Oil and Gas Investor

JUNE 2019

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ABOUT THE COVER: Boston's Longfellow Bridge, spanning over the Charles River, opened in 2018 after five years of renovations. Photo by Glenn Kulbako.

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LATEST CONTENT

NGL Energy Partners Doubles Permian Basin Water Footprint
NGL Energy Partners agreed to acquire privately held Mesquite Disposals Unlimited for $890 million, which the company claims will create the largest water transportation and disposal company in the Delaware Basin.

Opinion: A View Behind The Occidental-Anadarko Deal
CEO Vicki Hollub vaults her company into prime position in the prolific Permian Basin. Meanwhile, Chevron Corp. awaits the next big opportunity in the basin.

EOG Resources Targets High-Return Growth
EOG, which has assets in shale plays such as the Eagle Ford and Permian, is targeting about 14% oil growth this year and focusing on exploration.

Survey: Are US Shale Producers Still Hedging?
A challenge for oil and gas producers is how far out to hedge production, according to the recent survey by Opportune.

Shell Midstream In $800 Million Dropdown Acquisition From Sponsor
The dropdown acquisition will increase Shell Midstream Partners' interest in the Explorer and Colonial systems.

Abraxas Readies 'Stranded Asset' Sale Following Nonop Bakken Deal
Abraxas Petroleum has embarked on becoming a Permian pure play with a core Delaware Basin position but may hold onto its Bakken asset after all, said CEO Bob Watson.

ONLINE EXCLUSIVES

Oil, Gas Companies Preparing For The Impact Of The Energy Transition
Renewable energy methods such as solar and wind will almost certainly impact the amount of oil and gas consumed and therefore could lower pricing, some experts believe.

DUG Permian: Plains-Talking Armstrong On Love, Money
Retired CEO describes how the 1980s oil bust guided his thinking as he built a pipeline giant.

EQT Board Changes Not Enough Rice Brothers Say
The replacement of three long-serving members of the EQT board does little to cool down the proxy battle the Appalachia shale producer is facing from the brothers who built Rice Energy.

Videos

DUG Permian: Private Producer Panel - Making Core Of The Fringe
Privately held producers continue to extend the outermost boundaries of the horizontal Midland and Delaware basins.

www.HartEnergy.com/videos

What's Trending

1. Former WildHorse CEO Jay Graham Returns With Permian Basin Acquisition
2. Carrizo Oil & Gas Activist Investor Pushing Merger, Sale
3. Weatherford To File For Chapter 11 Bankruptcy
4. DUG Rockies: Bullish On The Bakken; San Juan Reinvigorated
5. Equinor Grows Deepwater Gulf Of Mexico Position With $965 Million Acquisition

2019 Awards Program

Welcome to *Oil and Gas Investor*'s 2019 Forty Under 40 program. Once again, we are shining a spotlight on the next generation of leaders shaping the oil and gas industry. Submit nominations today!

OilandGasInvestor.com/fortyunder40

HOLLUB'S OPUS

STEVE TOON,
EDITOR-IN-CHIEF

While we wait for the trophy to be hoisted, the battle for Anadarko Petroleum is now over and Oxy is the winner, having bested Goliath Chevron. The four-week saga was epic in the strategic maneuvers Occidental Petroleum Corp.'s CEO, Vicki Hollub, orchestrated to outplay and sequester its much larger rival into standing down.

But to what end? Occidental, after all, is already a premier producer.

When Chevron Corp. announced April 12 that it intended to buy Anadarko Petroleum Corp. for $33 billion, the oil and gas world buzzed about the first megadeal in years and the beauties of the strategic portfolio fit. Twelve days later, Occidental revealed it had been wooing Anadarko for almost two years prior, and refused to stand down with a $38 billion very public counteroffer, half cash, half stock.

Yet, apparently, Anadarko's board was hesitant about the required Occidental stockholder vote, so Hollub—in a matter of days—removed all obstacles for saying yes to her offer. In a 90-minute in-person chat with the nation's favorite billionaire, Warren Buffett, she secured $10 billion to add to the cash pile, and got French major Total SA to agree to onboard Anadarko's Mozambique LNG project in a simultaneous sale for $8.8 billion, mostly offsetting the new Buffett debt.

The moves took the cash portion above 78%, thereby stripping the need for a shareholder vote. With the ball back in its court, and Hollub staring them down, the Anadarko board could hardly decline.

Addressing shareholders at Occidental's annual investor-day-slash-victory party a day after Chevron passed on joining the bidding battle, Hollub said some had misconstrued her motivations as desperation when instead it was pure determination.

"We do love our portfolio—this is the best portfolio we've had since I've been at Oxy" over 38 years, she said in an investor call. "But Anadarko has great assets too."

So why did Hollub feel so compelled to buy Anadarko, a merger of near equals with an asset portfolio that seems misaligned?

Some say it was for the Permian assets. The deal will boost Occidental's Delaware Basin position by 53% to 690,000 net acres, and it will instantly become the largest Permian producer upon close at 533,000 barrels of oil equivalent per day. Not a bad bolt on.

But other pure-play Permian publics might have made more merger sense if this were purely a Permian play. What is Oxy to do with the D-J, Powder River and Uinta basins, the Gulf of Mexico, and midstream MLP Western Energy Partners, all part of the deal? Hollub could—and might—carve these out for divestiture. But this wasn't a total Permian motivation.

"It's much more than the Permian," Hollub said in an investor call.

Cash flow is one reason. In recent years Occidental excised lower return assets via a portfolio optimization and is in a production rebuilding phase to replace lost revenues. "This acquisition … accelerated our cash-flow creation," she said.

Anadarko's shale portfolio is on the verge of free-cash-flow generation, but its Gulf of Mexico position is a current cash cow. "It's amazing, the cash flow from the Gulf of Mexico," she said, noting the GoM is not a growth project in Oxy's forward plan. Conservatively, Oxy projects the deal will boost free cash flow by $3.5 billion. And with Wall Street demanding some shareholder swag, Anadarko cash flow gets the company to bigger, predictable dividends sooner.

Another reason is scale. Hollub referenced greater scale and geographic diversity as a way to deliver value. "Our scale of portfolio will be unique in the sector," she said. Pro forma, Occidental global production doubles to 1.4 MMboe/d, more than twice the average of the top 10 independents, and about half the size of a major. Compare to ConocoPhillips Co. at 1.3 MMboe/d.

Domestically, Occidental adds Anadarko's position as leading producer in the D-J Basin to its portfolio, expanding its footprint beyond the Permian alone. Emerging plays in the Powder and Uinta are bonus or divestitures.

But more so, I believe Hollub wants to etch her lasting mark into Occidental's history, taking it to the next level of super independent. "We believe this to be transformational for Oxy. It's very rare; in fact, generational." She touted the combination with Anadarko "would create a global energy leader with the scale and scope to lead our industry into the future."

It stands to reason Hollub wants Occidental to compete with majors in the oil field and on Wall Street. And when she walks away she wants to be known as a company maker, not as a corporate caretaker.

"We've studied this very diligently," she assured, characterizing the combination as "a really, really unique opportunity that … plays into our strengths. We see no risk in this, and that's what we want to communicate."

Anadarko is Hollub's opus.

FINDING YOUR FOOTING IN EARNINGS SEASON

CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

Equities in general are supposed to discount future market conditions, and that's why price targets are usually set on metrics projected for 2020, for example, rather than what is forecast for the next quarter or two. But energy equities have a shallow set of buyers, and trading strategies have found it often possible to make money selling stocks short ahead of quarterly conference calls.

It's hard to find a CEO today who is unaware of investor pressure on E&Ps to spend within cash flow and, as soon as possible thereafter, generate free cash flow. Also, it's sometimes hard to know exactly what drives a company's stock price, even if you're a CEO who knows which levers logically should deliver stock price performance. Take, for instance, first-quarter results by SM Energy Co.

"We are so close to growing within cash flow that we can almost taste it," said Jay Ottoson, SM Energy's CEO, noting his shared disappointment with investors over recent stock underperformance. Even with key quarterly metrics pre-announced—and incremental news being decidedly positive on drilling developments—SM's stock fell a further 9% at one point on the day of its earnings release.

The stock move was a bit of a head scratcher, noted one research house.

"We view the selloff here as overdone, particularly given the company's operations update this quarter, which quite frankly was one of the strongest we're seen this year," read a J.P. Morgan report. "Not only is the company's Merlin Maximus development tracking in-line with the company's Wolfcamp A vintages, the company also had some intriguing results from the Wolfcamp D, Dean and Middle Spraberry in its RockStar area, which was once believed to be a one or two bench play."

Back at the helm of Pioneer Natural Resources Co., CEO Scott Sheffield took time to find his footing against a backdrop of heightened expectations. Despite a beat on cash flow per share, plus a move to prioritize free cash flow by trimming growth targets to "mid-teens" from a prior 20% level, Pioneer's results fell short of expectations, with its stock down 8% at its intra-day low.

Obviously, candor on the part of Sheffield—recalling, "I didn't come back to sell the company"—may have prompted some investors to exit. As a Bernstein report commented, "Investors may have suspected a revolution; instead, they got an evolution," implying Pioneer's future would depend less on moves to consolidate the Permian and more on a path of moderate growth to deliver returns to investors.

On M&A, "I personally don't think that there's going to be a lot of M&A over the next one to two years," said Sheffield. However, "over the next five years, I think the majors will definitely start running out of inventory," he observed. Meanwhile, "smaller companies in the Permian are going to have to consolidate" to achieve lower general and administrative expenses and a better cost structure.

A clear winner in the short-term tumble of earnings season was Diamondback Energy Inc. Fast footwork late last year, as crude prices plummeted, led to it cutting three rigs and two spreads in the first quarter. Coupled with ongoing efficiencies in the Midland Basin, where drilling and completion costs came down 15% and 9% from the prior quarter, the result was capex that was 15% below consensus.

But the highlight of the quarter was Diamondback's announcement of a $2 billion stock buyback, or 12% of its market capitalization, based on its free-cash-flow outlook through year-end 2020. At $55 West Texas Intermediate, the company projects to generate "at least $750 million of free cash flow in 2020." In addition, it announced $322 million in noncore asset sales, expected to close on July 1, 2019.

"The signal that we've put forth today is that we believe that repurchasing our shares represents the greatest value on the M&A front, and that's a $2 billion acquisition that we're talking about," said Travis Stice, CEO of Diamondback Energy. "This is not just a one-time event; this is the board signaling that this is an ongoing return-of-capital strategy."

Diamondback's stock performance, closing up 7.7% after its earnings release, stood out amid overall energy sector volatility. A review by RBC Capital Markets indicated that more than 70% of its coverage traded lower on earnings, even as 90% of companies met or exceeded cash flow per share estimates.

How did it describe investor sentiment? "Challenging."


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BOTTOM DOLLAR

DARREN BARBEE,
SENIOR EDITOR

Plenty of analysts are reading Pioneer Natural Resources Co.'s Eagle Ford sale agreement like the terms of a surrender—the A&D equivalent of the Treaty of Versailles.

In the aftermath of the (ultimately one-sided) Anadarko Petroleum Corp. bidding war, there's been some myth-making over which E&P might be the next M&A target.

So some angst followed Pioneer's sale of 59,000 net Eagle Ford acres to private-equity-backed Ensign Natural Resources LLC for just $25 million in upfront cash. Pioneer's deal could ultimately be worth another $450 million, depending on WTI-based contingency payments. However, the earliest they kick in is 2023.

Analysts were nonplussed, even aghast, that the company's sale failed to pry open the bear trap the company was snagged on in the Eagle Ford. Pioneer's still on the hook for a large share of the minimum volume commitments (MVCs) owed to Enterprise Product Partners. The annual cost of those payments is roughly $160 million, depending on the analyst and the calculator.

Some analysts were harsh. One said Pioneer was essentially giving away its Eagle Ford assets. Another wondered why the company would do the deal that kept 80% of the MVCs on Pioneer's books.

It's tempting to recall here Chesapeake Energy's 2016 Barnett Shale garage sale. The company, working through paying off debt, let the Barnett go for essentially nothing just to be rid of the MVCs.

Not so for Pioneer, according to CEO Scott Sheffield on a May 7 earnings call.

In potentially one of the most scathing rebukes in his career, Sheffield said he was "surprised" by analyst commentary about the Eagle Ford deal. After more than a year of negotiations, the sale was Pioneer's best way out of a bad situation, he said.

Sheffield said he considered the transaction a "great opportunity" to divest underachieving assets that generate a margin of $12 per barrel of oil equivalent (boe). Each boe, incidentally, costs $14 to produce.

Should WTI stay somewhere between $60 and $65 per barrel, "we'll receive somewhere between $275- to $475 million in proceeds," he said. "You need to deduct somewhere between $200 million and $250 million for MVC" payments to Enterprise.

However, the MVCs are dependent on drilling activity, and Ensign says it will start up drilling activity fairly soon and then accelerate.

"So it's a net positive for the company," he said.

Sheffield is fixated on eliminating costs, including G&A, and running the company without the distraction of other plays. He noted that a recent report by James E. Parkman, co-founder of investment banking firm Parkman Whaling LLC, found that of 76 companies analyzed, half will either merge or go bankrupt during the next several years because of high G&A expenses and interest payments.

But what of the Anadarko deal, which Occidental Petroleum Corp. pried from Chevron Corp. for $57 billion?

Sheffield confessed to being surprised that Anadarko was the "first company to be taken out." Chevron came in ready to capitalize on the company's low stock price. "Now, Oxy is paying up for it, obviously."

In case anyone has forgotten, cash is not just king, but a terribly shy monarch in 2019.

Consider Abraxas Petroleum Corp., which, since January, has been actively marketing core assets in the Williston Basin of North Dakota, including 4,000 net acres in the heart of McKenzie County, N.D.

Abraxas had some bites on the package but has so far only sold $15.5 million of nonoperated Williston assets.

Abraxas CEO Bob Watson found it odd that interest for the company's nonoperated assets superseded its "crown jewel" asset.

"We were interested to see how much more aggressive the nonop buyers were than those interested in the entire package," Watson said on a May 7 earnings call.

Quizzed about why the core assets have been slow to sell, Watson pointed to Pioneer's recent deal.

"I think that is a pure testimony to the market that's out there today," he said. "I think that speaks to the fact that there just isn't any capital out there for people to use to make big acquisitions."

He said private-equity firms have "lockjaw" thanks to assets without an exit and capital markets that are indifferent to energy. That leaves shoppers with capital and little competition but who still have to "screw up the courage" to buy.

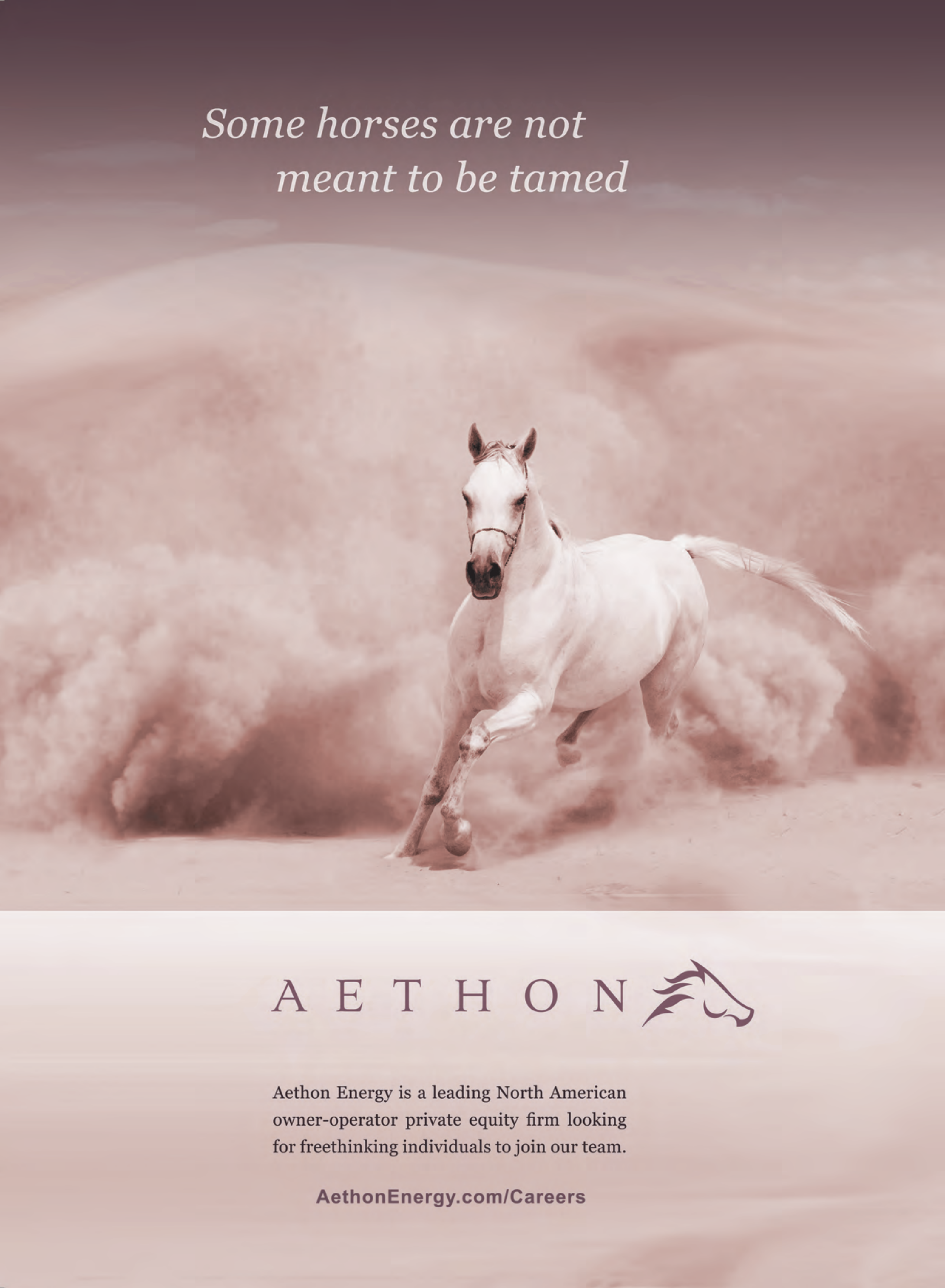
Majors may run short of inventory and some deals may happen, he said, "but I don't think there will be a wave of consolidation."

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
Midstream Texas	**June 5-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
CIPA Annual Meeting	June 6-9	Lake Tahoe, Calif.	TBA	cipa.org
IPAA Midyear Meeting	June 24-26	Colorado Springs, Colo.	The Broadmoor	ipaa.org
DUG East	**June 18-20**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Western Energy Alliance Annual Meeting	July 31-Aug. 2	Tabernash, Colo.	Devils Thumb Ranch Resort	westernenergyalliance.org
Unconventional Resources Tech. Con.	July 22-24	Denver	Colorado Convention Center	urtec.org/2019
Tipro Summer Conference	Aug. 7-8	San Antonio	Hyatt Hill Country Resort	tipro.org
EnerCom The Oil & Gas Conference	Aug. 11-14	Denver	Westin Denver Downtown	theoilandgasconference.com
The Energy Summit	Aug. 20-22	Denver	Colorado Convention Center	theenergysummit.org
Summer NAPE	Aug. 21-22	Houston	George R. Brown Conv. Center	napeexpo.com
DUG Eagle Ford	**Sept. 24-26**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.com**
A&D Strategies and Opportunities	**Oct. 22-23**	**Dallas**	**The Omni Dallas**	**adstrategies.com**
Executive Oil Conference	**Nov. 4-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
IPAA Annual Meeting	Nov. 6-8	Washington, D.C.	Fairmount, 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	TBA	energygamechange.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
Energy Capital Conference	**Mar. 2**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
Women in Energy Luncheon	**Mar. 4**	**Houston**	**Hilton Americas-Houston**	**womeninenergylunch.com**
CERAWeek by IHS Markit	Mar. 9-13	Houston	Hilton Americas-Houston	ceraweek.com
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

Email details of your event to Brandy Fidler, bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com.



Some horses are not meant to be tamed
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AethonEnergy.com/Careers


Hard work & vision
That's what got
us both here
TRUMP
TRUMP
HOTELS

Better breakevens elevate North American tight oil

Companies involved in developing North American tight oil are using knowledge gained to improve costs and breakevens, transforming what were once among the world's most expensive supply sources into one of the cheapest.

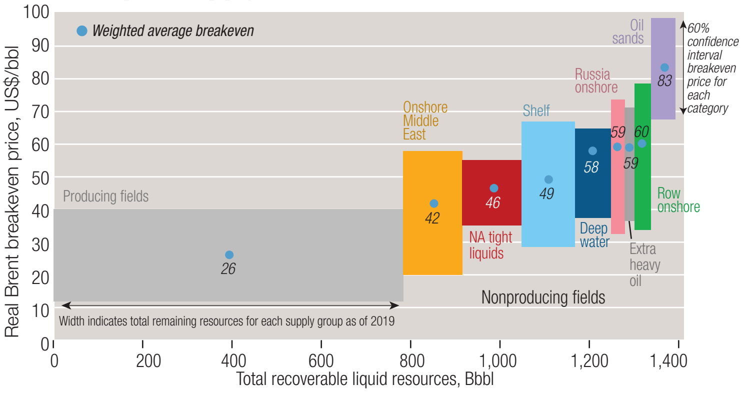
That's according to Rystad Energy, which released a report in April that ranks North American tight oil as the second cheapest source of new oil volumes globally. With a Brent breakeven cost of $46 per barrel (bbl), down from the average $68 in 2015, North American tight oil's cost of supply today trails only the Middle East onshore market.

The main drivers for the drop are lower unit prices and higher productivity, Espen Erlingsen, partner and head of upstream research for Rystad, told HartEnergy.com in a statement.

Unit prices, or prices E&P companies pay service companies, have dropped by about 30% since 2014, Erlingsen said. "This reduced the costs per well and improves the economics of new wells," he said. "Part of these costs savings are efficiency gains and some are lower margins for the service companies."

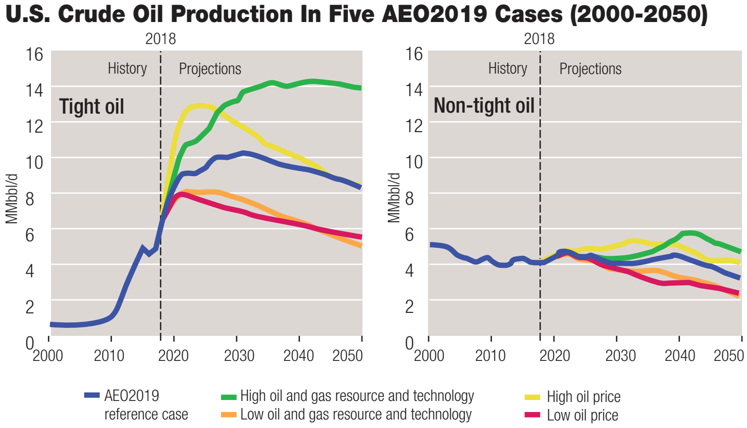
Oilfield service companies and E&Ps were both hit when an oversupply-driven market downturn sent oil prices tumbling in late 2014, impacting their financial coffers. In the years since, companies have gotten smarter about how they operate, turning to technology, improving drilling and completion techniques, and lowering costs. The changes have made tight oil resource developments less sensitive to oil price fluctuations compared to previous years.

Global Liquid Supply Curve



Source: Rystad Energy UCube

U.S. Crude Oil Production In Five AEO2019 Cases (2000-2050)



Source: Energy Information Adminstration

EOG Resources Inc., for example, said it has cut its Eagle Ford well cost to $4.4 million from $7.2 million in 2012. Like its peers, EOG—which described itself as the largest U.S. horizontal oil producer—is optimizing completion designs to improve well performance and reduce drilling times to lower costs.

Occidental Petroleum Corp. is also improving costs. The company reported this week that implementation of a new facility design by its Permian Resources business resulted in 60% fewer tanks, emissions reduction and a greater-than 30% cost improvement. This came as the company saw a 26% improvement in drill days and a 34% improvement in frack days from 2018 to 2019 in the Permian's Delaware Basin in West Texas.

"We get more oil from our wells in the short and long term, which generates high value and low development cost," Occidental CEO and president Vicki Hollub said on the company's first-quarter 2019 earnings call. "We are rapidly advancing our geomechanical and flow unit modeling, driving breakthroughs in completion design and well spacing, and mitigating parent-child impacts."

Occidental envisions further lower costs, including in the Delaware Basin, where it stands to benefit from its planned merger with Anadarko Petroleum Corp. Hollub said Anadarko's Delaware Basin properties would fit well within the top couple of tiers of Occidental's existing inventory.

Referring to some acreage between the Barilla Draw and southeastern Mexico, she said "there's some prime acreage in there" that the company believes are Tier 1 opportunities.

"Their inventory there, we believe, could be over 10,000 wells, and we believe that it would be very, very similar to our inventory," Hollub said. "We expect that over time, because of the lower cost that we can imply as a result of the entire trend, our two areas with theirs, we can further lower cost and infrastructure synergies so that we'll be able to move more wells down into the less than $50 breakeven category."

The Permian Basin's Midland and Delaware sub-basins have seen the largest improvements with breakeven prices down about 50% for both plays, Erlingsen said. He noted a better understanding of the formation and improved completion techniques are among the factors that have contributed to the rise in production from tight oil wells.

"Measured in total resources divided by lateral length per well, the well product has on average increased 15% over the past years," he said.

Strides have not been limited to the biggest U.S. oil field. Colorado's Denver-Julesburg Basin has seen breakeven improvements near 50%, while more mature plays such as the Eagle Ford and Bakken have experienced cost savings of about 35%.

But are these savings sustainable? Erlingsen believes so.

"The evidence of this is that despite the U.S. tight oil activity doubled from 2016 to 2018, the costs within the industry didn't grow too much," he said. "Hence we believe that the lower costs will stay and that the productivity gain will last."

The U.S. Energy Information Administration (EIA) projects U.S. tight oil production will continue rising through 2030, surpassing more than 10 million barrels per day (MMbbl/d). Tight oil production hit 6.5 MMbbl/d last year, the EIA said.

—Velda Addison

Energy Secretary lauds Trump's energy policies

It wasn't long ago that the U.S. dealt with a perceived energy scarcity.

But Deputy Secretary of U.S. Department of Energy Dan Brouillette said the country is far removed from those concerns now. The U.S. is now a world leader in the production of oil and natural gas and currently exports LNG to more than 34 nations on five continents.

So how did this happen?

"We did it by striking the right balance between technology, politics and economics," Brouillette said, while delivering the keynote address to kick off Baker McKenzie's 6th Annual Global Oil & Gas Institute on April 25. "Through innovation and technologies, the right policies, the reliance on a free and open market, we are transforming the oil and gas sector and opening what Secretary Perry calls a new American energy era."

There is no argument that the U.S. now works from a position of strength in oil and gas production. While the shift in positioning in the sector began under former President Barack Obama, Brouillette credits the current administration of President Donald Trump for "truly unleashing American energy" in recent years.

Between now and 2020, Brouillette said this country is expected to contribute half of the world's growth in oil and gas production. According to the EIA, in 2019, the U.S. expects to produce an average of 12.4 MMbbl/d of crude oil and that number is expected to increase to 13.2 MMbbl/d in 2020 all while remaining conscious of the movement for cleaner energy.

"This year we also expect natural gas to average 90.2 billion cubic feet per day and that will rise to 92.1 next year," Brouillette said. "And we have accomplished all of this while leading the world in reducing energy-related carbon emissions, cutting them by 14% in 2005 to 2017, and expect those emissions to continue to decline over the next few years.

"Those are truly astonishing numbers, especially considering that it wasn't too long ago that America was experiencing an energy shortage. In my lifetime at least, I remember long lines of cars waiting for short supplies of gasoline, not to mention concerns about peak oil."

Brouillette said one of the key components in the U.S. remaining in a position of strength in the oil and natural gas sector is that policies in this country must be designed for continued growth. Investing in infrastructure is at the top of the list.

As a cautionary tale, Brouillette pointed to policies in New England and the northeast region that made it more practical to buy Russian LNG rather than Marcellus Shale—one of the world's largest natural gas fields—that sits just a few hundred miles away. Anti-energy activists reportedly pressured locally elected officials in that region to block new energy infrastructure, like pipelines, that would have made it easier to bring American gas to the region. Also, the state of New York has not allowed any pipeline projects through its borders to transport natural gas from the Marcellus to the New England.

As a result, residents in New England have paid some of the highest energy bills in the country, according to a story that appeared in the Washington Examiner in March 2018.

"The United States is on track to be a net exporter of LNG in the coming years, and some of our citizens have to rely on foreign adversaries to supply or satisfy their energy needs." Brouillette said. "Policies like these lead to an astonishing and a willful loss of economic opportunity.

"In contrast, our administration is doing everything it can to foster innovation, to encourage responsible energy development and to build the infrastructure that we need in the future days."

Trump recently signed two executive orders implementing a comprehensive whole government approach to streamlining the development of energy infrastructure projects and reducing barriers to achieving that goal.

"The president has also approved new pipelines and removed what we refer to as Draconian restrictions on responsible oil and gas production here in the United States," Brouillette said. "The president is embracing regulatory reform so that the regulations can once again become the rules of the road rather than the barriers across it."

Brouillette credits the Department of Energy (DOE) for streamlining some the barriers, saying that for each new regulation within the government, the administration has removed 22 existing regulations. As an example, he said last September the DOE issued a rule that will expedite the permitting of small-scale exports for U.S. natural gas to places like the Caribbean and Central America where infrastructure and economic constraints limit large-scale LNG imports. The department also made changes to the reporting requirements to LNG export sales and contracts with the hopes that will increase efficiencies and streamline LNG exports.

"We are committed to working with our partners across the government to even further streamline the energy infrastructure permitting and the authorization process," Brouillette said. "On that note we applaud and we support FERC's [Federal Energy Regulatory Commission] new approach to expediting and improving the review of LNG terminal applications. It's a significant step toward bringing more U.S. LNG into the market and building on the successes of American natural gas."

In order to achieve this, the U.S. must let the markets work and trust that the invisible hand will work its wonders. He insists the U.S. is prepared to compete openly and fairly on world markets, he said.

"We will trade with any willing partner," Brouillette said. "Rather than seeing our oil and gas exports zero sum gain, we believe this will contribute to more fluid, transparent and competitive markets as well as leading the rising demand in Asia and other markets. And as we do we will keep our word and honor our contracts, and we expect others to do the same."

Brouillette said the approach of technology advances, smart policy and open trade also applies to the fast rising renewable and clean energy sectors.

"While I have focused on oil and natural gas, this administration is committed to an all of the above energy strategy," he said. "This approach of fostering innovation and technology, of getting the politics and the policies right and letting the markets work apply just as strongly to solar, to wind, to nuclear, to hydro and to carbon capture U.S. technologies.

"Together we are at the opening of a new era of American energy where we are promoting technology and innovation, prosperity, security and opportunity not only for all Americans but for all of the world."

—Terrance Harris

International oilfield services poised for growth

Investors who equate the international opportunity for oilfield services with the potential suggested by the budgets of U.S. shale producers and certain supermajors, whose capex spending plans are largely flat, may miss out on the broader cyclical upside, warned Morgan Stanley analysts.

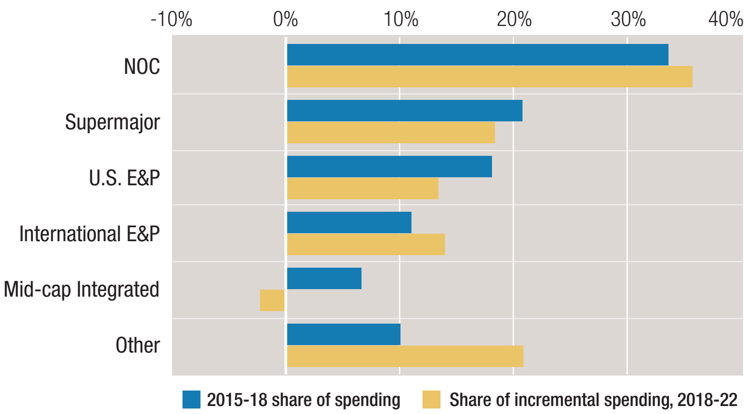
The analysts see international upstream spending on the rise largely driven by national oil companies (NOCs), which they believe will reverse gains in market share made by U.S. E&Ps during the shale revolution. Investors, however, are not yet taking this positive outlook of rising spending into account toward oilfield service stocks, according to a report released by Morgan Stanley Research in early April.

Morgan Stanley analysts see the misconception creating an international opportunity for oilfield service stocks with their top pick being TechnipFMC Plc. Also mentioned were Tenaris, Baker Hughes Inc., Transocean, Borr Drilling, Petrofac, Saipem, Subsea 7, Sembcorp Marine, Samsung Engineering, Larsen & Toubro, Hilong, Nabors, JGC and Modec.

