We're trying to push the technical limits," he said.

Completions were no exception. Stimulations of acquired wells and offset wells at sub 1,000 pounds of proppant per foot were "a little lackluster," he noted, so Gulfport ratcheted proppant intensity to 2,000 to 2,500 pounds per foot, taking learnings from its Utica program. "We saw an immediate opportunity to raise the bar. When you're talking about 250 feet of reservoir in multiple benches, we just saw that as a real opportunity to get more aggressive with our frack designs."

Gulfport deploys RS Energy's Prism platform, a data analytics model, to monitor parameters for drilling, completions and well results. It also develops its own 3-D earth model to extrapolate fracture stimulations and production from multiple zones.

At the end of the third quarter, net production in the Scoop had increased 41% year-over-year.

Upside abounds in emerging Scoop zones. Sitting on top of the Woodford is the Sycamore Formation, a 250-foot-thick section in which Gulfport holds about 40,000 net prospective acres. It has drilled two wells into it to date, one into the lower section with a 5,980 lateral and 15.7 million cubic feet equivalent per day (MMcfe/d) 24-hour rate, and another in the upper with a 9,600-foot lateral and a 7.8 MMcfe/d rate, 63% liquids.

"We're very encouraged by that. We're really excited about the Sycamore," Lawson said.

Gulfport began full-section development of Woodford wells in 2018 to capture cost efficiencies, and in 2019 plans to co-develop upper and lower Sycamore wells simultaneously with the Woodford. But there's one thing critical with that game plan, he said.

"You have to be able to execute from a drilling perspective. Everyone knows that these wells are a challenge; they are deep and geologically they are a challenge. If you can't execute from a drilling perspective, then you're just spinning your wheels. You have a lot of capital invested in one unit and are waiting on a return to come back."

Also prospective on Gulfport's acreage is the Caney Formation, which overlies the Sycamore and the Springer above that. The company drilled one Springer well in 2018—returning 79% oil and 11% NGL. But the Springer is for another day, Lawson said. "That is part of our development plans down the road—we're using our non-op dollars to explore and understand the extent of the Springer."

In January, Gulfport guided that it would run an average 1.5 rigs in the Scoop in 2019 and drill nine to 10 gross operated wells there during the year. It estimates it holds some 1,950 Scoop locations.

"I wouldn't say we have all of the answers," Lawson said. "We're still exploring, still trying to figure out how to make this whole project work. We are still trying to understand what it's going to take to gain the best returns on every dollar invested.

"One thing I can say is we are very confident in our ability to have repeated success both in the Woodford and the Sycamore. The results will bear that out."

Sycamore surprise

Gulfport and Continental aren't the only companies pleased with their Scoop returns. Greg Casillas, head geologist and president of privately held Casillas Petroleum, has been pleased with returns since the Tulsa-based company turned its attention to the Scoop two years ago.

Casillas controls 53,000 net acres prospective for the Woodford and Sycamore in a contiguous position straddling the intersection of Grady, McClain and Garvin counties. It is currently running three rigs and two frack spreads, and has drilled more than 40 wells in the past two years. Of these, it has completed 26 Woodford wells, accounting for 12% of all wells put on production in the Scoop core, and 14 Sycamore wells, representing 56% of total Sycamore completions.

"We are the leader in Sycamore completions," Casillas said.

Casillas, with backing from Kayne Anderson Energy Funds, started its Scoop venture in 2015, evaluating the Woodford and Sycamore reservoirs and then purchasing 12,500 acres from Chesapeake Energy Corp. and 30,000 from Continental Resources Inc. The premise: to expand the deeper portion of the Scoop play eastward and updip into a more shallow environment, yielding a higher oil component.

"We have proven this theory to be correct," said Casillas, "as we have drilled highly economic wells over the last two years with proven repeatability."

Casillas' slide presentation indicated the company executed a PSA with a nondisclosed seller in October to acquire an additional 28,000 Sycamore acres.

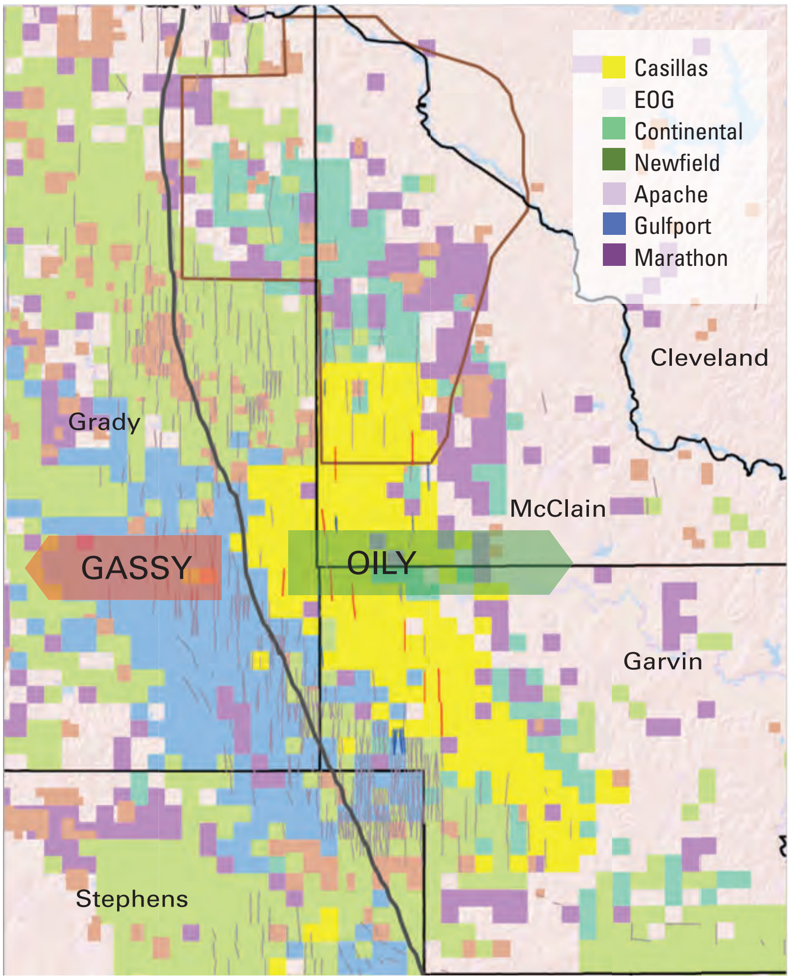
The company has executed lateral placement within two separate benches in both the Woodford and Sycamore.

The Woodford ranges from 100 to 350 feet thick on Casillas acreage, averaging 250 feet thick, at a vertical depth of 13,500 to 8,500 feet trending east. To date, the company has drilled 15 wells into the upper Woodford target and 11 wells into the middle Woodford target, with vertical separation of 100 to 150 feet. IP30s average 1,036 boe/d with 34% oil, 63% total liquids. Woodford EURs are 2.9 MMboe; rate of returns on the strip in early November were 59% for a $10 million cost for deeper wells; 72% at $9 million for more shallow wells. The breakeven price is $32/bbl.

The Sycamore is proving more interesting to Casillas. Here, thickness is similar to the Woodford, which it overlies, and the company is also targeting two benches. It has drilled six wells into the upper zone and eight wells into the lower with an average IP30 of 1,240 boe/d. Maybe more interestingly, the oil mix is 58%.

"We've revealed in our exploration efforts that the Sycamore is actually producing higher oil yields than is the Woodford, so we're extremely excited about that particular component," he said.

Casillas Asset Overview



Source: Casillas Petroleum Corp.

Based on a 23-well set, Sycamore EURs are 2.85 MMboe, with a 74% ROR at a $10 million well cost and 93% at $9 million. Breakeven is as low as $29 per bbl.

The difference in well costs reveals an evolution of completion design. After testing proppant concentrations as high as 3,000 pounds per foot, Casillas "decreased our proppant concentration substantially while maintaining fluid volumes at 3,000 pounds per foot," he said, lowering completion costs by $1 million per 10,000 foot of lateral.

Additionally, it tightened cluster spacing from 28 to 18 feet while increasing the cluster count to five per stage. "In making these modifications, we've actually exceeded the previous EURs from the larger proppant concentrations," Casillas noted.

The company planned to initiate its first Woodford-Sycamore co-development program in late 2018, testing 12 wells into the Woodford and eight in the Sycamore. It operates 65 total units, with a total of 877 operated locations and 1,299 nonoperated.

At the time of its presentation, Casillas' production totaled 17,000 boe/d (65% liquids), but the company expected to exit 2018 at 20,500 boe/d, with a target exceeding 40,000 boe/d by year-end 2021. The company anticipates being cash-flow positive by year-end. □

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RESOURCES

VOLATILE BUT RANGE BOUND

Two leading data providers tell a tale of woe for energy capital availability, but one credit analyst sees rays of hope ahead.

ARTICLE BY
CHRIS SHEEHAN,
CFA

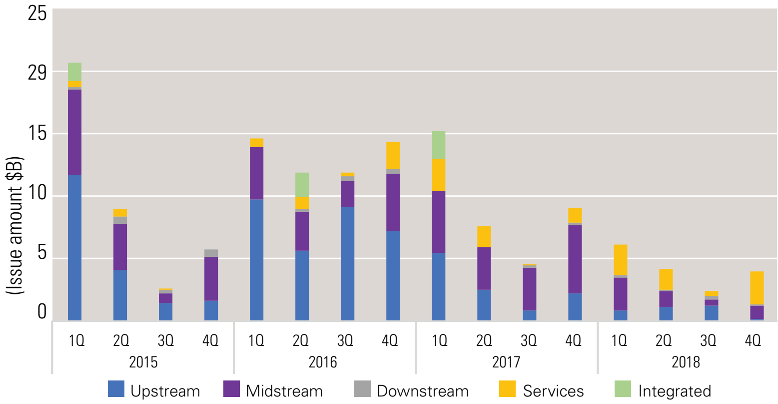
In the final quarter of 2018, what for several months had seemed like an improving, albeit uncertain, environment for capital raises, came crashing down. Another year of commodity volatility seems likely for 2019, with its attendant impact on capital markets.

When the price for West Texas Intermediate crude fell by year-end 40% from its Oct. 3 peak, a near shutdown of capital markets was almost inevitable. Concerns about a number of factors—weakening economic growth, U.S.-Sino trade friction, unexpectedly large waivers granted to buyers of Iranian oil, plus various wildcard issues—combined to create a severely negative market sentiment.

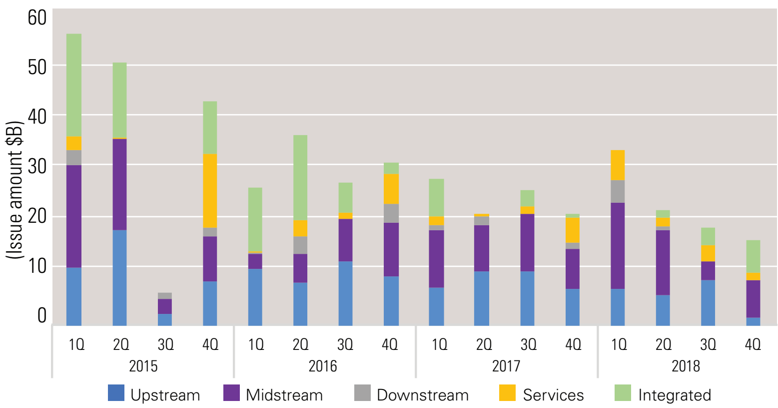
Equity issuance in the energy sector, already on a downward spiral early in the fourth quarter, evaporated in December. Likewise, issuance of debt followed a downward path, with energy high yield—accounting for about 16% of the high-yield market—particularly affected. By December, no high-yield paper, from energy or other issuers, had come to market.

According to data from Drillinginfo Inc., the last three months of 2018 were the worst quarter for upstream equity issuance since 2010. Only two upstream issuers came to market, raising $67.5 million. This was down as much as 94% from the third quarter of 2018 and down 97% from the roughly $2.2

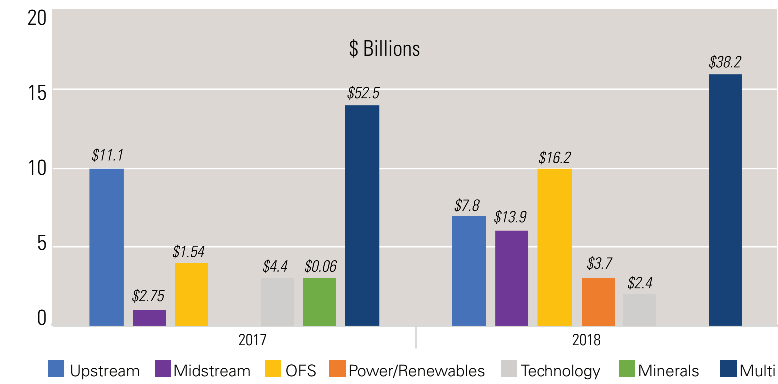
U.S. Equity Deals By Quarter (1Q15-4Q18)



U.S. Energy Bond Deals By Quarter (1Q15-4Q18)



Private Equity Fund Closures By Sector



Source: Drillinginfo Inc.

billion raised via 16 offerings in the final quarter of 2017.

In fixed income issuance, the fourth quarter of 2018 saw three upstream offerings that raised a total $1.47 billion, down 79% from the approximate $7 billion completed in the same quarter a year earlier. By contrast, upstream credit facilities launched or amended by banks moved sharply higher, totaling some $32.7 billion, up from $5.9 billion a year earlier.

Turning point

Fundraising in private equity (PE) last year seemed to reach a turning point, setting the stage for a performance akin to the Charles Dickens saying, "It was the best of times, it was the worst of times."

Preqin, a consultant covering the alternative asset industry, described energy funds as having had a "banner year" in 2018. Preqin data showed natural resources funds raised $93 billion, with $89 billion coming from some 77 "energy-focused" funds last year. However, energy's dominance of natural resources "may be an impediment to the asset class's long-term success," observed Preqin.

Drillinginfo was more emphatic in describing the clouds it sees gathering on the horizon for PE players.

PE sponsors in 2018 "have decelerated backing new upstream portfolio companies as exit strategies have been challenged throughout the year," according to Drillinginfo. Sponsors "tapped the brakes on backing new teams, as the IPO [initial public offering] option vanished, and fourth-quarter upstream M&A activity ground to a halt."

At $82 billion, the Drillinginfo estimate for energy-related fundraises in 2018 was not far from Preqin's $89 billion. However, there are differences between the two proprietary datasets.

The $82 billion was related primarily to North America funds. However, only 10% of the fund charters were dedicated specifically to the upstream sector, Drillinginfo noted, while nearly 50% had a multifaceted mandate that allowed greater latitude in investment decisions. Drillinginfo identified 54 new equity commitments to the upstream sector in 2018.

The narrow scope of funding for the upstream sector vs. that for multifaceted energy funds is reflected in the breakdown of Drillinginfo data. Capital raised by multifaceted funds, at $38.2 billion, made up by far the largest category. Upstream funding came in at just $7.8 billion, lower than both midstream, at $13.9 billion, and oilfield services, at $16.2 billion.

Preqin's $89 billion raised by energy funds included $58 billion raised by 51 North American-focused funds and $28 billion raised by 25 European-focused funds. Preqin noted a trend of greater amounts of capital being raised by a fewer number of funds. The largest fundraise was by KKR Global Infrastructure Investors III, which closed with $7.4 billion in commitments.

Record-high dry powder

As of June of 2018, Preqin estimated that natural resource funds' dry powder stood at "a record high of $238 billion." This followed fundraising milestones in 2018 when as many as 57% of funds exceeded their initial target size, while another 18% hit their targets. Looking forward, it said, some 305 natural resources funds had their sights set on raising $188 billion.

"Of these, 213 are energy-focused funds seeking to raise a total of $162 billion," according to Preqin.

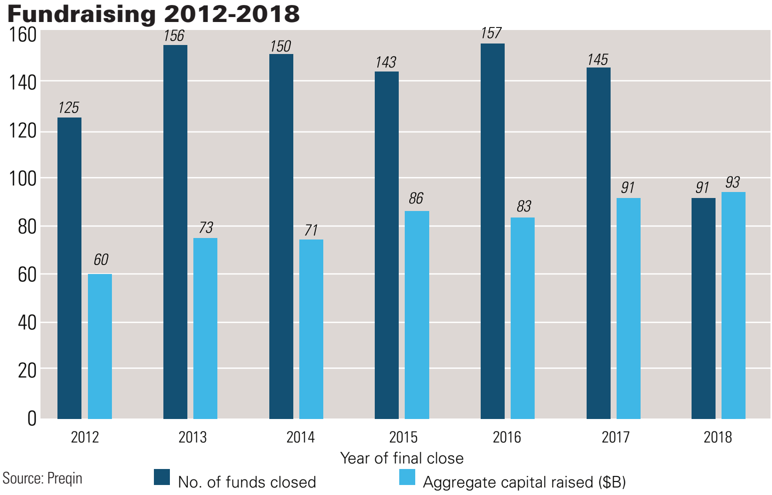
By early 2019, however, the lift in crude prices off year-end lows had far from buoyed prospects for a more vibrant capital market for energy. As investors awaited year-end results and forward guidance on 2019 capex and production, their mantra remained one of urging producers to spend within cash flow and prioritize investor returns (dividends, stock buybacks, etc.) over growth.

The latter investor sentiment—prevailing amidst a shortage of cash buyers and a history of E&Ps seeing their stocks punished for issuing equity—has severely soured the A&D market.

"It's just horrible. It's terrible out there," commented Chuck Yates, managing partner at Kayne Anderson Capital Advisors LP, referring at a late-January Private Capital Conference in Houston to the lack of activity in the A&D market. "How many versions of crap can we come up with to talk about the A&D market?"

The Kayne Anderson presentation included a slide showing how energy's share of the S&P 500 index has materially contracted over the last decade. Energy made up 13.8% of the S&P at year-end 2008, but its weighting in the S&P had fallen to 5.3% by the end of last year.

Annual Global Unlisted Natural Resources Fundraising 2012-2018



Source: Preqin

Fund distributions

A more focused survey of prospective capital formation in 2019 was conducted by Parkman Whaling, a Houston-based provider of advice and capital to the energy industry.

"U.S. private equity may have as little as $10- to $15 billion of capital available for new upstream deals in 2019, according to our recent poll of more than 40 of the most active private-equity firms in energy," said the Parkman Whaling note. "And fundraising remains challenged due to negative sector sentiment and lack of fund distributions available to be recycled by investors."

The Parkman Whaling note estimated uncommitted capital from existing PE funds at about $30 billion. In addition, it said fundraising efforts in 2019 are targeting an additional $15 billion, although it was skeptical the latter goal would be reached. With opportunities to invest described as "ample," this would lead to "more stringent underwriting criteria and a higher cost of capital."

Of course, in looking back over all of 2018—and not just the fourth quarter—year-over-year comparisons still show significant, but less steep, percentage changes in public equity market issuance.

Equity financing in the upstream sector in 2018 came to $16.5 billion, down 55% vs. 2017, according to Drillinginfo. Midstream financing, at $5.7 billion, was down 67%. Oilfield services were actually higher, up 31% at $7.2 billion, helped by six IPOs in the early part of the year. (A late-year Baker Hughes issue helped optically but simply involved existing equity being transacted between parties.)

In fixed income financing, the upstream sector issued $22.8 billion in bonds in 2018, down 35% from a year earlier, according to Drillinginfo. Bond issuance in the midstream sector totaled $39.8 billion, up 5%, while issuance by oilfield service companies came to $12 billion, up 41%. As sensitivity grew as to issuer quality, investment grade bonds rose to account for 85% of issuance in the fourth quarter.

