Oil and Gas Investor

NOVEMBER 2019

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: FourPoint Energy LLC examines frack sand as well as resin-coated sand (yellow) at the Matthews 1-4HC site in Roger Mills County, Okla. Photo courtesy FourPoint Energy LLC.

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LATEST CONTENT

Parsley To Acquire Jagged Peak In $2.3 Billion All-Stock Transaction
The acquisition of Jagged Peak will more than double Parsley Energy's position in the Delaware Basin, where the companies expect to generate G&A savings of about $25 million within the first year.

Goodnight Midstream Confirms Significant Capital Investment From Tailwater Capital
Tailwater Capital committed over $500 million of growth capital to support Goodnight Midstream's strategic objectives and to allow the company to continue to expand its service offering.

U.S. Shale Player EP Energy Files For Bankruptcy
The company has reached an "agreement in principle on a comprehensive restructuring with a number of its key creditors," the CEO said.

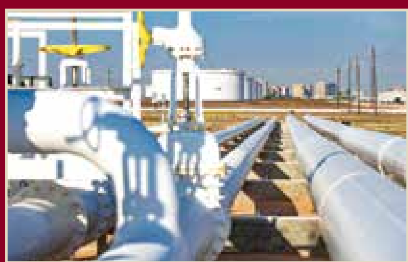
Digital Transformation Is Here. So, What's Next?
Study predicts key digital trends that will dominate the energy industry during the next few years.

NGL Energy Partners To Expand Permian Water Footprint With $600 Million Deal
NGL Energy Partners agreed to acquire Hillstone Environmental Partners, which owns a produced water transportation and disposal system located in the Northern Delaware Basin.

Southwestern Energy Brightens Outlook With Financial Update
Southwestern Energy strengthened its "financial resilience" as the Appalachia shale producer continues to face a low-price environment.

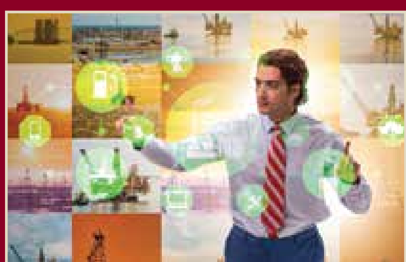
ONLINE EXCLUSIVES

Long-haul Capacity From The Permian Is Close To Pulling Even With Production
Some overshot is expected, but then a whole new set of pipes may be needed.



DUG Eagle Ford: Austin Chalk Is Back And Delivering Results
The Austin Chalk of east central Texas has perplexed, enticed and bewitched many into developing it.

Total Relying On People, Technology To Plot Path Through Energy Transition
Delivering the digital technology that its people need to exploit the oil and gas resources will be key to a successful future for French oil giant Total.



Videos

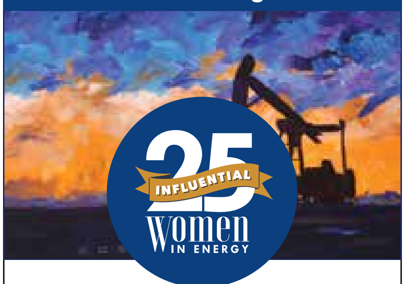
DUG Eagle Ford: Venado Oil & Gas On Fast Cycle Times
Venado Oil & Gas CFO, Branden Kennedy explains its roots in the Eagle Ford and how that holds its own against "Permania."

www.HartEnergy.com/videos

What's Trending

1. DUG Eagle Ford: Austin Chalk Is Back And Delivering Results
2. Halliburton Cutting 650 Jobs As Oilfield Business Slows
3. Opinion: Big Oil Should Rebel Against Its Customers
4. Parsley To Acquire Jagged Peak In $2.3 Billion All-Stock Transaction
5. Report: Grim Outlook For Gas Prices

Awards Program



Join top industry executives to celebrate *Oil and Gas Investor*'s 25 Influential Women In Energy honorees at a gala luncheon on March 20, 2020. Network and dine with distinguished leaders who have risen to the top of their professions and achieved outstanding success in the oil and gas industry.

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UPSIZED CASH FLOW

STEVE TOON,
EDITOR-IN-CHIEF

At the Scotia Howard Weil investor symposium in March 2018, held a year and a half ago as investor support faltered, E&P CEOs in succession pounded the podium defiantly defending their shareholder value and new promises of free cash flow over growth. Today, those same E&Ps are meticulously, painfully and humbly metamorphosing from ravenous, capital-consuming caterpillars to value-oriented, cash-flowing butterflies. The lingering question: Will that be enough to catch the eyes of those investors once again?

More needs to be done, claim sell-side analysts.

Simmons Energy analyst Ryan Todd laments that a large and growing number of investors have lost faith that the E&P sector can outperform in a \$50 to \$55 WTI world, despite the firm's prediction of a 3% free-cash-flow yield for its covered companies at \$55. It "just isn't compelling enough to get generalists off the sidelines," he said in an Oct. 11 report. "Things are heading in the right direction, but it is a LONG and brutal slog with a ways to go."

Cowen analyst David Deckelbaum in an Oct. 7 report said E&P execs are "unsurprisingly frustrated" with year-to-date stock performances despite a laser focus on free-cash-flow generation. Still, "management teams are resolute in their focus on capital efficiency heading into 2020 that may call for lower activity than anticipated."

Deckelbaum suggested E&Ps should match the S&P 500 growth benchmark of 5% with a 5%-7% FCF yield. He also anticipated guided 2020 budgets will be lower than Street expectations as companies take a wait-and-see approach on how their equities perform in a second year of free-cash-flow pursuit.

Joe Allman, a Baird analyst, in early October said more investors "seem convinced that E&P capital discipline is here to stay." He predicted that free-cash-flow yields for the top 50 E&Ps would double in 2020 over 2019 levels.

But Pearce Hammond, a Simmons analyst as well, went further. He indicated the investment community is demanding "a tangible line of sight to robust free-cash-flow yields and well-above-average dividend yields," emphasizing the importance of dividends. "In lieu of the race to zero-bound/negative interest rates, investors are increasingly attracted to sustainable and robust dividend streams," he said.

Why dividends? Dividends are cash in hand, and cash is king.

Investors want to be paid while they wait for energy fundamentals to improve, Hammond said. Investors distrust management capital allocation policies and prefer to get the cash directly. Recent buyback programs have sent shareholder cash "into the bonfire" as equity values further collapsed. And the globe is starved for yield as the 10-year U.S. Treasury hangs at 1.65%.

While \$50 oil prices might be just enough to garner a slight free cash flow pared with a sub-\$2 dividend yield, that's not good enough to entice investors, he noted, especially with the volatility that clouds the macro outlook.

Unfortunately, "the energy sector currently does not provide a depth of names delivering attractive and/or sustainable yields," he said, "but we expect that to improve in the years ahead as companies moderate spending, focus on generating free cash flow and increasingly return cash to shareholders through dividends rather than share buybacks."

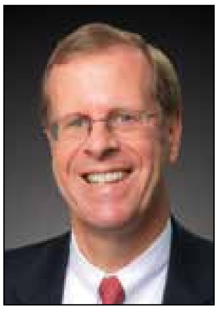
Hammond believes a "battleground" is emerging between investors and management teams around the buybacks vs. dividends argument, believing investors "far prefer" a sustainable dividend with headroom and a competitive yield. "While we understand the dollar cost averaging argument that some management teams espouse regarding buyback programs, it is hard to face investors after having repurchased shares at much higher prices. Unless energy equity performance meaningfully improves, we believe investors will increasingly reject management teams' desire to repurchase stock at the expense of a higher dividend."

His response to management teams "reluctant to get strangled" by too high of a dividend: Pay a special dividend annually if cash flow supports it.

To garner investor favor, cash flow is paramount. But the preferred method of delivery is straight into investors hands in the form of a cash dividend large enough to entice. More cash flow might be required.

"Improved alignment with new investors will be forthcoming when sustainable and high dividend yields underpin share prices and the oil price conviction improves," said Hammond. "Fundamentally reforming an industry and regaining investor sponsorship is likely to be a long-term endeavor—welcome to the maturation phase of the industry, and hail goodbye to the frenzied embryonic, anything-goes phase."

DO DARK CLOUDS DEEPEN OR LIFT?



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

Can market pessimism get any worse for the energy sector? Entering the first few days of the fourth quarter, the answer to the question was a clear, 'Yes.'"

A weak ISM Manufacturing Index report of 47.8 sparked a two-day sell-off of over 800 points on the Dow Jones Industrial Average, and several flag-bearing E&P stocks fell to new 52-week lows—even after the XOP (S&P Oil & Gas Exploration & Production ETF) set an all-time low in August.

For example, EOG Resources Inc. dropped to $69.47 per share, down 48% from what was a 52-week high of $133.53. Diamondback Energy Inc. fell to $82.44 per share, down 41.4% from its 52-week high of $140.78.

As a reminder, an all-time low on the XOP was set in early August, when West Texas Intermediate (WTI) prices were in the low $50s per barrel (bbl). Earlier, the XOP had sustained higher levels, even when WTI prices slumped to $42.53 (Christmas Eve 2018) or $26.14/bbl (February 2016).

This disconnect reflects in part the broad market's trend to funnel money into large-cap, momentum-driven tech stocks. ("Buy into strength, sell into weakness.") But years of poor energy performance also played a key part. After the drone attack on Saudi Arabia's oil facilities, one research firm questioned whether the events would "break the broader market momentum trade of short energy and long everything else."

As it turned out, any XOP gains due to the bombing of the Khurais oil field and Abqaiq stabilization facilities evaporated in just days as Saudi Aramco announced moves to restore shipments to clients.

What may be the biggest cause for concern for E&Ps is the supply/demand imbalance looming in 2020.

In a mid-September report by Tudor, Pickering, Holt & Co., for example, the firm forecast non-OPEC 2020 liquids supply growth of 2.2 million barrels per day (MMbbl/d), outpacing by far demand growth of 1.25 MMbbl/d. Estimates of non-OPEC demand growth have tended to drift down as the trade war has continued. An early October survey showed a range of demand growth estimates of 0.8 to 1.5 MMbbl/d.

In addition to ongoing gains in U.S. production, global oil growth has been marked by some key offshore projects. Among them is Equinor's Johan Sverdrup project in the North Sea, which started up in early October and is expected to ramp up from 200,000 to 440,000 bbl/d by next summer. Coupled with projects in Brazil and elsewhere, an "offshore surge" of 980,000 bbl/d is projected by Bernstein.

U.S. production growth is obviously a critical variable, especially against the backdrop of seasonally weak global demand in the first quarter. A report by Bernstein, issued prior to the bombing of Saudi Arabia's infrastructure, forecast an oversupplied market through the first quarter, assuming U.S. producers reinvest 90% of cash flow at a WTI price of $60/bbl—or even just 80% at $50/bbl.

"We don't like the oil macro situation into year-end," said Bernstein, encouraging E&Ps to focus on hedging. But if low oil prices in the fourth quarter are an early indicator of seasonally weak first-quarter demand, can something similar be said about out-of-favor energy stocks discounting future prospects?

The equity strategy and quantitative research group of J.P. Morgan put a "Buy" recommendation on the energy sector in late September, citing its "depressed valuation and extreme bearish investor positioning." In addition, "ongoing geopolitical tensions in the Middle East could help redirect flows into this universally hated and cheap sector."

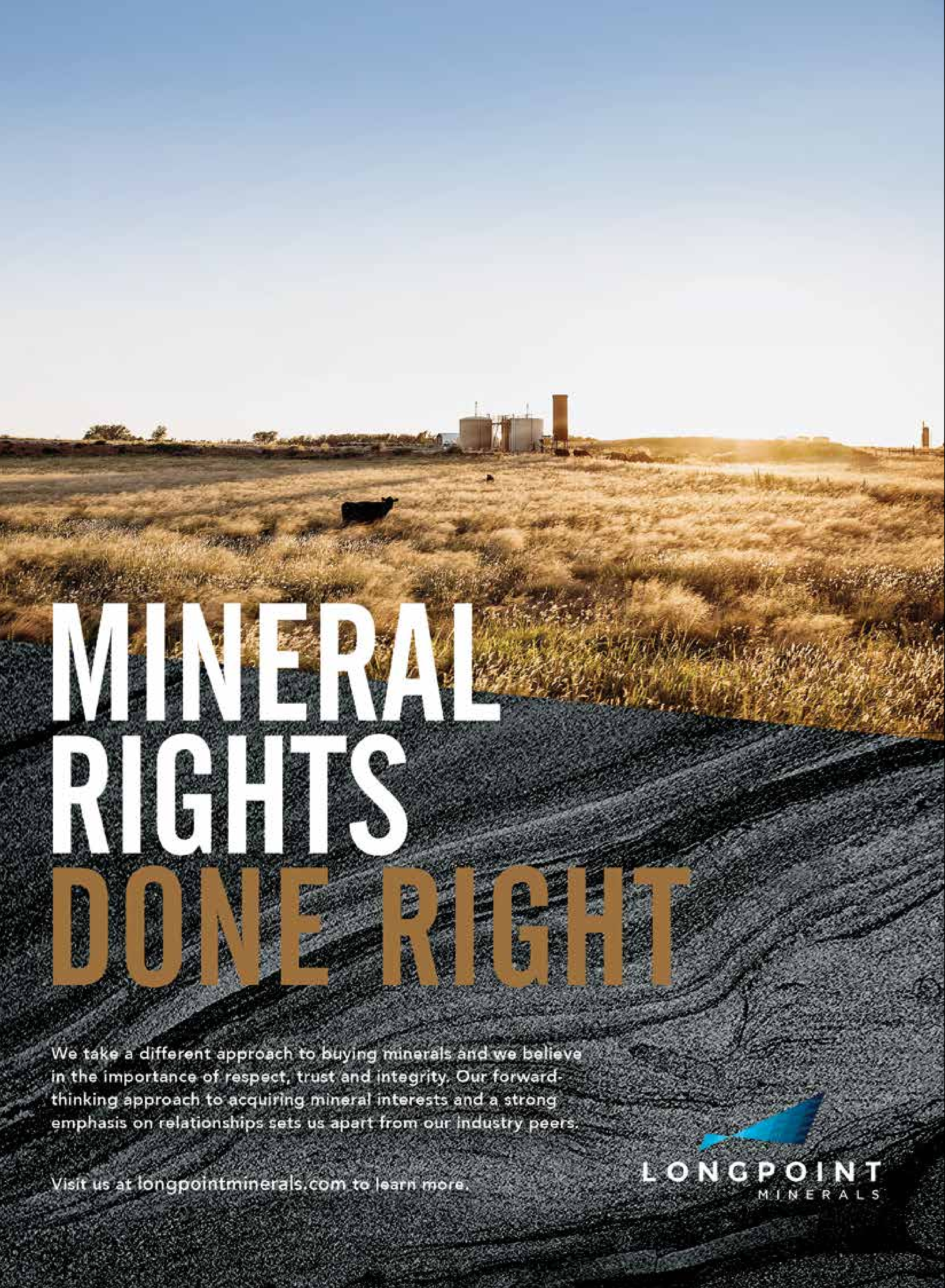
Most institutional investors have "abandoned the sector, with long-only portfolio managers holding below-benchmark sector exposure," said J.P. Morgan. "Absolute and relative valuations are at lows, with small-cap E&Ps trading below book value and at price levels seen almost 25 years ago. In contrast, corporate sentiment is bullish, with insider purchases rising to cycle highs."

The energy sector should be "a key beneficiary of stabilization/re-acceleration in the business cycle, which we expect to start playing out by early 2020 on global monetary and fiscal stimulus along with expectations of easing U.S.-China trade tension," observed J.P. Morgan. Moreover, investors can get into most energy companies "at below pre-Saudi attack levels," it added.

"The market should assign a structural premium to the equity-oil complex with the Middle East currently a geopolitical tinderbox," continued the J.P. Morgan group, noting a preference for value stocks.

Value investing?

Value investors have been waiting for years to see if the broader market will rotate from growth to value. Could this help lift the dark clouds in energy?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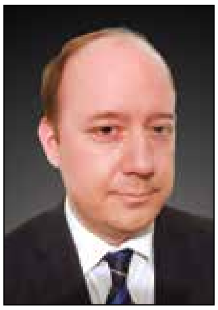
BILLIONAIRE GOT BACK



DARREN BARBEE,
SENIOR EDITOR

In the most unironic way possible, Carl Icahn's eponymous website pays homage to the words and wisdom of a master investor. Perhaps unsurprisingly, the investor quoted is Carl Icahn himself: "A lot of people die fighting tyranny. The least I can do is vote against it."

Just in case you imagine the legendary activist investor made this statement during the signing of the Declaration of Independence, the quote is taken from a 1988 Texaco shareholder meeting. Similar? Maybe. But, no, not quite the same thing.

Still, it was interesting to see Icahn in August assail the Occidental Petroleum Corp. acquisition of Anadarko Petroleum Corp. for a multiplicity of sins—the worst, apparently, being naive Occidental CEO Vicki Hollub's agreement to take $10 billion in financing from Warren Buffett.

Icahn complained that his fellow billionaire's financing deal was like "taking candy from a baby." Buffett received preferred stock that pays an 8% dividend yield and another $1.2 billion "simply for providing the financing," according to a letter Icahn sent to shareholders.

Yet as he tsk-tsked Hollub, Icahn extended a golf clap to Buffett.

"You can't blame, Warren, if Hollub was arrogant enough to negotiate a deal with Buffett of this magnitude despite her admittedly limited experience in M&A," Icahn wrote in August. "… One might say in Warren's defense that it was almost his fiduciary duty to Berkshire Hathaway to accept it."

Thanks for continuing to take a stand, Carl.

Still, this billionaire banter and few recent deals does raise a question: Is oil and gas investing the new yachting for the super wealthy? Many a billionaire has, of course, been made in the oil and gas world. But more recently, the billionaires have been seeking out investments in the void created by Wall Street.

Recall that in July, football fan Jerry Jones invested $475 million in Comstock Resources Inc. as it purchased Covey Park Energy LLC. To that point, Jones invested $1.1 billion in the company. For perspective: Jones bought a 357-foot superyacht in January for $250 million, Forbes reported. Steven Spielberg, for even more perspective, owns a 280-foot yacht. Icahn tried to sell his 177-footer in 2008, but apparently still owns it.

In September, at yacht-free Contango Oil & Gas Co., there seemed to be an inexplicable revving of the company's A&D engine—a mystery solved by a brief inspection of the billionaire under the hood. Real estate investor John C. Goff and his various companies own about 35% of Contango's equity—including a $25 million investment made in July.

In September, Contango put that money to use in a pair of acquisitions encompassing about 450,000 net acres in Oklahoma for $155 million. What's most notable about the pending deals for White Star Petroleum Inc. and Will Energy Properties is that they're worth about 78% of the company's $198 million market capitalization as of early October.

Contango, which has made its focus the southern Delaware Basin since 2016, released an investor presentation in September, available for download in a file cryptically named "Project Crusader." The presentation gives additional insight into the company's plans.

Contango wants to purchase strategic, long-lived PDP-focused assets in a market "ripe for consolidation." The pipeline of deals, it argues, is becoming more active, "with expected fall 2019 borrowing base cuts across the industry due to lower bank price decks."

The company will continue to develop its Permian Basin assets in its Bullseye development while hunting for deals in a down market.

In the province of billionaires, it seems there are those who parachute in, like Icahn, and those with boots on the ground, like Goff and Jones.

So, what might billionaires know that the market is missing? Jones bought the Dallas Cowboys in 1989 for $140 million. The franchise is now worth $5.5 billion. Goff, a Contango board member, made his fortune purchasing distressed debt in oil and gas, health care, insurance and banking before selling his company in 2007 for $6.5 billion. More recently he's invested in Canyon Ranch, "the recognized leader in healthy living and luxury spa vacations."

Billionaires are today's fashionable villains. In the book "The Triumph of Injustice," set to be released Oct. 15, two economists found that the 400 richest U.S. families paid a lower effective tax rate than the bottom half of American households.

But what billionaires with a little extra cash seem to have in common is knowing a bargain when they see one—and to them, oil and gas companies must look like iPads at Dollar General.

Also, yachts. They have that in common.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
Executive Oil Conference	**Nov. 4-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
IPAA Annual Meeting	Nov. 6-8	Washington, D.C.	Fairmont Georgetown	ipaa.org
DUG Midcontinent	**Nov. 19-21**	**Oklahoma City**	**Cox Convention Center**	**dugmidcontinent.com**
Marcellus-Utica Midstream	**Dec. 3-5**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**marcellusmidstream.com**
Privcap Game Change	Dec. 3-4	Houston	The Houstonian	energygamechange.com
Veterans in Energy Lunch	**Dec. 5**	**Houston**	**Marriot Marquis Houston**	**impactfulveteransinenergy.com**
2020				
Private Capital Conference	Jan. 23	Houston	JW Marriott Houston	ipaa.org
NAPE Summit	Feb. 3-7	Houston	George R. Brown Conv. Center	napeexpo.com
DUG Rockies	**Feb. 18-19**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
SPE A&D Symposium	Feb. 26	Houston	Petroleum Club	spegcs.org
Energy Capital Conference	**Mar. 2**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
Women in Energy Luncheon	**Mar. 4**	**Houston**	**Hilton Americas-Houston**	**womeninenergylunch.com**
EnerCom Dallas	Mar. 4-5	Dallas	Tower Club	enercomdallas.com
CERAWeek by IHS Markit	Mar. 9-13	Houston	Hilton Americas-Houston	ceraweek.com
DUG Permian	**April 6-8**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
OGIS New York	April 20-22	New York	TBA	ipaa.org
Mineral & Royalty Conference	April 27-28	Houston	Post Oak Hotel	mineralconference.com
Offshore Technology Conference	May 4-7	Houston	NRG Park	2020.otcnet.org
DUG Haynesville	**May 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
Midstream Texas	**June 2-3**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
CIPA Annual Meeting	June 4-7	Santa Barbara, Calif.	TBA	cipa.org
AAPG Annual Conv. & Exhibition	June 7-10	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
DUG East	**June 16-18**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Unconventional Resources Tech. Con.	July 20-22	Austin, Texas	TBA	urtec.org/2020
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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NewsWell

Conventional action slows as Wall Street favors lower risk

Operators are backing away from conventional drilling with conventional discoveries sinking during the past three years to the lowest level in seven decades. This is according to a recent report from IHS Markit.

U.S. E&Ps that once ventured abroad to drill for company-maker fields have retreated to the shale plays of the U.S. where the risk is less. The shales offer shorter cycle times and more flexibility in today's climate of uncertain demand and lower commodity prices.

The runaway success of unconventional drilling led producers to turn away from conventional drilling, "most drastically after oil prices collapsed in 2014," according to the study. The result could be significant reductions in future conventional reserve additions to global supply.

IHS found that along with low oil prices and competition from unconventional resources, the decline in conventional discoveries reflects the influence of financial investors "who question long-term, high-cost, frontier projects," according to the report. Keith King, senior advisor at IHS Markit and a lead author of the report, noted that shale players "can quickly turn an unconventional project off and stop or postpone drilling next month if oil prices fall."

It isn't only reduced drilling that has affected conventional activity, however. The report noted that "the average discovery size of conventional fields varies greatly with the maturity of the basins being explored," so as basins have been explored to a greater extent, the discoveries become more modest.

Deep- and ultra-deepwater areas yield discoveries that are five or more times greater on average than those made in shallow water and onshore, the report noted. Yet, operators are targeting deepwaters far less frequently.

"In 2014, 161 new field wildcats were drilled in deep and ultra-deepwater; by 2018 that number had dropped to 68 wells," the IHS analysts said. The same fall-off occurred in frontier/emerging phase basins.

Calling the current climate "risk-averse," IHS said the industry today prefers drilling in mature basins, near existing infrastructure, where they can bring a project online in two to three years."

That search for lower risk, more flexible investment targets will likely persist. Onshore and shelf projects will continue to dominate budgets, with the deepwater, frontier and emerging-phase basins seeing "only incremental gains," according to the report.

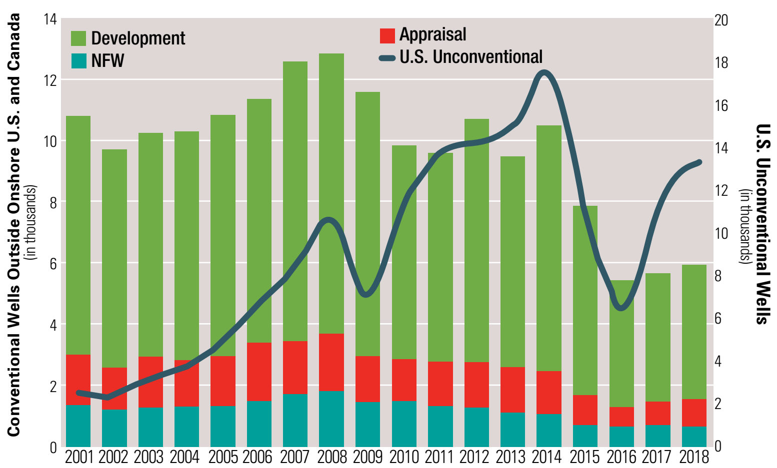
Overall, newfield wildcat wells in the U.S. alone have fallen by 60% since 2009, and IHS said the "percentage and absolute number of these wells drilled in areas with the largest discoveries has declined relative to areas with smaller discovery sizes."

King said a couple of factors could improve the outlook for conventional drilling. First, "lackluster returns from unconventional production onshore in North America may drive more operators back to conventional exploration in the longer term."

Second, strides in technology and cost reductions in the deeper plays could "rekindle interest in conventional exploration where larger discoveries are made."

—Susan Klann

Conventional Newfield Wildcat Wells, Appraisal, Development Vs. Unconventional



Source: IHS Markit

Still resilient, Eagle Ford the 'dark horse' of shales

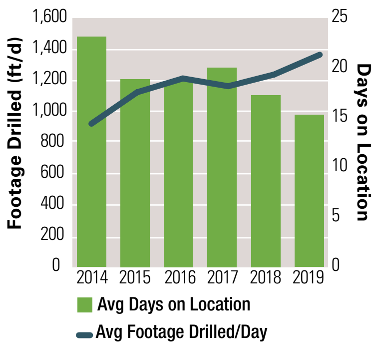
The Eagle Ford may be one of the most mature of all U.S. shale plays, but it's turning out to be one of the most resilient, too. Increased drilling permits to the Austin Chalk in the eastern portion of the play are keeping it relevant.

"We refer to the Eagle Ford as the 'dark horse,' because it remains one of the most economic basins in the country, and we are getting the most questions about it and the Austin Chalk," said Enverus analyst Bernadette Johnson, speaking at Hart Energy's DUG Eagle Ford conference and exhibition, recently.

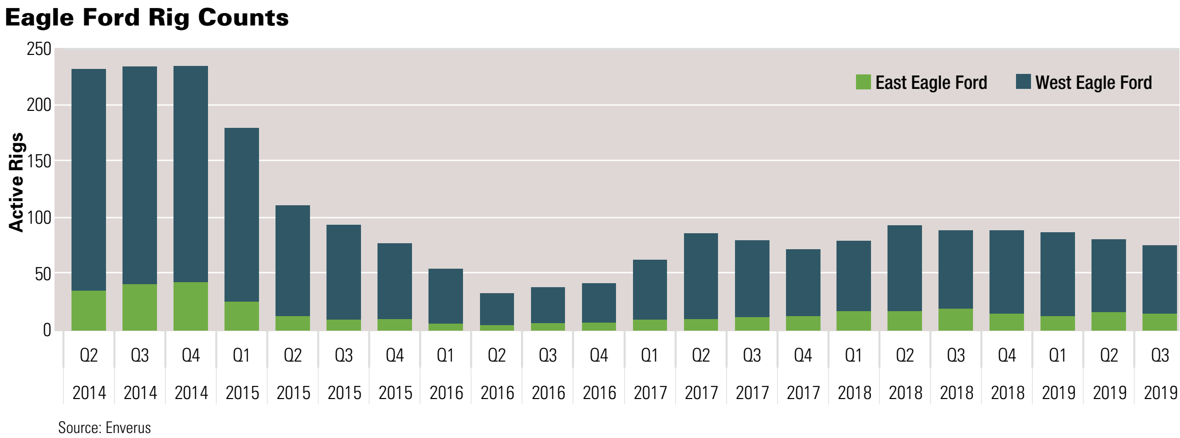
"In general, downspacing has been successful here, and more so than in any other play," she said.

The Eagle Ford rig count has been relatively steady compared to other plays through the industry's frequent commodity price

Eagle Ford Rig Metrics



Source: Enverus



upheavals. Drilling times also continue to improve and are now nearing 1,400 feet per day per rig.

More than 27,000 wells have been drilled in the play since Petrohawk Energy Corp. unveiled it in 2008. Today, Enverus breaks the huge play into the western half and eastern half, with differing characteristics.

The western portion is heavily drilled. More than 80% of the wells being drilled today in the western Eagle Ford are child wells, which indicates just how mature the play is, Johnson said. She cited a lack of core locations remaining in the east, especially in Karnes County, "although this is not concerning to us. This is a natural development for such a mature play."

However, interest seems to be shifting back to the east now, as the Austin Chalk play in Washington County, Texas, heats up, based on new drilling permits. There is interest north of the Karnes Trough also, in Wilson County, Texas.

"We're watching it closely, and it's very liquids-rich," she said. "Although the eastern Eagle Ford type curves are lower, the economics are actually better. The eastern part is not as mature."

In the southwest portion of the play the economics are driven largely by gas prices, with Enverus estimating operators need a breakeven price of at least $2 per thousand cubic feet. The average oil cut in the western portion is 61%, but clocks in at 82% in the eastern. Perforation intervals in the east have lengthened since 2014 to average 8,500 feet, which is longer than in the west.

Productivity in the east was first unlocked by Chesapeake Energy Corp.; this acreage has been managed by WildHorse Resource Development Corp. since 2016.

The eastern portion has shown more well productivity improvement per foot drilled since 2018 while the heavily drilled west has been consistent, Johnson said. "Again, the geology really matters. It depends on where you are for what you're able to do in terms of spacing and proppant."

—Leslie Haines

Report: Grim outlook next year for natural gas prices

The outlook for natural gas prices, at least over the next year or so, is bleaker than it has been in decades, according to a recent report from IHS Markit. A driving factor in the firm's forecast for prices to dip below $2 per million British thermal unit (MMBtu) (in real terms) at Henry Hub next year is oversupply from the Permian Basin. Pipeline infrastructure that is coming online is expected to unleash associated gas from the basin's vast oil production, overwhelming the market and pushing average prices below $2/MMBtu for 2020, the IHS analysts said. This would be the lowest average price in real terms since the 1970s, and in nominal terms, since 1995.

Demand is not the culprit. IHS noted that, in fact, domestic demand for natural gas is robust, having increased by an annual average of 14 billion cubic feet per day (Bcf/d) since 2017, while exports present another market for an additional 3 Bcf/d of LNG that is forecast for 2020. The problem: Abundant U.S. production has more than matched that growth with an additional 14 Bcf/d since January 2018, with an average of more than 90 Bcf/d forecast for this year and next. Permian added supply is expected to match or exceed LNG export potential.

"It is simply too much too fast," said Sam Andrus, executive director, IHS Markit, who covers North American gas markets. "Drillers are now able to increase supply faster than domestic or global markets can consume it. Before market forces can correct the imbalance, here comes a fresh surge of supply from somewhere else."

The Gulf Coast Express Pipeline, which was scheduled to come online in October, will allow for an additional 2 Bcf/d of production capacity from the Permian, the report noted, with an overall basin capacity increase of 6 Bcf/d through 2022.

"In all events the gas is going to get produced out of the oil well. The real change here is the transportation capacity," said Michael Stoppard, chief strategist for global gas, IHS Markit. "You go from a situation where producers, in many cases, were paying someone to take their gas to having an economic means of getting it to market."

The IHS analysts said that price shifts are already underway. "Gas prices fell by more than 60 cents/MMBtu between March and August as inventories climbed toward their five-year rolling average—despite record use of natural gas to generate electricity and growing LNG exports," the report found. The forecast is for U.S. Lower-48 storage inventory to emerge from this winter "at 2.1 Tcf [trillion cubic feet]—or 263 Bcf higher than the rolling five-year average—and head toward 4 Tcf in the fall of 2020."

Market forces will someday rebalance the market, but not until 2021, when they could average

$2.25/MMBtu, according to the report.

"What is unique here is the extent of reduction required," said Shankari Srinivasan, vice president, energy, IHS Markit. "But signs still point to this coming price fall having a limited shelf life rather than being the new normal."

—Susan Klann

ConocoPhillips, private equity see shale growth opportunities

Having fought back from a downturn while trying to please investors, the U.S. shale industry has continued to grow production with the Permian Basin in the driver's seat thanks to improved techniques and technology.

But there are still opportunities, according to panelists speaking during the Rice Alliance's Energy and Clean Technology Venture Forum in September.

"We today are only able to produce around 10%, plus or minus, of the oil and gas that's there. So, basically 90% is left and that's a big opportunity," said Steinar Vaage, senior vice president of operations, wells and projects for ConocoPhillips. "We're interested in ideas and ways on how we can get more out of the wells, more out of the subsurface, so we can increase our recovery."

ConocoPhillips grew production from its so-called "Lower 48 Big 3"—the Eagle Ford, Bakken and Permian Basin—by 26% year-over-year to 367,000 barrels of oil equivalent per day (boe/d) during second-quarter 2019. The company, which expects to operate 10 to 11 rigs in the Big 3 this year, is also piloting new completion designs.

Data from the U.S. Energy Information Administration (EIA) show about 8.68 million barrels of oil per day (MMbbl/d) and 80.87 billion cubic feet of gas per day (Bcf/d) were produced from the country's top seven most prolific basins. Those numbers were expected to rise to 8.77 MMbbl/d and 81.60 Bcf/d in September.

Still, shale drillers are trying to learn more about the rock, including determining how much of the rock is actually actuated during the hydraulic fracturing process, according to Vaage.

"We have some things we're doing but we need more in that space," Vaage said. "We don't really have good data other than what we see [in] production."

He added more automation is also being sought to conduct operations safer, faster and better.

Shale players have pumped higher concentrations of proppant and fluid, tinkered with cluster spacing and drilled longer laterals to get more oil from reservoirs while bringing down costs. But challenges remain, belowground and aboveground, as shareholders demand to see returns and others move toward cleaner sources of energy.

"As we talk with public companies and we talk with private companies, I think it is a challenging environment for all of us," said Basak Kurtoglu, senior vice president of Quantum Energy Partners.


EnCap Flatrock Midstream applauds Cogent Midstream management and the entire Cogent Team
In just 17 months you've grown system volumes in the Midland Basin to approximately 375 MMcfd, a 90% increase.
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CEO Dennis McCanless
COO Stan Golemon
SVP Business Development Marc Fergason
CFO Brad Alford

"But what we are all relying on is … technology."

Quantum Energy Partners, a Houston-based provider of private-equity capital, is present in nearly all basins in the U.S. and runs 28 rigs in North America and Canada.

"We have seen a lot of application of technology," she said, noting Quantum has operated in HP/HT environments, mitigated shallow fractured reservoirs and worked to drill longer laterals in different basins across the U.S. Across the basins, "the technology is the same; the way that we apply it is different. What makes it different is the mentality in how we approach it across the management teams. So, we embrace technologies as a company, but it doesn't end there; it has to go into our management teams and our portfolio companies."

Today, no one is going to sell their best acreage, and it is difficult to monetize assets in current market conditions, she said.

"Before, we would be selling these companies in two to three years' time frame. Now we are looking at four to seven years," Kurtoglu said.

She added, "Today's philosophy is we are here longer. Any technology that can help us to bring the cash flow earlier, that can help us improve efficiency, reduce cost, improve productivity," would be beneficial.

Quantum has invested in start-ups, including some that have pitched their products at the Energy and Clean Technology Venture Forum. Among these are Seismos, which offers real-time frack treatment and performance evaluation and RigUp Inc., which connects contractors with jobs offered by service providers and contractors. Both are based in Austin, Texas.

Among her advice to start-ups is to "put yourself on the other side," and tell companies what value will be created to help their bottom line. "It's not just a cool technology."

Another private-equity shop, Kayne Anderson Capital Advisors, doesn't back the new technology itself but "we do back entrepreneurs who use the best available technology, and we are willing to tweak it make it better," said Mike Heinz Sr., managing director for Kayne Anderson.

With 30 portfolio teams, Kayne Anderson is present in most of the major resource plays in the U.S., running 15 to 20 rigs this year.

"First off, capital is precious. Raising money is incredibly difficult. So, we're really not backing teams today that don't have assets," Heinz said, noting it is backing repeat teams that have turned profits.

When pitched with new technology services or products, he wants to know about the economics and what will be done differently to make acreage work. Drilling, he said, is focused on returning to areas where horizontal wells were previously drilled and applying today's learnings.

Like others in the industry, knowledge learned is being transferred from basin to basin.

"We don't think we're one of the last ones to bring in the innovation and so forth," Heinz said, responding to an attendee. "Oftentimes we're out there seeing what the majors are doing, and they tend to be quite

a ways' behind. … We think we're scouring the technology."

He spoke about how one of Kayne Anderson's portfolio companies was among the first to change sand mesh size and concentration in the Delaware sub-basin based on knowledge gained in the Midland sub-basin.

Panelists seemed to agree that the industry does embrace proven technology, though the rate of uptake varies depending on the type of company and its comfort level to certain technologies. Kurtoglu mentioned the acceptance of microseismic and how comfortable companies are with using data as examples.

"That's the challenge we are having when I think about the new companies coming in," she said.

—Velda Addison

Analyst: Bankruptcies are not an industrywide 'epidemic'

The U.S. shale industry has undergone a tortuous time of restructuring since the commodity price downturn that began in late 2014. A number of players have gone under, while the sector as a whole has had to severely alter the financial strategies that have long characterized the business, particularly the tendency to outspend cash flow.

Still, the U.S. shale industry is not going bankrupt by any means, according to a recent note from independent energy research and business intelligence firm Rystad Energy.

"In a nutshell, we do not believe the recent bankruptcies that have beset a number of shale players are indicative of an industrywide epidemic," said Alisa Lukash, a senior analyst on the company's North American shale team.

In many cases, bankruptcy is simply a way to reorganize debt and assets, the report said.

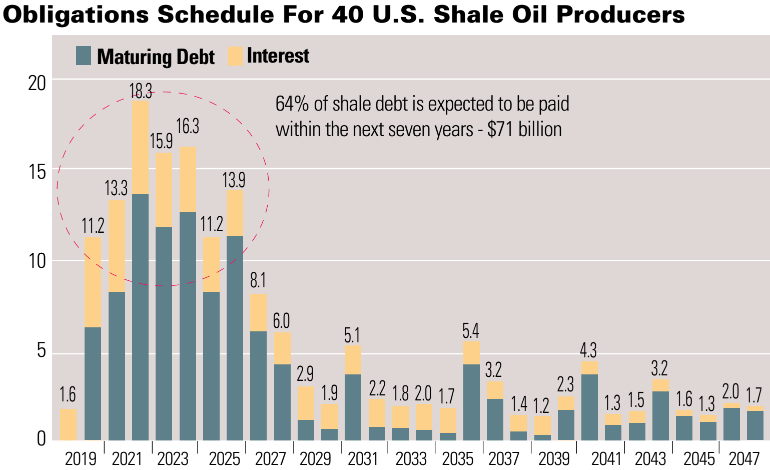
For example, Sanchez Energy Corp. filed Chapter 11 in August "in a bid to reduce its debt burden and improve its financial flexibility," according to Rystad. "Similarly, Halcón Resources Corp., which was delisted from the NYSE in August, has expressed uncertainty about its ability to remain in compliance with all the current covenants in its senior credit agreement."

While crude prices have risen recently, natural gas players haven't had any relief from low prices.

Not that the pressures of staying in business as commodity prices remain stifled hasn't created significant challenges for U.S. E&Ps. "During the next seven years, the top 40 U.S. shale oil producers are expected to spend about $100 billion on debt installments and interest unless further debt refinancing is applied," the report said. These 40, which represent about half of U.S. shale crude production overall in 2018, face interest payments of between $2.6 billion and $5.1 billion annually, "while the maturities schedule totals roughly $71 billion between 2020 and 2026."

After 2027, the level of maturing debt and interest burdening the E&P shale group drops significantly, to $8.1 billion combined from $13.9 billion projected for 2026, the Rystad team said. The high is expected to be $18.3 billion combined in 2022. By 2029, the total drops to $2.9 billion.

Obligations Schedule For 40 U.S. Shale Oil Producers



Source: Rystad Energy

Cash flow and spending have both fallen since 2018, the report noted. "In 2018, the same peer group generated $51.4 billion in cash flow from operations while spending $60.3 billion in capex, whereas cash flow from operations reached $23.7 billion during the first six months of this year and capex was $28 billion."

Financial pressures remain. "Overall we see more than $112 billion in outstanding debt for the considered peer group, with a combined enterprise value of $355.5 billion as of September 2019," according to the report.

"These numbers indicate a lack of financing to deal with the burden of the obligations. Given the low levels of external capital additions during the past 10 months, the probability of debt refinancing in the coming quarters seems relatively slim."

The shale group's diversity in terms of acreage quality and capital efficiency are two of the reasons the Rystad analysts expect the group to sidestep some of the stress that a few companies have fallen into. EOG Resources Inc. is an example of how some companies have successfully negotiated the current challenging commodity price environment, they said. The company "has increased production by 5% quarter-on-quarter, realized close to $1.1 billion in free cash flow in second-quarter 2019 and used the cash to pay down $1 billion in debt."