Unlike the U.S. independent E&P companies and international oil companies (IOCs), particularly the European majors which have embraced capital discipline, NOCs are currently spending twice the amount of IOCs, and the Morgan Stanley analysts expect them to outpace the industry going forward.

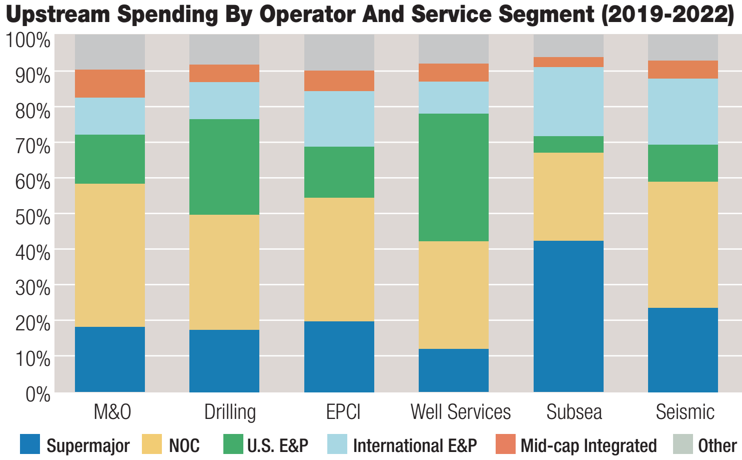
"International upstream spending started rebounding in 2018, and we expect it to accelerate, adding more than $10 billion to global spend

Share Of Upstream Spending And Incremental Spending



Source: Morgan Stanley Research estimates; Rystad Energy

Upstream Spending By Operator And Service Segment (2019-2022)



Source: Morgan Stanley Research estimates; Rystad Energy by 2022," the Morgan Stanley analysts said. "Most of this opportunity is outside of shale, highlighting the opportunity in international markets."

Further, the evidence is growing that the offshore, Middle East/North Africa and LNG markets are recovering. Highlighting ExxonMobil Corp., the analysts also noted that internationally focused E&Ps and some IOCs are also spending more.

The analysts think the upside from the international oilfield service market could be about 30%, based on previous cycles, and that this market is preparing for "liftoff."

"The market's focus on IOCs as a proxy for the industry ignores NOCs, despite 2018 spend of $210 billion and 33% of global upstream, twice the share of IOCs, which accounted for 18% of global upstream spending," the Morgan Stanley analysts said. "We expect aggregate NOC spending growth of approximately 4%/$4 billion to 2021."

The analysts forecast NOCs upstream spending growth of 18% between 2018 and 2020, and a 23% boost from international E&Ps for the same period.

Nor are supermajors, consisting of ExxonMobil, Equinor ASA, Royal Dutch Shell Plc, BP Plc, Total SA and Chevron Corp., excluded from forecasts for growth. For upstream alone, the supermajors' capex growth is significant for all six.

Morgan Stanley estimates, based primarily on company guidance, are "for group and upstream specific capex at these six companies to grow at an aggregate 4% to 2021 [1% to 2% excluding ExxonMobil]."

Key to this perspective is the fact, as the analysts note, that NOCs hold the largest share of oil production and reserves—producing more oil and gas than supermajors, E&Ps and mid-caps combined.

"Going forward, expectations are for NOCs to take a larger share of reserves, reversing U.S. E&Ps' gains from 2008 to 2024," the Morgan Stanley analysts said.

The majors, however, are spending less, after peaking in 2015 at 24% of upstream spending. Currently, the majors' share is at 18%.

The report notes that IOCs are expected to remain "material, especially for the subsea, LNG and drilling markets." NOCs are the drivers of jackup drilling, and they still represent 25% of subsea spend, with international E&Ps contributing about 20%.

European oilfield service stocks that involve international work still haven't recovered from the downturn, so the analysts see "the majority of the cyclical multiple expansion still ahead."

U.S. oilfield service providers also are still underperforming oil prices and producers. They are 121% below the U.S. market and 56% below the European market since the beginning of 2014. Further, P/BV (share price divided by book value) is just 10.5 times for European oil service providers, despite the 2018 increase in crude prices, while for the U.S. players it is "close to all-time lows."

Offshore action internationally offers opportunity, but LNG may be the biggest factor.

"We see the earlier-than-expected volume of LNG projects as the catalyst that accelerates the tightening of the global supply changes," the analysts said.

—Susan Klann

Frack sand surplus: The industry is better prepared

Well before the discussion turned to granular issues of quality, speakers at the inaugural DUG Sand conference addressed quantity. In short, there's too much.

"This is one of the industry's issues," said James Wicklund, Dallas-based managing director of Stephens Inc.'s energy group, during his April 15 keynote. "As it turns out, we have an awful lot of sand."

The surplus stems, most immediately, from the fourth-quarter price dives of frack sand and oil. But Laura Fulton, CFO for Hi-Crush Partners LP, compared recent troubles to the woes of second-quarter 2016 and saw a heartening contrast.

"What we experienced last fall was not the worst," she said. "I was around for the worst and that was clearly April, May, June 2016, and I really don't want to go back there as far as what was happening with prices."

Much of that derived from the plunge in oil prices from the downcycle. The industry experienced that in Fall 2018, too, as a barrel of West Texas Intermediate (WTI) fell from the mid-$70s in early October to the low $40s by the end of the year.

But WTI has recovered to the mid-$60s and the rig count looks good, she said. So why is the industry taking so long to rev up to previous levels?

Because of lessons learned from the brutal second-quarter 2016, Fulton said.

It took almost a year—from the start of the downcycle in fourth-quarter 2014 to third-quarter 2015—for the frack sand industry to pull 40% of capacity offline because of economic, logistical or customer base issues.

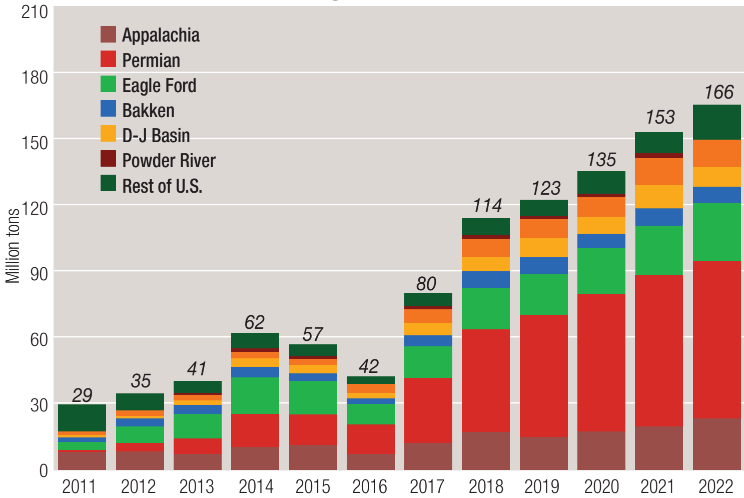
"Starting in September [2018], when we saw that prices were declining dramatically for frack sand, particularly Northern White frack sand, the industry responded extremely quickly," she said. Mines were idled and remain idled as Northern White sand producers slowly bring facilities back online.

"There's going to be a constraint, even more so in 2019 moving into 2020 on Northern White sand production capacity," she said. "We're not going to be mining as much Northern White sand as we have in the past, building up inventories for the wintertime."

And that's a good thing. As oil production continues to ramp up, demand for Northern White will, as well.

"I think the industry is behaving rationally and working to make sure that we maintain prices at a certain level and we're not economically disadvantaging ourselves and subsidizing our customers with the prices of sand," Fulton

Overall Demand is Growing Across Basins



Source: Hi-Crush Partners LP; Rystad

said. "Prices have stabilized for Northern White sand. Lessons have been learned."

Northern White sand continues to dominate in the unconventional plays, constituting a 55% market share, but cheaper in-basin sand has made inroads.

Demand for frack sand peaked in the Permian Basin around April 2018, said Erik Nystrom, vice president of strategic marketing at Covia. Since June 2018, the number of frack crews operating in the U.S. has declined 12%, taking with them a significant demand for sand.

The number of crews actually rose by 12% in the Rockies in the June 2018 to March 2019 time frame, but the other major shale plays—Permian Basin, Eagle Ford, Marcellus, Midcontinent, Bakken and Haynesville—experienced hits. The number of crews operating in the Midcontinent alone was reduced by 22% and in the Permian, 13%, according to Covia research.

As pipeline constraints likely ease in the Permian toward the end of 2019, the number of frack crews can be expected to increase along with a higher demand for sand. But will Northern White be able to maintain its advantage over in-basin?

"Clearly, I think everybody agrees Northern White has the highest quality," Fulton said. "Are you willing to pay for it? That's a different matter. That's where we've really seen the in-basin sands, with the Permian in particular, take off."

Since 2016, Northern White's market share in the Permian Basin has shrunk from 61% to 37%, while Permian in-basin's share has risen from zero to 37%, according to the Atlas Sand Co. LLC presentation by COO Hunter Wallace. Almost all of the difference is made up by regional and non-Permian in-basin sand.

"Some of the Northern White is actually going into basins that do not have an in-basin option available," said Wallace, explaining Northern white's continuing overall market advantage.

Nystrom made the quality argument for Northern White:

- West Texas crush strength is more dependent on particle-size distribution than Northern White;
- West Texas has about two to three times more impurities than Northern White pure crystalline silica;
- West Texas material degrades fairly significantly due to the lesser strength of each individual grain of sand; and
- Northern White crushes more evenly and each grain is able to withstand more closure stress.

Wallace explained the dramatic tilt in the past two years toward in-basin product as one based on producer results, despite Northern White's advantage.

"Over the same amount of time," he said, "operator EURs have continued to get better."

—Joseph Markman

Clues from early innings of E&P earnings season

Analysts with KeyBanc say they expect E&Ps focused in the Permian Basin to report weaker oil price realizations from the first quarter. No good deed goes unpunished might serve as a caption for the early group of first-quarter earnings announcements made by E&P companies.

A May 1 report from KeyBanc Capital Markets found while 12 out of 17 E&Ps that had reported to date had "surprised to the upside," beating production expectations and/or cash flow, 10 had sold off on the news. This occurred despite relatively strong oil prices.

"We think that this highlights the lack of buyers in the space right now as there isn't the incremental investor that is willing to step in and reward good results with a new position," Leo Mariani, KeyBanc analyst, said in the report.

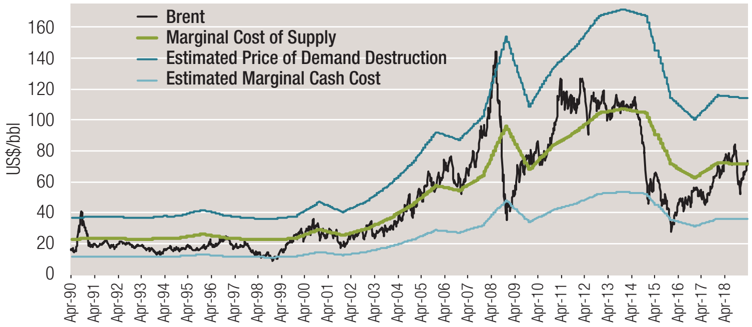
While only five out of those 17 companies reporting had what the market considered excessive capex for the first quarter, the report's authors think that capex concerns will persist as the earnings season continues. "We also expect Permian-focused E&Ps to report weaker oil price realizations with first-quarter 2019 as well," the report said.

The problem of not-enough buyers is likely to persist and continue to pressure E&P stocks, but the analysts think that stronger earnings for the second quarter indicate a buying opportunity at present.

As such, the analysts said their "high-conviction" ideas include Continental Resources Inc., EOG Resources Inc., Diamondback Energy Inc., Pioneer Natural Resources Co., Whiting Petroleum Corp. and WPX Energy Inc. They like these E&Ps for their low-cost oil assets and ability to generate free cash flow.

In addition, an estimated free-cash-flow analysis by KeyBanc found EOG, Pioneer, Continental, Diamondback as well as Occidental Petroleum Corp. and Concho Resources

Marginal Cost Of Oil For Top 50



Source: Corporate reports; Bernstein analysis and estimates

Inc. leading oily E&Ps out of the companies that had reported as of May 1.

Bernstein Energy said May 2 the results of a marginal oil cost survey were in-line with current spot prices but higher than the long-term oil forward strip price of $61.

In the survey of 50 of the world's largest listed oil and gas companies, the analysts found that the marginal cost of oil was $71/bbl based on 2018 reports from the group.

The report found that the global marginal cash cost of production for these top-sized companies increased by 16% to $36/bbl from $31 last year. "This represents the floor price for oil," the Bernstein analysts said.

The breakeven price on a net income basis, based on the global unit production cost of $32.90 per barrel of oil equivalent (boe), was $51.

"Industry profit ability is at the highest in the past five years with [return on average capital employed] at 10%," according to the Bernstein report. "With oil prices rising more than costs, industry margins increased by more than 200% in 2018."

Net income margins for the 50 companies doubled to 18% last year from 8% in 2017.

Cash-flow numbers were also impressive. Average organic free cash flow at $9.80/boe was the highest since 2000; operating cash flows rose by 23% year-over-year to $23.10/boe.

The Bernstein analysts look for the capex cycle to begin to turn this year for the industry, as the re-investment ratio (capex/operating cash flow) is the lowest since 2000, at 57%. Organic reserve replacement for 2018 was 183%, significantly greater than the last five-year average of 115%, according to the report.

Inflation trends may deliver a slightly higher marginal cost this year, the analysts noted.

—Susan Klann

What does Trump's executive order mean for energy investing?

Tucked into one of the two executive orders affecting the oil and gas industry that were signed by President Donald Trump on April 10 was a passage directing the secretary of labor to evaluate how retirement plans subject to federal oversight invest in the energy sector.

The president barely touched on that aspect during the signing ceremony in Crosby, Texas, near Houston. The thrust of the orders was to speed permitting of infrastructure projects by diminishing the ability of states to slow them down.

"My action today will cut through destructive permitting delays and denials," he told an appreciative crowd.

But the passage, Section 5, while ostensibly structured to protect investments in the energy sector could carry some long-term risk as well. And its inclusion in the order caught many in the industry off guard.

"This is a complete surprise to me," James F. Bowe Jr., a partner in the Washington, D.C., office of King & Spalding, told HartEnergy.com. "I had not heard about this being discussed until it came out in the order."

The text of Section 5 is straightforward. Within six months, the U.S. Department of Labor will review data of retirement plans subject to the Employment Retirement Income Security Act of 1974 (ERISA) "to identify whether there are discernible trends with respect to such plans' investments in the energy sector."

The secretary of labor will then review whether existing guidance on proxy voting should be changed.

"This appears to be suggesting that retirement plans subject to ERISA may be operating in some way—perhaps even suggesting that they are operating in concert—in a way relative to their investments in energy firms and I think, in particular, fossil fuel-focused companies—oil and gas producers, coal producers," Bowe said.

Perhaps it's just innocuous, he said, and will just result in a report and tweaks to guidance that won't mean much. Then again.

"My unvarnished view of this is that this is intended to intimidate plans that are subject to ERISA that have been engaging in aggressive advocacy in the direction of companies that are invested in the fossil fuel field and to suggest that their advocacy is inappropriate under ERISA," Bowe said." This, I think, is intended to suggest that to the degree that ERISA-governed plan sponsors are actively challenging fossil fuel companies' practices, policies, whatever, they ought to stop it."

To Michael Underhill, chief investment officer of Wisconsin-based Capital Innovations LLC, that is a positive direction for the energy industry.

"It would increase investment in fossil fuels as Trump's executive order is the latest measure that the Trump administration has taken seemingly against the use of ESG [environmental, social and governance] investments within ERISA plans," he told HartEnergy.com. "In 2018, the [Labor Department] issued guidance on what sponsors must consider when evaluating ESG investment options that has been viewed as more restrictive than guidance provided during the Obama administration. The Department of Labor retreated in April 2018 from Obama-era guidance on ESG funds, and the changes could have a chilling effect on the use of those products yet spur energy investments."

On April 23, the department issued a bulletin that plan fiduciaries can only consider the ESG standards of investments as they relate materially to financial considerations.

"The new bulletin will most likely make plan advisers and sponsors question whether to recommend or include ESG funds on plan menus," he said.

Neither Bowe nor Underhill believe that retirement plans bound by ERISA will head to court anytime soon to contest the order since it is too early to know what the department will recommend to the White House and how the guidance might be enforced.

There is, however, the risk of a directive by a pro-oil and gas administration backfiring on the industry in terms of fund managers avoiding energy company investments altogether to steer clear of oversight.

"In that sense, it would be an unintended consequence of this kind of activity because I wouldn't have thought that this administration's goal is to stifle investment in fossil fuel-focused companies," Bowe said. "But I could imagine that in a close case, a plan manager might say, 'know what? If we were to become active in this space and were to begin to want to express our views as to policy calls or investment directions of some of these companies, we will have the government considering whether we are committing a thought crime or not.'

"If I were that plan manager," he said, "I'd think that maybe my money would be better off put elsewhere where we might actually have an opportunity to influence the direction of the companies we invest in without having the government checking us."

—Joseph Markman

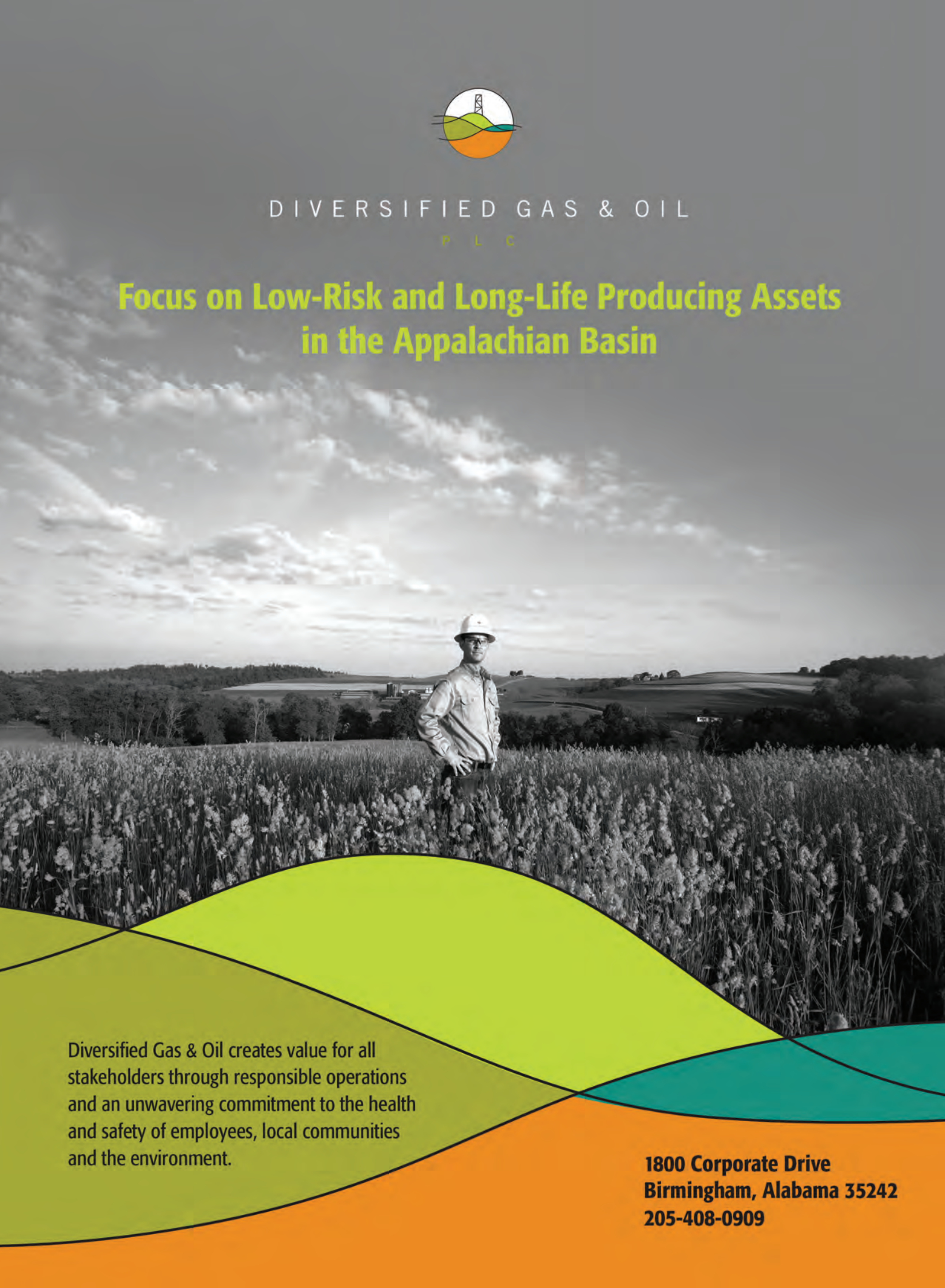
Industry changes needed to lure investors

Ryan Keys, co-founder of Midland Basin operator Triple Crown Resources, channeled his inner Frank Costanza during Hart Energy's DUG Permian conference.

Like the Seinfeld character sitting at his Festivus pole, Keys declared April 16 his Festivus and aired a list of grievances involving the oil and gas industry.

"At the root of these grievances is the current sentiment from the outside world and why we're seen as a bit of a pariah in the investment community," Keys told conference attendees. The intent, he said, was not to point fingers but to share lessons. "There are things we've done well but concentrating on those won't make us better."

The industry has not been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Wall Street's favorite lately, despite companies becoming more efficient, using technology and spending on economic wells, working to add value for shareholders.

Keys framed his list with the introduction of Permian Co., a combination of 13 pure-play Permian public companies. Altogether, Permian Co. boasts of 3 million acres in the Delaware and Midland basins with 1.6 MMboe of production. "At the same premium as Anadarko, this company would represent a $145 billion deal, plus or minus $5 billion," he said.

But Permian Co. has sold off more than 30% despite growing production 30%, Keys explained, sharing one of his grievances—"the investing public."

Negative free cash flows don't help.

The Institute for Energy Economics and Financial Analysis (IEEFA) pointed out in a March report that 2018 was expected to be a turnaround year for America's fracking industry. As oil prices improved amid record-setting production, the shale industry was expected to produce cash. But that didn't happen for the most part. Showing lost patience, investors responded by pulling back on the amount of equity and debt financing, according to the report. Norway's sovereign wealth fund opted to divest from oil and gas E&P companies.

"A healthy industry would generate enough cash not only to sustain its own capital spending, but also to pay off debt and reward stockholders—all while maintaining or even increasing its output to support rising stock prices," IEEFA said in the report. "Until fracking companies can demonstrate that they can produce cash as well as hydrocarbons, cautious investors would be wise to view the fracking sector as a speculative enterprise with weak and uncertain fundamentals."

The industry has not communicated its message well to the generalist investor, according to Keys.

"We're not telling in it a way a generalist or a layman can understand. So I think we need to get back to the very, very basics and communicate why Joe Investor's energy stock is going to go up and to the right."

Explain "how foundational our product is" and how "this boe enables basically life as we know it," Keys said. "I think if we concentrated more on connecting how our investors' lives are affected and improved by this boe, maybe less on a normalized 30-day IP," perhaps they'd pay more attention to the Permian Co. sales pitch.

In other words, tell investors about how much a barrel of oil equivalent can yield in plastics, electricity for an average home, or miles traveled for a car or passenger plane. Restricting capital to one of the few areas in the world with oil supply growth might worsen standards of living, he added.

But there is still room for improvement in terms of cost structure.

Also on Keys' list is the industry's inability to articulate the Permian value proposition and cost structure. This involves explaining to investors that if commodity prices are flat and production grows, then costs will shrink in areas such as lease operating expenses, gathering and transportation, and general and administrative (G&A), ultimately increasing margin. But that is only if infrastructure and the organization are designed to actual scale, Keys said.

"What we tell investors is that our cost structure can and should improve because our production and revenue should grow faster than those costs. Things like centralized compression and automation are large investments but the expense savings offers fairly quick payouts at that sufficient scale," Keys said. "On the G&A front that's a much bigger deal right now than it was even a year ago. Growing headcount proportionally with rig count won't offer that scalability. This means we have to be efficient at work."

However, free cash flow is considered investors' top complaint with the industry.

"Combined, Permian Co. spent about $2 billion more than it told investors that it would. So maybe there's a bit of a trust issue here," Keys said. Both drilling and completion (D&C) and infrastructure exceeded guidance.

He pointed out that at about $5,000 per acre fully built out infrastructure will lower full-cycle costs, and investors love hearing about this. "They like hearing about how a small water investment can remove a nickel and dime off the boe operating expense," he said. "Maybe if we talk more about that …and about what we want to build this year then we'd create more alignment between them, ourselves, our asset, our cash margins and our people—showing that the full-cycle economics of our assets work really nicely if they're patient and allow us to build that scale.

"Ultimately investors are looking for yield now much more than growth, and Permian Co. had negative 5% free cash flow last year," Keys added.

Another grievance: breakeven economics are misleading, according to Keys.

"NPV 10 breakeven is really useful for benchmarking and capital allocation. But I think we should leave it there and not let it get into investor materials," Keys said. "There is nothing about a well that has a half cycle rate of return of 10% that is breakeven. … A 10% rate of return well certainly does not make the equity break even. So when they [investors] hear a $30 breakeven and then see how the stock does … I can imagine that might be confusing."

—Velda Addison

U.S. LNG market saving the day with 11% growth

Since the U.S. first started exporting LNG from the Lower 48 in 2016, American LNG has become an unstoppable force.

"Frankly, I've never been more bullish about the future of LNG," said Renee Pirrong, manager of research and analysis at Tellurian Inc., during a technical session at the Offshore Technical Conference (OTC) on May 7.

Tellurian is a Houston-based company looking to challenge conventional thinking in the LNG industry. The company is currently in the midst of developing a portfolio of natural gas production, LNG trading and infrastructure that includes a roughly 27.6-million-tonnes-per-annum LNG export facility named Driftwood LNG near Lake Charles, La.

Pirrong, who took part in a panel at OTC on the LNG transition, said three major macro trends are transforming the market today:

- Supply push from the U.S. where an abundance of natural gas production cannot be consumed domestically;
- Demand pull coming from the rest of the world driven by economic development and emissions targets; and
- A shift to a commoditized LNG market.

Natural gas production in the U.S. continues to reach record levels. Dry-gas production through year-end 2018 was 24.6 billion cubic feet per day (Bcf/d) more than in 2010, according to Drillinginfo Inc. data.

"I don't think it's a surprise to anyone in this room that we're witnessing the U.S. emerge as a natural gas producing juggernaut," Pirrong said.

Last year, the U.S. produced about 83 Bcf/d of natural gas, which is up 11% on the year. Pirrong said Tellurian sees production growth continuing into the future, driving export growth.

Tellurian anticipates the U.S. will see about 20 Bcf/d of excess gas or incremental gas production occurring by 2025. "And all of this gas will need a home," Pirrong said.

Most of the production growth in the U.S. is coming from a handful of shale basins. In particular, Pirrong noted the surge of natural gas production in the Permian Basin calling it "truly remarkable."

"It's a hot topic for a reason," she said.

Oil producers like Chevron Corp., who also participated on the panel with Tellurian, have seen an increase in gas production in the Permian. The problem, however, is a lack of infrastructure available in the basin to absorb all of the gas and transport it to market. As a result, roughly half a billion cubic foot a day of gas is flared in the Permian Basin every day, Pirrong said.

"Now to put that into an LNG perspective, that's equivalent to about 4 million tonnes of LNG, which is equivalent to Thailand's entire LNG demand this past year in 2018," she said.

In some instances, some producers in the Permian Basin have had to delay production as natural gas prices in the basin traded in negative territory. For example, Apache Corp. said April 23 it temporarily halted production at its Alpine High assets within the Permian's Delaware Basin in late March.

"We need to develop the new infrastructure, both pipelines and LNG terminals to get that gas to market," Pirrong said. "And we really see the LNG market as sort of saving the day… There's really no better place to put it than in the LNG market, which we see growing at about 11% so far this year."

Ultimately, by the end of 2019, she said Tellurian expects there to be about another 30- to 40 million tonnes of LNG absorbed into global markets.

"Suffice it to say we expect there is a requirement for at least 100 million tonnes of incremental LNG capacity built around the world to meet the growing demand by 2025," she said. "And we actually think that number could be much, much higher."

At the same time, Pirrong said the market is undergoing a rapid shift to commoditization.

Long-term contracts will lose their dominance in the next five years as the product is increasingly recognized for what it is—a commodity. Replacing those contracts will be a system of commodity markets akin to crude oil, with prices fluctuating based on the supply and demand of a given day.

"That really challenges the existing business models that we've seen in the LNG industry," Pirrong said. "And it forces LNG developers to adapt to those changing market conditions."

In order to compete as the market transitions, Pirrong said Tellurian has been integrating up the value chain to deliver low-cost natural gas.

As a result, Tellurian is looking to acquire 15 trillion cubic feet of natural gas resources in the Haynesville Shale, which Pirrong called a low-cost basin.

"It's kind of at our back door in southwest Louisiana," she said.

Tellurian is also working to build pipeline infrastructure to reach into the Permian Basin to access that low-cost natural gas, which has been trading at negative prices this year, she added. "Which is just bonkers to think about."

—Emily Patsy

DUG Permian: companies talk best practices

Operators and service companies in the Permian Basin are tackling the relationship between parent and child wells, tweaking stage spacing and proppant loading and making other adjustments as they continue to optimize and move into full-field development.

But players are not using a one-size-fits-all approach in the biggest oil field in the U.S. Many operators are utilizing technologies offered by service companies to improve well performance, while also incorporating their own talents and knowledge gained from peers and past experience. They are doing so with eyes on improving EUR and adding value, without sacrificing the former early on in a well's life.

A panel of operators and oilfield service providers took to the stage April 17 at the DUG Permian conference to talk about completions and best practices surfacing in one of the world's most-watched basins.

"We have seen a lot of advancements that have been happening in the industry from a service efficiency standpoint and technology, which are allowing us to increase the number of stages that we can frack in a day," said Faraaz Adil, a Permian Basin-focused technical manager for Halliburton Co. "Operators are … reducing their cluster spacing, increasing the number of stages. They are trying to access as much of the reservoir as they can, and we are seeing advancements where we are using [technologies] like fiber microseismic to analyze the geomechanics."

Completion efficiency is also coming in the areas of lateral length, clusters and proppant loading, according to Rocky Seal, national product line sales leader of completions and wellbore interventions for Baker Hughes Inc., a GE company. He pointed out how there's been a lot of experimentation in the last four or five years in these areas, but lateral lengths have flattened out—averaging around 9,000 feet—in the past one and half years.

There are some exceptions to the norm.

Surge Energy, for instance, recently said its Medusa Unit C 28-09 3AH drilled a 17,935-foot (3.4-mile) lateral in the Wolfcamp A. At nearly three times the length of The Hollywood Walk of Fame, the company claims the well has the longest known lateral in the Permian Basin. The well will be completed and brought online later this year, the company said in a news release.

The Permian Basin remains the top oil-producing region in the U.S., producing about half of the more than 8 MMbbl/d produced in the country's top basins. But as oil price volatility continues causing some independents to cut spending while larger companies ramp up drilling plans, thoughts remain on making wells better.

Like its peers, Lario Oil & Gas Co., a private independent that's been around for about 90 years, has taken aim at stage counts. The average stage count per day for Lario has gone from about five to between eight and 10 when "zippering," or using a zipper fracks. "The pump-downs are what changes how many stages per day you get because of how long those are," said Christian Veillette, the company's vice president of operations.

"We're constantly trying to improve and optimize all of our processes—whether it's from sand delivery, fluid delivery. Everything is planned out in such a way that it's just a well-orchestrated show," he added.

Finding the incremental economic benefit is a task WhiteHorse Energy LLC aims to accomplish, according to its CEO, Hunt Pettit.

"Everything that was previously mentioned from stage spacing, cluster spacing, higher pumping jobs, the amount of proppant, the amount of fluid: it's a dynamic balancing act," said Pettit. "You're looking at the geology; you're looking at the geophysics; you're talking to your vendors; you're trying to talk with other operators to see what the best practices are. And then you take them back to your own asset and begin to implement them."

WhiteHorse has been using, for example, diverters at the tail end of its jobs in hopes of making contact and keeping fractures open. "So far, we've seen excellent results," Pettit said.

But Veillette pointed out the difficulty of diverting 10 clusters in the absence of short spacing.

"I see why people talk about it [using diverters] for parent wells, but people never talk about it for the child well," he said. "My point of contention is you could have tracers and tell me where you put fracks, but you truly don't know how far they went and which clusters took the fluid. So, you may have some longer fracks where you've pumped the diverter because you've sealed off some."

Veillette noted he is more of a fan of old-fashioned mechanical diversion.

"I feel like you need diverter for the exact opposite reason for your child well when you come back," he said. "You want to seal off where those fracks may have already impacted where the wellbore is being landed for the sibling well."