While issuance in the energy sector as a whole slowed in the fourth quarter, 21 bond issues were completed for a total of $16.2 billion. Most-active issuers were the midstream sector, with eight issues totaling $7.3 billion, and the downstream sector, with six issues totaling $6 billion. The upstream and oilfield service sectors each issued $1.5 billion in bonds.

Maturing energy bonds

Drillinginfo said it expected to see $96 billion of energy bonds to mature in the next 12 months, with 38% of those bonds coming due in the first quarter.

In December of last year, Moody's Investor Service published a report identifying key credit themes for energy in 2019. It currently has a "positive" outlook for both the E&P and midstream sectors.

Within a framework of "volatile but range-bound" commodity prices, and oil trading in a $50- to $70-per-barrel range, the E&P sector's improved capital efficiency and moderate prices "will support better cash flow through 2019," the report said. "As cash flow and asset values increase, companies will increase borrowing bases or access capital markets more easily."

In addition, according to the Moody's report, "midstream credit quality will finally improve."

But having easier access to capital markets may also be measured by a more stringent test: access to equity markets without punitive consequences to E&Ps, and even a re-opening of the IPO market.

Early in 2018, the oilfield service sector tapped the IPO market, with six offerings raising roughly $2 billion, according to Drillinginfo. Meanwhile, the upstream sector has launched three IPOs, but has done so using a SPAC (special purpose acquisition company) rather than a traditional IPO.

The last traditional IPO was completed more than two years ago, in January 2017, by Jagged Peak Energy Inc.

How long will it take until the next such IPO? ☐

A&D'S LONG AND TWISTED ROAD

The middle class of E&P companies is shrinking as consolidators target companies valued between $3- and $10 billion, leaving dozens of lesser-valued companies to sweat as access to public equity markets remains blocked and oil prices recede.

ARTICLE BY
DARREN BARBEE

FILE PHOTO

"The capital markets really have a huge effect on A&D," said Craig Lande, managing director of RBC Richardson Barr.

For the past two years, the oil and gas universe has been collapsing in on itself.

This is what life is like in the resulting public-market black hole: in January 2017, the publicly valued E&Ps totaled $562 billion. Two years later, values have been crushed down to $434 million, said Craig Lande, managing director of RBC Richardson Barr.

The strength of the A&D market was also partly a mirage, more akin to the down year of 2015 than it seemed. As RBC counts deals—at least $20 million qualifies—from 2010 to 2017 transactions averaged about $50- to $60 billion. RBC's tally of deals for the 2018 market was $44 billion.

Addressing the IPAA's Private Capital Conference audience on Jan. 24 in Houston, Lande said: "I think a lot of you will say, 'Well, it seems like the A&D market has been fairly soft, not a lot of things happened last year, so it's odd to say $44 billion.' I agree."

Partly, the 2018 deal total was inflated by the "anomaly" of BP Plc's deal to buy most of BHP Billiton's U.S. shale assets for $10.5 billion, he said.

"Not a lot of people got to play those" outsized transactions, Lande said. "You take that away and you're really talking more of a $33- to $34 billion market" for the year. That compares more to 2015, when the A&D market was really in bad shape and only $23 billion in deals were transacted.

There's quite a bit of silver in all of the gray. Chief among the good news is all of this has happened before, Lande said. It was a theme he repeatedly returned to that, he said, has either been forgotten or not yet learned: oil and gas is a cyclical business.

"Consolidation is going to happen, one way or the other, and I think everyone would agree it should in this kind of environment," Lande said.

Yet, since at least 2010, the oil and gas industry has been fixated but frozen on mergers. In 2018, M&A finally had its breakthrough.

But as deals were made and market values shrank, so did the middle class of E&Ps with market caps between $3 billion and $10 billion. That does not bode well for the majority of companies in our industry with a mix of disparate assets, poor acreage, high leverage or inadequate cash flow.

"You're going to see consolidation two ways," Lande said. "You're going to see the bigger guys pick off that sort of 'meaty middle,' the $3- to $10 billion companies and, unfortunately, you'll most likely see some of the smaller guys ultimately head toward bankruptcy" if market conditions don't change.

In January 2017, the number of companies in the $3- to $10 billion middle ground totaled 26. Now there are just 11 in that market-cap range.

"Those companies didn't get bigger," Lande said. "They got smaller or went away."

The middle ground E&Ps, it turns out, are important, he said. The middle is where companies have been giving way to the push and pull of the markets and, ultimately, consolidation. It's from there that the mergers of Concho Resources with RSP Permian and Diamondback Energy Inc. with Energen Corp. emerged.

"Now scale is everything," Lande said. "Bigger is better. You saw Concho buy RSP for about $9 billion and Diamondback Energy [buy Energen] for [about] $9 billion. Those [deals] moved the needle for those companies. There's only a few of those that remain right now that move the needle for the bigger companies."

The small number of companies still in the E&P middle ground will have targets on their backs or sights on each other as consolidation continues. Companies such as WPX Energy Inc. and Parsley Energy Inc., both with market caps of roughly $5.5 billion, are in the range of what Lande called a "meaningful" size—meaning they, too, can shift a company's dynamics.

"This is the sector, this area of $3- to $10 billion, in my mind, where they are going to consolidate [with] each other or the guys above them," Lande said.

Occasionally, smaller companies with appealing acreage, particularly in the Permian Basin, will "probably be picked off," Lande said. One such deal: Cimarex Energy Co.'s proposed acquisition of Resolute Energy Corp. for $1.6 billion, including $710 million in long-term debt. Resolute, with a market cap of about $750 million, holds about 21,000 net acres in Reeves County, Texas, in the Delaware Basin.

> "Consolidation is going to happen, one way or the other, and I think everyone would agree it should in this kind of environment."
>
> —Craig Lande, RBC Richardson Barr

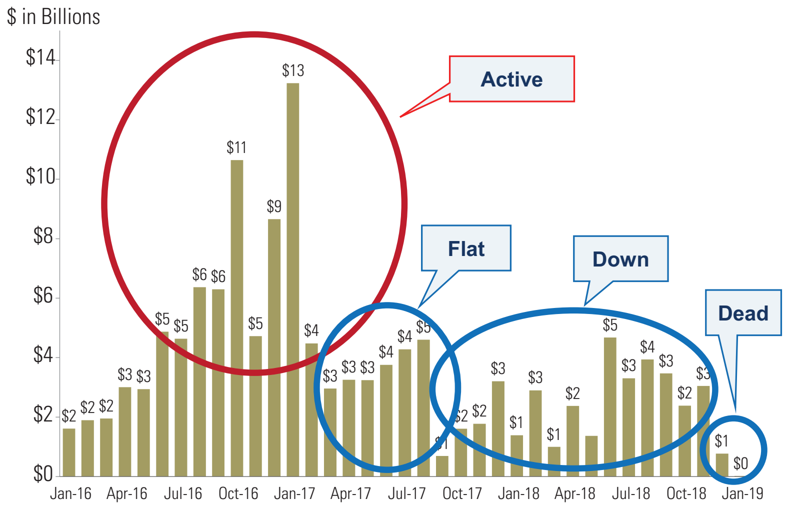
It's no coincidence mergers follow a period in which the oil and gas industry has come to terms with a market voicing its discontent with activists, outright hostility or withdrawal.

For most of 2016, the markets opened up.

"Publics were getting rewarded for paying $40,000 [plus] per acre for Permian resources, and that was great for my business," Lande said.

After funding the industrywide spending spree from 2010 to 2017 and financing an outspend of capital of about $200 billion during those years, the market has effectively been shouting down deals. Concho and Diamondback, among other

Monthly A&D Asset Supply



Source: RBC Richardson Barr

TERRAIN ADVANTAGE

Craig Lande, managing director of RBC Richardson Barr, notes several factors that make buying from public companies both a conundrum and opportunity:

Serendipity. "You're going to have all these zones that probably are underexploited or have never been exploited at all, that you don't have to necessarily mess with now," he said. "But a few years down the road they may look really interesting when prices recover."

Cost savings. Cutting lease operating expenses and overhead is essential. For anyone that can't buy an asset from a large company and streamline expenses, "you probably don't need to be in the private-equity world."

Cash flow. Anything you buy most likely spits out a lot of cash flow from day one," Lande said.

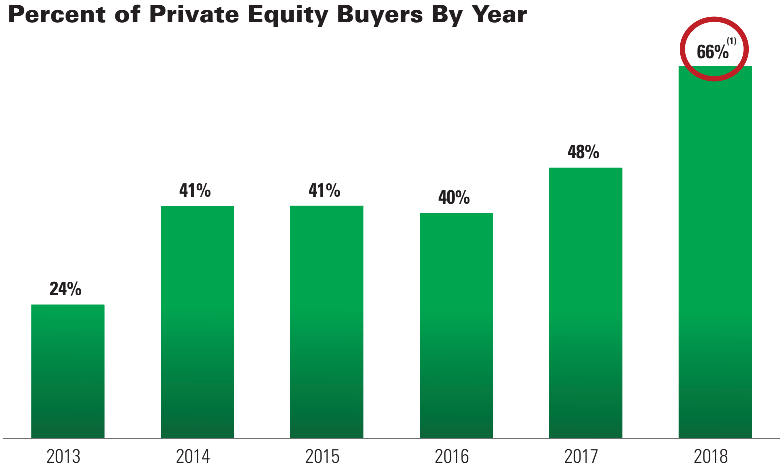
Valuation. Undeveloped acreage is less and less a part of the buying equation in transactions, with deals falling more closely in line with proved-developed-producing values.

While quickly flipping assets for a high return is unlikely, "down the road you've basically got all this upside, whatever comes of it, for free," Lande said. "I think there's just a ton of pros. Again, it's really calibrating ourselves that you can't flip acreage anymore and getting back what we used to do. There's a lot of money to be made; you've just got to hang on longer."

And that, Lande said, is the way it used to be before the shale boom years drove A&D.

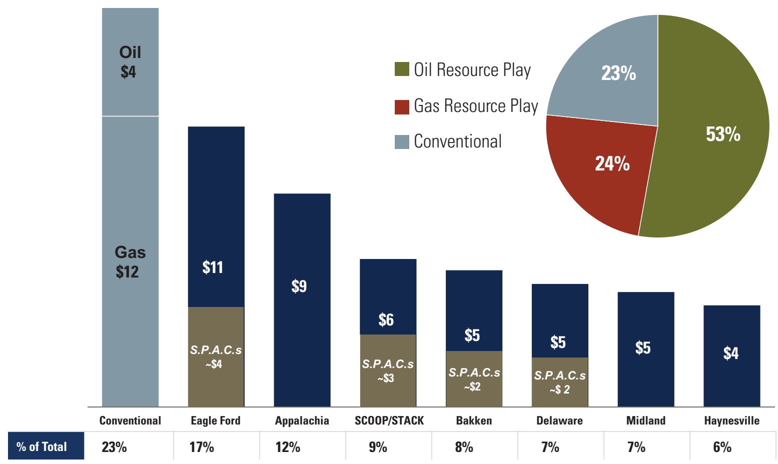
"Again, our business, oddly enough, is cyclical," he said. "I don't care if you're 25 years old and you're coming in to the business or you've been doing this for a long time. You know it is. If you don't, you should know it is."

Percent of Private Equity Buyers By Year



(1) Excludes BP/BHP deal.

Private Equity Asset Demand Since 2016 ($B)



Source: RBC Richardson Barr

consolidators, saw their stock prices suffer after announcing their deals.

The market effectively "stopped and said, 'No more equity for acquisitions—actually show us the stuff that you bought works,'" Lande said.

E&Ps are now expected to execute and show capital discipline. That shift in public market sentiment has driven public companies to become the dominant sellers in the market. For CEOs, it's a pain.

"They love buying. They don't like executing," he said. "It's a thankless job and, in this environment, investors expect perfection and, as you can see, a lot of people have been penalized for not being 'perfect.'"

Some months, A&D deals were as much as $10 billion. As the capital markets retreated there was first a flattening and then a nose dive.

"The capital markets really have a huge effect on A&D," he said.

By December, Lande counted four deals of more than $100 million, "and in my shoes, that's not good," he said.

Through most of January nearly no A&D—"a giant bagel"—occurred, he said. The good news: there are more opportunities to come and more assets will likely be on the market, he said.

M&A, as Lande sees it, begets A&D. Historically, companies that make big mergers typically sell off noncore assets.

In 2016, about 34% of sellers were public companies. In 2018, nearly 70% of the asset flow came from publics. Going back to 2014, "M&A has been a wonderful thing for A&D. It promotes A&D."

Whiting Petroleum Corp.'s $3.8-billion purchase of Kodiak Oil & Gas spawned four or five deals, Lande said. Other mergers, such as EQT Corp. and Rice Energy Inc., and Noble Energy Inc.'s purchase of Clayton Williams Energy Inc. and Rosetta Resources Inc. also set off related, noncore sales.

Since purchasing BHP's assets, BP plans to divest $5- to $6 billion worth of assets during the next two years. BP's noncore assets include the Wamsutter gas field in Wyoming, the San Juan Basin in New Mexico and the Arkoma Basin in Oklahoma.

RBC is handling Diamondback's divestiture of Central Basin Platform assets acquired with Energen, Lande said.

Encana USA Corp.'s pending $7.7-billion merger with Newfield Exploration Co., in theory, could produce divestitures in the Bakken, Arkoma, Uinta and perhaps the Eagle Ford.

"You would expect some divestitures to come out of that," Lande said.

Musing on the Encana deal, Lande noted that after an industry trend toward pure play companies, Encana is now diversifying. "We'll see if we can go back to diversity," he said. "Oddly enough, our industry is cyclical, if you hadn't realized it yet."

Private equity will be likely buyers, which continues to look for exits but still has more money than anyone with an estimated $95 billion in dry powder, Lande said.

"There's a lot of money. That's not the problem. It's obviously the tepidness right now to pull the trigger on deals," he said.

Private equity's targets have largely been outside of the Permian Basin. "It's places like the Bakken that really had been left for dead by the publics," he said. "Or the Eagle Ford, which was once considered the best rock, pound for pound. It probably still is in a lot of respects."

The Permian simply overshadows it, Lande said.

The days of buying acreage and flipping it within a year, sometimes without having to put a rig to work, are likely over.

"If you had an asset in an attractive resource play for over 18 months and hadn't sold it yet, then you were probably doing something wrong. That's how frothy of a market we were in for so many years with the shale revolution. However, times have changed and now we're back to where we used to be before the advent of resource plays—longer-term holds and cash flow and PDP."

Patient money is now required.

Lande noted that private equity has scooped up about $16 billion in conventional assets, including $12 billion in gas.

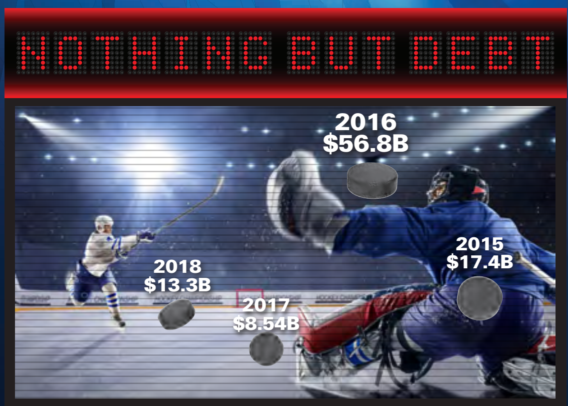
"These are the opportunities that have presented themselves the past few years," he said. Buyers that wait for a home run deal with excellent acreage in the core of the core are likely to have little to swing at. □

ARTICLE BY
DARREN BARBEE

CONTEST OF ENDURANCE

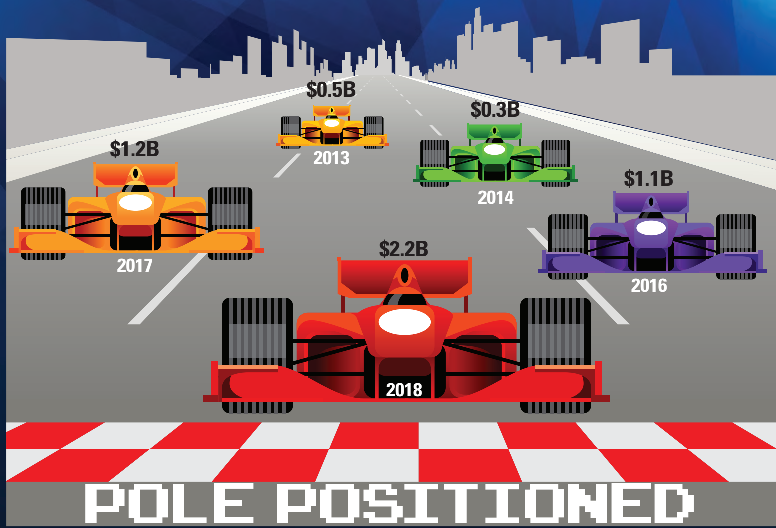
Forces within the energy sector compete for dominance.

The state of the oil and gas industry is a mixed blend: export opportunities beckon, LNG facilities are being built, upstream consolidation is expected and a barrel of oil may stay banded between $50 and $70 per barrel, testing E&Ps' claims of returns at low prices. Entering 2019, the outlook is less grim than it is pragmatic. Volatility is here to stay, it seems and this year seems on track to be as conflicted as the last. So here is the state of things: public markets closed off to all but a few E&Ps, Permian Basin deals still rule, bankruptcies still threaten and natural gas is on its way out—far out—of the U.S.



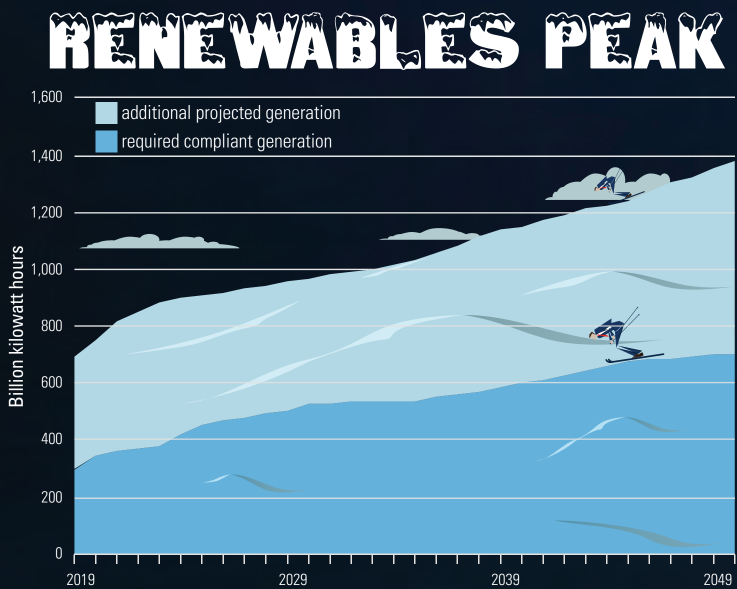
Since 2015, nearly 170 E&Ps companies have filed for bankruptcy, largely mirroring the trend in commodity prices, according to Haynes and Boone LLP's bankruptcy monitor. While E&P bankruptcies decreased in the past two years, the 40% drop in oil prices is cause for concern. Upstream companies have about $32 billion in maturities due in 2019, according to Moody's Investors Service.

Source: Haynes and Boone LLP



A steady drumbeat of royalty deals during the past five years finally went into overdrive in 2018, with deal volume (29) and value ($2.2 billion) both hitting peaks and exceeding 2016 and 2017 totals by $1 billion as deals began to pick up on undeveloped land.