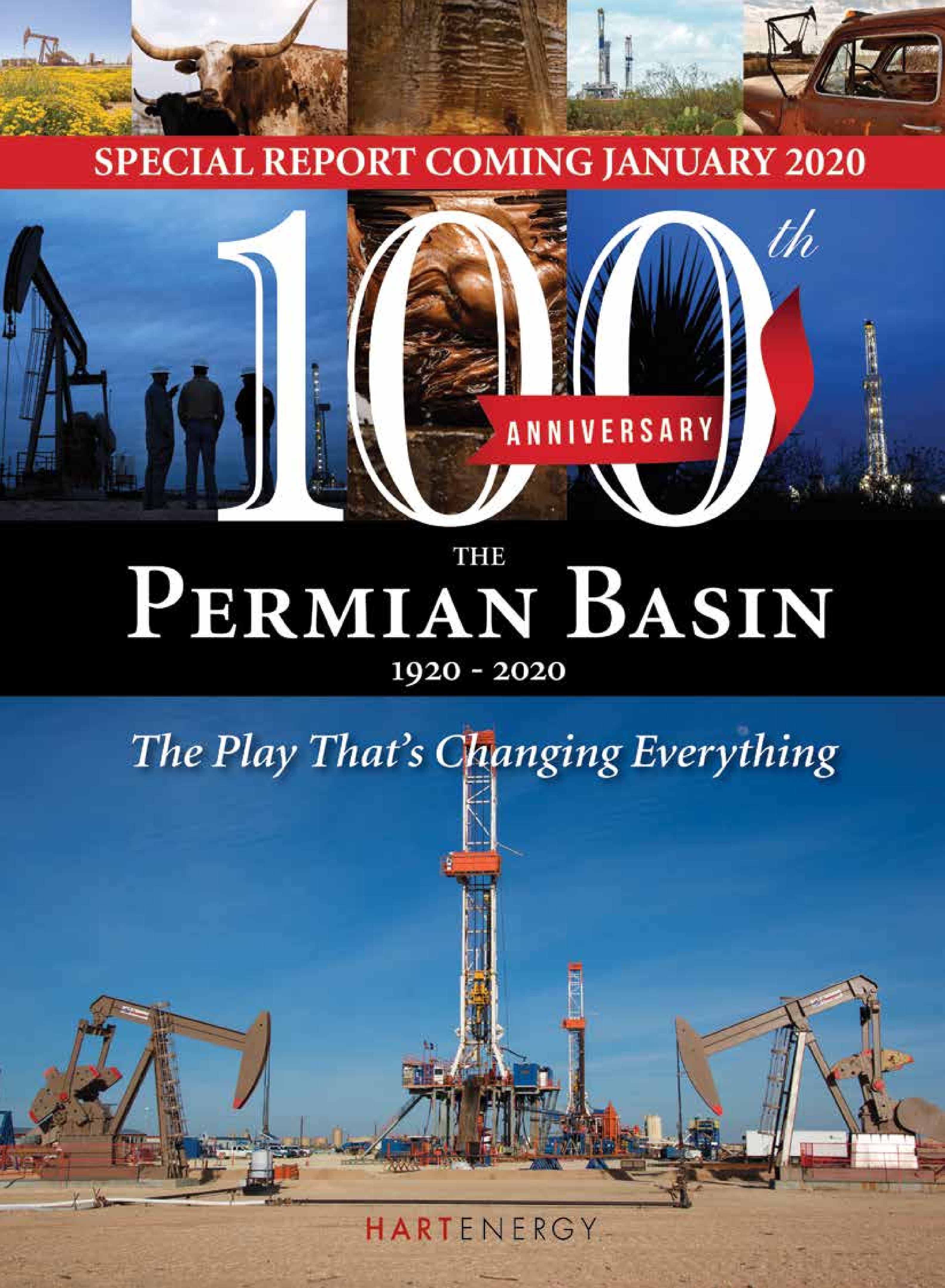
—Susan Klann

Well interaction data can foster ideal parent-child relationship

Avoiding parent-child friction seems unavoidable, especially in horizontal well pad infrastructure. To kick off field development parent wells are primarily drilled, completed and produced. But, once the adjacent child well is drilled, it enters a pressurized and stressed environment.

The more infill wells that are drilled in a section often leads to a higher water, lower oil production ratio and, ultimately, results in a steep decline in EUR. The argument posed is whether or not this is the result of well spacing.

Negligence toward the data is why some industry experts say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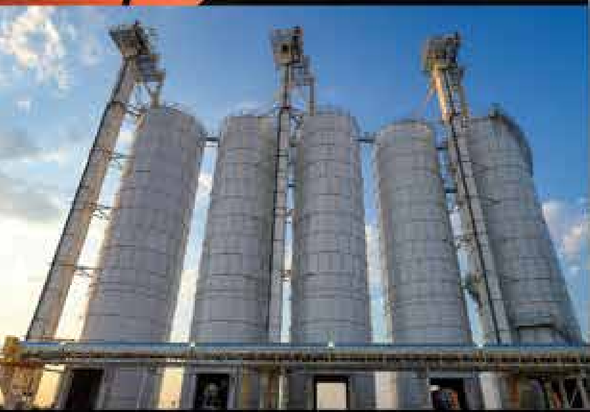

1920

An Invitation to

Celebrate This

February 1920

W. H. Abrams #1: the first commercial discovery of oil in the Permian was in Mitchell County, Texas. It began production in June, 1920 with 20 barrels per day, and marked the opening of Westbrook Field.

— Source: The Petroleum Museum, and Midland Reporter-Telegram, June 2009

100th ANNIVERSARY

COMING 2020

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1920 - 2020

The Permian Basin is like none other. It has played a major role in U.S. oil production for 100 years. Now it's contributing to exports—and it's not done yet. "The Permian" promises to sustain production for many years to come. In April 2019, U.S. oil production topped 12 million barrels a day for the first time—and Permian Basin production contributed 4.2 million barrels of that volume. What's more, experts now forecast Permian crude output will grow another 50% by 2025.

Hart Energy is commemorating the 100th anniversary of the world's most remarkable oil basin with a special, coffee-table book by the editors of *Oil and Gas Investor* and *E&P* magazines. This special commemorative book will showcase the basin's proud past, its current activity and its extraordinary significance to U. S. energy production and independence. It is sure to delight the most seasoned professional and intrigue young engineers, geologists, entrepreneurs and investors who are leading the industry in the 21st century.

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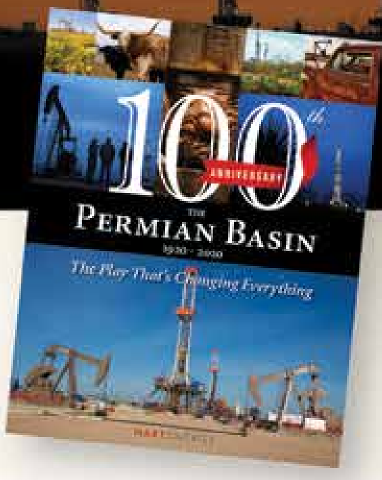


2020

January 2020

Hart Energy publishes a Centennial special issue to celebrate The Permian Basin's 100th Anniversary.

Featured Chapters:

From the Office of*…

U.S. President Donald Trump, **Secretary of Energy** Rick Perry, **Texas Governor** Greg Abbott, **New Mexico Governor** Michelle Lujan Grisham, former **Secretary of Commerce** and **Permian Strategic Partnership Chairman** Donald Evans, former **President** George W. Bush, **Midland Mayor** Jerry Morales and **Odessa Mayor** David Turner (*Requested)

Chapter 1 – History 1920 – 2020

The incredible ride through the booms and busts of oil and gas development in the Permian Basin has spanned a century. It's a story of constant change and innovation that has been essential to America's prosperity.

Chapter 2 – Drilling Activity

Current activity trends across the Northwest Shelf, Delaware Basin, Midland Basin and Central Basin Platform are captured, including rig deployment, major reservoir targets, early to full-field development plans, and oilfield service technology and logistics challenges.

Chapter 3 – Giving Back

Social responsibility, sustainability, environmental protection and strong corporate governance are crucial values that companies are embracing to address development issues and create lasting relationships between the industry and the region's residents.

Chapter 4 – Will To Succeed

The giants of the Permian Basin are those individuals who persevered through adversity, who disrupted tradition with new ideas, and who pioneered many innovations that have changed the worldwide industry.

Chapter 5 – Serving Up Technology

Operators and service providers are working together to rapidly evolve new and ever more effective technologies that aid in the discovery, production and transportation of Permian Basin oil and gas.

Chapter 6 – The Infrastructure Take-Away

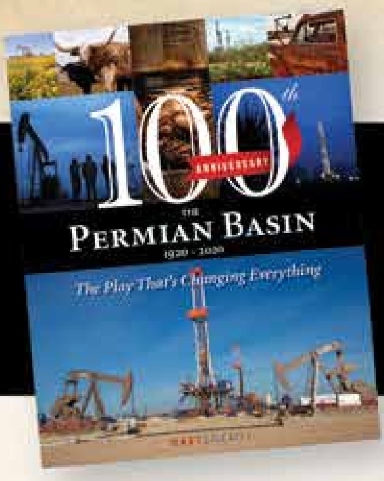
The midstream sector is working flat out to connect the Permian Basin's bountiful oil and gas production to domestic and international markets.

Chapter 7 – Capital Investment

Local lenders, friends and families often provided the seed money for early Permian Basin explorers. Now Wall Street and private equity are all-in on this amazing play.

Chapter 8 – The Future

The future is bright for economic development and job growth across the Permian Basin communities. The industry is working hard on workforce development and community projects, and Texas and New Mexico will unequivocally lead the way in America's energy independence story for decades to come.



The Permian Basin has given us so much to be grateful for, so let's do our part to accurately educate those who will lead our industry into the next 100 years.

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MARKETING: **Year-long visibility**

Hart Energy will also deploy a robust marketing campaign throughout 2020 promoting this report on social media, and in banners on HartEnergy.com. Each article will be posted in editorial cycles, and on a purpose-built microsite with open access that will house the digital copy of the special issue, plus all videos, profiles and participating sponsor logos. The special issue will be available for purchase online at the Hart Store.

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A Supplement To

Oil and Gas Investor

E&P

operators can't see that the answer is clearly no.

Experts examined the challenges of inter-well interference between parent wells and newly fractured child wells, and they uncovered the role of relative permeability during the Well Interference Forum at the DUG Eagle Ford conference in September.

Collection and analysis of frack-driven interaction data can provide the engineering information needed to avoid and mitigate the possible negative effects, according to Dr. Ali Daneshy, president of Daneshy Consultants International. They can also optimize the effectiveness of the completion and fracturing operations.

"With the present completion systems that we're using, frack-driven interactions are unavoidable," he said. "[However], the collection of frack-interaction data can provide very important engineering data information that we need in order to raise the level of fracture treatments to a higher level."

William Von Gonten Jr., president of W.D. Von Gonten & Co. Petroleum Engineering, agreed, saying high-resolution reservoir simulation modeling is the best preventive measure to mitigate underperformance of wells.

"I want to build a model that emulates what's actually going on downhole," Von Gonten said. "If I can build a model that accurately represents the fracture system then I can look at the stress, pressure and depletion of the rock and start to build a model on how to infill wells, sequence the stages, and then you can calibrate it to performance, fracture and microseismic data. We need a dynamic model that's running 24/7—as I'm fracking wells I'm predicting the next stage."

The hi-res data should include ash beds and calcite beds, measured fluid leak-off and centimeter scale rock properties like fabric, he said. To achieve centimeter scale, Von Gonten's company adopted the medical industry's centimeter resolution software used for brain scanning.

"Take the data and put it in a frack model that can handle that resolution, the fabric of the rock in centimeter scale, stress shadowing between the clusters and wells, and handle the depletion of the parent wells or older wells," Von Gonten said.

When water production increases due to frack hits during child well treatment, Von Gonten said the data should indicate a permeability problem rather than a spacing issue.

"If it is interference, the wells are robbing each other's oil, but they don't rob each other's water? The Eagle Ford doesn't make water, so any water you get back is coming from your fractures," he said.

Ideally, the model output will provide enhanced imaging on fracture geometry, conductivity and stress profiles for more accurate history matching. He said that in-depth interference data allots the history matching of both oil and water, fostering a better understanding of the reservoir.

"If you don't know what fractures look like, or the permeability and pressure of the rock, or where conductivity sits, how can you history match without that," he asked. "Instead of continuing to pump, why not have the model identify the solution?"

He said the responsibility rests in the hands of the industry to analyze the pool of data and produce—and benefit from—a real-time, predictive model rather than charts that illustrate the past.

"There's a lot of data, and we need to use it in real-time, dynamically, as we're fracking," Von Gonten said.

—Mary Holcomb

Big oil, energy start-ups provide blueprint for digital success

Plagued by a slow-moving pace when it comes to the adoption of technology, the oil and gas industry's apprehension has led to a race to second place. But, start-ups are developing valuable technology today that is fast tracking the digital transformation across the industry.

Today, the value of digital technology is being realized well before the adoption stage. During a panel discussion at Rice Alliance's annual Energy and Clean Technology Venture Forum at Rice University in September, a panel of technology executives detailed the challenges and opportunities of the digital transformation and technologies they've adopted to secure leading spots in the race.

"We are at a unique point in our industry where digital emerging technologies have the capacity to completely transform the way that we've been doing things for decades," said Nadia Bollinger, digital exploration manager at ExxonMobil Corp. "To that end, I'm sure that there are mixed emotions when we try to make sense of concepts like AI, IoT and digital twin. On one hand, looking at these digital emerging technologies can be really exciting, but on the other hand, it can feel very stressful."

Working in favor of the wave, Bollinger said ExxonMobil is firmly committed to the digital transformation and "to opportunities and collaboration to both identify and scale solutions."

The company saw the opportunity to start with its operations in the Permian Basin. Described as 'windshield time' at ExxonMobil, Bollinger found that the company's field technicians spend a sizable amount of time in their trucks, gathering data on well performance that has to be jotted down because reception is spotty in the basin, and then returning to the field office to record the information into the proper system in order to be analyzed.

"We looked at the Permian and thought there has to be a better way to do this. So, naturally [we thought] IoT sensors at the well sites like Edge Gateway devices to aggregate some of that data and maybe do some analyses, then send that information up to the cloud—that all kind of made sense," she said.

In partnership with Microsoft, the team developed an open framework that leveraged IoT, Edge Gateway and cloud storage to collect, process and analyze "the massive amount of data that's being generated by the minute" by all of ExxonMobil's different field aspects to enable real-time access to the data from anywhere at any time on the field, according to Bollinger.

ExxonMobil also translated its innovative efforts to additional parts of its business.

"In the manufacturing space, we have deployed a manufacturing data lake that collects operational data from our process control systems into a high-performance computing environment for the first time," she added. "We're now able to marry data that comes in different frequencies into a single place, so people can view that data and make new insights."

Tim Kopra, partner at Blue Bear Capital LLC, a venture fund that focuses on data-driven technology companies within the energy supply chain, detailed how his company seeks out start-ups to back.

"We love it when we find a company that's going to really target a very specific problem," Kopra said. "Find that problem that really needs to get solved and really hone that. Make sure you have the right solution and total addressable market because as a venture person we want to be able to help you scale."

Among the products that have caught the eye of Blue Bear is Everactive's batteryless sensor technology. The Eversensors utilizes energy harvested from the surrounding environment to create a data foundation of full-stack industrial IoT solutions. It senses and transmits data onto the company's Evercloud system to provide actionable insights.

"It's a really amazing company that's caught traction," Kopra said.

Blue Blear's portfolio also includes investment into GoExpedi, an e-commerce platform focused on industrial supply. Kopra described it as the "Amazon of the oil field."

"Being an oil and gas person, I was shocked that you couldn't just buy equipment and know what the price was and get it delivered. It seems like in this day and age it would be the normal thing to do," he said.

The process typically involves finding out the price for the desired product, placing a bid on it and then waiting a couple of weeks for delivery, he said. GoExpedi has created a way to streamline the process.

"GoExpedi puts 200,000 SKUs on their website and all the pricing is there—it's transparent—and they crush it with rock-solid execution delivering in 48 hours. So, the ability for them to expand is really amazing," Kopra said.

Jose Silva, emerging technologies and strategies manager at Occidental Petroleum Corp., has used his background as a geophysicist to stay on the innovative path. The company is currently building machine learning architecture that replicates the work of a geophysicist, but in a tenth of the time, Silva said.

With Big Oil and companies like ExxonMobil, Blue Bear and Occidental unveiling the value of going digital, the opportunity is apparent. But, the panelists agreed that without leadership and a switch in mindsets, the digital direction for non-participants will continue to be foggy.

"What's interesting to us is that some of the large oil and gas companies are very interested in transforming their processes and some are not, at all, or they don't really have the mindset," Kopra said.

"Digital transformation sounds like it's all technical, but at the end of the day the way that it succeeds is by intersecting people and solving those problems," he added. "It's a people business and to the extent that we expand that network and we have better introductions, the better we'll be able to do."

—Mary Holcomb

Analyst: Permian Basin venting, flaring level stabilizes

A rise in recent years of vented and flared gas from the prolific Permian Basin is still hovering near record highs, and fears are that the level could be prolonged as new wells come online in second-half 2019.

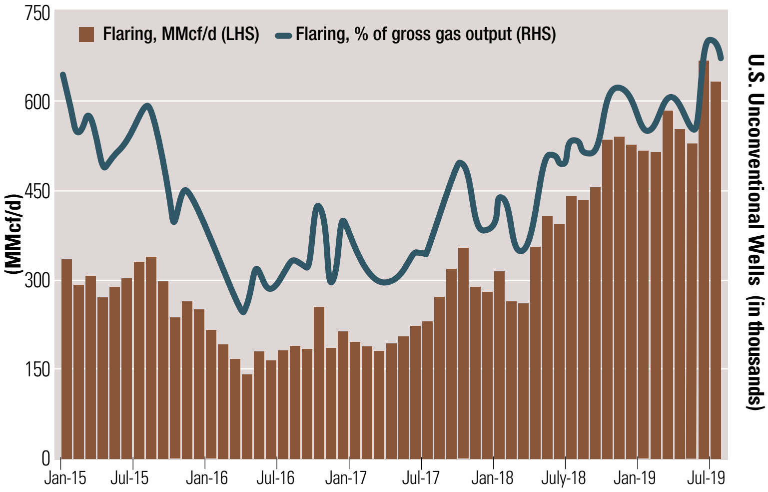
That's according to analysts at Rystad Energy, the energy consultancy that reported this week Permian Basin flaring and venting levels have stabilized between 600 million and 650 million cubic feet per day.

New pipelines en route are expected to provide some relief.

"However, it should be noted that the significant number of new well connections in the second half of 2019 might result in a sustained high flaring level, because from an operational perspective, associated gas flaring is normal in the first two weeks following an oil well completion," Artem Abramov, head of shale research, Rystad Energy, said.

The amount of gas flared has steadily increased, for the most part, in the Permian Basin as oil production has risen in recent years.

North Dakota Flaring And Venting By Month



Source: Rystad Energy ShaleWellCube

In Texas, flaring of associated gas from initial completion beyond 10 producing days is prohibited. But that state routinely grants exemptions to the rule.

Flaring is needed for safety reasons in some instances, and temporary flares may be used during well testing. But a lack of sufficient gas infrastructure needed to move gas, which flows along with oil from wells, to the market has prompted some oil companies to flare more often than not instead of shutting in wells and missing out of oil revenue.

Yet others consider the value of gas molecules—just like oil—when forming field development plans looking at the entire value chain.

Chevron, for example, has a no flaring policy.

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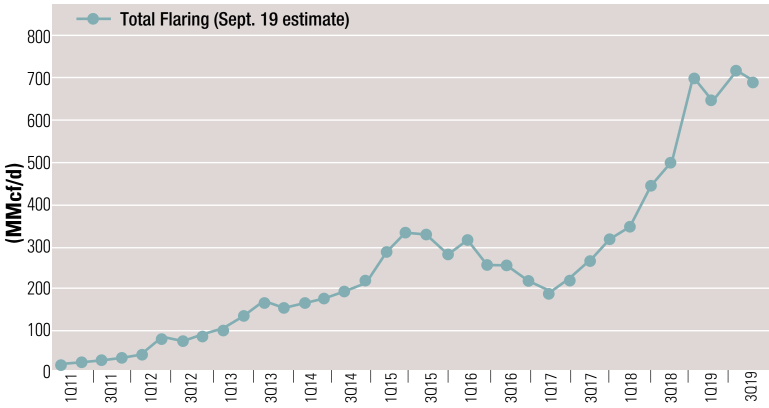
Permian Basin Flaring And Venting By Quarter



Source: Rystad Energy research and analysis, Rystad Energy ShaleWellCube

"When we consider a development area, we consider not just how many rigs it'll take, how many wells we can drill, what the production volume is, but how do we access markets whether it's gas or oil," Stephen Green, president of Chevron North America E&P, said in September during an event hosted by the Center for Strategic & International Studies. "That is why we've had a purposeful strategy of focusing on ultimate recovery resource but also an integrated strategy of the entire value chain."

The company, like some others, sees gas as potential feedstock for petrochemicals, LNG, heating, power generation, powering drilling rigs or pumping fleets.

Rystad, however, noted there has been some improvement on the venting side, notably in New Mexico, where the analyst said vented and flared gas amounts are reported separately instead of together like they are in Texas. Analysts reported that on average between 5% and 15% of the total flared and vented production stream is vented, or released without combustion.

"In particular, reported data from recent quarters shows a significant decrease in the frequency of venting relative to flaring, with only 8% of waste gas being vented," Rystad said in a news release.

New pipelines coming online are expected to ease takeaway capacity woes. These include Kinder Morgan Inc.'s Gulf Coast Express Pipeline, which provides about 2 Bcf/d of natural gas capacity to Texas Gulf Coast markets.

Elsewhere, venting and flaring levels are "generally low," Rystad said, adding the exception is North Dakota's Bakken.

"As of summer 2019, data from North Dakota show that 22% to 23% of produced gas was flared—twice as much as the state would like to achieve under the current regulations," Rystad said.

Those are flaring levels never seen before, according to Abramov.

—Velda Addison

Study: Oil industry can save $100 billion with digitalization

Upstream companies can save as much as $100 billion through automation and digitalization initiatives in the 2020s, according to a new report by Rystad Energy. The report says service companies are reinventing themselves to help operators unlock the savings.

In 2018, over 3,000 upstream companies spent $1 trillion on opex, wells, facilities and subsea capex. Although there are varying amounts of potential savings within offshore, shale and conventional activity budgets, yet digitalization can lead to efficient operations, saving 10% of the amount spent last year.

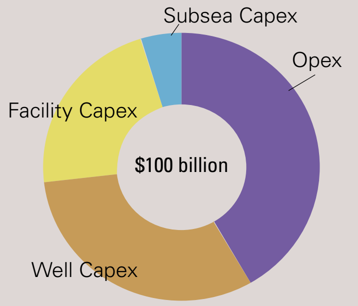
Operators expect digitalization to reduce drilling costs by 10% to 20%, and facility and subsea costs up to 30%. However, the study reported that cost reduction will vary across different field developments or drilling operations. Adoption across the entire value chain of suppliers from national oil companies to majors to smaller E&Ps will vary, so the realistic efficiencies and synergies will be closer to 10% by the end of the next decade.

"Many key industry players are setting optimistic goals, but the realization of these initiatives largely depends on how freely data is shared amongst companies and how commercial strategies are deployed to drive this development," said Audun Martinsen, head of oilfield service research. "However, based on our analysis of 2018 capital spend and operational budgets, we believe savings could easily reach $100 billion."

Upstream companies are rolling out new technologies, trying to keep up in the digitalization race, with major releases by Schlumberger Ltd., Baker Hughes and TechnipFMC during the past three months. Moreover, the oil market downturn has given upstream operators and service providers a strong incentive to adapt efficient operations or face shutdown.

In September, Chevron Corp. and Schlumberger announced a partnership with Microsoft to create petrotechnical and digital technologies to visualize, interpret and ultimately obtain meaningful insights from multiple data sources across exploration, development, and production and midstream sectors.

Digitilization And Automation Potential By Budget Cost



Source: Rystad Energy ServiceCube, September 2019

Martinsen added that in addition to cost savings, digitalization initiatives can also improve productivity by increasing uptime, optimizing reservoir depletion strategies, improving the health, safety, and environment of workers and minimizing greenhouse emissions.

—Faiza Rizvi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BOOMERS, SOONER

Oklahoma producers are intensifying multisection-lateral and multizone development of their liquids-rich leasehold, bringing production nearer to first spend. They're also paring costs by millions per well.

FourPoint Energy LLC field operation manager Eddie Johnson inspects a pumpjack location at sunrise in Washita County, Okla., in the western Anadarko Basin. PHOTO COURTESY FOURPOINT ENERGY LLC

ARTICLE BY
NISSA DARBONNE

The rig count in the Anadarko Basin has fallen from about 175 in 2018 to about 90 in August. Several operators are reporting getting more work done with less iron in the field—rather than diminished interest in the basin—as spud-to-TD days fall precipitously.

Continental Resources Inc.'s "row development" and Encana Corp.'s "cube development" have rigs essentially marching across leasehold. The "marching" part isn't metaphorical either, as the rigs actually "walk."

Meanwhile, in the western Arkoma gas-liquids play, shallow decline rates have enabled operators to rig down for a while without affecting cash flow. They were seeing half-priced NGL prices entering autumn.

And, in the western Anadarko Basin, FourPoint Energy LLC continues to shift its program within its nearly 750,000 net acres, drilling on demand whatever commodities the market values most.

In addition to exceeding production expectations, Continental Resources Inc.'s 75-contiguous-section SpringBoard project in the northern Scoop is exceeding operational expectations, said Jack Stark, president.

SpringBoard

In the southern Anadarko Basin—in the Scoop area—Continental is landing in the Woodford and Springer as well as testing laterals in the Sycamore, which is the age equivalent of the Stack's Meramec and sits between the Springer and Woodford.

Continental announced its Scoop-Woodford play in 2012 and the Scoop-Springer in 2014. In May of 2018, it announced the 75-square-mile SpringBoard project at the northern end of the Scoop.

Stratigraphic Column

Age	Stack	Scoop	Arkoma Stack
Mississippian	Chester	Caney	Caney
	Meramec	Sycamore	Mayes
Devonian	Woodford	Woodford	Woodford
	Hunton	Hunton	Hunton

Source: Canyon Creek Energy-Arkoma LLC

Through the second quarter of 2019, SpringBoard has made some 5 million barrels (bbl) of oil, gross. Resource potential is estimated at up to 400 million barrels of oil equivalent (MMboe), gross.

The E&P has an average of 75% working interest in SpringBoard. EURs in the project are expected to average some 1.3 MMboe from the Springer, about 80% oil; from the Woodford, between 1 and 1.5 MMboe, about 70% oil.

The concentrated development means more than 90% of production to date is connected to a network of pipe. Some 60 wells were online in the project by mid-August: 46 Springer; 14 Woodford.

Another 30 wells were expected to be online by year-end. Estimated total locations in the project area are 85 Springer wells and up to 250 Woodford and Sycamore wells.

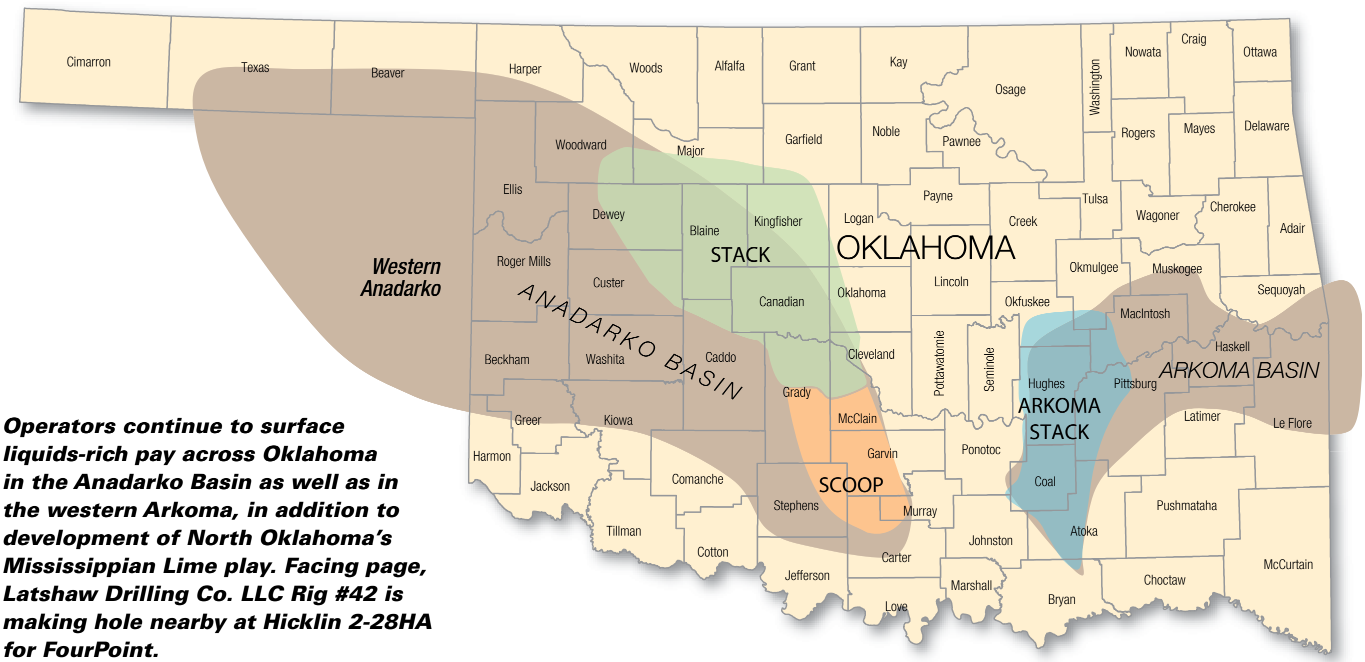
Initially, Continental estimated it would add 16,500 bbl to daily net oil production by the end of third-quarter 2019. In the second quarter, it was already averaging 15,000 barrels per day (bbl/d), and new estimates were for 18,000 by the end of the third quarter. The revised estimate is an average of 22,000 bbl/d in this quarter.

The Springer's thickness is between 15 and 90 feet; the Sycamore, 150 to 200; the Woodford, 125 to 200.

In a placement plan Continental calls "row development," the 75-contiguous-section area is also exceeding operational expectations, said Jack Stark, Continental president. "It's just been an exceptional project for us."

First, "the reservoir rocks themselves are pretty darn exceptional," Stark said. "They're delivering every bit as well as or better than we anticipated." The completion recipe is essential, "but if you don't have the best rock, you're not going to get the best results."

Continental began leasing in the area it named "Scoop" in the Anadarko Basin in 2008. "It was a very tough economic time,"



Operators continue to surface liquids-rich pay across Oklahoma in the Anadarko Basin as well as in the western Arkoma, in addition to development of North Oklahoma's Mississippian Lime play. Facing page, Latshaw Drilling Co. LLC Rig #42 is making hole nearby at Hicklin 2-28HA for FourPoint.

PHOTO COURTESY FOURPOINT ENERGY LLC


PHOTO COURTESY ENCANA CORP.

Stark noted. "You had the fallout in the financial institutions. But we managed to lock up really what we consider to be the core."

Pat Bent, senior vice president of operations, said SpringBoard "is an operational dream, when you think about having the opportunity to have that contiguous of an acreage position."

Continental moved in with 14 rigs initially, landing wells side by side across the entire play.

"You think about the optimization opportunities," Bent said, "looking at what the rig next to you did, being able to optimize on that—not only in the Springer but in the Woodford as well."

Row development

Drill days for Springer wells have declined from 46 to about 32. Woodford-well cycle time fell from about 55 days to an average of about 23 by this summer. The team, led by Tony Barrett, vice president of exploration, determined the pressure profile in Scoop would accommodate a no-set casing design for the Woodford program.

Bent said, "No-set refers to the intermediate casing string. You still have a full string of production casing, but you're able to eliminate the intermediate casing, and that was a $1-million savings [per well]."

Further operational savings have pared Woodford costs by an additional $2 million. Continental plans to exit 2019 with 12 rigs across Oklahoma, seven fewer than were budgeted.

Stark said, "The well count for the year doesn't change. It's just the number of rigs we need to get that done has been reduced."

As for completions, the SpringBoard team, through mid-September, completed 22% more lateral feet than budgeted and at 17% less cost, Stark said. "So it gives you a good indication of not only the cycle-time efficiencies but the capital efficiencies that we're achieving out of this."

SpringBoard gas is shipped to the premium-price North Texas market. Water is shipped to Continental's in-play recycling facilities. Bent said, "We can reuse that water for stimulation purposes, which minimizes our water use and cost."

SpringBoard oil—"that's our best netback," Stark said—goes to an in-play CVR Energy Inc. refinery at Wynnewood. It receives a roughly $3/bbl premium to West Texas Intermediate (WTI).

"So everything just lines up really well in SpringBoard to make our operation one of the most efficient in Oklahoma," Stark said.

Row-development wells are primarily 2-mile laterals. Bent said, "There were situations from the lease perspective where we had a few 1-mile wells, but that was the exception rather than the rule."

Rigs drill from east to west. Stark said, "So this is true row development, as we are manufacturing the hydrocarbons from the reservoirs in a very uniform and methodical manner."

The completion recipe can vary. Bent said, "It's similar in nature. But, again, we try and optimize across all of our plays. So stage spacing, proppant loading, fluid loading vary slightly within that play—pad to pad and formation to formation."

But they're small changes, Barrett said. "Not big swings. 'Tinkering' is probably an accurate description.

"Throughout the testing and early development of our project areas, we find the right recipe for our completion and, in general, only make modest changes to the design unless we acquire new data that suggest a major change is warranted.

"The goal is always to maximize production from any given wellbore. Our next challenge is to try to find a way to do it cheaper that will enhance returns."

Using a no-set casing design for Woodford wells in the Scoop has resulted in a $1 million savings per well, said Pat Bent, Continental senior vice president of operations.

Stack extension

In Blaine and Custer counties in the Stack-play westerly extension north of SpringBoard, Continental has two rigs drilling. The Meramec and Woodford are the targets; they're deeper here in this overpressured area of the Stack. Five units had been completed this year through mid-September.

Stark said, "All five of those are outperforming our type curves. Two of the five—the Jalou and the Simba units—paid out in a little under a year. They were that good of performers."

More recently, the three one-section wells from the oil-window Lugene unit had a combined initial rate of 9,270 boe/d, averaging 3,090 boe/d per well with 1,540 bbl/d of oil each.

The five wells from the condensate-window Tolbert unit had an initial rate averaging 3,740 boe/d with 1,180 bbl/d of oil each.

Spacing currently is four wells per zone, Stark said. "It will vary a bit from unit to unit. But that seems to be the model, and that's what's playing out."

Two newer Stack units were being completed at press time—the Reba Jo and the Shulte. "Those are seven-well units where we're developing two zones. We expect to have some very good results from those as well."

These two units are in the oil window. In each, four wells are landed in the Upper Meramec; three, the Lower Meramec. Barrett said, "About 12 months ago, we began moving back more into the oil window, and that's what you're seeing now."

Continental operates more than 40% of Stack wells that have had first-30-day IPs of greater than 1,500 boe/d. "It's quite striking," Barrett said. "We've said all along that zip code matters."

EURs range up to 2 MMboe. Stark said, "They're some of the biggest wells we have drilled in our careers. The reservoirs we're tapping into here are great performers, giving us great economics, great returns."

Continental's overall Oklahoma oil production—including the Scoop and Stack—is up 35% year-over-year to more than 36,000 bbl/d. Its total Oklahoma production is up 10% year-over-year to more than 128,000 boe/d.

Facing page, Helmerich & Payne Inc. drills for Encana Corp. in the Stack play that is focused in Blaine County and in western Canadian and Kingfisher counties, Okla.

Continental's overpressured Stack units are delivering enormous IPs. "We've said all along that zip code matters," said Tony Barrett, vice president of exploration.

Stack core vs. fringe

So why the grumbling on Wall Street about the Stack? Is something wrong with it?

Stark said, "No, no, no. It's a good question because you've heard a lot of mixed results [from some operators] out here. It has everything to do with geology."

Continental added a map to its investor presentation, Barrett said, "because we got that question a lot from the investment community." It indicates where the largest IP wells are in the Stack; they're in the original core play and in the adjacent, westerly extension.

"What it shows is where you are in the play really matters. Geology does matter," Barrett said.

The Stack play was introduced in 2013 by Newfield Exploration Co., now part of Encana Corp., in the original core in western Canadian and Kingfisher counties. Usually, a new play will draw other operators to see what they can do in their leasehold and pick up more land.

Early assumptions may be that the targeted rock is all the same, east to west, north to south. But the results aren't.

"You've got Continental that's knocking it out of the park," Barrett said. "And some other people are struggling. But there is nothing wrong [with Continental's share of the Stack].

"We're in great geology. We're highly overpressured. We've had a ton of success—four quarters of wells that are as good as most of us have ever drilled in our career."

Stark said, "If you look at where Stack started [with Newfield] and then you look at what the investment community ultimately started to call Stack, it was a much bigger footprint."

Areas on the periphery, particularly east of the original play, "just underperformed," Stark said. "The results coming from our area farther to the west are looking very good."

Continental discovered the Ames astrobleme conventional field in northern Oklahoma in the early 1990s, made a horizontal success on the Nesson Anticline later that decade, was an early entrant in the fracked horizontal Montana Bakken in the early 2000s, made an IPO-level company out of the fracked horizontal North Dakota Bakken, invented the Scoop play and led the westerly extension of the Stack.

What's the secret? Stark said, "Basically, it's being an early entrant in a play and really understanding the geology. It has enabled us to have dominant positions in core portions of these plays. Combined with our operational expertise, you have a winning combination."

In Oklahoma in particular, Barrett added, "Continental has a 51-year history. We operated in a lot of these plays before horizontal. Our understanding of the basin, the rock and how to operate here are huge advantages for us as a company."

Encana Stack

Encana purchased Stack founder Newfield Exploration in February for $5.5 billion in stock and $2.2 billion of debt assumption.

In the control room while Xtreme Drilling Corp. Rig #23 drills the Harris 4HB for FourPoint in Wheeler County, Texas.

PHOTO COURTESY FOURPOINT ENERGY LLC


PHOTO COURTESY FOURPOINT ENERGY LLC

Completions personnel view a frack underway on the Matthews 1-4HC for FourPoint in Roger Mills County, Okla.

Newfield had been operating in the Anadarko since 2001 while Lower 48 exploitation was still vertical, except for the beginning of the fracked horizontal Bakken play.

Newfield began a horizontal program in the dry-gas area of the western Arkoma Basin Woodford in 2005. Beginning in 2011, it pieced together more than 265,000 net acres in the Anadarko, naming the play Stack, for liquids pay from tight Meramec and the Woodford. It revealed the position in 2013.

A distinct name for it was essential in differentiating it from the high-water-cut Mississippian Lime play to the north, according to other Stack operators. The Meramec is Mississippian Lime.

But, in the Stack, it sits under the Chester Shale, which is a barrier between the Meramec and the water. To the north, the Chester seal is eroded, thus the water cut there.

Encana is now the largest Oklahoma oil producer at some 163,000 boe/d, 65% liquids, ending second-quarter 2019. It brought 89 Meramec wells online this year through August. Infill wells' IRR is more than 50%.

Net leasehold in the state is some 360,000 acres. Capex toward its Oklahoma program this year is $850 million. It sold its gassy Arkoma Basin portfolio in August for $165 million.

As its Stack leasehold—focused in Canadian, Kingfisher and Blaine counties—has been HBPed, Encana has moved to pad development. The Meramec is still the primary target, but it's been able to add deeper Woodford into units more often.

The current completion recipe is largely its 2018 version. "Generally speaking, the size of the job—the proppant per foot, the gallons per foot—hasn't changed that much over the last, say, 12 months," said Matt Vezza, Encana vice president and general manager, Anadarko operating area.

What has changed is that Encana brought enhanced completions to the play, accelerating the speed of completions. "We went from pumping our stimulations at 80 barrels a minute to 100 barrels a minute or more."

Reducing time spent has cut frack-job costs, but it is also bringing first revenue closer to first spend. "You get through the 'cubes' quicker."

Encana calls its pad development "cube development." Completing cubes quicker is resulting in a faster learning cycle, Vezza said. "You can apply improvements to the next cube development and accelerate those learnings."

What *is* the difference between cube and pad development? It's several sections rather than a two-section rectangle. In one aerial image, four rigs are at work, side by side—like a zipper frack, but a zipper drill.

"Logistically, we set the location up differently," Vezza said. "There's a lot more efficiency in how we move equipment. That's been a huge win.

"Cube development isn't just about the subsurface. It's also a lot to do with how you manage logistics and supply chain at the surface."

Costs per well have fallen by $1.4 million under Encana to $6.5 million. "We've experienced a significant amount of cost savings due to supply-chain management—how we self-

In just a few months, Encana Corp. has cut Stack new-well costs by $1.4 million, said Matt Vezza, vice president and general manager, Anadarko operating area.

George Solich, FourPoint president and CEO, said the company has greatly reduced drilling time and costs.