However, more companies are using diverters. Faraaz puts the percentage at more than 60% to 70%. But how diverters have been used over time has changed, he added. Instead of just dropping a certain volume and hoping for the best, companies are taking a more calculated approach in terms of volumes and learning of the possible benefits beforehand.

It also, perhaps, helps to have downhole cameras.

With much conversation around cube development, Faraaz acknowledged well spacing could become a big challenge. Monitoring offset well pressures and examining bottomhole data to gauge cluster efficiency are among the techniques used to help determine cluster efficiency, he said.

"Everybody wants to stimulate as much oil volume as we can," he said. "To assist that we might have to do different things, so we're coming up with changes in the way diversion is done." This includes incorporating automation and looking at pressure fluctuations before changes are made to improve cluster efficiencies.

—Velda Addison

Floyd Wilson: Wildcatting has changed

Legendary shale pioneer Floyd Wilson recently left Halcón Resources Corp., the company he founded, resigning in February after activist investor Fir Tree Capital Management's call to sell the debt-laden company. But he has already formed Falconer Oil & Gas Corp. to go after the brass ring again—the ninth company he has created.

"We're still wildcatting, just in a modern way. We can be dismissive of what investors need, but we shouldn't be."

Speaking at the DUG Permian conference, he admitted the world has changed. Exploration in the past decade unlocked all of today's great shale plays, but wildcatting has changed since then—investors look upon it more guardedly now and demand financial discipline. That's just the facts, he said. "Some investors have grown impatient and that's reasonable.

"Wildcatters still need to be measured, appropriately or sadly; traditional wildcatters like me need financial oversight … maybe especially me," said Wilson.

Wilson said consolidation in the E&P space is inevitable, especially now that pad drilling takes so much capital, more than most small companies can access. "There's no point in being the last owner of an oil and gas well. You need to create a real business and build something someone else will want to replicate or improve.

"There's no need for another 1,000-barrel-a-day company in any of these plays. There's no point in owning a tiny oil and gas company. It has to have legs and be somewhat sizeable, and attractive to someone else, eventually."

The former founder, chairman and CEO of Petrohawk Energy Corp. and Halcón said he's had the good fortune to work for companies that discovered the Fayetteville and Eagle Ford shales, and had some of the first Permian Wolfcamp success as well. "Success comes from having good people and being stubborn," he said.

But today wildcatting has become more about figuring out how to drill better, faster, cheaper, Wilson said. Today's geoscientists work closely with engineers. Discoveries are made every day, he said, but it's as much about how to drill efficiently, as to how to figure out a new play.

Operating within cash flow is very important, he conceded, but that can't be done in the early stages of a play during wildcatting. A company can have success in the early stages without cash flow but it needs to operate within cash flow later as it develops a play. "Living within cash flow is a reasonable ask," he said.

He said investors also ask, why do you want more locations; why do you need more sand? "These are reasonable questions."

Wilson said he could have operated within cash flow at some point in every E&P business he's owned, although he admitted he never had. He said the companies he ran could have achieved free cash flow eventually.

"I never ran a company that operated within cash flow until I sold it—and then all the cash flow came in at once." The serial entrepreneur is known for building and then selling Petrohawk, one of the earliest shale leaders, to BHP Billiton for $12.1 billion in 2011 ($15.1 billion with assumption of debt). At the time it held about 1 million acres in the Haynesville and Eagle Ford shales and Permian Basin. In December 2010, it had already sold off its Fayetteville Shale assets to ExxonMobil's XTO Energy Inc. for $575 million.

Wilson formed Halcón Resources soon after. He again tried to acquire shale assets but ran up debt. In 2016, Halcón voluntarily entered bankruptcy court but emerged two months later, having eliminated $1.8 billion of debt. Low oil and gas prices still had the company on the ropes, however, and at one point the stock had declined to just $1.17 per share.

—Leslie Haines

ENERGY STOCKS AND THE ENVIRONMENT

U.S. asset managers have rushed to incorporate ESG (environmental, social and governance) factors in their funds. What does this portend for funding flow in energy, an area already striving to deliver a returns-based strategy to investors?

Boston represents a hotbed of insitutional funds facing pressure to consider ESG in their investments.

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Primary industry activities, whether in farming, mining or drilling for oil and gas, often affect the environment and society. Deciding what level of impact is appropriate is typically set by a region's regulations or guidelines. For today's energy sector—a key driver of growth for many economies—the conversation is rapidly broadening as goals are set in pursuit of a low-carbon economy.

Are such trends influencing worldwide portfolios by tilting them away from energy investments? And is anti-fossil fuel sentiment growing to the point that it's a factor in overall investment decision-making? How widespread are divestments driven by anti-fossil fuel policies—both now and looking to the future?

The answers depend on who is asked. Some signs, particularly in Europe, point in that direction. Others, more frequently in the U.S., offer a wider spectrum of views, with some reporting little or no impact from anti-fossil fuel sentiment.

The oil and gas sector is a key part of Norway's economy and is projected to contribute 17% of its GDP in 2019. The sector employs some 170,000 people. However, a recent decision was taken to keep the Lofoten Islands area off-limits from drilling, despite estimates that it holds 5% of total undiscovered resources on the Norwegian continental shelf.

"Climate comes before cash!" was the cry in April from a demonstrator in front of the Norwegian parliament, reflecting the growing anti-fossil fuel sentiment among some of its citizens. A month earlier, Norway's $1-trillion Government Pension Fund Global declared it would divest its E&P stock holdings.

"ExxonMobil [Corp.] alone has a market cap that exceeds every solar and wind company, in aggregate, in the world," observed Pavel Molchanov, senior vice president covering the alternative/clean technology sector for Raymond James & Associates Inc.

ESG

In the U.S., professional asset managers seem to be moving in a similar direction and increasingly offering "sustainable funds" that incorporate environmental, social and governance (ESG) considerations. For example, a recent report by Morningstar estimated that, in 2018, there were 351 sustainable funds, up nearly 50% from 235 in 2017.

"Sustainable investing emphasizes material ESG issues that contribute to a more thorough financial analysis," according to Morningstar, which provides ratings of mutual funds and other investment vehicles. "It encourages direct investment in areas like renewable energy and green technologies as the world transitions to a low-carbon economy."

A hard nut to crack is the size of assets in this category: Do you need a sledgehammer or a nutcracker?

According to the Global Sustainable Investment Alliance (GSIA), assets under management (AUM) in Europe formed the largest pool of sustainable investment assets, standing at $14.1 trillion at the beginning of 2018. The next-largest pool is in the U.S., with AUM of $12 trillion, having grown markedly from $8.7 trillion at the start of 2016, according to the GSIA.

Trillions of dollars!?

According to Morningstar, AUM from the 351 funds in its report came to $161 billion. Moreover, if the report focused "only on those with the more comprehensive sustainability criteria," the AUM figure dropped to $89 billion, it reported.

The category's "AUM and fund flows, though both higher than ever before, remain tiny compared with the overall U.S. fund universe," it added.

Obviously, much depends on how tightly, or loosely, these various categories of fund assets are defined.

For perspective, if looking to invest in what is broadly called renewable energy, the opportunity set is far from unbounded. As an example, electric power generated in the U.S. by renewables in 2017 made up less than 17% of all electric power, according to U.S. Energy Information Administration data. The renewable sources were 7.4%, hydropower; 6.3%, wind; 1.3%, solar; and 1.6%, biomass.

By contrast, natural gas continues to be the largest power source for electricity in the U.S. The relatively clean-burning fuel accounted for 32.1% of electric power generated in 2017, more than the once top spot held by coal, which stood at 29.9%. Nuclear power—disliked in some environmentalist circles, but favored elsewhere for its low-carbon technology—generated some 20% of electricity.

Growing, but still only a 'sliver'

"The share of renewables and low-carbon technology is increasing, and, as a result, the market cap of the companies involved in the sector is increasing," said Pavel Molchanov, senior vice president covering the alternative/clean technology sector for Raymond James & Associates Inc. in Houston. "But renewables are still only a small sliver of the investable energy universe."

A Sustainable Funds Glossary

ESG Consideration	Funds considering ESG are those that incorporate ESG without orienting their entire investment process and outcomes around it. Many asset managers now say they consider ESG information when making investment decisions.
ESG Integration	The largest number of sustainable funds fall into the ESG integration category. These are funds that broadly integrate ESG criteria throughout their investment processes. They exhibit higher levels of commitment to sustainable investing than do ESG consideration funds—in many cases, much higher. The typical ESG integration fund's portfolio is tilted toward companies that its managers believe are addressing material sustainability challenges in ways that will make them better investments.
Impact	Impact investing is generally defined as "investments made into companies, organizations and funds with the intention of generating social and environmental impact alongside a financial return." Until recently, it has referred largely to investments made by high net worth and institutional investors in impactful projects or companies.
Sustainable Sector	Offerings that focus on "green economy" industries like renewable energy, energy efficiency, environmental services, water infrastructure, and green real estate are grouped as sustainable sector funds.

Source: Morningstar, Sustainable Funds U.S. Landscape Report, February 2019


John A. Penney Co., Inc.
ONLY

ESG Factors

Environmental Factors	Social Factors	Governance Factors
Natural resource use	Workforce health & safety	Board independence
Carbon emissions	Diversity/opportunity policies	Board diversity
Energy efficiency	Employee training	Shareholder rights
Pollution/waste	Human rights	Management compensation policy
Sustainability initiatives	Privacy/data security	Business ethics
	Community programs	

Source: BofA Merrill Lynch

Overleaf, Boston's financial district is located in the city's downtown area and is a hub to a number of banks, brokerages and law firms.

"ExxonMobil [Corp.] alone has a market cap that exceeds every solar and wind company, in aggregate, in the world," he added.

Molchanov traces the roots of growing anti-fossil fuel sentiment—and its impact on investing—to Europe.

"The environmental/green movement is more widespread in Europe than anywhere else, and its influence is being felt in the financial sector," he said. "As far as types of organizations taking part in divestment, most are non-profits: public-sector pension funds and university or church endowments.

"However, three of the top four are financial-services firms, so the private sector is playing a role as well."

A Raymond James study published last August of institutions divesting fossil fuel holdings showed the top four, with AUM ranging from $800 billion up to $1.9 trillion, to all be based in Europe. All four committed to divesting their coal-sector holdings, while two of the four additionally pledged to move out of oil-sands investments. The divestment process began two to four years ago.

Taking a broader view, encompassing all divestment plans—not just the top four—Raymond James estimated assets subject to divestment at less than $50 billion. This was based on aggregate AUM of institutions with divestment plans ($4- to $5 trillion), an assumed energy weighting in line with the S&P 500 and MSCI World Index (6% to 7%) and more than 80% of divestments concentrated in the narrower coal and oil-sands segments.

While a combination of factors typically goes into most investment/divestment decisions, the Paris Agreement undoubtedly played a role in investor attitudes on ESG issues.

"There's no question that in the last decade—particularly in the last three years or more since the Paris Agreement—there has been greater and greater investor awareness of environmental sustainability as an investment strategy," Molchanov said.

"At the Paris Agreement in December 2015, there was a lot more talk about climate change and carbon emissions."

However, the simultaneous timing of two trends—the signing of the Paris Agreement and a collapse in crude prices beginning in late 2014—has made it harder to assess the impact of each factor, especially given the string of losses in energy equities during recent years.

"Big investors are nervous about possible legislation on climate change arising over the next 20 years," said Robert Plummer, vice president with energy research and consulting firm Wood Mackenzie.

Are weak asset inflows into energy aggravated by anti-fossil fuel sentiment or is it simply a case of subpar performance?

"Oil and gas has underperformed the S&P 500 in eight of the last nine years—every year with the exception of 2016," Molchanov said. "Investors have just been so frustrated by energy stocks that there's a lot of apathy.

"Eight years of underperformance helps explain why investor appetite for oil and gas equities is a lot lower than it used to be historically."

A story of mainly small caps

While the renewables sector has a number of long-established players, they are not of the scale of many larger oil companies. As of mid-April, Florida-based electric-power behemoth NextEra Energy Inc. had a market cap of about $90 billion. In Europe's wind sector, Orsted A/S, Vestas Wind Systems A/S and Siemens Gamesa Renewable Energy SA had market caps of around $31 billion, $18 billion and $9 billion, respectively.

"There are some large companies in the sector, but investing in renewables and clean tech is still largely a story of small caps," said Molchanov. "It's a wide spectrum. Some are profitable; some are not.

"But as the share of low-carbon energy in the global energy mix rises over time—and it's rising every year—it follows that the relative market cap and relative investability of the companies will also be on the rise."

For investors taking a proactive view of energy—and looking for those companies with advantaged ESG practices—the Raymond James analyst suggested screening for producers that actively seek, among other measures, to avoid oil spills; reduce the flaring of gas; and pursue steps to lower carbon emissions and methane leaks.

Climate change policies

Robert Plummer, a vice president with Scotland-based research and consulting firm Wood Mackenzie, was quick to highlight the faster pace of developments related to ESG issues that has occurred among European investors vs. their U.S. counterparts.

"I think Europe is quite a way ahead of the U.S. in considering these issues and concerns of general investors," said Plummer. "When I speak to fund managers, they say they're getting lots of questions from clients, such as university pension funds or other institutions.

"They're saying, 'I don't want you to invest in oil sands,' or they're nervous about complying with their policies on climate change."

Plummer cited a couple of companies that planned to take advantage of current market sentiment to raise "ESG energy funds." By contrast, "general investors have gone off traditional oil investments massively over the last four or five years," he said.

Despite recent gains, "the performance in the energy sector has been pretty painful."

One of the key factors for U.K.-based integrated producers is that "they've got very big brands. They employ over 50,000 people. And if you want bright, young people to come and work for you—and it's generally the younger generation that is environmentally more sensitive—you have to attract them by saying 'We're going to drive the change'" during what WoodMac calls "the transition phase."

Investments by European integrated producers in the renewables sector account for "less than 10%" of capex budgets each year, Plummer said. In some cases, there is an opportunity cost in pursuing the projects. WoodMac studies show renewable projects often generating sub-10% returns, trailing traditional energy-project returns on an unrisked basis.

"If you're competing to undertake an offshore-wind project, for example, it's a very competitive market," said Plummer. "It's relatively low risk, and you're not pushing the boundaries on technology.

"It's difficult to see how you can generate high returns. And you're seeing low returns on solar projects. When you have auctions for the licenses, it's incredibly competitive."

What is the trade-off that makes the relatively modest returns on renewables attractive? "There's a general concern of risk," said Plummer.

"Big investors are nervous about possible legislation on climate change arising over the next 20 years. If you've done nothing, you may expect to face someone trying to bring litigation against you."

Traction in investor mindshare

Based in Boston, Jeremy Javidi has a highly opportune position to evaluate issues affecting flows into energy and the potential effect ESG issues may have on the sector.

A Royal Caribbean cruise ship is docked at Flynn Cruiseport Boston in South Boston's Seaport District.

"The key to ESG investing is to be an active fund manager, but not an 'activist,'" said Jeremy Javidi, lead portfolio manager of Columbia Small Cap Value I Strategy. "ESG is a tool in the toolkit; it's not a philosophy."

Not only is he the lead portfolio manager of Columbia Small Cap Value I Strategy, he also is the portfolio manager chairman specifically overseeing all proxy-voting issues related to ESG issues, at Columbia Threadneedle Investments.

Columbia Threadneedle's most recent tally of AUM is $459 billion. It estimates that it has some $29 billion—about 6% of its assets—in funds with a "responsible investment" (RI) moniker, akin to a "sustainable" designation. The RI funds are growing at about a 15% annual rate in AUM at Columbia Threadneedle, which Javidi says is typical for the fund industry as a whole.

Having spent 17 years working with Small Cap Value I Strategy, Javidi is a generalist with a significant amount of experience in the energy sector. His fund, as of early April, was positioned to benefit from a higher commodity price, and "E&Ps make up the majority of our energy holdings," he said.

Against the overweight E&P position, the fund was underweight in oilfield services and refining.

RI funds are a fund category "that is gaining traction in terms of investor mindshare," Javidi said. "It has been driven mainly by our European clients, as well as some of our U.S. institutional clients and some of our other foreign clients.

"For now, we're not seeing a lot of traction for ESG investing from U.S. retail clients through mutual funds, although they do increasingly align their investments with their viewpoints," he added.

"The key to ESG investing is to be an active fund manager, but not an 'activist.' ESG is a tool in the toolkit; it's not a philosophy. If ESG is the only thing you look at, it's an incomplete picture of how stocks work.

"Over years and years, it's been shown that the stock market is correlated to the direction of earnings. If earnings are going up, stocks go up."

ESG funds are, by and large, able to invest in E&Ps, although accessing certain ESG data is a high priority. "A sustainability report showing a policy that considers all the stakeholders in how you operate your business is a very important dataset for all these ESG investors," Javidi said.

"Just as fundamental investors, like me, are looking to have 10-Ks, 10-Qs and earnings releases, a lot of the ESG investors are looking to have sustainability reports that allow them to conduct their analysis.

"Right now there is a dearth of data out there. Any kind of E&P data that demonstrates superiority from an ESG perspective can actually attract ESG funds. It's another way of differentiating yourself relative to your peers.

"In a commodity business, like oil and gas, it helps to have data showing fewer accidents on the job site, better environmental track record, more safety controls, etc."

For smaller E&Ps, with less scale of production, this may represent a challenge, but "the data doesn't have to be voluminous, like for ExxonMobil or BP [Plc]. It's not a matter of how much data; it's about presenting it in a way that helps another subset of investors have a better understanding of the company.

"I don't want E&Ps that we invest in having to hire a consultant to produce a report."

Javidi pointed out that relevant data relates to information that is most material

Workers cross over the Fort Point Channel on the Summer Street Bridge at rush hour. The channel separates South Boston from downtown.

from a financial perspective. This narrows down data to that which can help judge the sustainability of an investment from a financial point of view.

The firm's "ESG Materiality" is based on the research framework that can be obtained from the Sustainability Accounting Standard Board (SASB).

In addition, good governance practices should "start to permeate throughout the oil and gas industry," Javidi said. "Earlier, when E&Ps were smaller, they tended to invite their friends and family onto their boards.

"What is really important now is board composition, board tenure, making sure that those on the board of directors really are diverse in terms of background and thought."

Paradigm shift

Javidi described the transition that the energy sector is undertaking as it moves from a "technology play" to an "industrial play" as a "paradigm shift." In the industry's early days, when it was "truly a technology investment," investors were willing to shoulder losses from a set pool of investments in expectations of a long-term total return, he recalled.

With the prior investment pool depleted, a new brand of investors with new metrics has emerged, he said. The new investors are no longer striving for production growth and maximizing net asset value, but, rather, a return on invested capital (ROIC) that is above an E&P's weighted average cost of capital (WACC) and, with it, the ability to generate a free-cash-flow yield.

"We're really excited if the industry continues on that track," Javidi said. "This year, with the tailwinds of higher oil prices, if we see managements restrain their natural tendency to increase capex budgets, I think the market will view that restraint very favorably—that is, in seeing that the incremental free cash flow is not going to be put right back into the ground."

As E&Ps progress from single wells to multiwell pad development, he continued, "now is the time to show their operational efficiency and how much they can drive down the cost of a barrel, so they can maximize their margins and improve their ROIC.

"And as their ROIC exceeds their WACC, that's the time to make a decision as to re-accelerating growth."

Javidi characterized the ESG factor as "a sub-plot" in the overall refocusing of the industry to a sustainable business model. And he is optimistic about the outlook for E&Ps.

"What I've seen time and time again is that the market is always greedy," he commented. "As these companies transform their business models, and as they demonstrate that they can earn their cost of capital—even in a very capital-intensive sector like oil and gas—the money will come flowing right back to the sector. People are waiting and looking for those opportunities.

"And those opportunities will accrue to those operators who are more efficient, who can really streamline their operations with multiwell pads, pipelines and infrastructure.

"The new breed of investor wants to see a return on investment: How much did you invest in the ground, and what returns have you generat-

"I can't recall we've ever had a client say that it was redeeming from us because of a fossil fuel ethic," said Shawn Reynolds, portfolio manager for the Global Hard Assets Fund at VanEck Corp.

ed on that investment? I think the industry is moving in a really strong direction."

Assessing for ESG

New York-based VanEck Corp. has a good view of fund flows from a variety of vantage points. Not only does it manage traditional energy investments, but its hard asset fund also has exposure to a number of renewable investments. In addition, VanEck's exposure to mining investments gives the firm insights into how ESG issues affect not just energy, but also other primary industries.

As for the impact of anti-fossil fuel sentiment, there is always "headline risk, but we really haven't seen any overt outflow of funds because of it," said Shawn Reynolds, portfolio manager for the Global Hard Assets Fund at VanEck. "I can't recall we've ever had a client say that it was redeeming from us because of a fossil fuel ethic."

Notably, as with many other professional asset managers, VanEck is a signatory to the Principles for Responsible Investment. "Everybody has to be assessing how their process deals with ESG factors," said Reynolds.

"If you think about what we do in various major sectors—oil and gas, mining, farming—you have to worry to varying degrees about the potential environmental impact. There's always been environmental opposition to these projects, and there's often been risk of damage or disaster."

In addition, the emphasis on the social issues of ESG has increased significantly, ac-

Boats sail by Boston's financial district and the historic Old North Church in the Italian North End.

cording to Reynolds. "For example, if you go to a copper mine in Zambia, we don't want to see just the copper mine and the ore-processing operations," he said.

"We also want to see what the camp looks like, what kind of local communities exist, what level of health and educational facilities are available, what kind of water has been put in place by the company. We take site visits very seriously."

Similarly, the governance element of ESG characteristics has been increasingly in focus, said Reynolds. "We have a very active engagement on the governance side with almost every company in which we invest," he stated.

"Has engagement ratcheted up over the years? Absolutely, it has. Part of active management is assessing how governance is working at the company, and whether it needs to be improved. Again, that's inherent to our process."

"Big investors are nervous about possible legislation on climate change arising over the next 20 years. If you've done nothing, you may expect to face someone trying to bring litigation against you."

—Robert Plummer, Wood Mackenzie

Opportunities lacking

Given the rapid rise in the number of sustainable and SRI/RI funds, the impression might be that some serious dollars are be-

A HOLISTIC APPROACH

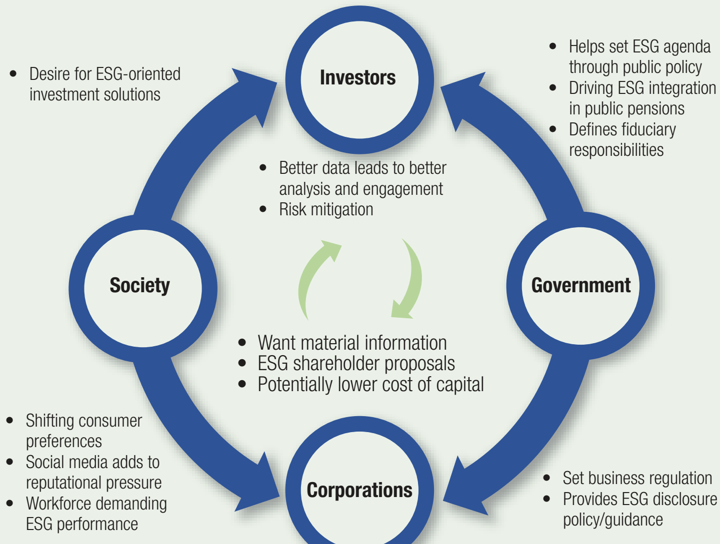
Alanna Fishman, vice president with Cornerstone Energy Solutions, draws a distinction between current ESG investing and some prior practices that simply excluded investing in specific companies or industry verticals. Cornerstone provides strategic advisory and business consulting services to firms across the energy sector, including developing, managing and communicating ESG and sustainability programs.

"The attraction of ESG investing—and why people are actively participating in the space—is because it is no longer 'exclusionary,' said Fishman. "Investors do not have to exclude whole swaths of investment opportunities, which reduce the potential universe of securities and can impact returns. In oil and gas, ESG provides a holistic vantage point of risk along with financial considerations, such as value and growth. It's no longer a case of mandating complete divestiture from oil and gas to incorporate ESG.

"It's widely recognized that we're not moving away from oil and gas quickly; we've built our economy around it," continued Fishman. "What's new is that some of the major players in the industry—BP [Plc], Royal Dutch Shell [Plc], ExxonMobil [Corp.], etc.—have realized that there is an inherent value in being a best-in-class actor and by considering ESG factors in their business strategy and risk mitigation plan."

"Now what's happening is that investors are saying, 'We don't have to choose between doing what is socially responsible and getting returns for our clients. We are able to tilt our portfolios toward companies that are best-in-class actors, so that you can have E&Ps or oilfield service companies in a portfolio. And that brings diversification, which can mitigate market risk. That's the difference: We've gone from exclusionary to tilting and best-in-class integration."

Key Stakeholder Influences



Source: Goldman Sachs

Facing page, the Custom House Tower, once the tallest building in Boston until 1964 (when the Prudential Tower opened), is in the heart of the financial district and is now a hotel.

ing put to work. Is that the case, especially among active managers?

"We've done research on actively managed, environmentally focused funds, and there is very little out there that is investible at the institutional level," said Reynolds. For a typical pension fund, he said, most potential holdings in the sector would fall short due to being either too small or too volatile; having an ill-defined process and little or no track record; or lacking adequate back-office controls.

From a pure environmental or an ESG perspective, players of substance in the sector appear to be few and far between, according to Reynolds. "In fact, we've had a really hard time even defining what that opportunity set is. How big is the universe? It's not that big. That's probably why you don't see a very large, established actively managed fund in the sector up to this point."

Setting aside Tesla Inc. and a handful of other stocks, "it's hard to get liquidity and market cap without going way down in scale, which in turn creates structural risk unrelated to the fundamentals of the company you're investing in," said Reynolds.

"That poses market risk, liquidity risk. To find 40 to 60 stocks in which you can invest in this space is really, really hard."

The charter of the VanEck Global Hard Assets Fund calls for investments in not just energy, but a variety of hard assets. For example, the fund has holdings in Ormat Technologies Inc., which owns and operates geothermal energy plants, producing electricity; in Glencore Plc, the world's largest producer of cobalt, a critical component in batteries; and Sunrun Inc., the largest U.S. residential solar-installation company.

Reynolds cautioned against too heavy an emphasis on a single one of the ESG factors. As an example, he cited the early entrants into solar business—dubbed "evangelicals"—who were driven by environmental issues, but lacked a sustainable business model. By comparison, Sunrun changed the solar model around by initiating the leasing of solar equipment, he said. The stock was up 85% in 2018, he added.

With seemingly a much smaller opportunity set in the renewable sector, what's the outlook like back on the traditional energy side of the fence?

"Nobody had ever invested in shale before, and we're just now getting to the harvest stage," observed Reynolds. "The inflection from investment to harvest is now being reflected in the financial performance.

“Creation: Light” is one of the seven sculptures from Spanish street artist Okuda San Miguel’s “Air Sea Land” installation in the streets of Boston Seaport. Facing page, a window washer rappels down the Harvey building, built in the 1900s, which is now condominiums.

“E&Ps are talking about generating FCF, there is a dramatic increase in share repurchases and dividends are growing very significantly. The E&P sector is doing the right thing with its return of capital.

“As every quarter goes by, and they continue to be disciplined—and continue to stick with this new strategy of return of capital—they will be rewarded. And the big thing will be that we’ll likely see multiples expand.”

Most approachable market

“The trick with renewables is you have a lot of people chasing them, and you face very competitive markets,” said William Prather III, head of natural resources and infrastructure at UTIMCO.

William Prather III is head of natural resources and infrastructure at UTIMCO, which is based in in Austin, Texas, and makes investments on behalf of the University of Texas and Texas A&M University systems. He is in charge of investments made in several main sectors: energy, metals and mining, infrastructure and agriculture.

Private-sector investments are generally benchmarked against Cambridge Natural Resources, an index developed by Cambridge Associates LLC and is weighted close to 90% energy. The predominantly U.S. upstream energy weighting reflects the latter’s “huge” market size and liquidity, with estimates of $500 billion of global capex spent each year and a roughly similar annual opex, according to Prather.

“You’re talking big markets,” Prather commented. Given its size, “it’s the most approachable market. People find it very easy to step into it.”

In terms of tilting investments more towards renewables, Prather pointed to U.S. studies that indicate the U.S. is “a fair bit behind our global counterparts on the percentage of the population that believes in climate change.” As a result, “I would expect European investors to have a much more entrenched view of hydrocarbons and what levels are sustainable.

“I think renewables are an important part of people’s portfolios. The trick with renewables is you have a lot of people chasing them, and you face very competitive markets.

“In the U.S., a levered return on a new renewable-power asset, like wind or solar, is sub-10%. Those are tough returns from a portfolio context if you’re competing with private equity returning mid-teens percent.”

As a result, investors have started to look overseas, with Japan attracting interest, according to Prather. The initial rounds of renewable development were getting fairly attractive power purchase agreements or “feed-in tariffs,” guaranteeing a price for electricity from the government. With these, power plants could be built and generate attractive returns—but returns outside the U.S.—he said.

A growing renewables pie

“The renewables pie is growing, and it will continue to grow. It’s just really competitive,” Prather said. As for talk of the renewables sector being able to completely replace traditional energy investing, “my personal opinion is ‘No.’ When I model it out, I think you still have 10 to 15 years before you even see crude oil demand roll over.”

Looking at the transportation segment of demand, the passenger vehicle market is likely to be the most prone to transitioning away from oil to an alternative energy source, according to Prather. Trucking will find it harder to transition due to the weight of batteries and the distances involved. And, of course, the airlines will be slowest: “Think about the weight,” said Prather.

Outside transportation, the chemicals and plastics sector will tend to be somewhat immune to declines in its demand for oil. “It’s really hard for these companies to transition off hydrocarbons when they’re effectively making new products out of oil,” observed Prather.

In addition, the “funny thing is that people say fossil fuels don’t have a place in the market, but natural gas is a much cleaner fossil fuel. It plays an important role and it will continue to play an important role. Not many people have natural gas consumption really going down in their models.” □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AMEREDEV, PART TWO

Representing a new generation of nimble entrepreneurs, Ameredev CEO Parker Reese had quick success in his first private-equity outing. With the E&P playing field shifting, can he do it again?

INTERVIEW BY
STEVE TOON

Ameredev CEO Parker Reese, who launched his first company at age 30, was first drawn to the international adventure oil and gas offered. Instead, "the very best opportunities were right here in the U.S."

When Parker Reese was very young, he played on a giant sand pile deposited on the side of his grandparents' house, the remains of a frack job performed by his grandfather's operating company in Kansas. Reese is a third-generation oilman—his father also worked for a large oil company—so it is no surprise he followed in the family boot steps.

"My vintage of professionals had as much experience in the U.S. unconventional business as anyone. We've been there since the beginning of it."

Today, at 35, he is the CEO of Ameredev II, an EnCap Investments-backed private company based in Austin and with a position in Lea County, N.M. Reese formed Ameredev II in March 2017 with a $400 million equity commitment from EnCap, which has since been upsized to $700 million.

Reese's early allure to the oil and gas fields was derived from the critical need for energy around the world and visions of global mega projects such as North Sea developments. Instead, his opportunity came in short-cycle unconventional projects in U.S. shales.

"Growing up around a major oil company, I was inspired by the scale and international nature of the projects those companies executed, but as I have moved into my own career, I have seen that the best work to do was drilling Wolfcamp Shale wells in the Permian Basin," he said. "The very best opportunities were right here in the U.S."

A petroleum engineer graduated from Texas A&M University, Reese's first deployment out of college was with ConocoPhillips Co. and into the South Texas Lobo Wilcox Trend. He then spent time as a reservoir engineer with public midcap Cimarex Energy Co. and then with privately held Three Rivers Operating Co., or 3ROC, going smaller with each migration. Each taught him valuable lessons along his path to independence.

At ConocoPhillips, which was still a major at the time, he saw how the power of the balance sheet gave the company tremendous capacity to engineer every aspect of a problem and then to make huge projects happen. He identifies Cimarex as a technically excellent company with a laser focus on rates of return. "That is a company built to last, and something we want to emulate in a lot of ways at Ameredev."

He characterizes 3ROC CEO Mike Wichterich as "a commercial genius" who takes a brute force approach in problem solving, identifying every bottleneck and every solution to formulate a strategy. In putting together a position, Wichterich would analyze 100 deals, bidding on 20 to get to three transacted. "You have to have enough shots on goal to be successful. That's what rubbed off on me at 3ROC."

Reese formed Ameredev I in January 2015 and accrued 16,700 net acres in Ward County, Texas, before selling out to Callon Petroleum Co. for $633 million in February 2017, barely enough time to get two wells down.

Ameredev II is focused on the Delaware Basin's eastern slope with a contiguous, 27,000-plus net acre position crafted through some 50 deals. It has drilled seven wells with five producing nearly 5,000 barrels of oil equivalent per day (boe/d) presently. The company is building its own infrastructure, including a crude gathering network, water gathering and treatment, and is contracted with Salt Creek Midstream for gas gathering and processing.