Sources: Deloitte, 1Derrick's M&A Database

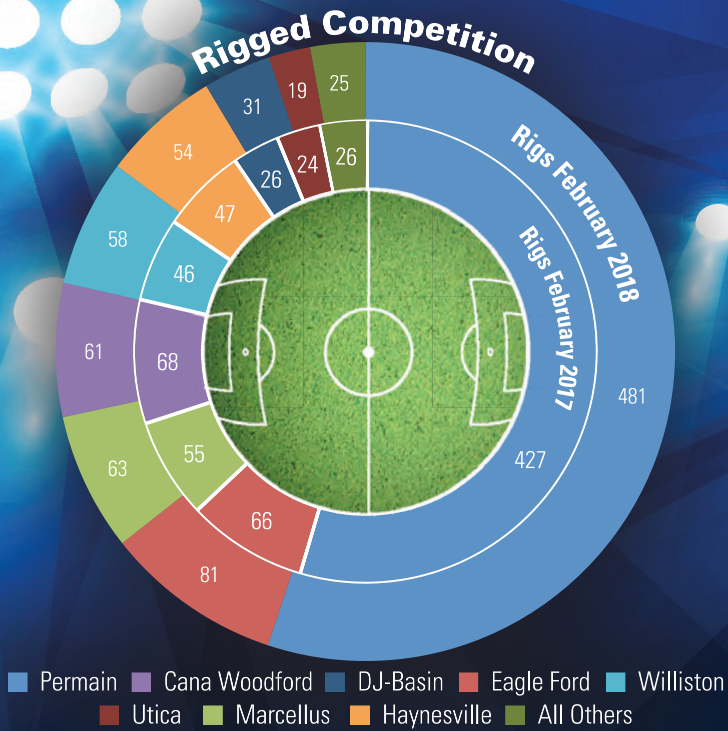


Cost effectiveness, tax credits, state initiatives or demand for cleaner energy have cranked up solar and wind generation beyond expectations even with more rigorous requirements in states such as California, New Jersey and Massachusetts—all while adding pressure to fossil fuel power generation.

Source: EIA

In the public markets, the less you know the better. At least 10 oil and gas companies, including five with upstream companies, have registered to IPO but have held off in a hostile market. Another six blank-check oil and gas companies, known as SPACs, have accumulated nearly $1.5 billion in funding—they just don't have the assets.

Source: PwC



Permian Box Seats

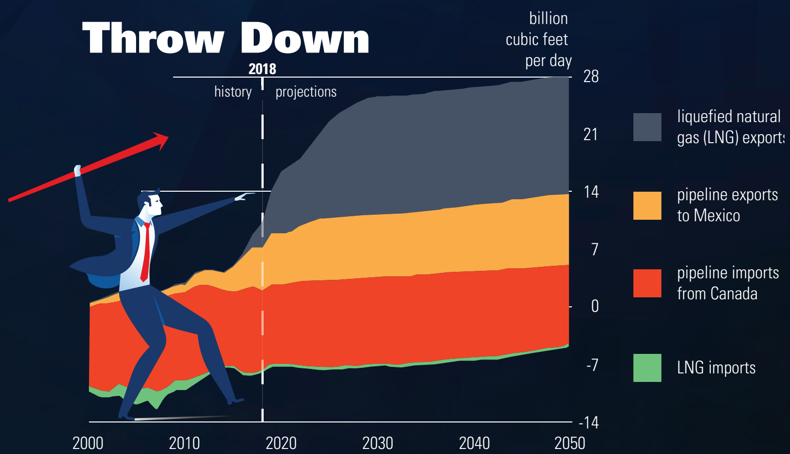
While oil prices ended down in 2018, in the first week of February, the Permian Basin continued to dominate rig counts and added rigs compared to 2017 while other basin's rig counts fluctuated slightly.

Meteorologists worldwide are routinely mocked for trying to predict tomorrow's weather, so take these WTI predicts as discrete moments in the space-time-market continuum.

M&A took some predictable turns in 2018—hello, Permian Basin—though the Haynesville announced its first deal of more than $100 million in more than a year with QEP Resources Inc.'s sale to Aethon III for about $735 million.

Source: Investor, PwC, Deloitte

Throw Down



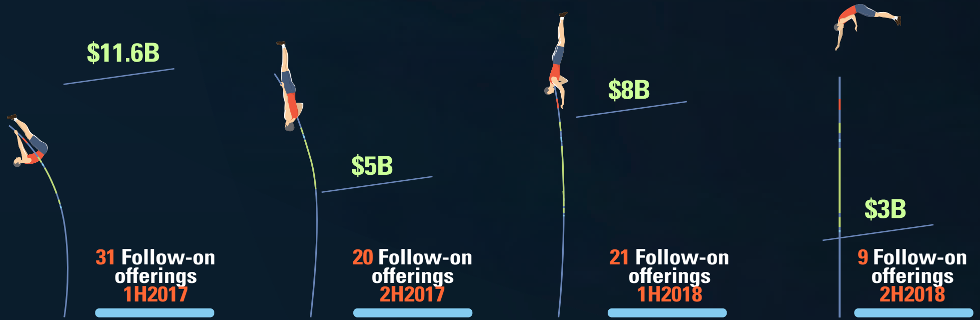
The U.S. path to net energy exporter in part is tied to expected growth in natural gas and NGL production, while LNG export facilities competed by 2022 increase export capacity even more. Pipeline buildout to Mexico with increase exports until 2030, when domestic production begins to displace U.S. exports.

Source: EIA

The Market Vault

Despite 2018's surprising uptick in WTI prices, the number of follow-on equity offerings fell to its lowest point in the second half of 2018, particularly as the fourth quarter saw an E&P stock price blowout. On the other hand, it wasn't Alerian MLP Index bad—where losses in a single day topped $30 billion.

Source: PwC



Rice Brothers Vie For EQT Control

TOBY AND DEREK Rice are doubling down on their calls to transform **EQT Corp.** into the lowest-cost gas operator in the U.S. by taking control of the company and installing Toby as CEO.

The brothers hosted an investor call on Feb. 5 to lay out their turnaround plan for EQT to live up to promises shareholders were made when the merger between EQT and **Rice Energy Inc.** closed about a year ago. The Rice brothers have keenly watched the EQT merger, in part because their fortunes are tied to EQT's performance since the 2017 merger. Rice was paid $1.3 billion in cash and another $5.4 billion tied to EQT's equity.

EQT management has said it's likely they will try to buy back stock soon as part of an effort to blunt the Rice brothers' return to the executive suite. Toby Rice also offered a rebuttal on Feb. 5 to EQT management's comments, which sought to discredit Rice's projections as inflated and based on outdated market conditions.

UNLIKELY ACTIVISTS

The Rices, dissatisfied with EQT's performance since selling Rice Energy Inc. to the company, are agitating for a new management team and new CEO: Toby Rice.

"After believing in the Rice results following extensive due diligence, a five-month integration and a year of operations, EQT now claims that the primary synergy justification it gave for the Rice merger just 14 months ago no longer exists," he said. "We disagree."

While EQT has a rich history, Rice said that this history comes with "some baggage—bureaucratic processes, silos and old systems and dated technology. These are the self-described legacy issues that the company has been trying to address for years to no avail."

While Rice said he has no personal animus toward EQT management, "we strongly believe that we can remove at least 25% of the costs from the business while meeting EQT's production targets," he said. "We're going to add new blood and new technology to revive this business so that it can live up to the potential that its asset base merits and generate the results that shareholders deserve."

On the call, the Rices offered a blueprint for realizing EQT's potential to decrease well costs and improve its free cash flow profile by adding proven leadership, implementing a technology platform and utilizing effective planning.

"We took 80% stock in the merger, and we remain major shareholders in the business because we believe these results are possible," Rice said. "We just don't believe it is possible with the current leadership."

Rice's plan has attracted support from fellow EQT shareholders including **D. E. Shaw**, who publicly released a letter to the EQT board in early January expressing its support for the Rice team.

In the event EQT continues not to engage with the Rice team in "a meaningful and constructive manner," Toby Rice said they plan to challenge EQT's board at the company's upcoming annual meeting.

During the call on Feb. 5, Rice noted that Rice Energy exited 2017 as a top 10 producer of natural gas in the U.S. and generated peer-leading operational results and shareholder returns

The performance was a result of an organizational, technological and cultural transformation Toby Rice led at the company, he said. "This transformation allowed Rice to deliver basin-leading well costs and well productivity with confidence and consistently beating guidance."

As the company's president and COO, Rice established a focus on technology with a data-driven approach to operations in the field and office. He also created a digital work environment, which enabled the company to grow with fewer people and streamlined processes.

Brothers Daniel, Toby and Derek, who formed the company in 2007, agreed to the sale of Rice Energy to EQT for roughly $8.2 billion in the most expensive U.S. shale merger of 2017. The transaction included $6.7 billion in cash and stock and the assumption of about $1.5 billion in debt or preferred equity. Also, Daniel Rice, CEO of Rice Energy, and former Rice director Robert F. Vagt joined the EQT board following closing of the merger in November 2017.

At the time of the sale, Rice Energy was producing and gathering more than 2 billion cubic feet per day (Bcf/d) of gas from a 250,000 net acre Appalachian Basin position in the core of the Marcellus and Utica shale plays.

The merger was not only set to create the largest natural gas producer in the U.S. but also result in savings of overhead and capital efficiency creating an expected $2.5 billion in synergies.

According to Rice, he and his brothers spent the five months following the announcement of the merger with EQT management laying out the blueprint that led to Rice Energy's operational success—their people, technology and planning.

However, Rice claims EQT ignored their assistance and instead decided to move forward without the internal systems and critical personnel who were responsible for Rice Energy's success.

As a result, despite the new scale gained by the merger, EQT's performance has lagged this past year including a 2018 operational miss. Yet 90% of EQT's 2018 and 2019 activity is focused within Rice Energy's footprint, Toby Rice said.

"From the outside looking in, it feels like EQT is a big company with this large unwieldy asset but when you dig into what is actually being developed it's not," he said. "In this footprint, we successfully managed all aspects of a large-scale development program including sand and water logistics, midstream takeaway, leasehold obligations. Essentially all of the operational issues that have challenged EQT, we successfully handled at Rice Energy."

After the Rice team made its plans public in December, EQT management held a Jan. 22 analyst call in which EQT CEO Robert McNally called the plan "fundamentally flawed." Instead, the company laid out its own initiative for 2019.

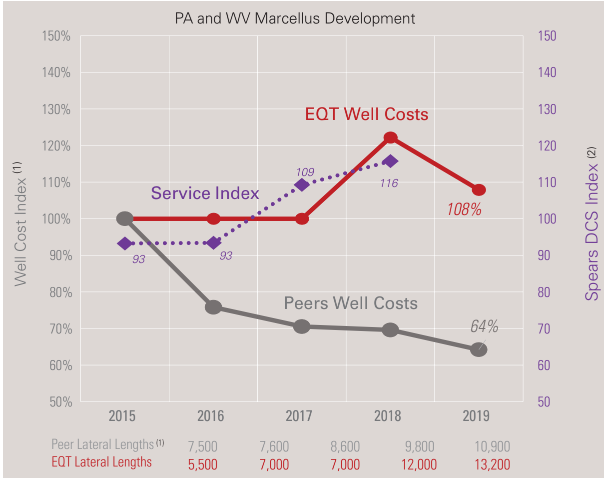
Under its plan, EQT expects to generate around $2.7 billion of accumulated adjusted free cash flow during the next five years. Aiding cash-flow generation would be $100 million of cost savings, an initiative to trim a further 10% of costs across its development program, as well as an up-to-21% decline in forecasted capex this year vs. 2018.

Further, Reuters reported McNally as saying it was "highly likely" EQT would seek to buy back shares in the "near term."

Shareholder reaction to EQT's plan was broadly negative, with EQT shares ending 5.5% lower, according to the Reuters report on Jan. 22.

Rice said EQT's 2019 development plan would set up EQT to be one of the highest cost operators amongst its peers. He added that he is now even more confident in the Rice team's ability to generate $500 million per year of additional free cash flow over EQT's current plan.

Indexed Well Cost Performance Over Time



Source: Rice, company presentations, earnings releases

"This is not a personal attack on the current management team, but they simply do not possess the necessary experience or track record to navigate this path forward … In my opinion, this transformation is not going to come from legacy leadership, a generic goal setting initiative or simply hiring a new COO," he said. "This transformation starts with the right vision and goals—a vision that reflects the potential of the asset base and translates to goals that are achievable."

—*Emily Patsy*

January: A Tough Month For Deals

DESPITE OIL PRICE volatility late last year leaving oil and gas producers struggling with A&D, a few operators in Colorado and the Permian Basin have managed to strike deals.

PetroShare Corp. recently agreed to sell nonoperated interests in Wattenberg Field within the Denver-Julesburg Basin in Colorado, the company said in Jan. 15 filings with the U.S. Securities and Exchange Commission (SEC).

The Englewood, Colo.-based company entered a purchase and sale agreement in January to sell all its nonoperated interest in horizontal wells in Wattenberg. The sale does not include any of PetroShare's operated interest in its Shook Pad, where it has 14 producing wells and 88 permits in process.

The buyer, an undisclosed independent third-party, will purchase the assets from PetroShare for $16.5 million in cash.

The transaction is notable for being one of the few publicly announced upstream A&D deals in the U.S. so far in 2019. Smaller, scattered deals include the Jan. 18 purchase by **Amazing Energy Oil and Gas Co.** of working interest in Lea County, N.M., from **Wyatt Energy LLC**. The $2 million transaction includes 56% working interest on two leases in the Permian Basin.

Nearly a month into 2019, **Talos Energy Inc.**'s U.S. Gulf of Mexico acquisition is so far the leader of the pack among deal makers. The Houston-based independent E&P said it acquired a roughly 9.6% nonoperated working interest in the Gunflint producing asset in the company's Mississippi Canyon core area on Jan. 11 from an affiliate of **Samson Energy Co. LLC** for $29.6 million.

Erratic oil prices have weakened the A&D asset market during the final quarter of 2018. West Texas Intermediate crude futures ended the year down nearly 25% from 2017 at about $45.15 per barrel (bbl) after reaching a four-year high of $77.41/bbl in June 2018.

In 2018, more than $52 billion in upstream deals closed, according to Hart Energy, though weak oil prices and faltering stock prices wreaked havoc on December deals.

PetroShare is a core Wattenberg operator with a position covering roughly 34,000 gross (10,000 net) acres in Weld and Adams counties in Colorado, according to a company investor presentation from October.

The company has about 300 gross (65 net) horizontal Niobrara/Codell locations across its position, based on predominately 2-mile lateral length wells.

The aggregate consideration payable to PetroShare for the sale is subject to purchase price adjustments, including but not limited to adjustments for certain title, environmental defects and casualty losses asserted prior to the closing.

The sale has an effective date of Jan. 1 and is expected to close Feb. 25, the SEC filing said.

—*Emily Patsy*

WPX Deals $300 Million In Delaware

PHOTO COURTESY WPX ENERGY

LIKE OTHER COMPANIES in the Permian Basin, **WPX Energy Inc.** is selling interest in midstream companies with some of the proceeds going toward upstream asset acquisitions, the company said Feb. 4.

In all, WPX agreed to sell $200 million in midstream and upstream assets and plans to redeploy $100 million for acquisitions in its Stateline operations in the Delaware Basin. In the background, the company is regrouping as it puts the brakes on 2019 spending and production.

The transactions will leave WPX Energy with a net cash inflow of about $100 million, while its 2019 capex will be slashed by more than $350 million.

"We remain opportunistic as we manage our portfolio with respect to disciplined development and capital execution," Rick Muncrief, WPX Energy chairman and CEO, said in a news release.

WPX, an independent energy producer with core positions in the Permian and Williston basins, agreed to sell its 20% equity interest in WhiteWater Midstream's Agua Blanca natural gas pipeline. The company will continue to be a shipper on the line.

WPX will also divest its Nine Mile Draw E&P assets in southern Reeves County, Texas. The assets include 5,600 net acres and an average 1,500 boe/d of production in an area outside of WPX's core Stateline development in the Delaware.

WPX will also purchase 14,000 surface acres within its Stateline operations for $100 million, the company said. The Stateline acquisition comprises about 14,000 surface acres in WPX's core development area within the Delaware. Information on the seller and associated production has not been released.

WPX holdings in the Stateline area currently include roughly 60,000 net acres, according to Gabriele Sorbara, principal and senior equity analyst with **The Williams Capital Group LP**.

"We expect WPX to continue to further block up its position, build scale and increase efficiencies in the Delaware Basin," Sorbara wrote in a Feb. 4 research note. "The WhiteWater sale occurred as planned, and its equity interests in the Oryx pipeline systems are expected in [second-half 2019]."

Sorbara noted The Williams Capital Group values WPX's equity interests in the Oryx pipeline at $400 million.

WPX's sales of its equity pipeline interests and upstream assets are expected to close in the first quarter, according to the company release.

Agua Blanca is a natural gas residue pipeline servicing the Delaware Basin. The system consists of roughly 90 miles of 36-inch diameter pipeline and 70 miles of smaller diameter pipeline crossing portions of Culberson, Loving, Pecos, Reeves, Ward and Winkler counties in West Texas.

The Agua Blanca transaction was also a part of another acquisition for a 60% stake in the line by **First Infrastructure Capital** from WhiteWater Midstream and its financial sponsors, **Denham Capital Management** and **Ridgemont Equity Partners**. The Houston-based investment firm announced the acquisition on Feb. 4.

WPX will continue to be a shipper on the Agua Blanca line, which has an initial capacity is about 1.4 billion cubic feet per day with significant expansion plans underway.

The company reduced its full-year 2019 capex guidance to between $1.1 billion and $1.275 billion from prior guidance of $1.45 billion and $1.65 billion, which analysts with **Capital One Securities Inc.** said represents a 23% cut at guidance midpoint.

Production guidance was also lowered by 6% to between 149,000 barrels of oil equivalent (boe/d) and 161,000 boe/d. WPX reduced its 2019 rig count to eight from 10, with two rigs to be dropped in the first quarter. The company plans to run five rigs in the Permian Basin and three rigs in the Bakken within the Williston for the rest of the year.

Tudor, Pickering, Holt & Co. and **Credit Suisse Securities (USA) LLC** advised WPX on the Whitewater transaction.

Simmons Energy, a division of **Piper Jaffray**, was the exclusive financial adviser to **First Infrastructure Capital**. **Sidley Austin LLP** was lead counsel for WhiteWater and Denham. **Troutman Sanders LLP** was lead counsel for Ridgemont. **Latham & Watkins LLP** was lead counsel for WhiteWater management. **Milbank, Tweed, Hadley & McCloy LLP** was lead counsel for **First Infrastructure Capital.**

WPX A&D Announcements, Feb. 4

Divest	Agua Blanca natural gas pipeline 20% interest
Divest	5,600 net acres, 1,500 boe/d, Reeves County, Texas
Total divestitures ($MM)	$200
Acquisition	14,000 net acres, Stateline area
Total acquisitions	$100 million

Source: WPX Energy Inc.

Devon Takes $191 Million For CBP Assets

DEVON ENERGY CORP. sold its Central Basin Platform (CBP) assets located in the Permian Basin to **Stronghold Energy II** for $191 million in January, according to transactional adviser **RBC Richardson Barr**.

RBC said Devon "divested certain oil and gas properties" in the basin, *Investor* first reported. The sale, which had been pending as recently as Jan. 24, closed in January, RBC confirmed to *Investor*.

Devon said on its third-quarter earnings call that it had opened a data room for the assets, which produce 4,000 boe/d, 45% of which is oil.

Stronghold, a private company based in Midland, Texas, is backed by private-equity firm **Warbug Pincus** since January 2018. The company formed in 2017 to focus on acquiring acreage in the CBP.