With more than 7,500 feet of hydrocarbon-charged rock, FourPoint Energy LLC has "the ability to chase oilier zones, and that's what we're focused on," said Jacob Shumway, vice president, engineering.

source sand and chemicals—and how we set up the location."

Encana is landing between six and eight wells per two-section unit. Putting two of these units together, "we're completing from 12 to 16 wells. We drill them, we rig off, we complete them and, then, we move onto the next site."

From the cube approach, the target is spud to first sales in 90 days.

Scoop and Score

Encana also gained leasehold and production from Newfield in the Scoop. All five of the rigs it had at work in Oklahoma in mid-September were drilling in the Stack, however.

Vezza said, "We do go into the Scoop from time to time. In fact, we plan to move rigs there soon. But, in 2019, about 85% of our activity has been in the Stack."

Its Oklahoma rig count is down about three or four from 11 at year-end 2018. But the company hasn't cut capex. Instead, with cube development, "we are more efficient, enabling us to run fewer and result in the same amount of production on an annual basis.

"We're going to try to stay at around four or five rigs next year. We're just getting more efficient all the time. We're getting better at drilling. We're getting better at completions; going from 80 barrels a minute to 100 just makes our cycle time so much quicker.

"Effectively, we're turning on a similar number of wells, even though we're at a lower rig fleet."

Newfield had launched another Oklahoma play—the Score—in 2017. It's named for testing laterals in the Sycamore, Caney and Osage. It's put a couple of Osage wells in the Stack and, early this year, a couple of Caney wells in the Scoop.

Vezza said, "Those are good targets and it's in our inventory. When we get back in the Scoop in a bigger way, especially the northern Scoop, [the Sycamore] would be something that we work into the plan."

In the Stack, it's landing only in the Meramec and Woodford right now. EUR from the Meramec is 1.3 MMboe on average, about two-thirds liquids.

In well placement, "we think you can fracture the entire Meramec no matter, really, where you place your wells. But geometry of that fracture will be a little bit different depending on where you place your well.

"So we think staggering offers an advantage of more effectively accessing and draining the resource in the Meramec."

Stack logistics

Encana is using Permian and Anadarko completion services and products interchangeably. "We can contractually use our sand volumes between both basins," Vezza said. "It creates economies of scale in contracting and utilization. You can get better rates and contracts."

Although Encana isn't taking sand from one basin to the other right now, being in both plays—each with in-basin mines—is resulting in a contract price that reflects an opportunity to transfer all of its business to mines in either basin. "It helps with managing risk," Vezza said.

Prior to the merger, it might have been using in-basin sand; the completion provider was sourcing it. Today, it is self-sourcing sand and all of it is in-basin.

Before buying Newfield, Encana told The Street it would reduce well costs by $1 million post-merger. There was skepticism. "And then you see it happen literally right out of the gate," Vezza said.

By mid-September, savings per well had further grown to $1.4 million.

Some Permian field personnel were moved to the Anadarko "and they are just phenomenal. The collaboration between the operational teams from across the assets has been remarkable. Our teams are working together to find efficiencies everywhere," Vezza said.

"They know that, if they can save minutes, those minutes add up to hours and those hours add up to days. And they're focused on doing it safely and doing it right. That translates into better wells and lower cost."

There are more efficiencies to come, he added. "We really feel like we're just getting started."

Western Anadarko

Denver-based FourPoint Energy has nearly 750,000 net acres—most of it HBP—in the western Anadarko Basin where the Granite Wash, Cleveland and Lower Cleveland, aka the Marmaton, are the primary targets these days.

It has Tonkawa acreage too, but most of the Tonkawa inventory was developed by Chesapeake Energy Corp. prior to FourPoint taking in that portfolio in 2015.

"While we haven't drilled a horizontal Tonkawa since last year, we are working on a number of locations to drill as part of our 2020 program," said Brendan Curran, FourPoint vice president of geology.

"We have just been more focused on the Lower Cleveland and a couple of areas in the Granite Wash this year. The Tonkawa is probably the most mature of the plays on our footprint."

Last year, FourPoint shifted rigs from the more gas-prone areas of the Granite Wash to the oily Cleveland and Lower Cleveland as gas-basis differentials increased.

Jacob Shumway, vice president, engineering, said, "We've made a concerted effort to increase our liquids mix.

"Given that we have more than 7,500 feet of hydrocarbon-charged rock, we have the ability to chase oilier zones and that's what we're focused on."

The operator has more than 20 pay zones in its leasehold. Since 2014, FourPoint has made wells in 18 benches with "economic success in all of them," Shumway said.

George Solich, president and CEO, said, "All gas-dominated basins have challenges in today's commodity-price environment. But with a strong technical approach, FourPoint has been able to drill some of the best wells in our Midcontinent history by greatly reducing drilling time and costs, being very specific with well placement and optimizing our completions."

FourPoint, whose founders have worked the western Anadarko in start-ups since 2000, is using a 4.0 drilling and completion model.

Having consolidated a great deal of acreage, "we hit the reset button" in 2016, said Scott Goodwin, vice president of operations, "and we brought new technology, better processes and better tools to the basin."

Drilling times have been halved. "So we're drilling wells twice as fast as we were just three years ago," Goodwin said. "And we're also doing that in a more challenging environment in terms of taking them from short to long laterals."

Meanwhile, savings on completions and other services, including using in-basin sand, have resulted in overall savings of 30% of total well costs. On a cost-per-foot basis, 2016 started at about $900; currently, it's about $620.

As the laterals are longer, the savings are further compounded. "That rolls up to millions of dollars of savings per well."

Extended laterals

Tony Cristelli, vice president of land, said the Oklahoma Energy Jobs Act in 2017 has contributed to FourPoint being able to drill multisection laterals, while "other operators that previously held these Oklahoma assets were unable to capture those efficiencies."

The law change permits multisection laterals in any formation—shale or not. Previously, extended laterals were allowed under a 2011 law in shale formations only.

Some of the western Anadarko play is in the Texas Panhandle, where extended laterals were already allowed, but a large portion of the play is in Oklahoma. Shumway said, "So [the Oklahoma law change] was a really big deal for us.

"Not having to drill two vertical portions of hole and now accessing twice the rock, you have an immediate cost savings."

In 2018, 29 of its 43 new wells were extended laterals, Curran said. "FourPoint started executing those long laterals immediately [upon the law change]. We've continued to weight our program toward long laterals."

The company is adding more leasehold where it is strategic. "We're always in the market to some degree," Cristelli said. "But, at this point, we're focused on execution and return on invested capital through the drillbit."

Inventory is 9,000 locations. Among them, between 500 and 1,000 are economic at current commodity prices, assuming at least a 20% rate of return. The stream is about 20% crude oil, 25% NGL and 55% gas.

Spacing, productivity

FourPoint had two rigs at work in September. "We started the year with five," Goodwin said. "As our cycle times have continued to drop, we're drilling more wells with fewer rigs."

Completions tested are more than 2,500 pounds per foot in the play, but the main recipe is 1,000 to 1,200 pounds per foot.

Upon Oklahoma's law change to allow multisection laterals in any formation in the state, FourPoint immediately began landing extended laterals, said Brendan Curran, FourPoint vice president, geology.

C&J Energy Services Inc. completions personnel ready to frack Matthews 1-4HC for FourPoint in Roger Mills County, Okla.

FourPoint is adding leasehold where it is strategic, but, "at this point, we're focused on execution and return on invested capital through the drillbit," said Tony Cristelli, vice president, land.

Facing page, a frack job underway on Matthews 1-4HC for FourPoint in Roger Mills County, Okla.

Curran said, "We're not dealing with rock that is quite as tight as the formations being exploited in the Bakken, Eagle Ford or Permian." Within FourPoint's leasehold, it has increased its completion intensity in some zones; in others, it hasn't.

"I don't know if I would call it larger fracks," Curran said. "We've been doing a lot of work to optimize stage and cluster spacing and the right proppant per foot." Results have improved well productivity between 10% and 40%.

In the Granite Wash, where FourPoint has landed wells in the past three years in six different zones, "you have pretty high rock quality. We haven't had to pull the lever much on the frack size."

Wells are stacked there in about 3,000 feet of pay. Shumway said, "We didn't have to worry too much about vertical communication." Within the stratigraphy, "there are very good barriers between our target zones.

"We have quite a bit of breathing room here. But we're also not trying to push the limits of getting less than maybe 150 feet of separation."

FourPoint is averaging three Granite Wash wells per bench in a section, Curran said, "and we're looking closely at additional benches we can add."

There are more than 100 type-curve areas in FourPoint's acreage; many of them are prolific, Goodwin said. A modern Wash well, for example, can be expected to make 20 million cubic feet (MMcf) and hundreds of barrels of condensate per day.

Wells in more liquids-rich plays, like the Lower Cleveland, have recently come on at more than 1,000 bbl/d of oil, he added.

Cristelli said the western Anadarko's complexity has given FourPoint an advantage in producing it and in valuing bolt-on acreage. "Rigorous internal technical modeling has helped us pinpoint where we want to target opportunities—from both a development and transactional perspective.

"There is more variability in the geology out here than in [a shale play]."

Shumway said, "It takes more from a technical perspective to make sure you're laying out your development plan appropriately."

But, Cristelli added, "our portfolio yields optionality on the commodity-price environment. If we want a more oil-weighted program, we have the flexibility to do that.

"There are also abundant gas reserves; if we want to focus on a more gas-weighted program, we can transition to that as well."

Solich said, "The Midcontinent region remains a world-class hydrocarbon resource with thousands of locations yet to be drilled."

Liquids Arkoma

In the new Arkoma Basin play, Old Ironsides Energy LLC-backed Calyx Energy III LLC is landing horizontals in the Caney, Mayes and Woodford. The Caney is at about 3,000 feet, the bottom of the Woodford is at about 4,700 feet and the Mayes, which is age-equivalent of the Meramec, sits between.

"With all those zones, your recoverable gas per section is in kind of world-class numbers out there," said Cal Cahill, president and CEO.

In this mostly three-county play—centered around Hughes County—in the western Arkoma, it's wet gas. "But nobody wanted to mess with that in a horizontal because it's so hard to get the gas to move [at normal pressure].

"We felt the technology had come along where we could come back here and try it."

Tulsa, Okla.-based Calyx has 210,000 gross, 150,000 net, acres—in Hughes, Okfuskee, Okmulgee and McIntosh counties, about 60% HPB. The Caney covers the entire holding.

For the Mayes, it fracked two wells. The first was marginal with a 10% to 15% type of return. "I think it's probably the oiliest well in the Arkoma. We're seeing cums around 75,000 bbl."

Calyx moved back into more of the Woodford wet-gas mode for the second well. "And early results are similar to what you would see on a Woodford."

"Our first Caney, a 4,000-foot-lateral test was just a test. The one-section lateral shouldn't have been enough to make a well. But that one actually is still producing today," Cahill said. "That's going to be about 2 Bcf, which was enough to get us our money back on a 4,000-foot well.

"So it's been an encouraging play—challenging, but encouraging."

While the formations are at a shallower depth than in the Anadarko, they're cooked because they were deeper at one time—some 10,000 to 12,000 feet deeper. "It got thermally mature."

Btu from the zones ranges from 1,260 to 1,300 for gallons per Mcf (GPM) of 5.4 to 7. "Most of the time, we're about 50:50 liquids-gas."

Calyx's leasehold is about 20 miles northwest of the northern end of the former Newfield Arkoma property. There, production is dry gas. "Our southernmost acreage, we stopped at [the beginning of] dry gas," Cahill said.

"We had to choose: Are you a dry-gas company or a wet-gas company? The plants are going to be built for the recovery of the liquids."

The neighborhood pointed to Calyx doing better with wet gas. "If I have dry gas, I have to compete with the Haynesville, and they're 23 to 27 cents closer to market than I am."

Calyx designed its gas plant to handle 6.2 GPM. Tall Oak Midstream III bought it and finished construction of the gathering system and built a 200-MMcf plant. Other gas-processing facilities in the area are, at most, 2 GPM, if handling any liquids at all, Cahill said.

10-year model

Cahill has worked with the Old Ironsides team dating back to when the latter was part of Liberty Mutual Holding Co. and had 25% nonop interest in Calyx I's assets.

For the current Calyx, Cahill was looking for private equity that could wait as long as 10 years. It was 2014, and Cahill didn't think "the five-year [PE] model, with the volatility we anticipated coming up, was a good model."

The Old Ironsides team was willing to go 10 years. In addition, "they were willing to allow us to not only have a gas company, but a pipeline company, plus a water company." Cahill didn't expect existing pipe in the area—as much as 60 years old—could handle the type of wells he was expecting.

"They would be between 5 and 10 MMcfe a day. So we had to lay pipeline." In addition, building a water system would keep costs "as low as we felt we needed to develop this."

Reusing water pared freshwater need by 5.4 MMbbl in 2018.

Calyx I and II had operated in northern Oklahoma where there is a high water cut. "You know the old belief that 'if 30,000 bbl a day is good, then to inject 80,000 must be better.' That didn't work very well [in northern Oklahoma]. They ended up having issues."

Calyx III picked the wet-gas area of the Arkoma in part because water isn't as great an issue. It has two disposal wells; neither injects more than 15,000 a day. "And our intent is to try to put as little into disposal as possible."

This depends on the frack schedule, though: There is a lot of flowback water after a zipper frack, but very little otherwise. "Typically, they're probably working 20% of the time. It's a timing thing—where you just got hit by too much water, so you have to put some in the ground."

Calyx has 96% working interest in its wells. Production is between 105 and 120 MMcfe right now with an average Btu of some 1,250. In mid-September, it had a three-well frack underway. It dropped its rig in July and was expecting to rig back up at press time for some infill drilling.

NGL prices

NGL prices have fallen precipitously this year. Cahill said, "It was getting crazy enough out there to reassess what we wanted to do. So we chose to settle back down."

He doesn't think the poor price will last as long as some forecasts. "I'm still bullish on liquids, even as horrible as they are right now."

Laterals are two-section and up to 11,400 feet. "Being as shallow as we are, there's a lot where you couldn't even do that—get pipe in it. The farther you go like that, the more your well is not going to be level.

"You're going to have some humps in it and all. Right now, I would say our sweet spot next year will probably be right around 10,000 feet.

"The rock is incredibly broken up in all the zones but more in the Caney and the Mayes than the Woodford. It just has more brittleness to it."

Proppant has been as much as 1,500 pounds per lateral foot and, lately, closer to 900. "Now that's a lot lower than other people. But, since we're shallower, our fractures end up staying open longer.

"We're in that massive sweet spot of where there's relaxation. So the fracturing created with the formation of the basin has really splintered up the rock. It's part of how we get our well costs as low as we are now."

FourPoint's drilling times have been halved, "so we're drilling wells twice as fast as we were just three years ago," said Scott Goodwin, vice president, operations.

PHOTO COURTESY FOURPOINT ENERGY LLC

As the land rush has concluded, consolidation among liquids-rich, PE-backed western Arkoma Basin producers may be promising, said Luke Essman, president and CEO of Canyon Creek Energy-Arkoma LLC.

Facing page, a truck travels to FourPoint's Harris 4HB drill job in Wheeler County, Texas. FourPoint has more than 7,500 feet of hydrocarbon-charged rock with more than 20 pay zones.

Water is about 35 barrels per foot, so one well is about 250,000 bbl of water and 7.5 to 9 million pounds of sand. In 2018, costs were about $425 per foot on a 10,000-foot lateral; this year, about $365. "So you're looking at a 10,000-foot well at $3.6 million.

"We're proud to be called a low-cost operator. There were many years they were calling us 'cheap blank blanks,' but this is kind of our MO. This is when we thrive."

The average type curve is about a 7-Bcf well for the Caney and Woodford; for the Mayes, it's early, but Calyx has defined at least 6 Bcf.

F&D is about 51 cents per Mcfe. "Part of our low costs is that we don't haul water. Operating costs for water is less than 20 cents a barrel to handle. I lay my water pipeline when I'm laying the gas pipeline."

Netback in August was about $2.10, "which is horrid. But, then, I have read that some operators over in the Permian—companies I really respect—have experienced minus-45-cent netbacks. So I can't complain about my $2.10."

Oklahoma legislation that permits extended laterals in any rock in Oklahoma has been a great help in the new Arkoma play, he added. "Our area has a lot faulting. So we need to be able to move around.

"The faulting is good, but you don't want to cross too many big faults, if you don't have to. So [the new law] gives us that ability to put up to three sections together, if that's what we need to do. We had no doubt that we had a profitable play once that became available."

Calyx expects by year-end 2020 to be making up to 175 MMcfe/d, including about 23,000 bbl/d of liquids. If a sale of the portfolio isn't possible, "we'll go into maintenance mode.

"Our declines are very, very flat—especially in the Caney, and it appears to be the same in the Mayes, but it's a bit early before I say that—compared to what most people have to deal with."

The production level can be maintained with 25 wells a year, he said. The Woodford decline rate is "a B Factor 1.5, which is still good.

"We have 10 years. We'll keep going until somebody's ready to buy it."

Develop, rather than sell

Tulsa-based Canyon Creek Energy-Arkoma LLC entered the Arkoma in the spring of 2014, buying leasehold, selling leasehold, buying other leasehold. Luke Essman, president and CEO, said, "I guess it's been kind of a roller-coaster of results in the basin, as you would expect from targeting new benches, new intervals within existing benches.

"And, then, applying modern development, modern completions—both on frack sizes, stage spacing, pumping, all parts of the completion."

Backed by Vortus Investment Advisors, Canyon Creek operates currently in the wet Arkoma play. Recovery per lateral foot from the Woodford and the Mayes has improved a great deal.

"We've seen better liquids recovery [here] across the western edge of the basin, and that's going to be principally in NGL barrels and some crude oil in production."

Reduced NGL prices this year have affected the industry overall. "[Canyon Creek has] achieved quite a bit of our original thesis of what we could accomplish in the basin related to production."

Rather, price "has moved against us," Essman said.

Along the traditional private-equity timeline of a five-year exit target, Canyon Creek would be ready but for the anemic A&D market. Rather, it is transitioning from an "asset generator" model to a "develop mentality," which is occurring amongst many private-equity-backed E&Ps.

"Our best rate of return that we see in creating enterprise value for investors is through development, if we're not going to get significant upside for our asset in the A&D market.

"We're an active oil and gas company; we can convert those undeveloped reserves to developed reserves and create cash flow and value that way."

Encana got PV-10 PDP value for its Arkoma package, which is almost entirely in the dry-gas Arkoma Woodford. "With our drilling results around 30% rate of return, it's good business for us to convert those results into PDP value if the mark is at a 10% rate.

"We'll go through that development process because that's good value-generation for our investors."

Laterals, fracks

Canyon Creek is also landing two-section laterals, depending on faulting. The average length is 8,500 feet. Frack jobs have tested proppant and fluid of as little as 1,000 pounds and 1,200 gallons per lateral foot to up to 2,100 pounds and 2,500 gallons.

"We're seeing diminished return as we increase our frack size and just don't see that we need that large of frack to stimulate the rock efficiently."

Instead, the greatest change is in how stages are being pumped, "what our rates are, what our timing of pumps are, the diversion that we can use in our fracks and even going as far as shutting in and pulsing our fracks to increase our stimulated rock volume from our activity," Essman said.

"That's where we've seen the biggest results. It's not necessarily hitting it with a bigger hammer, but being more precise on how we're fracking. What that process is is giving us better results."

EUR for Canyon Creek in both the Woodford and Mayes is about 13 Bcfe for a 10,000-foot lateral, about half NGL and about 5% crude oil.

In the Mayes, Btu is similar across its leasehold and drilling speed is faster than in the Woodford. "It's more homogeneous rock, so our bits react more favorably vs. the Woodford.

"We're able to run quite a few of our laterals with one bit [in the Mayes]. It's maybe three or four in [one] Woodford [lateral]. So that's going to shave off three or four days of drilling."

The shallow depth of the formations in the play area is "both a blessing and a curse in that it's highly fractured, highly faulted."

Pressure is normal, "right at or a little bit below bubble point for a lot of our production, which is why we get quite a bit of gas and NGL uplift but don't see the oil production."

$19 to $9

In January, Arkoma NGL pricing was 37% of WTI or about $19/bbl. "Today, we're more at 22% of WTI, which is going to be $9 to $10," Essman said.

With 50% to 60% of revenue coming from NGL sales, "it moved our economics significantly lower." Meanwhile, over the years, Canyon Creek's type curves have improved dramatically and costs have fallen.

"The baseline economics still stand. It's just been a significant downward move in NGL pricing that has affected the basin," Essman said.

"And that's not on a differential basis at all; that's just on top-line pricing coming out of the back of processing plants out of the Arkoma."

Canyon Creek and other basin operators intending to exit have switched from that business model to "developing within cash flow, modestly growing production, working on capital efficiency. We're now settling into our assets and are going through more repeatable development."

Canyon Creek may be a consolidator in the basin instead. As the land grab has concluded, operators are collaborating. "The [play] parameters have been set; now it is more a focus on development going forward."

Across all basins, as public companies have mostly suspended further acquisitions, Essman sees "quite a bit of opportunity that's popping up that allows good operating teams to take advantage of development opportunities—and, potentially, acquisition opportunities—to build sustainable companies.

"It's a change from what we saw over the last decade [of selling start-ups] generally to the public market. We're all figuring out how to build sustainable companies with the assets.

"I continue to think we're going to be successful with that and are well on our way to doing that."

At the intersection

Oklahoma City-based Antioch Energy LLC is landing laterals in the new Arkoma play in the Woodford and Mayes and not currently in the Caney.

"We selected our acreage to have what we see as the best of all three, but there's a lot of Caney development already going on," said Nathaniel Harding, co-founder and president of the Outfitter Energy Capital-backed operator.

"So we just focused our current technical and intellectual firepower on Woodford and Mayes."

The acreage is consolidated and majority controlled. It hosts some of the best Woodford wells in terms of IRR in the basin, he said.

"And you also have premium Mayes and Caney geology. Where those three intersect is where we drew our line and were very disciplined in putting together a focus position."

At $2.15 natgas and with NGL prices halving this year, a number of wells in Antioch's area are still at 45% to 65% IRR. EUR is more than 1 Bcfe per thousand lateral feet. A two-section well costs about $4.6 million.

"And the decline is very shallow. So that all makes for what we're seeing as some of the

Antioch Energy LLC isn't seeing frack hits between the Woodford and Mayes during completions, said Nathaniel Harding, co-founder and president.

PHOTO COURTESY FOURPOINT ENERGY LLC

best Woodford economics, including among all Woodford wells over the years in the [overall] basin."

The shallow decline rate has allowed operators in the new Arkoma play to suspend drilling for months without affecting overall production greatly. It's not a treadmill kind of play.

"That's right," Harding said. "We see three things that are unique to the Arkoma that make it possible to quickly build free cash flow."

Capex is low as the wells are shallow. Cycle time from spud to first production can be as quick as two months. "Spud-to-spud cycle time for even 2-mile laterals is two weeks. And they frack really well."

And, thirdly, the low decline. "You don't have the treadmill effect of always trying to just replace your production. Because of those three technical characteristics, you're able to build a free-cash-flow profile more easily than you can in most places."

Non-interference

Woodford and Mayes laterals are landed in wine-rack format with three or four Woodfords and three or four Mayes wells, Harding said. "We've done different pilots, measuring different designs, all verifying that we do not have issues between the Woodford and Mayes, given certain completion-design parameters."

"Even during completions, we won't see frack hits between them."

In the Caney, which is shallower than the Mayes, there is support for five wells per section. Between the two formations, there are a couple hundred feet of ductile gray shale.

"So you have plenty of separation both from completions and production. You have a barrier. You can really just do whatever you want with the Caney with no effect.

"You can space however you want. You can complete however you want with the Caney and have no effect on the Mayes."

The Caney pays but, for Antioch, "it's just a matter of our focus and our bandwidth," thus landing in only the Mayes and Woodford for now. "But we want to double down in this play, so, certainly, in our future we would plan to develop Caney wells."

Antioch is "in a good position because we had a relatively conservative approach on putting together our acreage. That turns out to have been wise in a financial environment that's been really tough throughout the industry."

Free cash flow is "really what this liquids-rich Arkoma is built for." Besides the low capex, fast cycle time and low decline curve, "you're in Oklahoma, where you have a good regulatory environment, services and institutional knowledge, and proximity to the Gulf Coast.

"That's another upside story for why we want to be in the Arkoma: We're able to get access to markets and have some of the best differentials in the Lower 48." □

Rigs drill simultaneously for Encana in a cube development in the core of the Stack play in Oklahoma.

PHOTO COURTESY ENCANA CORP.

BROTHERHOOD OF MINERALS

Sanjit and Shan Bhattacharya built a nimble and flexible mineral buying company that competes on the ground with much bigger companies. And wins.

INTERVIEW BY STEVE TOON

PHOTOS BY JUSTBYOU PHOTOGRAPHY

The popularity of minerals investing has blossomed over the past few years as oil and gas equities have trended downward, but the principals of Red Stone Resources LLC first ventured into the space as unconventional shale plays were heating up. Sanjit Bhattacharya, as a young real estate developer in Lawton, Okla., made his first personal investments in the Bakken Shale in 2007. He was later joined by his brother Shan, a software developer, when Red Stone formally launched in 2012.

Neither had a background in oil and gas.

Each attended Cameron University in Lawton, where their father taught finance, and who also trained his sons in the art of investing. Sanjit began investing in real estate at 19 and while going to school. He received his business degree and sought an entrepreneurial path via his already established real estate development venture.

Shan's computer science degree took him on a path that included factory automation and robotics for Goodyear, missile systems with the Department of Defense and Lockheed Martin Corp., and safety and security software for British firm LDRA.

Both were destined for a much different path.

The company that would become Red Stone grew out of Sanjit's personal minerals portfolio. He recycled profits from sales of minerals interests in the Bakken and Fayetteville shales into new investments, including an early entry into the Scoop/Stack play. Shan left his software career in 2017 to partner with his brother full time.

Today, the still-privately held company, based in Edmond, Okla., holds some 20,000 net mineral acres across four basins: the Anadarko, Appalachia, Haynesville and the Permian, its newest basin entry as of 2017. The firm employs 30 people with regional offices in Oklahoma City, Pittsburgh, Dallas and Marshall, Texas.

Investor You both had careers outside of oil and gas, and no educational nor family background in the industry. What was the impetus for the starting up a mineral acquisition company?

Sanjit I saw the amount of wealth created in the oil and gas space, especially in Oklahoma, which is such an oil-centric community. And I had some friends in the space that had done very well. It piqued my interest. I had the real estate platform and corporate finance background, so how could I use that skill set and transition to another industry that has equal or greater risk adjusted rate of returns?

There is a significant arbitrage between minerals and upstream E&P. There's really

"Being internally funded makes our decision-making process a lot faster and nimbler both on the buy and sell side. It helps our organic buying, and we can be opportunistic on the sell side as well."

—Sanjit Bhattacharya

"We prefer those smaller deals because they allow us to source directly from the land owner. We believe that we can buy smart and stay disciplined and with boots on the ground."

—Shan Bhattacharya

no capex in minerals. There's a saying, you know, that once you spend money on the minerals, it's the last check you'll ever write. If you are dealing with nonop and you're with the wrong operators, you can get drilled to death. It's a lot more risk as well. So it seemed like a good fit for us.

And it's a highly scalable business. The size of the minerals market is $500 billion-plus. If you look at public companies in the mineral space, there is less than $10 billion in market capitalization, so it's barely 2% of the market right now.

Shan We weren't energy guys as a family, but we were finance guys. From a very young age, our father opened up the Wall Street Journal and helped us analyze companies. We would take our lawn mowing money and buy stocks. He instilled in us the value of finding good investments and doing that kind of analysis up front and building a capital base. That was really fun for me.

Sanjit learned how to save his capital better than I did. In his teens and early 20s, he started doing well for himself; he learned the value of capital early and built his dry powder.

Sanjit The oil and gas space is a very capital intensive industry. There are a lot of deals out there, and a lot of people don't have the capital to acquire assets. And we did. So that's what really got us in this space.

Investor How did you take the leap? Did you both quit your other jobs before starting?

Sanjit No, no, no. We made some investments in some overrides in the Bakken Shale in Mountrail County and bought some assets in southeastern Oklahoma in '07 when unconventional drilling was picking up.

Investor Did you start with outside capital or just personal investments?

Sanjit It was just personal money that I'd saved up.

Investor How much did you get started with?

Sanjit I started with $1 million in savings.

Investor And now? Any private equity or other investors?

Sanjit Red Stone is right now funded completely based on the family balance sheet.

Investor Does that limit what you can do?

Sanjit There are some pros and cons with that. We've been able to aggregate a significant number of acres and, with rotation of capital, really scale our platform. Being internally funded makes our decision-making process a lot faster and nimbler both on the buy and sell side. It helps our organic buying, and we can be opportunistic on the sell side as well, which provides us a lot of flexibility.

Investor So how big of a deal can you do right now?

Sanjit Earlier this year we closed a transaction for around $10 million, and we recently closed another transaction for $4 million. But our average size deals are sub-$1 million.

Shan We prefer those smaller deals because they allow us to source directly from the land owner. We believe that we can buy smart and stay disciplined and with boots on the ground. That gets us value early in the process when we buy, so when we put these larger packages together, the arbitrage is significant.

Investor Who are you typically acquiring from—individuals or other mineral companies?

Sanjit Our focus is buying on the ground, organic buying with our multibasin platform. Our strategic advantage is the organic relationships that we have with land owners. We've done thousands of deals, as small as 5 acres to 2,000.

Investor What would you say is your strategy for building your mineral-focused company?

Sanjit We have a very strict and repeatable underwriting process and guidelines. We do a deep dive from a technical basis with the engineers and geos that we have in house. Once all the boxes have been checked from a technical basis, we look at where we can scale in an area. And not by just a few acres but thousands of acres of high-quality rock with best-in-class operators.

The basins we take a look at also have the best-in-class operators with the right amount of capex. You can always have good rock, but if they don't have the money to actually fully drill out those areas, then returns can be affected. We're highly cognizant of that.

Shan We're not the only organization with this particular approach, but we pride ourselves with our intensity and laser-like focus on execution. Our acquisition team members quickly do due diligence when the deals show up—our engineers, geologists, attorneys and finance team—are right there to jump on these deals as they come in. So we can be much more responsive and very targeted.

And it's not just execution, but adding technology, to make sure we have a transparent, traceable, nimble process and then rinse and repeat as fast and as many times as we can to maximize our pricing advantages.

Investor Has the space become more competitive? How is that affecting your strategy?

Sanjit The space has become a lot more competitive compared to five years ago. There's been a lot of institutional money coming in, private-equity portfolio companies, hedge funds, pension funds, insurance companies, family offices and a lot of smaller companies as well. However, we've used some strategic advantages.

Investor Such as?

Sanjit Because we're fully integrated, we seem to be able to be very nimble and fast. We have engineers and geologists in house. We use our technical teams to identify the core rock, then use our aggregation buyers that are in house to buy the minerals. We also have an in-house business development team to sell those minerals if we need to. We use in-house attorneys, of which we have five, to run our title. We're able to streamline this process in a much more efficient manner where we're able to give answers to our mineral owners and close a lot quicker.

Shan On the buy front, to stay sharper and stay ahead of the crowd, we have a digital tapestry across our entire organization. We have a robust CRM system for all of our buyers, marketing automation for targeted mail outs, phone calls and emails with our own software that cleanses the data so we can get through to landowners in more efficient manner.

We've built a proprietary mineral inventory database system that tracks all of our assets and all the associated activity, leasing, drilling units, all tied to it. And we can pull analytics from that to make sure that we track our inventory wells and strategically plan exits.

In addition to that, we subscribe to a lot of third-party data providers. We pull all of that data in, cleanse it and put it in a system in the cloud that does quantitative analysis and analytics. We push that data out with visualization platforms like Spotfire and various types of maps to serve all the stakeholders within the company.

All of this is cloud-based. So even though our teams are based in different locations, we're all hooked together and can access this information in real time and be responsive. So when Sanjit and I go on vacation, we can just crack open the laptop and jump into any deal and look at any map. We can annoy our wives for a few minutes while we get a deal closed and then be right back to them.

Investor So you've used your software expertise to give Red Stone a strategic advantage in the buyer's market?

Shan That's my mandate, to find a way to use technology to leapfrog the paper way of doing business. The entire space is evolving, so we have to evolve faster to be in the upper 10%, 5% of performers in our space. It's not just software but building an organization and linking it all together to internal systems, then applying hardcore data algorithms to pan for gold in all that data. It's not just a think tank in a closet; rather, it's something that's living, tangible and that's implemented day to day.

"All of this is cloud-based. So even though our teams are based in different locations, we're all hooked together and can access this information in real time and be responsive."

—Shan Bhattacharya

"If you buy under good rock and under the best-in-class operators with large enough capex dedicated to that particular area, then the probability of your acres getting drilled is much higher."

—Sanjit Bhattacharya

Investor I noticed you have a data analyst on staff. Why is that role important to a mineral buyer?

Shan That's worked out well for us. There's so much data out here on every well and its production, all the revenue that comes in, all the updated activity that's going on constantly. As the outside world is continuously changing, we have to parse and pool together all that data, stitch it together and make it readily available to serve every part of the organization.

Our data science and software team built out that infrastructure. And once the infrastructure is there, then you have the opportunity to discover and implement the killer apps. You can model out time to development across every asset, every basin, every operator, every bench, and integrate that into evaluating individual deals as they come through.

And you can render any subset of that data with any particular layer across different kinds of visualization interfaces, and slice and dice that data on the fly.

Sanjit We analyze historical data on time to development, for instance, from the time operators permit to the time they put a rig on it to the time they drill it and complete it. That helps us analyze what we can pay for deals we are evaluating. Some operators go from permit to completed wells in four months where others may take 10 or 11 months, and that makes a big difference in internal rate of return over the course of three or four years.

Investor As a mineral holder, you have no control over the development pace and thus presumably your income. How do you strategize around this?

Sanjit The two risks are the lack of control over the development and the speed of development, right? We can't tell the operators, 'Hey, go drill on my acreage.' But if you buy under good rock and under the best-in-class operators with large enough capex dedicated to that particular area, then the probability of your acres getting drilled is much higher.

The other thing we do to mitigate that risk is line-of-sight development. We try to buy minerals that at least have a permit on it that gives us an indication that this is going to get drilled soon.

Investor Are you saying that you don't even make an offer until a permit has been filed for a particular region?

Sanjit That's never 100%, but again, if we do buy minerals that are not under the rig or permit, they're going to be in the absolute Tier 1 area under the absolute best operators, and we don't deviate from that.

Investor Theoretically that sounds like a good plan, but everybody else would be doing that as well. Are these mineral acres really available? Are you having to spend higher than everybody else to get them?

Sanjit Because of the technical expertise, added technology and our deep organic relationships on the ground, that helps us get to those acres faster. Don't get me wrong, it's still a race, but we win a pretty good share of those races.

Shan When that deal hits our table, it goes into the system, and we act on it quickly. We think faster than the average guy in our space. If there's a family member that's looking at five different offers that are closing in 30 to 45 days, and we can close them in five or 10, they tend to go with us.

And often that offer is hand delivered. Somebody shows up to a house, sits down and has a cup of coffee with them putting a face to the name. It's not just a letter in the mail.

Investor Public companies have more of an urgency to get cash flow coming in house, but a private company does not have the same motivation. Are you willing to reach further down the path of development to get better pricing and be patient?

Sanjit That's a different line of sight. We have a certain percentage of our assets that we're comfortable with where it's a medium line of sight, and we price it accordingly.

Investor Are you concerned about E&Ps reducing capex and rig count falling? What do you do in that situation?

Sanjit We stay as focused as we can to keep buying the best rock. As the rig count falls, operators will focus on the absolute best rock, so the rigs actually start coming together and more in focus in certain areas. As prices drop and rigs drop, only the best of the best gets drilled. And if your minerals are there, and it still doesn't have a rig on it, the chances of you getting drilled increases, because Tier 2 and Tier 3 areas go away, and only the Tier 1 gets focused on.

Investor Do you have any aspirations to expand to other basins?

Sanjit We're currently focused on these basins, and right now we're sticking to our knitting on these four. But that being said, never say no. We're opportunistic. We know the Eagle Ford and the Powder River, and we got started in the Bakken. If we see a seismic shift of rigs and capital going to a different basin, we have the technical expertise to dive into it and make a run at it.

Investor What's ultimately your goal? Do you have an exit strategy or is this a long-term hold?

Sanjit We buy, we aggregate and then we sell, as long as it meets our underwriting thesis. Having said that, we are close to an inflection point: At the right time, we would be open to consider a capital partner as long as there is alignment and good chemistry. The capital partner would need to believe in our vision, strategy and team, and help us scale and grow even faster than what we have been able to accomplish on our own.

Shan Sometimes when I ask Sanjit if he ever wants to just sit on a beach and relax, he says, 'What's the fun in that?' We enjoy this, so the machinery keeps improving and evolving, and we enjoy coming to work every day and doing the business. So even as we make exits in our assets, we acquire others to take their place. We have no plans for a corporate exit in the near future. □


WE'RE GEARED
TO CREATE VALUE.

CONSOLIDATION ON THE CLIMB

There's a near-consensus on consolidation, but who are the buyers, and what's the right price?

ARTICLE BY
CHRIS SHEEHAN, CFA

There's little question that U.S. unconventional resource development has moved into manufacturing mode from what once was an era of nimble E&Ps aggregating acreage and testing target zones. Now a premium value is accorded economies of scale, an advantage enjoyed by integrated and many large-cap producers, while small/mid-cap (SMID) E&P stock valuations have been deeply derated.

With E&Ps facing a narrowing range of options, uncertainty is in the air. Access to capital markets, both equity and debt, is no longer available to many E&Ps. A new set of investors is increasingly pressing for "organic growth" and free cash flow (FCF). Priorities include cutting costs, extending liquidity, bolstering balance sheets, reducing FCF breakeven and returning money to investors.

No small challenge. Or maybe even mission impossible, if striving to reach all the above goals at once.

But what if consolidation can pave the way to greater scale and more easily attained economics? Could consolidation revive investor interest in energy, even if oft called-for mergers have—perhaps ironically—been met mainly by market sell-offs? Could an answer be to structure mergers as "zero premium" or "low premium" transactions among so-called "mergers of equals"?

Certainly, consolidation has worked in the past, especially when valuation disparities are wide. Even recently, management of Chevron Corp. described its now-expired attempt to take over Anadarko Petroleum Corp. as "an opportunistic bid" that was prompted by the sell-off of the E&P sector in last year's fourth quarter, according to a recent RBC Capital Markets report.

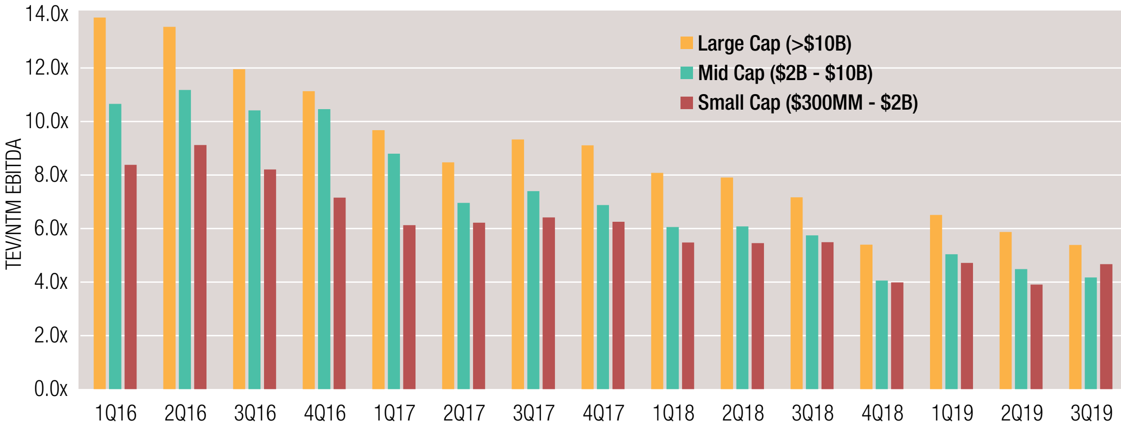
At the time of Chevron's bid for Anadarko, the average valuation held by Chevron and four of its peers was roughly 25% above that of Anadarko and eight other E&Ps, according to RBC. As of late August, after "continued derating of the E&P space," the valuation gap was "much more extreme" at a 60% premium to the E&P group, said RBC, "although notably this is skewed by a few names."

Compression of values

Away from the majors, historical valuation metrics may have less relevance, as much of the E&P sector has seen a sharp compression in values, with SMID-cap names losing several turns in enterprise value-to-EBITDA, or EV-to-EBITDA, ratios. Collectively, the sector's stock values, as currencies for potential transactions, have largely fallen to levels unforeseen a few years ago.

So, with seemingly most E&P valuations under pressure, is a spree of consolidation set to get underway?

Historic Forward EBITDA Multiples



Source: Seaport Global Securities LLC

"There's a greater need to achieve scale in operations, especially with the advent of unconventional resources," said Charles Meade, senior analyst with Johnson Rice.

Clearly, benefits can accompany a combination, particularly in the areas of general and administrative (G&A) expenses and potential synergies in field operations if adjoining or nearby acreage exists in a common basin. But, equally, other issues abound: Which of the two executive teams will prevail? Will combined leverage blow out the balance sheet? What's a good premium to pay, if any?