Reese chatted with Investor *about his entrepreneurial philosophies and his plans for Ameredev.*

Investor What motivated you to take an entrepreneurial tack?

Reese Leading teams is just something that I'm passionate about. It's challenging and rewarding to be able to build a company with a talented team. It's taking all of those skills and putting them to the test in a competitive arena.

Investor How old were you when you first did that?

Reese I was 30 years old.

Investor That's a pretty bold move. What gave you that desire to take that chance?

Reese I had the benefit of working closely with the management at Three Rivers and with Cimarex. I had the chance to do a lot of critical work at those two companies. Both of those companies are very lean and mean, and I got a lot of repetitions in.

And, my vintage of professionals, you know, we had as much experience in the U.S. unconventional business as anyone. We've been there since the beginning of it. It started in 2005 to 2007 in a serious way, so we've been there for the whole thing.

Ameredev II, with 27,000 net acres in Lea County, N.M., is being built for long-term development.

Also, 2015 was a great time to start a company. There was a lot of dry powder in the private-equity space, and it was a good time to have a new management team to offer up.

Investor It was also a time of weeping and gnashing of teeth in the oil and gas space.

Ameredev I & II Positions

Reese That's right. And that was a challenge for us. It was easy to raise money, but it was hard to put it to work. If you remember, people didn't want to sell at what they felt was a low oil price environment and low valuations.

That was the struggle, finding something to buy. In Ameredev I, we chased an incredible amount of leads. And after we looked at 150 deals, it was clear where we wanted to be investing to build a position where we thought we could achieve good returns for our equity.

Investor Ameredev I was a very short cycle—what was the secret of your success there?

Reese It was not the expected result. We were planning on going a lot further in development; we were building our back office and our operations team and our procedures, and the layout of the field to go longer. But public equity investors were just pushing these small and midcap independents to capture as much resource as they could, and we were getting inbounds from multiple guys that really wanted to buy it.

So we asked them for a number and the number was a good answer. Our technical perspective is to get the most value, but the commercial answer was that the quick exit was a unique opportunity at a unique moment in time. I'm glad that we exited when we did, because even if the asset, fundamentally, could be worth more, it would be harder for those same companies to buy it later. We felt like we made a good return.

Investor How did you build your position in Ameredev II? Was it more difficult than the first time?

Reese We looked at a wide area. We looked at the D-J Basin, Ark-La-Tex and the Powder River Basin. We looked at the Midcontinent. In each case, we did a regional analysis to understand the key drivers of the resource density, the productivity of the wells and the economics.

When that initial 12,000 acres in southern Lea County showed up as an opportunity, it was the clear leader from a life-cycle rate of return standpoint. So, we did 18 acquisitions in that one month to form that 12,000 acres. Over the next year and a half we did 24 more acquisitions for 13,000 more acres. Then we did several trades and some divestitures. We took scattered acres and put them into our main block where they're a part of high working interest, long-lateral units.

We essentially upgraded the value of those acres to us. And what we're left with is a little over 27,000 net acres with 96% working interest. All of these units are 2-mile laterals, except for right along the state line, where they're 7,000 footers.

That really scrappy land and business development strategy—where we looked at all of these deals and worked them really fast—was a key part of making Ameredev II work in capturing this highly contiguous position in the Delaware Basin.

Investor Can you tell me what an average price paid per acre is for your position?

Reese That's one of the few numbers we don't talk about. But I would say there is plenty of value to be realized just by aggregating land, right? If you said it cost a dollar an acre to lease all this, then just by the fact that it's put together, it's worth a lot more than that, just by the fact the work is done and you have the certainty of getting one deal, versus all those little pieces.

Investor Did you take a geological risk by being so far eastward in the basin? What gave you confidence this would work?

Reese When we initially got into this, it was definitely viewed as risky—it was a step out. We were looking at the logs from old wells and saw that the key productive reservoirs continued across the position, and we had seismic that showed that the basin continued. We felt like it was a good risk.

And we've got some wells down now. Every modern log that we have has demonstrated a better reservoir than we had mapped before. We are ecstatic about our well results. Further seismic interpretation is showing this area as really special.

Investor Tell me about your program so far.

Reese We've got five wells producing, we've got two that are completing right now, and one that's drilling.

There are two 7,000-foot wells on the Azalea Pad; those are our first two. To the north, there are two wells on Red Bud. Those are stacked laterals; they're actually pretty close. Those wells have all turned out phenomenal. Next, we have the Firethorn, and that was a 2-mile lateral. Unfortunately, we were only able to complete about 1,700 feet of it. It's still a strong well on a per foot basis, and it demonstrates we've got a great reservoir there.

Next, we've got the Nandina and Golden Bell that we've drilled on a two-well pad. We are completing those as we speak. Then we've got the Magnolia that we are drilling right now.

Investor Is this a one-rig program?

Reese We've got one rig going right now, and we're going to two rigs very soon.

Investor What are you targeting?

Reese Our existing wells are all in the Wolfcamp X, the A and the B. Basically, the program for this year stays in those zones. The First and Second Bone Spring look good, and we may add those on in the year, but that's the next stuff we would test after that.

Investor You've published results on four wells all above 2,000 boe/d on IP30. Are you pleased with the results?

Reese They have exceeded all of our expectations so far.

As we climb updip from the deepest part of the basin, we've got a very low water cut in the reservoir. Our wells typically produce around 1-to-1, water to oil, whereas the Delaware Basin, on average, is 3-to-1, and some areas as high as 10-to-1. It's a tremendous advantage.

Investor Can you talk about what your drilling and completions look like?

Reese We're doing about 2,700 pounds per foot in a slickwater design. We have about a 125-foot stage length. We're using 100 mesh in-basin sand and recycled water, which really reduces the cost of what we're doing tremendously. Atlas Sand, specifically.

On the drilling side, we have a huge focus on safety. The eastern margin of the Delaware Basin has hydrogen sulfide in the gas. We've made a big investment in how the field is set up, in terms of having ambient air monitoring and automated shut-in valves. We designed the field to a very high standard for operational excellence.

Investor Downspacing and concerns about parent-child well degradation have become prevalent in the basin. Are you concerned about that, or accounting for that in your projected development program?

Reese So, there's two things to separate. One is parent-child, and the other is just the actual spacing. The parent-child is where you go back and frack a well later, and I think that there's a lot of progress being made in the industry now to mitigate the degradation of the child well. With re-pressurizing the parent well and modifying frack designs and positioning of the lateral vertically, there are a lot of things that are going to mitigate that problem.

But the other one is just interwell spacing. There is a demonstrated degradation in the ultimate recovery of the well with tighter spacing. It causes a trade-off between how many wells do you want to pack into a section vs. what is the incremental rate of return for each of those sticks you're packing in.

As a private investor, our focus is to maximize the rate of return. I think the industry, in general, is going down that path. You see a lot of public operators upspacing their inventory to prioritize rate of return over just having absolutely the maximum number of locations.

We're still not certain on what the ultimate spacing is on our position. One of the reasons we're going to two rigs is we want to drill multiple spacing pilots.

The principle is we want to maximize rate of return, and I think that is going to lead us to larger, more intensive completions at a wider spacing, because we're trying to make oil for the least amount of capital. We're not trying to just maximize the amount of holes we can put in the ground.

Investor As a small private, are you experiencing any challenges with takeaway capacity in the Delaware?

Reese We're really not. Last year, we had limited production and we took a big differential hit on most of the barrels we sold last year, but we didn't lock ourselves into anything.

As we build the Trophy pipeline system, we're going to have the freedom to market

"If we're going to develop the asset, we're going to end up wanting to keep it because the distributions we can spin off far exceed our cost of capital."

"We want to maximize rate of return, and I think that is going to lead us to larger, more intensive completions at a wider spacing, because we're trying to make oil for the least amount of capital."

our barrels where and on the terms we want that are optimal for Ameredev. Ultimately, we feel like our best value risk proposition is having optionality in how we can market our crude.

Investor How important is water infrastructure? How much are you investing into that?

Reese It's going to be critical as we go into the full development phase of the Permian Basin to have water infrastructure. Ameredev is unique in that we've got a concentrated, contiguous footprint. This allows us to take produced water from any battery in the field and bring it back to a couple of central storage tanks or pits. We can treat and we can push back recycled water to our fracks. We're saving a tremendous amount of the cost, from $2.50 a barrel, full cycle, to something like 25 to 50 cents, full cycle.

The other piece that's key here is the connectivity of the system; the network effect is really important. We're connected to other outlets to where we can work with other water systems. This enables effective long-term development of the assets.

Investor You're investing a lot more capital into infrastructure than just drilling wells.

Reese Right. There's more than that, too. We're putting in a cell tower out there.

We think the ability to move data from the field to headquarters is critical for long-term efficient development. There is cell service, but we want to have bandwidth to move telemetry and automation and real-time video data from the field to the office so that we can optimally manage the life cycle of the development and production of the field.

Our facilities are engineered for the long term because, ultimately, we're designing this as if we have to live with it for a long time. We're trying to develop a field such that we can provide the lowest cost, safest barrels anywhere in the world, because we want to compete with the rest of the Permian Basin and the rest of the world for the lowest cost of supply barrels. And that's how we win and how we provide a service to the country and the world.

Investor What about your private-equity investors? They typically like an exit to get cashed out. What is your exit strategy?

Reese We're shifting at this point. We have no idea what an exit would look like for Ameredev II.

The future development of this asset outpaces even our cost of capital for private equity. And so, if the capital markets are going to demand a return of capital from their investors and, thereby, push us to take this asset to being a free-cash-flow positive asset, then at that point our equity distributions are huge. So that can be a really good way for us to earn a return, also.

But if we're going to develop the asset, we're going to end up wanting to keep it because the distributions we can spin off far exceed our cost of capital. I think the private-equity investors can see the value in those long-term returns. That's clear to them; the returns are there, and where there are good returns, capital finds a way to make it happen. Ultimately, if everyone's making money, we're going to find a solution to that question.

But there is still a lot of time. We're going to get to free-cash-flow positive and to full return of capital early. I don't think we're going to have a tough time answering that question when we need to.

Investor So is this a "yieldco" model?

Reese Think about it this way: When a private-equity company exits, they just

PHOTO COURTESY AMEREDEV II

push cash back to the unit holders. We're going to sell barrels instead of acres. We can distribute more cash that way.

Investor Do you perceive the private-equity model as changing?

Reese Absolutely. I think you're going to see more and more of these where the return comes from distributed cash flow to the equity holders as opposed to a full exit of the asset. For the past 10 years we were in this high growth cycle, but we're in a more moderated cycle of restraint now, and the better returns are going to come from distribution of cash flow.

Investor Do you think that's a short-term cycle, or a longer-term paradigm shift?

Reese It feels very long term right now. What would it take to change that? I think probably another supply crunch. That doesn't feel like it's on the horizon; it feels like we have ample sources of supply around the world and, in particular, U.S. growth.

Investor What do you think the Permian will look like in three to five years?

Reese We're fortunate we already have our dance ticket. I think the majors and a handful of large independents are going to dominate the basin. They're going to dominate infrastructure and services. They're going to dominate in terms of the activity level that they bring. And it's going to be their growth engine. For Permian assets to deliver meaningful growth to an Exxon or Chevron, they have to invest tremendously.

Investor What's Ameredev's plan for 2019?

Reese Continue to build the crude gathering system, continue to delineate all the way east and all the way to the north position, test spacing and multiple pilot projects, grow production and operate safely. And be best in class with operational excellence.

Investor How many wells are you anticipating for the full year?

Reese If we did 16, then that's just the Wolfcamp X, A and B. But, we could add and test the First or Second Bone Spring, or the Avalon. The plan is very flexible.

Investor Do you want to grow your position?

Reese We've really slowed down. Our focus is moving into development of this asset. We want to maximize the life-cycle rate of return and return capital to our equity holders. It has influenced the way we put this position together in terms of the trades, and it's guided our strategy in terms of where we're putting wells in the infrastructure we're building. So at the end of the day, we are a rate-of-return focused entity. And that is the answer.

But we're deal junkies. If there is a strategic opportunity, we're going to look at it.

Investor What advice would you give to someone who might be considering breaking away to becoming independent themselves?

Reese It's a really tough time right now. With private equity having the flight to quality, with reduction in potentially the number of portfolio companies out there, and then even the number of firms out there, it is a very tough time to be entering this phase.

The key thing is this is a team sport, and you need to have the best team around you. A talented, multidiscipline team is what makes it work; it's what makes it rewarding.

Investor So is the opportunity for a start-up to come in to the Permian limited or nil?

Reese The odds are against them, but I don't want to bet against an entrepreneur who wants to commit capital on their idea in the Permian Basin. That seems like a bad bet. You don't want to bet against the American entrepreneur. □

Ameredev II's well Red Bud State Com 115H, targeting the Wolfcamp A formation with a 9,674-foot lateral, flowed 2,813 boe/d (83% oil) on IP30.

U.S. LNG

U.S. companies will be at the forefront in making final investment decisions this year for LNG plants that will begin commercial production in the mid-2020s.

ARTICLE BY
SCOTT WEEDEN

Flexibility and innovation are the names of the games for the worldwide LNG industry. The industry requires flexibility in its business models in highly competitive LNG markets. Innovation is needed to accelerate industry growth to meet an expected shortfall of 150 million tonnes per annum (mtpa) by 2035.

"As reservations over capital spending and uncertainty over LNG pricing persist, the study reveals increasing interest in the sector finding more agile and flexible approaches to LNG production and trading," services firm DNV GL AS reported in an April outlook, "The LNG Era Takes Shape."

"The new era we see emerging for the LNG sector will demand new thinking from our industry to ensure that a rapid evolution in demand and supply can be met. For ex-

PHOTO COURTESY SEMPRA ENERGY

ample, our research shows signs of the sector opening up to new players, contracting models and pricing strategies."

A DNV GL survey revealed "the majority of LNG-focused oil and gas professionals—85%—believes several new LNG infrastructure projects will need to be initiated in 2019 to ensure supply can meet demand post-2025."

However, more than two-thirds (69%) "believe price uncertainty is limiting investment in LNG mega-projects."

The firm forecasts global LNG production will increase from 250 mtpa in 2016 to around 630 mtpa by 2050.

Agility will also be key to protecting LNG buyers against risk. About 72% of LNG professionals believe buyers need more flexible contracts, where LNG volumes can be reduced, tenures shortened and delivery locations changed, the firm added.

In January, Rystad Energy analysts predicted an LNG supply cliff post-2020. "At least 50 mtpa of new capacity needs to be approved over the next two years to avoid a supply shortfall. At the same time, a pick-up in new project final investment decisions (FIDs) during the next two years will benefit a select group of E&Ps, oil majors and LNG-focused service companies, the report noted.

A peak in supply growth at more than 30 mtpa in this cycle will occur in 2019, which could put downward pressure on LNG spot prices as supply outstrips demand, causing surplus capacity for spot supply, the analysts noted.

"Looking ahead, we see a significant shortfall in LNG supply in the early 2020s. Demand is expected to grow to 450 mtpa by 2025 and 560 mtpa by 2030 when the market will need over 600 mtpa of capacity. With LNG supply growth likely to 'fall off a cliff' post-2020, we see a looming deficit in the market," they concluded.

Preparing for fierce competition

U.S. LNG producers will be at the forefront of those making FIDs this year toward beginning commercial production in the mid-2020s. But projects in East Africa, Russia, West Africa, the Mediterranean Sea,

Train 1 Cameron LNG Phase 1, a three-train LNG-export project under construction in Hackberry, La., has reached its final commissioning stage and began receiving feed gas. LNG production is expected for later this quarter.

"We believe the next wave of North American LNG projects to reach a positive FID will be those that can offer their customers superior pricing flexibility," said Matt Schatzman, president and CEO of NextDecade.

Australia, Mexico and Canada will be vying for the same markets.

"In the past, international and national oil companies led the global LNG market, but it has now been diversified," Young-Myung Yang, executive technical advisor for Korea Gas Corp. (Kogas) and its former CTO and head of R&D, said in the DNV GL report. "New players with new business models—mainly based in North America—are entering the LNG market and changing the market structure and price dynamics."

The U.S. Energy Information Administration (EIA) estimated in late 2018 that U.S. LNG export capacity will reach 8.9 billion cubic feet per day (Bcf/d) by the end of 2019, ranking it third-largest behind Australia and Qatar. At the end of 2018, the EIA expected U.S. export capacity to reach 4.9 Bcf/d as two new LNG trains became operational.

DNV GL reported, "New market actors could be key to bridging the divergent interests of LNG buyers wanting flexibility, and sellers who demand long-term cash-flow certainty to support major investments. This was once the domain of oil majors, but commodity traders are now emerging as a significant new breed."

Innovative indexing

Innovation in LNG price indexing was displayed at the LNG2019 conference in Shanghai in April, where two firsts in the LNG industry were announced. Tokyo Gas Ltd. and Shell Eastern Trading (Pte) Ltd. signed a heads of agreement (HOA) that included an innovative pricing formula based on coal indexation.

Another unique aspect of this HOA is that Shell can supply the LNG from its global LNG portfolio instead of from a specific LNG plant.

The second innovation involved NextDecade Corp.'s Rio Grande (Texas) LNG project and Shell NA LNG LLC. A 20-year sales and purchase agreement (SPA) was signed on April 1 for the supply of 2 mtpa to begin in 2023. The SPA is the first-ever long-term contract for U.S. LNG indexed to the Brent crude oil price. About 75% of the total will be indexed to Brent and the remainder to U.S. gas prices.

"We believe the next wave of North American LNG projects to reach a positive [FID] will be those that can offer their customers superior pricing flexibility," Matt Schatzman, NextDecade president and CEO, said at LNG2019.

"When we at NextDecade consider how to make our business model competitive, we listen to our customers. They consistently tell us 'flexibility,' and that is precisely what we are offering: multiple LNG pricing options, including Brent indexation, to meet our customers' needs in today's dynamic and evolving global LNG market."

In addition to indexing Brent crude and Henry Hub gas, NextDecade is offering long-term LNG supply indexed to Agua Dulce and Waha hubs and is exploring other hubs. "Indexing to Agua Dulce and Waha allows customers to leverage South Texas and West Texas gas prices, which are expected to trade below Henry Hub," he said.

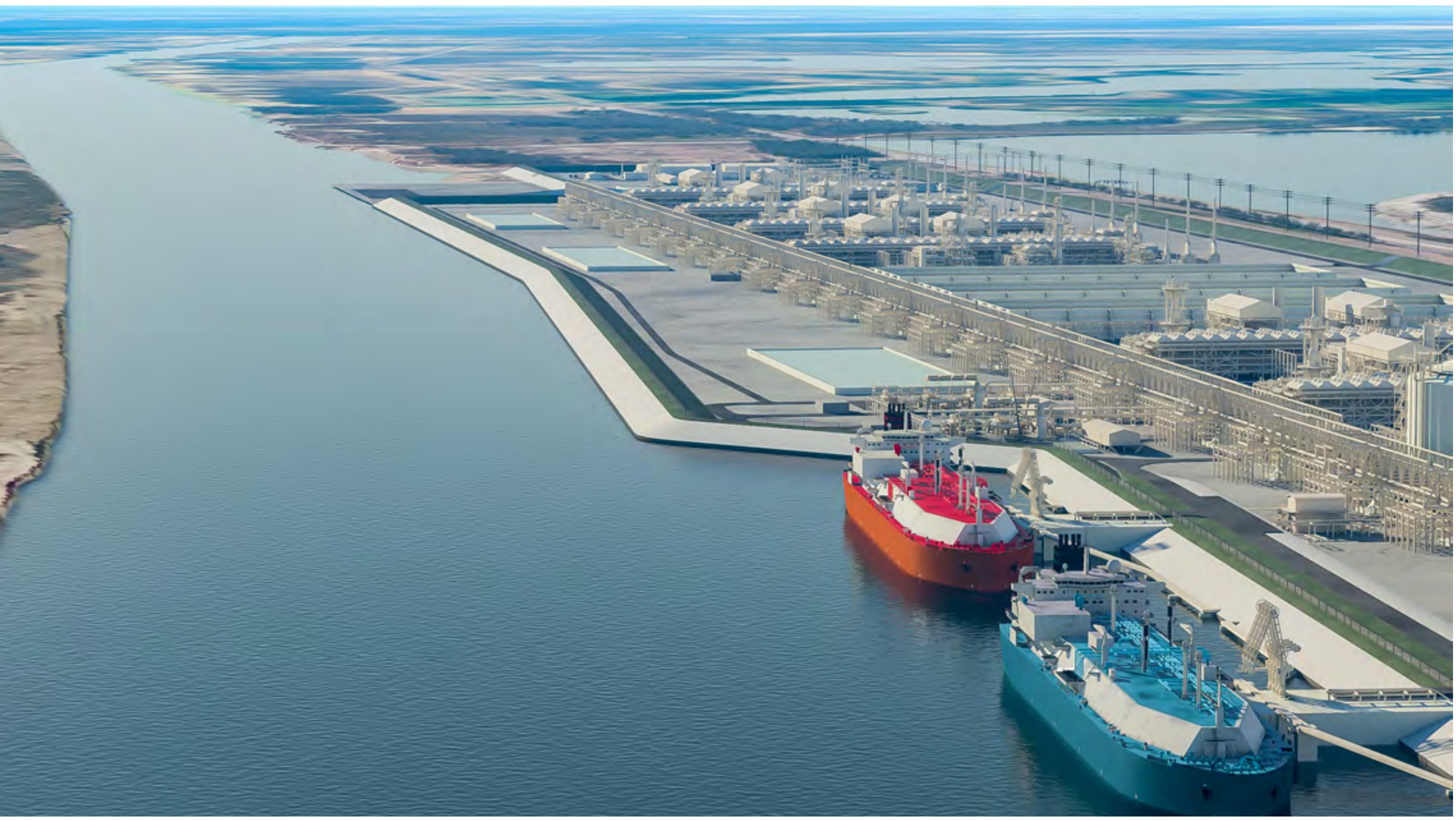


PHOTO COURTESY NEXTDECADE

An artist's rendition shows the layout for NextDecade's Rio Grande LNG plant in Brownsville, Texas.

He added, "LNG projects need to offer long-term LNG indexed to oil, Henry Hub and potentially other [indices] as the LNG market evolves over the coming years. We believe successful projects will be those that offer LNG on multiple indexes, providing customers the flexibility they are seeking in today's market."

"We believe our ability to offer multiple pricing options maximizes our total addressable market and will ensure success for our Rio Grande LNG project, making NextDecade a leader among the next wave of LNG suppliers.

"The ability to offer Brent pricing has been a game-changer for our Rio Grande LNG project. It has accelerated our commercial marketing."

The company's portfolio of LNG projects includes the 27-mtpa Rio Grande LNG in Brownsville, Texas, and the 4.5-Bcf/d Rio Bravo Pipeline from the Agua Dulce area to Rio Grande LNG. NextDecade intends to develop the largest LNG export solution linking Permian Basin associated gas to the global LNG market.

NextDecade received final bid packages for the engineering, procurement and construction (EPC) contract in April from both Bechtel Corp. and Fluor Corp. The FID is expected before October.

Also in April, the Brownsville Navigation District said NextDecade agreed to privately fund the deepening of the Brownsville Ship Channel to 52 feet from the Gulf of Mexico to the company's LNG project site. The Brazos Island Harbor Channel Improvement project is scheduled to begin in the first half of 2020 and be completed by 2023.

Three plants, two countries

Sempra Energy is turning its two LNG import terminals—Cameron LNG in the U.S. and Energia Costa Azul (ECA) in Mexico—into export plants, while building the new Port Arthur LNG plant in Texas.

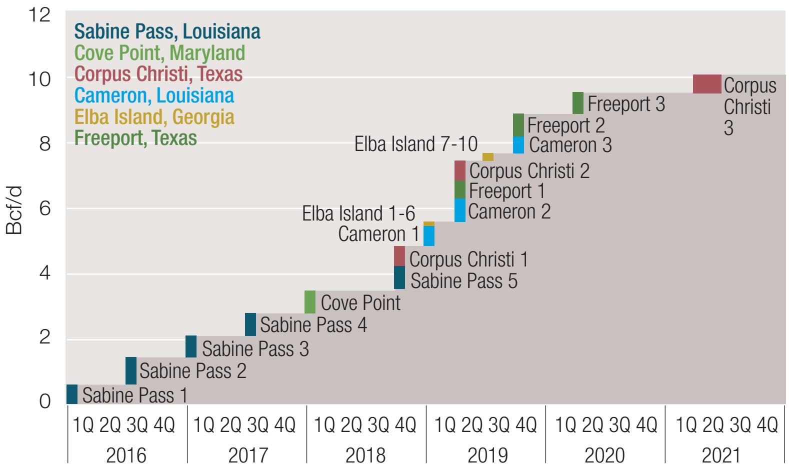
"As the economics transition to natural gas from other fuel sources, we see tremendous growth in demand [in] Europe. You see some countries—our Polish deal for example—looking for security of supply. Others want to take advantage of price certainty, different indexation or low prices in the U.S., given the shale gas revolution," said Justin Bird, Sempra LNG president.

"Given the amazing growth of the Permian Basin, we think the U.S. will play a critical role in the supply of LNG to the world as time goes on."

With its LNG terminals on both the East and West coasts of North America, Sempra finds itself in an enviable position. "We have what we call five world-class LNG projects. Importantly, we have the opportunity to supply portfolio players with LNG from the West Coast as well as the Gulf Coast," Bird said.

"We think there is a large market opportunity. Our natural geographic markets will play a critical role in that."

U.S. LNG Export Capacity, 2016-2021



Source: Energy Information Administration

U.S. LNG export capacity will top 10 Bcf/d by 2021.

Sempra is more focused on its North American infrastructure. "Our CEO has an ambition to be North America's premier energy infrastructure company. We have an ambition within our LNG business to have 45 [mtpa] of export capacity at these five projects," he added.

Bird noted that Sempra LNG is in a privileged position to capture this opportunity. "One, we have development experience. Two, we have partnerships and strategic alliances with a lot of the key parties. Three, we have our world-class LNG projects."

The company has five projects at three locations: Cameron LNG phases I and II; ECA phases I and II; and Port Arthur LNG.

Cameron is the 12-mpta facility with three LNG trains. "We are getting very close to starting operations on the first train. That project is 100% sold on a tolling basis to Total [SA], Mitsui [& Co. Ltd.] and Mitsubishi [Corp.]. Those same three parties are on the equity side. We call that Cameron Phase I," he said.

Total came into the project when it bought Engie SA's LNG business in 2017. "I think it is important that Patrick Pouyanne, Total's chairman and CEO, said Total was basically acquiring this Cameron interest for the Phase II expansion [trains 4 and 5]," he said.

Sempra is currently doing technical studies, with the intent of completing them soon, and then look at the development of Phase II.

Since the plant is a tolling facility, the customers supply the gas. "Our customers basically deliver gas to the flange and each of them has their own sourcing. Then we deliver LNG to the other flange," he added.

The greenfield Port Arthur LNG facility will be in Jefferson County, Texas, with a capacity of about 11 mtpa. In 2018, Sempra signed an agreement with the Polish Oil & Gas Co. for 2 mtpa beginning in 2023.

For its gas supply, the company is looking for a location that will give them the ability to source from multiple basins.

"Given the amazing growth of the Permian Basin, we think the U.S. will play a critical role in the supply of LNG to the world," said Justin Bird, Sempra LNG president.

"We're continuing to work with Bechtel … toward an EPC. We are actively engaged in marketing the remaining volumes. We expect the FID by the end of 2019 or first-quarter 2020," he said.

Pacific Coast

In "Field of Dreams," Ray Kinsella is told, "Build it and they will come." Bird tells his team, "When they come, we will build it. That is marketing driven."

ECA is about 30 miles south of the U.S.-Mexico border. "We have two projects there. Phase I is our mid-scale project—3 mtpa—and Phase II is the large-scale project—12 mtpa. Like Cameron, ECA has an existing regas contract or existing facility contract," he said.

"We are working with those regas customers to terminate those contracts early so we can advance the development of Phase II."

For Phase I, ECA's liquefaction plant can co-exist with the regas contracts. Sempra LNG and its Mexican subsidiary IEnova have signed HOAs with Total, Mitsui and Tokyo Gas Co. Ltd. TechnipFMC Plc and Kiewit Corp. are working on the FEED. The FID is expected at the end of 2019.

Sempra will be working with IEnova on Phase II. In March, ECA received U.S. Department of Energy authorization to export U.S.-produced gas to Mexico and to re-export LNG to countries that do not have a free-trade agreement with the U.S. from its Phase I and Phase II facilities. Gas most likely from the Rockies and the Permian Basin will be delivered by existing pipeline to Phase I.

"For Phase II, we will build our own new line, mostly in Mexico. We would have a large pipeline that would come from the Permian Basin or Waha area. IEnova owns about 40% of the natural gas pipelines in Mexico," he said.

Bird emphasized that Sempra is "a little different from the others. I call us an LNG infrastructure business. I basically look to form strong relationships or alliances with big strategic players. I am more interested in building infrastructure that allows our customers to take advantage of U.S. natural gas and export it to the world."

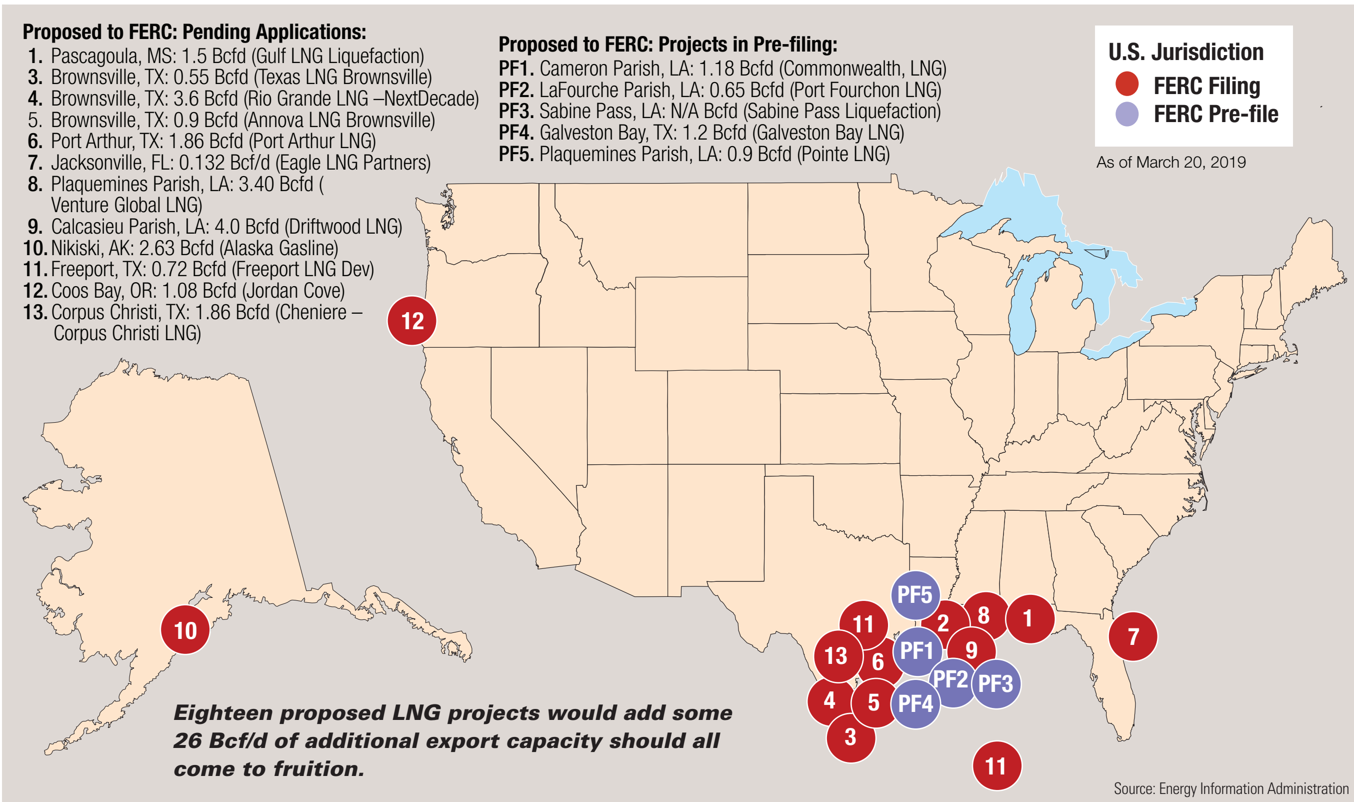
To do that, the company faces some challenges. One of the biggest is what the EPC market is going to be. What if all those projects get built? What will that mean for good builders?

"For the industry, it is 'How do we get the right qualified people to build all these facilities?' And how do we do it in a safe and right manner?" he said.