Stronghold is led by Steve Weatherl, an ExxonMobil Corp.-trained geologist with extensive Permian Basin experience.

With the CBP sale, Devon is closing in on $4.6 billion in sales as part of its portfolio simplification target of $5 billion in divestments. In November, Devon closed a $50-million sale of its Barnett Shale assets in Wise County, Texas. In October, the company closed the sale of 9,600 noncore Delaware Basin assets to **Carrizo Oil and Gas Inc.** for $215 million.

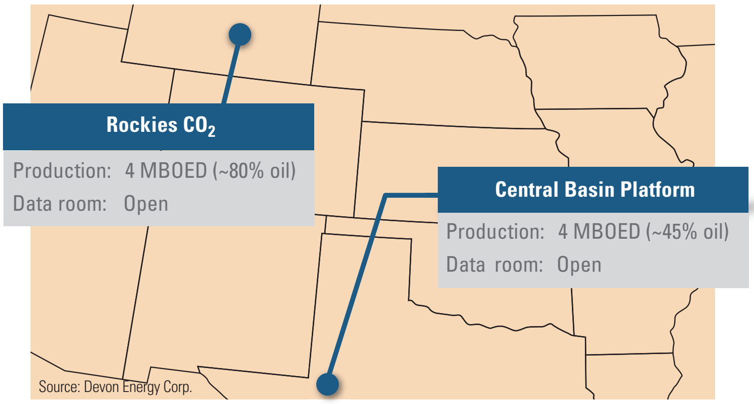
Devon continues to move forward with the monetization of its Rockies CO_2 noncore assets, **Seaport Global** analysts said in a Jan. 22 report. The Rockies assets generate about 4,000 boe/d, 80% of which is oil. Bids for those assets were expected by Devon at the end of 2018.

Devon Energy 2018 Closed Sales

Buyer	Asset	($MM)
EnLink Midstream	Midstream interests	$3,125
Fleur de Lis Energy LLC	Barnett Shale	$553
Carrizo Oil & Gas Inc.	Delaware Basin	$205
Undisclosed	Barnett Shale	$50
Total		$3,933

Source: Oil and Gas Investor (excludes JVs)

Devon Pending Divestitures



Kimbell Royalty Strikes Again

KIMBELL ROYALTY PARTNERS LP wasted little time in 2019 by continuing its buying spree of oil and gas mineral and royalties in the U.S. with an acquisition from private-equity firm **EnCap Investments LP**.

The Fort Worth, Texas-based company said Feb. 7 that EnCap agreed to sell certain oil and gas royalty assets in a 100% equity transaction worth about $151.3 million. The majority of the assets' production is located in the Eagle Ford Shale, Permian Basin, Haynesville Shale and Powder River Basin.

The assets produce about 1,600 boe/d and include 12,200 net royalty acres, increasing Kimbell's total net royalty acre position by 9% to roughly 144,100 net royalty acres across the continental U.S.

The acquisition includes oil and natural gas mineral and royalty interests controlled by the private-equity firm through **Phillips Energy Partners**, **Phillips Energy Partners II** and **Phillips Energy Partners III**.

The production mix of the EnCap assets is about 38% oil, 48% natural gas and 14% NGL on a 6:1 basis and roughly 77% of revenue is from oil and NGL.

Kimbell said 17 rigs are actively drilling on the EnCap acreage.

Including the pending EnCap transaction, Kimbell has completed over $700 million in acquisitions in less than six months, which Bob Ravnaas, CEO of Kimbell's general partner, said positions the company as one of the leading consolidators within the U.S. royalty and minerals space.

"This acquisition kicks off what we believe will be another year of consolidation within the oil and gas mineral and royalty space in the U.S.," Ravnaas said in a statement. "After giving effect to this transaction, we have nearly quadrupled our production since our IPO and will have royalty interests in approximately 95,000 wells across the U.S."

In 2018, Kimbell agreed to acquire one of the nation's largest mineral and royalty acquisition companies, **Haymaker Minerals & Royalties LLC**, in a cash-and-stock deal worth roughly $404 million.

Kimbell's December deal included interests in the Eagle Ford and Bakken shales and Permian and Appalachian basins.

"Like the Haymaker acquisition and the recent dropdown transaction, we believe this acquisition is an excellent fit with our existing portfolio of mineral and royalty assets," Ravnaas said. "We expect not only immediate cash flow accretion in the near term, but also additional future development from an outstanding list of leading operators."

The purchase price of the EnCap acquisition is composed of 9.4 million newly issued units in **Kimbell Royalty Operating LLC**, which Kimbell expects will further reduce its leverage ratio.

EnCap elected to receive 100% equity in this transaction, demonstrating "our commitment to partner with the Kimbell team as they continue to execute on their impressive growth strategy," Marty Phillips, managing partner and founder of EnCap, said in a statement.

The transaction has an effective date of Jan. 1. EnCap will be subject to a 120-day lockup after the closing of the transaction, which Kimbell expects to occur in late March, according to the company press release.

Baker Botts LLP was legal adviser to Kimbell Royalty Partners in connection with the acquisition. **RBC Richardson Barr** was exclusive financial adviser and **Vinson & Elkins LLP** acted as legal adviser to EnCap, the release said.

—Emily Patsy

TRANSACTION HIGHLIGHTS

PERMIAN BASIN

■ **MCM Energy Partners LLC** said it recently sold leasehold in Ward and Loving counties, Texas, as the privately held Permian company continues to pare down its portfolio.

An undisclosed company agreed to acquire MCM Energy Partners' acreage for $42 million, according to an MCM press release on Jan. 8.

Including the recent sale, MCM Energy Partners said it has sold over 4,800 net acres of operated and non-op leasehold in the Permian's Midland and Delaware basins during 2018 for more than $90 million. The company will also add to that with the anticipated sale of Midland Basin leasehold for about $20 million expected to close in first-quarter 2019, the release said.

EAGLE FORD

■ **Chesapeake Energy Corp.** said Feb. 1 that it has completed its acquisition of **WildHorse Resource Development Corp.**, creating an Eagle Ford oil producing powerhouse for Oklahoma City-based Chesapeake.

The acquisition, announced in October, is valued at about $4 billion in cash and stock, including the assumption of WildHorse's $930 million net debt.

Chesapeake intends to finance the cash portion of the WildHorse acquisition, which was expected to be between $275 million and $400 million through its revolving credit facility.

Doug Lawler, Chesapeake CEO, said in a statement: "In 2018, Chesapeake Energy continued to build upon our track record of consistent business delivery and transformational progress through both financial and operating improvements. The addition of the WildHorse assets to our high-quality, diverse portfolio, combined with our operating expertise and experience, provides another oil growth engine with significant oil inventory for years to come and gives us tremendous flexibility and optionality to help achieve our strategic goals."

Pro forma, Chesapeake's position in the Eagle Ford will grow to roughly 655,000 net acres with about 150,000 bbl/d of production, about 60% oil. The company also expects the combination to help it save between $200 million and $280 million in annual costs.

DELAWARE BASIN

■ Texas' University Lands has selected a new joint venture (JV) to serve as the exclusive preferred water services provider on its 167,000 Delaware Basin acreage position through an agreement with **H2O Midstream** and **Layne Water Midstream**, the companies said Jan. 22.

The JV, known as **UL Water Midstream LLC** (ULWM), was formed by H2O Midstream and Layne Water Midstream to develop and operate water infrastructure on the University Lands acreage located across West Texas in Ward, Winkler and Loving counties within the Southern Delaware Basin. Under its agreement with University Lands, ULWM will source groundwater and gather, store, transport, recycle and dispose of produced water from oil and natural gas wells.

The agreement with University Lands also includes an incentive sharing structure that encourages the rapid development of full-cycle water midstream infrastructure with a long-term goal of reducing water logistics costs for operators, increasing revenue for the Texas Permanent University Fund, reducing the environmental impact of water handling, and enhancing the sustainability of University Lands acreage, according to the companies' press release.

MONTNEY

■ **SemGroup Corp.** expanded its footprint in Canada's Montney shale play last week through an acquisition made by a new joint venture (JV) between the Tulsa, Okla.-based company and global investment firm **KKR & Co. Inc.**

The JV, **SemCAMS Midstream ULC**, will combine assets of SemGroup's Canadian subsidiary and **Meritage Midstream ULC**, which SemCAMS Midstream agreed to acquire on Jan. 10 for C$600 million (US$449 million) concurrent with the formation of the JV.

Pro-forma for the acquisition, SemCAMS Midstream will have roughly $1.3 billion of assets in Alberta, analysts with **Capital One Securities** said in a Jan. 10 research note, adding that the JV may also serve as a potential IPO platform in 12 to 36 months, depending on market conditions.

SemGroup will hold 51% common equity ownership in SemCAMS Midstream with KKR owning the remaining 49%.

ALASKA

■ **Eni SpA** said Jan. 3 it plans to boost its total Alaska production following an acquisition offshore the state's North Slope coast.

The Italian oil major agreed to acquire the assets consisting of 70% working interest plus operatorship in the Oooguruk oil field in the Beaufort Sea about 5 kilometers (3.1 miles) off Alaska's North Slope coast from an affiliate of Dallas-based privately held **Caelus Energy LLC**. The terms of the transaction weren't disclosed.

Eni already owns the remaining 30% working interest in the Oooguruk oil field, which has been in production since 2008. The company said the acquisition of Oooguruk's remaining interest provides the addition of 7,000 bbl/d of oil production and important operational synergies with the nearby Nikaitchuq Field. The acquisition also further strengthens Eni's presence in Alaska after its recent purchase of exploration leases covering about 350,000 acres located in the Eastern North Slope from Caelus in August 2018.

IN MEMORIAM: KEVIN HIGGINS, FORMER PRESIDENT OF HART ENERGY

It is with great sadness that Hart Energy mourns the death of its former president and chief operating officer, Kevin F. Higgins, who passed away at his home in Rockaway, N.J., on Feb. 1, 2019. He was 56.

He was surrounded by his family after putting up a courageous fight against cancer.

"Kevin meant so much to us, personally and professionally. A man of honor and of the highest integrity, he was a friend, mentor and partner who possessed a dry wit and was always ready to debate you. He truly cared about Hart Energy and every one of our employees," said Rich Eichler, CEO of Hart Energy.

"Forward thinking, analytical, driven and ever curious—Kevin was a genuine leader," said Rey Tagle, senior vice president of data services. "He had perfected the art of motivating others with his unique balance of praise, tough love, and self-deprecating humor."

Kevin's loss is felt keenly by everyone at Hart Energy. It was our privilege to know and work with him.

Rest in peace, Kevin.

LIVING WITHIN CASH FLOW

RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

Got free cash flow?

If not, it's time to get with the program. E&Ps may have been reworking 2019 capex budgets lower in an uncertain environment as NAPE got underway in Houston but, to a company, all were certain on the main course of action going forward. Publicly held E&Ps universally agree that they will become shareholder friendly.

That philosophy encompasses a range of actions from buying back outstanding shares, decreasing burdensome leverage and/or maintaining a consistent dividend, at least for those who provide dividends.

Implied, though not yet realized in a majority of cases, is the need to become free-cash-flow neutral. Most E&Ps are targeting 2020 for getting their corporate heads firmly above water.

This is an important inflection point in oil and gas.

For years, the energy story was about production volume growth. Wall Street showered energy companies with cash to drill holes in the ground. Even in recovery after the 2014 to 2016 price collapse, management teams spoke openly about capital efficiency as frequently as the industry used to talk about being "liquids-rich" after natural gas prices collapsed in 2008.

Wall Street closed its wallet for production volume growth at the end of 2017. High oil prices masked the capital short fall for a while. When commodity prices fell in 2018, energy equities led all sectors down during the financial swoon. From a macro standpoint, energy has fallen from 16% of S&P value at peak in 2008 to 6% currently.

Or, commiserate with the reports of investment bank sell-side personnel who deserve an "A" for effort in promoting the sector, even as they recount brutal one-on-one meetings with an energy indifferent clientele.

Admittedly, energy generated a strong equity market rally year-to-date, but those gains mostly reflect the steep year-end devaluation.

What makes this time different? Watch for the structural impact on the energy business model. The type of companies that thrived in a world of abundant capital and available resources will no longer rule the new era. Back then, the pursuit of production volume growth supported a business model in which C-suite personnel originated out of exploration or operations. Senior management assembled proficient technical and operations teams, really the best and the brightest in exploration and development. Boards of directors bought in on the production volume growth story and structured compensation to reflect gains in production, even as a majority of companies lost money.

Production volume growth rose despite lower inputs of drilling rigs and stimulation crews in the post-2014 recovery.

Now the question is how managerial and technical teams will adjust to a new business reality where the emphasis is on operating profitably within cash flow in a capital-intensive business. E&P management teams now face one of the greatest transformational challenges in recent history, one that requires a different set of managerial skills and an entirely different business philosophy.

There have been some dry runs. Discussion about free-cash-flow neutrality has been ongoing for half a decade. Since 2014, E&Ps have promised to reach rationality in business within the preceding two years. Each year, that time frame was pushed out another year.

E&Ps received temporary reprieve with the one-year oil price rally that ended in September 2018. The windfall was directed mostly into operations with some allocation to shareholders. However, the commodity price tailwind hampered the industry's ability to turn away from the production volume growth narrative in favor of business rationality.

Instead, E&Ps generated terms like capital efficiency to explain how they were getting better in operations even while earnings reports show many lost money as a business. During the five-year period ending in 2017, a basket of E&P firms spent $1.40 for every $1 in revenue. That was not a sustainable business model

There is good news. The sector in aggregate reached zero outspend at the end of the third quarter of 2018. However, the demographics were lopsided with about 30% of the sector generating positive cash flow—mostly larger publicly held companies operating in the Permian Basin. Two-thirds of publicly held E&Ps remained on the outspend treadmill. The sector benefitted as oil prices topped out in the mid-$70 range.

Those days are gone. Several E&Ps are cutting 2019 capex by 15% to 20%. Now the question is whether management teams can adjust quickly enough to reach consistent cash-flow neutrality with sub-$60 oil.

EASTERN U.S.

1 ***T.D. Energy Inc***. is planning to drill a 1,700-ft Aux Vases venture in Marion County, Ill. The Wamac Field well, #1 T. 1 T. Borum, will be in Section 19-1n-1e. The Ponchatoula, La.-based company has completed several wells in the reservoir, including a successful re-entry, also in Section 19: #1 Smith was tested in 2009 pumping 8 bbl of crude and 80 bbl of water per day from Benoist Sand at 1,420 ft. The Wamac Field well was deepened by T.D. Energy to 1,500 ft after originally being abandoned in 1982 at 1,394 ft. The company's #1 Kent in Section 19 was drilled in 2016 to 3,039 ft, with 5 1/2-in. casing set to a much shallower depth of 833 ft.

2 Mount Vernon, Ill.-based ***Wood Energy Inc.*** has scheduled a deeper pool wildcat in Illinois' Irvington East Field. According to IHS Markit, #8 Whacker is targeting pays in Trenton from a site in Jefferson County. The proposed 4,999-ft well will be in Section 31-1s-1e. Several Irvington East Field wells have been drilled in the northern half of Section 31. Offsetting Wood Energy's scheduled test is a 1,968-ft oil well drilled in 2008: #5 Wacker was tested pumping 80 bbl of crude per day from Upper Cypress Sand at 1,730-36 ft. The deepest drilling in Irvington East Field is just south of Wood Energy's planned location. Completed in 2008 by ***Deep Rock***, #7 Wacker was drilled to 5,000 ft in Platteville. Well production comes from Upper Cypress Sand at 1,729-34 ft. The deepest production in Irvington East field comes from the Benoist Sand at around 1,950 ft.

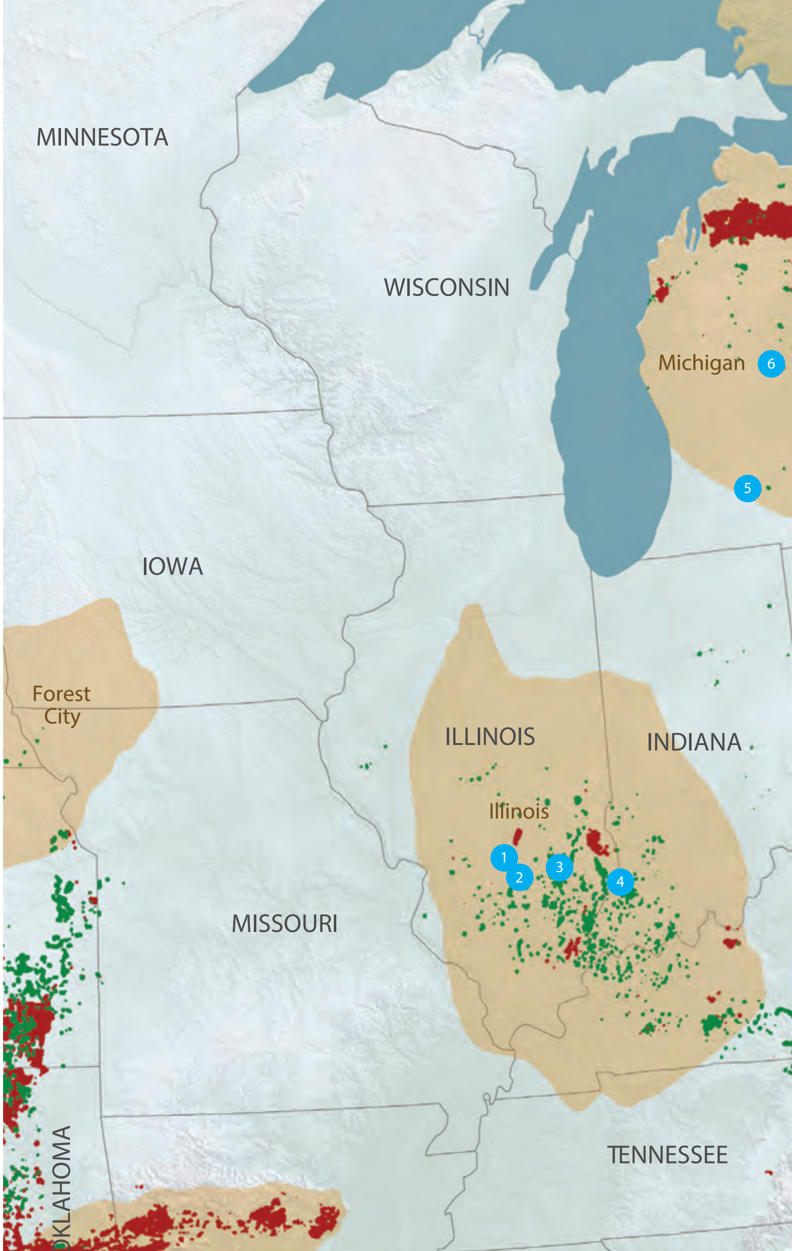
3 ***CountryMark Energy Resources*** received permits for two wells in Section 14-1s-6e of Wayne County, Ill. The #2 Hilliard is targeting Warsaw with a planned depth of 4,100 ft. The #5 Paul White has a planned depth of 2,800 ft and will be targeting St. Louis. The ventures are in Johnsonville South Field. CountryMark's headquarters are in Evansville, Ind.