In terms of arriving at the "right" premium to pay, one of the earliest advocates of a zero premium combination has been Kimmeridge Energy Management Co., led by founder and managing partner Ben Dell. He remains a staunch advocate of consolidation, describing the energy sector as "massively disaggregated" and in need of "single basin champions."

In addition to backing E&Ps as a private-equity (PE) sponsor, Kimmeridge has held positions in a number of publicly traded energy securities, including that of PDC Energy Inc. Dell actively encouraged the board of PDC Energy to evaluate a possible combination after Kimmeridge had built a position, mainly in January and February of 2019, of a little over 5%.

Zero premium structure

"What the industry needs is zero premium combinations, where synergies and cost reductions increase returns to the shareholders, and SG&A [selling, general and administrative] is removed and management compensation is redesigned on absolute performance," Dell told *Investor* in the spring of 2018. Also noteworthy was a position paper that Kimmeridge posted to its website on the subject of zero premium mergers.

"Investors have seen very few instances of these initial synergies actually materializing into improved financial performance after a deal has closed," said Betty Jiang, CFA, senior E&P analyst at Credit Suisse.

"Since the reward for scale is so great," the paper said, "we believe E&Ps should seek to consolidate with similarly sized companies, ideally on a zero premium premium basis." Counterintuitively, it said with some insight, "a zero premium transaction could end up having the highest uplift."

As it turned out, PDC Energy entered into a definitive merger agreement to acquire SRC Energy Inc. in August 2019. The all-stock deal was, in effect, structured as a merger of equals, although some pointed to terms amounting to a slight, 4% "take-under" of SRC Energy. In post-announcement trading, the stocks of both PDC Energy and SRC Energy traded measurably higher.

PDC's stock ended the day up 17.4% at $29.65 per share; SRC's stock was up 12% at $4.65 per share.

The positive market reaction allowed investors to breathe a sigh of relief. Reflecting a reversal from earlier negative reaction to a series of mergers structured with significant takeover premiums, a research report by Johnson Rice & Co. was soon issued with the title, "How did the PDCE/SRCI (combination) break the run of (1 + 1 < 2) mergers?"

"The market wants to see consolidation among similarly sized companies, with no premiums, where the fruits of those combinations accrue to shareholders, and where you can be comfortable that you're not giving away a premium for future synergies," observed Dell, following the PDC-SRC merger. In addition, without a premium being paid, short sellers have little role to play, he noted.

Short sellers minimized

"When you look at the investor base that's left in the energy group, there are not a lot of true, long-only investors left," he commented. "So, if you pay a premium, the hedge fund community is going to sell short your stock pretty aggressively. But if you have a merger of equals, there's no negative story out there to short. There are only cost synergies and benefits."

Kimmeridge had earlier pressed PDC Energy to consider a consolidation strategy, and Dell was quick to commend the company for executing "essentially what we had recommended.

"Fundamentally, these companies are doing the right thing and should be applauded, especially SRC's CEO, Lynn Peterson," he said. "SRC is the one really making the brave bet, being the smaller of the two, and agreeing not to take a premium, realizing that's better for its shareholders. In the end, the SRC investors got a big uplift in their equity through the transaction. That's the key element."

Single basin champions

Further industry consolidation is likely to continue across multiple basins, according to Dell.

"The Niobrara in the D-J [Denver-Julesburg] Basin is arguably a single field. The question is, 'Why do you want 10 operators in a single field?' Whether you see operators consolidating to create a dominant player, or 10 E&Ps forming a joint operating agreement [JOA], it comes down to taking costs out of the development of a single field."

In terms of what constitutes a target level of scale, Dell pointed to 200,000 barrels of oil equivalent per day (boe/d), a threshold he estimated half the industry did not now reach. The PDC-SRC combination, on a pro forma basis, had output of nearly 200,000 boe/d in the second quarter. Of this, roughly 166,000 boe/d was produced in the D-J, making it the second-largest producer in the basin.

However, over time, Dell could see little reason not to consider further possible avenues to add scale.

"If I were PDC-SRC, I would look at consolidating with the D-J position held by Noble Energy [Inc.], or creating a joint venture with Occidental Petroleum Corp.'s assets [previously owned by Anadarko Petroleum Corp.]," he commented. "It doesn't necessarily have to be a merger. It can be a JOA, or a joint venture, or a single field unit operating agreement."

Why stocks 'get hammered'

As indicated earlier, a recent Johnson Rice report focused on a conundrum regarding consolidation in the energy sector. It explored two questions.

First, why is it that, after investors have "clamored for consolidation," the stocks taking part in a merger frequently "get hammered by the market?" And, second, while not unusual to see an arbitrage narrow on announcing an all-stock acquisition—with the bidder's stock falling and the target stock rising—why would "the combined market cap of merging companies (end up) lower post-deal than pre-deal?"

In an analysis by Johnson Rice of 20 mainly E&P mergers in the energy sector, two findings came to light. One was that, post-merger, about half of the combined equity values of companies involved in a merger trailed their benchmark (for E&Ps, the XOP, or S&P Oil & Gas Exploration & Production ETF). A second was that "more than half" saw an absolute decline in combined market cap vs. pre-deal levels.

In theory, commented Johnson Rice, "investors who believe in synergies should reward the combining companies via increased market capitalization. But this hasn't been happening much in energy."

So what are some of the pitfalls that, in practice, may befall E&P mergers?

One of the key issues relates to the synergies projected in a merger being credible, noted Johnson Rice. Transaction costs in mergers are real and incurred upfront, whereas synergies tend to be less tangible and are only realized over a period of years. Another relates to balance sheet strength: What may be a de-leveraging transaction for one party may be one that levers up the balance sheet of another.

But among the chief drivers of mergers is still the issue of scale and what to do with E&Ps that are sub-scale. And the problem is unlikely to be solved by combining two sub-scale producers to create a third that is also still sub-scale, whether in the E&P or in the oilfield services sector, said Johnson Rice.

'Engineering and production'

"There's a greater need to achieve scale in operations, especially with the advent of unconventional resources," said Charles Meade, senior analyst with Johnson Rice. "The industry has become more focused on engineering and optimization in unconventional plays. The joke is that the sector used to be called 'exploration and production,' and now it's 'engineering and production.'"

Given the resource is largely now a known factor, it's "more a matter of how much you can get out and at what cost," he continued. "Scale is one of the things you need to have to run an efficient rig and completion operation, and also spread out the fixed costs of operating over a larger base of production. That's a different game than it was 10 years or more ago."

Although it may vary by basin, Meade pointed to three rigs and one completion crew as typically being the "minimum acceptable" scale, while five to six rigs and two completion crews would be preferable in order to afford E&Ps greater flexibility in operating. "Just at that level—five to six rigs and a couple of completion crews—that's a $1 billion capex program. That's the big drive to merge."

Assuming roughly $400 million of EBITDA is needed to fund a minimum three-rig, $400 million annual capex budget, as well as an EV-to-EBITDA multiple of 4 times, this would imply an enterprise value of around $1.6 billion. In turn, assuming a leverage ratio of net debt-to-EBITDA at a conservative 1.5 times, or about $600 million, this would imply a market capitalization of roughly $1 billion, noted Meade.

Stakes at the table

"It's hard to get investors to care if you're below $1 billion market cap or even $2 billion," he said. "I'm not saying that's right, or it will always be that way, but that's the way it is

G&A METRICS FOR SMID-CAP E&Ps

Tudor, Pickering, Holt & Co. (TPH) conducted a study on general and administrative (G&A) expenses borne by the E&P sector within a framework of a variety of metrics, including G&A per barrel of oç equivalent (boe), G&A as a percentage of EBITDA, G&A as a percentage of market capitalizat²n, etc.

"We expect the subject to remain topical," said the TPH study, given the potential for increased M&A activity in which "G&A is typically the lowest hanging fruit to realize tangible synergies." The TPH study examined G&A levels at not only small/mid-cap (SMID-cap) public companies, but also at private E&P companies.

"The punch line is that private names are blowing away SMID-cap names (and some large caps) on cost metrics," said TPH. For oç-oriented names, private operators spent an average of $1.65 to $1.70/boe on G&A, markedly less than the average $2.90/boe for TPH's oç coverage. For gas-oriented names, private E&Ps' G&A fell into a range of 50 to 70 cents/boe vs. $1.20/boe for TPH's gas coverage.

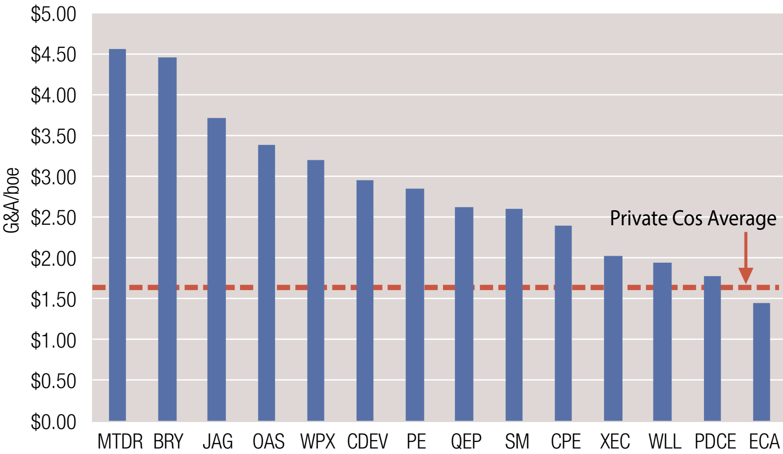
Given SMID-caps' substantially poorer G&A metrics vs. large-cap and private sector E&Ps, "many SMID-caps lack the scale or inventory to compete for investment dollars relative to large-cap peers," said TPH. Its report pointed to two courses of act²n: "pursuing mergers to gain scale whçe driving tangible cost synergies;" and lowering G&A via "right-sizing of the organizat²n into 2020."

The SMID-cap oç group has the "widest dispers²n" of G&A per boe metrics, said the TPH report. Data showed only Encana Corp. to have a G&A metric below the private E&P range of $1.65 to $1.70/boe, whçe nine SMID-caps showed G&A at least twice that of the private E&P average. Following mergers by Callon-Carrizo and PDC-SRC, TPH cited expected G&A reduct²ns of 31% and 21%, respectively.

For the SMID-cap oç sector as a whole, if G&A per boe moved toward a "best in class" level—put at about $1.50 per barrel, or less—the savings would come to roughly $680 mçl²n. Using a 10% discount rate to arrive at a present value, and then applying a 6 times multiple, this could create a boost in equity value of some $3.76 bçl²n to $4 bçl²n, or a jump in equity appreciat²n of 10% to 15%.

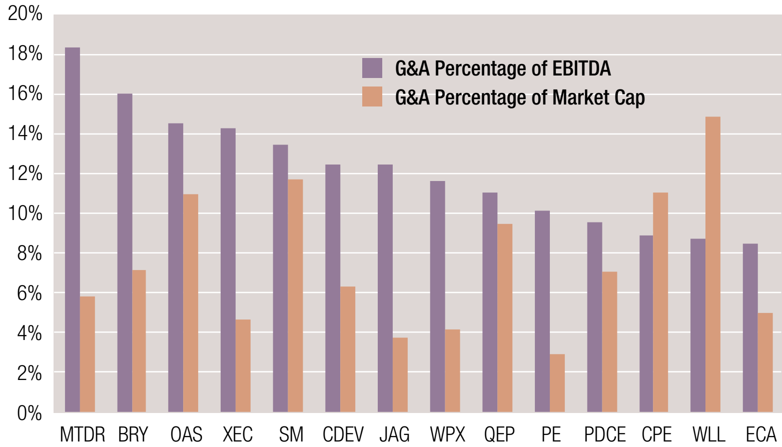
Looking at the natural gas sector, the TPH report said that whçe M&A activity was "less likely in the near term given absolute debt levels and our bearish view on the forward curve, G&A reduct²ns could materially help some names weather a $2.25 to $2.50/Mcf [thousand cubic feet] environment." TPH data showed only one E&P, Cabot Oç & Gas, with G&A per boe that was lower than the private sector's 50 to 70 cents/boe.

2019E G&A Spend Per Boe For Select SMID Caps



Source: Tudor, Pickering, Holt & Co.

2019E G&A Over EBITDA, Market Cap



Source: Tudor, Pickering, Holt & Co.

right now. For an E&P trying to be an efficient operator in an unconventional play, those are the stakes at the table right now. The market is saying, 'If you're not at least that big, then it's unlikely you'll be good at what you're doing.'"

In addition, in the near term, E&Ps are striving for more efficient levels of G&A, as measured on a per barrel of production basis, said Meade, "but I don't see that as the big, strategic driver."

Obviously, a number of factors played a role in each of the 20 M&A transactions reviewed by Johnson Rice in its report. That said, deals received poorly by the market generally reflected two factors: one involving migration by E&P into new basins, where synergies are less identifiable; and another involving mergers where—even after combining—the merged entity is still at sub-scale levels.

As for moves into a new basin, "I don't want to suggest there's no benefit from increased scale, but they are certainly diminished as compared to benefits of an intra-basin increase in scale," said Meade.

The positive reception received by a handful of other deals, such as the PDC-SRC transaction, was attributed to several factors: synergies viewed as being credible; transactions structured with zero or low premiums, providing little room to argue the acquirer was 'paying too much for this'; and combined leverage that was low, since "leverage has been just anathema in this market," he added.

"The deals that worked have typically been intra-basin consolidations, where synergies are more credible and deals have low leverage metrics," Meade said.

Meade is cautious, however, as to how broadly—or for how long—this formula may be applicable.

"I don't think there's a single magic formula. But this is one formula that, in the current environment, seems like it's going to work," he said. "That's not to suggest it's a formula that will work forever. But it seems to be what the market would like to see now."

The PDC-SRC combination is described as a "no-premium premium deal" by Betty Jiang, senior E&P analyst with Credit Suisse. A positive reaction by investors may reflect the M&A market becoming more attuned to investor demands for mergers of equals, but she is not expecting a short-term swirl of similar deals due to a variety of factors that are likely hard to replicate.

First, why did the market effectively reward SRC Energy with a post-announcement takeout premium?

"It was a good deal and an accretive transaction, particularly in terms of FCF and with management committing to an increased return of FCF to shareholders, which should support the continued positive performance of the stock," said Jiang. "SRC also had a very good balance sheet. By combining with SRC, PDC's balance sheet remains very good. They're not sacrificing their balance sheet in the merger."

'Clear, deliverable synergies'

The combination also brings together two sets of assets with "clear, deliverable synergies," she said. In addition, any prior concerns of inventory depth at PDC are put to rest, as it is adding 86,200 net acres of core Weld County acreage for a total of 182,000 net acres. This gives PDC, now the second-largest producer in the D-J, about 10 years of risked inventory in the basin at its 2020 projected pace of drilling.

These positives helped overcome what was a series of deals that failed to deliver, according to Jiang.

"What we've seen in the past is that E&Ps have tried to justify deals with synergies, mainly G&A and some operational synergies," observed Jiang. "However, investors have seen very few instances of these initial synergies actually materializing into improved financial performance after a deal has closed. Post-deal, the economics have rarely translated into one-plus-one equals more than two."

As a result, this has "created a reluctance on the part of investors to pay for synergies upfront in the form of an M&A premium," according to Jiang. "And if the market doesn't believe in the synergies, or doesn't want to give operators credit for those synergies upfront, then the market value of the premium paid in a deal is typically taken out of the buyer's pro forma market cap."

'Basin jumping deals'

Another instance of investors being loathe to assume up-front synergies involves "basin jumping" deals, where a buyer goes into a basin in which it lacks an operational track record, said Jiang. This may take shareholders by surprise, prompting questions such as not only, "Why go into a different basin?" but also, "Are there unknown issues with your current asset portfolio?"

This may have contributed to negative reaction to deals such as Callon Petroleum Co.'s purchase of Carrizo Oil & Gas Inc. Not only did Callon pay a 25% premium, but the acquisition also took Callon, previously a pure-play Permian operator, into the Eagle Ford, and "that de-rated the shares," commented Jiang. "The market reaction reflects in part an additional discount for multibasin E&Ps vs. pure-play Permian names."

An early indication of the PDC-SRC deal potentially bucking the negative trend of M&A deals came in the wake of a news item—but no formal announcement as yet—suggesting a merger.

"With no additional details, PDC traded up on the headline," recalled Jiang. "This was very different from any of the other merger headlines we've seen. The initial reaction to the PDC-SRC deal showcased that the market had already approved the synergistic benefits of having two companies combine that are located right next to each other and are trading at similar valuations.

"The uncertainty was what price was going to be paid," she continued. "After the deal was announced, and terms called for a slight discount to Friday's closing price—in essence a 'no premium' deal—then it really outperformed. It showed that the synergies were upside rather than baked in upfront. The market could see identifiable synergies: the acreage right next to one another, G&A that clearly can be reduced, etc."

So does the PDC-SRC deal offer a sure-fire recipe for success that other E&Ps can also implement?

"It's a success case that may make other managements think of it as a possible path," commented Jiang. "At the same time, very few managements are really willing sellers at little to no premium at current stock price levels. If you have good assets, a good balance sheet, and your stock is at or near an all-time low, do you expect E&Ps to rush into a deal with little to no premium?

"On the other hand, buyers say their shareholders are pressuring them to not do deals where they pay up for assets, which means they can offer only very little to no premium. It's difficult for the two sides to come together. The ones that really need to consolidate for financial reasons tend to have higher leverage. And it's difficult for an E&P with a good balance sheet to buy one with a bad balance sheet."

A 'slow, arduous process'

Steve Trauber, head of global energy investment banking at Citi, sees consolidation in energy as likely being a challenging process—but an imperative one—given a variety of social and other issues.

"I think interest in the sector will grow as consolidation becomes increasingly necessary," said Trauber. "It is going to be a slow, arduous process. It is likely to take several years for the sector to consolidate into a much stronger position. Companies are going to have to merge to survive. There's no doubt about that."

According to Trauber, "almost everybody in the sector recognizes that consolidation is the right thing for the sector. People aren't holding out, saying, 'Look, I don't think it's the right thing to do.' Everybody recognizes it. The problem is that everyone thinks that they are going to be the buyer. There's not a lot in it for them financially to sell."

"Almost everybody in the sector recognizes that consolidation is the right thing for the sector," said Steve Trauber, head of global energy investment banking at Citi. "The problem is that everyone thinks that they are going to be the buyer."

Trauber praised the PDC-SRC deal, in which Citi advised SRC, saying "the reality is that they're not selling; they're combining on a stock-for-stock basis. These are the deals people want to see. You're not transferring wealth from one side to another. The value being created from real synergies is accruing to the shareholders. These types of deals have to happen more readily."

As for the Callon-Carrizo transaction, Trauber said a natural arbitrage trade of 5% to 8% was typical in a takeover, and the steeper selloff may have reflected doubt about the size of synergies, a move into a new basin and an expectation among some investors that Callon would be a takeover candidate rather than an acquirer. "When it goes the other way, people sit on the sidelines," he commented.

However, Trauber viewed both PDC and Callon as going on to be "natural acquirers" in their basins.

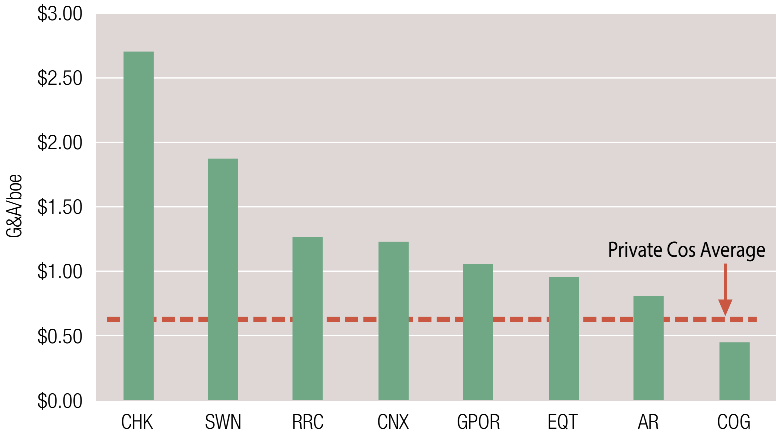
"At the end of the day we have to have some natural acquirers who can consolidate basins and take out costs," he said. "There is just too much cost in these companies, and there's too much leverage. Because they're small, the cost of debt is so much higher. They need to get bigger so the costs of equity and debt can decline and so they can generate substantial returns in excess of the cost of capital."

'A better buyer'

"Once you get bigger, you become a much better buyer because there are a lot of E&Ps out there that don't have the scale to be a buyer," he continued. "This sector is consolidating, and there will be winners and losers. The winners will be those that do smart deals and get bigger."

According to Trauber, combining two $2 billion or $3 billion E&Ps should only be "a first step," since the advantages are not much greater than with a $3 billion company. "Until these guys get over $10 billion, they're still too small," he said. "Every company out there that is sub-$10 billion knows they need to buy or sell. The question is: 'Who is the right buyer, and which ones are going to be sellers?'"

2019E G&A Spend For Gas-Oriented E&Ps



Source: Tudor, Pickering, Holt & Co.

In terms of transactions getting done at recent low valuation metrics for E&Ps, "you've got to look at what is the relative value of what you are buying vs. the relative value of what you are selling in a stock-for-stock transaction," said Trauber. "You're giving up your currency at a low value, but you're buying something at an equally low level. And the synergies are what help give you scale."

In two or so years, the energy sector should be "stronger" and comprise producers that may be fewer in number but capable of making "substantial returns," predicted Trauber. "But until they combine, take costs out of the business, increase scale of operations and drive greater efficiencies, it's hard to see investors coming back to the sector."

Michael Bodino, managing director of E&P and midstream investment banking at Seaport Global, offered a historical perspective of M&A trends as well as a forecast of M&A activity.

The recent energy environment is somewhat reminiscent of 1999, when Dot.com investing was "all the rage," and the energy sector's access to capital was "nonexistent," recalled Bodino. This led to a surge in M&A activity during the 1999 to 2000 period marked by a number of highly notable transactions: what is now BP Plc buying Amoco Corp, Chevron Corp. acquiring Texaco Inc., etc.

While Bodino noted recent A&D activity has trailed prior periods, he counted 10 public energy M&A transactions in a trend that began in March of 2018. In terms of public mergers during the past 18 months or so, this was roughly equivalent to the total of M&A transactions completed during the prior four years from 2014 to 2017, he said.

"The bigger picture is that we expect to see another 10 transactions over the next 18 months," said Michael Bodino, managing director, E&P and midstream investment banking, Seaport Global.

Reading the tea leaves

"My reading of the tea leaves is that we're going to see quite a bit of M&A activity through next year—and maybe beyond that," he said. "The bigger picture is that we expect to see another 10 transactions over the next 18 months. We've talked to a lot of companies that are receptive to having conversations if it makes sense. No one is drawing a line in the sand and saying, 'never.'"

Bodino cited three ingredients generally needed in a successful merger. First, "it's got to be accretive," meaning an E&P with a higher multiple stock acquiring a lower multiple one. Second, it should be de-leveraging, leaving investors with a "financially healthy company." Third, it has to add inventory that "competes for dollars on an economic basis in the combined company."

With investors urging E&Ps to generate FCF, "the only way you're going to free up your capital is to cut costs and reduce capex," he continued. "And that means you have to reduce leverage, which means you have to reduce G&A, which means you've got to get to scale. Very few smaller E&Ps are successfully growing organically out of cash flow after servicing debt and paying their G&A."

In a study by Seaport Global of SG&A as a percent of EBITDA, looking at E&Ps with an enterprise value of less than $10 billion, SG&A expenses accounted for 23% and 18% of second-quarter 2019 and full-year 2019 estimated EBITDA, respectively. The above figures were calculated on a simple average basis, noted Bodino, and on a weighted average basis would come in at a reduced level of around 10% to 15%.

"If you can cut $100 million of duplicative G&A, and assume a five multiple of EBITDA, this would translate into $500 million of equity that could be created by a merger," observed Bodino.

'The best athletes on the field'

Of course, any merger is at risk of involving considerable downside from job losses, although in some cases employees may be able to "transition," said Bodino. "There are very few deals where it is, 'thanks, we don't need anyone.' The survivor wants the best athletes on the field. They go through a lot of due diligence to make sure they have the best team possible."

Even if M&A lies ahead, Bodino signals caution about assuming it will follow the zero premium model.

"We don't have many examples of zero premium mergers, just the PDC-SRC. That one doesn't mean we're going to have a bunch of zero premium transactions," said Bodino. "I think the premium is a function of relative value as much as anything else. The problem is that the relative value of a lot of these E&P companies is relatively low, and they're under pressure from shareholders to perform."

While exactly how mergers are structured may be open to debate, the dynamics of the broader market may in the end force the hand of E&Ps.

"We've got to get bigger to be relevant," said Bodino. "Twenty-five years ago we used to define small-cap stocks as less than $1 billion. Today, in the broader market, small-caps are considered to be sub-$10 billion. When you look at the energy sector, we really have an amalgamation of small-cap names. There are very few that qualify as mid- or large-cap when you compare them to the broader market." □

OILFIELD SURVIVALISTS

Caught in a cutthroat competition, oilfield service companies are pitted against one another for business, E&Ps are taking advantage of an oversupplied market and a recognized-need for consolidation is crawling along.

ARTICLE BY
DARREN BARBEE

Oilfield service companies are perhaps faster, leaner and more efficient than they've ever been—and it's killing them.

Veteran executives and observers don't mince words. Debt-laden service companies are "holding ticking time bombs." Some are adopting capital austerity budgets. In a crowded group of companies, most don't have the leverage to negotiate good rates with their upstream customers.

And time is slipping away.

"There are a number of players in our space with a lot of debt, probably not great prospects. I do think you will see more restructuring," Liberty Oilfield Services CEO Chris Wright told *Investor*.

The services industry is a world turned upside down. That some companies won't survive may be a given. But the sentiment among industry leaders is that for the sector to thrive, the best-case isn't whether companies will fail—but if enough will.

Jim Wicklund, managing director at private-investment bank Stephens Inc., said there are roughly 100 public oilfield service companies globally, about 80% of which are microcaps worth less than $1.5 billion.

Wicklund sees a need to radically thin the herd to about 25 or 30 companies.

"There are sub-sectors inside of service, and that's why I'm saying it'd be 30. You need three to five players, big players, in every sub-sector," he said.

The service industry's oversupply takes place against the backdrop of a relentlessly dropping total U.S. rig count. In the first nine months of the year, an average 5.6 rigs were taken off the field each week. The week of Jan. 4, the rig count stood at 1,075. The week of Sept. 27, the count had fallen to 855, according to Baker Hughes. For land rigs alone,

PHOTO COURTESY LIBERTY OILFIELD SERVICES

Inside a data van's "nucleus of operations," oilfield service personnel monitor operations in the Denver-Julesburg Basin.

Oilfield Service 2019 Bankruptcy Filings

Filing Date	Company	Total Debt
Feb. 15	Cornerstone Valve LLC	$7,909,737
Feb. 15	Well Head Component Inc.	$840,406
March 11	Gasper Rice Resources Ltd.	$2,484,425
June 10	Longhorn Paving & Oçfield Services Inc.	$3,131,973
July 1	Weatherford Internat^{2}nal PLC	$7,427,067,000
July 3	Compress^{2}n Generat^{2}n Services LLC	$4,212
July 11	Shale Support Global Holdings LLC	$127,899,025
July 11	Sçver Creek Services Inc.	$11,922,381
July 15	Emerge Energy Services LP	$48,322,110
July 26	MWM Oç Company Inc.	$2,323,827
Aug. 23	KP Engineering LP	$29,528,892
Aug. 26	EPIC Companies LLC	$146,447,757
Aug. 31	Industrial Piping Solut^{2}ns Inc.	$639,252
Sept. 2	Pangea Industries Inc.	$2,292,047
Sept. 10	360 Internat^{2}nal Inc.	$1,784,518

Source: Haynes and Boone LLP September Bankruptcy Tracker Report

"More than half of companies out there are for sale," said Chris Wright, CEO of Liberty Oilfield Services. "There's a desire in the industry [to consolidate]."

the past 12 months ended in September saw nearly one in five taken offline.

If the oil rig count is seems to be on a familiar angle of descent, it's because horizontal gas rigs have already skidded over the same runway.

In 2008, the gas rig count peaked at about 1,600. By January 2016, it fell to 148 gas-directed rigs, a 90% drop, according to Jeffries.

Yet, gas production "went up every year," Wicklund said.

Three years later, Wicklund sees the same pattern. The rig count drops, but "we're still expected to be a million barrels a day oversupplied in 2020," he said. "This could be the market we're in for the next couple of years."

With too much equipment and too many companies, nearly all are suffering. The OSX index of publicly traded oilfield service companies shed about 20% of its value from January to September.

"Collapsing earnings combined with banks that are generally unwilling to refinance debt mean rafts of service companies may end up in the hands of their lenders," said Richard Spears, vice president and co-founder of Tulsa, Okla.-based market research firm Spears & Associates Inc. "That rarely works out well for employees or customers."

Next year, Spears told *Investor*, "will be the battle of the balance sheets."

That battle has begun. Companies that cut deeply during the downturn are now starting to saw past the bone and into the marrow.

National Oilwell Varco (NOV), for instance, slashed $3 billion in personnel costs and $1 billion in overhead during the three years of the downturn. In first-quarter 2019, the company began hunting for another $120 million in annualized cost savings.

In the second quarter, the company enacted a voluntary, early retirement plan and embarked upon the redesign of several administrative functions to move closer to a shared services model, NOV CEO Clay Williams said on a July 30 earnings call.

With E&Ps living under a mandate to live within cash flow, an oversupplied service market allows E&Ps to gravitate toward the cheapest bidders.

"If that means screwing your service customers for right now, so be it," he said. "So, right now the lowest [priced] job wins."

The squeeze

In August, Key Energy Services president and CEO Rob Saltiel told analysts listening in on an earnings call that the road so far in 2019 had been uneven.

Upstream companies no longer plan their budgets on an annual basis. "The fact is that our clients now manage their budgets on a quarterly, if not monthly basis," he said. Key Energy did not respond to requests for additional comment.

To their credit, many oilfield service companies continue to drive improvements in efficiency, which allow upstream companies to realize better returns even as oil prices rarely stray above $65 per barrel. In the first six months of 2019, the median price of oil was $56.60, according to U.S. Energy Information Administration data.

Spears said E&Ps are taking advantage of service-sector weakness and the lengths to which the industry will go to get business.

"This is an excellent time to be an oil company and a terrible time to be a service company," Spears told *Investor*. "Service firms have almost no ability to negotiate favorable contract terms because the competitor down the street will work for a dollar less."

He added that 2020 is already shaping up as a battle of the balance sheets. As the new decade begins, service company prices could increase within six months of a climb in drilling activity—but, Spears said, "is that a 2020 event?" Service companies have become, in a sense, "fairly commoditized" and, as a result, are stretched thin, Wicklund said.

"Unless you're very special in some way, you're just being buffeted by whoever bids the lowest."

That sets up a near-impossible challenge for services companies that, just like E&Ps, are being judged on their ability to return capital to investors.

The squeeze on oilfield service companies has a crucial flaw, Wicklund argued. Service companies need to reinvest in equipment.

"Eventually, it will come back to bite E&P companies, because the service companies won't have had the capital to reinvest in new equipment," he said.

At some point, upstream companies will put out a request for proposal and no one will bid because they won't have the equipment for the job.

"But, as with most things in life, we don't deal with an issue until it hits us in the face," Wicklund said.

In a cutthroat environment, Saltiel said the obvious way out of the industry's labyrinth is consolidation. Mergers, he said, are the most efficient way to increase scale, reduce costs and create value for investors.

"Every business line we compete in is very price sensitive," he said. "Only the lowest-cost players can thrive through the cycle."

But, he added: "It takes two willing boards and shareholder bases to make consolidation happen."

The industry, he said, continues to wait on the sidelines and hope.

The A&D snag

In June, C&J Energy Services and Keane Group Inc. announced a combination hailed by analysts as a merger of equals. Pro forma, the new company would be worth about $1.8 billion with $255 million in net debt.

"Consolidation always occurs at this point in the cycle," Spears said. "The valuations of companies being bought are typically quite low, and the acquirer doesn't always survive, but if they do survive, the following upturn in business creates enormous wealth for shareholders and launches a bunch of great opportunities for employees."

Why aren't there more? The holdup, industry professionals say, is competing interests among companies.

"More than half of companies out there are for sale," Wright told *Investor*. "There's a desire in the industry [to consolidate]. It's sort of a theoretical desire. Making it happen—it's happened slower than I would have guessed," he said.

Consolidation has stalled, in part, because some companies have "misaligned incentives to get deals done. I hear plenty of stories that are preventing deals from happening," he said.

Wicklund offered a more blunt assessment: The sticking point isn't whether financial benefits or potential synergies will arise.

The obstacle is "what we are euphemistically calling 'social issues,'" he said.

A consolidation means some workers may lose their jobs. But in a merger, at least one CEO is "definitely going to lose their job."

Consider two midsized companies in which both CEOs earn $4 million annually, Wicklund said.

"Which one of us is going to lose our job? And whoever loses their job, where are they going to go out and find another $4 million a year position in the current market?

"I only want to combine if I'm the one who keeps my job," Wicklund said. "And if everybody says that, who combines?"

Wicklund said the C&J-Keane transaction succeeded because C&J CEO Don Gawick agreed to walk away.

The service industry also lacks a large-scale aggregator of service businesses. Among the sub-sectors in the service space, there aren't any easily identifiable consolidators in sand, pressure pumping or drilling.

"Pick a sub-sector of the market and there's nobody," Wicklund said. "Who's going to consolidate the pressure pumping market?"

With consolidation largely stalled, Wicklund said service companies will continue to scrape by and be shut out of badly needed capital. Private-equity and institutional investors aren't interested in investing in the smaller companies, Wicklund said.

"The oilfield service industry arguably has six investable names," such as Halliburton Co., Schlumberger Ltd. and NOV, he said.

For companies unable to serve E&P giants such as ExxonMobil Corp., "the concern is you're going to end up with a significantly bifurcated market where the big service companies work for the big oil companies and everybody else fights it out at the bottom.

"So it's not consolidation for consolidation's sake," Wicklund added. "It's a whole bunch of different issues driving the need for scale."

The bankruptcy edge

In 1987, as Ratliff Drilling Co. started to unravel financially, the company surrendered 13

Charles Beckham Jr., a bankruptcy attorney at Haynes and Boone, said some oilfield service companies appear to be "hanging on by their fingernails, trying to maintain market share."

Liberty Oilfield Services developed its Quiet Fleet during the downturn to serve customers, particularly in Colorado, that conduct operations near expanding population centers.

rigs to two Oklahoma banks and prepared to liquidate.

But some banks today, fearing a repeat of the 1980s, don't want to own rigs. As lenders move away from ruinous liquidation to converting debt to equity, bankruptcy has become a competitive advantage for some companies.

"Collapsing earnings combined with banks that are generally unwilling to refinance debt means rafts of service companies may end up in the hands of their lenders," he said.

"Nobody has to sell anything," Wicklund said. "Nobody quits operating. There were no repercussions."

Wicklund calls it the American Airlines problem. At a time when other major carriers were filing bankruptcy, American Airlines stayed out of the courthouse. Then they found out they couldn't compete.

"Everybody else had written down their debts to zero, and their returns were significantly better," he said. "So, American Airlines had to declare bankruptcy just to play on a level playing field with the other airlines. And so now if your competitor goes bankrupt, he is now a stronger competitor than he was before. Not a weaker one."

For oilfield service companies, bankruptcy doesn't result in vanishing assets, he said.

"Every company that's gone through bankruptcy—Key [Energy Services], Basic [Energy Services]—they didn't have to sell a single workover rig. All their debt turned into equity, and they never missed a beat," he said.

Charles Beckham Jr., a bankruptcy attorney at Haynes and Boone, said some oilfield service companies appear to be "hanging on by their fingernails, trying to maintain market share."

He said more bankruptcies may be filed.

"The fewer rigs that people have working out there means they're all competing against each other in the different segments in the oilfield industry," Beckham said. "So, there's over capacity."

While companies will promote their safety and quality to customers, their true leverage may be in pricing.

They are continuing to chase the work. And the easiest way to get a new contract is to bid less than their competitor, he said. "And if you're losing money on each job bid, it's impossible to make it up on volume."

Self-fulfilling profits

Like their upstream counterparts, service companies are intent on being disciplined stewards of capital. But there's a paradox worthy of Socrates' "all I know is I know nothing" at the heart of the services industry.

"You actually have to have some capital to spend before you spend it in a disciplined manner," Wicklund said.

Service companies are caught in multiple catch-22s, none perhaps as self-defeating as their relentless drive to create more efficient services—which leads to greater obsolescence of their fleets.

"If you're 10% more efficient, than I effectively have 10% more capacity than I needed before," Wicklund said. "So until some of this equipment starts to wear out, we're going to be an oversupplied market."

Technology has been both a saving grace and an Achilles' heel for some companies.

"We're victims of our own supply," Wright said. "What fixes oversupply? Two things: disciplined investing and time."

Liberty, which Wright describes as a company of self-described "tech nerds," focuses solely on hydraulic fracturing. The company runs 23 frack fleets, including 14 in the Rockies and nine in Texas' Permian Basin and Eagle Ford Shale.

Wright pointed to Liberty's cash returned on the capital invested, which only dipped into negative territory in 2016, at the height of the downturn. The company saw 44% returns on investments in 2017 and 43% in 2018.

Wright recognizes that the industry's improvements in drilling rates have buoyed the overall oil and gas industry. And that advances create "downward pressure on prices of services that are getting much more efficient."

But Liberty said more sophisticated companies look at total costs. E&Ps may spend about $30,000 a day for equipment and manpower at a drilling location. Competitors may charge lower rates, but take 45 days to do a job Liberty can finish in 30.

"That saves them $400,000. With Liberty moving faster, you also get oil on 15 days sooner. So you get revenues earlier," Wright said.

Liberty intends to stick to its strategy during the downturn: meet customer demand. The company began to develop its quiet fracturing fleet in the summer of 2014 and continued to work on the fleet during the downturn, rolling it out in the summer of 2016 "when things were awful."

The company could have shut down the research or laid off employees as other companies did. Instead, "we played the long game," Wright said.

Once again, however, the industry is in an inhospitable environment. Service companies are chasing technological advancements, especially in machine learning and automation.

But technology may yet aid service companies by turning focus inward, into how it can benefit their businesses.

"The industry has really not spent a whole lot of capital on the technology of running a business. They spend all their money on technology for their downhole tools or whatever their product is," Wicklund said. "So, this cycle you're seeing companies start running their businesses better."

Still, the industry sees technology as leading the way in the field as well.

"This is what brought the shale revolution," he said. "This is what will distinguish the winners and losers: differential technology."

The number of companies will still need to shrink as market conditions tighten even more.

"That process from where we were five years ago to where we'll be in two or three years is indeed painful," Wright said. □

MIDSTREAM M&A GETS PRIVATE

A majority of midstream deals are now orchestrated by private-equity buyers, and some public companies are getting big money offers to abandon their ticker symbols and go private.

ARTICLE BY
DARREN BARBEE

"The most fundamental change that's occurred is that the capital markets have largely been closed to both upstream companies but also to midstream companies," said Frank Murphy, managing director and co-head of energy investment banking at Robert W. Baird & Co.

Like something from an ancient myth, the great steel forges of the Mediterranean have spun out hundreds of miles of pipeline to cross the Permian wilderness.

And the buildout has been expensive. Beginning in 2018, transactions for midstream infrastructure assets in the Permian and elsewhere in the U.S. exceeded $100 billion, particularly as companies looked to simplify corporate structures last year, according to PwC.

But the tumult in the oil and gas markets has dogged midstream companies, driving down their value through mid-2019 even while the sector's EBITDA remained steady during the downturn and has grown significantly since, according to a July 30 report by Moody's Investors Service.

Like their upstream customers, midstream companies have increasingly been denied the inexpensive capital from the market or lenders since the downturn.

"It's been a pretty rough period," said Frank Murphy, managing director and co-head of energy investment banking at Robert W. Baird & Co. "The most fundamental change that's occurred is that the capital markets have largely been closed not only to upstream E&Ps but also to midstream companies."

That's opened the door for private-equity buyers, and they've been busy.

In May, IFM Global Infrastructure Fund made what Barclays called the "first meaningful corporate-level" offer to take Buckeye Partners LP private in a $6.5 billion deal. The transaction has a $10.3 billion enterprise value. The Buckeye buyout followed ArcLight Energy Partners' March announcement to take American Midstream Partners (now Third Coast Midstream) private for $300 million.

And in August, Blackstone Infrastructure Partners made a take-private offer to Tallgrass Energy LP at a nearly 36% premium to its stock price that valued the company at about $5.5 billion.

Public deals continue to emerge, but at a slower rate.

Energy Transfer LP said in September it would buy SemGroup Corp. in a unit and cash transaction worth about $5.1 billion.

Peter Bowden, global head of energy for Jefferies LLC, served as exclusive financial adviser to SemGroup and the sale of Pegasus Optimization Managers LLC, a high-horsepower compression platform backed by Apollo Global Management Inc., to a portfolio company of EQT Infrastructure.

As the midstream sector has fallen out of favor in the market, private-equity firms have stepped up with "the fire power to do important transactions," Bowden said.

If market conditions persist, "you will see more and more of these take-private proposals. These are good businesses that generate real returns. If the public doesn't want to own them, then private investors will," he said.