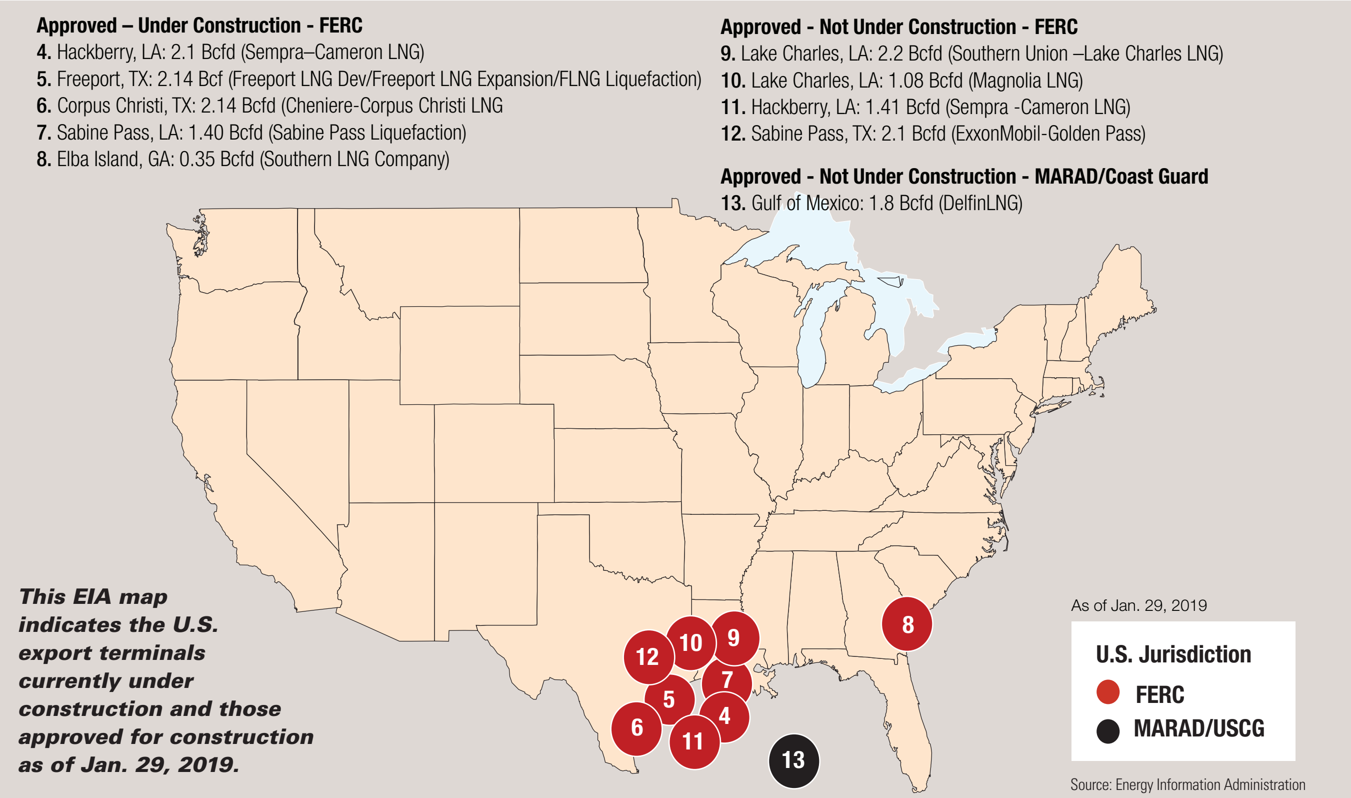
"If you ask me my clear goal, it is to be what we call North America's premier LNG company, which, for us, means we will get this 45 mtpa of capacity built and see where we go from there," he said.

He has challenged his team to see how they can expand the capacity for both Port Arthur LNG and ECA. "It is a very exciting time to be in the LNG space. We're doing reinvestment. We've gone through that cycle at Cameron, and we're doing that cycle at ECA.

Proposed U.S. LNG Export Terminals



Approved U.S. LNG Export Terminals



This EIA map indicates the U.S. export terminals currently under construction and those approved for construction as of Jan. 29, 2019.

"America will be at the forefront of adding to the world's clean energy in our ability to supply gas from the Permian Basin."

Energy Transfer, Shell

In March, Energy Transfer LP and Shell US LNG LLC signed a project framework agreement (PFA) that provides the framework to further develop a large-scale LNG export facility at the Lake Charles LNG plant in Louisiana.

Lake Charles LNG, which is one of the oldest import terminals in the U.S., is owned by Energy Transfer. BG Group Plc, which is now part of Royal Dutch Shell, was the sole customer for that regasification terminal.

"With the shale revolution, it didn't make any sense for BG to be importing natural gas [amid] low U.S. natural gas prices. It then became economic—at least for BG—to consider investing with us or signing a long-term contract for us to build an export facility on the same site," said Tom Mason, Lake Charles LNG president and Energy Transfer executive vice president and general counsel.

"We went down the path with BG for several years, including going through the whole permitting process with the Federal Energy Regulatory Commission and [U.S.] Department of Energy, which took a lot of time and money. We reached the stage where we were ready to pull the trigger with BG. And then Shell acquired BG," he explained.

The development agreement with BG expired at the end of 2016. "Shell was trying to understand what to do with BG. In late spring of 2017, Shell came back to us and said, 'We like Lake Charles, and we want to continue discussions,'" he said.

That accelerated the project in 2018 and culminated in the PFA in March. "The PFA sets forth all the commercial terms to move forward on the development of the export facility. It was a different arrangement this time with Shell being a 50:50 equity partner in the project. Also each of us will have 50% of the LNG offtake."

There was a long-term regas services contract with BG that was inherited by Shell. "The commercial arrangements are that Shell will continue to make those payments through the expiration of the regas contract in early 2030," he added.

This is the first foray into the LNG business for Energy Transfer. The export facility will be a brownfield project with existing assets such as LNG storage tanks, jetties, piping and a lot of other infrastructure. The facility will have a capacity of 16.45 mtpa.

Natural gas will be supplied through Energy Transfer's pipeline system.

The location will allow Energy Transfer to source gas from multiple basins. "There are some pipeline modifications that Energy Transfer needs to do to reverse the flow of gas through the existing pipeline connected to the Lake Charles facility. The modifications will include additional pumps, meters and so forth along with additional pipeline interconnects," he said.

The target for the FID, which is subject to several requirements, is the second half of 2020. Goals are "based on the locking up of long-term LNG offtake contracts that will

"We wanted to do this project with or without Shell. But Shell's the most logical partner based on their position as the largest LNG marketer in the world," said Tom Mason, president, Lake Charles LNG, and executive vice president and general counsel for Energy Transfer.

provide us with steady cash flow streams with an attractive rate of return. This is an ideal project for a pipeline company like us.

"We wanted to do this project with or without Shell. But Shell's the most logical partner based on their position as the largest LNG marketer in the world. We're very pleased to have Shell as our partner.

"We're pursuing the project on a very cooperative basis. They've got incredible talent in LNG engineering and project development. They're dedicating a lot of resources to the project."

Mason sees the success of the project being dependent upon receiving a cost-competitive EPC bid. The company has been engaged in discussions with the potential EPC contractors. On May 3, Lake Charles LNG issued an invitation to tender to U.S. and international consortia to bid for the EPC contract.

There are always questions about labor availability on the Gulf Coast. "We think Lake Charles is an ideal location based on the abundance of skilled workers in the area that can be brought to bear on projects of this size and scale.

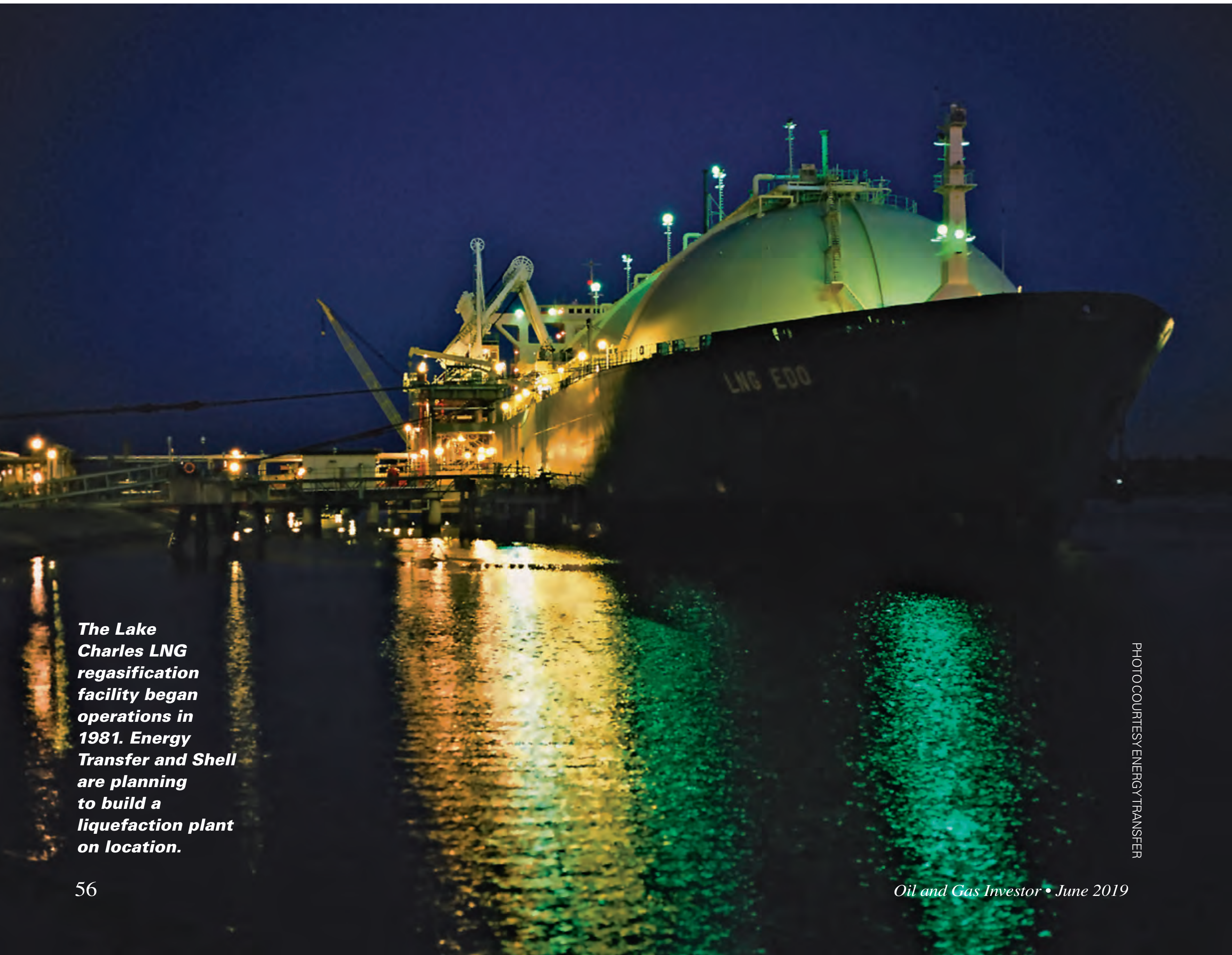
"Louisiana is a business-oriented state that appreciates the value of infrastructure projects. We are very happy to be in a location with enthusiastic state and local governments," he said.

Another big challenge is marketing its 50% of the LNG offtake. China, other Asian countries and Europe are big markets. "China LNG demand is growing incredibly. In the last three years its demand for LNG has grown 35% to 40% year-over-year.

"It is a big market, but the challenge is to get through the trade disputes with China and the U.S. We are encouraged that these trade disputes will get resolved, and we will have a very open Chinese market at that time," Mason said.

Energy Transfer is working with customers on innovative LNG pricing. "Every customer is unique and has their own outlook on U.S. natural gas prices and also other index prices.

"We are actively pursuing alternate LNG offtake pricing with some customers and, concurrently, are in discussions with U.S. natural gas producers to obtain longer term natural gas supply arrangements tied to similar innovative natural gas price indexing." □



The Lake Charles LNG regasification facility began operations in 1981. Energy Transfer and Shell are planning to build a liquefaction plant on location.

PHOTO COURTESY ENERGY TRANSFER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TRANSFER OF POWER

Europe-based Royal Dutch Shell is outpacing U.S.-major counterparts in clean energy investing.

ARTICLE BY DARREN BARBEE

In early 2018, Royal Dutch Shell Plc became the owner of U.K. energy provider First Utility, and the first major oil and gas company to offer broadband internet service.

In March, the new business unit, Shell Energy Retail Ltd., also switched 700,000 British households to 100% renewable electricity. In 2019, the company intends to roll out a range of smart home offerings, including thermostats and electric vehicle (EV) charging.

Majors have tinkered, from time to time, with new technologies or made bets through investments that, in retrospect, seem far afield of their main business lines. Examples include metals, coal, butter and meat-processing.

Investors have raised questions about climate change for decades. But, more recently, they have begun to see climate change as a financial issue, said Andrew Logan, senior director, oil and gas, for Ceres, a nonprofit that works with more than 160 institutional investors that manage $26 trillion in assets.

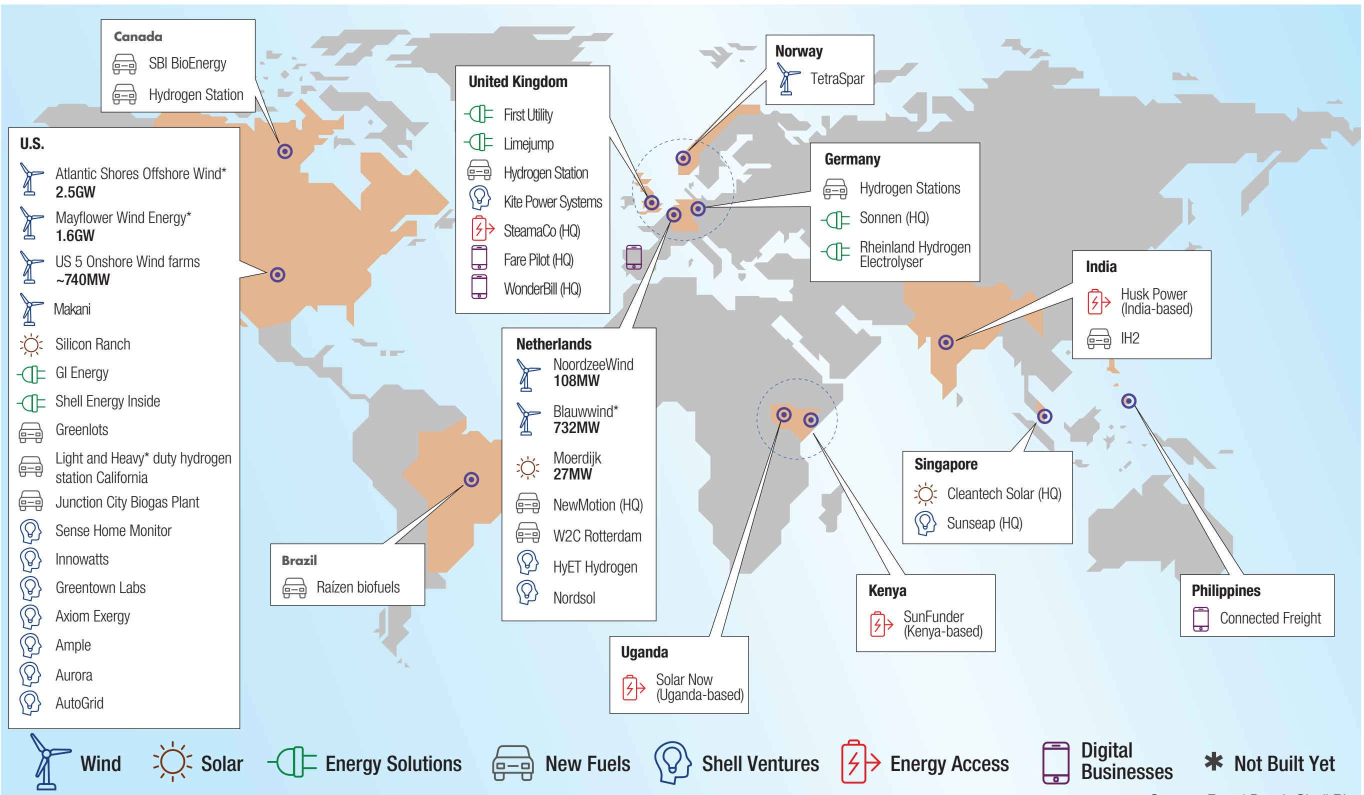
"There's been a pretty dramatic ramping up in interest and concern in the past couple of years," he told *Investor*.

Pockets of energy investors may be focused more narrowly on water or proppant. "But I would say there is a sort of base level of concern over climate change and what it means for the long-term financial health of the industry that is pretty universal, at least among the investors we work with."

Since 2018, majors and large independents have taken a more deliberate approach to investment in renewable energy. Companies such Shell, BP Plc, France's Total SA and U.S. independent Occidental Petroleum Corp. acquired or entered partnerships in solar power generation, wind farms, and EV battery companies and infrastructure.

"Within the sector, we've seen plenty of evidence over the past 18 months of more focus on that sort of green space," said Richard Taylor, a London-based oil and gas analyst for Fitch Solutions. "Shell, for example, at the beginning of last year, invested

Shell's Renewable Portfolio



Source: Royal Dutch Shell Plc

Andrew Logan, senior director, oil and gas, for Ceres, said producers are following paths that tend to be "as lean and low-carbon as [they] can while remaining oil and gas companies."

in Silicon Ranch [Corp., a Tennessee-based] solar company."

Shell is lauded by investor groups and analysts as a leader among oil and gas producers that are making room in their portfolios for green energy solutions. Since 2016, when Shell created its business line New Energies, the company has opened a comfortable lead over its rivals.

Others have followed with similar approaches. As of first-quarter 2019, Total said April 26 its new integrated gas, renewables and power segment would spearhead its low-carbon electricity production.

Shell is also earmarking up to $2 billion a year to buy into a buffet of renewable energy and alternative fuel companies, Taylor said. In relation to total capex, the annual spend is proportionately low, he added; in 2018, Shell's capex was nearly $25 billion.

"There's definitely been growth in this area," he said. "And there's also been a shift in the rhetoric, more broadly, in the reporting of these companies to now acknowledging these investments and how they're important, even if small."

In addition to purchasing a 44% stake in Silicon Ranch, Shell more recently purchased Sonnen, Europe's largest maker of lithium-ion battery packs, and a California-based EV charging company. In California, it is working to build hydrogen filling stations.

Early on, Shell recognized the energy transition won't be made through a single energy source, said Jason Klein, Shell vice president for U.S. energy transitions strategy. Rather, the transition to new types of energy will occur at differing rates across the globe.

"Right now, in New Energies, I'd say we're mining for value, and we're making modest investments across the entire value chain to figure out where Shell [can] make the most contributions and get the best return," Klein told *Investor*.

"So, we are looking at investments that offer end-to-end solutions. We've got investments in solar and wind, batteries, demand management and demand response."

Since 2010, 24 of the largest oil and gas producers invested $22 billion on alternative energies, according to a November 2018 report by CDP, an advocacy group that represents more than 525 investors with $96 trillion in assets. Major oil and gas capex was expected to account for 1.3% of spending in 2018.

However, some majors—particularly Shell and Total—have upped spending and taken a hard look at power generation. Shell has said it will invest an average $1- to $2 billion annually through the end of the decade on new renewable power sources.

"We've been making investments across the entire power side—on the generation side," Klein said.

Power plans

Last July, Total closed on a majority stake in French electric company Direct Energie for about $1.6 billion. Shell has set its sights on adding power generation as the "fourth pillar" of its business alongside oil, gas and chemicals, according to Bernstein Research analyst Oswald Clint.

"Gobbling up rivals in the power sector is relatively cheap when armed with an oil company's gigantic balance sheet," Andy Critchlow, S&P Global Platts head of Europe, Middle East and Africa news, wrote in a March report.

In 2018, Shell's annual net income was $23.9 billion. By contrast, Florida-based NextEra Energy Inc., one of the world's largest renewable energy producers, generated about $16.7 billion in total revenue and net income of $6.6 billion.

In the U.S., Shell has become a leading player in the clean power market with its trading position. Shell manages 10 gigawatts in the U.S. with roughly a third produced by renewable energy sources, Clint wrote.

The company sees the electricity business changing radically during the next 25 years and wants to be a leader in providing that power. Klein said, "Certainly, we see power as part of the huge part of the puzzle going forward.

"We believe we can be the largest electric company by 2030. Here in the U.S., we're unique in that the U.S. has multiple different market models in different parts of the country to see what works for different customers."

In Europe, Shell has made a series of investments beginning in October of 2017 with NewMotion, an Amsterdam-based provider of smart-charging solutions for homes, businesses and vehicles. The company has added electricity storage and its U.K. electricity provider, Shell Energy.

"They're now hoping to link those investments into providing services for European-centric customers," Fitch's Taylor said. "I assume the plan is to spread that business model across the globe."

BP has entered EV charging with the June 2018 acquisition of Chargemaster, U.K.'s leading EV-charging infrastructure firm, Taylor said.

The U.S. is a key market, as well, because a segment of the U.S. population is also clamoring for cleaner energy solutions, Shell's Klein said. "The somewhat unique thing about the U.S. is this really is being driven from the bottom, by and large," he said.

"We're seeing a growing interest at the consumer level and also seeing it at large businesses, particularly consumer-facing businesses that want to decarbonize themselves and their logistics chains for their customers," he said.

While state and local governments are upping their approach to renewable power, "it isn't being driven by governments mandat-

Selected Major Oil Company Investments Since 2018

Date	Country	Company	Brief Description of Development
January 2018	U.S.	Royal Dutch Shell	Shell to acquire 43.83% of U.S. solar company, Silicon Ranch Corp., including a portfolio of about 880 megawatts of projects in operation or contracted.
January 2018	U.K.	BP	BP invested $5 million in U.S. firm Freewire Technologies for EV charging.
February 2018	U.S.	Royal Dutch Shell	Shell extended a credit facility to Inspire Energy Holdings, a company providing clean power, smart home and energy management services.
March 2018	France	Total SA	Total paid $1.73 billion for a majority stake in electricity provider Direct Energie.
May 2018	Netherlands	Total SA	Total acquired WinWatt, a Dutch solar energy solutions company that provided solar panels, heat pumps and loading poles used to generate electricity.
May 2018	Israel	BP Plc	BP venture fund invests $20 million in StoreDot, which aims to commercialize ultra-fast battery technology as early as 2019.
June 2018	U.K.	BP Plc	BP acquired ChargeMaster, the U.K.'s largest EV charging network with 6,500 charging points across the country.
August 2018	U.S.	Royal Dutch Shell	Shell has led a Series A investment round raising $31 million for Ample, a California start-up that aims to utilize autonomous robotics and smart battery technology to improve EV performance.
September 2018	France	Total SA	Total won 112 megawatts of solar and 12.2 megawatts of small hydro projects in auctions in France. The solar photovoltaic park, when operational, will produce over 120 gigawatts per year.
September 2018	U.S.	BP Plc	BP invested in U.S. start-up Fulcrum Bioenergy to turn biomass into low-carbon transportation fuel. The Sierra BioFuels plant in Nevada, planned for 2020, will convert garbage to fuel.
October 2018	Kazakhstan	Eni	Eni said it would start building a 48-megawatt wind farm in Kazakhstan in fourth-quarter 2018.
November 2018	U.S.	Occidental Petroleum Corp.	Occidental Petroleum's venture capital arm made investments in NET Power, an innovative carbon capture start-up.
November 2018	Norway	Equinor	Equinor increased its ownership of Scatec Solar to more than 10%.
December 2018	Spain	Repsol	Repsol acquired Spanish solar power company Valdesolar Hive, a firm currently developing one of the most ambitious solar projects in Spain.
December 2018	Singapore	Royal Dutch Shell	Shell acquired a 49% stake in Cleantech Solar, a Singapore solar developer that finances, constructs, owns and operates solar projects.
January 2019	U.S.	Royal Dutch Shell	Shell acquired Greenlots, a North American-focused company that provides a suite of electric mobility solutions.
March 2019	Germany	Royal Dutch Shell	Shell acquired Sonnen, a German rival to Tesla and Samsung, in providing homeowners with lithium-ion battery packs powered by solar energy.
April 2019	U.S.	Royal Dutch Shell	Shell New Energies invested in an EcoSmart Solution subsidiary that integrates sustainable infrastructure technology in master planned communities.
April 2019	Greece	Equinor	Equinor said it is exploring offshore wind generation in Greece.

Source: Company announcements, Fitch Solutions, *Oil and Gas Investor*

ing things as much as it is being driven by consumers and business."

Silicon Ranch, having about 880 megawatts of power generation, is working on providing 102.5 megawatts of power for Facebook's data center in Georgia. Mayflower Wind Energy LLC won a U.S. wind-lease auction offshore Massachusetts with a $135-million bid. Mayflower is a joint venture of EDPR Offshore North America LLC and Shell Energies US LLC.

Klein said electrification will be the fastest-growing trend in energy as the world works to meet the climate goals of the 2016 Paris Agreement.

"The power market is going to grow faster than any other market because the best way to decarbonize a developed economy such as [the U.S.] is to move as much stuff to electricity as possible and move as much as possible of the grid to renewable. We're seeing that take hold already."

Refueling

When chemist Elliot Berman started to pursue an idea for a new type of solar cell a half-century ago, a chance conversation led him to what was then known as Exxon Corp. His work there resulted in reducing the price of solar cells to $20 per watt from $100 in the early 1970s.

In the past few years, major oil and gas companies have chased new technologies, some with more zeal that others and, at times, with a less than clear plan on how to integrate new energy into existing portfolios.

"We've also taken our first move into solar," Equinor ASA CEO Eldar Sætre said at IHS Markit's CERAWeek in March. "We don't know exactly how to do it. But it's too big to ignore, so we include that as part of our strategy going forward."

Equinor, which changed its name from Statoil last year, has been at the forefront of offshore wind in the U.K., Poland, Norway and more recently, New York and Massachusetts.

"We're a pretty big payer when it comes to offshore wind," Sætre said. "That plays into our skills."

The company is also exploring floating offshore wind platforms, which Sætre said has a

Shell's LNG Portfolio

Source: Royal Dutch Shell Plc

much bigger potential globally for capturing wind resources in deeper waters. In April, the company said it was also exploring floating wind generation offshore Greece.

ExxonMobil Corp. is less directly investing in renewable energy since its work in the 1970s with solar cells. The company has sought wind and solar power for its Permian Basin operations from other providers and reached 12-year power-purchase agreements in late 2018.

The Irving, Texas-based major is spending to research advanced biofuels and algae with a goal of producing 10,000 barrels per day by 2025. An ExxonMobil spokesman said the company wasn't able to comment for this article.

BP is taking a more cautious approach than Shell or Total. Partly, that's because the company has been hampered by liabilities associated with the Deepwater Horizon oil spill, Ceres' Logan said.

"In the last year or so, you see them making interesting investments in solar, batteries and EV charging," he said. "It's really cherry picking what they see as opportunities to grow a new business on the clean energy side of the house. Where they're going to go in the future is a little less clear."

Richard Taylor, oil and gas analyst for Fitch Solutions, said shareholder "rebellions" have been seen across the wider energy space through this year.

Two years ago, BP invested $200 million in Lightsource, one of Europe's largest solar development companies. By 2018, Lightsource's reach extended to Brazil, India, Australia and six U.S. states.

And, in April, BP announced it would incentivize about 36,000 of its employees by tying an annual cash bonus to the company's emissions-reduction targets. This follows Shell's announcement that it would tie executive compensation to its climate goals.

BP has also said it would integrate the climate goals of the Paris Agreement into how it spends money, Logan said.

Shell's Klein said the variety of Shell's investments is a bit like putting pieces of a puzzle together to find the best solution for customers in a specific market. "It will vary country to country. But I think we're making a lot of investments here in the U.S. in particular to try to find out where is the value for Shell in the chain.

"At the end of the day, we believe the customer end of the market is going to be the most interesting where Shell can add the most value and earn the best return."

Shell created New Energies as a separate business line alongside its upstream and downstream businesses. New Energies is hinged on how to make a transition to a low-carbon energy future to manage the risks of climate change, while also producing more as an industry "to extend the benefits of energy to everyone on the planet," Klein said.

"Since that time, we've made quite a few investments across the spectrum of new fuels and power-related businesses."

The major is exploring alternative fuels, including hydrogen, "which has a real big role to play in the long term as a clean, high-density, liquid fuel," Klein said.

In California, Shell is working with carmakers Honda Motor Co. Ltd. and Toyota Motor Corp. to build the infrastructure to supply their vehicles' hydrogen fuel cells. Shell is also working with the Port of Long Beach for heavy-vehicle hydrogen fueling.

Shell already operates hydrogen-power stations in the state, with nine more in development for both heavy-duty and light-duty vehicles.

"To make hydrogen work as a clean energy solution, you have to solve this chicken-and-the-egg problem," Klein said. "You need a vehicle manufacturer, and a fueling infrastructure provider and some government support for the technology to be aligned. And, right now, that's happening in California."

The company also purchased Greenlots, a Los Angeles-based company, in January. Greenlots provides EV charging and energy management software, including grid management services. It has deployed projects in 13 countries.

With its March acquisition of Germany's Sonnen, Shell has also invested in household and small business batteries to help manage intermittency. "What we're trying to do is find offerings that work for everybody," Klein said.

"For a lot of people in light passenger vehicles, it might end up being EVs, so we're working on EV charging infrastructure and providing renewable power through that."

While the goal and focus are clear, renewable energy is not yet streamlined. Wind and solar are susceptible to intermittency—darkness and calm air—which will make power systems more complex.

"The energy transition isn't going to happen overnight," Klein said. "We need to rewire the entire global economy, which is just a huge undertaking."

The bridge to get there, he said, is natural gas, "which is why we continue to invest in gas, and LNG and our traditional portfolio alongside our New Energies investments."

Bridges and bunkers

Nearly three years have passed since BG Group and Shell finalized their $53-billion merger. At the time, Tudor, Pickering, Holt & Co. analysts said Shell was making a conscious decision to pull back from U.S. shale and "stick to its strengths—deep water [and] LNG."

Klein said, "Today, one in five LNG shipments in the world belongs to Shell."

The investments offer an opportunity to take advantage of prolific shale resources. Among other projects, Shell and partner Energy Transfer LP are developing a large-scale LNG export facility in Lake Charles, La. It is also purchasing LNG from Cheniere Energy Inc.

"We see a significant role for U.S. LNG," Klein said.

In December, Shell supplied fuel to the first LNG-fueled cruise ship, owned by Carnival Corp.

The company already engages in LNG bunkering in Europe and is building an LNG bunker barge to transport LNG from the Elba Island facility in Savannah, Ga., to Carnival ships in Florida. And it remains on the global hunt for areas where demand for lower-carbon solutions is most acute. Shell's strategic advantage includes its brand, its trading business and the size of its retail footprint.

"We serve 30 million customers around the world [each day]," Klein said. "We have one of the biggest retail footprints on the planet."

Rebellions

European majors have tended to spend far more than their U.S. counterparts on renewable energy, while realigning their portfolios toward gas and setting climate-related targets, according to CDP.

Fitch's Taylor said shareholder "rebellions" have been seen across the wider energy space through this year. That includes ExxonMobil, where investors pushed for the company to publish an annual assessment of the impact of climate policies on its business, despite long-standing board opposition.

The shareholder proposal was backed by investors with $1.9 trillion in assets under management, including the state pension fund for New York and the Church of England's investment fund.

New York State Comptroller Tom DiNapoli said ExxonMobil should come in line with its "biggest European peer, Shell," noting that it as well as Total have started long-term emission-reduction targets following investor engagement. ExxonMobil appealed to the U.S. Securities and Exchange Commission, which sided with the company.

Yet ExxonMobil has taken positions in favor of climate regulation, including backing a carbon tax and joining the Oil and Gas Climate Initiative. The company also announced initiatives to lower greenhouse-gas emissions associated with its operations by 2020, including reducing methane emissions by 15% and flaring by 25%.

Ceres' Logan said oil and gas producers such as Chevron Corp., ExxonMobil, ConocoPhillips Co. and Occidental are following paths that tend to be "as lean and low-carbon as [they] can while remaining oil and gas companies."

Among investors, Logan expects to see continued nervousness about the approach that Chevron, ExxonMobil and its U.S. peers are taking. "That will lead to lower levels of investment or increased levels of activism and pressure from investors."