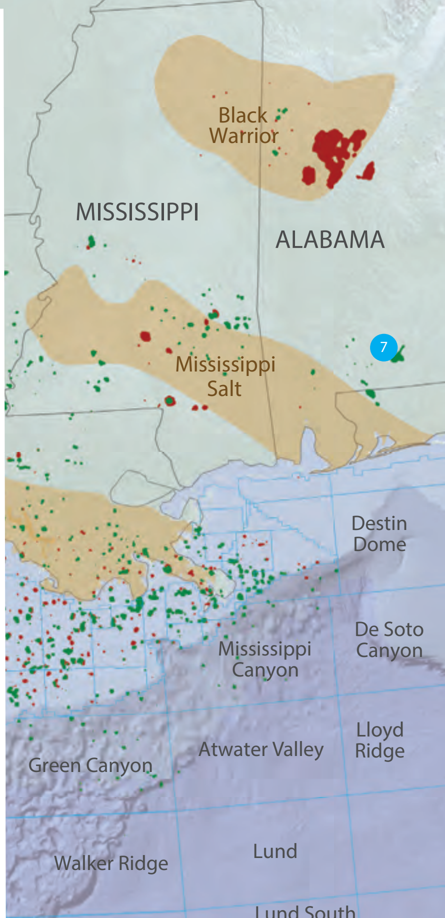
4 In Gibson County, Ind., ***Southern Triangle Oil Co.*** has received permits for two wells in Section 27-2s-12w in Owensville Consolidated Field. The #2 Robert Almon Etal Comm is targeting Renault with a planned depth of 2,462 ft and #2 Fred Smith Etal Comm has a planned depth of 2,534 ft and is targeting Aux Vases in Mauck Field. Southern Triangle is based in Mount Carmel, Ill.

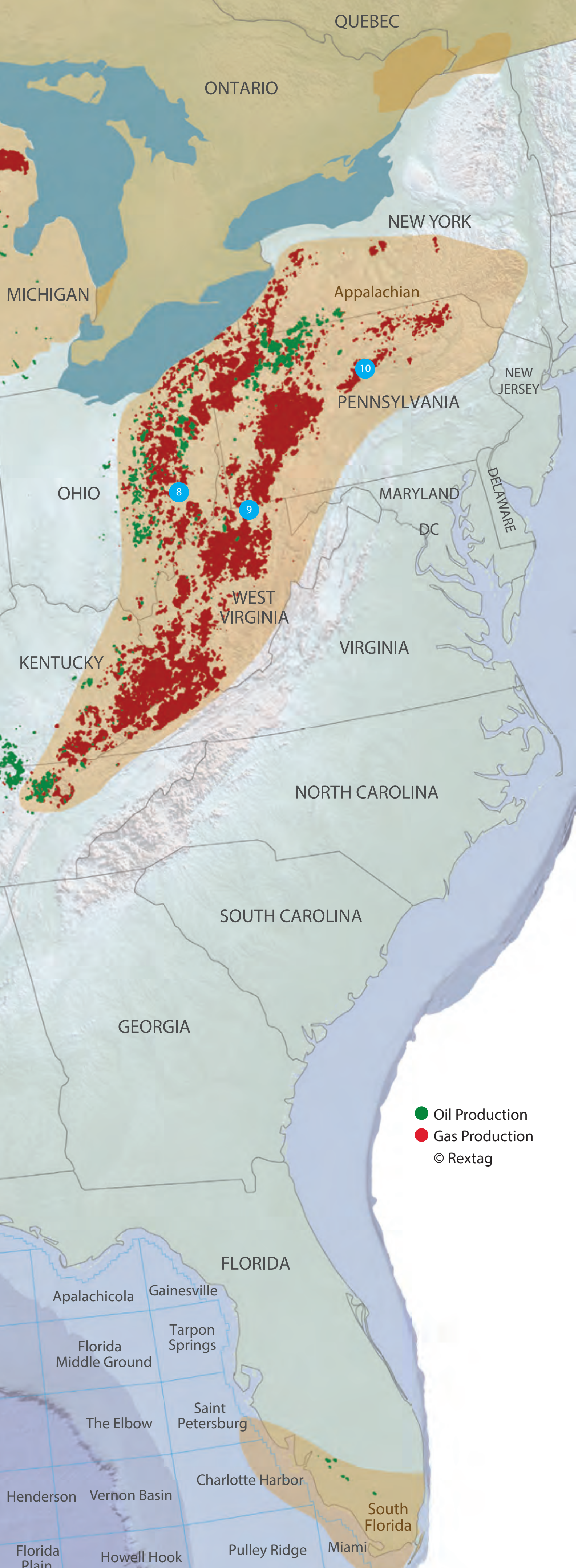
5 ***Savoy Energy LP*** has announced a Trenton oil discovery. The #1-34 Seymour is in Section 34-3s-8w in Kalamazoo County, Mich. It flowed 200 bbl of oil and 20 Mcf of gas per day. The well was tested on 14/64-in. choke and the flowing tubing pressure was 200 psi. It was drilled to 4,050 ft with 5 1/2-in. casing set on bottom. The 246-ft-thick Trenton pay was encountered at 3,440 ft. Production is from acidized perforations at 3,664-66 ft. Savoy's headquarters are in Traverse City, Mich.

6 A Dundee Lime wildcat has been scheduled in Montcalm County, Mich., by San Antonio-based ***W.B. Osborn Oil & Gas***. The #1-8 Venton Trust has a planned depth of 3,550 ft and will be in Section 8-11n-5w. According to IHS Markit, numerous Dundee Lime wildcats have been drilled in Section 8, including the nearby #1 George Hilliard. The 3,449-ft wildcat was abandoned in 1963. Other tests in Section 12 were also abandoned between 3,400-3,500 ft. W.B. Osborn has also permitted two other tests within 3 miles south at #1-22 Stratton in Section 22—it has a planned depth of 3,050 ft and is targeting Traverse Lime. The #1-22 Marshall is also targeting Traverse Lime and it has a proposed total depth of 3,025 ft. Also in Section 22 is the operator's #2-22 McAlvey. The Ferris Field well was tested in October 2018 flowing 35 bbl of crude, 12 Mcf of gas and 18 bbl of water from an unreported Traverse Lime zone.

7 ***Ventex Operating Corp.*** has scheduled the first horizontal test in Alabama's Brooklyn Field. The #1 Cedar Creek Land & Timber 13-5 will be in Section 13-3n-13e in Conecuh County and will bottom to the southwest. The Smackover oil test has a planned depth of 12,100 ft. A successful completion would extend Brooklyn Field about 1 mile southeast. Several directional wells have been completed in Brooklyn Field, including ***Fletcher Petroleum***'s #1 Anderson Johnson 11-9 in Section 11. The 11,988-ft well was completed in 2018, flowing 393 bbl of 46-degree-gravity crude and 143 Mcf of gas per day from Smackover at 11,797-11,808 ft. Ventex is based in Dallas.

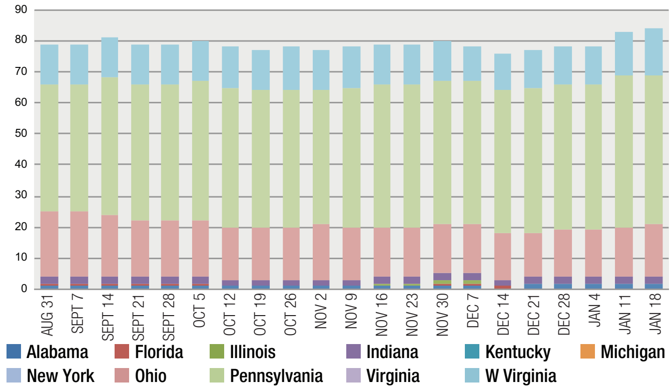






Eastern U.S. Rig Count

Aug. 31, 2018-Jan. 18, 2019



Data compiled from Baker Hughes

8 ***Ascent Resources LLC*** has received permits for five Utica wells in Monroe County, Ohio. The Barnesville Consolidated Field wells will be drilled from a pad in Section 11, Quaker City 7.5 Quad, Milwood Township. The #9H Watson E MLW GR has a planned depth of 7,490 ft. The #11H Watson E MLW GR has a planned depth of 7,475 ft and will be drilled to the southeast. The #1H Watson W MLW GR has a planned depth of 7,500 ft and will be drilled to the southwest. The #3H Watson W MLW GR has a planned depth of 7,050 and will be drilled to the south. About 20 ft west on the pad, #5H Watson W MLW GR has a planned depth of 7,450 ft and will be drilled to the southeast. Ascent's headquarters are in Oklahoma City.

9 ***Consol Energy Inc.*** received permits for three Marcellus ventures in Maple-Wadestown Field in Monongalia County, W.Va. The wells will be drilled from a pad in Battelle Dist., Wadestown, 7.5 Quad. The #1-WDTN5GHSM has a planned depth of 17,991 ft and a planned true vertical depth of 7,715 ft and will be drilled to the east. The #1-WDTN5HHSM has a planned depth of 16,939 ft and a planned true vertical depth of 7,715 ft. It will bottom to the west. The #1-WDTN5NHSM has a planned depth of 21,610 ft and a planned true vertical depth of 7,715 ft. It will be drilled to the south-west. Consol's headquarters are in Canonsburg, Pa.

10 Two extended-lateral Marcellus Shale wells were reported by Oklahoma City-based ***Chesapeake Operating Inc.*** The Lovelton Field wells were drilled from a pad in Sullivan County, Pa., on an 825-acre lease in Section 6, Dushore 7.5 Quad, Cherry Township. The #4HC Joeguswa had a lateral length of 13,803 ft. It was tested flowing 62.6 MMcf per day with a flowing pressure of 2,600 psi. The #5HC Joeguswa has a lateral length of 9,808 ft and was tested flowing 73.4 MMcf per day with a flowing pressure of 3,000 psi. According to completion details submitted to Pennsylvania state regulators, the wells reported extremely high open-flow rates—#4HC Joeguswa flowed 94 MMcf per day from perforations at 8,037-21,765 ft and #5HC Joeguswa had an open-flow rate of 116 MMcf per day at 8,234-17,777 ft.

GULF COAST

1 ***Recoil Resources*** has completed two Eagleville Field producers in Wilson County (RRC Dist. 1), Texas. The #2H Sekula A flowed 610 bbl of 34-degree-gravity crude, 302 Mcf of gas and 1.5 Mbbl of water from an acid- and fracture-treated Eagle Ford Shale zone at 8,742-16,570 ft. It was drilled to 16,648 ft, 8,983 ft true vertical, and is on an 855-acre lease in Andres Hernandez Survey, A-17. Tested on a 20/64-in. choke, the flowing casing pressure was 1,375 psi. The offsetting #3H Sekula A produced 685 bbl of 35-degree-gravity crude, 336 Mcf of gas and 1.734 Mbbl of water per day. Production is from acid- and fracture-treated perforations at 8,742-16,530 ft and it was drilled to 16,630 ft, 8,977 ft true vertical. Gauged on a 22/64-in. choke, the flowing casing pressure was 1,462 psi. The parallel laterals of both wells bottomed within 1.5 miles southeast in Karnes County (RRC Dist. 2) in Andres Hernandez Survey, A-4. Recoil's headquarters are in Houston.

2 ***Aethon Energy Operating LLC*** announced results from a Cotton Valley gas well in Bald Prairie Field. Located in Robertson County (RRC Dist. 5), Texas, #1 Pharis Ranch Gas Unit is producing 7.772 MMcf per day from perforations at 15,350-15,800 ft. The directional venture was drilled to 16,116 ft with a true vertical depth of 16,075 ft. It is on a 704-acre lease in Robert Henry Survey, A-19. Tested on a 22/64-in. choke, the flowing casing pressure was 5,490 psi. The directional well was drilled to 16,116 ft (16,075 ft true vertical) on a 704-acre lease in Robert Henry Survey, A-19. Aethon's headquarters are in Dallas.

3 According to IHS Markit, Houston-based ***Sabine Oil & Gas LLC*** has completed two horizontal Cotton Valley wells in Ruck County (RRC Dist. 6), Texas. The #1H Viper 1-J.B. Alford (AW) flowed 11.16 MMcf of gas, 51 bbl of 52.6-degree-gravity condensate and 1.937 Mbbl of water per day. Production is from acid- and fracture-treated perforations at 10,829-19,364 ft. The well was drilled to 19,708 ft, 10,672 ft true vertical. The offsetting #1H Viper 3-J.B. Alford (AW) is producing 10.712 MMcf of gas, 61 bbl of 52.4-degree-gravity crude and 1.573 Mbbl of water per day through acid- and fracture-treated perforations at 11,080-18,981 ft. The horizontal well was drilled to 19,035 ft (10,698 ft true vertical). The Minden Field wells were drilled from offsetting surface locations in Thomas J. Jackson Survey, A-15. The parallel laterals bottomed within 2 miles south-southeast.

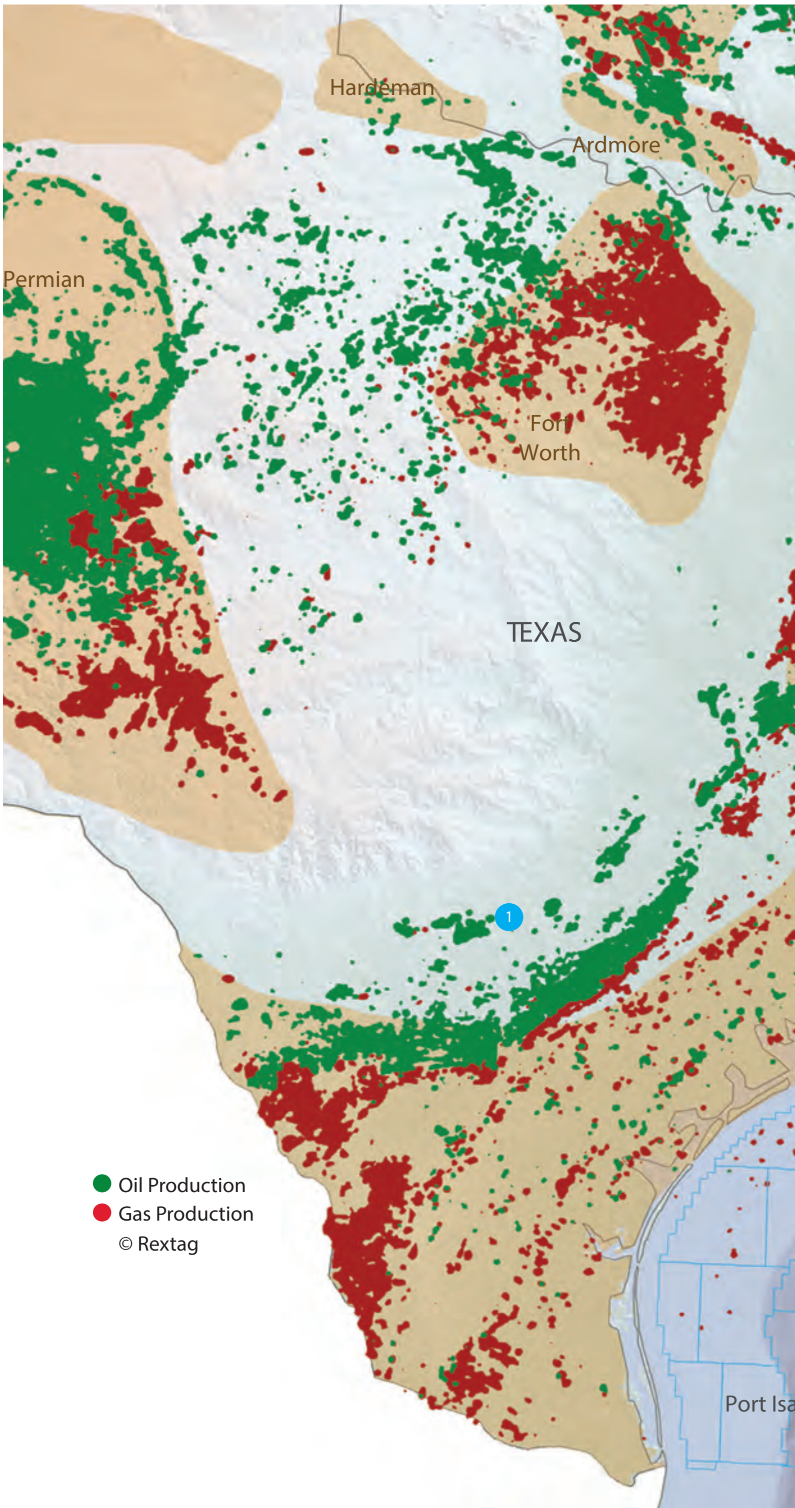
4 A Cotton Valley discovery was announced by ***Barrow-Shaver Resources Co.*** in Cass County (RRC Dist. 6), Texas. The #1 Downs flowed 194 bbl of 51-degree-gravity crude, 430 Mcf of gas and 184 bbl of water per day. Production is from acid- and fracture-treated perforations at 11,614-73 ft. Gauged on a 20/64-in. choke, the flowing tubing pressure was 450 psi. The 12,100-ft oil well is on a 160-acre lease in the Raymond Sunigas Survey, A-942. Barrow-Shaver is based in Tyler, Texas.

5 ***BP Plc*** has completed a Haynesville Shale well in Carthage Field. Located in Angelina County (RRC Dist. 6), Texas, #1H Velo Gas Unit flowed 6.816 MMcf of gas and 744 bbl of water per day from a fracture-treated zone at 15,435-22,849 ft. Tested on a 14/64-in. choke, flowing tubing pressure was 10,657 psi and shut-in tubing pressure was gauged at 12,881 psi. It was drilled to 23,054 ft and the true vertical depth is 15,897. It is on a 960-acre lease in William White Survey, A-645, and bottomed about 2 miles south in James Gilliland Survey, A-284. BP is based in London.

6 A development test has been scheduled by The Woodlands, Texas-based ***Anadarko Petroleum Corp.*** for the expansion of Horn Mountain Field. The #8 OCS G18194 will be in the southwestern portion of Mississippi Canyon Block 82 (OCS G35313). It will bottom south in Block 126. Area water depth is 4,300 ft. In 2018, the company won exploration-plan approval to drill as many as 16 tests from various surface locations on Block 81 (OCS G35312), Block 82 and Block 126. There has been no production to date from blocks 81 and 82.

7 A subsalt exploratory test was drilled by ***GulfSlope Energy Inc.*** on the Houston-based company's Tau prospect in Ship Shoal Block 336 (OCS G35244). The #1 OCS G36121 was drilled to an estimated total depth of 29,728 ft, and it bottomed south in Block 351. Water depth in the area is 305 ft. According to GulfSlope, the exploratory test was to be drilled through almost 10,000 ft of salt, testing Upper and Middle Miocene sands. Numerous Pleistocene wells have been drilled on Block 351 and under previous lease OCS G26078, and field production from 2007 through 2016 totaled 2.4 MMbbl of crude/condensate, 2.9 Bcf of gas and 3.8 MMbbl of water from 8,540-9,506 ft.

8 ***BP Plc*** is drilling another development test as part of

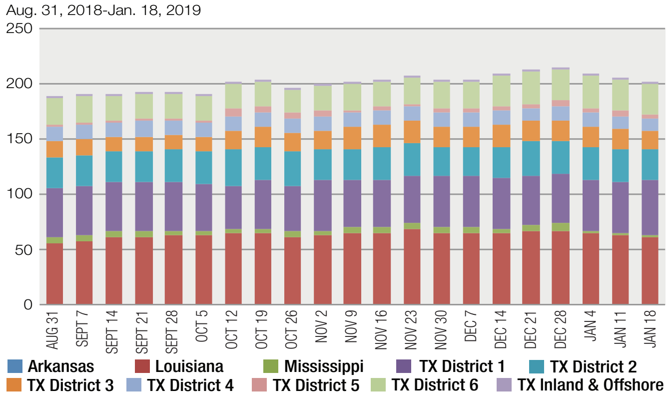


the company's Mad Dog Field expansion. The test is in Green Canyon Block 825 at #8 OCS G09982. It is expected to bottom east in Green Canyon Block 826. Area water depth is 4,900 ft. In addition, the company intends to place a second production facility in the area—the Argos floating production unit is scheduled for the southwestern portion of Block 825.