The prominence of private-equity buyers has changed significantly since the roaring shale boom days before 2014, Murphy said.

Consider: In 2014 and 2015, about 85% of midstream transactions involved what Murphy calls strategic buyers—primarily public companies. Collectively, private-equity and infrastructure and sovereign wealth funds made up the remainder of buyers.

Business is still moving. In August, Baird and Detring Energy Advisors announced an exclusive alliance targeting midstream mergers, acquisitions and divestitures. Detring will provide expertise in technical underwriting and upstream forecasts, while Baird provides strategic advice and transaction services to midstream clients.

Murphy said that in 2014, before oil prices plummeted, midstream activity was concentrated in MLPs.

"Since then, the midstream public capital markets have been more or less shut," he said.

The market's indifference to midstream has caused public companies to shift their focus "from acquiring assets to managing and in some cases to divesting assets," he said.

Today, private-equity-sponsored companies, infrastructure funds and pension and sovereign wealth funds represent nearly half of the market's buyers, up from about 15% in 2014. "They just stepped in to be major buyers in the marketplace today," he said. "In part because the strategic buyers have limited access

As the midstream sector has fallen out of favor in the market, private-equity firms have stepped up with "the fire power to do important transactions," said Peter Bowden, global head of energy for Jefferies LLC.

"Over the last 18 months, we've been kind of approaching what I would call a transitional phase in the midstream market where we're concluding one infrastructure cycle and beginning another," said Patrick Knapp, an attorney with McGuireWoods' M&A practice.

to capital, and they've been told by investors to stop growing for growth's sake instead manage their current portfolios to generate more economic returns."

'The Permian requirement'

One basin among all others has driven first upstream and now midstream sector M&A: the Permian.

Jefferies' deals with private-equity acquisitions have focused squarely on "establishing a position or getting bigger" in the basin. As of Sept. 27, Permian rigs made up 58% of the most recent Baker Hughes rig count—up slightly from 56% a year ago.

"What has driven much of the midstream dealmaking is what I call the 'Permian requirement,'" Bowden said. Because of the high levels of activity there, he said, "it is a nonoptional resource, in our view."

Still, many of Jefferies' transactions have involved smaller businesses backed by "boutique private-equity firms" selling to larger, generalist private-equity and infrastructure firms, Bowden said.

"The buyers in those large transactions were predominantly focused on establishing a position or getting bigger in the Permian Basin."

In the past 12 months, at least 35 Permian midstream deals have been publicly announced, with about half of those deals disclosing deal values of $18 billion.

Despite the market's negative reaction to public midstream transactions, "that doesn't mean that [public] buyers aren't making good deals," he said. "These are good businesses. Under these market conditions, CEOs need to manage their businesses in a manner that meets their strategic priorities rather than catering to market sentiment, which is unlikely to improve in the near term."

A larger movement in the midstream sector may be afoot, underscored by pipeline capacity that now roughly matches the Permian, said Patrick Knapp, an attorney with McGuireWoods' mergers and acquisitions practice. New pipelines projects that have been in the works for years are coming online, and a huge increase in basin takeaway capacity has reached a level "unlike anything we've ever seen before."

"There's been a change in growth patterns that has been driven largely by strategically focused E&P growth centered around free cash flow rather than pure production numbers," he said. "It's not so much about producing as many barrels as I can produce anymore from an E&P's perspective. It's about maximizing your free cash flow and producing the right amount of barrels."

The industry is now evolving its preferences for infrastructure. As drilling programs have expanded, the need for other infrastructure has accelerated.

"We've seen traditional oilfield service businesses such as water disposal evolve in the past few years to become more midstream-centric businesses," Knapp said, "where you're seeing pipeline buildout and large contract commitments and large capital programs built around these water disposal companies."

In the past year, at least nine deals have focused on water infrastructure, including produced water management.

Derek Detring, president of Detring Energy Advisors, said that several operators own legacy water infrastructure, especially in the Permian Basin.

"They have been putting contracts in-place providing separate entities to charge themselves certain fees per barrel of water," he said, "where they can potentially combine with offset operators' water systems before they sell … or potentially take that vehicle public."

The epic momentum of building and buying seems to be changing, Knapp said.

"Over the last 18 months, we've been kind of approaching what I would call a transitional phase in the midstream market where we're concluding one infrastructure cycle and beginning another," Knapp told *Investor*.

"What we've seen in the midstream over the past five to 10 years is an extraordinary buildout in takeaway capacity and particularly pipeline infrastructure," he said.

With E&Ps reducing capex and large-scale drilling programs at an advantage, "at the end of the day, I think that is probably pointing to more consolidation in all of the upstream, midstream and oilfield service sectors in the Permian," Knapp said.

Disconnect

Is the M&A market just misunderstood?

In the past six years, U.S. midstream companies have struggled to return to pre-downturn valuations and deliver value to shareholders above the cost of capital, despite consistent production volume growth and margin recovery, according to PwC's second-quarter oil and gas deals report.

And M&A has been frowned upon by investors.

Barclays said Sept. 9 that the appetite for large-scale deals among public companies seems "fairly muted" because of a focus by midstream companies on deleveraging and weak public valuations of assets. In echoes of the upstream market, midstream investors are also expressing a preference for balance sheet strength.

"M&A talk wanes but doesn't disappear," Barclays said a report.

Under normal market conditions, the transactions Bowden has seen would have been made by investment-grade pipeline companies.

"Because the public markets are in such bad shape, public companies that have growth initiatives need to generate proceeds from something and selling minority interests in assets, joint ventures and divesting noncore assets all offer a path to funding their growth initiatives," Bowden said. "Without those types of transactions, some companies are simply going to have to eliminate a portion of their forward growth projects."

Growth Of Texas Pipeline Mileage

Year	2014	2015	2016	2017	2018	2019 (YTD)
Miles	425,939	431,997	439,771	448,446	466,623	469,737
Total Increase	N/A	6,058	7,774	8,675	18,177	3,114
Percent Increase		1%	2%	2%	4%	1%

Source: Texas Railroad Commission

However, capital appears too expensive for some public midstream companies.

In September, The Williams Cos. Inc. management was asked about its reported consideration of a bid, with Global Infrastructure Partners, for Noble Energy Inc.'s midstream business, Noble Midstream Partners LP, according to Barclays.

Without commenting on the report, Williams said that it "viewed its cost of capital as too high to use its own capital as a source of funds" but wouldn't preclude it from partnering with a private-equity fund, Barclays said.

The PwC noted that midstream, as a whole, has struggled to generate returns above the cost of capital—posting roughly 1% negative annual returns compared to capital costs from 2015 through 2018.

"Continued PE interest in midstream during prolonged challenged times has driven investors to rethink their approach to asset commercial diligence," said Bassem Salama, director of energy strategy at PwC.

Investors are also concerned with increased contract risks due to potential E&P bankruptcies, the increased time and complexity required for regulatory approvals and new short-to-medium term contract arrangements, PwC said.

The overall market has been shaped by the upheaval of the past five years, as upstream and midstream markets moved from the roaring shale boom with high oil and gas prices to a lower commodity price environment and a need to focus activity on areas with the highest economic returns, Murphy said.

"The midstream market's gone through this evolution," he said. "It … parallels what's going on in the upstream market where the strategic [buyers] are taking a much more disciplined approach, de-emphasizing acquisitions and managing their portfolios to generate free cash flow and keep leverage at lower levels."

Bowden said the market tends to penalize public companies and particularly buyers during a downcycle. But public-equity firms have recognized the value in those companies, even as they've fallen out of favor with investors.

"Private investors don't care about the ticker symbol," he said, adding, "These are good businesses that generate real returns.

"If the public doesn't want to own them, then private investors will." □

Robert W. Baird & Co. and Detring Energy Advisors announced an exclusive midstream alliance in August as the two collaborate on transactions, said Derek Detring, president of Detring Energy Advisors.

U.S. MIDSTREAM ACQUISITIONS & DIVESTITURES

Deals announced from July 1, 2018 through Sept. 30, 2019. All deals, updated in real time, are now available at HartEnergy.com/ad-transactions.

Third-Quarter 2019

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
7/2/19	UGI Energy Services LLC; UGI Corp.	TC Energy Corp.	1,275	Purchased the Columbia Midstream Group subsidiary, which owns five gathering systems in the SW core of the Appalachian Basin comprising 240 miles of pipeline and 2,675,000 MMBtu/d of capacity.
7/31/19	Altus Midstream Co.	Enterprise Products Partners LP	N/A	Acquired a 33% equity interest in the Enterprise subsidiary that owns the Shin Oak Pipeline that transports NGL production from multiple basins, including the Permian, to Mont Belvieu, TX.
7/31/19	Lagoon Water Solutions LLC	Continental Resources Inc.	85	Purchased a water gathering and recycling system in the Stack play in Blaine County, OK; includes long-term agreement for water sourcing, gathering and disposal services.
7/31/19	Solaris Water Midstream LLC	Concho Resources Inc.	N/A	Formed a JV to focus on produced water logistics at scale in the northern Delaware Basin located primarily in Eddy County, NM; includes a long-term produced water management.
8/5/19	Delek US Holdings LP; MPLX LP; Rattler Midstream LP	ExxonMobil Corp.; Lotus Midstream LLC; Plains All American Pipeline LP	N/A	Acquired stakes in the Wink to Webster crude oil pipeline project serving Permian Basin producers in W TX; Delek US purchased a 15% ownership interest ranging from $340MM to $380MM.
8/6/19	Caliber Midstream Holdings LP; Triangle Petroleum Corp.; BlackRock Inc.	American Midstream Partners LP; ArcLight Capital Partners LLC	N/A	Purchased crude oil gathering and pipeline transportation system in McKenzie County, ND, serving Bakken Shale producers within the Williston Basin.
8/7/19	Qatar Investment Authority (QIA)	Stonepeak Infrastructure Partners Co.; Oryx Midstream Services LLC	550	Purchased a significant stake in Oryx Midstream Services, the largest privately held midstream crude operator in the Permian Basin based in Midland, TX.

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
8/8/19	Undisclosed	NGL Energy Partners LP	300	Bought TransMontaigne Product Services and associated SE refined products assets; comprises exclusive rights to 18 terminals including two in GA plus line space along Colonial and Plantation pipelines.
8/21/19	H2O Midstream LLC; EIV Capital LLC	Sabalo Energy LLC; EnCap Investments LP	N/A	Purchased Sabalo's Permian produced water infrastructure located in the northern Midland Basin.
8/21/19	Pembina Pipeline Corp.	Kinder Morgan Inc.	1,546	Purchased ownership of the U.S. portion, extending from MI to ND, of the Cochin Pipeline, which is currently moving light condensate.
8/27/19	Blackstone Infrastructure Partners; The Blackstone Group LP	Tallgrass Energy LP	3,030	Launched take-private proposal to acquire remaining shares in Leawood, KS-based Tallgrass at $19.50 per share in cash.
8/29/19	Greenway Technologies Inc.	Mabert LLC	N/A	Formed JV for an ownership interest in the Infra Technologies US gas-to-liquids plant located in Wharton, TX.
9/5/19	NJR Midstream; New Jersey Resources Corp.	Macquarie Infrastructure and Real Assets Inc.; Macquarie Group Ltd.	367.5	Bought 100% membership interest in the Leaf River Energy Center LLC, a natural gas storage facility in SE MS.
9/16/19	Energy Transfer LP	SemGroup Corp.	5,100	Acquired Tulsa, OK-based SemGroup in a cash and stock deal including the assumption of $5B of debt; SemGroup's key areas of operation include western Canada, the Midcontinent and the Gulf Coast.
9/17/19	Eco-Energy Inc.	Continuum Energy Services LLC	N/A	Purchased the Stone Mountain gathering, processing and terminal assets in the southern Appalachian Basin.
9/18/19	Plains All American Pipeline LP	Occidental Petroleum Corp.	650	Acquired Occidental's remaining stake in Plains comprising of 15MM shares plus another 15MM shares of Plains' general partner.
9/26/19	NGL Energy Partners LP	Hillstone Environmental Partners LLC; Golden State Capital	600	Purchased all equity Hillstone interests acquiring a produced water transportation and disposal system located in the northern Delaware Basin in the state line area of Eddy and Lea counties, NM, and Loving County, TX.

Second-Quarter 2019

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
4/2/19	Stonepeak Infrastructure Partners Co.	Oryx Midstream Services LLC; Concho Resources; Post Oak Energy Capital LLC; Quantum Energy Partners; WPX Energy Inc.	3,600	Purchased substantially all of the assets of Midland, TX-based Oryx Midstream, which owns and operates a crude oil gathering system in the Delaware Basin in the Permian.
4/10/19	Crestwood Equity Partners LP	The Williams Cos. Inc.	484.6	Bought Williams' operated 50% interest in Jackalope Gas Gathering Services, a Powder River Basin JV between the companies in Converse County, WY.
4/15/19	Concho Resources Corp.	Frontier Midstream Solutions IV LLC; Frontier Energy Services LLC	N/A	Formed 50:50 JV to build Beta Crude Connector LLC, a new gathering and transportation system in the Midland Basin with initial capacity of 150,000 bbl/d of crude oil; Frontier will serve as operator.
4/24/19	XRI Holdings LLC; Morgan Stanley Energy Partners	Fountain Quail Energy Services LLC; CSL Capital Management LP	N/A	Bought the Permian Basin water treatment and recycling division Fountain Quail Water Treatment for cash and equity.
5/6/19	Bison Oilfield Services LLC	Cobalt Environmental Solutions LLC; Blue Sage Capital	N/A	Purchased Cobalt, a water disposal business in the Scoop and Merge plays of OK's Anadarko Basin.
5/6/19	Bison Oilfield Services LLC	Big Star Trucking LLC; Vista Disposal Solutions LLC	N/A	Acquired Big Star's OK water hauling division and certain existing and pending saltwater disposal permits owned by Vista during 1Q 2019.
5/8/19	MPLX LP; Marathon Petroleum Corp.	Andeavor Logistics LP; Marathon Petroleum Corp.	9,000	Acquired Andeavor, another midstream affiliate of Marathon Petroleum, in a unit-for-unit merger agreement.
5/10/19	IFM Investors	Buckeye Partners LP	6,500	Acquired Houston-based Buckeye for $41.50 per unit in an all-cash transaction; includes networks of integrated midstream assets primarily in the East Coast and Gulf Coast regions of the U.S., as well as in the Caribbean.
5/13/19	Shell Midstream Partners LP	Royal Dutch Shell Plc	800	Bought in a dropdown additional interests in the Explorer and Colonial systems, which have the capacity to deliver some 3 MMbbl/d of refined products.
5/14/19	NGL Energy Partners LP	Mesquite Services LLC	890	Acquired the northern Delaware Basin-focused produced water disposal company through a combination of Permian assets in Eddy and Lea counties, NM, and Loving County, TX.
5/17/19	GIC Private Ltd.	Five Point Energy LLC; WaterBridge Resources LLC	N/A	Acquired a 20% minority equity stake in WaterBridge, a Houston-based water midstream company with growing positions in the Permian's Delaware Basin and the Arkoma Basin; transaction implies a roughly $2.8B enterprise value.
5/21/19	Plains All American Pipeline LP	CVR Energy Inc.	36	Bought a 1.5-MMbbl crude oil terminal located in Cushing, OK.

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
5/28/19	Delek Logistics Partners LP; Delek US Holdings Inc.	Plains All American LP	128	Formed a JV to support the expans²n of the Red River pipeline system from Cushing, OK, and the Permian Basin to U.S. Gulf Coast markets; includes purchase of a 33% minority ownership interest.
5/29/19	Altus Midstream Co.	Apache Corp.	161	Purchased a 26.7% equity interest as part of an opt²n tied to its format²n in the Permian Highway Pipeline, which wçl transport natural gas from the Delaware Basin to Texas Gulf Coast markets.
6/1/19	Total SA	Toshiba Corp.	815	Bought Toshiba's U.S. LNG business including Freeport LNG train 3 agreements that add 2.2 mtpa of LNG plus an $800MM cash payment.
6/10/19	Hartree Bulk Storage LLC; Oaktree Capital Management LP	Martin Midstream Partners LP	215	Bought Gulf Coast natural gas storage assets with 50 bçl²n cubic feet of working capacity in N LA and MS.
6/10/19	Plains All American Pipeline LP	Phçlips 66 Co.	N/A	Formed 50:50 JV to construct the $2.5B Red Oak Pipeline transporting Permian crude from Cushing, OK, to TX Gulf Coast markets.
6/24/19	Archrock Inc.	Elite Compress²n Services LLC; JDH Capital Co.	410	Acquired substantially all of Victoria, TX-based Elite Compress²n Services asset; includes about 430,000 hp located primarçy in the Eagle Ford Shale and S TX reg²n as well as in the Permian Basin, Scoop/Stack and Marcellus/Utica.
6/24/19	Harvest Midstream Co.	Archrock Inc.	30	Purchased about 80,000 active and idle compress²n hp.

First-Quarter 2019

1/3/19	WaterBridge Resources LLC; Five Point Capital Partners LLC	Concho Resources Inc.; COG Operating LLC	N/A	Acquired Concho's produced water assets in the southern Delaware Basin including three disposal wells with 45,000 bbl/d of permitted capacity and about 44 mçes of pipeline.
1/22/19	UL Water Midstream LLC	H2O Midstream LLC; Layne Water Midstream; Layne Christensen Co.	N/A	Formed JV to develop and operate water infrastructure on the University Lands acreage located across W TX in Ward, Winkler and Loving counties within the southern Delaware Basin of the Permian.
1/30/19	NGL Energy Partners LP	DCP Midstream LP	N/A	Purchased DCP's wholesale propane business, generally consisting of seven NGL terminals in the eastern U.S.; also includes an import/export terminal in Chesapeake, VA.
1/31/19	The Blackstone Group LP; Blackstone Infrastructure Partners	Tallgrass Energy LP; Kelso & Co.; The Energy & Minerals Group; Tallgrass KC LLC	3,200	Purchased controlling interest in the Leawood, KS-based midstream energy infrastructure company operating across 11 states.
2/4/19	First Infrastructure Capital Advisors LLC	WhiteWater Midstream LLC; Denham Capital Management LP; Ridgemont Equity Partners	N/A	Acquired WhiteWater, including its 60% stake in Agua Blanca, a Delaware Basin intrastate natural gas pipeline system.
2/4/19	First Infrastructure Capital Advisors LLC	WPX Energy Inc.	N/A	Acquired WPX's 20% equity interest in WhiteWater Midstream's Agua Blanca natural gas pipeline in the Delaware Basin.
2/19/19	The Blackstone Group LP; GSO Capital Partners LP	Targa Resources Corp.	1,600	Purchased a 45% stake in Targa Badlands, which operates oç and gas gathering and processing assets located in the Bakken and Three Forks shale plays within the Wçliston Basin of ND.
2/25/19	San Mateo Midstream LLC; Five Point Energy LLC	Matador Resources Co.	N/A	Formed a new midstream JV, San Mateo II, to expand current gathering, processing and saltwater disposal capacity for Matador's northern Delaware Basin operat²ns; 51% owned by Matador plus operat²nal control.
2/26/19	Hess Infrastructure Partners LP	Summit Midstream Partners LP	N/A	Bought the water gathering assets of the T²ga Gathering System located in the Bakken within the Wçliston Basin in Wçliams County in western ND; includes addit²nal $7MM of possible future contingent payments.
2/26/19	Hess Midstream Partners LP	Summit Midstream Partners LP	67	Purchased the crude oç and gas gathering assets of the T²ga Gathering System located in the Bakken within the Wçliston Basin in Wçliams County in western ND; includes addit²nal $7MM of possible future contingent payments.
3/4/19	Pin Oak Energy Partners LLC	Appalachian Midstream Partners LLC	N/A	Purchased Somerset Gas Gathering of Pennsylvania LLC, which owns and operates a 72-mçe midstream pipeline in the Appalachian Basin that extends from the Lewis Run delivery point in McKean County, PA, to the TransCo Leidy Hub interconnect in Clinton County, PA.
3/8/19	Noble Midstream Partners LP	EPIC Midstream Holdings LP	N/A	Bought a 30% equity interest in the EPIC Crude Pipeline, which wçl transport crude in the Permian Basin and Eagle Ford Shale into the Corpus Christi, TX, market.
3/12/19	Enagás SA	Tallgrass Energy LP; The Blackstone Group LP; Blackstone Infrastructure Partners	590	Purchased a 10.93% indirect ownership interest in Leawood, KS-based Tallgrass Energy.
3/14/19	Equitrans Midstream Corp.; EQM Midstream Partners LP	Eureka Midstream Holdings LLC; Hornet Midstream Holdings LLC	1,030	Purchased 60% of Eureka Midstream and 100% of Hornet Midstream, Appalachia gas gathering systems averaging about 1.6 Bcf/d of gathered volume from 200,000 dedicated acres in the core Marcellus and Utica across OH and WV.

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
3/18/19	ArcLight Energy Partners LLC; ArcLight Energy Partners V LP	American Midstream Partners LP	284.6	Purchased, for cash, in a merger transaction, all outstanding common units of Houston-based AMID not already held by affiliates of ArcLight for $5.25 per unit.
3/18/19	Canada Pension Plan Investment Board (CPPIB)	The Williams Cos. Inc.	1,340	Formed JV to consolidate Williams midstream operations in the western Marcellus and Utica basins of OH; includes CCPIB purchase of a 35% ownership stake in the combined Ohio Valley Midstream and Utica East Midstream systems.
3/18/19	The Williams Cos. Inc.	Momentum Midstream LLC	740	Bought Momentum's 38% stake in the Utica East Ohio Midstream system and assumed operatorship.
3/20/19	Nuevo Midstream Dos LLC; EnCap Flatrock Midstream LLC	Republic Development Partners LLC; ArcLight Capital Partners LLC	N/A	Purchased ArcLight-backed Republic Midstream, which owns and operates a crude oil gathering, storage and intermediate transportation in the Eagle Ford Shale in S TX.
3/21/19	Gravity Oilfield Services Inc.; Clearlake Capital Group LP	MBI Oil & Gas LLC	N/A	Purchased certain water disposal infrastructure in the Bakken.
3/25/19	Enbridge Inc.	Kinder Morgan Inc.	N/A	Bought out Kinder Morgan's stake Texas COLT, a proposed U.S. Gulf Coast deepwater crude export venture between Enbridge, Kinder Morgan and Oiltanking Partners.

Fourth-Quarter 2018

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
10/3/18	Salt Creek Midstream LLC	Noble Midstream Partners LP	N/A	Formed 50:50 JV partnership named Delaware Crossing LLC to develop a crude oil pipeline and gathering system in the Permian's Delaware Basin in W TX.
10/9/18	Antero Midstream Corp.; Antero Midstream GP LP	Antero Midstream Partners LP; Antero Resources Corp.	N/A	Acquired all outstanding Antero Midstream Partners units in a stock-and-cash transaction; includes conversion of combined entity to a corporation.
10/10/18	EPIC Midstream Holdings LP; EPIC Y-Grade Holdings LP	Southcross Energy Partners LP; Southcross Holdings LP	N/A	Purchased an NGL fractionation facility in Robstown in S TX with current capacity of 64,000 bbl/d.
10/15/18	Tallgrass Energy LP	Silver Creek Midstream LLC	N/A	Formed expanded JV in the Powder River Basin named Powder River Gateway; Tallgrass is operator and holds 51% stake while Silver Creek owns 49% stake.
10/22/18	EnLink Midstream LLC; Global Infrastructure Partners	EnLink Midstream Partners LP	N/A	Purchased all outstanding common units of ENLK not already owned by ENLC in a unit-for-unit exchange transaction with an implied price of $18.46 per unit.
10/23/18	Enable Midstream Partners LP	Velocity Midstream Partners LLC; Velocity Holdings LLC	442	Acquired Tulsa, OK-based Velocity Midstream; includes crude oil and condensate gathering and transportation assets in the Anadarko Basin's Scoop and Merge plays.
10/31/18	WaterBridge Resources LLC; Five Point Capital Partners LLC	Halcón Resources Corp.	325	Acquired all of Halcón's water infrastructure assets across the Delaware Basin; includes gas and oil gathering pipelines as well as gas treating assets.
11/2/18	EagleClaw Midstream Ventures LLC; Blackstone Energy Partners LP	Pinnacle Midstream LLC; I Squared Capital	N/A	Acquired Pinnacle, which operates natural gas and crude gathering pipeline, crude storage facilities and gas processing assets in the Delaware Basin.
11/2/18	InstarAGF Asset Management Inc.	Buckeye Partners LP	450	Purchased nonintegrated domestic pipeline and terminal assets in CA, FL, NV and TN.
11/8/18	Oasis Midstream Partners LP	Oasis Petroleum Inc.	250	Bought 15% interest in Bobcat DevCo and 30% interest in Beartooth DevCo; includes gas gathering, compression and gas lift, crude oil gathering, produced water gathering and disposal and water infrastructure assets in the Williston Basin.
11/8/18	Western Gas Partners LP	Anadarko Petroleum Corp.; Western Gas Equity Partners LP	4,015	Acquired substantially all of Anadarko's remaining midstream assets, primarily in the Delaware Basin of W TX and D-J Basin of NE CO, including all common units of WES as part of a simplification transaction.
11/12/18	Tallgrass Energy LP	NGL Energy Partners LP; NGL Water Solutions Bakken LLC	91	Bought NGL Bakken water operations comprised of five saltwater disposal wells located in McKenzie and Dunn counties, ND.
11/15/18	Elevate Midstream Partners LLC; Tailwater Capital LLC	Woodland Midstream Partners LP; Orion Pipeline LLC	N/A	Acquired gas gathering, treating and processing assets located throughout the core of the Haynesville and Cotton Valley formations in E TX.
11/15/18	Williams Cos.	Brazos Midstream Holdings LLC; Morgan Stanley Infrastructure Partners	N/A	Formed midstream JV plus agreement to pursue residue gas solutions in the Permian Basin; Williams will contribute its existing Delaware Basin assets in exchange for 15% minority JV interest with Brazos holding remaining 85%.
11/15/18	Sunoco LP	American Midstream Partners LP	125	Bought American Midstream's refined products terminaling with terminals located in Caddo Mills, TX, and North Little Rock, AR.
11/30/18	Equitrans Midstream Corp.	EQM Midstream Partners LP; EQGP Holdings LP	N/A	Acquired 100% ownership of EQM's general partner EQGP through negotiated purchases and limited call right.

Date Announced	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Estimated Value ($MM)	Comments
12/6/18	Easton Energy LLC; Cresta Energy Capital	Wçliams Cos. Inc.	177	Bought pipeline systems in the Gulf Coast area consisting of about 416 mçes of pipelines primarçy used to transport NGL from var²us supply sources to petrochemical consumers in TX and LA markets.
12/11/18	Hess Infrastructure Partners LP	Hess Corp.	225	Acquired Hess' existing Bakken water services business consisting of over 150 mçes of existing water gathering pipelines capturing about 24,000 bbl/d of produced water in ND.
12/19/18	Altus Midstream LP	Kinder Morgan Inc.	N/A	Bought a 15% equity interest in the Gulf Coast Express Pipeline Project to transport up to 1.98 Bcf/d of natural gas from the Permian Basin to the TX Gulf Coast.
12/19/18	WaterBridge Resources LLC; Five Point Energy LLC	NGL Energy Partners LP	238.8	Bought southern Delaware Basin water infrastructure assets comprised of nine saltwater disposal facçities and about 10 mçes of pipeline in southern Reeves and Ward counties, TX, with about 275,000 bbl/d of total permitted capacity.
12/21/18	Zenith Energy Ltd.	CorEnergy Infrastructure Trust Inc.	61	Bought the petroleum products terminal facçity in Portland, OR, and CorEnergy's remaining interest in the Joliet Terminal in IL.

Third-Quarter 2018

7/30/18	Harvest Midstream Co.; Hçcorp Energy Co.	Wçliams Cos. Inc.	1,125	Bought Wçliams' Four Corners area assets within the San Juan Basin in San Juan and R² Arriba counties, NM, and La Plata County, CO.
7/30/18	Wçliams Cos. Inc.; KKR & Co. LP	Discovery Midstream Partners LLC; TPG Growth	1,173	Purchased Dallas-based Discovery Midstream, which operates assets in CO's D-J Basin primarçy in Adams and Weld counties, as part of a 40:60 JV.
7/31/18	Undisclosed	Crestwood Equity Partners LP; Crestwood West Coast LLC	N/A	Purchased 100% of the equity interests of Crestwood West Coast, which includes a small gas gathering and processing system, fract²nator, butamer and var²us raç and truck terminal and storage facçities serving West Coast NGL customers.
8/1/18	Energy Transfer LP; Energy Transfer Equity LP	Energy Transfer Partners LP	27,000	Purchased all outstanding public limited partner units in Energy Transfer Partners in a unit-for-unit exchange; changes name to Energy Transfer LP.
8/1/18	ONEOK Inc.	Martin Midstream Partners LP	195	Purchased the remaining 20% interest in the West TX LPG Pipeline, an NGL pipeline system serving the Permian Basin.
8/3/18	NextEra Energy Pipeline Holdings LLC; WhiteWater Midstream LLC; MPLX LP	Targa Resources Corp.	N/A	Formed JV through a LOI to develop the proposed Whistler Pipeline Project to transport natgas product²n from the Permian to markets along the TX Gulf Coast.
8/8/18	Kayne Anderson Acquisit²n Corp.; Altus Midstream LP	Apache Corp.	3,500	Formed JV for the creat²n of a new Permian midstream company, Altus Midstream, valued at $3.5B and anchored by Apache's gathering, processing and transportat²n assets at Alpine High in the Delaware Basin.
8/8/18	Lotus Midstream LLC; EnCap Flatrock Midstream LLC	Occidental Petroleum Corp.	N/A	Purchased the Centur²n pipeline system and an SE NM crude oç gathering system that extends across the Permian Basin to Cushing, OK.
8/8/18	Moda Midstream LLC; EnCap Flatrock Midstream LLC	Occidental Petroleum Corp.	N/A	Bought the Oxy Ingleside Energy Center and certain crude oç and LPG infrastructure located near the mouth of the ship channel in Corpus Christi, TX.
8/8/18	S.T.L. Resources LLC	UGI Energy Services LLC	N/A	Formed midstream JV for infrastructure development, transport and marketing of S.T.L.V's product²n from a port²n of its Appalachia acreage in Clinton County, PA.
8/20/18	Alinda Capital Partners	SemGroup Corp.	350	Acquired 49% interest in the Maurepas Pipeline, a crude oç pipeline system in the LA Gulf Coast reg²n owned and operated by SemGroup.
8/21/18	Ontar² Municipal Employees Retirement System (OMERS); OMERS Infrastructure Management Inc.	Plains All American Pipeline LP; Magellan Midstream Partners LP	1,438	Purchased 50% interest in BridgeTex Pipeline, a 400,000 bbl/d crude oç pipeline that extends from the Permian Basin to Houston.
8/23/18	American Midstream Partners LP	Enterprise Products Partners LP	N/A	Formed JV to optimize Gulf Coast assets; includes purchase opt²n for 25% stake in Enterprise's Pascagoula gas processing plant in MS subject to the complet²n of modificat²ns to the High Point pipeline system.
8/23/18	Getka Energy LLC; EnCap Flatrock Midstream LLC	Pacer Energy Marketing LLC	N/A	Purchased the former Pacer Energy Terminal located in Cushing, OK, which houses crude oç storage tanks and several LACT units.
8/24/18	Enbridge Inc.	Spectra Energy Partners LP	3,300	Acquired all outstanding public common units of Spectra.
8/29/18	Sçver Creek Midstream LLC; Taçwater Capital LLC	Genesis Energy LP	300	Bought Genesis' Powder River Basin midstream assets consisting of a pipeline, associated crude oç gathering system and raç facçity.
9/5/18	EagleClaw Midstream Ventures LLC; Blackstone Energy Partners LP	Caprock Midstream LLC; Energy Spectrum Capital	950	Purchased the midstream operator with assets focused in the southern Delaware Basin in Reeves and Ward counties, TX.
9/12/18	Undisclosed; ArcLight Capital Partners LLC	Targa Resources Corp.	160	Bought refined products and crude oç storage and terminaling facçities in Tacoma, WA, and Baltimore, MD.

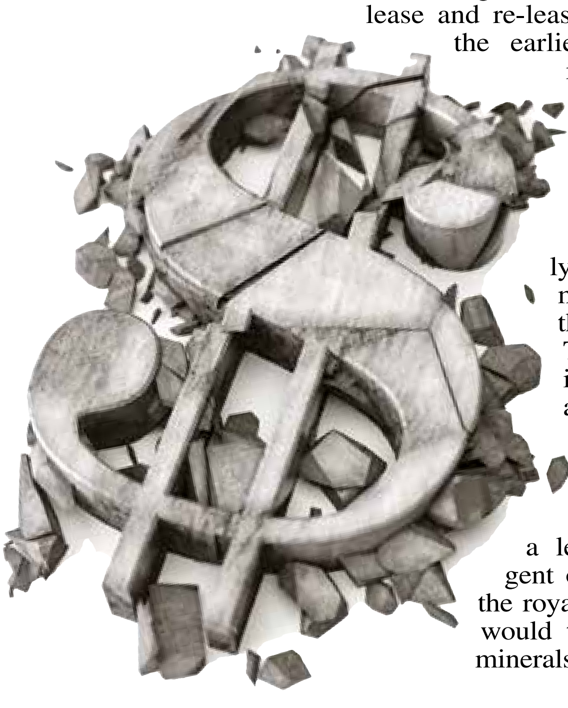
VALUING NONPRODUCING MINERALS

When it comes to putting a price on dormant mineral interests, the multiple of lease bonus method has its shortcomings. Consider a market valuation method instead.

ARTICLE BY
ALAN HARP JR., CFA

Mineral and royalty buyers are often required to assign value to miscellaneous, lower dollar-value, nonproducing minerals. Buyers know how they want to price producing royalties and properties in attractive areas likely to get developed in the near term, but they rarely have confidence assigning value to mineral tracts that may be unleased and located in a county where there is little ongoing oil and gas development.

Historically, the market has used an approach referred to as the multiple of lease bonus method (MLBM). The MLBM suggests that the value of nonproducing minerals may be equal to a multiple of 2.5x to 3x a representative lease bonus. For example, if minerals in an area are being leased for $200 per acre, the MLBM suggests the minerals are worth $500 to $600 per net mineral acre. The MLBM is based on the logic that a mineral owner may lease and re-lease (upon expiration of the earlier lease) the subject minerals multiple times over the course of an assumed holding period, earning a lease bonus payment upon each new lease.



However, as is widely known, there are many shortcomings to the MLBM approach. The 2.5x to 3x range is somewhat arbitrary, and lease bonus income is not the sole source of mineral income. Also, the amount of lease bonus paid by a lessee is often contingent on or interrelated with the royalty rate so the MLBM would theoretically overvalue minerals where the lessor negotiated a high lease bonus rate at the expense of a lower royalty rate. Moreover, it can be difficult to define a representative lease bonus rate, especially during periods of rapidly changing lease bonus rates.

We considered market evidence to evaluate the accuracy of MLBM. We analyzed transaction data for 87 nonproducing mineral properties (lots) sold by EnergyNet from January 2013 to October 2018. EnergyNet is a major player in this marketplace. In 2018, EnergyNet sold over 2,300 separate lots (of all property types, including nonproducing minerals) with an aggregate sales value of approximately $2.2 billion.

EnergyNet provided us with confidential and anonymized data on more than 500 nonproducing mineral transactions during this period. We added other data points to this data set, including drilling permit counts, rig counts by county and lease bonus information, to create the master database described in this article.

Nonproducing mineral transaction database

The 87 transactions were sorted by selling price per net mineral acre (price/NMA) from highest to lowest and categorized the data into deciles. For each decile, we calculated a median, as shown in Figure 1. The data points include sales price, net mineral acres sold, price/NMA, baseline lease bonus and the other items shown.

The main takeaway from the market study is that the actual price/NMA was widely divergent from the values predicted by the MLBM. Less than 5% of the 87 transactions had an MLB between 2.5x and 3x. About 23% of the transactions had an MLB of less than 1x.

A market-based valuation framework

So, if the MLBM is not a reliable nonproducing mineral valuation model, can the market data be used to develop an alternative

Figure 1: Median Measure For Each Decile

Decile	Sale Price	Net Mineral Acres (NMA) Sold	Price/ NMA	Number of Drilling Permits Filed in Subject County During 12 Months Preceding Sale Date	Number of Drilling Rigs in Subject County at Sale Date	Baseline Lease Bonus Per Acre	Multiple of Lease Bonus	WTI Crude Oil Price Per Barrel (At Sale Date)
DecÕe 1	$321,000	32.5	$11,913	262	13	$1,100	9.2x	$54.94
DecÕe 2	$110,000	20.0	$5,750	340	12	$1,000	5.8x	$70.77
DecÕe 3	$125,00	25.0	$4,000	165	13	$2,500	1.7x	$57.96
DecÕe 4	$82,000	40.0	$2,186	134	3	$628	3.5x	$60.72
DecÕe 5	$80,000	47.8	$1,600	199	6	$324	4.7x	$66.91
DecÕe 6	$84,000	65.1	$1,201	178	6	$495	3.1x	$52.76
DecÕe 7	$54,000	82.5	$699	162	10	$650	1.1x	$69.71
DecÕe 8	$82,500	250.0	$453	41	1	$100	5.4x	$49.07
DecÕe 9	$81,775	467.8	$204	52	1	$227	0.9x	$70.34
DecÕe10	$100,000	2,044.8	$72	17	1	$20	1.0x	$69.17

Source: Stout Risius Ross LLC

valuation approach? Using multiple variable regression, we attempted to develop an equation that could be used to predict nonproducing mineral values.

We recognized going into the analysis that there are multiple factors that impact mineral valuation, and our independent variables were based on more general, countywide data rather than data on a more specific area surrounding the subject minerals (such as a 5-mile radius).

After running the regression analysis, we found that the baseline lease bonus and drilling rig count (independent variables) were significant drivers of mineral value but other factors should be considered in developing value. A sample output from the model is shown in Figure 2.

The predicted values from the model could be high or low relative to true market value, depending on other factors not captured in the regression model. The most important other factor is the specific location of the minerals within the subject county. For example, mapping may show that the subject minerals lie far from or just outside a clearly defined permitting and development area, in which case the model's value likely would need to be adjusted downward.

Other factors that influence nonproducing mineral value and should be considered in the valuation include oil and gas lease terms (royalty rate, gross or net royalty provisions, acreage retention language and continuous drilling clauses), the technical capability and drilling budget of the lessee or operator, the status of the minerals (for example, whether the subject minerals are HBP or recent permits have been filed directly on or close to the subject tract), size of the mineral tract, outlook for commodity prices, takeaway infrastructure in the area, and political or environmental issues.

Figure 2: Regression Model Scenarios And Outputs

Inputs	Scenarios						
Drçling Rigs in County at Sale Date	0	0	0	0	1	2	1
Baseline Lease Bonus Per Acre	$15	$50	$100	$500	$500	$500	$750
Output							
Implied Price/NMA, Rounded	$15	$45	$90	$445	$605	$770	$825

Source: Stout Risius Ross LLC

Mineral valuation in high-value, rapidly developing areas

The framework discussed in this article is not highly useful for high dollar-per-acre minerals. High-value areas include promising geological areas where lease bonus rates, drilling permits and drilling rig counts are high.

A current example would be the Midland and Delaware sub-basins of the Permian Basin where nonproducing minerals are selling for $10,000 to $20,000 per NRA (net one-eighth royalty acre). For high-value, rapidly developing areas, the valuation process typically involves an Income Approach based on an engineering drill-out analysis as well as a market approach based on price-per-acre data.

In these areas, transaction data are more readily available (but still very difficult to obtain) because of buying by publicly traded mineral buyers as well as other funds which may be required to report the data. In these areas, the market approach is based on a price/NRA basis rather than a price/NMA basis.

A defensible approach

Mineral valuation cannot be mechanized or boiled down to a formulistic approach. Many variables are involved in the process, and professional judgment is required. The regression model discussed herein is based on market transaction data and should be a more defensible valuation approach for miscellaneous, nonproducing minerals if used as a starting point as compared to the commonly used MLBM. □

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BATTERIES CANNOT SAVE THE GRID OR THE PLANET

The dream of a battery-centric energy supply is seductive, but the reality is that proponents of such a transformation misunderstand the capabilities and limitations of battery technology.

ARTICLE BY
MARK P. MILLS

ILLUSTRATION BY
STEFANO MORRI

PART 2 OF A THREE PART SERIES

Batteries are a central feature of "new energy economy" aspirations. It would indeed revolutionize the world to find a technology that could store electricity as effectively and cheaply as, say, oil in a barrel, or natural gas in an underground cavern. Such electricity-storage hardware would render it unnecessary even to build domestic power plants. One could imagine an OKEC (Organization of Kilowatt-Hour Exporting Countries) that shipped barrels of electrons around the world from nations where the cost to fill those "barrels" was lowest; solar arrays in the Sahara, or coal mines in Mongolia (out of reach of Western regulators), or the great rivers of Brazil.

But in the universe that we live in, the cost to store energy in grid-scale batteries is about 200-fold more than the cost to store natural gas to generate electricity when it's needed. That's why we store, at any given time, months' worth of national energy supply in the form of natural gas or oil.