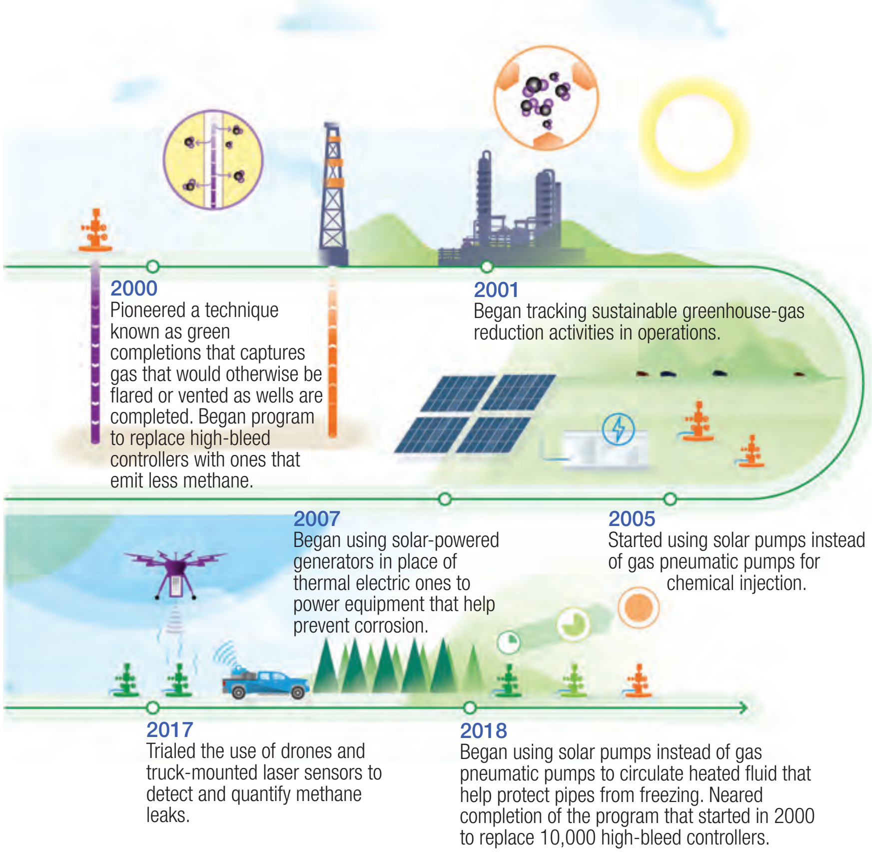
Shell, by contrast, has been lauded as a leader in the clean-energy space among international oil producers. Klein said Shell is proud to be leading the pack.

"We absolutely see a role to work with others to collaborate and develop solutions, but we're not going to wait around for everyone," he said. "We're going to lead and find our way to thrive.

"We've been in business for more than 100 years, and we're determined to be relevant and competitive for the next 100 years." □

Electrification will be the fastest-growing trend in energy as the world works to meet the climate goals of the 2016 Paris Agreement, said Jason Klein, Shell vice president for U.S. energy transitions strategy.

BP's Energy Transition



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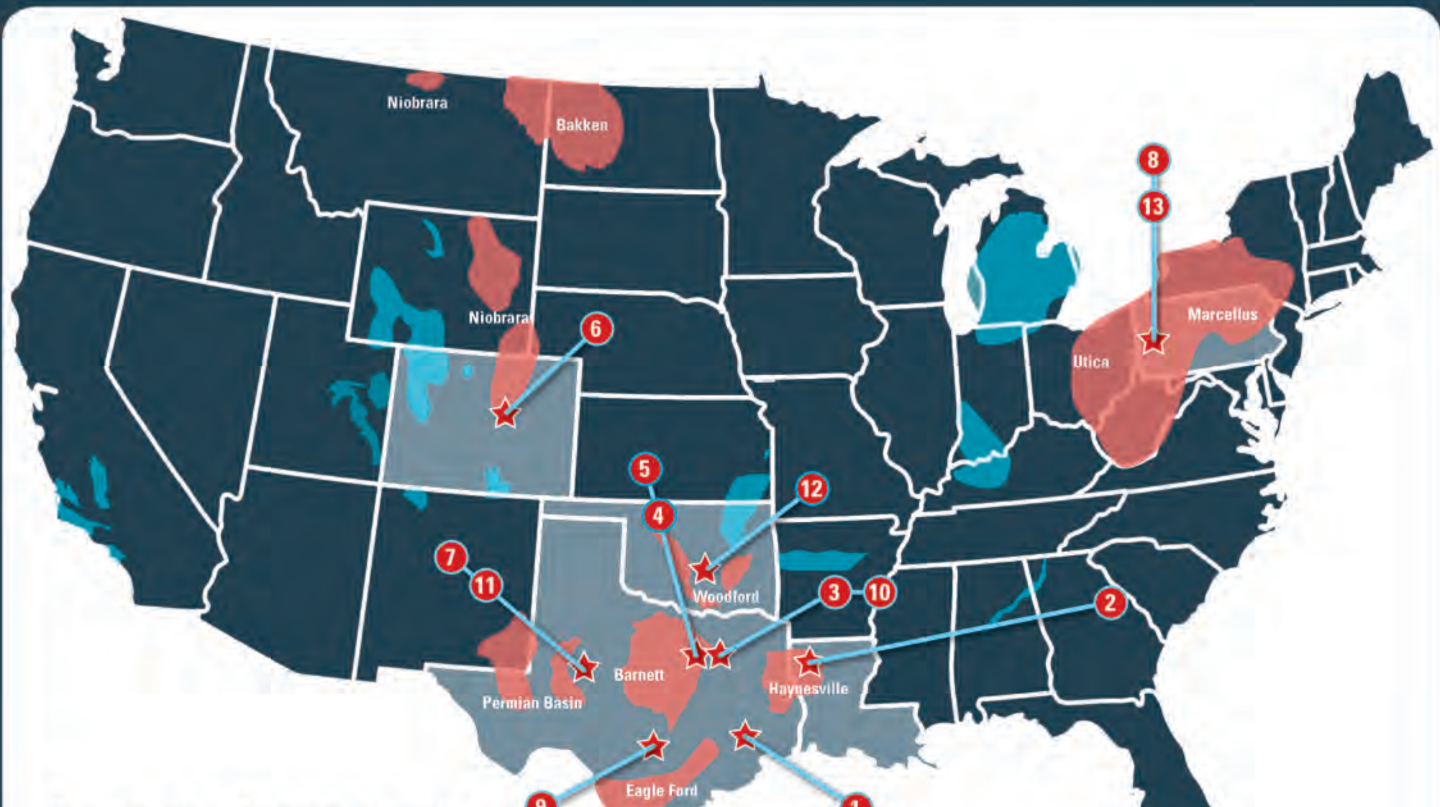

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FAMINE OR FEAST?

The plight of private equity in an exit-challenged market pivots on perspective. And focusing on the lack in the short term risks missing the abundance in the longer view.

ARTICLE BY
STEVE TOON

ILLUSTRATION BY
ROBERT D. AVILA

Private capital is perplexed. The flight of capital out of public oil and gas markets in recent quarters put a pinch on monetizations for private investments. And that creates a conundrum for private investors: flee the space as have the generalist public investors, or double down?

Several private-equity sponsors have discussed the unusual environment for capital in public forums recently and how they are adapting to trapped investments as exits evaporate.

The investor base

Despite rumors to the contrary, limited partners have not abandoned oil and gas, according to several private-equity sponsors speaking at *Oil and Gas Investor*'s Energy Capital Conference in Dallas in March.

For one, Post Oak Capital maintains a "very stable investor base," said Frost Cochran, managing director and founding partner, although the allocation to the space is not as large as in the past. Nonetheless, "they think in decades, not quarters," he said, "and that exposure is important to them."

Post Oak Capital is settling in for the long haul regarding exits, said Frost Cochran, managing director and founding partner. "We're going to have longer hold periods, and our companies need to be designed and structured for the long haul."

At a minimum, oil and gas is "effectively a hedge" in their portfolios as to their exposure with other sectors. And even though energy is currently in the red, "sometimes your hedges are out of the money," he said. "But you need to be hedged in the event it goes the other way, and sometimes it does."

Some do recognize the true fundamental value that's in the space right now, however: as it transitions from capture mode to free cash flow and true cash on cash generation. "It needs to be proven, but I think there's enough capital out there that believes that's probably going to be the case, so that they continue to allocate to the space," Cochran said.

Geer Blalock, managing director with Denham Capital, emphasized that LPs and investment managers recognize the critical nature of shale production to global supply and want to remain exposed, but "competitive tensions" are apparent in their conversations. Headwinds such as capital allocation, portfolio construction and the weighting of E&P within the S&P 500 have the limited partners adjusting portfolios accordingly.

"On top of that, you have an expanded number of sponsors going out and seeking more and more capital as intensity continues to build," he said, "but we've got a supportive base of investors as well who have taken a view internally on how they want to manage and approach their energy exposure."

Preston Powell, managing director of Carnelian Energy Capital Management LP, said that fair weather investing in the private capital world plays out similarly to retail investors investing in the overall stock market.

"A lot of times some of these investors come in when things are going really well, and they load up on exposure when they did not have it in the space before," he said. "And then they pull back when things get a little bit tough. That's certainly played out in the public markets, and more recently you've seen that play out with certain investors in the private market as well."

The energy private-equity markets experienced a run-up with successes in the early 2010s, and funds got much larger. Yet those returns over the past three years, at least for some, he said, have been compressed, "and you've seen some of those investors pull back."

Nonetheless, "there are a lot of other investors who've stayed in the market who have actually put more money in this time because they see the opportunity."

The exit

The bugaboo in private equity remains the exit—or lack thereof. Money deployed in the past three years and today is largely trapped in portfolio companies unable to find a monetization through sale or IPO. How do you build a concept today that will get sold?

Blalock said private equity and corresponding management teams have to focus on developing assets that mirror the capital markets' requirements on public companies, as they will be the ultimate consumer of the assets. "Our charge as private-equity buyers is to build what the market needs or anticipate what the market will need in the future and build accordingly."

Historically, private equity sold assets into a market window focused on establishing inventory. Now, "you're either going to have to compete with that existing inventory and try to stack up with the best econom-

Geer Blalock, managing director with Denham Capital, said a successful exit comes down to building businesses that have strategic value to the end owner … while maintaining as much exit optionality as possible.

Despite some investors fleeing the market, Preston Powell, managing director of Carnelian Energy Capital Management LP, said, "there are a lot of other investors who've stayed in the market who have actually put more money in this time because they see the opportunity."

ics, or deliver cash flow that can be utilized and accretive to the cause."

Post Oak is settling in for the long haul regarding exits, Cochran said. While sponsors with sub-$1 billion funds like Post Oak do have the ability to continue to build bolt-on assets for larger buyers, these are workable only in a healthy or marginally healthy market for capital markets-funded companies. That doesn't exist for anyone currently, he said, "so we're going to have longer hold periods, and our companies need to be designed and structured for the long haul."

In the meantime, that return of capital to some extent may come from recapitalizations of portfolio companies to extend ownership for longer periods of time. "You need to have teams that are built for that and have a portfolio that's built for duration. That's the case whether it's an upstream investment, midstream or oilfield service. Duration is important. All of us are learning to live with greater duration with our management teams and our portfolio."

Carnelian, alternately, has found a sweet spot for monetizations in the current climate, said Powell, by being further downmarket in size from the larger private-equity funds.

"We're in the middle market; we'll typically do $50- to $100 million equity checks. For companies of our size, many times the exits are still digestible for some of these public or larger private companies. They can find ways to finance an acquisition if you've turned $50- or $75 million into $150- or $200 million. They're not having to go out and issue equity or do a bond offering to close a deal. We're still finding potential avenues to find liquidity on that route."

Private consolidations

With ongoing chatter regarding how small and midcap E&Ps should consolidate to create scale to appease public investors, the same discussions flow down to the private sector where seemingly myriad portfolio companies dot the landscape. And while these equity sponsors acknowledged that some of the larger energy private-equity funds are rolling up teams with geographical synergies, by and large they are not.

"Consolidation is a continuing theme on both the public and private side, and it makes sense for economies of scale," Blalock said. However, Denham purposefully constructs a portfolio that is differentiated to avoid overlapping on both on a strategic and geographic basis, "so there aren't necessarily those synergies to be realized," he said. "That's intentional."

And bigger doesn't exclusively equal better, he emphasized.

"The real goal we try and strive for is building with intent and purpose, so [creating] thoughtfully designed organizations built for purpose for their associated strategy, and accepting that duration is here to stay for a period of time. You can do that and be small and nimble in a lower part of the marketplace that doesn't see the same level of competition."

Similarly, Post Oak's portfolio of companies doesn't overlap in ways to create synergies, but the company has previously combined management teams with other equity-sponsored companies. Those consolidations were win-win strategies to the private-equity sponsors and to a large extent the management teams as well, he said.

"There is a place where you capture cost synergies, particularly in a long hold period on execution, by doing that."

The risk, perhaps ironically, he noted, is in becoming too large by consolidating.

"We consolidated a company several years ago, and on the exit the capital markets were required to facilitate the exit. Had we not merged that might not have been the case," Cochran said. "We complicated the exit, but the asset became more valuable by doing that."

But merging portfolio companies, as much as it might seem to make sense, is not an easy task, according to Powell.

"One of the things we've seen that's a challenge to that is the relative valuation considerations and the different perceptions of the management teams and the private-equity firms involved. Getting everyone to agree that this company is worth Y and this one is worth X, and those make sense together, has been a challenging exercise," he said.

"We've worked on it in a couple of different instances and will continue to work on it, but as of yet, those have been more difficult conversations than I would expect in this market."

Building durability

Patience and duration are necessary in the current environment, Cochran said. And while some management teams continue to hope for an imminent exit at a perceived relative valuation, they're due for a dose of "market therapy," he noted.

"Sometimes that's helpful to an impatient management team, to keep going out there and pushing to understand where their asset value is and to be shown by the market. But rarely is private equity surprised about where the market views our assets at any given time," he said. "And so we wait patiently for those windows to find our exits or recap opportunities, and to shepherd our management teams that direction also."

What is the sweet spot for an equity-sponsored company to exit? Denham's Blalock said there is no one answer. "It comes down to building businesses that have strategic value to the end owner. You can build small, strategic bolt-ons that go hand and glove with someone's existing position," while maintaining as much exit optionality as possible, he said.

If there is a potential pitfall in business planning, he said, it's centering a business plan around a specific exit and trying to

AN EXCELLENT TIME

Talara Capital Management's David Zusman views many of the private capital investors of the past decade as venture capitalists. Their model: fund a team with a blank check, buy a lot of land, delineate and extend a field with a few wells, and flip. His point: That model is an anomaly born out of the resource-grab phase of the shale boom, and investing models are now returning to development-oriented strategies based on margins.

"Some of our peers are finding that their venture capital-oriented models aren't working in this market, and they're needing to shift to thinking about holding their assets for longer. In the day and age we live in today, you've got to be the low-cost provider as the industry matures," he said.

"The days of just drilling a well here and there and delineating are over. Now you've got to be running a continuous rig and continuous crew, getting economy of scale like you're a manufacturer."

Houston-based private-equity firm Talara finds no need to change its model; its strategy was always as a developer of properties. A typical Talara investment will target assets with technological upside potential in the $20- to $25 million range, equitize it with about $100 million, then develop half of the potential locations during a five-year period with some $300- to $400 million in capex.

"This is a margin business," said Zusman, co-founder and managing partner. "We're putting dollars into the ground and then we're reinvesting it in drilling more wells. We are turning leases into cash flow and returning that cash flow back to investors. That cycle of cash flow is what's underwriting our investments."

And that model is tailor-made for public shareholders today seeking cash flows. "It's really the maturing of the industry. You're going to get a shift toward more development-oriented capital spending as opposed to land delineation spending."

The buyers of such PDP-oriented assets have changed over time, he noted, but he expects "a more significant push" during the next five years as yield becomes more important. "We expect there to be a fairly liquid market for those exits," he said. "There will be more and more yield buyers in the market. We've seen that already."

Talara Capital Management's David Zusman is the most excited about acquisitions opportunities as he has been in the past 10 years. "The market is ripe today to do some very smart things. It doesn't feel like everybody is jumping in just for the sake of jumping in."

Zusman also sees limited partners adjusting to the changing environment in energy. "The industry always changes and, if you're not on the cutting edge of those changes, you're going to be left behind. LPs view themselves the same way," he said. "We think that the current environment is ideal for our strategy."

Specifically, investors are increasingly wanting to back general partners that are more operationally involved with their properties and are closer to the assets, he said.

"There's been a clear trend to focus on funding the development of specific assets to be able to reach fruition, developmental cash flow, rather than just giving blank checks to a team and hoping to flip."

Zusman is the most excited about acquisitions opportunities as he has been in the past 10 years. "The market is ripe today to do some very smart things. It doesn't feel like everybody is jumping in just for the sake of jumping in."

He conservatively estimates some 8,000 small property owners in the U.S. with assets under a $50 million value that are more undercapitalized now than ever before.

"They can't get the RBL facilities like they used to from the banks, they oftentimes don't have an engineering team to really deploy the latest modern technologies, and they often don't have that level of capital efficiency to get a rig, get a crew and keep that rig and crew running continuously."

The opportunity is to bring in a strong operating team, recapitalization, technological efficiencies and a consistent manufacturing program.

"Our inbound calls from those smaller property owners who need a solution are way up. There are more compelled sellers today at this level who need a development partner. Many of them want to keep a small minority stake in the business—5%, 10%, 15%—so they can ride our coattails of development. That's okay with us."

For those private-capital investors focused on development, it's "an excellent time" to generate solid returns, he said. "It's just back to blocking and tackling, right?"

build an asset package for a specific buyer. "You just can't be that predictive on the timing or the profile of who's going to own it. You need to build something that has insulated margins."

One example in Denham's portfolio is Covey Park Energy LLC, a large Haynesville Shale-focused business that has been strategic in acquiring and growing its asset base. It's been so successful, in fact, that it is now either a logical consolidator or consolidatee in the region, Blalock said, "but it's taken other exit options off the table.

"They are essentially a public company masquerading as a private company, but the public markets are closed, so we have to pivot another direction to find creative ways to ultimately monetize that business. In the meantime, it's a business built to grow and develop and is accreting equity value as we go."

And if you do try to plan the exit, it's never the way you thought it was going to work out, Cochran said.

"We gave up on that a while back. Some of our teams have been so successful that the exit got complicated because of their

NGP partner Bob Edwards said its portfolio companies are drilling ahead with the exit in mind. "We're profitably growing value with the expectation that the capital markets open up again. It's the private capital that has been investing over the next couple of years that will have inventory to serve up to the more efficient, larger companies."

success. They became so large that it became difficult for who you might have thought would have been the logical buyer to then transact because it was going to take a protracted capital-raising process for them to execute."

Carnelian's Powell adds flexibility to the necessary qualities in a portfolio strategy today. He described one particular company the sponsor took to market last year expecting to sell to one buyer in one package, but eventually sold it to four buyers in four pieces.

"We ultimately got to a good outcome, but it wasn't what we had in mind when we started the business. But the flexibility was important in getting to the exit we all needed. Whether it's selling in pieces, recapitalization or consolidating, often what you had in mind when you started the business will look very different at the end."

Preparing the harvest

NGP partner Bob Edwards acknowledged that, with capital markets closed to large public companies, "it does stall our exits." But Edwards views this period as "an enormous opportunity for acquisitions," he said, at CERAWeek by IHS Markit in March. In the meantime, NGP's portfolio companies are drilling ahead.

"Most of the private equity in this phase of the development cycle, we're drilling. We're profitably growing value with the expectation that the capital markets open up again. It's the private capital that has been investing over the next couple of years that will have inventory to serve up to the more efficient, larger companies."

The disconnect in the markets is centered on the markets' disbelief at returns being flashed by the public E&Ps, he said, and that's where the deep value investors like private equity can come in. "We're not guided by the analysts on Wall Street when we have management teams that can deliver 50% to 70% IRR wells. That's a good return until the publics are consolidated and begin to have disciplined growth."

Edwards said it is a fundamental dichotomy for investors to ask high-growth companies to distribute cash out when capital is still required to maintain production and keep production flat. "The reality is with shale wells declining at 40% to 50% per year, this industry requires a capital machine continuing to pump capital."

Edwards said private-equity portfolio companies—particularly NGP's—are as efficient in their drilling and their capex as they can be considering their relative size to larger companies, "but we know they are not as efficient as Exxon will be with 30 to 40 rigs running in the Permian Basin. What's the role of a $5 billion enterprise value Permian pure play when you need to drill 20-well pads? We're not necessarily the natural owner of those assets," he said.

Still, private capital is investing in value, and value still exists, he assured. "Ultimately, private equity is going to sell to the majors or to the large E&Ps when the markets give them the signal it's OK to openly grow again."

At the moment, although the markets are not rewarding public companies for adding yet another year of inventory to their already swollen inventory of high-return locations, those will soon be depleted. In three or four years, he said, as assets are developed and proven up, the markets will again look to replenish the inventory via the consolidated winners.

Further out, the resource potential for private capital is vast, he said. With shale EURs in the 8% to 10% range of original oil in place, "nobody can tell you what enhanced oil recovery means for shale.

"This idea of working the entire decline curve cycle from initial acreage capture to primary development to whatever secondary development means in shale, to mature production, those are all life-cycle stages that private capital like ours has taken advantage of."

Edwards expects to hold assets "for a little bit longer in this era," but he's fine with that while drilling economic wells in core positions. But his view is that this is an era of plenty rather than lack. "This is an ecosystem where there is a role for private capital to jig when the capital markets are jagging." □


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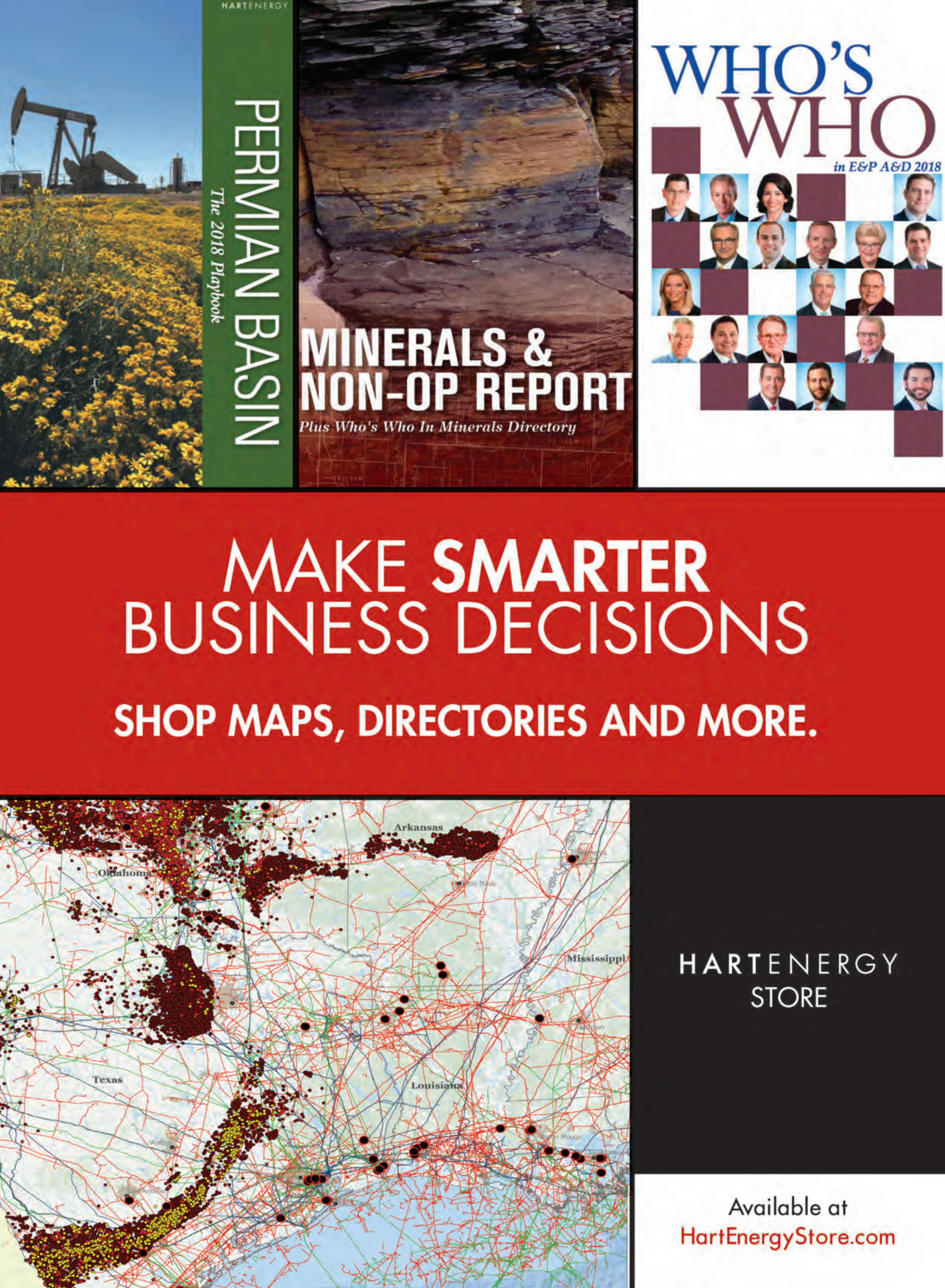

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OPEC MAKES PEACE WITH SHALE

While many second-tier producers struggle with the effects of added U.S. crude supply, the big three make common cause.

ARTICLE BY GREGORY DL MORRIS

"I have had OPEC officials tell me that if they had known how it would all play out, they would not have made that announcement late in 2014 that they were holding production steady," said Helima Croft, managing director, RBC Capital Markets.

Many executives in the U.S. oil industry have vivid memories of the "Arab Oil Embargo" of 1973. Now that the shale bonanza has vaulted the U.S. into the position of a major oil exporter, there must be no small sense of satisfaction among those who recall all too well the long lines at gasoline stations and lowered thermostats of their youth.

For the perceptive, there must also be a strong sense of irony. Because in becoming a major player in petroleum, the iconic independent producer has adopted wholeheartedly the objective of a stable price range within sustainable levels for both buyers and sellers. That of course, has been the objective—at least the economic objective—of OPEC from its founding in 1960.

In the giddy first years of the shale era there was fanciful talk of "energy independence." That had little to do with economics or logistics and a great deal to do with exorcising the demons of energy dependence in the '70s. What has developed is energy interdependence. Where one stands depends on where one sits, and unconventional development means that the U.S. now sits at the head table with Saudi Arabia and Russia.

"Some people believed that shale would free the U.S. from global geopolitics and supply disruptions," said Helima Croft, managing director and global head of commodity strategy at RBC Capital Markets' research division. "That foreign-policy promise from the Permian has not materialized." If anything, becoming a major exporter of crude and LNG, beyond the existing robust business in fuels and petrochemicals, has increased the involvement of the U.S. in global energy dynamics.

The fulcrum for the lever of sanctions against Iran and Venezuela, Croft explained, is that U.S. production continues to expand. Of course the sanctions are taking heavy barrels out, while the U.S. is putting light barrels in, but being a major exporter of any crude puts the U.S. at the table.

That position has been acknowledged by OPEC. "I have had OPEC officials tell me that if they had known how it would all play out, they would not have made that announcement late in 2014 that they were holding production steady," said Croft. "They knew prices would drop, but they were expecting a short stay in the $70-a-barrel range and that shale would break. No one saw oil with a three handle on it."

"A good majority of the wells in the U.S. can be economical at $50 or a little above. The question then becomes: Can OPEC be economical at $50 plus?" said Greg Haas, director of Stratas Advisors.

In a large irony, it was domestic politics that drove OPEC to back down. "Could they have held out longer?" Croft asked rhetorically. "Some investors say shale was starting to break. There were bankruptcies. But sovereign producers would have gone bankrupt first. The social contract they have with their citizens is prosperity for loyalty. Their oil sustains their economies. Just look at what happened recently in Sudan and Algeria. Those governments fell because they did not deliver the prosperity."

Four years from the low point, oil prices have reached a "tolerable place," said Croft. "Seventy-five dollars for Brent and $67 for WTI [West Texas Intermediate] is fine."

Greg Haas, director of Stratas Advisors, concurred. "Currently we are at $65/bbl [barrel] for WTI, at least $60 plus. Brent is $70 plus. That looks like the correct range. A good majority of the wells in the U.S. can be economical at $50 or a little above. The question then becomes: Can OPEC be economical at $50 plus?"

Saudi Arabia is the low-cost producer. "Their finding costs are super cheap," said Haas, "in the single digits. But when Brent was at or below that level, their fiscal troubles came to the fore quickly. [Because their national budget is tied to oil exports] we think their floor price is closer to $70 or $75. Regardless of low finding costs, that is what they need to keep their economy going."

So the U.S. and Saudi Arabia are yin and yang: the U.S. as the high-cost producer, but with a private market, no baggage on the price. Saudi has oil for the asking, and then extracts from it the wherewithal to run the kingdom. "So we have reached petroleum détente. Russia is just along for the ride," Haas added. "They are somewhere in between on costs."

"The U.S. sanctions are starting to bite on Iran, and the collapse of Venezuela means that OPEC as an entity has taken a hit. Coupled with the rapid growth in U.S. oil production, OPEC's ability to move prices is now hampered absent cooperation from other producers."

—Kenneth B. Medlock, Rice University

Twice the trough but half the peak

That situation implies the end of the "lower-for-longer" theory that was in vogue since the price collapse of late 2014.

"For several years, people were speculating what kind of recovery in oil prices there would be," said Haas. "There was talk of a V-shape, or a U-shape, or a bathtub. "

Prices have doubled since the trough but remain half of the peak. Rather than a recovery per se, it seems more like the price electron has simply moved to a higher price orbital. That looks sustainable. "It is hard to imagine Brent getting back to $100 or $140," said Haas.

Détente confirms that OPEC has accepted the U.S. as a major oil exporter. It is widely understood that the Thanksgiving turkey OPEC delivered in 2014 by announcing a production high and causing prices to collapse was intended to beat back shale producers. "Whatever the intent, look where we are now," said Haas. "Prices are higher for both WTI and Brent, and U.S. production is greater."

A tolerable price range aside, Croft hastened to add, the situation is highly unstable. "We have two major exporters under sanctions. We have yet to see how Iran reacts. Libya is on the verge of civil war. It is a very chaotic situation, and will be a real test of whether or not U.S. exports are enough to keep things balanced. I would not necessarily take that bet. Shale can certainly do some heavy lifting, but we don't know how much it can sustain."

There is a historical pattern to the geopolitical premium that has been factored into global oil prices. Any premium arising out of uncertainty of supply is a factor of a tight market, said Kenneth B. Medlock III, a Baker fellow in energy and resource economics and senior director of the Center for Energy Studies at the Baker Institute for Public Policy at Rice University.

"If you look back to 2008, there was very little inventory, OPEC's spare capacity was very low, and there was little supply responsiveness at the margin. Any air of uncertainty puts that premium on," said Medlock.

"It is easy to forget how quickly the upstream evolves," he added. "In the '70s and '80s, when oil prices were high, every mom and pop borrowed money to drill for oil. There were a lot of bad loans made followed by waves of consolidation. Shale is no different. The first step is always the entrepreneurs. Over the next five years we will be seeing a lot more consolidation."

Contrast that to just six years later. By 2014, the shale bonanza had begun to show its size, and the U.S. was already discussing the resumption of exports. "OPEC was trying to determine if shale was a long- or short-term phenomenon," said Medlock. "It seems quite clear that it is now a long-term phenomenon. By the end of 2014 we also had bloated inventory because demand growth had slowed. So, there was little reason for any geopolitical premium. Moreover, the emergence of shale has added a very responsive new source of supply, meaning it will take much more substantive geopolitical pressure to drive a premium in the market."

As evidence he noted that there have been several current dislocations in global crude supply, with no evidence of any lasting premium moving into prices: Venezuela's implosion, U.S. unilateral sanctions on Iranian crude and ominous pronouncements out of the new government in Mexico indicating an about-face from the policies and legislation of the previous administration to open the energy sector to foreign investment.

Hampered helpers

As if to underscore Medlock's point, there was a muted reaction to the sudden pronouncement out of the U.S. administration April 23 that it would not renew waivers of the sanctions against Iranian crude. Brent moved higher by about two and a half dollars a barrel that afternoon, but ticked lower the very next day.

"Even with all that going on, I don't really see the oil market in a situation where a large risk premium could be reinjected," said Medlock. "Maybe a little, but not much. If anything the response by U.S. producers to the price collapse in 2014-15 showed the world how responsive shale is to the international market. The new presence of another major exporter and the ability of fringe producers to react in a short time significantly reduce the ability of OPEC to move the market by itself."

Croft at RBC is not sanguine that the other two North American producers can pick up much slack. Looking north she is rueful. "The current situation is so set up for Canada. Who else has the heavy barrels U.S. big refiners need? They just have not kept up with the infrastructure so they can't answer the call." That is one area where Croft credits Saudi Arabia: "They don't just have the production capacity; they have the infrastructure and the logistics."

Canada should be a major exporter, said Haas at Stratas. Its internal political frustrations at being unable to get molecules to market have been well reported. "The shortage of pipelines means they can't get crude to buyers who are willing to pay more," said Haas, but that is actually a common problem.

Outside of OPEC, the two other North American producers that could play larger roles but are hamstrung by internal politics, said Medlock. Canada, as has been well reported, has a serious pipeline constraint building new pipelines or even expanding existing ones.