9 ***Venture Oil & Gas Inc.*** has spud another Cotton Valley test in the company's New Home Field, IHS Markit reported. In Smith County, Miss., #1 Jernigan 6-10 is a 16,400-ft directional oil test and is in Section 6-10n-13w. Nearby production is within 1 mile southeast at the New Home Field opener. Completed by the company in 2017, #1 Sims 7-8 in Section 7 flowed 217 bbl of 49-degree-gravity crude, 827 Mcf of gas and 2 bbl of water from Cotton Valley at 15,522-15,670 ft. The well was directionally drilled to 16,100 ft. The field's confirmation well, #1 Stringer 8-11 in Section 8, was completed in early 2018, flowing 281 bbl of 45-degree-gravity crude and 420 Mcf of gas per day from perforations at 14,784-14,991 ft. Venture is based in Laurel, Miss.

Gulf Coast Rig Count

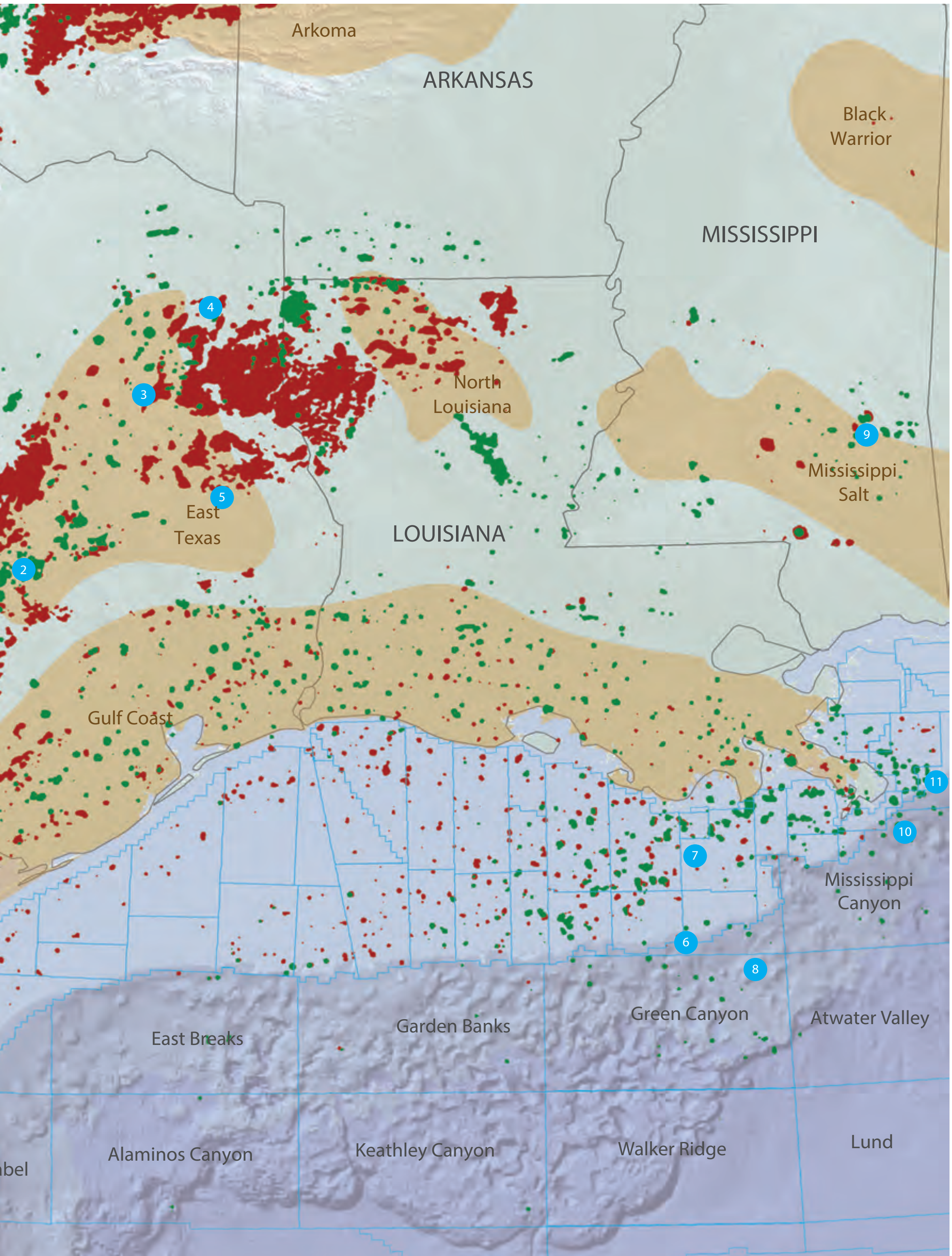
Aug. 31, 2018-Jan. 18, 2019



Data compiled from Baker Hughes

10 According to ***BP Plc***, advanced seismic imaging technology has increased the resource estimate for Thunder Horse Field in the Gulf of Mexico. Proprietary algorithms developed by BP enhance a seismic-imaging technique (full waveform inversion) to process data in only a few weeks. Application of this technology and reservoir characterization, according to BP, has now identified a further 1 Bbbl of oil in place in the field. Thunder Horse Field encompasses Mississippi Canyon blocks 777, 778, 821 and 822. The same advanced seismic imaging was applied to BP's Atlantis Field, with the company recently deciding to spend $1.3 billion on a field-expansion project. Atlantis Field (Green Canyon Block 743) came online in 2006 and wells produce from Williana, Pliocene and Miocene at 16,460-22,486 ft. BP operates the Thunder Horse area and holds a 75% stake in the field. The remaining 25% is owned by ***ExxonMobil Corp***.

11 ***LLOG Exploration & Production*** announced a Mississippi Canyon Block 387 discovery. The #1 OCS G22873 encountered oil pay in high-quality Miocene sandstone reservoirs. It was drilled to an unreported depth in 6,600 ft of water. According to the Covington, La.-based company's exploration plan, a second test could be drilled on adjacent Block 386 (OCS G34438) west. Blocks 386 and 387 make up LLOG's Nearly Headless Nick project. The project was previously known as the company's Moby Dick prospect. First production is expected by the end of 2019, with the discovery to be tied back to the Delta House facility on Mississippi Canyon Block 254.



MIDCONTINENT & PERMIAN BASIN

1 ***Driftwood Energy Operating LLC*** completed an extended-lateral Wolfcamp producer on the Spraberry Trend in Reagan County (RRC Dist. 7C), Texas. The #1H Dogwood was tested on-pump flowing 1.254 Mbbl of 40.3-degree-gravity crude, 1.171 MMcf of gas and 1.599 Mbbl of water per day. Production is from fracture-treated perforations at 7,561-17,657 ft. The well was drilled to 17,743 ft, 7,353 ft true vertical, and is in Section 177, Block 1, T&P RR Co Survey, A-551, on a 1,446.7-acre Midland Basin lease. The lateral bottomed 2 miles south in Section 200. Driftwood's headquarters are in Dallas.

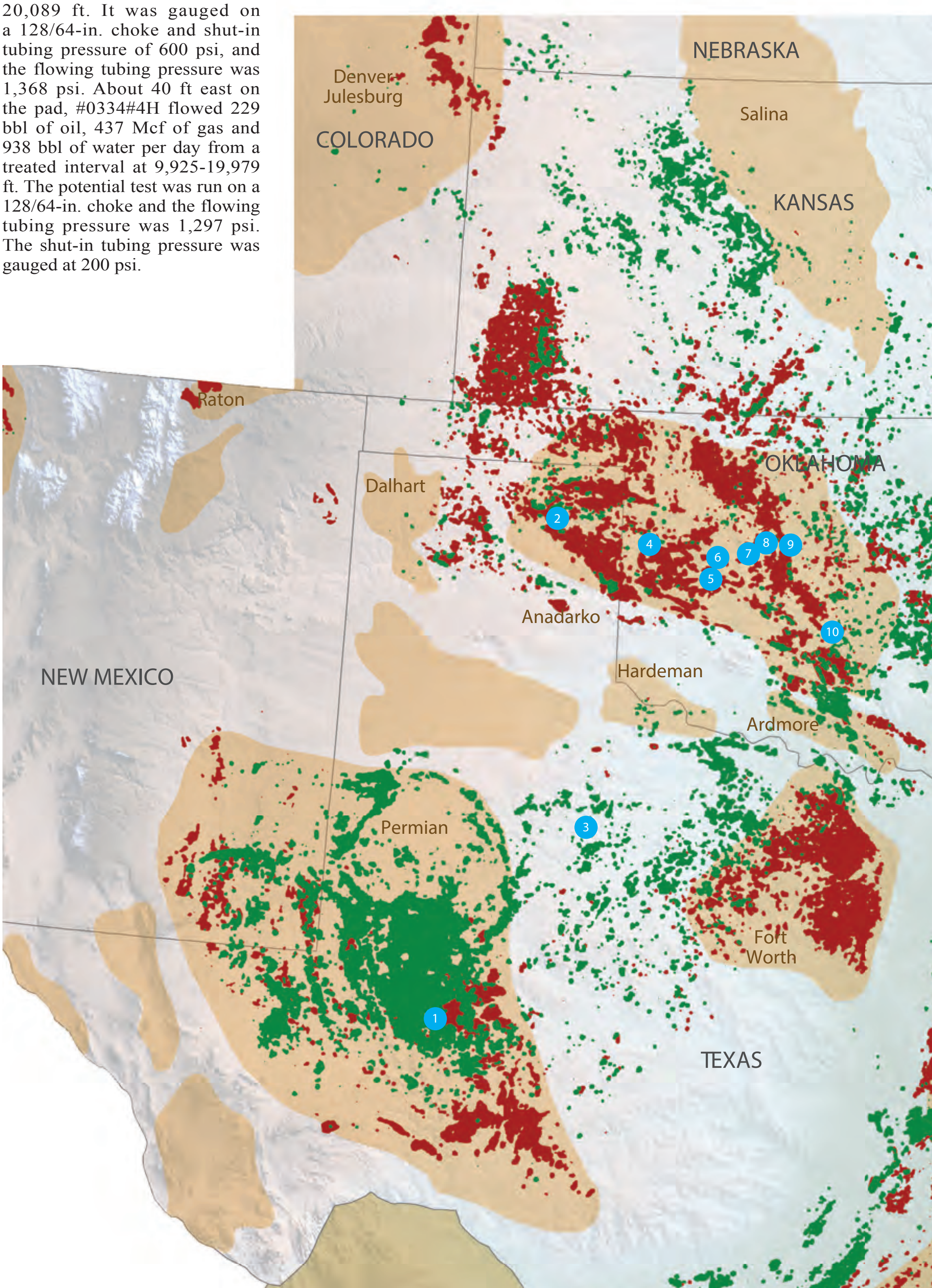
2 ***Latigo Petroleum Inc.*** reported the completion of two horizontal Cleveland wells from a drillpad in the western Anadarko Basin. The #3153H Mayo Clinic C is in Section 153, Block C, G&M Survey, A-626, in Roberts County (RRC Dist. 10), Texas. It was tested on gas lift, producing 623 bbl of 40-degree-gravity oil, 1.07 MMcf of gas and 280 bbl of water daily from a fracture-stimulated, open-hole interval at 7,285-12,822 ft. It was drilled to 12,822 ft and the true vertical depth is 6,781 ft. It bottomed about 1 mile north in Section 143, A-479. About 40 ft south on the pad, #1153H Mayo Clinic C initially flowed 596 bbl of oil with 1.37 MMcf of gas and 490 bbl of water per day when tested on gas lift. Production is from a fractured open-hole interval between 7,350 and 13,043 ft (plugged-back total depth) in a parallel Cleveland lateral that was drilled to the east and bottomed in Section 142, A-606. Latigo is based in Houston.

3 ***Gunn Oil Co.*** has completed a Fisher County (RRC Dist. 7B), Texas, workover as a new pool discovery in FGY Field. The #1 Grunden GC pumped 146 bbl of 43-degree-gravity oil and 16 bbl of water per day from acid- and fracture-treated perforations in Saddle Creek at 4,891-98 ft. Drilled to 6,017 ft, it was plugged back to 5,609 ft before completion. It is in Section 121, Block 2, H&TC RR Co Survey, A-126, on a 40-acre lease northwest of the Bend Arch on the Eastern Shelf of the Permian Basin. Gunn's headquarters are in Wichita Falls, Texas.

4 In Ellis County, Okla., Houston-based ***EOG Resources Inc.*** completed two Marmaton wells in Section 3-17n-24w of Ellis County, Okla. The #0334#3H Miller initially flowed 1.193 Mbbl of 43-degree-gravity oil, 961 Mcf of gas and 2.013 Mbbl of water per day. It was drilled to the north to 20,151 ft with a true vertical depth of 9,446 ft. The venture bottomed in Section 34-18n-24w and production is from an acidized and fractured interval between 9,968 and 20,089 ft. It was gauged on a 128/64-in. choke and shut-in tubing pressure of 600 psi, and the flowing tubing pressure was 1,368 psi. About 40 ft east on the pad, #0334#4H flowed 229 bbl of oil, 437 Mcf of gas and 938 bbl of water per day from a treated interval at 9,925-19,979 ft. The potential test was run on a 128/64-in. choke and the flowing tubing pressure was 1,297 psi. The shut-in tubing pressure was gauged at 200 psi.

5 ***Continental Resources Inc.*** has completed a two-section horizontal Woodford producer at #1-29-20XHW Wild Goose in Section 29-14n-14w in Custer County, Okla. It was tested on a 44/64-in. choke flowing 19.7 MMcf of gas and 5.135 Mbbl of water per day. The flowing tubing pressure was 4,134 psi. It was tested after acidizing and fracturing at 15,907-25,459 ft. This Thomas South Field well was drilled to the south to respective measured and true vertical depths of 25,459 ft and 15,139 ft with a bottomhole location in Section 20-14n-14w.

6 A Meramec discovery in the Stack play was announced by ***MEP Operating LLC***. The #1HX-0916 Spanish Castle Magic initially flowed 22.3 MMcf of gas per day, with 1 bbl of 51-degree-gravity condensate and 979 bbl of water per day. The well is in Section 9-14n-14w of Custer County, Okla. It is producing from acidized and fractured perforations at 14,004-22,137 ft in an approximate 1.5-mile south lateral. It was drilled to 22,320 ft, 14,109 ft true vertical, and bottomed in Section 16-14n-14w. Tested on a 28/64-in. choke, the shut-in tubing



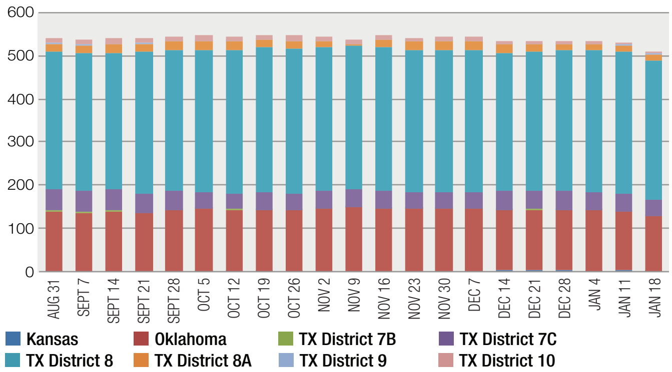
pressure was 7,200 psi and the flowing tubing pressure was 5,300-psi. MEP's headquarters are in Houston.

7 A high-volume Woodford completion was announced by Oklahoma City-based ***Continental Resources Inc.*** The #1-6-7XHW Simba initially flowed 29.8 MMcf per day, with 50 bbl of 56-degree-gravity condensate and 4.453 Mbbl of water per day. The Blaine County, Okla., discovery is in Section 6-14n-12w. Production is from an acidized and fractured interval at 13,267-23,085 ft that extends southward across the section and bottomed in Section 7-14n-12w. It was drilled to 23,217 ft, 13,371 ft true vertical. The Squaw Creek Field well was tested on a 42/64-in. choke with a shut-in tubing pressure of 5,975 psi and a flowing tubing pressure of 5,001 psi.

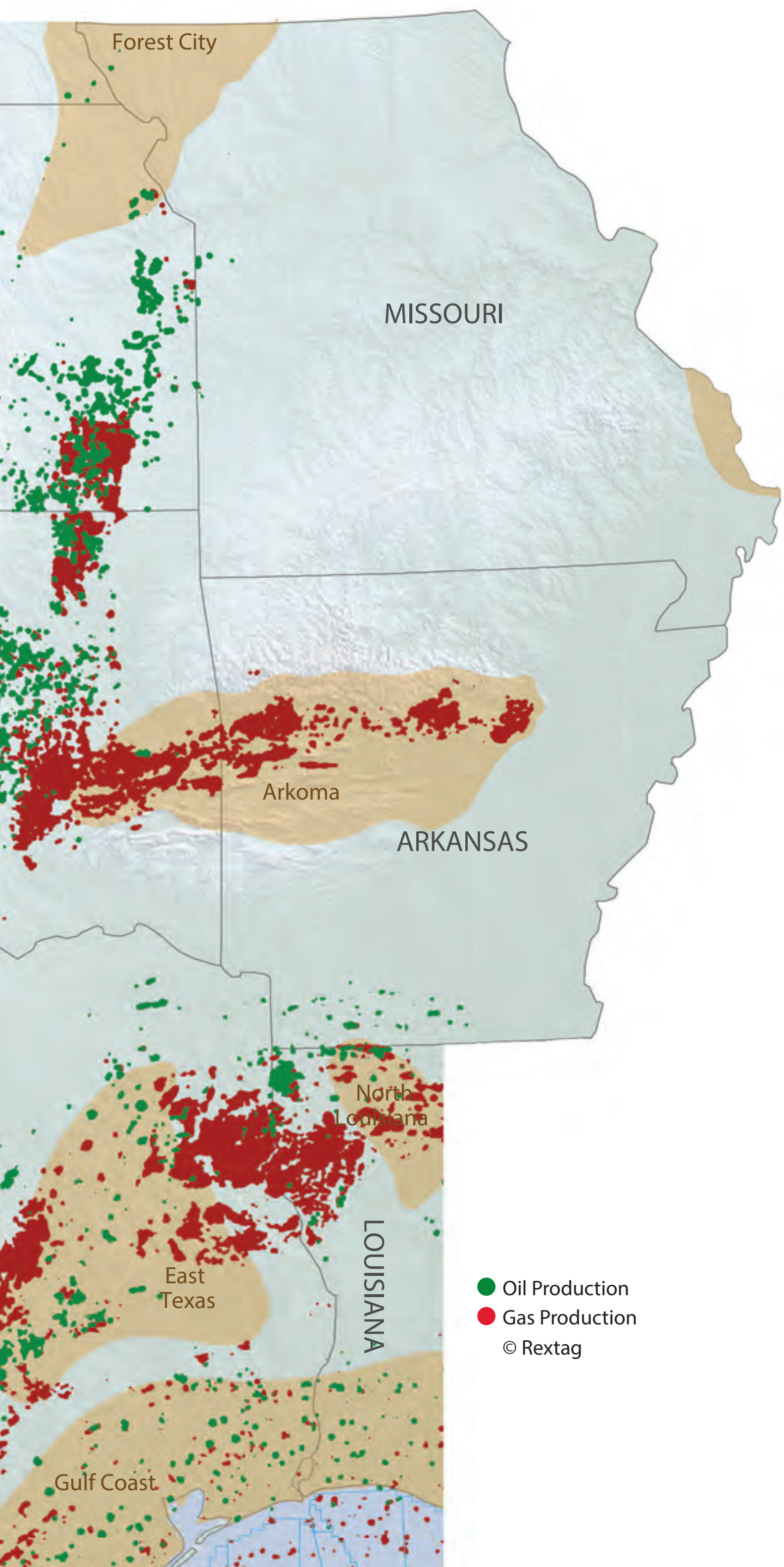
8 ***Continental Resources Inc.*** announced results from four Meramec wells that were drilled in a density pilot program in the overpressured gas/condensate window of the Anadarko Basin-Stack play. The wells were drilled from a pad in Section 31-15n-12w of Blaine County, Okla. All the wells were drilled with parallel laterals extending south across Section 6-14n-12w and bottomed in Section 7-14n-12w. Measured depths range from 23,076 to 23,262 ft, with true vertical depths between 12,657 and 12,878 ft. The #4-6-7XHM Simba was tested at 12,684-22,909 ft flowing 26 MMcf of gas, 504 bbl of 58-degree-gravity condensate and 1.715 Mbbl of water per day following acidizing and fracturing. Gauged on a 34/64-in. choke, the shut-in tubing pressure was 7,525 psi and the flowing tubing pressure was 5,393 psi. About 30 ft east on the pad, #5-6-7XHM Simba flowed 22.7 MMcf of gas, 673 bbl of condensate and 2.846 Mbbl of water per day. It was tested on a 38/64-in. choke with a flowing tubing pressure of 4,712 psi and a shut-in tubing pressure of 6,605 psi. Production is from treated perforations between 12,928 and 23,086 ft. About one-half mile east, #6-6-7XHM Simba initially flowed 24.7 MMcf of gas, 694 bbl of condensate and 1.916 Mbbl of water per day. It was tested on a 36/64-in. choke and the respective shut-in and flowing tubing pressures were 7,100 psi and 4,841 psi. Another 30 ft to the east, #7-6-7XHM Simba produced 20.2 MMcf of gas with 982 bbl of condensate and 2.944 Mbbl of water per day. Gauged on a 40/64-in. choke, the flowing tubing pressure was 4,061 psi. It was perforated, acidized and fractured between 12,836 and 23,014 ft. Continental's headquarters are in Oklahoma City.