Battery storage is quite another matter. Consider Tesla, the world's best-known battery maker: $200,000 worth of Tesla batteries, which collectively weigh over 20,000 pounds, are needed to store the energy equivalent of one barrel of oil. A barrel of oil, meanwhile, weighs 300 pounds and can be stored in a $20 tank. Those are the realities of today's lithium batteries. Even a 200% improvement in underlying battery economics and technology won't close such a gap.

Nonetheless, policymakers in America and Europe enthusiastically embrace programs and subsidies to vastly expand the production and use of batteries at grid scale. Astonishing quantities of batteries will be needed to keep country-level grids energized—and the level of mining required for the underlying raw materials would be epic. For the U.S., at least, given where the materials are mined and where batteries are made, imports would increase radically. Perspective on each of these realities follows.

How many batteries would it take to light the nation?

A grid based entirely on wind and solar necessitates going beyond preparation for the normal daily variability of wind and sun; it also means preparation for the frequency and duration of periods when there would be not only far less wind and sunlight combined but also for periods when there would be none of either. While uncommon, such a combined event—daytime continental cloud cover with no significant wind anywhere, or nighttime with no wind—has occurred more than a dozen times over the past century—effectively, once every decade. On these occasions, a combined wind/solar grid would not be able to produce a tiny fraction of the nation's electricity needs. There have also been frequent one-hour periods when 90% of the national electric supply would have disappeared.

So how many batteries would be needed to store, say, not two months' but two days' worth of the nation's electricity? The $5 billion Tesla "Gigafactory" in Nevada is currently the world's biggest battery manufacturing facility. Its total annual production could store three minutes' worth of annual U.S. electricity demand. Thus, in order to fabricate a quantity of batteries to store two days' worth of U.S. electricity demand would require 1,000 years of Gigafactory production.

Wind/solar advocates propose to minimize battery usage with enormously long transmission lines on the observation that it is always windy or sunny somewhere. While theoretically feasible (and not always true, even at country-level geographies), the length of transmission needed to reach somewhere "always" sunny/windy also entails substantial reliability and security challenges. (And long-distance

transport of energy by wire is twice as expensive as by pipeline.)

Building massive quantities of batteries would have epic implications for mining

A key rationale for the pursuit of a new energy economy is to reduce environmental externalities from the use of hydrocarbons. While the focus these days is mainly on the putative long-term effects of carbon dioxide, all forms of energy production entail various unregulated externalities inherent in extracting, moving and processing minerals and materials.

Radically increasing battery production will dramatically affect mining, as well as the energy used to access, process and move minerals and the energy needed for the battery fabrication process itself. About 60 pounds of batteries are needed to store the energy equivalent to that in 1 pound of hydrocarbons. Meanwhile, 50 to 100 pounds of various materials are mined, moved and processed for 1 pound of battery produced. Such underlying realities translate into enormous quantities of minerals—such as lithium, copper, nickel, graphite, rare earths and cobalt—that would need to be extracted from the earth to fabricate batteries for grids and cars. A battery-centric future means a world mining gigatons more materials. And this says nothing about the gigatons of materials needed to fabricate wind turbines and solar arrays, too.

Even without a new energy economy, the mining required to make batteries will soon dominate the production of many minerals. Lithium battery production today already accounts for about 40% and 25%, respectively, of all lithium and cobalt mining. In an all-battery future, global mining would have to expand by more than 200% for copper, by at least 500% for minerals like lithium, graphite and rare earths, and far more than that for cobalt.

Then there are the hydrocarbons and electricity needed to undertake all the mining activities and to fabricate the batteries themselves. In rough terms, it requires the energy equivalent of about 100 barrels of oil to fabricate a quantity of batteries that can store a single barrel of oil-equivalent energy.

Given the regulatory hostility to mining on the U.S. continent, a battery-centric energy future virtually guarantees more mining elsewhere and rising import dependencies for America. Most of the relevant mines in the world are in Chile, Argentina, Australia, Russia, the Congo and China. Notably, the Democratic Republic of Congo produces 70% of global cobalt, and China refines 40% of that output for the world.

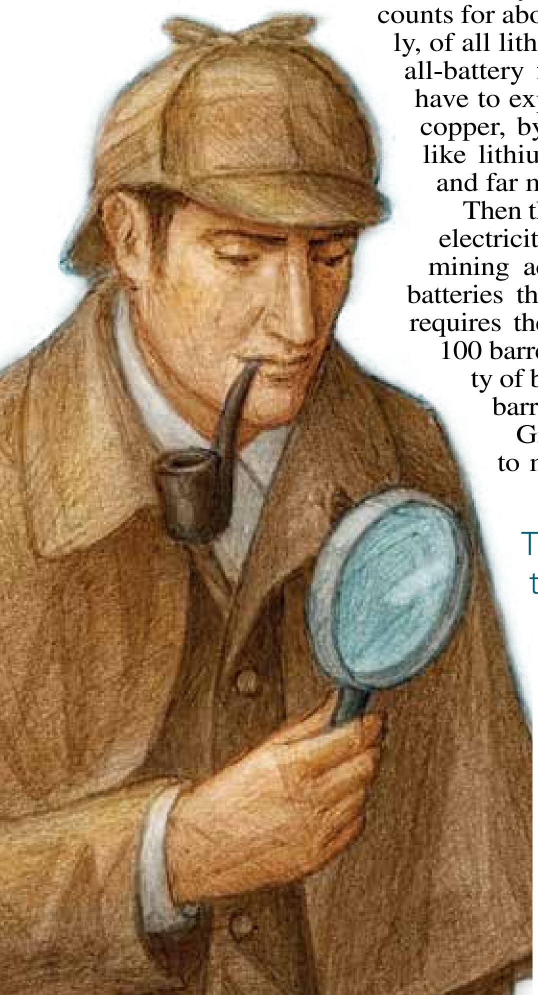
China already dominates global battery manufacturing and is on track to supply nearly two-thirds of all production by 2020. The relevance for the new energy economy vision: 70% of China's grid is fueled by coal today and will still be at 50% in 2040. This means that, over the life span of the batteries, there would be more carbon-dioxide emissions associated with manufacturing them than would be offset by using those batteries to, say, replace internal combustion engines.

Transforming personal transportation from hydrocarbon-burning to battery-propelled vehicles is another central pillar of the "new energy economy." Electric vehicles (EVs) are expected not only to replace petroleum on the roads but also to serve as backup storage for the electric grid.

Lithium batteries have finally enabled EVs to become reasonably practical. Tesla, which now sells more cars in the top price category in America than does Mercedes-Benz, has inspired a rush of the world's manufacturers to produce appealing battery-powered vehicles. This has emboldened bureaucratic aspirations for outright bans on the sale of internal combustion engines, notably in Germany, France, England and, unsurprisingly, California.

Such a ban is not easy to imagine. Optimists forecast that the number of EVs in the world will rise from today's nearly 4- to 400 million in two decades. A world with 400 million EVs by 2040 would decrease global oil demand by barely 6%. This sounds counterintuitive, but the numbers are straightforward. There are about 1 billion automobiles today, and they use about 30% of the world's oil. (Heavy trucks, aviation, petrochemicals, heat, etc., use the rest.) By 2040, there would be an estimated 2 billion cars in the world. Four hundred million EVs would amount to 20% of all the cars on the road—which would thus replace about 6% of petroleum demand.

In any event, batteries don't represent a revolution in personal mobility equivalent to, say, going from the horse-and-buggy to the car—an analogy that has been invoked. Driving an EV is more analogous to changing what horses are fed and importing the new fodder.



The challenge in storing and processing information using the smallest possible amount of energy is distinct from the challenge of producing energy, or of moving or reshaping physical objects. The two domains entail different laws of physics.

Moore's Law misapplied

Faced with all the realities outlined above regarding green technologies, new energy economy enthusiasts nevertheless believe that true breakthroughs are yet to come and are even inevitable. That's because, so it is claimed, energy tech will follow the same trajectory as that seen in recent decades with computing and communications. The world will yet see the equivalent of an Amazon or "Apple of clean energy."

This idea is seductive because of the astounding advances in silicon technologies that so few forecasters anticipated decades ago. It is an idea that renders moot any cautions that wind/solar/batteries are too expensive today—such caution is seen as foolish and shortsighted, analogous to asserting, circa 1980, that the average citizen would never be able to afford a computer. Or saying, in 1984 (the year that the world's first cell phone was released), that a billion people would own a cell phone, when it cost $9,000 (in today's dollars). It was a 2-pound "brick" with a 30-minute talk time.

Today's smartphones are not only far cheaper; they are far more powerful than a room-size IBM mainframe from 30 years ago. That transformation arose from engineers inexorably shrinking the size and energy appetite of transistors and consequently increasing their number per chip roughly twofold every two years—the "Moore's Law" trend, named for Intel co-founder Gordon Moore.

The compound effect of that kind of progress has indeed caused a revolution. During the past 60 years, Moore's Law has seen the efficiency of how logic engines use energy improve by over a billionfold. But a similar transformation in how energy is produced or stored isn't just unlikely; it can't happen with the physics we know today.

In the world of people, cars, planes and large-scale industrial systems, increasing speed or carrying capacity causes hardware to expand, not shrink. The energy needed to move a ton of people, heat a ton of steel or silicon, or grow a ton of food is determined by properties of nature whose boundaries are set by laws of gravity, inertia, friction, mass and thermodynamics.

If combustion engines, for example, could achieve the kind of scaling efficiency that computers have since 1971—the year the first widely used integrated circuit was introduced by Intel—a car engine would generate a thousandfold more horsepower and shrink to the size of an ant. With such an engine, a car could actually fly, very fast.

If photovoltaics scaled by Moore's Law, a single postage stamp-sized solar array would power the Empire State Building. If batteries scaled by Moore's Law, a battery the size of a book, costing 3 cents, could power an A380 to Asia.

But only in the world of comic books does the physics of propulsion or energy production work like that. In our universe, power scales the other way.

An ant-size engine—which has been built—produces roughly 100,000 times less power than a Prius. An ant-size solar PV array (also feasible) produces a thousandfold less energy than an ant's biological muscles. The energy equivalent of the aviation fuel actually used by an aircraft flying to Asia would take $60 million worth of Tesla-type batteries weighing five times more than that aircraft.

The challenge in storing and processing information using the smallest possible amount of energy is distinct from the challenge of producing energy, or of moving or reshaping physical objects. The two domains entail different laws of physics.

The world of logic is rooted in simply knowing and storing the fact of the binary state of a switch—i.e., whether it is on or off. Logic engines don't produce physical action but are designed to manipulate the idea of the numbers zero and one. Unlike engines that carry people, logic engines can use software to do things such as compress information through clever mathematics and thus reduce energy use. No comparable compression options exist in the world of humans and hardware.

Of course, wind turbines, solar cells and batteries will continue to improve significantly in cost and performance; so will drilling rigs and combustion turbines. And, of course, Silicon Valley information technology will bring important, even dramatic, efficiency gains in the production and management of energy and physical goods. But the outcomes won't be as miraculous as the invention of the integrated circuit, or the discovery of petroleum or nuclear fission. □

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Radically increasing battery production will dramatically affect mining, as well as the energy used to access, process, and move minerals and the energy needed for the battery fabrication process itself. About 60 pounds of batteries are needed to store the energy equivalent to that in 1 pound of hydrocarbons. Meanwhile, 50 to 100 pounds of various materials are mined, moved and processed for 1 pound of battery produced.

A&D Watch

EDITED BY
DARREN BARBEE

Roan Resources To Become Citizen's In $1 Billion All-Cash Deal

THE FIRST MAJOR E&P transaction of fourth-quarter 2019 was another combo, this time with private-equity-backed **Citizen Energy LLC** agreeing Oct. 1 to purchase **Roan Resources Inc.** for $1 billion in cash.

The deal may portend take-private offers for public companies that have largely been scorned by the public market—a trend already emerging in the midstream sector. It also follows a pattern set in the third quarter in which no single play or basin dominated transactions. Citizen's offer for Roan's Oklahoma assets follows deals announced in the Barnett, Bakken, Eagle Ford, Marcellus and Permian.

The merger, if approved by Roan shareholders, would pay $1.52 per share of common stock, a 24% premium on its Sept. 30 closing price. Most of the cash paid by Citizen, a Tulsa, Okla.-based company backed by **Warburg Pincus LLC**, would absorb Roan's $780 million net debt.

The "deal metrics screen muted" based on the company's second-quarter production, which averaged about 50,000 barrels of oil equivalent per day (boe/d), including 26% oil, analysts with **Tudor, Pickering, Holt & Co.** (TPH) said.

TPH priced the transaction at about $20,000 per boe/d or marginal undeveloped value.

"Of note, Roan has also elected to temporarily reduce its drilling and development activity and to suspend all completion activity," TPH said in an Oct. 1 report. A "private takeout by a PE sponsor amid a depressed valuation is certainly interesting to see as Roan's story is certainly not unique."

The midstream sector has seen similar take-private offers, including a May deal by **IFM Global Infrastructure Fund** to take **Buckeye Partners LP** private for $6.5 billion. In August, **Blackstone Infrastructure Partners** made a similar offer to **Tallgrass Energy LP** for $5.5 billion.

John Spears, market research director for **Enverus**, noted in an Oct. 2 report that similar deals could emerge.

"We could see other small-cap E&Ps with high debt and low share prices take similar buyout offers," he said.

Roan was created in 2017 from the ashes of **Linn Energy Inc.** in partnership with Citizen when the companies established a position of 140,000 net acres in the Merge, Scoop and Stack plays.

Roan also named Rick Gideon, a former executive at **Devon Energy Corp.**, as CEO on Oct. 1. The company said he would start his new responsibilities immediately.

Joseph A. Mills, Roan's executive chairman of the board who had been handling chief executive duties following the resignation of former CEO Tony Maranto in April, said the Citizen deal was a culmination of its review of strategic alternatives. In April, Roan disclosed that it received multiple, unsolicited "indications of interest" to buy the company and would evaluate a potential sale or merger.

"The board unanimously determined that an all-cash transaction with Citizen Energy is in the best interests of our stockholders and the company and will deliver value to our stockholders at a premium to our recent share price," Mills said.

Citi and **Jefferies LLC** are serving as financial advisers to Roan with legal counsel from **Vinson & Elkins LLP**. **BofA Merrill Lynch** is serving as financial adviser to Citizen Energy with legal counsel from **Latham & Watkins LLP**.

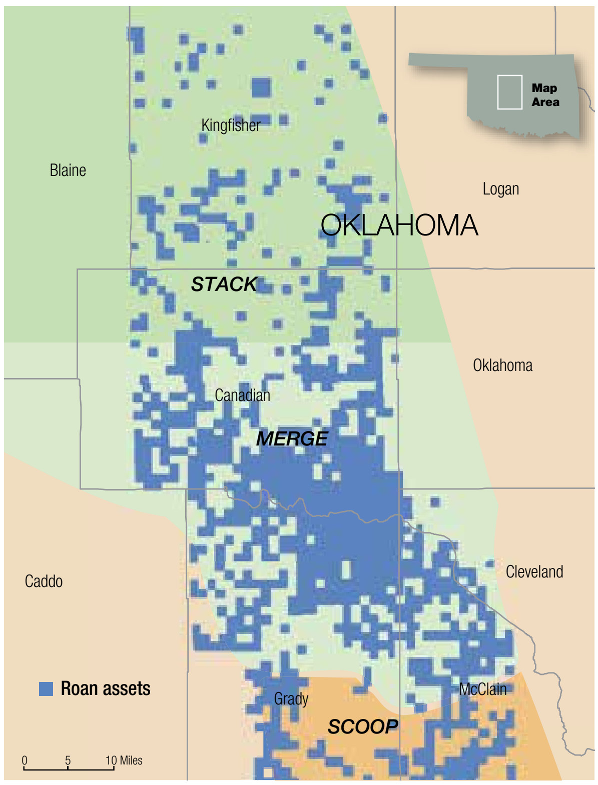
—Darren Barbee

At-A-Glance: Roan Resources

Net production (boe/d)	50,800
Percent Oil	26%
Rigs running	3
EBITDAX ($MM)	$79.3
Net acres	182,000
Net acres, Merge	117,300

Source: Roan Resources Inc.

Roan's Oklahoma Assets



Source: Roan Resources Inc.

Contango Outbids Mach Resources For Oklahoma's White Star

CONTANGO OIL & GAS Co. outbid Tom Ward's **Mach Resources LLC** in an Oklahoma bankruptcy auction in September to win the assets of **White Star Petroleum LLC** for $132.5 million, Contango said.

The acquisition is the second focused on Oklahoma and, if both deals close, will gather an acreage position of more than 450,000 acres for a cost of roughly $155 million.

On Sept. 27, Contango said it entered an agreement to acquire the assets of White Star and certain affiliates as part of the Oklahoma City-based company's Chapter 11 bankruptcy process. White Star, formerly **American Energy-Woodford LLC**, was founded by the late Aubrey McClendon as an Oklahoma-focused E&P business. Ward and McClendon co-founded **Chesapeake Energy Corp.**

Mach and partner **Bayou City Energy Management LLC** bid on the White Star assets on Sept. 12 and executed an asset purchase and sale agreement. However, at the bankruptcy court hearing, Contango proposed a transaction on "substantially the same terms" as Mach, but at a higher purchase price. Mach declined to make a matching or higher offer, according to bankruptcy documents.

Houston-based Contango said the deal will add average production of 15,000 boe/d as well as 20 million boe of PDP reserves as of the transaction's effective date of July 1, 2019. Contango said it would divide the acreage, totaling 315,000 net acres, into the three operating in Oklahoma's Stack, Anadarko and Cherokee areas.

White Star filed for bankruptcy protection on May 28 with disclosed, total debt of $343.7 million, according to **Haynes and Boone LLP**. The company's production consists of liquids weighted at 63% oil and NGL. The acreage is 80% HBP.

About 65% of the wells are operated by White Star and are mature fields with strong cash flow and significant development potential from PDNP and PUD opportunities. The White Star assets also include integrated gathering and saltwater disposal systems, which reduce lease operating expenses and add third-party cash flow.

Contango's deal, set to close in fourth-quarter 2019, follows another Oklahoma-centric transaction by the company, despite its reputation as an operator in the southern Delaware Basin, Wyoming and the shallow-water Gulf of Mexico.

On Sept. 12, Contango said it would acquire from **Will Energy Corp.** 159,872 net acres, including 12,560 acres in North Louisiana for $20 million and $3 million in stock. Will Energy properties, which are about 95% HBP, produce about 1,400 boe/d, including 34% liquids production.

The acquisition is also set to close in the fourth quarter.

Wilkie S. Colyer, Contango's president and CEO said, the White Star deal "fits well from a geographic perspective with our recently announced pending acquisition of the Will Energy oil and gas assets.

"We expect White Star to add approximately $60 million in asset level cash flow over the next 12 months," he said. "It increases the company's production by a factor of almost four times and more than doubles our PDP reserves, all at a very attractive purchase price that is substantially below PDP PV-10."

Haynes and Boone LLP is representing Contango in its acquisition of the White Star assets.

—Darren Barbee

White Star Petroleum Asset Overview, 2Q19

District	Net acres	Operated wells	Nonoperated wells
Stack	45,000	36	135
Anadarko Basin	31,800	49	110
Cherokee	238,000	490	73
Total	314,800	575	318

Source: Contango Oil & Gas Co.

ExxonMobil Divests Norway Assets For $4.5 Billion

EXXONMOBIL CORP. SIGNED an agreement Sept. 26 with **Vår Energi AS** for the sale of its nonoperated upstream assets in Norway for $4.5 billion as part of its previously announced plans to divest about $15 billion in nonstrategic assets by 2021.

"Our objective is to have the strongest, most competitive upstream portfolio in the industry," said Neil Chapman, senior vice president of ExxonMobil. "We're achieving that by adding the best set of projects we've had in many years and divesting assets that have lower long-term strategic value. This sale is an important part of our divestment program, which is on track to meet our $15 billion target by 2021."

The transaction includes ownership interests in more than 20 producing fields operated mostly by **Equinor**, including Grane, Snorre, Ormen Lange, Statfjord and Fram, with a combined production of approximately 150,000 boe/d in 2019.

The transaction is expected to close in fourth-quarter 2019, subject to standard conditions precedent, including customary approvals from regulatory authorities. The majority of the ExxonMobil employees impacted by the sale will transfer to positions at Vår Energi.

Samson Chooses Powder Over Green River

TULSA, OKLA.-BASED SAMSON Resources II LLC has completed its transition to become a Powder River Basin-focused pure-play E&P with the sale of its Greater Green River Basin assets, the company said Sept. 30.

The private, Wyoming-focused E&P, which also sold some noncore acreage in Johnson County, Wyo., is also exploring strategic options for its assets in the Powder River Basin (PRB), where it holds roughly 154,000 net acres.

The PRB in recent years has attracted oil and gas companies eager to tap resources of its stacked plays, including the Niobrara and Mowry shales.

Samson's strategic alternative review of its PRB assets will be launched in fourth-quarter 2019, CEO Joseph A. Mills said Oct. 1 in a separate news release.

But the company gave no assurance that "the evaluation of strategic alternatives will lead to a transaction."

The two buyers in the Green River Basin and noncore acreage sales were not disclosed.

The noncore acreage—8,500 acres in the PRB—had no associated production, Samson said.

Proceeds from the sales will be used for general corporate purposes and payment of a $46 million distribution scheduled to be paid on Nov. 20, the company said. The Greater Green River Basin asset sale had an effective date of July 1, 2019.

> "Samson remains committed to executing its business plan and to the continued development of its extensive PRB assets."
> —Joseph A. Mills, Samson Resources II LLC

In a December 2018 investor presentation Samson described its Greater Green River Basin assets as a "highly consolidated liquids-rich play." Production at the time was 2,950 boe—53% liquids.

The company has a net production of 5,000 to 6,000 boe/d in the PRB, where its drilling capital budget for 2019 is an estimated $98 million.

"Samson remains committed to executing its business plan and to the continued development of its extensive PRB assets," Mills said in the Sept. 30 release before mentioning "recent strong drilling results." He added that exploring strategic alternatives for the assets is "consistent with the strategy the company has pursued since emerging from bankruptcy in 2017."

Samson reported Oct. 1 that two horizontal Turner Formation wells in its Hornbuckle area in Converse County, Wyo., exceeded predrill type curves.

The Brushy Creek Fed 3772-0631 #1FH had an IP30 of 1,708 boe/d (87% oil) from a 9,716-foot lateral, and the Reynolds Fed 3872-3106 #3FH had an IP30 of 1,674 boe/d (88% oil) from a 9,803-foot lateral, the company said.

"The Brushy Creek and Reynolds wells represent a meaningful step-out away from existing Turner production and help expand the growing reserve potential of the Turner Formation in the Powder River Basin, where Samson has a significant leasehold position," Mills said.

"These wells move to prove up [about] 17,000 net contiguous acres in our operated Hornbuckle area for the Turner Formation alone."

—Velda Addison

NGL Energy Partners Buy More Permian Waterworks

NGL ENERGY PARTNERS LP agreed to a multimillion-dollar acquisition on Sept. 26 that is set to boost the Tulsa, Okla.-based company's growing water midstream footprint in the Permian Basin.

In the agreement, NGL Energy Partners will acquire all of the equity interests of **Hillstone Environmental Partners LLC**, owner of a produced water transportation and disposal system located in the northern Delaware Basin, from **Golden Gate Capital** for $600 million. NGL plans to fund the acquisition through preferred equity and debt commitments.

Mike Krimbill, NGL's CEO, said the Hillstone transaction is highly complementary to the company's Delaware Basin asset footprint, which NGL claimed earlier this year to be the largest following its acquisition of **Mesquite Disposals Unlimited LLC**.

"We have made substantial progress in our ongoing water strategy in the Delaware Basin, and the Hillstone acquisition represents another important milestone for our Water Solutions franchise following the closing of our combination with Mesquite in July," Krimbill said in a statement on Sept. 26.

Hillstone's northern Delaware Basin system provides water pipeline and disposal infrastructure solutions to producers with a core operational focus in the state line area of southern Eddy and Lea counties, N.M, and northern Loving County, Texas. The company has an aggregate of over 110,000 acres contracted under long-term dedications with priority disposal rights or minimum volume.

The system currently consists of 19 saltwater disposal wells, representing roughly 580,000 bbl/d of permitted disposal capacity, and a newly built network of produced water pipelines with about 680,000 bbl/d of transportation capacity. Hillstone also has an additional 22 permits to develop another 660,000 bbl/d of disposal capacity, according to the NGL Energy Partners press release.

NGL expects to integrate the Hillstone system into its existing Delaware Basin platform to maximize uptime and redundancy for its producer customers.

Doug White, NGL's executive vice president of water solutions, said the integration of the Mesquite assets is fully underway.

"The certainty of offtake and reliability of our integrated system of large diameter pipelines will provide approximately 2.7 million barrels per day of operational disposal capacity in the Delaware Basin, including the addition of Hillstone," White added in a statement.

This transaction, which NGL estimates has been made at a roughly 7x multiple of forecasted run-rate EBITDA once certain contracted volumes are online next year, is expected to be accretive to distributable cash flow per unit in fiscal 2021, the first full year of ownership, the company release said.

Barclays is financial adviser to NGL. Barclays and **Jefferies** provided committed debt financing to NGL to support the transaction. **Winston & Strawn LLP** is NGL's legal counsel on the Hillstone transaction. **Hunton Andrews Kurth LLP** is serving as the company's legal counsel on the financing transactions.

Tudor, Pickering, Holt & Co. and Jefferies are financial advisers to Golden Gate Capital and Hillstone. **Kirkland & Ellis LLP** and **Nob Hill Law Group PC** provided legal counsel to Golden Gate Capital and Hillstone.

Talos 'Hanging With Big Dogs' After GoM Deals

TWO SEPTEMBER DEALS by **Talos Energy Inc.** with **BP Plc** and **ExxonMobil Corp.** highlight the level of trust the company has established as a U.S. Gulf of Mexico (GoM) operator.

In a farm-out agreement with BP, Talos traded 75% of its working interest in Green Canyon Block 821 while BP operates the Puma West project. The deal means Talos' prospect will be within range of BP's Argos platform, which will add production capacity of 140,000 boe/d by 2021. The agreement does not require Talos to promote or carry well costs. Talos will pay for its 25% working interest share in the wells' cost.

Talos also acquired 100% working interests in ExxonMobil's Hershey prospect, located on Green Canyon blocks 326, 327, 370 and 371. The deal requires no upfront money from Talos.

Both deals suggest that the major oil companies trust Talos' judgment and skill.

Mike Kelly, an analyst at **Seaport Global Securities**, said the "two savvy business developments" show that Talos is capable of "hanging with the big dogs."

The transactions tell "a lot about Talos' capabilities and reputation in the GoM," Kelley said in a Sept. 19 report.

PHOTO COURTESY BP PLC

"These relationships could also prove massively beneficial moving forward."

Talos also continues to target assets that can be developed and tied to existing infrastructure.

"The structure of the ExxonMobil transaction is a prudent risk-adjusted way to gain exposure to a needle moving exploration prospect," Kelly said.

At Puma West, BP will initially spud a well before the end of October using the Seadrill West Auriga ultra-deepwater drillship, Talos said. The prospect consists of sub-salt, Miocene target zones believed to be similar to the prolific Mad Dog Field—less than 15 miles from the proposed well location.

The Puma West prospect was identified and permitted by Talos following seismic reprocessing efforts in the company's Green Canyon core area. Talos said it would work with BP to drill and evaluate the prospect, located in Talos-owned Green Canyon Block 821, in the fourth quarter of 2019.

In the ExxonMobil Hershey prospect, Talos will become designated operator of Green Canyon blocks that constitute roughly 23,000 gross acres. Talos described the prospect as a large, sub-salt Miocene prospect with potential for several stacked horizons. Talos estimates oil-weighted, gross unrisked resources of up to 300 MMboe. Hershey could be developed as a subsea tie-back to multiple Talos-controlled Green Canyon facilities or with new, dedicated infrastructure.

Tim Duncan, Talos president and CEO, said exploration of the Puma West prospect is a timely and material opportunity for Talos.

"While not scheduled in our original 2019 drilling program, by moving quickly the company is able to work with a world-class operator in a potentially significant subsea tie-back project located on Talos acreage," Duncan said. "We believe that coupling Talos' initial prospect evaluation with BP's known expertise in the region provides the best opportunity for success, and we look forward to initiating the project" in October.

—Darren Barbee

Diamondback's Mineral Hunter Unleashes $1 Billion Quarter

DIAMONDBACK ENERGY INC.'S acquisition machine in the mineral space seems to be running at a breakneck pace so far this year.

In the third quarter alone, dealmaking by **Viper Energy Partners LP**, a subsidiary of Diamondback, totaled more than $1 billion of closed or committed acquisitions. Pro forma for all recent transactions, Viper's acreage position now represents 23,990 net royalty acres, up from 15,870 net royalty acres as of June 30. About half of the acreage is operated by Diamondback.

"To date in 2019, our acquisition machine has now acquired over 9,000 net royalty acres for approximately $1.2 billion across more than 100 transactions, and importantly, we have more than doubled our exposure to Diamondback-operated properties," Diamondback CEO Travis Stice said in a statement on Oct. 7.

Viper kicked off the third quarter with a roughly $700 million dropdown acquisition of about 5,000 net royalty acres from Diamondback in July. In September, the company followed that up with a $150 million all-equity transaction to acquire 1,358 net royalty acres from private-equity-backed **Santa Elena Minerals LP**.

Then, on Oct. 7, Viper bolstered its dealmaking for the quarter with the announcement that it had closed an additional 25 acquisitions for an aggregate purchase price of about $193.6 million in third-quarter 2019. In total, the company added about 1,272 net royalty acres.

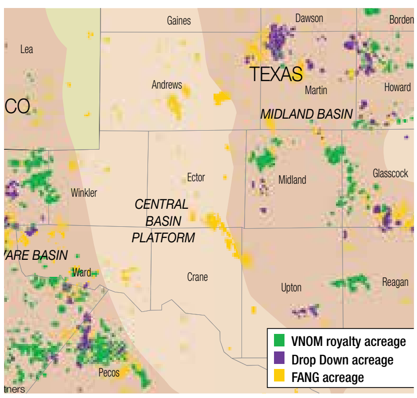
According to Viper, the two notable acquisitions of these were a $100 million deal for 682 net royalty acres across the Midland Basin and a $68 million deal for 363 net royalty acres concentrated in southeastern Lea County, N.M.

"The acquisitions closed during the third quarter, along with the previously announced dropdown and the pending acquisition of assets from Santa Elena, highlight Viper's unique ability to leverage our scale to aggressively consolidate the fragmented private mineral market in the Permian Basin," Stice said in his statement.

The dropdown closed on Oct. 1, and the acquisition from Santa Elena is expected to close later during the fourth quarter. Viper intends to finance the cash portion of the recent acquisitions with cash on hand and borrowings under its revolving credit facility, according to a company press release.

—Emily Patsy

Viper Mineral Assets



Source: Viper Energy Partners

TRANSACTION HIGHLIGHTS

LOWER 48

■ **Cabot Oil & Gas Corp.** reached an agreement on Sept. 30 to sell its 20% ownership interest in **Meade Pipeline Co. LLC** to a subsidiary of **NextEra Energy Partners LP** for $256 million, or over 13 times expected 2019 EBITDAX (non-GAAP).

Meade owns approximately 39% of the Central Penn Line, the greenfield pipeline segment of the Atlantic Sunrise project. This transaction is expected to close during the fourth quarter of 2019, subject to customary closing conditions and adjustments.

Proceeds from this transaction, in addition to the company's ongoing operating free cash flow, will allow Cabot to continue to enhance shareholder value by returning capital to shareholders through a combination of a growing dividend and an opportunistic share repurchase program.

BMO Capital Markets served as financial adviser to Cabot.

■ **Occidental Petroleum Corp.** will delay divesting part of its ownership in **Western Midstream Partners** until next year after failing to attract an offer it deemed attractive, people familiar with the matter told Reuters on Oct. 4.

The Houston-based E&P company purchased Western Midstream earlier this year as part of its $38 billion acquisition of **Anadarko Petroleum Corp.**, a move which gave Occidental substantial Permian Basin acreage but also assets in areas it had previously exited or had little interest in.

Occidental has moved to offload some of these superfluous positions. It signed an $8.8 billion agreement with **Total SA** for Anadarko's African assets in May and held talks in recent weeks with possible buyers, including private-equity firms and infrastructure funds, about selling some of Western Midstream.

However, a decline in pipeline stocks since the end of July has impacted Western Midstream's value. Its market value is down nearly 18% since July 30. Occidental was unwilling to sell at a price it deemed too low, according to four sources familiar with the matter.

GOM

■ **Chevron Corp.** said on Oct. 4 it signed an agreement with a unit of **Royal Dutch Shell Plc** to buy a 40% stake in three deepwater blocks in the Mexican Gulf that the Anglo-Dutch firm won in auctions under the nation's energy reform.

The deal was approved earlier this week by Mexico's oil regulator, the National Hydrocarbon Commission.

"This agreement further strengthens the company's upstream Mexico portfolio and advances its growth strategy in deepwater exploration," Chevron spokesman Ray Fohr said. He did not disclose the value of the deal.

Chevron's Mexico unit is the lead operator of two consortiums for exploring and developing deepwater blocks in the Mexican Gulf: one in Block 3 of the Perdido Basin and the other in Block 22 of the Salina Basin.

DELAWARE BASIN

■ **Abraxas Petroleum Corp.** said Oct. 3 it has executed two agreements selling noncore assets and other nonoperated acreage in Reeves County, Texas, for a total of about $7.9 million.

The transactions with the undisclosed buyers are expected to close in November, the company said in a news release. Combined, the assets produced on average about 310 boe/d, nearly half of which was crude oil, in August.

The San Antonio-based E&P, which has operations in the Rocky Mountain region and the Permian Basin, has been streamlining its portfolio, aiming to become a Delaware Basin pure play and to generate free cash flow.

Earlier this year, the company said it sold nonoperated assets in North Dakota's Williston Basin for $15.5 million. At the time, the sale represented roughly 5% of Abraxas' Bakken daily production of 7,000 boe.

AFRICA

■ **Occidental Petroleum Corp.** has completed the sale of **Anadarko Petroleum's Mozambique LNG** stake to **Total SA** for $3.9 billion. Occidental previously entered into a binding agreement to sell Anadarko's African assets to Total for $8.8 billion.

Following the completion of the Mozambique transaction, Occidental and Total continue to work toward closing the remaining Africa transactions in Algeria, Ghana and South Africa pursuant to the definitive agreement signed in August, the companies said.

Occidental also completed the sale of its holdings in **Plains All American Pipeline LP** and Plains GP Holdings for $650 million.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AUSTIN CHALK REDUX

RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

What's the word on the Austin Chalk?

How about mixed? Good, troubling and confusing results make 'mixed' the best term to employ in describing recent news flow about the greater Chalk. The legacy play arcs across the Gulf Coastal plain from near the Mexican border on the west to an emerging play just east of the Mississippi River. Chalk history is fascinating, with the play producing almost 1 billion barrels of oil in its 50-year history and more than 4 trillion cubic feet of natural gas.

Chalk interest was revived once again last year, first in the emerging play on trend near the intersection of Mississippi and Louisiana, east of the Mississippi River, where Marathon Oil Corp., ConocoPhillips Co. and EOG Resources Inc. were involved in a big acreage land grab.

This occurred simultaneously with news about the Chalk in the eastern Eagle Ford (east of the San Marcos arch) where WildHorse Resource Development Corp. generated positive news using modern well completion techniques before selling the acreage it bought from Anadarko Petroleum Corp. for $625 million to Chesapeake Energy Corp. for $3.98 billion.

Meanwhile, a steady stream of independents, many privately held, chipped around the edges, blocking up Chalk acreage and experimenting with completion modalities. Results of those efforts are now becoming public. This, too, has been all good.

Then came second-quarter 2019 earnings. ConocoPhillips noted that three of its four Louisiana wells in the emerging Chalk were big producers, only the production was 90% water with oil cuts under 100 barrels per day (bbl/d) of oil. The company plans to divest the 210,000 acres it acquired previously. Similarly, at least one EOG neighboring well in the emerging Louisiana Chalk trend has produced significant water volumes.

That said, EOG, Devon, Cimarex and Australis have filed more than 60 permits recently in the emerging Chalk east of the Mississippi River.

Still, consider the ConocoPhillips news troubling.

This would not be the first time the Chalk promised much only to deliver economic heartache. The natural fractures through the Chalk have always been a source of large flush hydrocarbon production. But production declined quickly as operators drained the fractures. Early horizontal efforts in the 1990s involved attempts to intersect multiple fractures via openhole completions, though the results were the same, even if it took longer to get there.

Meanwhile, the industry has learned a lot about tight formation plays in the intervening years. It appears possible to obtain matrix production via the application of tight formation drilling and completion technologies, including longer laterals, closer stages and larger proppant loading in a slickwater plug and perforate configuration. In other words, think of Eagle Ford drilling and completion methodologies applied uphole in the Chalk carbonate.

In Webb County, SM Energy Co. completed a second Austin Chalk test in the second quarter with a 30-day peak rate of 3,200 barrels of oil equivalent per day (boe/d), 19% oil, 38% NGL. The Watson State 167H featured a 12,875-foot lateral. SM Energy's earlier Chalk test, the Galvan Ranch C 917H, generated a peak rate of 2,500 boe/d on a 7,886-foot lateral. The company plans two more Chalk tests by year-end.

So the news contains opposite results at opposite ends of the greater Chalk. As for the middle, TreadStone Energy Partners used Hart Energy's DUG Eagle Ford conference to discuss recent efforts in Hearne Field, an Austin Chalk play formerly operated by Anadarko Petroleum where TreadStone has 52,000 HBP gross acres. There are nine rigs active in the area, and increased developmental efforts have propelled area oil production from a low of 37,000 bbl/d in 2017 to 80,000 bbl/d currently.

To date, TreadStone has drilled 20 infill Austin Chalk wells. The company has evolved its completion recipe and now cases and cements Chalk completions on stage spacing under 150 feet and proppant loading up to 2,500 pounds per foot. Previously, the completion modality relied on multilateral openhole wells and commingled multiformational production with low proppant treatment.

However, openhole completions created well integrity issues. TreadStone is reporting 30-day IPs of 945 bbl/d and 10-month cumulative production of 160,000 bbl, a threefold increase over legacy Chalk wells, and is extending the completion modality lower to tap the Eagle Ford.

There is a limit to how many times one can apply the term "revival" to a 50-year old play. Tantalized by occasional good news in otherwise mixed Chalk results, operators are exploring whether the third time will be the revival charm.

EASTERN U.S.

1 Indianapolis-based ***Superior Oil Co.*** completed a White County, Ill., well in Section 4-5s-14w. The New Harmony Consolidated Field well, #1 Greathouse E S, was tested flowing 113 bbl of 38.4-degree-gravity oil and 1 bbl of water per day from a combined zone in Benoist Sand and Lower Ohara at 2,723-2,920 ft. The well has a projected depth of 2,922 ft.

2 In Section 30-2n-8w in Knox County, Ind., ***Siskiyou Energy*** reported completion details on an Aux Vases completion. The Monroe City Consolidated Field well, #7 Harrell Wade Unit, was tested flowing 50 bbl of oil and 30 bbl of water per day. Production from the 2,170-ft well is from perforations at 1,450-1,455 ft. Siskiyou is based in San Antonio.

3 A Red Rose Run Sand completion was reported in Wayne County, Ohio, by Parkersburg, W.Va.-based ***HG Energy LLC***. The #03-BG Nussbaum Gordon & Majorie had a projected depth of 6,550 ft and was tested flowing 1 Mcf of gas per day after acidizing. The Mount Eaton Field well is in Section 4-15n-11w, and it is producing from perforations at 6,284-6,300 ft.