With Ottawa effectively nationalizing one line expansion, and a new pro-development government in the main energy province of Alberta, it is expected that progress will be made on getting more molecules to market. It will be several years, but "once those pipes exist, Canada becomes a larger and more market-responsive exporter," said Medlock.

Looking south, the situation in Mexico is more recondite. The new left-leaning president—Andrés Manuel López Obrador, often known by his acronym, Amlo—has called for massive domestic investment in upstream and downstream and has been critical of foreign investment. "Amlo is definitely playing to his base," said Medlock.

That stance has been criticized within and without Mexico as fuzzy nostalgia for a golden age of Pemex, but Medlock noted that Amlo has approached the energy question as part of his anti-corruption campaign. "He is getting very high approval ratings thus reinforcing his stance," said Medlock. "There is a lot of risk. The optimal approach for foreign companies is to stay engaged by acting on previous investments, but not to actively seek new investment at the moment."

The new administration in Mexico raised eyebrows with its rumblings against foreign investment, but RBC's Croft noted the pattern of production has been down for a while. The rhetoric is new, but "if you pull the data on Mexican production, it has been declining for some time due to lack of investment."

Dominant Firm Theory

Beyond the balance of the big three, the two other variables in the equation are the second-tier producers, and the question of demand, noted Haas. "There seems to be some expectation within OPEC for diminished production from Iran, because of the U.S. sanctions, from Venezuela, which could be in a catastrophic situation, and perhaps even from Libya, Nigeria or Algeria. With any of that, there could be some slackening of curtailment by OPEC, specifically from Saudi Arabia."

That willingness to raise production if output from other member states declines indicates contentment with the current price range. That means OPEC leadership has accepted the reality of the U.S. as a major exporter.

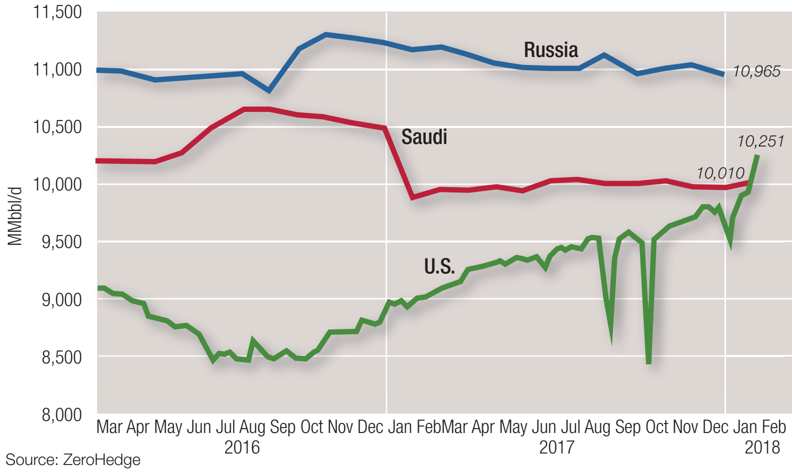
"Refineries in California and on the East Coast are effectively isolated from Permian production by the Jones Act," Haas explained. "Any supply disruption will cause price dislocation." The Jones Act requires that trade between U.S. ports be handled in ships owned, operated and crewed by U.S. citizens.

While the discussion of petroleum politics and economics usually involves supply, Haas stresses the importance of demand. "At the end of the day, that is what is needed. We now live in a world that is supply rich. The next level questions are about demand, especially energy in developing nations."

Examining the supply disruptions more closely, they mostly affect OPEC members. "The U.S. sanctions are starting to bite on Iran," noted Medlock, "and the collapse of Venezuela means that OPEC as an entity has taken a hit. Coupled with the rapid growth in U.S. oil production, OPEC's abil-

"OPEC was trying to determine if shale was a long- or short-term phenomenon. It seems quite clear that it is now a long-term phenomenon," said Kenneth B. Medlock III, senior director of the Center for Energy Studies at the Baker Institute for Public Policy at Rice University.

U.S., Saudi, Russia Crude Production



Source: ZeroHedge

ity to move prices is now hampered absent cooperation from other producers."

Those realities have created an unusual situation where it is actually the Saudis who are motivated to seek the cooperation of Russia, and not the other way around. Conventional thinking holds that Russia seeks a place on the world stage, and thus has recently collaborated with OPEC.

Medlock explained that under the "Dominant Firm Theory, the U.S. sanctions have made it imperative for the Saudis to engage with Russia. One of my grad students, Peter Volkmar, is writing his thesis on that very point."

He adds that Russia is not the same leaky, creaky oil producer that was portrayed several years ago. "Thanks to the work of new partners from the West, Russia is a better operator. It still lags the West by most metrics, but is definitely better."

In contrast, Venezuela may be in worse shape. It is widely understood that the political and social chaos of the Maduro dictatorship has caused exports to atrophy. "Whenever recovery happens it will happen in fits and starts," said Medlock. "Presumably some increase could come quickly, but there are real concerns about the physical infrastructure. It is aging and in need of repair, the extent of which is highly uncertain."

"For all the bashing of the organization, the idea of putting some limits on supply to stabilize prices is in the long-term best interest of producers," said Robert Bryce, a senior fellow at the Manhattan Institute.

Mid-ocean point of arbitrage

As all of this plays out, Medlock suggests that the simplest way to monitor the balance between the U.S. and OPEC is to follow the point of arbitrage between WTI and Brent crude. "It is now on the open water, which already shows how much things have changed. It used to be that WTI traded at a premium to Brent, and the point of arbitrage was [the pipeline and terminal hub of] Cushing, Okla."

Then, pipes were reversed to flow from Cushing to the Gulf Coast. "Brent is now trading at a premium to WTI because the point of arbitrage is now somewhere in the Atlantic."

Reviewing the latest export data, Robert Bryce, a senior fellow at the Manhattan Institute, noted that energy companies in the U.S. upstream and downstream sent crude oil and refined products to more than 100 nations in January. Last year, LNG was shipped from the U.S. to about 30 countries, including Kuwait and the United Arab Emirates. "Beyond that, it is an open secret in Houston that Saudi Arabia is shopping for a long-term LNG supplier so they can stop burning crude to make electricity," said Bryce. "They can get much more value exporting the oil or refining it. Selling LNG to OPEC members is like selling coal to Newcastle, or ice to Eskimos. Choose your simile. It shows how dramatically the U.S. as a major exporter has changed the fundamental structure of the global energy market."

That, in turn, "has driven a complete rethinking of the allocation of capital," to energy-related businesses and assets, he added. That process has been going on for quite some time, but the exclamation point was the $33-billion deal Chevron Corp. struck in April to buy Anadarko Petroleum Corp., an iconic and long-lived major independent that well predated the shale bonanza.

Consolidation may bring a note of coherence to the notoriously fractious U.S. upstream sector, but Bryce hardly anticipates lock-step discipline. "There really never has been any coherence in the sector," he recalled. "As far back as the 1930s, the Texas Railroad Commission had to implement prorationing to bring some rationality to the industry and put some reasonable brakes on supply."

Bryce is very clear that he "is no fan of OPEC." That said, he added, "For all the bashing of the organization, the idea of putting some limits on supply to stabilize prices is in the long-term best interest of producers. The history of U.S. production has always been boom and bust. It took decades for producers to come around to some regulation."

While OPEC clearly has diminished influence in the shale era, "the organization is not going away," Bryce said. "It clearly has been weakened from its heyday in the 1970s, but it has been in business for more than half a century, and there are many reasons—internal and external—to keep it together."

The Russian collaboration with OPEC is a different matter. "That has always been an alliance of convenience," said Bryce. "OPEC can't effectively control cheating on quotas within its own organization. So there is certainly no enforcement for what Russia does."

Notably, there is no OPEC in LNG, nor is there likely to be any such thing, which is good, said Bryce. "The U.S. will soon have more LNG export capacity than any other country. And as I testified before the U.S. Senate, that is good for the U.S. balance of trade, good for the worldwide economy and good for the environment, as LNG replaces the burning of coal and crude oil to produce electricity in the Middle East and Asia." □

OF MUTUAL INTERESTS

After stints as Silicon Valley tech CEO, bond analyst and Hollywood screen writer, Karl Brensike found his stride in the ups—but mostly downs—of the oil and gas mineral sector as co-founder of Haymaker Minerals & Royalties.

ARTICLE BY
DARREN BARBEE

On a pleasant April afternoon, standing before about 600 people gathered in the Post Oak Hotel in Houston, Karl Brensike was in his element, telling the story of the mineral business.

It's a personal story for Brensike. He's the wunderkind co-founder of Haymaker Minerals & Royalties. He's an overnight success, 20 years in the making. His career has moved forward haltingly, built more on busts than booms—first as tech company CEO and later asset manager, screenwriter, co-founder of upstream E&P Remora Oil & Gas and finally as CEO of Haymaker.

Brensike has rubbed shoulders with would-be Silicon Valley visionaries, New York's financial wizards, the Los Angeles entertainment scene (not his favorite) and, lastly, wildcatters.

"I think oil and gas has the greatest group of people that you would ever want to be associated with," he said.

It shows at the Post Oak, as he stands before his fellow mineral brethren. The Post Oak itself, with elegant décor and an inhouse Bentley and Rolls Royce dealership, underscores the theme of Brensike's World Oilman's Mineral & Royalty Conference: business is good. It's just taken a long time for the sector to convince others that it could be.

Brensike turned toward the giant presentation screen that displayed his slides and couldn't resist having a little fun. "I kind of feel like a weatherman," he said, mimicking a forecaster pushing weather across the screen as the crowd laughed.

Brensike asked for a show of hands: Who had ever been to his hometown of Olney, Md.? Few, if any, went up.

In a deadpan voice, Brensike said, "Important statistics about Maryland: 6.1 million people. Currently there are no rigs running."

As the crowd continued laughing, he added, "and there is actually zero oil production in the state of Maryland."

Olney is not a place where a person grows up with wildcatter dreams. But Brensike is a full convert.

By 2018, at just 41 years old, Brensike led Haymaker as it plowed through 420 acquisitions of mineral and royalty interests for about $355 million. That year, Haymaker sold its remaining assets to Kimbell Royalty Partners, concluding a divestment program of more than $630 million.

At the mineral conference, Brensike unfolded the broader developments that shaped the oil and gas mineral sector.

The initial hurdle was money. Swaying early investors in 2009 was difficult, and private-equity firms had no interest in investing in minerals. By 2013, as Haymaker was beginning to form, the market was slightly more receptive. More recently, mineral companies have flourished. Most recently, in April, Brigham Minerals closed its IPO, which opened at $18 per share and, in its first days of trading, sat above $20 per share.

The change in attitude, to Brensike's thinking, can be traced to the June 2014 IPO of Viper Energy Partners LP, which set out to raise $100 million but pulled in more than $130 million by the time it closed.

If history textbooks divide eras by AD and BC, the mineral world is separated by Before Viper and After Viper. Viper, with its general partner held by Diamondback Energy Inc., was a flashpoint for the mineral industry.

"Once Viper went public, the cat was really out of the bag and institutional investors were looking at the mineral space for the first time," he said.

Haymaker was, at the time, just one year old.

Selling is such sweet sorrow

On March 21, 2019, a month before the mineral conference, Brensike sat at his desk with a direct line of sight to the entryway of the small, inauspicious office space in North Houston where he's working.

Brensike shook hands, outfitted in a relatively subdued golf shirt and cap. He was expected later that day for a tee off at the Texas Wildcatters' Open, an annual event held by the Independent Petroleum Association of America (IPAA), of which Brensike is a board member. Brensike is very active in the oil and gas community. He knows how to network. In addition to the IPAA, he is on the board of World Oilman's Tennis Tournament and the Youth Development Center's annual roast committee. He also created the World

"The initial Haymaker was basically an index for the entire U.S. oil and gas energy complex. If you bought Haymaker you would get exposure to conventional, you'd get unconventional, you'd get oil, you'd get natural gas."

"In this industry, good things tend to happen when you bring people together."

Oilman's Poker Tournament 13 years ago and co-organizes an annual A&D ski trip with Meagher Energy Advisors.

"In this industry, good things tend to happen when you bring people together," he said.

Asked about his golf game, Brensike replied matter-of-factly, "I'm terrible. I'm absolutely terrible. I did however, once hit a hole in one during a round in which I shot a 118."

A friend offered to let Brensike use the office space as he and his partners unwind Haymaker's affairs, closing out the business, distributing stock and shuttering the old office near Houston's Memorial Park.

For a deal that closed in July, Brensike said he had found a surprising amount of work to do.

"It's funny, anybody that started a private-equity company, you talk to them in the first few months, it's always like 'oh, man, I had to get paychecks set up and get insurance and a website and email and furniture and an office and all of this stuff.' You don't realize when you sell it, it's like 10 times more work, because you have to unwind everything."

Brensike, nearly always self-deprecating, said Haymaker really began with his foray as a convertible bond analyst.

Asked what a convertible bond analyst is, Brensike responded: "I wish I could tell you. I wasn't very good at it, which is why I got into oil and gas."

About six years after forming Haymaker, Brensike said the final sale has been bittersweet for him.

For the investors and employees, all of whom owned equity in the company, "they all did really well." Some, since leaving Haymaker, are also starting their own companies.

"I think that's one of the more fulfilling things. There are these quotes about 'judge yourself on how good of a leader you are by how many leaders you create.' And it's been great to see other Haymaker alumni go out and do good things."

Still, on a personal level, Brensike and his partners had a vision of transforming into a public company.

"We know how good we are at buying these assets and managing them and marketing them," he said. "There's still probably a little piece of us that wishes that we could have been the big group that went public and are running it all, but at the same time, we did great by our investors and everybody in the company."

Dot-bomb

Brensike's early ambitions had nothing to do with oil or gas. He was interested in professional tennis and screenwriting.

While he ultimately took up writing for a brief time, he thinks unkindly on it.

"You deal with the entertainment types in there, and some of them have extremely difficult personalities."

Both of Brensike's parents were in the medical field: his father a doctor and mother a nurse.

"My dad was a cardiologist, who, ironically, died of a heart attack when I was seven years old," he said.

Brensike entered the University of Southern California as a double major in the entrepreneurship school and the film school, which were both ranked top in the nation.

In 1999, fresh out of USC, Brensike entered the dot-com universe, which was then fully booming.

He recalls it as a time when "you could be 22 years old and have a really good idea and you could get venture capital money in order to explore it."

Like most everyone, he was unaware of the epic collapse around the corner.

Brensike and a few other people formed a company called netHESIVE. The company was focused on using artificial intelligence to connect people together based on shared interests, "to basically improve search capabilities as the web continued to grow," he said.

"We called it Google before Google. Obviously, it was not as good as Google."

The company grew to about 25 people before the bubble burst and, in 2001, the company merged with Channel Intelligence Inc.

Google, it turns out, bought the merged company in 2013 for a reported $125 million in cash.

"It's kind of funny, that deal ended up paying off, but on an hourly basis from 2001 to 2013, I don't think we got paid very well on it," he said.

For a while, Brensike kicked around Los Angeles, an unemployed tech company CEO. With an agent at William Morris, he turned to writing screenplays and books—"just paid gigs to work with other writers and producers here and there. I was decent."

More than anything he found the subjectivity of Hollywood frustrating.

Oil and gas, he would find much later, was far more practical. "At least here, if you drill a good well, you get paid and people recognize it."

Around that time, a college mentor and USC alum offered him a job in Greenwich, Conn., at Argent Funds Group. He was offered a shot learning about the finance industry and convertible bonds.

"That's when I hated convertible bonds, but I fell in love with energy," he said.

Low yield

While in Hollywood, Brensike had missed the business world, particularly the spreadsheets and the numbers, but he wasn't quite prepared for the tediousness of an analyst job.

In his April mineral conference, he depicted the job on a slide using a picture of an office worker who looks bored enough to swallow his tie.

Brensike said he found the work dull.

"They just had me reading documents, looking for certain very specific passages on make-whole premiums and all this different kind of specialized financial terminology," he said. "To be honest, I was kind of ready to move on."

But in 2003 and the following year, the fund owner wanted to get back into the energy industry even though the firm knew its investors considered drilling funds too risky.

But what caught his eye were minerals and royalties, "because they behave a lot like bonds."

"You get all the benefits of bonds in that a diversified royalty portfolio distributes a consistent monthly revenue stream, but you have far more upside with very limited downside," he said. "When we looked across the whole investment universe, we couldn't imagine a better investment for yield-oriented investors, yet we soon realized there was no way for investors to get exposure to this amazing asset class. That's when we decided to create Cornerstone Acquisition & Management Co. to start buying minerals and royalties."

Leaving behind the tedium of the bond business, he instantly took to oil and gas. While the learning curve on convertible bonds was steep—30 years steep—energy was new.

With no energy experts at Argent, "I was able to dig into minerals and get up the learning curve as much as anybody else in the firm at that point," he said. "I was just incredibly interested in every facet of it. That's how I got started on this path."

In November 2004, Brensike began his new job as senior managing director for Cornerstone, where he managed a fund called Caritas Royalty Funds.

Slowly, an economic tsunami was moving toward the company and the global economy.

Zero interest

Looking out over the city of Paris, on his honeymoon in 2011, Brensike told his wife he had a confession.

"Honey, you're not the first person I've been with to the Eiffel Tower," he said.

"Oh god, which one was it," she asked.

"It was Vasilis."

"I figured," she said.

Vasilis Mouratoff was an early partner in a fund they managed for Argent called the Caritas Royalty Funds.

The funds were based out of San Diego, but Brensike wasn't home often.

"I would be probably traveling two, three weeks out of the month, to Houston and Midland, [Texas], and everywhere else, and really just pick up my mail in San Diego, while I was building out our network at Cornerstone," he said.

Since half of the fund's investors were international, Brensike and Mouratoff spent a great deal of time explaining to foreign investors that mineral ownership in the U.S. was radically different than in, say, Europe, where the government owns the rights.

The company ultimately held $130 million worth of assets under management.

"We made some great acquisitions. The Caritas funds were some of the best-performing energy funds over the time period. Things were really great," he said.

Then 2008 came. With pressure to put more capital to work and oil at $120 a barrel, some speculated the price per barrel could rise to $200. Cornerstone didn't think that was likely, and Brensike said the company reset all of its hedges in June 2008, locking in prices at $135 per barrel.

The Great Recession ravaged the global economy yet Cornerstone "had a fantastic year in 2008. I think we were up 18%," he said. "But the whole rest of the hedge fund blew up."

Without the hedge fund's capital, the company was unable to line up new acquisitions and execute on them. Brensike and Mouratoff turned to private-equity providers for money.

"What we learned in 2009 is that private equity had absolutely zero interest in minerals and royalties," he said.

Private-equity firms were skeptical that anyone would sell their minerals, and they wouldn't be able to model returns without operator control.

But the private-equity firms liked the two men and asked them to consider starting an operating company. With friends, Brensike and Mouratoff formed Remora.

After a few years of operating in South Texas and investing in drilling programs in West Texas and the Panhandle, Brensike and Mouratoff were looking back at the mineral space. Cornerstone's acquisitions had been primarily conventional assets. Now the shale revolution was raging.

They were skeptical that MLPs, which had become a yield investment of choice for energy investors, were sustainable or that they were doing what investors had envisioned as they continued to buy earlier stage, high decline assets and run up debt.

Then, looking back at how Cornerstone had fared, they saw the company continuing to produce a fantastic yield, Brensike said.

"You could just set your watch: every month you were going to get your distribution," he said.

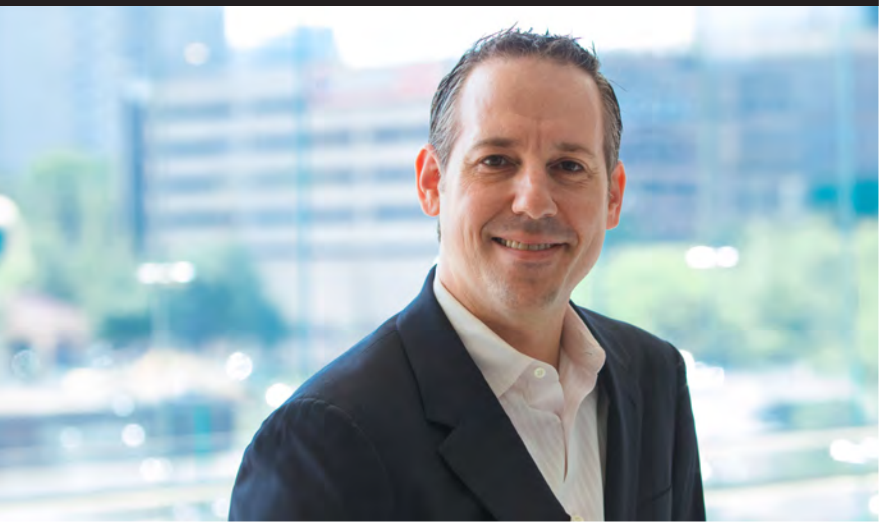
Minerals, crystalized

Brensike and Mouratoff saw minerals and royalties as "just the greatest investment in the world."

They also believed there would be a public mineral and royalty space; that there needed to be one; and "that we should create it."

Brensike saw minerals as a way for investors to gain access to energy investments without having specialized knowledge of which plays to invest in and without having to divine whether Diamondback Energy Inc., Parsley Energy Inc., Concho Resources Inc., EQT Corp. or some other company was the best investment.

"I hated convertible bonds, but I fell in love with energy."



Private-equity firms were skeptical that anyone would sell their minerals, and they wouldn't be able to model returns without operator control, said Karl Brensike.

"What we were trying to build at the initial Haymaker was an index for the entire U.S. oil and gas energy complex," he said. "Basically, if you bought Haymaker you would get exposure to conventional, you'd get unconventional, you'd get oil, you'd get natural gas."

The company purchased interests in every major producing basin.

The proliferation of shale companies had also taken out some of the risk of development timing to produce revenue.

"You kind of knew where the shale was, and that it was going to be developed, and you had better, more reasonable assumptions than" buying into a conventional oil field, he said.

They brought in a third partner, Doug Collins, a petroleum engineer who could look at shale reserves and help guide investments uniformly across the portfolio as COO and chief engineer.

In 2013, the newly formed Haymaker team again sought out backing from private-equity firms.

Haymaker made presentations to 12 firms. Eight of them told Brensike flat out that they were "never going to invest in minerals and royalties because we don't do non-control investments, and we don't know what the exit would ever be for these," Brensike said.

Four of the firms were receptive. Haymaker partnered first with Kayne Anderson Capital Advisors, "under the thesis that we were going to build this company and take it public." Later they would add funding from KKR.

Five years later, Brensike said, five mineral companies have gone public. And of the dozen firms they spoke with in 2013, all are "heavily invested in minerals and royalties now," he said.

Brensike planned for Haymaker to be one of the first to IPO, but another slump was on the way.

Body language

Insiders at Haymaker called it "reading operator body language"—a term of art coined for predicting where and when E&Ps would drill.

Collins, with a background at ExxonMobil Corp. and Netherland Sewell & Associates, could think like an E&P.

In its partnerships with operators, Haymaker bought mineral interests alongside E&Ps with a degree of confidence in what their drilling schedule would be.

But in other cases, knowing how E&Ps might behave—shifting production to certain areas or the pace of development—allowed Haymaker to "read that body language to get ahead of the drillbit," Brensike said.

As the company evaluated acquisitions, it was the bedrock of Haymaker's strategy. Stay ahead of the drillbit.

Collins could read not just how companies were developing but, as a petroleum engineer, which targets were likely to be drilled and even how completions would be set up.

By 2014, Haymaker was just hitting its stride. For most of its maiden year, 2013, the company was busy hiring, seeking out operator partners and building a data map that gave the company a set of coordinates: the location of mineral interests they wanted and their value.

Near the very end of 2013, the company made its first phone calls to sellers and closed two deals for "a whopping $725,000," Brensike said.

The next year, at a breakneck pace, Haymaker bore down on acquisitions, making 350 deals—nearly one per day—for about $210 million. Haymaker also purchased the Cornerstone assets Brensike and Mouratoff had run years before at Argent.

Then, after Thanksgiving 2014, oil prices began to fall, marking the beginning of one of the worst downturns in the industry's history. And with it, Haymaker once again found opportunity.

Haymaker slowed down in 2015 by necessity. Haymaker's staff found its strategy of staying ahead of drilling increasingly challenging because "everybody stopped drilling," Brensike said.

The company took a breather, streamlining its management systems and regrouping as it organized itself for an eventual IPO.

The company also began to focus on the most active areas—the Delaware and Midland basins.

"We got in there very early, before any of that activity happened, and we were able to aggregate a nice position for a very reasonable price," he said.

As Delaware A&D began its hot streak in 2016, Haymaker took advantage as other private-equity-backed mineral companies came on the scene, hunting for Permian assets.

Rather than get caught up in bidding wars and escalating prices, Haymaker said the Permian climate "drove us to sell."

"Prices went up about four times or more from what we were acquiring for," he said.

A year later, with oil prices still erratic and generally low, Brensike moved to build the scale he wanted for the company with a purchase of mineral assets from Chesapeake Energy Corp.

The Chesapeake acquisition was incredibly complex because of the ways in which former Chesapeake CEO Aubrey McClendon had built the architecture of his mineral ownership through over 80 separate entities, some with various financial strings attached, such as volumetric production payment vehicles.

"If you knew Aubrey McClendon, you know he wouldn't buy a cup of coffee without putting it in its own separate LLC," Brensike said.

Haymaker rented out a suite at a local hotel with an unimpressive view of railroad tracks and had the room cleared of furniture.

"We put in a bunch of folding tables," he said. "We called it Haymaker East."

There, a group toiled for months over the transfer of ownership, including dealing with some 400 operators spanning 382 counties and 11,000 check stubs.

Straw man market

The Haymaker logo—a sketch of an antique horse-drawn hayrake—could be taken straight from a 19th century farm equipment ad.

Sitting the equipment on a sunny yellow field, presumably of hay, underscores its purpose to smooth out the crop so it can dry evenly.

The more modern meaning of haymaker is that of a wildly thrown punch—the sort that the oil market was winding up for Brensike and his partners as they entered 2017.

In January of that year, Kimbell Royalty Partners had gone public with an IPO, and Brensike believed Haymaker would be next. Haymaker was then bigger than Kimbell and, he thought, would be better received by the market.

But market sentiment in the oil and gas industry had soured badly by the summer—a distaste that, with few exceptions, continues.

Brensike recalls meeting with one major bank that told them they loved Haymaker. He was momentarily pleased, before they added, "this is something that we would totally invest in—if we ever make another investment in energy."

The rules had also changed in the public markets. Where $30 million or $40 million in EBITDA would spark interest, now investors wanted far more liquidity and cash flow.

Ultimately, Haymaker was faced with a choice: continue building scale or join up with another company.

The company decided to sell, pairing with what it saw as its best natural partner: Kimbell. The companies' acreage overlaps in many basins and, combined, would total 11.1 million gross across in 28 states.

"In private equity, there's one goal: return on investment for your investors, and that has to guide all of your decisions," he said. As Kimbell's offer came around, "that was the best option on the table to get both Kayne and KKR what they valued most out of the deal."

Brensike felt comfortable taking part of the deal's proceeds in Kimbell equity because of Kimbell's leadership team, headed by chairman and CEO Bob Ravnaas.

As he sees it, the only way to blow up a mineral company is to overlever and make a transaction with too much debt.

"Bob's been doing this for 30 years," Brensike said. "He's not going to do that."

Since the company wasn't developing or drilling, "you just keep cashing checks."

True believer

In the days before Haymaker was formed, Brensike went on a fact-finding mission. He spoke with five or six of the largest mineral owners, asking why they hadn't considered taking their holdings public.

"The answer was uniformly, 'I make $10 million a month sitting at my ranch. Why would I ever want to run a public company?'"

Brensike is possibly the closest the mineral and royalty sector will ever get to its very own evangelist. His mineral conference in April was partly a way to extol the virtues of the business model—and lament that it still doesn't get the attention it deserves.

What he saw years ago, when he first began examining mineral buying, is a simple business model that gives an investor exposure to energy but eliminates most of the risk.

"We just saw running this company and providing this service to investors that nobody had ever thought to do before," he said.

The risk remains low even if an operator goes bankrupt: "Another operator just comes in," he said. "The risk profile is so low, the stability is so great. It was unfathomable to us—why hasn't somebody done this before?"

Toward the end of his presentation on stage at the Post Oak Hotel, Brensike showed a slide of returns by sector since Jan. 1, 2018. The minerals sector outpaced all others, up at least 30%, while E&Ps have been swatted into negative territory.

"Minerals are absolutely outperforming every other facet of any market," he said. "If you think about what investors want, it's free cash flow, it's low risk [investment]."

While the mineral sector is part of oil and gas, he says, it's a separate business model.

"We are distanced as far as we can be performance wise [from E&Ps]," he told the Post Oak audience. "I think we need to start distancing ourselves a little messaging wise."

Brensike said he's also ready to start making plans for what comes next for him. Asked what another company will look like, Brensike cagily avoided any specifics. But he allows, lightheartedly, "it's most likely to be in minerals and royalties, but that's all I can tell you right now." □

> "Minerals are absolutely outperforming every other facet of any market. If you think about what investors want, it's free cash flow, it's low risk."

BETTING ON ORYX MIDSTREAM

There were handshakes and smiles all around after private-equity firm Stonepeak Infrastructure Partners purchased Oryx Midstream in the biggest midstream deal to date.

ARTICLE BY GREGORY DL MORRIS

When Stonepeak Infrastructure Partners struck a deal to buy Oryx Midstream Services LLC on April 2, the biggest midstream deal in history was no steely-eyed showdown. Quite to the contrary, the principles told *Investor* that building the system and discussing the sale were the collaborative efforts growing from respect and trust.

If the $3.6 billion paid for Oryx is surprising, the system was hiding in plain sight all along. "We have done a good job over the years of building out the midstream from our upstream knowledge base and positions," said Dheeraj Verma, president of Quantum Energy Partners, one of the investors in Oryx. The others were Post Oak Energy Capital and two producers, Concho Resources Inc. and WPX Energy Inc.

Oryx is the largest privately held midstream crude operator in the Permian Basin. It owns and operates a crude gathering and transportation system underpinned by nearly a million acres under long-term dedications from more than 20 shippers, including many of the Permian's leading oil and gas producers.

"We have done a good job over the years of building out the midstream from our upstream knowledge base and positions," said Dheeraj Verma, president of Quantum Energy Partners.

The system's 2.1 million barrels of storage and 1,200 miles of pipe in service and under construction span eight counties in Texas and two in New Mexico. Upon completion, Oryx's total Delaware Basin transportation capacity will exceed 900,000 barrels per day.

Oryx II, in the northern Delaware Basin, is now in service, and volumes are ramping up, said Jack Howell, partner and head of energy at Stonepeak. "That was a key factor for us. We wanted the full system operational without construction risk. There is significant production in the region that was still on trucks waiting for this system to be completed. We are already seeing a substantial volume increase."

The timing of the deal was very deliberate. "From the perspective of an infrastructure fund, this is what we do," said Howell. "The system sits on top of the best rock in North America with a uniquely diversified customer base which, in our view, significantly de-risks the exposure to movements in commodity prices. The management team, led by Brett [Wiggs] and Karl [Pfluger], is excellent. Not only are they staying, they are investing alongside us."

Oryx is already among the largest midstream operators in the Permian, and Stonepeak has said it is keen to expand much further. Howell reiterated that eagerness but was circumspect about details. "As it stands today, Oryx is a great platform. We are planning to take it to the next level."

Post Oak is predominantly an upstream investor, explained Frost W. Cochran, founding partner and managing director. "We and Quantum were early investors in the Delaware, and we realized that there was limited infrastructure in the area. We were trucking crude. It was abundantly clear that midstream infrastructure needed to be built, but none of the legacy midstream companies were willing to do that. So we put together a top midstream team to do that."

There are several possible reasons that the big public midstream firms demurred, Cochran said. "We were so close to the rock that we knew what we had, but the strategics were still in the show-me mode. They wanted three years of results to get proof of need. We knew we could not wait that long."

He also acknowledged that the Midland Basin "was going gangbusters at the time. There was already infrastructure in place so the strategics could just build out at less risk. We were willing to take the risks in the Delaware that the traditional midstream companies were not willing to take."

Cochran credits the management team at BC Operating for helping to get the idea off the ground. Both Post Oak and Quantum had interests in BC Operating, which had 51,500 acres in the northern Delaware Basin in New Mexico—Post Oak through Crown Oil Partners and Quantum through Crump Energy Partners II.

"We did a lot of work on the rock in the Delaware Basin," said Verma. "The Midland Basin was getting all the attention, but not a lot of people had made the jump to the Delaware back then. The first big anchor tenant for Oryx in the Delaware was BC Operating. That was the starter kit." BC Operating was acquired by Marathon Oil Corp. in 2017 for $1.1 billion, making that major independent an important anchor shipper.