Midcontinent & Permian Basin Rig Count

Aug. 31, 2018-Jan. 18, 2019



Data compiled from Baker Hughes



9 ***Continental Resources Inc.*** completed a Blaine County, Okla., Meramec discovery at its increased density project. The #2-25-24XHM Lookabaugh is in Section 36-15n-11w and was tested flowing 8.42 MMcf of gas, 2.547 Mbbl of 51-degree-gravity condensate/oil and 2.313 Mbbl of water per day. The Watonga-Chickasha Trend venture was drilled to the north to 21,508 ft, 10,974 ft true vertical, and bottomed in Section 24-15n-11w. It was tested on a 44/64-in. choke and was perforated, acidized and fractured at 11,354-21,333 ft. The shut-in tubing pressure was 3,887 psi and the flowing tubing pressure was 2,355 psi. Continental is based in Oklahoma City.

10 According to IHS Markit, ***Rimrock Resource Operating LLC*** has completed a southeastern Anadarko Basin-Scoop play well in Garvin County, Okla. The #1-18-07UWH Bullard is in Section 19-2n-2w and flowed 1.39 Mbbl of 42-degree-gravity oil, 2.05 MMcf of gas and 1.659 Mbbl of water per day from Upper Woodford. It was tested on a 64/64-in. choke and the shut-in tubing pressure was 15 psi and the flowing tubing pressure was 325 psi. It was perforated, acidized and fractured between 8,548 and 16,703 ft in a north lateral drilled to 16,130 ft (7,561 ft true vertical) and bottomed in Section 7-2n-2w. Rimrock's headquarters are in Tulsa, Okla.

WESTERN U.S.

1 ***Royale Energy Inc***. announced preliminary drilling information for a Great Valley Basin test in Sacramento County, Calif. The #33-1 CRC-RVGU is in Section 33-4n-3e and was drilled to an estimated depth of 10,000 ft. The venture encountered 174 net ft of probable gas zones and 37 net ft of possible gas zones, as determined by log analysis. The Rio Vista Field was cased and production tests are planned. Rio Vista Field produces from more than 15 stacked Tertiary and Upper Cretaceous reservoirs since its discovery in 1936. Royale's headquarters are in San Diego.

2 A second exploratory test on the Cat Creek Anticline in Garfield County, Mont., has been scheduled by ***Ballard Exploration Co***. The #31-1 Burlington will be in Section 31-15n-31e and will evaluate Pennsylvanian Tyler oil zones to 2,600 ft. The planned well will be north of the east dome of the northwest/southeast-trending Cat Creek complex, which produces from Lower Cretaceous Cat Creek Sands and Jurassic Ellis. Nearby production is about 1 mile northwest at #1 Jackson Coulee in Section 36-15n-30e, a 4,570-ft Amsden discovery that opened a new producing area in the Cat Creek complex. The 1989 completion initially flowed 183 bbl of oil per day from acidized perforations at 2,392-2,404 ft and 2,424-34 ft. Ballard's headquarters are in Houston.

3 ***BP Plc*** completed a horizontal Mancos producer in the San Juan Basin in San Juan County, N.M. The #604-3H Northeast Blanco Unit Com is in Section 13-31n-7w and was tested flowing an average of 10.2 MMcf of gas per day. The venture was drilled to the east to 17,389 ft, 7,080 ft true vertical, and bottomed in Section 18-31n-6w. It was tested through a 22/64-in. choke following 48-stage fracturing between 7,581 and 17,169 ft with a flowing casing pressure of 2,475 psi. BP's headquarters are in London.

4 IHS Markit reported that ***EOG Resources Inc.*** completed a horizontal Turner producer in the Powder River Basin that initially flowed 600 bbl of oil, 2.088 MMcf of gas and 1.704 Mbbl of water per day. The #368-1402H Catapult is in Section 14-39n-73w of Converse County, Wyo. Production is from a lateral extending from 10,203 ft northeastward to 22,250 ft. It bottomed in Section 2-39n-73w and the true vertical depth is 11,623 ft. It was tested on a 26/64-in. choke after 32-stage fracturing between 12,595 and 22,121 ft with a flowing casing pressure of 2,100 psi. EOG is based in Houston.

5 Denver-based ***Anschutz Oil Co.*** announced results from two extended-reach horizontal Turner producers in the Powder River Basin. The wells were drilled from a pad in Section 26-35n-71w in Converse County, Wyo. The #3571-26-35-13 TH Viking-Federal initially flowing 724 bbl of oil, 1.424 MMcf of gas and 1.683 Mbbl of water per day. Production is from a lateral extending from 10,770 ft southwestward to 19,960 ft at a bottomhole location in Section 35-35n-71w. The true vertical depth is 11,761 ft. It was tested on a 24/64-in choke following 27-stage fracturing between 12,183 and 19,659 ft. The #3571-26-35-14 TH Viking-Federal produced 585 bbl of oil, 1.163 MMcf of gas and 1.782 Mbbl of water per day. It was tested on a 24/64-in. choke after 36-stage fracturing between 12,045 and 21,585 ft. The lateral extends southward to 21,845 ft and bottomed in Section 35-35n-71w with a true vertical depth of 11,740 ft.

6 In Converse County, Wyo., Denver-based ***Anschutz Oil Co.*** has completed an extended-reach horizontal Turner producer in the Powder River Basin that produced 669 bbl of oil, 1.347 MMcf of gas and 2.093 Mbbl of water per day. The #3571-23-35-16 TH Loki-Federal is in Section 23-35n-71w and production is from a lateral extending from 10,757 ft to the south to 22,290 ft, 11,969 ft true vertical, and bottomed in Section 35-35n-71w. It was tested on a 20/64-in. choke after 37-stage fracturing between 12,116 and 22,139 ft.

7 IHS Markit announced that Oklahoma City-based ***Chesapeake Operating Inc.*** completed two horizontal Turner producers in the Powder River Basin portion of Converse County, Wyo. The #31-34-68 A TR 20H Rankin initially flowed 596 bbl of oil, 1.331 MMcf of gas and 460 bbl of water per day from a drillpad in Section 31-34n-68w. Production is from a horizontal lateral extending southward to 21,365 ft (10,619 ft true vertical) and bottomed in Section 7-33n-68w. It was tested on a 20/64-in. choke following 25-stage fracturing between 11,073 and 21,202 ft. The flowing tubing pressure was 3,004 psi and the flowing casing pressure was 3,540 psi. The #31-34-68 A TR 22H Rankin produced 374 bbl of oil, 872 Mcf of gas and 441 bbl of water per day. It was tested on a 20/64-in. choke after 25-stage fracturing between 11,029 and 21,155 ft. The Turner lateral extends southward to 21,310 ft (10,615 ft true vertical) and bottomed in Section 7-33n-68w.

8 An extended-reach Middle Bakken completion in Roosevelt County, Mont., was tested flowing 1.091 Mbbl of oil, 818 Mcf of gas and 1.711 Mbbl of water

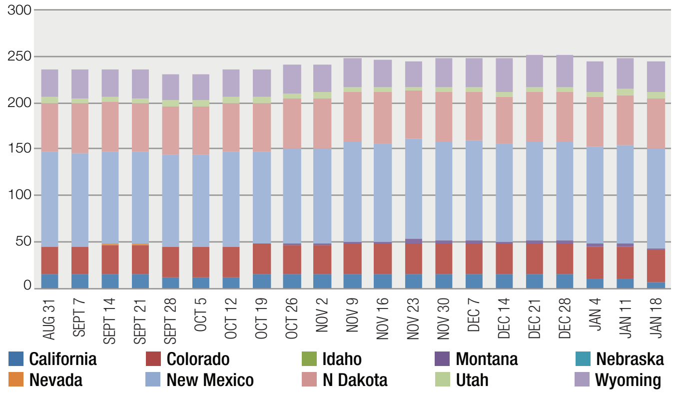
per day. Houston-based ***Kraken Operating LLC***'s Williston Basin completion, #14-23-1H Della, is in Section 11-27n-57e. Production is from a lateral in southward to 20,479 ft and bottomed in Section 23-27n-57e. It was tested following an undisclosed number of fracture stages between 10,406 and 20,479 ft.

9 ***Kraken Operating LLC*** has completed two extended-reach horizontal Middle Bakken tests on a common drillpad in Section 7-25n-59e in Richland County, Mont. The #17-20-1H Mayson Phoenix was drilled to the south to 20,700 ft (10,268 ft true vertical) and bottomed in Section 20-25n-59e. It initially flowed 1.41 Mbbl of oil, 1.12 MMcf of gas and 3.513 Mbbl of water per day from a fractured interval at 10,589-20,626 ft. The #7-6-1H RKT Carda was drilled to the north to 20,686 ft (10,295 ft true vertical) and bottomed in Section 6-25n-59e. It initially flowed 1.366 Mbbl of oil, 1.095 MMcf of gas and 3.204 Mbbl of water per day from a fractured horizontal interval at 10,577-20,616 ft. Additional completion information is not available.

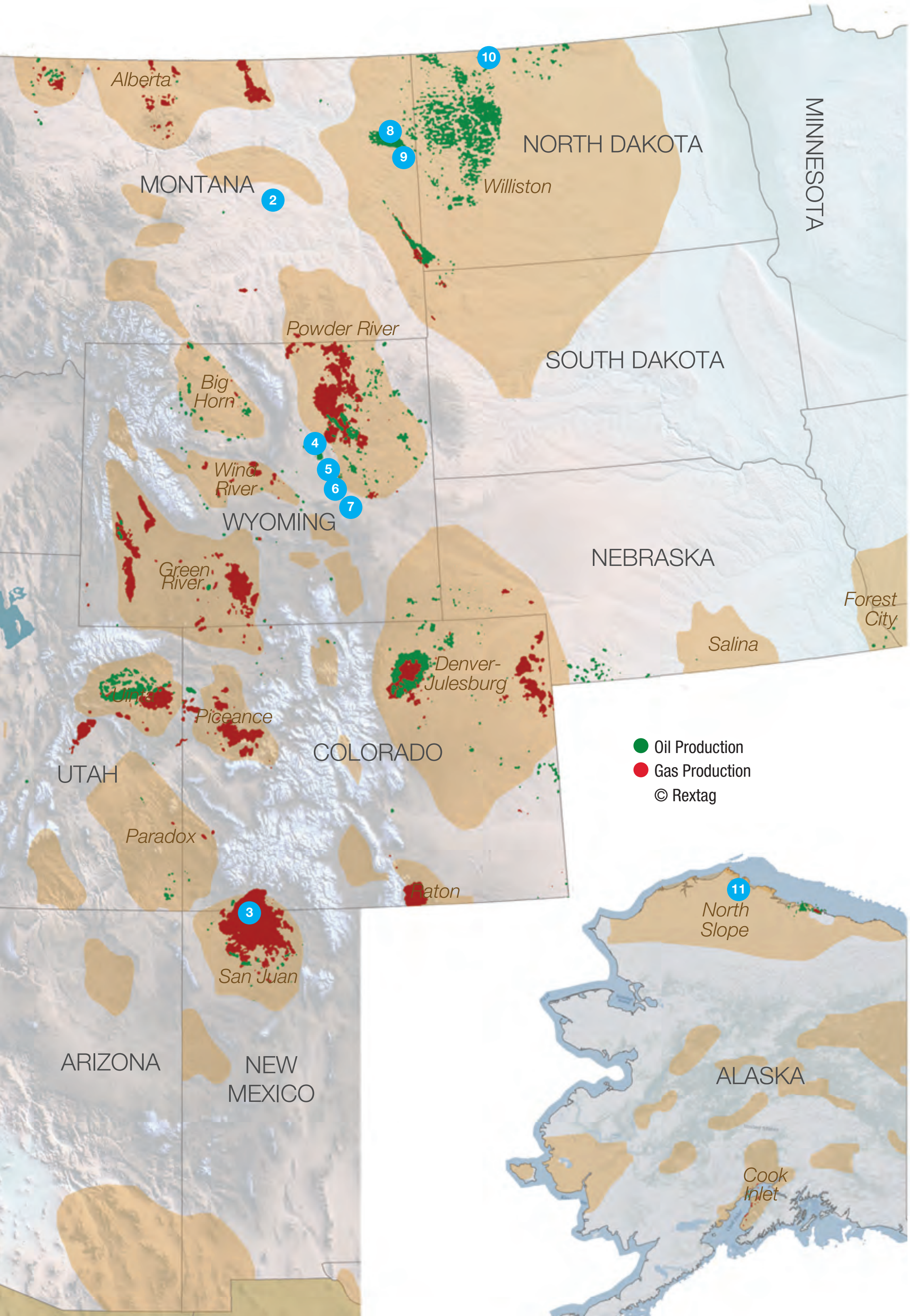
10 Results from a horizontal Madison delineation test were announced by San Antonio-based ***Windridge Operating LLC***. The Burke County, N.D., discovery, #36-25-1H Kestrel-State, is in Section 1-163n-93w and pumped 242 bbl of oil with 389 Mcf of gas and 632 bbl of water per day. Production is from a horizontal lateral in the Nesson member of Madison extending from 6,335 ft northward to 12,283 ft (5,826 ft true vertical) and bottomed in partial Section 25 of partial Township 164n-93w. It was tested following 49-stage fracturing between 6,269 and 12,134 ft.

Western U.S. Rig Count

Aug. 31, 2018-Jan. 18, 2019



Data compiled from Baker Hughes



11 Permits have been granted to Sydney-based ***Oil Search Ltd.*** for two directional North Slope exploratory tests targeting Nanushuk. The #1 Pikka-B will be in Section 35-11n-5e of Umiat Meridian. It will be drilled to a planned true vertical depth of 6,513 ft. The #1 ST-A-Pikka-B will be drilled as a sidetrack off the initial well and will be drilled to the west with planned true vertical depth of 4,923 ft. It will bottom in Section 34-11n-5e. According to the company, the Pikka B wells will delineate the area and could impact on the subsurface basis of design. Conventional coring is planned in both wells along with a full suite of logging-while-drilling, wireline logging, including fluid sampling.

INTERNATIONAL HIGHLIGHTS

According to the International Energy Agency (IEA), global oil demand is expected to be higher in 2019 than 2018, mostly due to lower oil prices.

Prices for crude are about 30% below the four-year peak reached in October 2018 even though there were economic-growth concerns for the world's two largest consumers, China and the U.S., which are in a trade dispute. In late 2018, OPEC and its partners have announced substantial production cuts.

According to the IEA, daily oil consumption will expand by 1.4 million barrels (MMbbl)—about 1.4%—in 2019, slightly higher than last year's expansion of 1.3 million. "Faltering manufacturing and slumping exports have stirred concerns that China's economy, the oil market's engine of growth for more than a decade, is slowing. A prolonged trade battle with the administration of President Trump is only darkening the outlook."

Cuts by OPEC and partners should slowly stabilize world markets. To fully implement its agreed cutbacks, OPEC would need to cut about 900,000 barrels of daily output in January, with its allies reducing by a further 370,000.

At the same time, the U.S. shale-oil boom continuation through mid-2019 is expected to be 1.3 MMbbl/d, which is lower than the 2018 mark of 2.1 MMbbl/d.

—Larry Prado

1 Colombia

An operational update by ***Amerisur Resources*** was announced for #1-Indico on the CPO-5 block in Colombia. The well initially flowed 4.53 Mbbl of 35.9-degree-gravity oil from Lower Sands (LS3) with a water cut of 0.33%. It was tested in a 40/64-in. choke and the wellhead pressure was 241 psi. Initial analysis by the Cardiff, Wales-based company indicated a 209-net-ft oil column in LS3 Sands with no oil/water contact. Additional testing, including a directional drilling program, is planned. A second well has been spud at #1-Calao, which is targeting Aguila in a structure alongside #1-Indico to the southwest.