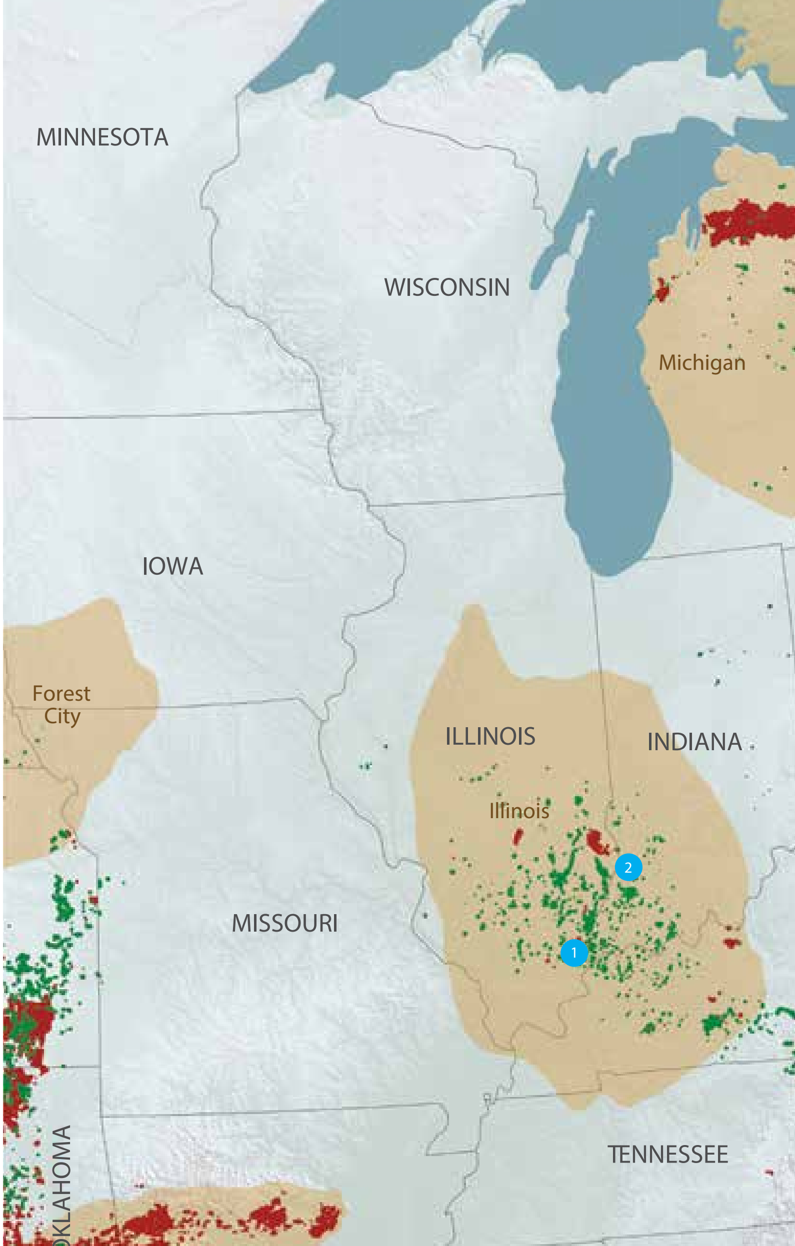
4 Oklahoma City-based ***Gulfport Energy Corp***. completed a Utica Shale well that was tested flowing 11.22 MMcf of gas with 287 bbl of water per day. The #6H Green Gary S WSH MN is in irregular Section 17-4n-6w in Little Muskingum River Field in Monroe County, Ohio. The well was acidized and fractured, and production is from perforations at 9,524-14,528 ft. It was drilled to 14,620 ft, and it bottomed to the south. Additional completion information was not available.

5 ***Rex Energy Corp.*** completed a Utica discovery in irregular Section 6-15n-6w in Carroll County, Ohio. The #11H Goebeler Unit produced 998.4 bbl of oil, 3.41 MMcf of gas and 7.636 Mbbl of water per day. The Carrollton Consolidated Field well was drilled to 16,505 ft with a true vertical depth of 7,545 ft and was completed after acidizing and fracturing. Rex Energy is based in State College, Pa.

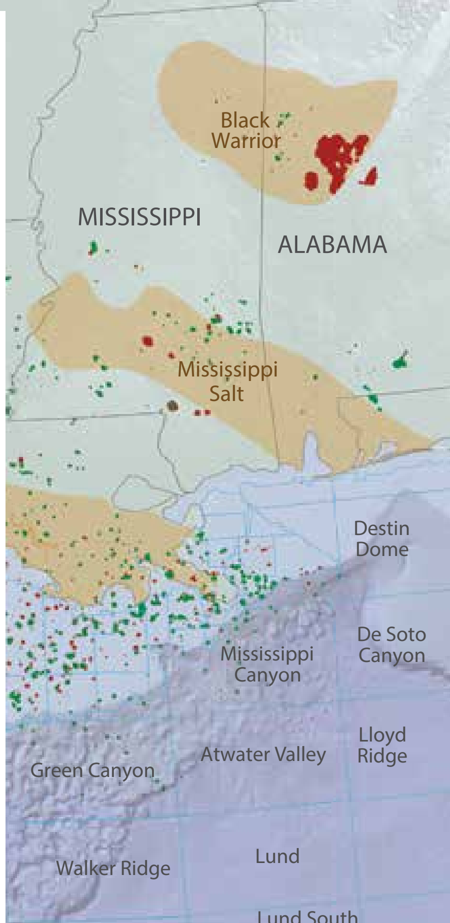
6 A Belmont County, Ohio, Utica well by ***Ascent Resources*** initially flowed 20.617 MMcf of gas with 564 bbl of water per day. Located in Section 5-6n-3w, #2H-A Seabright Clr BL was drilled to 19,020 ft and bottomed to the southeast with a true vertical depth of 10,134 ft. Production is from acidized and fractured perforations at 10,230-18,853 ft. Ascent Resources is based in Oklahoma City.

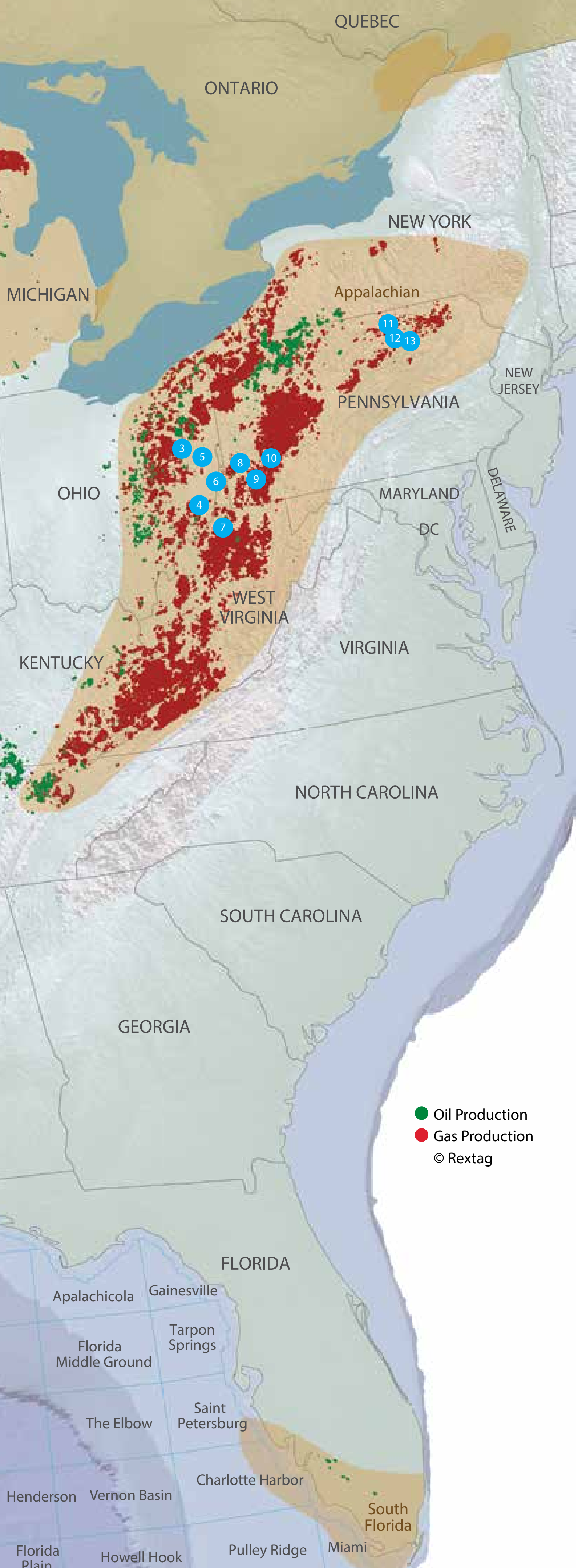
7 In Tyler County, W.Va., ***Jay-Bee Oil & Gas*** completed three Big Moses Field-Marcellus Shale wells from a drillpad in McElroy Dist., Shirley 7.5 Quad. The #1A Dopey was drilled to 12,551 ft with a projected true vertical depth of 6,630 ft. It produced 5.2 MMcf of gas with a shut-in casing pressure of 2,800 psi from a fractured zone at 7,170-12,368 ft. The #4 Dopey produced 4.1 MMcf of gas from a fractured and perforated zone at 7,276-10,854 ft with a shut-in casing pressure of 4,100 psi. It was drilled to 11,038 ft, 6,656 ft true vertical. The #2 Dopey was drilled to 12,858 ft with a true vertical depth of 6,630 ft and flowed 5 MMcf of gas per day with a shut-in casing pressure of 2,750 psi. The 12,858-ft well had a true vertical depth of 6,630 ft. Jay-Bee is based in Cairo, W.Va.

8 ***Range Resources Corp.*** announced a Marcellus Shale completion in Beaver County, Pa. The #7H Fat Albert 11966 Unit is on a 148.77-acre lease in Section 2, Burgettstown 7.5 Quad, Hanover Township. It was tested flowing 24.48 MMcf of gas from acidized and fractured perforations at 7,032-13,386 ft with a shut-in casing pressure of 2,165 psi. The discovery is in a new, unnamed field and was drilled to 13,459 ft with a true vertical depth of 5,689 ft. Range is based in Fort Worth, Texas.



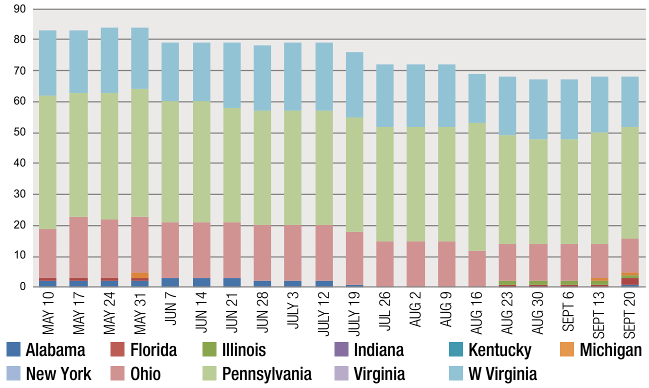
9 According to IHS Markit, ***Range Resources*** had two Marcellus Shale discoveries in Washington County, Pa. The Linden Field wells were drilled from a pad in Section 2 Hackett 7.5 Quad, Nottingham Township. The #5H Mizia James 11676 Unit was tested flowing 12.672 MMcf of gas per day with a shut-in casing pressure of 1,700 psi. It was drilled to 20,729 ft, and the true vertical depth is 7,174 ft. Production is from a fractured zone at 8,250-20,654 ft. The #13H Mizia James 11676 Unit was drilled to 17,850 ft, 7,207 ft true vertical, and flowed 23.784 MMcf of gas with a shut-in tubing pressure of 1,800 psi. Production is from a fractured zone at 9,043-17,802 ft.





Eastern U.S. Rig Count

May 10, 2019-Sept. 20, 2019



Data compiled from Baker Hughes

10 A Marcellus Shale discovery by Pittsburgh-based ***EQT Corp.*** was tested flowing 26.104 MMcf of gas per day. The Gump Field well, #7 Stattler Road, is in Section 5, Oak Forest 7.5 Quad, Whiteley Township in Greene County, Pa. It was drilled to 29,068 ft, 8,100 ft true vertical, and was tested on an unreported choke size with a shut-in casing pressure of 3,400 psi. Production is from fractured perforations at 8,835-20,937 ft.

11 ***Southwestern Energy*** announced results from a Marcellus Shale well in Bradford County, Pa. The Herrick Field completion, #8H Blaine-Hoyd, is in Section 8 Le Raysville 7.5 Quad, Stevens Township. It was drilled to the north to 14,522 ft, 5,975 ft true vertical. It was tested flowing 10.05 MMcf of gas with no reported water per day with a shut-in casing pressure of 1,750 psi, and production is from fractured perforations at 6,398-14,446 ft. Southwestern's headquarters are in Spring, Texas.

12 A ***Chesapeake Operating Inc.*** Marcellus discovery in Bradford County, Pa., produced 25.807 MMcf of gas per day. The Herrick Field well, #3H Shumhurst, is in Section 5, Laceyville 7.5 Quad, Tuscarora Township. It was drilled to 12,983 ft with a true vertical depth of 6,888 ft. Production is from a 25-stage fractured zone at 7,391-12,743 ft with a shut-in casing pressure of 2,950 psi. Chesapeake is based in Oklahoma City.

13 In the Dimock Field portion of Susquehanna County, Pa., ***Cabot Oil & Gas*** announced results from four Marcellus Shale completions in Section 5, Springville 7.5 Quad, Springville Township. The #8H Hauser was drilled to 15,989 ft, 7,486 ft true vertical. It was tested flowing 28.1 MMcf of gas with no reported water per day. Production is from perforations at 8,106-15,911 ft. The #6 Hauser was drilled to 17,935 ft, 7,444 ft true vertical. It flowed 37.9 MMcf of gas per day from perforations at 8,259-17,864 ft with a shut-in casing pressure of 1,500 psi. The #16H-U Hauser J was drilled to 15,795 ft, 7,354 ft true vertical, and was tested flowing 15.5 MMcf of gas per day with a shut-in casing pressure of 900 psi. Production is from perforations at 8,259-17,864 ft. The #16H-U Hauser J was drilled to 15,795 ft, 7,354 ft true vertical. It produced 15.5 MMcf of gas per day with a shut-in casing pressure of 900 psi. The #12H-U-Hauser J was drilled to 17,481 ft, 7,161 ft true vertical. It produced 16.3 MMcf of gas from perforations at 8,273-17,227 ft with a shut-in casing pressure of 1,150 psi. Cabot's headquarters are in Houston.

GULF COAST

1 IHS Markit reported that ***EOG Resources Inc.***, based in Houston, completed four horizontal Eagle Ford wells in Eagleville Field in Karnes County (RRC Dist. 2), Texas. The ventures were completed from a common drillpad in Section 29, Newton H. Morris Survey, A-456. The #4H Korora D was tested flowing 2.572 Mbbl of 34-degree-gravity crude, 908 Mcf of gas and 1.633 Mbbl of water per day through acid- and fracture-treated perforations at 8,581-18,197 ft. The flowing tubing pressure was 1,010 psi during testing on a 40/64-in. choke. The well was drilled to 18,294 ft (9,122 ft true vertical) and bottomed 2 miles to the southeast in Section 49, George Rounds Survey, A-248. The #1H Korora A was tested flowing 1.56 Mbbl of crude, 542 Mcf of gas and 1.851 Mbbl of water from 8,647-18,169 ft. It was drilled to 18,259 ft, 9,076 ft true vertical. The #2H Korora B was drilled to 18,241 ft, 9,097 ft true vertical, and was tested flowing 1.789 Mbbl of oil, 624 Mcf of gas and 1.749 Mbbl of oil per day. The #3H Korora C was drilled to 18,217 ft, 9,065 ft true vertical, and flowed 1.738 Mbbl of oil, 581 Mcf of gas and 1.889 Mbbl of water per day.

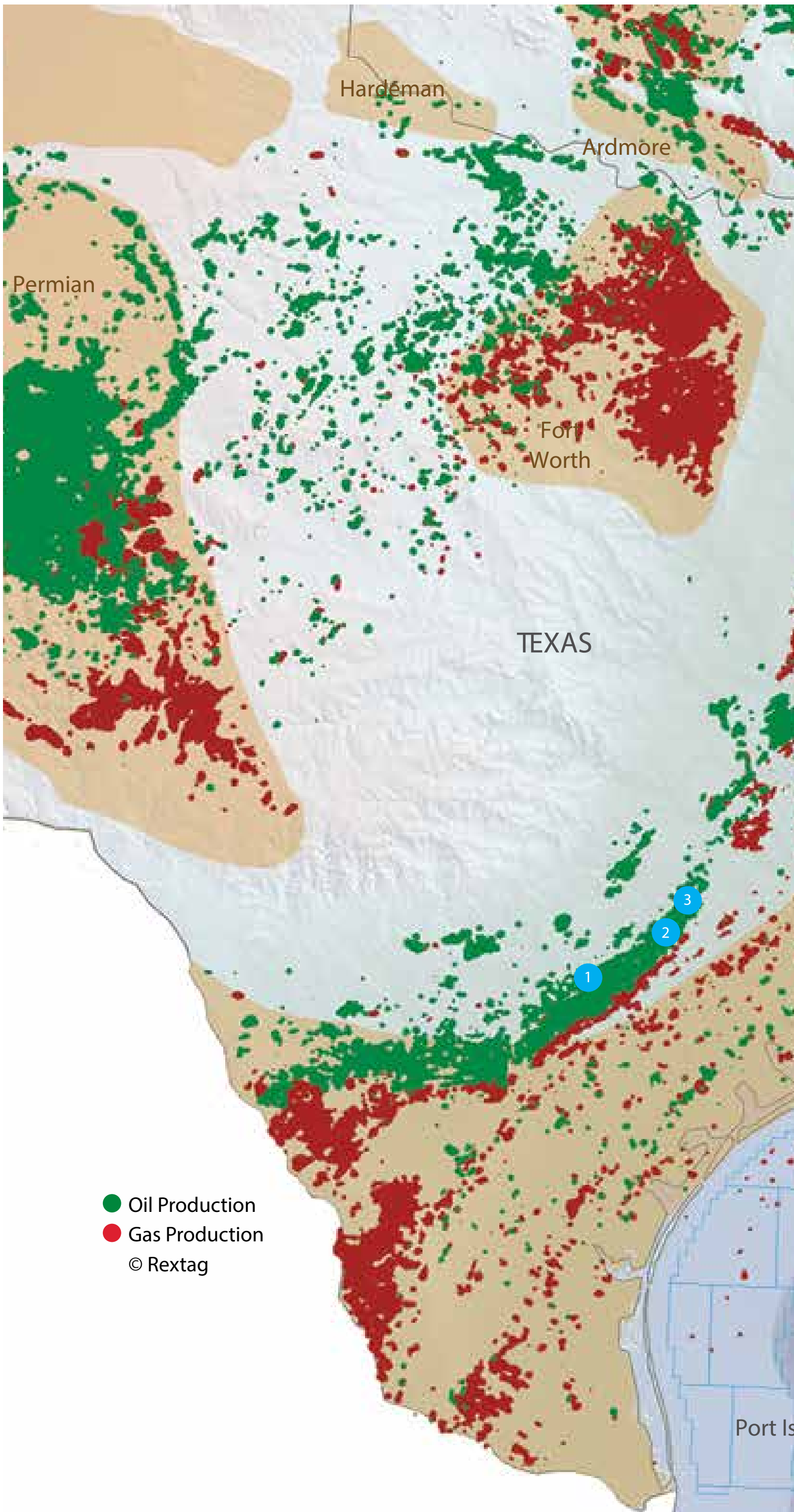
2 Two Eagle Ford-Eagleville Field wells were completed by ***Penn Virginia Oil Corp.*** in Joseph McCoy Survey, A-46, in Gonzales County, (RRC Dist. 1), Texas. The #6H RCRS Jane was tested flowing 1.067 bbl of oil with 670 Mcf of gas per day. It was drilled to 15,774 ft, 10,383 ft true vertical, and is producing from an acidized and fractured zone at 11,041-15,459 ft. It was tested on a 16/64-in. choke with a flowing tubing pressure of 2,675 psi. The #7H RCRS-Jane flowed 832 bbl of oil, 494 Mcf of gas and 463 bbl of water per day. It was drilled to 17,350 ft, 10,194 ft true vertical, and production is from acidized and fractured perforations at 11,118-17,253 ft. Gauged on a 14/64-in. choke, the flowing tubing pressure was 2,744 psi. Penn Virginia's headquarters are in Houston.

3 Dallas-based ***Rosewood Resources Inc.*** completed two Eagle Ford producers from a drillpad in Section 46, Isbell Alexander Survey, A-286, in Gonzales County (RRC Dist. 2), Texas. The #3H Double T Ranch was drilled to 14,840 ft, 9,891 ft true vertical, and it produced 885 bbl of oil, 272 Mcf of gas and 1.984 Mbbl of water per day. Production is from fractured perforations at 10,697-14,786 ft. Tested on a 26/64-in. choke, the flowing tubing pressure was 1,255 psi. The #4H Double T Ranch was drilled to 15,894 ft, 9,892 ft true vertical, and it flowed 846 bbl of oil, 276 Mcf of gas and an unreported amount of water per day from perforations at 9,977-15,826 ft.

4 ***GeoSouthern Operating*** completed two Austin Chalk gas wells in Fayette County (RRC Dist. 3), Texas, in Giddings Field. The #1H Carter Unit flowed 10.296 MMcf of gas, 265 bbl of 57.2-degree-gravity condensate and 1.8 Mbbl of water per day from an acid- and fracture-treated zone at 13,520-21,291 ft. The flowing casing pressure was 4,649 psi when tested on a 28/64-in. choke. The well was drilled to 21,465 ft (13,152 ft true vertical) in the John Townsend Survey, A-303, and bottomed about 2 miles to the northwest in Robert Peebles Survey, A-78. The offsetting #1H Wilson Unit flowed 9.336 MMcf of gas, 278 bbl of 54.8-degree-gravity condensate and 2.136 Mbbl of water per day from acid- and fracture-treated perforations at 13,434-21,655 ft. Tested on a 28/64-in. choke, the flowing casing pressure was 4,848 psi. The venture was drilled to 21,817 ft, 12,995 ft true vertical, and bottomed within 2 miles to the northwest in Benjamin Greenville Survey, A-50.

5 Three Haynesville Shale-Caspiana Field discoveries were reported by Dallas-based ***Aethon Energy Operating LLC*** from a drillpad in Section 24-15n-13w in DeSoto Parish, La. The #1-Alt Peace J M 24-13 HC produced 21.857 MMcf of gas and 319 bbl of water per day. The venture was drilled to 21,415 ft, 11,123 ft true vertical. It was tested on a 24/64-in. choke with a flowing casing pressure of 7,752 psi, and production is from a fractured zone at 11,500-21,346 ft. The #1-Alt Pace 24-13 HC was drilled to 21,231 ft, 11,135 true vertical. It produced 21.917 MMcf of gas and 438 bbl of water per day when tested on a 26/64-in. choke. Production is from fractured perforations at 11,570-21,160 ft. The #2-Alt Peace J M 24-13 HC flowed 22.748 MMcf of gas and 289 bbl of water per day from fractured perforations at 11,630-21,556 ft. It was tested on a 26/64-in. choke, and the flowing casing pressure was 7,422 psi.

6 IHS Markit reported that ***GEP Haynesville*** has completed four extended-lateral Haynesville Shale wells in Section 17-17n-12w, Bossier Parish, La. The #001 Lucky 17-18-19 HC flowed 31.295 MMcf of gas and 689 bbl of water from a fracture-treated zone at 11,529-21,018 ft. The flowing casing pressure was 7,243 psi on a 30/64-in. choke. The horizontal Sligo Field well was drilled to 21,235 ft (11,408 ft true vertical) and bottomed to the south in Section 17-17n-12w. The offsetting #003-Alt Lucky Family 17-20 HC flowed 28.248 MMcf of gas and 1.137 Mbbl of water per day from fracture-stimulated perforations at 11,285-20,848 ft. It was drilled to 21,060 ft (11,366 ft true vertical) and bottomed about 2 miles to the south in Section 20. One-half mile to the east, #004-Alt Lucky Family 17-20 HC flowed 29.348 MMcf of gas and 2.022 Mbbl of water pay from perforations at 11,290-21,017 ft. The offsetting #005-Alt Lucky Family 17-20 HC flowed 28.983 MMcf of gas and 1.824 Mbbl of water per



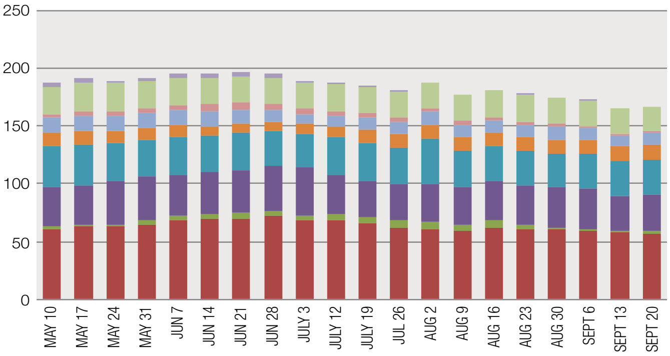
day from perforations at 11,336-20,984 ft. GEP Haynesville is based in The Woodlands, Texas.

7 ***Range Resources*** has completed a horizontal Cotton Valley gas well in Lincoln Parish, La.'s Simsboro West Field. The #1-Alt Heard 13-24H flowed 4.608 MMcf of gas, 1 bbl of crude and 4.128 Mbbl of water daily from an acid- and fracture-treated zone at 11,266-16,978 ft. It was tested on a 32/64-in. choke, and the flowing casing pressure was 2,180 psi. The Fort Worth, Texas-based company's sidetracked well was drilled in Section 13-18n-4w and bottomed within 1.5 miles to the south in Section 24. It was drilled to 17,130 ft, and the true vertical depth is 11,689 ft. The original hole was abandoned at 11,800 ft.

8 New York City-based ***Hess Corp.*** has scheduled a development test in the company's Stampede Field, a deepwater Miocene reservoir. The #4SB OCS G26315 will be drilled in the northern half of Green Canyon Block 512, and area water depth is 3,500 ft. Stampede is a joint development of the Pony and Knotty Head discoveries. In May 2019, six Hess-owned wells in the area recovered 1 MMbbl of crude and 518 MMcf of gas from Upper Miocene at around 30,000 ft. Cumulative field production is more than 10 MMbbl of crude and 5.3 Bcf of gas.

Gulf Coast Rig Count

May 10, 2019-Sept. 20, 2019



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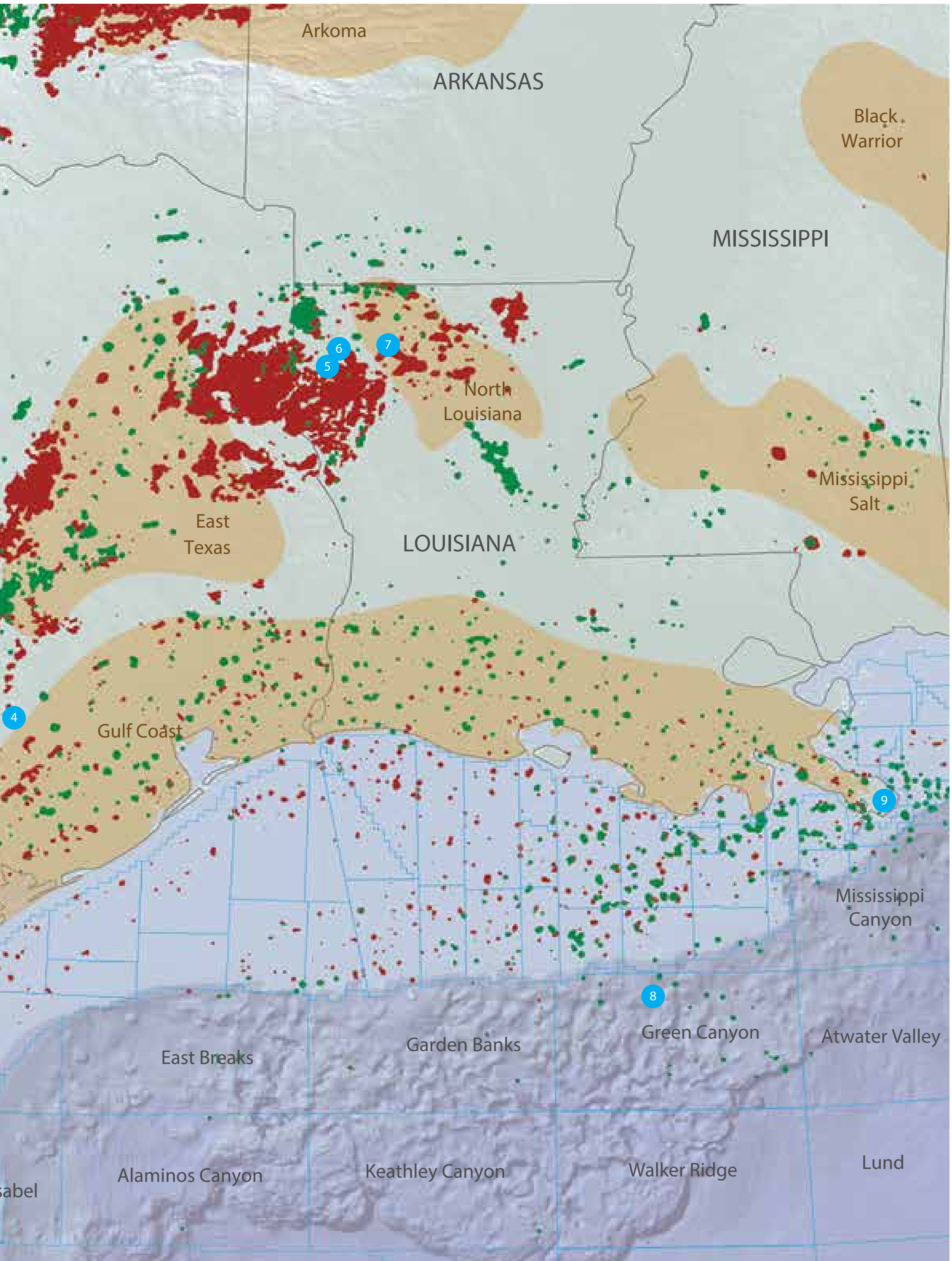


9 A development test on Breton Sound Block 30 in Louisiana State waters has been permitted by ***Upstream Exploration***. The #1 State Lease 21864 has a planned depth of 10,000 ft and will be in the southwestern corner of The Breton Sound Block 33 Field. The test will target Upper Miocene. According to IHS Markit, comparable production in the field came from #4 State Lease 14217, a directional sidetrack within one-half mile to the southwest in adjacent Block 34. The well was completed in 2004 flowing gas from perforations at 9,648-56 ft in Cib Carst (Miocene). Allocated recovery from the sidetrack totaled 325.7 MMcf of gas and 102.95 Mbbl of condensate through 2009. Upstream's headquarters are in Metairie, La.

MIDCONTINENT & PERMIAN BASIN

1 In Eddy County, N.M., ***EOG Resources Inc.*** completed a Wolfcamp well, #701H Stella Blue 30 Federal Com, that flowed 2.478 Mbbl of oil, 14.43 MMcf of gas and 7.757 Mbbl of water per day. The Purple Sage Field well is in Section 30-26s-31e. It was tested on a 64/64-in. choke, and the shut-in casing pressure was 2,513 psi. Production is from fractured perforations at 11,500-21,067 ft, and it was drilled to 21,231 ft, 11,015 ft true vertical.

2 ***Oxy USA Inc.*** announced results from a Cotton Draw Field well in Eddy County, N.M. The #001H Platinum MDP1 34-3 Federal Com is on Section 34-23s-31e, and it produced 2.257 Mbbl of oil, 3.166 MMcf of gas and 5.464 Mbbl of water per day. Drilled to the north to 20,219 ft, 10,068 ft true vertical, production is from acidized and fractured perforations at 9,626-20,182 ft. It was tested on a 64/64-in. choke, and the shut-in casing pressure was 709 psi. Oxy's headquarters are in Los Angeles.

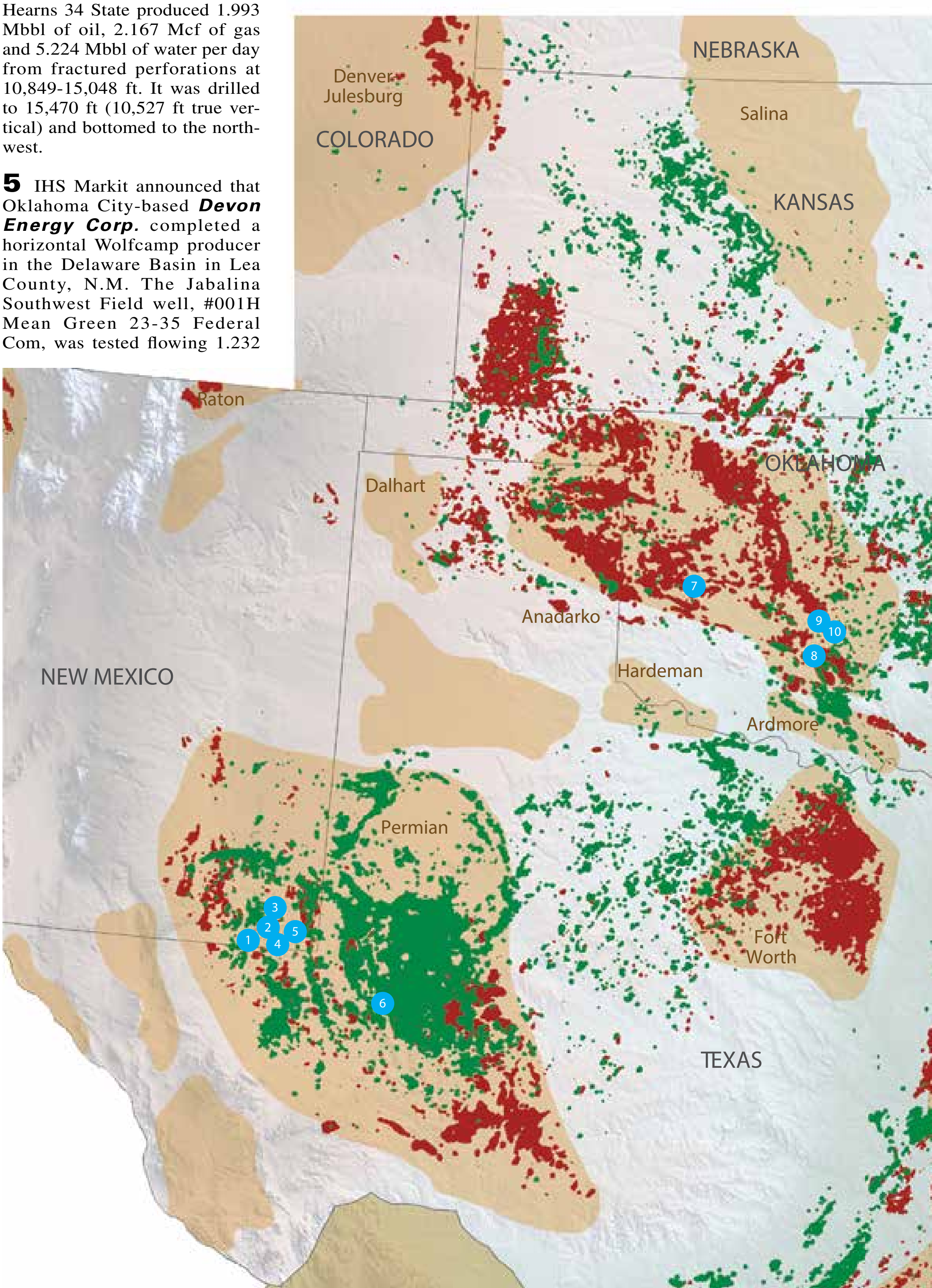
3 In Lea County, N.M., ***EOG Resources Inc.*** announced results from a Wolfcamp completion in Section 16-25sS-33e. The #703H Green Drake 16 Fed Com produced 4.077 Mbbl of oil, 7.957 MMcf of gas and 8,420 bbl of water per day. The Draper Mill Field well was drilled to 19,986 ft, 12,400 ft true vertical, and was drilled to the northeast. Gauged on a 52/64-in. choke, the shut-in casing pressure was 2,957 psi, and production is from a fractured and perforated zone at 12,861-19,995 ft.

4 Two Bone Spring completions were reported in Section 34-24s-33e in Lea County, N.M. by ***EOG Resources Inc.*** The #502H Hearns 34 State Com produced 2.789 Mbbl of oil, 3.899 MMcf of gas and 6.455 Mbbl of water per day. It was drilled to 21,065 ft, 10,818 ft true vertical. Production is from fractured perforations at 11,148-21,034 ft. Gauged on a 58/64-in. choke, the flowing casing pressure was 910 psi. Within one-half mile to the west, #406H Hearns 34 State produced 1.993 Mbbl of oil, 2.167 Mcf of gas and 5.224 Mbbl of water per day from fractured perforations at 10,849-15,048 ft. It was drilled to 15,470 ft (10,527 ft true vertical) and bottomed to the northwest.

5 IHS Markit announced that Oklahoma City-based ***Devon Energy Corp.*** completed a horizontal Wolfcamp producer in the Delaware Basin in Lea County, N.M. The Jabalina Southwest Field well, #001H Mean Green 23-35 Federal Com, was tested flowing 1.232 Mbbl of oil, 1.794 MMcf of gas and 6.579 Mbbl of water daily. Production is from acidized and fracture-treated perforations at 12,956-23,113 ft. The well was drilled to 23,240 ft in Section 23-26s-34e. The lateral bottomed almost 2 miles to the south in irregular Section 35 with a true vertical depth of 12,637 ft.

6 A horizontal Wolfcamp oil well in the Reagan County (RRC Dist. 7C), Texas, portion of the Midland Basin was announced by Houston-based ***RP Operating LLC***. The #1H Cider A 203-226 pumped 1.136 Mbbl of oil, 927 Mcf of gas and 1.036 Mbbl of water per day from Spraberry. The discovery is in Section 203, Block 1, TP& RR Co Survey, A-562. It was drilled to 17,676 ft with a true vertical depth of 7,158 ft and bottomed about 2 miles to the south in Section 226. Production is from perforations at 7,770-17,620 ft.

7 Denver-based ***FourPoint Energy LLC*** has completed two horizontal Des Moines producers at a southern Anadarko Basin pad in Section 32-10n-18w, Washita County, Okla. The #1HB Tango 29X20-10-18 was

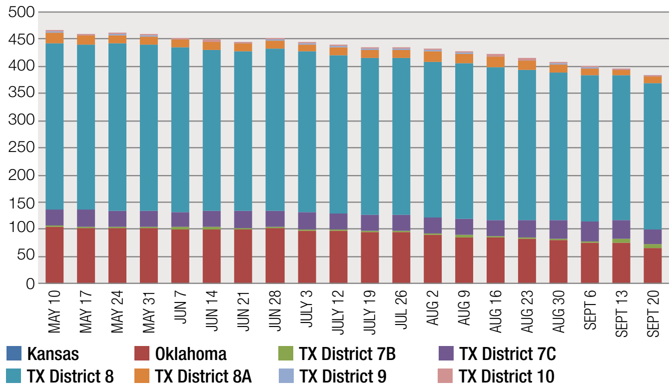


tested in Des Moines Granite Wash G flowing 17.8 MMcf of gas, 237 bbl of 51-degree-gravity condensate and 270 bbl of water per day. It was drilled to 21,767 ft to the north across Section 29 and bottomed in Section 20-10n-18w. The true vertical depth was estimated at 12,352 ft. Gauged on a 17/64-in. choke after acidizing and fracturing, the flowing tubing pressure was 2,890 psi. Twenty ft to the west, #2HA Tango 29X20-10-18 produced 617 bbl of 45-degree-gravity oil, 1.78 MMcf of gas and 1.608 Mbbl of water per day. It was drilled with a parallel lateral to 20,702 ft, then perforated, acidized and fractured at 11,594-20,530 ft in the Britt interval of Des Moines Granite Wash. The planned true vertical depth was 11,169 ft. It was tested on a 12/64-in choke, and the flowing tubing pressure was 1,600 psi.

8 Oklahoma City-based ***Gulfport Energy Corp.*** announced completion results for two horizontal Woodford producers in Grady County, Okla. According to IHS Markit, #3-27X34H Jeannie was drilled in Section 27-5n-6w and initially flowed 21.5 MMcf of gas, 628 bbl of 56-degree-gravity condensate and 2.763 Mbbl of water per day. It was drilled to 21,455 ft, 15,215 ft true vertical, and bottomed in Section 34-5n-6w with production from perforations at 15,350-21,308 ft. About 20 ft north on the pad, #4-27X34H Jeannie flowed 15.4 MMcf of gas with 558 bbl of condensate and 1.621 Mbbl of water per day. It was tested on a 34/64-in. choke and is producing from perforations at 15,252-21,619 ft. The venture was drilled to 21,770 ft, and the true vertical depth is 15,229 ft. The Chitwood Field wells were acidized and fracture-stimulated.

Midcontinent & Permian Basin Rig Count

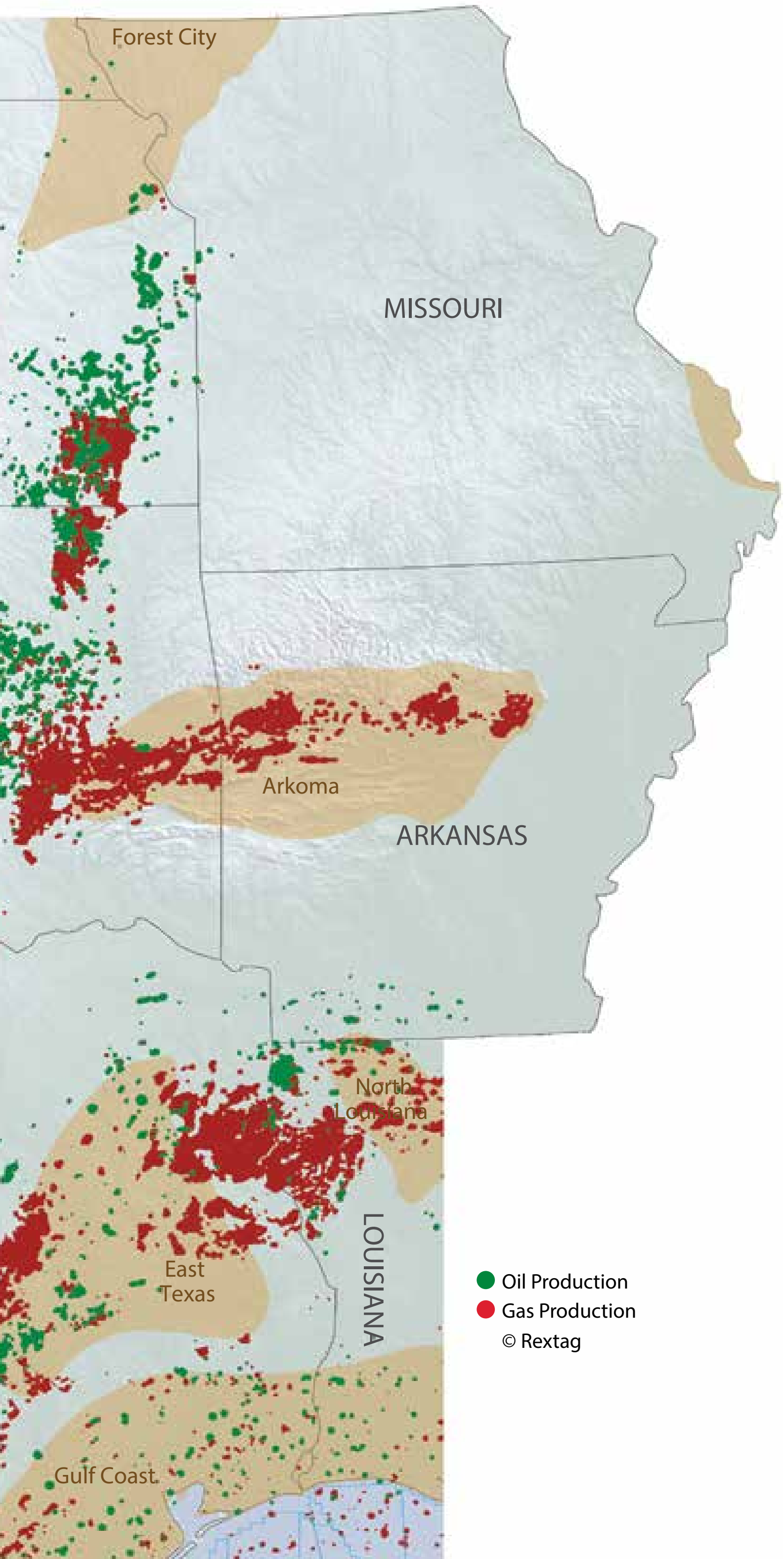
May 10, 2019-Sept. 20, 2019



Data compiled from Baker Hughes

9 Two new horizontal Springer Shale wells have been completed by ***Continental Resources Inc.*** in the Scoop play in Grady County, Okla. The wells were drilled from a pad in Section 27-7n-6w. The #3-27-34-3-10XHS Walters West produced 461 bbl of oil, 713 Mcf of gas and 3.035 Mbbl of water per day. It was tested on a 22/64-in. choke from perforations at 12,431-24,183 ft, following acid and fracture treatments. The lateral was drilled to the south 2 miles across sections 34-7n-6w and 3-6n-6w and bottomed in Section 10-6n-6w with a true vertical depth of 13,076 ft. The #4-27-22XHS AC Walters is within one-half mile to the northeast, and it was drilled to 21,696 ft (12,036 ft true vertical). It was perforated, acidized and fractured at 12,451-16,435 ft and 16,483-21,524 ft and flowed 327 bbl of oil, 547 Mcf of gas and 2.602 Mbbl of water per day. Continental's headquarters are in Oklahoma City.

10 IHS Markit reported that ***Continental Resources Inc.*** completed two horizontal Springer Shale wells in the Anadarko Basin-Scoop play in Grady County, Okla. In Section 35-7n-6w, #2-35-2-11XHS Martha initially flowed 347 bbl of 47-degree-gravity oil, 626 Mcf of gas and 3.017 Mbbl of water per day from acidized and fractured perforations between 12,369 and 23,878 ft. It was tested on an 18/64-in. choke with a flowing tubing pressure of 3,535 psi, and the shut-in tubing pressure was 4,830 psi. It was drilled about 2 miles to the south across Section 2 and bottomed in Section 11-6n-6w. The respective measured true vertical depths are 24,060 ft and 12,927 ft. About 1,500 ft to the east in Section 35-7n-6w, #3-35-2-11XHS Martha flowed 347 bbl of oil, 533 Mcf of gas and 2.987 Mbbl of water per day. Production is from a treated parallel lateral at 12,359-23,463 ft and was tested on an 18/64-in. choke. It was drilled to 23,583 ft, 12,827 ft true vertical, and bottomed in Section 11-6n-6w.



WESTERN U.S.

1 In Sweetwater County, Wyo., ***Southland Royalty Co.*** completed a horizontal Lewis discovery that flowed 4.299 MMcf of gas, 402 bbl of oil and 1.609 Mbbl of water per day. According to IHS Markit, #1-8H Chain Lakes H5, Section 1-23n-93w, is producing from a lateral extending from 12,077 ft southward to 16,825 ft. The true vertical depth is 11,606 ft. It was tested on a 22/64-in. choke after 18-stage fracturing (plug-and-perf) between 12,077 and 16,825 ft in the Lewis F zone. The casing pressure was 3,100 psi. Southland is based in Fort Worth, Texas.

2 ***Samson Resources*** completed a Frontier producer in Section 29-39n-74w in Converse County, Wyo. The #39-74fh Allemand Fed 21-2017 was tested flowing 1.327 Mbbl of oil, 4.367 MMcf of gas and 493 bbl of water per day. The Hornbuckle Field well was drilled to 22,711 ft, 10,533 ft true vertical. It was tested on a 22/64-in. choke with a shut-in tubing pressure of 4,029 psi and a flowing tubing pressure of 3,322 psi, and it bottomed in Section 17-39n-74w. Production is from fractured perforations at 12,761-22,439 ft.

3 Houston-based ***EOG Resources Inc.*** announced results from two Crossbow Field-Parkman completions in Section 8-41n-72w of Campbell County, Wyo. The directionally drilled #410-0820H Arbalest was drilled to 17,885 ft, 7,786 ft true vertical, and was tested flowing 1.292 Mbbl of oil, 2.917 MMcf of gas and 2.236 Mbbl of water per day. Production is from fractured perforations at 8,190-17,782 ft. About 20 ft to the northeast, #411-0820H Arbalest flowed 1.018 Mbbl of oil, 3.287 Mcf of gas and 2.598 Mbbl of water per day. Production is from perforations at 8,803-19,094 ft. The well was drilled to 19,094 ft, 7,793 ft true vertical, and was tested after acidizing and fracturing.

4 Oklahoma City-based ***Devon Energy Corp.*** announced results from a Turner completion in Converse County, Wyo. The #3XTH RU JFW Fed 10-153972 initially flowed 1.305 Mbbl of oil, 2.34 MMcf of gas and 632 bbl of water daily. It was drilled in Section 10-39n-72w and is producing from a lateral in Turner drilled to the south to 20,188 ft, 11,061 ft true vertical, and it bottomed in Section 15-39n-72w. It was tested on a 24/64-in. choke after 30-stage fracturing between 11,335 and 20,050 ft. Devon is based in Oklahoma City.

5 Two horizontal Turner producers in the southern Powder River Basin were announced by Oklahoma City-based ***Chesapeake Operating Inc.*** The wells were drilled from a pad in Section 12-34n-72w of Converse County, Wyo. The #22H SFU (Sundquist Flats Unit) 12-34-72 USA C TR initially flowed 395 bbl of 43.2-degree-gravity oil, 419 Mcf of gas and 530 bbl of water per day. Production is from a Turner lateral drilled to the southeast to 21,325 ft at a bottomhole location in Section 18-34n-71w. The true vertical depth is 12,227 ft. It was tested on a 30/64-in. choke after 22-stage fracturing between 12,677 and 21,243 ft. The #21H SFU 12-34-72 USA C TR was completed flowing 971 bbl of oil, 903 Mcf of gas and 805 bbl of water per day. Production is from a lateral drilled north-northwestward to 20,077 ft, 12,225 ft true vertical, and it bottomed in Section 1-34n-72w. It was tested on a 30/64-in. choke following 19-stage fracture stimulation between 12,880 and 19,995 ft.

6 ***Chesapeake Operating Inc.*** announced results from two Turner Sand wells completed at a drillpad in Section 19-35n-70 in Converse County, Wyo. The #18H BB 19-35-70 USA A TR was drilled to 22,167 ft, 11,561 ft true vertical, and was tested flowing 936 bbl of oil, 479 Mcf of gas and 1.185 Mbbl of 42-degree-gravity oil per day. It was tested on a 40/64-in. choke, and the shut-in tubing pressure was 977 psi. Production is from perforations at 12,047-22,046 ft. The #17H BB 19-35-70 USA A TR was drilled to 22,144 ft, 11,565 ft true vertical. The venture flowed 1.164 Mbbl of oil, 388 Mcf of gas and 878 bbl of water per day. Production is from perforations at 12,019-22,096 ft.

7 In Weld County, Colo., ***Extraction Oil & Gas Inc.*** reported results from two Wattenberg Field wells in Section 28-1,-68w. The #34S-20-15N Coyote Trails produced 652 bbl of oil, 1.598 Mcf of gas and 192 bbl of water per day from commingled perforations in Codell at 9,870-19,385 ft and Fort Hays at 12,193-13,553 ft. It was drilled to 19,485 ft, 8,170 ft true vertical, and tested on a 20/64-in. choke with a flowing tubing pressure of 1,740 psi and a flowing casing pressure of 2,744 psi. The #34S-20-16N Coyote Trails was drilled to the south to 19,307 ft, 7,773 ft true vertical. It produced 633 bbl of oil, 1.206 Mcf of gas and 283 bbl of water per day from Niobrara perforations at 9,685-19,194 ft. Gauged on a 20/64-in. choke, the flowing tubing pressure was 1,740 psi, and the flowing casing pressure was 2,744 psi. Extraction's headquarters are in Denver.

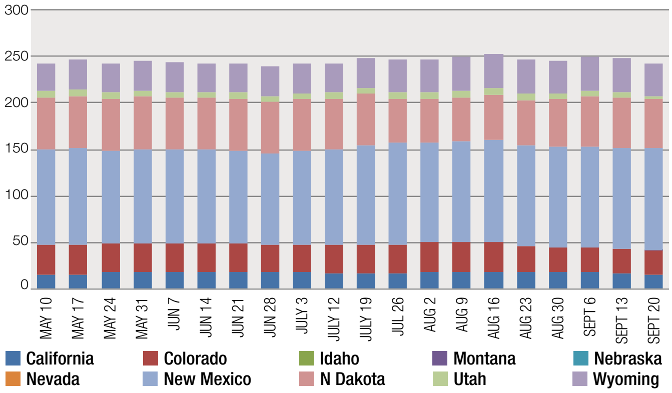
8 A Middle Bakken discovery in Richland County, Mont., flowed 1.465 Mbbl of oil, 989 Mcf of gas and 1.347 Mbbl of water per day. The ***Continental Resources Inc.*** horizontal completion, #2-34H Baird-Federal, is in Section 34-27n-53e. Production is from a lateral

drilled to the southwest about 2 miles to 18,840 ft with a bottomhole location in Section 3-26n-53e. The true vertical depth is 9,056 ft. It was tested following fracture stimulation between 9,425 and 18,840 ft, and the number of stages were not disclosed. Continental is based in Oklahoma City.

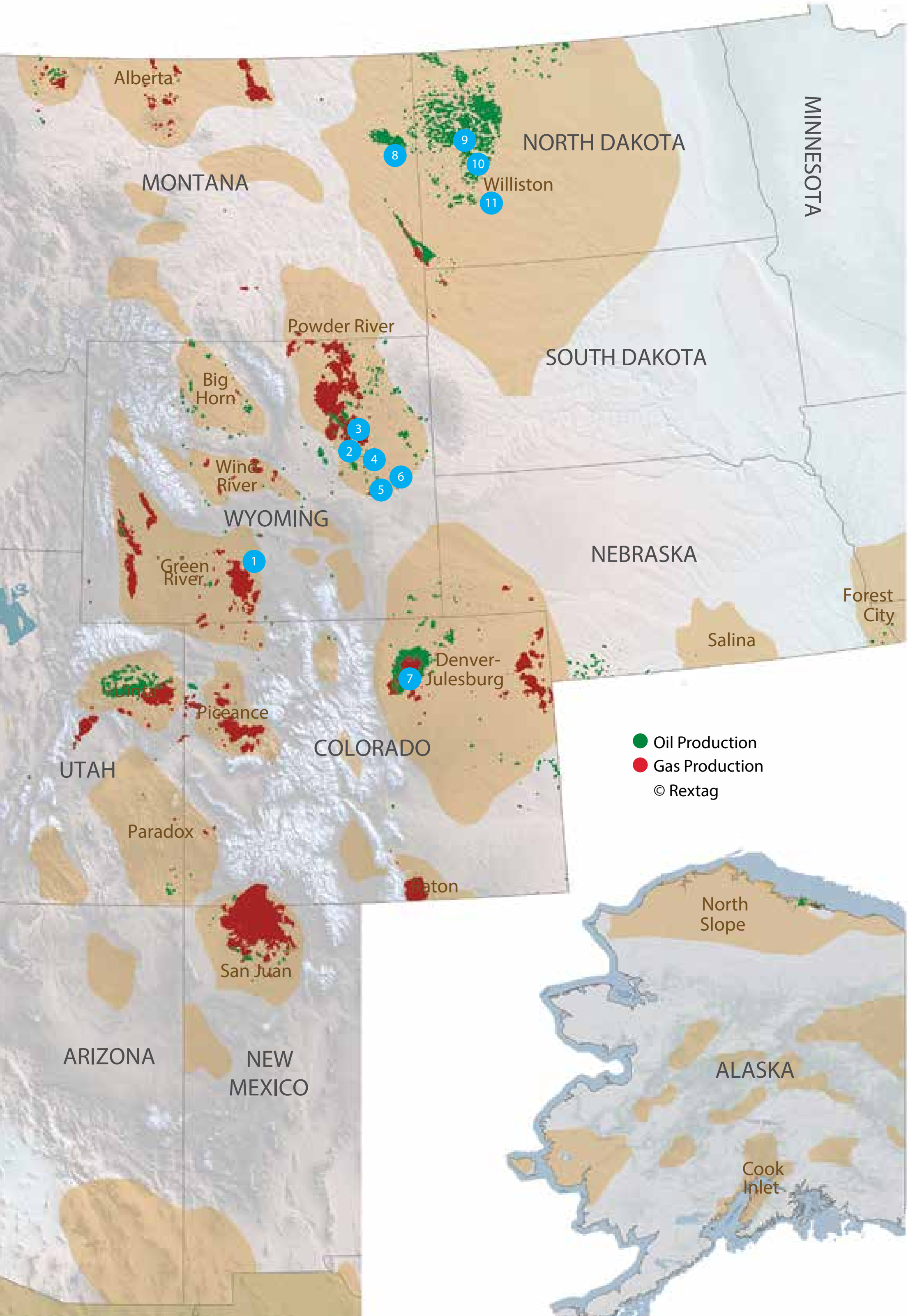
9 ***Hess Corp.*** completed two Three Forks-Capa Field Wells in from a drillpad in Section 19-155n-95w in Williams County, N.D. The #155-95-3031H-8 CA-Ferguson Smith well was drilled to 22,298 ft with a true vertical depth of 9,880 ft. It flowed 2.001 Mbbl of 42-degree-gravity oil, 1.822 MMcf of gas and 1.228 Mbbl of water per day. Production is from acidized and fractured perforations at 10,041-20,264 ft. Gauged on a 36/64-in. choke, the flowing tubing pressure was 1,347 psi. The #155-95-3031H-7 CA-Ferguson Smith well was drilled to 20,430 ft, 9,970 ft true vertical. It produced 1.496 Mbbl of 42-degree-gravity oil, 1.26 MMcf of gas and 1.736 Mbbl of water per day. It was tested on a 36/64-in choke, and the flowing tubing pressure was 1,172 psi from a Three Forks interval at 10,161-20,430 ft. Hess is based in New York.

Western U.S. Rig Count

May 10, 2019-Sept. 20, 2019



Data compiled from Baker Hughes



10 A ***Hess Corp.*** completion in McKenzie County, N.D., was tested flowing 10.626 Mbbl of oil, 27.6 MMcf of gas and 5.599 Mbbl of water per day. The #153-94-2734H-8 AN-Bohmbach in Section 22-153n-94w. Production is from a horizontal Middle Bakken interval at 11,084-20,749 ft. The Antelope Field well was drilled to 20,749 ft, 10,749 ft true vertical, and was drilled to the south and bottomed in Section 34-153n-94w. Gauged on a 76/76-in. choke, the flowing casing pressure was 1,666 psi.

11 A horizontal Middle Bakken producer on the Fort Berthold Indian Reservation by ***Marathon Oil Corp.*** flowed 8.448 Mbbl of oil with 7.083 MMcf of gas and 7.811 Mbbl of water per day. The #21-16H Reyes-USA is in Section 9-150n-93w of Mountrail County, N.D. Production is from a two-section lateral extending from 11,140 ft southward to 21,227 ft (10,704 ft true vertical) at a bottomhole location in Section 21-150n-93w. It was tested on a 108/64-in. choke after 40-stage fracturing between 11,255 and 21,092 ft.

INTERNATIONAL HIGHLIGHTS

The bombing of the Saudi Arabian petroleum facilities and any retaliatory military action by Saudi Arabia or allies, including the U.S., presents extremely risky challenges.

According to an IHS Markit report, the combination of precision, range and damage indicates a stronger capability than previously seen. The attacks indicate the ability of the weapons used to bypass Saudi air defenses, and it signals to Gulf Arab states and the U.S. that their own infrastructure and military installations could be similarly targeted. Should Saudi Arabia retaliate, its energy, aviation, desalination, electricity and energy infrastructure would almost certainly be hit. Other possible targets in the region include air force bases in Kuwait, Qatar, and the United Arab Emirates and naval facilities in Bahrain.

Increasing the risk environment would occur if Saudi Arabia blames Iran for the attack, retaliates against Iran directly, or against Iraqi Popular Mobilization Units, or if the U.S. declares its willingness to support any Saudi military retaliation.

Decreasing the risk environment would occur if Saudi Arabia refrains from blaming Iran directly; if the U.S. gives Iran economic incentives to negotiate, such as oil export waivers or a credit line, directly or through European countries, meeting Iran's precondition to negotiate; or finally if the Saudis refrain from intensive bombardment of Yemen.

—Larry Prado

1 ***Trinidad***

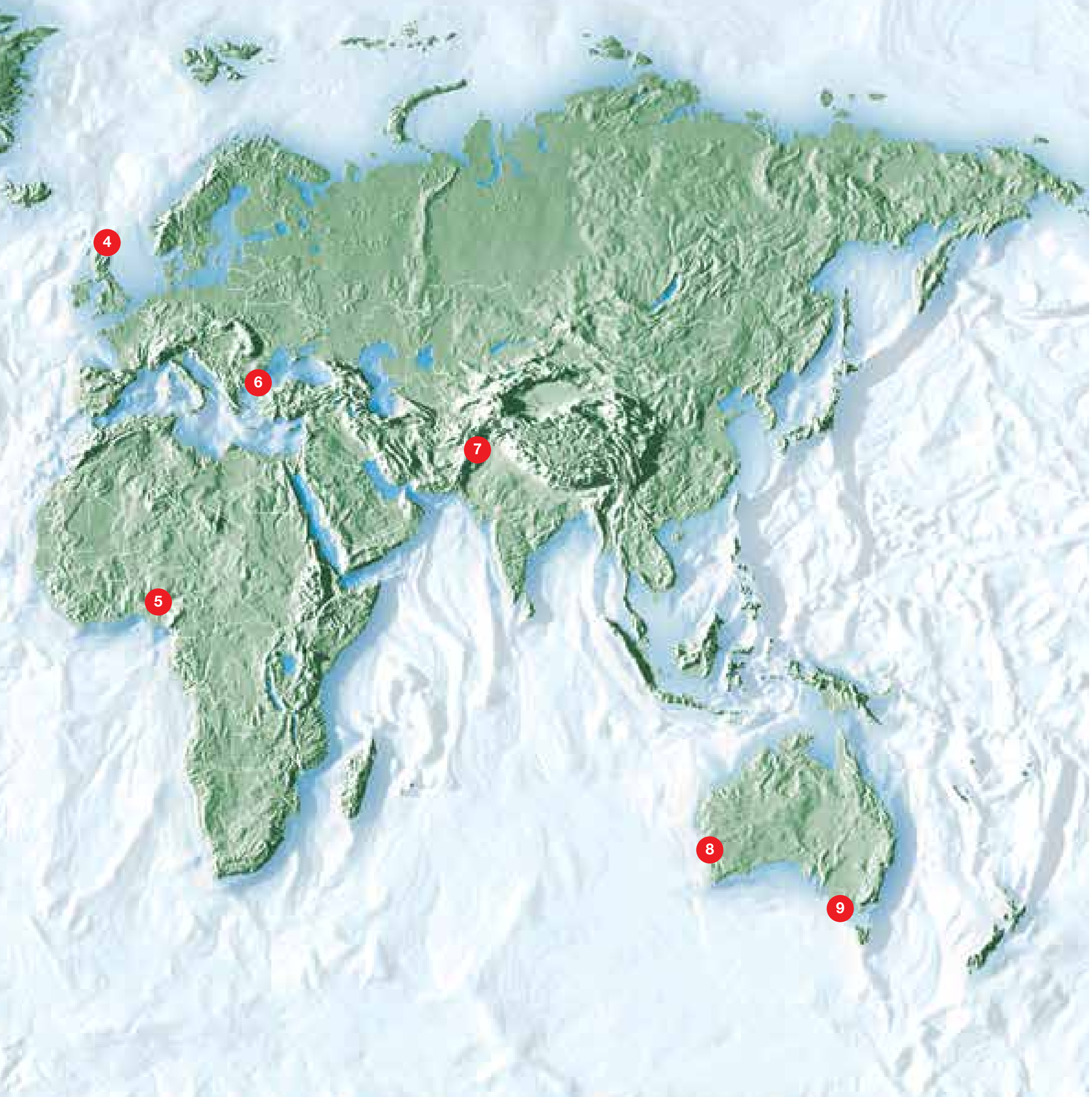
Touchstone Exploration's first exploration well in Trinidad's Ortoire Exploration Block has encountered four zones with prospective gas accumulations. According to the company, the onshore exploration well, #1-Coho, was drilled to 8,560 ft, and well logging indicates four gas-bearing packages in the Herrera member of the Mid-Miocene-aged Cipero Formation. Two sand packages with approximately 64 ft of net gas pay were encountered in Upper Herrera Gr7b section between 5,486 and 5,782 ft. The Gr7b Sand packages were similar to results in offsetting #1-Corosan, where similar sands tested flowing about 8 MMcf per day. Wireline logging also indicated two prospective gas sand packages in the Herrera Gr7c section between 6,530 and 7,240 ft. The two sand packages contain a combined 41 ft of probable net gas pay which was not tested. In addition, logging identified the presence of oil sands in Lower Herrera Gr7b repeat section at 7,788 ft, and the lower quality, 100-ft thick gross interval does not currently appear to be commercially prospective. The rig will be move to drill #1-Cascadura, which is the second of four initial exploration wells the company plans to drill on the block. Touchstone is based in Calgary.

2 ***Guyana***

Tullow Oil has tested exploration well #1-Joe and, according to the London-based company, has opened a new Upper Tertiary oil play in offshore Guyana's Guyana Basin. The well was drilled to 2,175 m and is in 780 m of water. Evaluation of logging and sampling data has confirmed that the venture encountered 14 m of net oil pay in high-quality, oil bearing sandstone reservoirs of Upper Tertiary age. The exploration well is the first oil discovery to be made in Upper Tertiary and de-risks the petroleum system in the west of the Orinduik block, where a number of Tertiary and Cretaceous age prospects have been identified. The data from #1-Joe will be evaluated with a previous discovery at #1-Jethro. A follow-up well is planned at #1-Carapa on the Kanuku license. Tullow is the operator of the block with a 60% interest, along with partners ***Total*** (25%) and ***Eco Atlantic*** (15%).

3 ***Guyana***

ExxonMobil Corp. reported an oil discovery on the Stabroek Block of offshore Guyana at #1-Tripletail in the Turbot area. The discovery adds to the previously announced estimated recoverable resource of more than 6 Bbbl of oil-equivalent on the Stabroek Block. The discovery hit approximately 108 ft of a high-quality, oil-bearing sandstone reservoir. The well was drilled in 6,572 ft of water. After completion operations, the drillship was moved to drill #1-Uaru to the east of Liza Field. Irving, Texas-based ExxonMobil plans to have a total of four drillships operating in the area. ExxonMobil is the operator of the block and holds 45% interest, along with ***Hess Corp.*** (30%) and ***China National Offshore Oil*** (25%).



4 *U.K.*

Hurricane Energy announced an oil discovery at exploration well #205/26b-14 Lincoln Crestal in the Greater Warwick Area of the U.K. sector of North Sea Block 205/26b. The well was tested flowing 9.8 Mbbl of oil per day with the use of electrical submersible pumps. According to the London-based company, the average rate was 4.682 Mbbl of 43-degree-gravity oil per day. No formation water was produced. The Lincoln Crestal is the second well in a three-well program in the Greater Warwick Area. It was drilled to 1,780 m and included a 720-m horizontal section of fractured basement reservoir. The well will be suspended, and the rig will move to drill the third well in the 2019 drilling program, #204/30b-A Warwick West. Hurricane is the operator with 50% interest in the Greater Warwick Area following ***Spirit Energy***'s farm-in into the P1368 and P2294 licenses in September 2018 for the remaining 50%.

5 *Nigeria*

Eni announced a gas and condensate find in the deeper sequences of the Obiafu-Obrikom fields, in OML61, in Nigeria's onshore Niger Delta. The #41-Obiafu Deep was drilled to 4,374 m and encountered a gas and condensate accumulation within the deltaic sequence of Oligocene age of more than 130 m of high-quality, hydrocarbon-bearing sands. Initial estimates indicate that the discovery holds 1 Tcf of gas and 60 MMbbl of associated condensate in the deep drilled sequences. Additional testing and appraisal work are planned. According to the Rome-based company, the well can deliver in excess of 100 MMcf of gas and 3 Mbbl of associated condensates per day.

6 *Turkey*

Results from a flow test in the second stimulated zone at #1-Inanli in Turkey's Thrace Basin were announced by ***Valeura Energy***. The zone at 4,176-4,217 m was targeted to test a shallower area of tighter and less fractured rock to determine gas flow potential and fluid characteristics. The well flowed 130 Mcf of gas per day along with a condensate-gas ratio of about 10 bbl/MMcf with 4 bbl of water per day. According to the Calgary-based company, the results indicate that gas can be produced from the lower-quality reservoir and also confirms the low water rates associated with the gas production at these depths. The current estimate of resource on the site is 10 Tcfe of unrisked gas, including 236 MMbbl of condensate. Valuera is preparing the well for the stimulation and expected to extend into late 2019.

7 *Pakistan*

An oilfield discovery has been announced by operator ***MOL*** in the TAL Block in Pakistan's Khyber Pakhtunkhwa Province. New reserves were discovered in the TAL concession on the Kohat Plateau at #2-Makori. According to the company, testing indicates that the well is capable of producing approximately 1.844 Mbbl of oil with 18.25 MMcf of gas per day. The new discovery has de-risked exploration in deeper fault blocks in the TAL Block leading to new upside opportunities. Production from the TAL Block accounts for about 20% of Pakistan's oil production (approximately 17 Mbbl per day). The most recent discovery was made in 2011. ***Oil and Gas Development Co.*** and ***Pakistan Petroleum Ltd.*** each holds a 28% interest, and ***Pakistan Oilfields*** and MOL hold 21% and 23% interest, respectively. MOL is based in Budapest.

8 *Australia*

Strike Energy has announced a new conventional gas discovery at #2 West Erregulla in Kingia Sandstones in Western Australia. The well is in EP 469 and was drilled to 5,017 m and encountered a 97-m gas column with a net pay of 41 m and porosities of up to 19%. No gas-water contact has been observed. Drilling will continue through the High Cliff Formation. Strike operates EP 469 in the Perth Basin with a 50% interest, with ***Warrego Energy*** holding the balance. The #1990 West Erregulla well flowed 23 bbl of 47-degree-gravity oil during a drillstem test. Total prospective P50 resources are estimated to be 1.16 Tcf of gas and 7 MMbbl of oil. Strike is based in Thebarton, South Australia.

9 *Australia*

Cooper Energy Ltd. announced a new gas field discovery at exploration well #1-Annie in VIC/P44 in offshore Victoria's Otway Basin. The well was drilled to 2,442 m in 58 m of water and encountered productive Waarre C and Waarre A sandstones. The primary target, Waarre C, hit a gross gas column of 70 m with a net pay thickness of 62 m. Wireline logging operations were conducted to collect pressure, and sample data have been completed and collected for resource volume estimates and to determine gas composition with additional testing planned. The well will be plugged and abandoned, and the rig will move to drill the second well in the program at #1-Elanora. Cooper's headquarters are in Brisbane.

A DIET OF DEBT

Capital market activity in the energy sector has essentially dwindled down to higher-quality debt issues. Equity deals have been limited to secondary offerings, that is, existing equity positions trading hands rather than new equity being issued. High-yield debt issues have also come to a standstill.

Debt issuance in the E&P sector included a $1 billion senior note issue by Noble Energy Inc. Noble issued two tranches: $500 million of 3.25% senior notes due 2029 priced at 99.982 to yield 3.252%; and $500 million of 4.2% senior notes due 2049 priced at par. Proceeds are for a tender offer for $1 billion of 4.15% notes due 2021.

WPX Energy Inc. priced $600 million of 4.5% senior notes priced at par. Proceeds are to fund a purchase of up to $550 million of WPX's outstanding 6% notes due 2022 and 8.25% notes due 2023. Also, Murphy Oil Corp. priced $500 million of 4.75% senior notes at par, with proceeds to tender for $500 million of 6% notes due 2023.

Debt issuance in the midstream sector included a $1.5 billion senior note offering due 2029, upsized from a previous $1 billion, by Cheniere Energy Partners LP. The notes bear interest of 4.5%, were priced at par and mature in 2029. Proceeds are to pre-pay all term loans under its senior secured credit facilities and for general corporate purposes, including construction of Train 6 at its Sabine Pass liquefaction project.

Plains All American Pipeline LP issued $1 billion of 3.55% senior notes due 2029, priced at 99.801% to yield 3.572%. Proceeds are to repay part of its $500 million 2.6% senior notes due 2019 and its $500 million 5.75% senior notes due 2020.

In secondary offerings, Plains All American and Plains GP Holdings LP raised $321.4 million and $330.8 million, respectively, through sales of 14.98 million PAA common units at $21.46 per unit and 15 million Class A shares at $22.05 each. Proceeds accrue to the seller, an Occidental Petroleum Corp. subsidiary.

—Chris Sheehan

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Baker Hughes, a GE Co.	NYSE: BHGE	Houston	$2.84 bçl²n	Closed a secondary offering of 132.25 mçl²n shares of BHGE Class A common stock, par value $0.0001 per share by **General Electric Co.** and **GE OÕ & Gas US Holdings I Inc.**, **GE Holdings (US) Inc.** and **GE OÕ & Gas US Holdings IV Inc.** at a price to the public of $21.50 each. This closing includes the underwriters' exercise of their opt²n in full, purchasing an addit²nal 17.25 mçl²n shares of Class A common stock from the selling stockholders. BHGE did not offer any shares of Class A common stock in the offering and did not receive any proceeds from the sale of shares in the offering. GE and its affçiates ceased to hold more than 50% of the voting power of all classes of BHGE's voting stock. **J.P. Morgan**, **Citigroup**, **Goldman Sachs & Co. LLC** and **Morgan Stanley** are acting as joint lead book-running managers. **BofA MerrÕl Lynch**, **BNP Paribas** and **Evercore ISI** are acting as joint book-running managers for the offering.
Plains All American Pipeline LP	NYSE: PAA	Houston	$652.2 mçl²n	**Plains All American Pipeline LP** and **Plains GP Holdings LP** announced the pricing of concurrent secondary public offerings by **Oxy Holding Co. (Pipeline) Inc.**, a wholly owned subsidiary of **Occidental Petroleum Corp.**, of 14,977,890 common units of PAA at a price to the public of $21.46 each and 15 mçl²n Class A shares of PAGP at a price to the public of $22.05 each. The gross proceeds from the sale of the PAA common units and PAGP Class A shares by the selling securityholder are expected to be approximately $321.4 mçl²n and $330.8 mçl²n, respectively. PAA and PAGP wçl not receive any proceeds from the offerings. **Barclays** is acting as the sole underwriter for the offering.

DEBT

Cheniere Energy Partners LP	NYSE: CQP	Houston	$1.5 bçl²n	Announced that it has upsized and priced its prev²usly announced offering of sen²r notes due 2029. The principal amount of the offering has been increased from the initially announced $1 bçl²n to $1.5 bçl²n. The CQP 2029 Notes wçl bear interest at a rate of 4.5% per annum and wçl mature on Oct. 1, 2029. The CQP 2029 notes are priced at par, and the closing of the offering is expected to occur on Sept. 12, 2019. Cheniere Partners intends to use the proceeds from the offering to prepay all of the outstanding term loans under its sen²r secured credit facçities due 2024 and for general corporate purposes, including funding future capex in connect²n with the construct²n of Train 6 at the Sabine Pass liquefact²n project. After applying the proceeds from this offering, only a $750 mçl²n revolving credit facçity wçl remain as part of the CQP credit facçities, which is undrawn.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Noble Energy Inc.	NYSE: NBL	Houston	$1 bçl²n	Announced that it has priced an offering of $500 mçl²n of 3.25% sen²r notes that wçl mature on Oct. 15, 2029, and $500 mçl²n of 4.2% sen²r notes that wçl mature on Oct. 15, 2049, pursuant to an effective shelf registrat²n statement that was prev²usly fçed with the Securities and Exchange Commiss²n. The price to the public for the 2029 notes and the 2049 notes is 99.982% and 99.93% of the principal amounts, respectively. The company intends to use the net proceeds from the offering, together with cash on hand or avaçable liquidity, to purchase in a cash tender offer or redeem any and all of its outstanding $1 bçl²n aggregate principal amount of the 4.15% sen²r notes due 2021 and to pay fees, premiums, expenses and unpaid and accrued interest related to the tender offer or redempt²n. **BofA Securities Inc.**, **Mizuho Securities USA LLC** and **MUFG Securities Americas Inc.** served as joint book-running managers, and **BMO Capital Markets Corp.**, **Citigroup Global Markets Inc.**, **DNB Markets Inc.**, **J.P. Morgan Securities LLC**, **PNC Capital Markets LLC**, **Scotia Capital (USA) Inc.** and **TD Securities (USA) LLC** are acting as the passive book-runners.
Plains All American Pipeline LP	NYSE: PAA	Houston	$1 bçl²n	Announced that it has completed an underwritten public offering of $1 bçl²n aggregate principal amount of 3.55% sen²r unsecured notes due Dec. 15, 2029, at a public offering price of 99.801% with a yield to maturity of 3.572%. Total net proceeds of the offering were approximately $989.1 mçl²n. The partnership intends to use the net proceeds from the offering to partially repay the principal amounts of its $500 mçl²n 2.6% sen²r notes due 2019 and $500 mçl²n 5.75% sen²r notes due 2020 at their respective maturity dates in December 2019 and January 2020, and, pending such repayment, for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisit²ns, capex and addit²ns to working capital. **Citigroup Global Markets Inc.**, **Mizuho Securities USA LLC**, **MUFG Securities Americas Inc.** and **Scotia Capital (USA) Inc.** acted as joint book-running managers and representatives of the several underwriters.
WPX Energy Inc.	NYSE: WPX	Tulsa, Okla.	$600 mçl²n	Priced its public offering of $600 mçl²n of its 5.25% sen²r notes due 2027. The notes were priced at 100% of par. The offering was upsized from the prev²usly announced $500 mçl²n aggregate principal amount and is expected to close on Sept. 24, 2019, subject to customary closing condit²ns. The net proceeds from the offering wçl be approximately $592.5 mçl²n after deducting underwriting discounts and commiss²ns and before estimated offering expenses payable by WPX. The company intends to use the net proceeds from the offering and, if necessary, any other sources of avaçable funds, which may include borrowings under its sen²r secured credit facçity, to fund its prev²usly announced cash tender offers for its outstanding 6% sen²r notes due 2022 and 8.25% sen²r notes due 2023. **BofA MerrÕl Lynch**, **J.P. Morgan** and **MUFG** are acting as lead book-running managers
Murphy Oç USA Inc.	NYSE: MUR	El Dorado, Ark.	$500 mçl²n	**Murphy USA Inc.** announced that it has priced its prev²usly announced offering of $500 mçl²n aggregate principal amount of sen²r notes due 2029 by its wholly owned subsidiary, **Murphy OÕ USA Inc.** The notes wçl be guaranteed on a sen²r unsecured basis by Murphy USA and by certain of Murphy USA's domestic subsidiaries. The notes wçl be issued at an issue price of 100%. The offering is expected to close on Sept. 13, 2019, subject to customary closing condit²ns. The notes wçl bear interest at a rate of 4.75% per annum, payable semiannually in arrears on March 15 and Sept. 15 of each year, commencing March 15, 2020. The notes wçl mature on Sept. 15, 2029. Murphy USA intends to use the net proceeds from the offering plus cash on hand to consummate the cash tender offer announced today for any and all of Murphy Oç USA's outstanding $500 mçl²n aggregate principal amount of 6% sen²r notes due 2023. **J.P. Morgan Securities LLC**, **RBC Capital Markets LLC** and **Stephens Inc.** are acting as joint book-running managers.

COMPANIES IN THIS ISSUE

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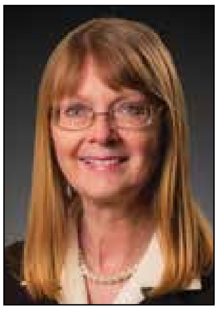

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

We can thank our lucky stars that the U.S. has become an energy powerhouse. This unforeseen event has changed the balance of payments via commodity exports and, in turn, altered the global geopolitical calculus (see the Saudi drone attacks). It is boosting oil town economies and creating jobs (Midland and Odessa perennially rank among the cities with the lowest unemployment rates in the U.S.).

But this lofty perch is beset with threats. These range from government intervention to changing consumer attitudes. Now, there are lawsuits against pipeline construction and against the big banks that fund oil and gas development. Combine all this with a perceived slowdown in oil demand growth, and E&P companies have a lot to think about—all while trying to make a buck and give half of that back to their investors before they bolt.

Here are a few comments we've gathered that provide insight. First, Ray Walker, the COO of Encino Energy LLC and former COO at Range Resources Corp., was a pioneer in the Marcellus Shale. At Hart Energy's annual DUG East conference in Pittsburgh earlier this year, he reminded us of some central facts. "The rock rules, no matter how good you think you are as a frack engineer.

He also cited capital discipline that's becoming the new norm throughout the upstream world. It has improved many an operator's financial profile, but at the expense of the service companies' margins. "You have to ask yourself, 'How do I get more cash flow for the money I am putting in the ground?'"

Many of the early shale plays that caused so much excitement and hype are maturing. Some are in the deliberate manufacturing phase that will also lead to EOR, led by the majors' increased commitment to unconventional plays.

For example, more than 27,000 wells have been drilled in the Eagle Ford since Petrohawk Energy Corp. unveiled it in 2008. Where does it stand today, now that it is one of the most mature of all U.S. shale plays? It's turning out to be one of the most resilient.

Lately operators have been applying for more drilling permits to the Austin Chalk Formation in the eastern portion of the play, which is keeping it relevant. Its proximity to the Texas coast for exports or petrochemical feedstock is another big plus. Technical progress continues as producers fine-tune operations and well spacing.

"We refer to the Eagle Ford as the 'dark horse,' because it remains one of the most economic basins in the country. We are getting the most questions about it and the Austin Chalk," said Enverus analyst Bernadette Johnson, speaking at Hart Energy's 10th annual DUG Eagle Ford conference recently.

"In general, downspacing has been successful here, and more so than in any other play." The Eagle Ford's drilling times have improved and are now nearing 1,400 feet per day per rig.

Enverus breaks this play into the western and eastern half, each with different characteristics. More than 80% of the wells being drilled today in the western Eagle Ford are child wells, which indicates just how mature the play is, Johnson said. She also cited a lack of core locations remaining in the east, especially in Karnes County, "although this is not concerning to us. This is a natural development for such a mature play."

However, interest is shifting back to the east now as the Austin Chalk play in Washington County heats up, based on new drilling permits. There is interest north of the Karnes Trough in Wilson County.

"We're watching it closely, and it's very liquids-rich," she said. "Although the eastern Eagle Ford type curves are lower than in the western part, the economics are actually better. The eastern part is not as mature."

In the southwest portion of the play the economics are driven largely by gas prices, with Enverus estimating operators need a breakeven price of at least $2 per thousand cubic feet. The average oil cut in the western portion is 61%, but clocks in at 82% in the eastern. Perforation intervals in the east have lengthened since 2014 to average 8,500 feet, which is longer than in the west.

The eastern portion has shown more well productivity improvement per foot drilled since 2018 while the heavily drilled west has been consistent, Johnson said. "Again, the geology really matters. It depends on where you are for what you're able to do in terms of spacing and proppant."

In most shale plays, the quality of previously unproductive, uneconomic or "un-sellable" acreage is being revealed with more clarity. Value is being turned around by using smarter drilling and completion practices, coupled with more precise well spacing.

So after a wild decade of exploration and outsized spending, the shale business has turned into a true business, with a long tail of cash generation ahead.