2 Colombia

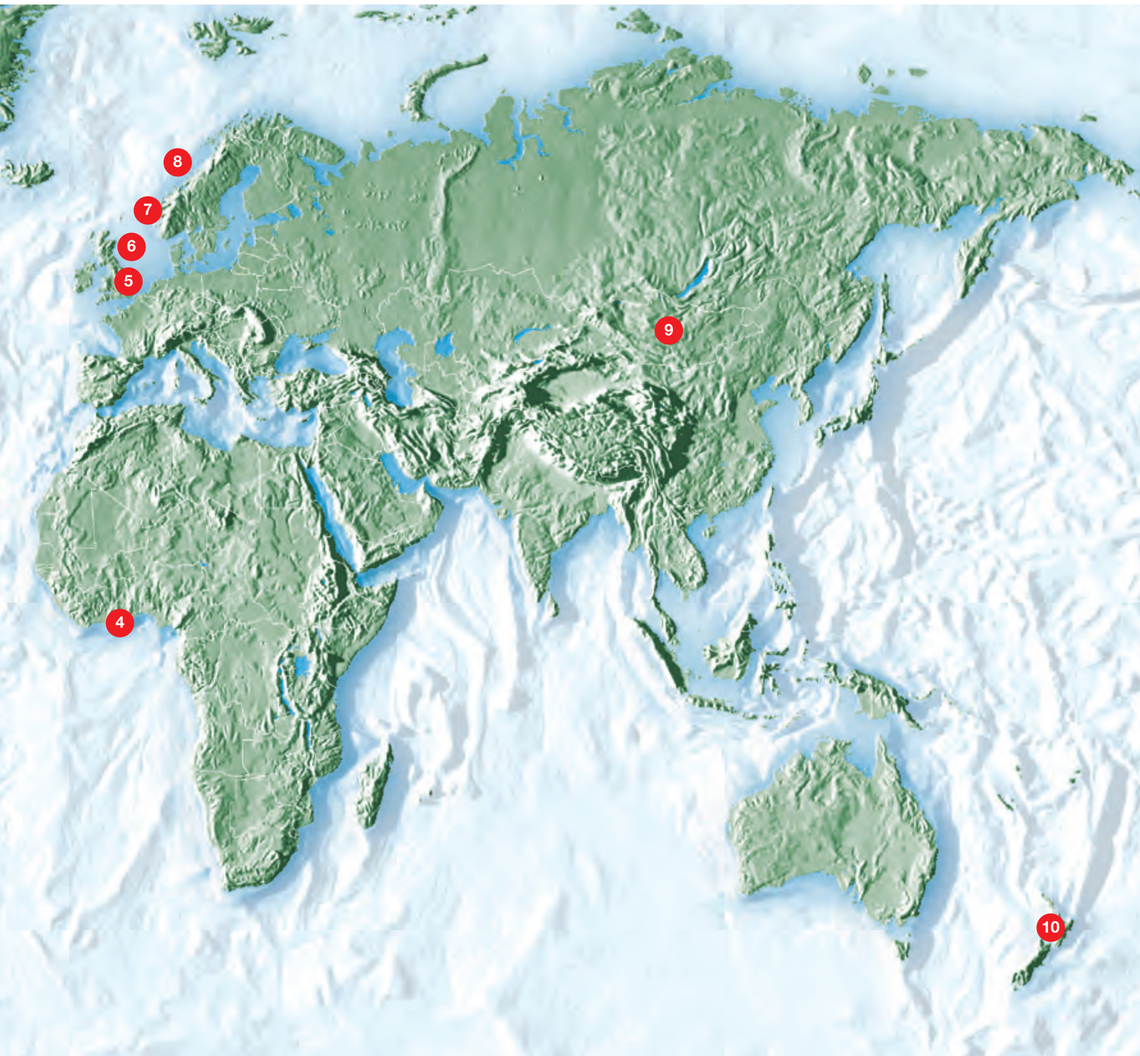
Test results were announced from #2-Andina in Colombia's Capachos Block. The venture by operator ***Parex Resources*** encountered potential oil-bearing reservoirs in the Une, Guadalupe and Mirador. The well was drilled to 17,500 ft. The Une was first tested and had a final production rate of 2.545 Mbbl of oil and 8.7 MMcf gas per day. In Lower Guadalupe, the test averaged 3.9 MMcf of gas and 2.407 Mbbl of oil per day with a water cut of 3%. The #2-Andina was drilled about 400 m southeast from discovery well #1-Andina to delineate the discovery. Pressure recorders installed in #1-Andina confirmed the connectivity and continuity of the Lower Guadalupe reservoir between the wells. Parex owns 50% with partner ***Ecopetrol***.

3 Bolivia

Repsol YPF announced results from an exploration well completed in Gran Chaco Province, Bolivia. The #1-X Chaco Este confirmed the existence of shallow gas resources of approximately 200 MMcf and 11 MMbbl of liquids in the Chorro, Tupambi and Iquiri formations. A total of 11 development wells will be drilled in 2019—five gas wells and six oil wells. According to the Madrid-based company, the maximum production of this field is expected to be about 35 MMcf of gas and 5 Mbbl of oil per day.

4 Ghana

Aker ASA completed an offshore Ghana Tano Cape Three Points (DWT/CTP) block appraisal well, #4A-Pecan. Based on previously completed seismic surveying and recent wells, the discovery is estimated to contain gross contingent resources (2C) of 450 to 550 MMboe. The appraisal well was drilled to 4,870 m and is in 2,667 m of water. Two additional appraisal wells are planned and the Oslo-based company's estimate of potential could increase to between 600 MMboe and 1 Bboe. In addition, there are identified multiple well targets to be drilled as part of a greater area development after submission of the development plan. The main purpose of #4A-Pecan was to confirm regional geology in the area and to identify deep oil/water contact in the Pecan reservoir. Aker is the operator of the block with a 50% participating interest. Partners include ***Lukoil*** (38%), ***Ghana National Petroleum Corp.*** (10%) and ***Fueltrade*** (2%).



5 U.K.

Egdon Resources Plc has spud exploration well #2-Biscathorpe in PEDL253 in Lincolnshire, U.K. The venture is a test of one of the U.K.'s largest onshore unappraised conventional oil prospects with mean prospective resources of 14 MMbbl (gross). It has a planned depth of 2,100 m. It is targeting a structural/stratigraphic trap in Basal Westphalian sandstone reservoir at a depth of 1,800 m where the reservoir is expected to thicken to the north of the crest of the structural high. A 1987 well drill by ***BP PLC*** at #1-Biscathorpe hit a 1.2-m-thick, oil-saturated section of the sandstone reservoir. Partner in the test is ***Union Jack*** with a 22% license interest. Edgdon Resources is based in Hampshire, U.K.

6 U.K.

An estimate by ***i3 Energy Plc*** stated that its 100%-owned Serenity Prospect and Greater Liberty in License P.2358, Block 13/23c, in the U.K. sector of the North Sea, is estimated to contain a P50 oil-in-place volume of 197 MMbbl. The Westhill, Scotland-based company has been assessing a structure in the northern portion of Block 13/23c interpreted to be the westerly extension into Block 13/23c of the 2005 Tain discovery. The original discovery produced 32-degree-gravity API oil in Captain and Coracle sands. i3 Energy is the operator of License P.1987, Block 13/23c, Liberator Field, and the Serenity Prospect with 100% interest.

7 Norway

Faroe Petroleum announced the results of the Brasse East exploration well #31/7-3 S and Brasse appraisal sidetrack #31/7-3 A in the North Sea. The Brasse East well, #31/7-3 S, was drilled to 2,247 m and was targeting a separate structure east of Brasse Field. The well encountered 48 m (gross) Jurassic reservoir with excellent properties. The Brasse sidetrack appraisal well, #31/7-3 A, was drilled to 2,254 m. Preliminary analysis of the logging-while-drilling data indicated that the well encountered 40 m (gross) hydrocarbon-bearing Jurassic reservoir. Additional wireline logging is underway. Aberdeen-based Faroe holds a 50% working interest and is the operator.

8 Norway

Stavanger-based ***Equinor*** announced results from exploration well testing in the Norwegian Sea's Ragnfrid North (6406/2-9S). According to the company, the gas and condensate discovery has recoverable resources estimated at between 6- and 25 MMboe. Ragnfrid North is south of the Kristin platform. The license partners will now evaluate the discovery for development and tie-into Kristin Field and additional testing of the Kristin South Project. Equinor is the operator of production license PL199, Block 6406/2, and the Ragnfrid North discovery well with 52% interest in partnership with ***Petoro***, holding 27%, ***ExxonMobil Corp.*** with 15% and ***Total*** with the remaining 6%.

9 Mongolia

Petro Matad is preparing to drill an exploration well in Mongolia's Block IV in the Tugrug Basin. The well, #1-Wild Horse, has a planned depth of 2,200 m. The recoverable resource potential is estimated to be 480 MMbbl of oil. The Wild Horse prospect is a prominent structural high on the flank of the Baatsagaan Basin. The structure has elements of four-way dip closure and fault closure. At Block V, next to Block IV, data and sampling operations were completed at the exploratory well #1 Snow Leopard, according to the Isle of Man, U.K.-based company, and data and samples are currently being tested.

10 New Zealand

New Zealand Oil & Gas announced results from exploration well #1-Kohatukai in New Zealand's Taranaki Basin in the PEP55768 permit area. According to the operator, it hit gas in its secondary target Eocene Matapo Sandstone at 3,602 ft. The well has a secondary objective in Mangahewa Sands, where elevated mud gas readings were reported. The rig is drilling ahead to the planned total depth and wireline formation evaluation will begin, with a possible downhole reservoir fluid sampling program. PEP 55768 is operated by ***Mitsui*** with 50% interested in partnership with Auckland-based ***New Zealand Oil & Gas***, holding 25%, and ***OG Oil and Gas Ltd.*** with 25%.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BACK IN BUSINESS IN 2019

While capital market conditions are still far from normal, business has at least begun once more in terms of equity and bond offerings. Surprisingly, equity issuance included an IPO, albeit on more modest terms than planned. A handful of mostly midstream companies issued debt, and private-equity (PE) sponsors made equity commitments chiefly in the midstream sector.

Launching an IPO was New Fortress Energy LLC (Nasdaq Global Select Market: NFE), which priced 20 million Class A shares at $14 each for net proceeds of $257.6 million. The offering size and pricing was below the expected 22.2 million share offering at a range of about $17 to $19 each. The stock's closing price for the first five days of trading averaged $13.80.

New Fortress Energy describes itself as an integrated gas-to-power company, whose aim is to use stranded gas converted into LNG to meet power needs. The company operates two terminals for importing LNG, in Jamaica, with a further four under development in other locations. Offering proceeds are earmarked for construction of terminals and liquefaction facilities.

PE sponsor Blackstone Energy Partners LP has backed Waterfield Midstream with a $500-million equity commitment. Waterfield is a provider of water management services led by co-CEOs Scott Mitchell and Mark Cahill who previously built the commercial water infrastructure platform for Western Gas Partners in the Permian Basin. The company plans to pursue both greenfield developments and acquisitions.

Already, Waterfield has a 15-year contract with Guidon Energy to build a new system to handle the latter's water gathering and disposal needs across its 40,000-acre position in Martin County, Texas. In addition, Waterfield entered into an agreement with EagleClaw Midstream to operate the company's water assets in Reeves County, Texas. Assets include 390,000 barrels per day of permitted water disposal capacity.

Debt markets gained traction, particularly with higher-quality midstream and oilfield service names: Energy Transfer Operating, raising $4 billion; Schlumberger Ltd., $1.6 billion; Targa Resources Partners, $1.5 billion; Transocean Ltd., $550 million; Magellan Midstream, $500 million; and DCP Midstream, $325 million.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Blackstone Energy Partners LP	N/A	New York	US$500 million	Funds managed by **Blackstone Energy Partners LP** have formed **Waterfield Midstream**, a full-cycle provider of water management services, including water gathering, treatment, recycling and disposal, to provide solutions to producers in the Permian Basin. Waterfield is Blackstone's water midstream platform in the Permian and has a $500 million equity commitment to pursue greenfield development and acquisitions of water-related infrastructure.
Clear Creek Midstream LLC	N/A	Tulsa, Okla.	US$300 million	**Clear Creek Midstream LLC** announced an initial venture capital commitment of $300 million from **EnCap Flatrock Midstream**. Clear Creek is an independent energy company focused on the development of midstream infrastructure for oil and gas producers working in shale plays across North America. It plans to pursue organic, greenfield projects and select acquisition opportunities. Clear Creek is led by CEO and founder **Rick Van Eyk**, an industry veteran with track record of value creation at energy companies, including **EnLink Midstream** and **Occidental Petroleum Corp**.
New Fortress Energy LLC	NASDAQ: NFE	New York	US$257.6 million	**New Fortress Energy LLC** announced the pricing of its IPO of 20,000,000 Class A shares representing limited liability company interests in New Fortress at $14 each. The Class A shares was expected to begin trading on the Nasdaq Global Select Market under the ticker symbol "NFE" on Jan. 31. In addition, New Fortress granted the underwriters a 30-day option to purchase up to an additional 3 million Class A shares at the IPO price. New Fortress intends to contribute the net proceeds of the offering it receives to **New Fortress Intermediate LLC**, its subsidiary, in exchange for limited liability company units in NFI (NFI LLC Units). NFI intends to use such net proceeds in connection with the construction of its terminals and liquefaction facilities, as well as for working capital and general corporate purposes, including the development of future projects.

These deals and details on thousands more are available in real time in a searchable, sortable database at HartEnergy.com.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
GasLog Partners LP	NYSE: GLOP	Monaco	US$96.3 million	Completed public offering of 8.5% Series C Cumulative Redeemable Perpetual Fixed to Floating Rate Preference Units, raising gross proceeds of $100 million and net proceeds of $96.3 million.
Crescent Pass Energy LLC	N/A	Houston	US$75 million	Talara Capital Management LLC, a Houston-based private-equity firm investing in the North American upstream energy sector, has formed Crescent Pass Energy LLC supported by a $75 million line of equity investment. Based in Spring, Texas, the company is focused on horizontal development opportunities in East Texas and Northern Louisiana, with a primary focus on the liquids-rich Cotton Valley trend.
Seismos Inc.	N/A	Austin, Texas	US$11 million	Secured a $10.5 million equity financing led by Quantum Energy Partners with follow-on participation from Javelin Venture Partners, Osage University Partners, ATP fund, Hicks Oilfield and other existing investors. The financing will support the company's growth and future product development.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Energy Transfer Operating LP	NYSE: ETPD	Dallas	US$4 billion	Announced the offering of $4 billion of senior notes in three tranches: $750 million aggregate principal amount of 4.5% senior notes due 2024; $1.5 billion aggregate principal amount of 5.25% senior notes due 2029; and $1.75 billion aggregate principal amount of 6.25% senior notes due 2049. The notes were priced to the public at 99.646%, 99.789% and 99.850%, respectively, of their face value. ETO intends to use the net proceeds of approximately $3.96 billion from this offering (i) to make an intercompany loan to Energy Transfer LP, which will use the proceeds therefrom to repay in full its $1.22 billion term loan due Feb. 2, 2024; (ii) to repay in full its 9.7% senior notes due March 15; its 9% senior notes due April 15 and its subsidiary's 8.125% senior notes due June 1; (iii) to repay a portion of the borrowings under its revolving credit facility; and (iv) for general partnership purposes.
Schlumberger Ltd.	NYSE: SLB	Houston	US$1.6 billion	Schlumberger priced $1.6 billion of senior notes in two tranches: $750 million of 3.75% senior notes due 2024 at 99.792 to yield 3.795%; and $850 million of 4.3% senior notes due 2029 at 99.932 to yield 4.309%. The company expects to use the proceeds to repay outstanding debt.
Targa Resources Partners	NYSE: NGLS-A	Houston	US$1.5 billion	Targa Resources Partners, a subsidiary of Targa Resources, priced $1.5 billion of senior notes via two offerings: $750 million of 6.5% senior notes due 2027 at par to yield 6.5%; and $750 million of 6.875% senior notes due 2029 at par to yield 6.875%. Proceeds are for the full redemption of the company's outstanding 4.125% notes due 2019, and for general partnership purposes.
Enable Midstream Partners LP	NYSE: ENBL	Oklahoma City	US$1 billion	Enable Midstream Partners LP has entered into a $1 billion three-year unsecured term loan agreement. Enable has initially borrowed $200 million under the agreement, and a delayed-draw feature provides Enable the flexibility to make up to $800 million in additional borrowings for up to 180 days from Jan. 29. Enable expects that borrowings will be used for general partnership purposes, including the repayment of existing and future indebtedness and funding of capex.
Magellan Midstream Partners LP	NYSE: MMP	Tulsa, Okla.	US$500 million	Magellan Midstream Partners priced $500 million of 4.85% senior notes due 2049 at 99.371 to yield 4.890%. Proceeds from the offering will be used to redeem the company's outstanding 6.55% notes due July 15.
DCP Midstream	NYSE: DCP	Denver	US$325 million	DCP Midstream priced an add-on $325 million offering of 5.375% senior notes due 2025 at 100.75 to yield 5.230%. Proceeds from the offering will be used for general partnership purposes, including the funding of capex and the repayment of revolver drawings.
Freeport LNG Development LP	N/A	Houston	US$225 million	A subsidiary of Freeport LNG Development LP priced $225 million of BBB-rated, 5.550% senior notes due 2039 at 96.532 to yield 5.895%. Proceeds from the offering will be used for general corporate purposes.

COMPANIES IN THIS ISSUE

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

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A NEAT HAT TRICK

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Is maintenance capital the new, wholesome benchmark?

Back in the day, this industry was all about spending more capital. Today that is changing. The goal used to be leasing as much acreage far and wide as you could. Send an army of landmen to every county and line them up on the doorstep of the courthouse at dawn. Plant a stake in every play, ink more joint ventures and farm in to every well that is proposed; get access to more data than anyone else, if nothing else.

Once all that was done, the industry turned its focus to displaying raw growth of oil, gas and NGL production, quarter after quarter. Build more high-spec rigs. Keep those drillbits turning. Buy your way into more drilling inventory for the out years.

Next in the industry's 21st century evolution, strategy became about drilling faster and cheaper with much longer laterals, and with more precision. It became about crafting enhanced completions using ever-more sand and water, with experimentation on whether to add or subtract.

In the past three years, it was all about perfecting these processes, from leasing to the sales line, whether that be ordering equipment in a certain way, and scheduling frack crews six months ahead, or lining up firm transportation for water, oil and gas. More recently, it has also meant using big data analytics and algorithms to fine tune all of the above, to knock another dollar per barrel out of the cost equation.

Now, the next wave seems to be about determining how much maintenance capex is needed to keep the decline rate flat (maybe to grow production ever so slightly), and therefore, extend the timeline to drill out the inventory. But of course you have to keep accumulating inventory or your investors begin to grow pale.

This is fine, if we want to create better returns on a more judicious allocation of capital. No more crazy outspending of cash flow. But at some point in time, keeping U.S. oil and gas production flat will not be enough to satisfy rising global demand, as OPEC Secretary General Mohammed Barkindo warned when he met with several oil CEOs at the World Economic Forum in Davos recently.

Then too, although the investor cry today is "Give us returns," we've noticed that even as CEOs reported they will be careful by moderating production growth and spending wisely within cash flow, analysts seemed disappointed that some will not grow production much this year. So which is it, growth or returns? This is the age-old dilemma of the industry.

If you are an equity investor, you'll no doubt get the most bang for your buck if you find those few E&P companies that outshine the rest by being able to deliver modest production growth within a conservative capex level, and on top of that, that can return cash to shareholders at the same time. It's a neat hat trick.

When we scanned some analyst reports on fourth-quarter results, the same theme emerged.

"PDC Energy Inc. gives you what we consider the gold standard for FY19: 20% production growth with free cash flow (FCF). We also love FY20; we're now forecasting 13% year-over-year production growth and a 9% FCF yield," said Mike Kelly at Seaport Global Securities in a research note.

As for Range Resources Corp., Tudor, Pickering, Holt & Co. said in a note that what draws its attention is Range's maintenance capital potential (maybe $525 million), which will focus on FCF generation and repairing the balance sheet over growth. "While we will have to wait for official guidance in a few weeks to see if Range moves in this direction on spending, we continue to believe gas companies need to materially cut growth capital to attract fundamental long-term interest, given structural macro headwinds in the space."

Analyst Leo Mariani at KeyBanc Capital Markets said, "We prefer E&Ps with low-cost oil assets that can grow production at attractive rates while generating free cash flow. Free cash flow could be a little tough to come by in 2019, but the better-positioned E&Ps should be close to neutral. Our high-conviction ideas include FANG, OXY, PXD and WPX."

I hope you'll join us, and send some of your colleagues, to attend the DUG Permian conference April 16 and 17 in Fort Worth, Texas, along with the Permian Minerals Forum April 15; and looking ahead, join us also for DUG Rockies in Denver May 14 and 15. The Midland and Delaware basins continue to surge and attract plenty of capital. The Denver-Julesburg Basin dodged an anti-fossil fuel challenge, midstream facilities have come on line, and operators there are working ahead. Finally, stay tuned for the Powder River Basin, which is the next coming attraction, in the words of Anadarko Petroleum Corp. CEO Al Walker. All aspects of drilling in these premier basins will be "explored" at Hart Energy's two DUG conferences.