The next big tenants on Oryx's system were Jagged Peak Energy Inc., J Cleo Thompson and Patriot. The latter two were acquired by Occidental Petroleum Corp. for more than $1 billion each, while Jagged Peak, a Quantum portfolio company, was taken public for about $3 billion.

The next big steps were signing Concho and WPX as investors, not just shippers. "That was based on long-standing relationships and trust," said Verma. "Those two partners were also crucial to the overall momentum and footprint of the business."

It is not surprising that Stonepeak was ready to finalize growth plans even as it was closing the Oryx deal. "We've been familiar with Oryx for some time," said Howell. "We have long had the view that the Permian would be the key driver of U.S. hydrocarbon production growth, and the way we play that is through the midstream. We have long been an investor in Plains, and we have multiple downstream JVs [joint ventures] with Targa."

A year ago those ventures bought Targa's 25% interest in the Gulf Coast Express Pipeline, a 20% interest in the Grand Prix Pipeline and all of Targa's next fractionation train at Mont Belvieu, Texas, that will be filled with liquids primarily from the Permian.

Closing the biggest midstream deal in this hemisphere catches everyone's attention, but Verma stressed that there is no silver bullet. "It was broad-based collaboration among two private-equity firms, two Midland families, two big public producers and multiple upstream portfolio teams. It was building a great business the old-fashioned way, by ultimately delivering a superior value proposition to the customers."

He noted in particular the Oryx leadership team of Wiggs and Pfluger was instrumental in the success of the business. "They were able to convince customers of their ability to deliver a superior outcome and were able to win everyone's trust and collaboration. They were also able to attract and motivate a strong team of professionals like Josh Ham, general counsel; Martin McHale, COO; and Mike Rose, executive vice president for engineering and construction."

It is important to note that Oryx was hardly built in a vacuum. "The major pipeline companies were there all along," said Verma. "Incumbents like Plains All-American [Pipeline] are still the biggest in the basin. They won their fair share of business, and so did we. The basin grew so dramatically and so fast that there was enough for everyone to say grace over. I have to say again we competed well on price and service."

The differentiator for Quantum would seem to be size, but Verma explained that is a function of patience and operational expertise. "There are at least five other private-equity firms that built great midstream businesses across the Permian Basin. Many of them were sold early as they were still building out and growing. As in any business, it is easier to build a $200 million business, hard to grow it to a $1 billion level and even harder to grow it into a $3-plus billion business."

Verma is adamant that just as patience and perseverance is the key to the size and scale of their businesses, fair dealing and collaboration with others is essential to their success. He gives great credit to Concho and WPX for putting their money where their molecules were, and stresses that their faith in Oryx was paid back with interest. All the investors in Oryx did well by openly and actively collaborating with each other.

"Oryx was built as a strong collaboration between half a dozen key constituents," Verma added. "We were passionate about treating everyone equally and ensuring alignment from beginning to end. Every investor got their pro-rata share of the successful outcome."

Oryx Midstream grew faster and larger than any of the investors imagined. "It started simply as a tactical response to a physical need," Cochran related, "and grew quickly into an entrepreneurial opportunity. As soon as we started siting rights-of-way, other producers saw that we were solving a problem." Concho Resources became not just a major shipper but an investor in Oryx I in the southern Delaware. WPX did the same in the northern Delaware.

It might seem odd for shippers to take equity positions in a private-equity-backed midstream venture, especially publicly traded producers. "Concho and WPX are very entrepreneurial firms," said Cochran. "They are very good at recognizing opportunities, especially ones with a technical edge."

The Post Oak M.O. is to build assets from the ground up and sell. "Once we had crude and cash flowing through Oryx I, we had done our job," said Cochran. "We hired Jefferies to market the business. But by then we committed to Oryx II. Stonepeak was among those interested. They and everyone else wanted Oryx II as part of the deal. We were not prepared to sell for an under-construction discount, so we stopped the process until II was operational."

Stonepeak alone among the initial shoppers took note of the first-quarter 2019 completion date for Oryx II and made a pre-emptive offer. "It was a relatively short conversation as Stonepeak was already familiar with the assets and the team. We had an agreement in a few weeks."

"There were a few midstream strategics hanging around the hoop as well," Cochran added. "But Oryx had gotten so big that they did not have the capacity to pay cash. And none of the owners wanted to manage an illiquid position after the sale." □

"The system sits on top of the best rock in North America with a uniquely diversified customer base which, in our view, significantly de-risks the exposure to movements in commodity prices," said Jack Howell, partner and head of energy at Stonepeak.

Scala Energy's Bluto State Unit 2312 – 1H in Culberson County, Texas, is the furthest western Upper Wolfcamp horizontal in the Delaware Basin.

PHOTO COURTESY JONAS HARRELL/SCALA ENERGY

PERMIAN PRIVATE E&Ps

The Permian Basin continues to make headlines nearly every day for its production growth, value creation and challenging midstream woes. ExxonMobil Corp. and Chevron Corp. have recently unveiled their big ambitions for the Permian. The dramatic takeover fight for Anadarko Petroleum Corp. centers on Permian heavyweight Occidental Petroleum Corp.'s ambitions for developing APC's Permian acreage.

But let's not forget that scores of smaller, private E&Ps are chasing big Permian dreams too. They will continue to lease acreage and build their production throughout the Permian and innovate through technology. Several are pushing the economic boundaries to the west in the Delaware part of the basin, and further north and south in the Midland Basin.

This special report profiles several private companies whose executives spoke at Hart Energy's recent DUG Permian conference in Fort Worth, Texas. It is a rare opportunity to learn more about the assets and strategies of these E&P companies, many of which are backed by private-equity firms. Which ones are building toward an exit soon, and which ones are building for longer-term, full-field development?

Whatever their plans, they join the chorus of Permian players who extoll the benefits of this basin and contribute to its rapidly growing production.

—The Editors

PROFILES BY
LESLIE HAINES
AND ELLEN CHANG

Admiral Permian Resources LLC

Adding value to the western Delaware Basin's Combo Play.

Midland-based Admiral Permian Resources LLC was formed two years ago during what CEO Denzil West concedes was a difficult time in the industry. The executive team knew that buying acreage in the core of the Permian Basin would be too expensive. They decided to focus instead on the western edge of the Delaware Basin, with the company's main acreage now on the Reeves-Culberson county line in West Texas.

Although this acreage is pushing the boundaries of the basin to the west, nearby operators, including EOG Resources Inc., Cimarex Energy Co., Chevron and BPX Energy, indicate the zip code is good, geologically speaking. Some are calling it the Combo Play as it produces oil, gas and liquids.

"We knew that going to the core was going to be expensive, and as a private company we weren't going to make any money if we overpaid for acreage. We knew we were going to need to stick to the periphery and prove things there through execution and operations," said West.

"This was an area that has a somewhat dubious background and some questions about it. But the petrophysics are great, comparable to what was in Loving County nearby; the only difference is its about 1,500 feet shallower, which actually helps us on our economics quite a bit, as far as drilling and development costs."

In April 2018, Admiral Permian acquired leasehold interests and related assets from another private E&P, Three Rivers Operating Co. III LLC. This deal included more than 59,000 net acres in Reeves and Culberson counties (1,400 owned surface acres). The properties produced more than 15,000 net barrels of oil equivalent per day (boe/d) at the time. Since then, production has increased to 18,000 net boe/d, mainly in Culberson County. Some 21 wells have been completed.

Simultaneously to the Three Rivers deal, Ares Management contributed private equity

"Because of the volume of gas and the ability for it to help drive our production, gas has become an asset," said Denzil West, CEO of Admiral Permian Resources LLC.

Admiral Permian Snapshot

Net acreage	59,000
Counties	Culberson, Reeves
Net production (boe/d)	18,000
Backers	Ares Management

to the Midland-based company. The team has a deep operating background, having drilled 400 wells from 2006 to 2016 as a private E&P with no outside financial backing, so the Ares capital infusion was a big step.

"The objective that first year of operations was to take the main zone that we knew and core that up, and that's the Wolfcamp A. But we were also keenly interested in developing potentially a second zone. That would be a home run as far as valuation."

Since it acquired that acreage, the company has grown production substantially, "and we control a lot of our infrastructure."

During the first year after the transaction, Admiral Permian was busy focusing on the Wolfcamp A. "And, there was this acreage that wasn't really proven up. We wanted to expand that systematically to improve our value," West said. "As development and results warranted, we wanted to develop infrastructure that would support us long term. We've got a large contiguous acreage set which allows us to develop infrastructure very well." Indeed, Admiral Permian now has 150,000 barrels of saltwater disposal (SWD) capacity.

The company's well results have been good. The best, Daltex 42-43 8A, reported an IP30 of 1,100 barrels per day (bbl/d) and almost 10 million cubic feet a day (MMcf/d), extending productive acreage in the southern part of the Delaware Basin. It was drilled to 7,402 feet.

As Admiral Permian moved south and west in the area, there were challenges, but West said he felt this was the opportunity to prove up what the company has and try to expand the core. Two Wolfcamp B tests were drilled in the middle of the acreage (near where ConocoPhillips Co. had drilled years ago with marginal results). Admiral Permian's first well in this area showed an IP30 of 700 bbl/d and nearly 11 MMcf/d of gas.

Admiral Permian's first-year production in this area totaled about 348,000 boe/d, more than what many others had achieved, including about 150,000 bbl of liquids. The laterals were 1.5 miles long and drilling time has declined to less than 20 days, spud to spud, regardless of lateral length. Admiral Permian's completion costs have fallen 33% while frack intensity has increased 25%.

"Because of the volume of gas and the ability for it to help drive our production, gas has become an asset," West said. "We are really strong in oil compared to everybody else, but we are top tier on gas and liquids production."

West admitted nobody is happy with gas prices in the Delaware Basin, which in recent weeks had declined to below zero at the Waha hub.

"This is not a gas area, it's a liquids-rich play, and we have very resilient breakevens. So we're excited because we feel like we've taken some acreage that was dubiously thought of and proved it up with a second Wolfcamp zone, and we're now moving into full pad development." □

Ajax Resources II LLC

A model exit sets the stage for a new start-up.

Ajax Resources I is an example of a spectacular private-equity-backed exit, one of several large deals that have occurred in the prolific Permian Basin in the past two or three years. Lessons from the company's growth trajectory inform the industry and will color how Ajax II proceeds in its next endeavors.

Ajax I, formed in 2015, purchased 25,800 acres in the increasingly active northern Midland Basin from W&T Offshore Inc., for $376 million, aided by backing from private-equity firm Kelso & Co. At the time of this transaction, the prospectivity of the northern Midland was thought to be somewhat marginal, but Ajax ended up proving otherwise—selling it less than three years later for $1.2 billion ($900 million in cash). The buyer, Diamondback Energy Inc., held acreage immediately adjacent to and just north and south of where Ajax was drilling.

When Ajax bought the original W&T package it included 200 vertical and horizontal wells, primarily in Martin and Andrews counties, and production was about 3,000 bbl/d. By the time it sold to Diamondback, it had grown production to 12,000 boe/d (88% oil). Ajax was able to prove up the acreage with some 367 net horizontal locations left in inventory for the buyer.

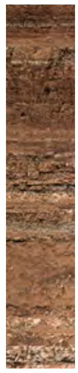
What drives this kind of value creation? For one thing, Ajax's team has been together for 15 years, since the early Haynesville Shale days, and it has drilled over 500 wells. A culture of operational efficiency, drive and an emphasis on G&G analysis (geological and geophysical) was key, according to COO Daniel Rohling. In past iterations the team had drilled over 300 wells in the Permian alone, and those learnings were applied to the new asset acquired from W&T.

"Diamondback started to notice that our wells performed as good as theirs, some even better, but we were drilling three benches and they were only drilling one," recalled CEO Rich Little, speaking about the fast growth of Ajax I during the annual IPAA Private Capital Conference this past January.

Today, the Ajax team is scouting for further opportunities in the Permian with Ajax II.

At the time of the 2015 purchase, the industry faced a lot of headwinds because of the oil price downturn. "The debt and equity markets were either headed for the hills or they were already there," Rohling said, "so being able

> Daniel Rohling, Ajax Resources II LLC COO, said, "From a value perspective, it starts and ends with a reservoir. Everything we do gets back to G&G."



to put together a program to purchase this and then put together a delineation program was pretty substantial. But what we saw coming in was there was a lot of resource there. There were multiple benches that weren't being played yet that we thought we could delineate, and not only delineate, but we felt that they would compete for capital with the primary target, which was the Lower Spraberry at the time."

The investment thesis was to be consistent, to validate the Lower Spraberry, work over the existing wells that had been acquired, and drill in the Middle Spraberry and Wolfcamp A, said Little.

As Ajax put down some great wells in the Lower Spraberry, it also successfully tested the Middle Spraberry and Wolfcamp A. In addition, it made several operational improvements, as it took the average drilling time of 40 days from spud to rig release down to 20 days, and lease operating expenses dropped from $7 or $8 to about $4/boe.

By 2017, it had taken cores and performed high-end log suites, and did a spacing test on 640 acres before getting ready to sanction full development, Little said. In the 12 months from October 2017 to October 2018 (the exit to Diamondback), Ajax grew production by 75%. "By September, we were drilling within cash flow," Little said, with two six-well pads.

At about this point, however, Ajax realized the next step it needed was to build more scale. It had some deals in the pipeline to acquire more acreage in the area with the aim of growing production. But meanwhile, the Diamondback team came calling—it was operating right next door and had enough scale, its acreage surrounded that of Ajax, and it could see the good well results Ajax was getting.

"They were able to see that they could parlay both ours and their well results with their capital structure and realize a ton of value from day one. So we worked together through October 2018 to close on what was a great story and great deal for Ajax," Rohling said.

"Scale comes in a lot of different aspects, but we tend to think about it from the PDP [proved developed producing] side. For us, we think it always starts and ends with the reservoir," Rohling said. "Everything gets back to G&G. Everything else we do is secondary to that point. We've got to be able to get out there and put together wells that will compete for capital across anybody's discipline or acreage. By that, we mean continually driving operational efficiencies while we increase EURs and IPs."

Doing this will create value, which in turn, allows the acreage to compete for capital vs. other opportunities. Achieving scale is important whether a company is trying to compete for capital, create a good reserve number to underpin a borrowing base, or become an acquisition target, Rohling said.

"We didn't talk a whole lot about it, but as you get into whether or not you're going to do full-scale development in a cube style, container style, single well or pad development, it's all about value and being transparent to your investors, no matter if it's shareholders or LPs." □

Caza Petroleum LLC

Go-private pure player uses capital infusion to move into pad development.

Caza Petroleum LLC, the Houston-based pure-play Delaware Basin operator in southeastern New Mexico, has rebounded since it was recapitalized in 2015 by Talara Capital Management, a Houston- and New York-based investment firm focused on private equity for the energy sector.

Talara spent $45.5 million to acquire and restructure Caza, paying off debt and taking control of its assets in the Delaware Basin. The investment firm retired the company's first-lien debt, convertible bonds and the payables at a significant discount, creating an aligned waterfall structure with management for future reward. It also injected $85 million of growth capital to develop its assets.

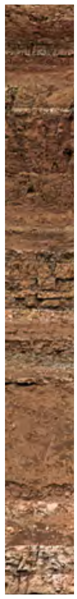
The restructuring and injection of new capital allowed the company, which had been on the verge of bankruptcy, to start drilling on the property in Lea and Eddy counties in New Mexico.

Since 2016, Caza changed its capital structure and was able to develop a drilling program and grow its reserves by 400%, said Randy Nickerson, COO of Houston-based Caza. Previously, Nickerson served as vice president of exploration for Caza and chief geophysicist for Sanchez Oil & Gas from 2004 to 2011. The company's assets in the Delaware Basin are now worth $465 million in total reserve value, including $161 million in PDP assets.

Caza Petroleum Snapshot

Net acreage	7,000
Counties	Lea, Eddy
Net production (boe/d)	4,500
Backers	Talara Capital Management

Caza Petroleum COO Randy Nickerson said many operators waste too much money on delineation and science. "We are focused on finding and producing low-cost hydrocarbons through the drillbit and recycling our cash flow. We are essentially a manufacturer."



Talara's recapitalization of Caza allowed the company to "get into development mode," he said. Now the company touts acreage proven up with multiple benches and plans to develop and increase its PDP assets with Talara. Caza has a total of 7,000 net acres with 207 locations.

Caza is operating in two core areas—Lea and Eddy counties, N.M., with production of 4,500 net boe/d. In Lea County, the company operates 5,000 net acres that is "premier acreage with 10 stacked pay zones with nine planned wells in 2019, including one well that is already drilled and completed," Nickerson said. Also, Caza operates 2,000 net acres in Eddy County, which has eight stacked pay zones, with plans to drill four wells this year.

Caza is running one rig and intends to develop on pads going forward, drilling out a single zone at a time to minimize parent-child well issues.

One strategy that Caza deploys to maintain its capital is to systematically hedge a "good percentage" of its wells to lower their risk for the downside of oil prices, he said. The company is mostly HBP (held by production).

Compared to Caza's operations in 2013, the basin now has been completely developed and is "coming into the core instead of the fringe," Nickerson said. In the North Laguna Area targeting Third Bone Spring Sand, the first two wells drilled exceeded expectations.

"We're actually performing better than a lot of the other ones out there, and we're on the fringe," he said. "The number of wells has expanded dramatically. The basin has changed and is very giving."

Production here is 76% liquids, Nickerson said.

While Caza experienced a slow point in 2018 similar to its competitors and dropped a rig due to oil differentials impacting the industry, the company has been able to increase its production while decreasing its lifting costs through its water and SWD agreements, electricity costs and improvement of its chemical treatments and analytics.

The company has also teamed up with Salt Creek's crude gathering system. By the end of 2019, Caza will have pipelines connected to 95% of its oil production and decrease transportation costs. It has up to 20,000 bbl/d dedicated to both the Salt Creek and the EPIC pipeline, which are expected to start up in third-quarter 2019.

This development gives the company flexibility to transport oil to Corpus Christi, Texas, or Cushing, Okla.

"We're risk averse and trying to maximize our returns for our owners," Nickerson said. □

Colgate Energy LLC

Delaware Basin-focused company pivots to prepare for the long haul.

This Midland-based company was formed in 2015 with a focus on taking advantage of that down market period and staying focused on the core of the best basin—the Permian. "We have a company motto that we do not like to take geologic risk," said Will Hickey, co-founder and co-CEO. His partner is James Walter.

An initial capital commitment of $75 million announced in February 2016 has since grown to $450 million, all from Pearl Energy Investments and Natural Gas Partners. "As it stands today, we've grown the company to 31,500 net acres; about two-thirds is in Reeves County, Texas, and about a third is in New Mexico, mostly in Eddy County."

Net production is now over 12,000 boe/d. The company has drilled 17 wells in six different benches (primarily Wolfcamp A and B) and 12 of those are online. Hickey said he's projecting to have $200 million of EBITDA over the next 12 months and be cash-flow positive by year-end. A single 10,000-foot well investment of about $12 million generates a PDP, PV-10 value of about $40 million, he said.

"You can really ramp EBITDA quickly with a two-rig program."

Later this year, Colgate will test its first well in New Mexico, as well as test the Second and Third Bone Spring benches in Texas. "We're going to finish our appraisal program and finish our HBP program; we are about 75% held by production now and expect to be finished sometime later this year. Then we're going to transition to large-scale development in 2020. I'd say we as a company, and our investors, are very excited about the potential of this asset."

Like most E&P companies, Colgate has witnessed a transition in the private-equity business model as more E&P investors demand cash flow and returns, and fewer large public E&Ps want to buy. Colgate has altered its strategy somewhat as a result.

"When we formed the company, as you can imagine, we were in a time when all of our peers had laid out a proven and consistent model and we did not plan on deviating from that model. We were going to lease and buy ... spend numerous hours and time trying to consolidate, put land together for long lateral development, drill a couple of wells on each bench to prove the rock was good, and then we were going to sell it, as the public E&Ps were in need of inventory and were happy to buy acreage.

Colgate Energy Snapshot

Net acreage	31,500
Counties	Eddy, Reeves
Net production (boe/d)	12,000
Backers	Pearl Energy Investments; NGP

"James and I were excited. So we picked up our first rig in 2017 and drilled our first two horizontal wells, relatively shorter-lateral Wolfcamp A wells. Both had made consistently over 1,000 bbl a day of oil … both paid for themselves in the first year. At this point, we had followed our plan to a T. We had infrastructure in place, so we said, 'Next step, let's sell this thing.'

"Then around the second quarter of 2017, [capital markets and M&A] just came to a halt…. Nobody needs to be buying their 15th year of inventory. With this backdrop in this new world, we rethought what we're doing and decided this is an opportunity to really grow the business into something that was more what the world was looking for."

The Colgate team decided it needed to HBP more acreage, get the midstream infrastructure in place and transition into full development mode. It need to appraise the primary target bench with short laterals and then, drill the 2-mile laterals and test all the benches.

"We had to grow production and EBITDA to get it in place that we'd have the ability to finance a six-well, eight-well, 10-well pad before you see a dollar of revenue coming back," Hickey said.

To make sure the effort returned dollars back to the equity owners, Colgate had to make sure its infrastructure was built out ahead of time, he said. "I mean, these wells move so much fluid that if you don't have

Will Hickey, co-CEO, said Colgate Energy LLC revised its strategy when the typical private-equity business model changed. He projects the firm will be cash-flow positive later this year.

oil, gas and water takeaway on pipe, it's very difficult to make money," he said.

"I would say that we noticed as you move toward full development, it creates additional opportunities of ways to take advantage of your asset base. This comes with buying minerals ahead of the drillbit and building out the gathering system."

To meet its new goals, Colgate drilled eight wells. Its average IP30 was 284 boe/d per 1,000 feet of lateral. It drilled mostly 10,000-foot wells but drilled two that had laterals of 12,000 feet. The wells consistently outperformed expectations, Hickey said, with cumulative production of 330,000 bbl in 160 days.

"The Wolfcamp A in this area is a great mix with 70% to 75% oil cut. Only two of the eight we drilled are on artificial lift. But it's not just about the A. As you think about cube development, you need to test the other benches too. We've drilled three Wolfcamp B wells … I would say they compete as well as anything. The B wells are equally good as the As. They are still relatively low water-oil ratio and extremely high-pressured."

Colgate has increased its net daily production from about 4,000 boe/d in October 2017 to about 12,000 boe/d now.

"We've been fortunate that the prolific nature of these wells has allowed us to grow strictly off a typical RBL [reserve-based loan]. We haven't had to dip into equity funds. Early appraisal: we love the A, we love the B, we love the C."

How does Colgate intend to drill these locations without parent-child issues? In one particular 1,280-acre unit, it started by drilling one Wolfcamp A and B some 330 feet off the eastern lease line and in about six months, it will come back and drill a third well on the west side of the lease, leaving a 4,500-acre fairway down the middle that can be drilled later when full development kicks in.

"The point of this whole thing is cash flow," Hickey said. "We've grown our EBITDA from about $50 million a year in 2017 to $200 million a year, and we're projecting that with a two-rig program, we'll be cash-flow positive sometime later this year. Then we'll transition to large-scale development in 2020." □

Discovery Natural Resources LLC

Reinvigorating the southern Midland Basin.

Since 2017, activity has revived in the southern part of the Midland Basin. Larger operators are re-entering the area, and many private E&Ps are in the play. These companies have seen a step-change in well performance and an uptick in horizontal drilling permits (238 in the past six months). Discovery Natural Resources is all in.

This Permian pure play was formed in 2003 with some backing by an affiliate of Fidelity Investments. The Denver-based company had operated in multiple basins over time, but today focuses on the southern Midland Basin where the Wolfcamp thickens to the southeast. Through acreage swaps and acquisitions the company now has 110,000 acres in the area, primarily in Reagan County, Texas, and some in nearby Irion County. It has 825 producing wells and 1,300 horizontal locations.

Gross production in 2018 was about 26,000 boe/d, but "with the application of two or three rigs this year, we expect to increase that production by about 20%," said CEO Steve Turk. He joined Discovery in 2017 after serving as COO for SandRidge Energy Inc. and, before that, for HighMount Exploration & Production Co.

In the mid-2000s, the company began moving into Crockett County, where it started developing a gas play and still operates it as the gassy Adams Baggett Field. In 2010, the company began assembling its Reagan County acreage position. Some in the industry considered the southern Midland too gassy and maybe even uneconomic, but Turk disagrees.

"Why do we like the southern Midland Basin and our position there? It's an exceptional opportunity, with a thick and consistent 1,500-foot section of Wolfcamp that is 70% to 75% liquids rich. We think the oil in place is roughly 150 million bbl per section, and we're fortunate to have a contiguous position. A plus, we lease 80% of our acreage from only one mineral owner, the Texas Scottish Rite Hospital for Children in Dallas. They're a wonderful group of people to work with."

The majority of the company's inventory supports longer laterals of 2 to 3 miles. "It is unlikely that in the foreseeable future we will

Steve Turk, CEO, Discovery Natural Resources LLC, favors the southern Midland Basin, citing its lower costs, improving well results and uplift from NGL.

Southern Midland Basin vs. Northern Midland Basin (Based on 1,280-acre DSU)

	SMB	NMB
Entry cost ($/acre)	$20,000	$50,000
Avg. EUR	930 Mbbl	1,250 Mbbl
% Oil	50%	68%
Wells/section	21	28
Well cost (2-mile)	$6.3 MM	$8.0 MM
Full-cycle IRR	33%	35%

Source: Discovery Natural Resources LLC

For the average recent well in the southern Midland Basin, 180-day cumulative production has increased 41% since 2016.

Discovery Natural Resources Snapshot

Net acreage	110,000
Counties	Reagan, Irion, Glasscock
Gross production (boe/d)	26,195

drill anything less than a 10,000-foot lateral," Turk said.

Infrastructure is in place to handle development. "Our east-well Bell Corridor ranges from 4 to 7 miles in width, and we have solid infrastructure in place. We leveraged our experience and the saltwater disposal assets that we developed during the vertical phase of this asset, and now we have water infrastructure where we can move both fresh and salt water.

"This gives us the advantage and moves our horizontal drilling costs down into the $2/bbl range. We have plans to extend this infrastructure to the northeastern and southeastern part of our acreage to fully access and move water to points where it is most needed. This allows us to move into what we call rolling development phase."

This phase allows the company to simultaneously develop five zones in the Wolfcamp: two in the A, two in the B and one in the C, and it also limits parent-child impacts, Turk explained.

"In rolling development we build two pads, put two rigs on those pads and drill 10 to 12 wells. Then we move the rigs off and come in and complete those wells. Then we move next door and build an additional couple of pads and begin drilling those wells. At this time, we turn on the first pad, but the pad in between the new area and the previously developed area of two pads is dormant—we're not turning them on, to mitigate any parent-child issues that might be present."

Turk said Discovery Natural is focused on technology to optimize the asset. Some 95% of the acreage has seismic data, and the team uses various models such as the geo-cellular model, the earth model, reservoir models and a frack model to optimize results. The company can drill a 10,000-foot lateral and frack it with more than 2,000 pounds of sand per foot for roughly $6 million. Operating costs have also come down.

"This year we'll be able to drive our fully loaded operating costs down below $10 a barrel, and that does include G&A," he said.

The southern Midland Basin is a great neighborhood, Turk said, with some of the offset operators including Pioneer Natural Resources Corp. and Apache Corp., although this area is now dominated by private E&Ps. Initial efforts by the industry in the 2010 to 2014 period led to the basin's reputation as being too gassy and potentially not as good as the northern Midland. Too, many of the largest operators left to focus on the Delaware Basin. However, with new technology being applied and modern fracks, the returns are significantly better or competitive with other basins, not only in Texas but elsewhere, Turk said. Many operators have returned since the 2016 downturn. Since 2017, over 1,000 horizontal wells have been drilled in the southern Midland.

Turk said the higher costs found in the northern Midland Basin, and the higher oil content, are offset by lower entry and lower drilling costs in the southern portion of the basin. NGL uplift also helps. A low oil-to-water ratio of about 2-1 mitigates some of the issues found in the Delaware, where the water cut is much higher and disposal issues are more acute. □

Henry Resources LLC

Long-time family operator weighs decision to "mow down or slow down."

Henry Resources LLC shifted its efforts to horizontal drilling during the past few years, which has proven to be profitable, said president David Bledsoe. A long-time Midland oil operator, the company's CEO, Jim Henry, was credited with discovering the Wolfberry play, the largest Midland Basin discovery in more than 50 years.

In 2013, Henry Resources turned its attention to the horizontal potential in the Midland Basin, and the company drilled its first Spraberry/Wolfcamp wells in 2014, said Bledsoe, who has 33 years of oil and gas experience and joined Henry Resources in 2007. Bledsoe spent six years at Occidental Petroleum in the business development group. Prior to that, he was the division engineering manager at Bass Enterprises, where he worked for 11 years. Bledsoe worked for Amoco Production before moving to Bass.

By 2015, Henry Resources turned its capital focus to horizontal drilling, said Bledsoe. Since 2012, the company has drilled and completed around 240 vertical wells as well as 72 horizontal wells since 2014.

The company is currently running one horizontal rig although it laid down a second rig in March. For the past three years, Henry has run one horizontal rig consistently as long as there was enough cash flow, he said.

The company's strategy now is to make "fringe in the core" instead of the opposite.

"This is the thing we're wrestling with the most today," Henry Resources president David Bledsoe said, regarding multibench development. "As a small operator, we don't have real deep pockets."

Henry Resources Snapshot

Gross acreage	18,700
Counties	Midland, Upton, Ector, Martin, Reeves, Crane
Producing wells	153

Its plan is to cobble together difficult acreage, making it drillable in the core, he said.

Unlike vertical drilling, where the company could take some operational and financial risk, Henry Resources cannot take any geological risk in horizontal drilling, Bledsoe said. "We've stuck to the core acreage, drilling $8- to $10 million wells. If it's not economic, it's painful; we can't afford to do that."

The strategy of the company now includes a "plan with the end in mind" and includes testing all target benches first, Bledsoe said. He reiterated that early testing for spacing is important because it dictates the parent-child well relationships for the rest of the development life and also dictates well spacing.

Henry is adapting to horizontal development vs. vertical development. "If you're going to mow down a section, then you're going to spend $80- to $100 million before you get a drop of oil out of the ground. [That's] a deep, deep capital hole. That is a significant issue for a small, capital-constrained operator," he said.

The alternative, he said, is to slow down and drill smaller four- to six-well pads, rotating on and off the section every six to 12 months, which smooths out cash flow. However, that strategy elevates the risk of parent-child well degradation.

"This is the thing we're wrestling with the most today. As a small operator, we don't have real deep pockets."

The company currently produces about 8,000 net bbl/d, an all-time high, he said. Reserve growth in the company has increased from 8 million boe in 2013 to 28 million boe today.

One of company's strategies is to maintain nearly no debt or a low debt position, "not because the capital markets tell me to, but because I have a man down the hall telling me to," he said, referring to Jim Henry. "You've got to keep our name in the phone book." But the company has a line of credit that is used to meet cash flow needs occasionally, Bledsoe said, which is usually paid off in four to six months.

In the Delaware Basin, the company has 1,900 gross acres and two producing wells with plans to run one to two rigs during the next three years. The company's project, Wild Turkey, in Reeves County, includes 1,280 gross acres with two PDP wells with plans to drill 12 wells during the next two years.

The deal for Wild Turkey was signed in July 2018 with a waning lease, leaving Henry Resources with only 17 days to move its rig from the Midland Basin to cross the lease line before it expired in August. By November, the company had two wells online and is currently drilling a three-well pad.

In the Central Basin Platform, Henry has 2,800 gross acres and 13 vertical PDP wells. The company is also planning to run one rig over the next year, but is considering divesting it to fund its horizontal projects.

In the Midland Basin, Henry operates about 14,000 gross acres with 138 PDP wells, including 100 low-risk locations in inventory. The goal is to run one to two rigs during the next three years.

The company continues to operate its BITS joint venture in Midland County with Chevron. It involves 3,100 gross acres in which Henry holds a 25% working interest. In addition to prior vertical wells, since 2015, Henry has drilled 29 horizontal wells into the Lower Spraberry and one Wolfcamp A well, which Bledsoe characterized as "very good" considering it's at the edge of the platform.

Henry is budgeting $80- to $140 million annually over the next three years to keep one to two horizontal rigs in action. It will maintain one vertical rig for another year to drill up its Crane County acreage. □

Scala Energy LLC

Far western Delaware explorer finds profit on the fringe.

The risk that Houston-based Scala Energy LLC took when the company was formed is paying off, said Allen May, executive vice president of business development and exploration. Scala Energy has concentrated its drilling program on the western edge of the Delaware Basin in Texas, a place private-equity-backed companies had avoided. Now, Scala has 38,000 net acres in the basin with 12 wells down and is targeting up to $1 billion invested in assets.

"We think it's the best basin in the world," May said. "The western Delaware is a good place to make money."

In 2012, before Scala was founded, the western Delaware Basin had little vertical production and limited Wolfcamp logs, May said. Early horizontal explorers experienced high gas volumes but little oil in the Lower Wolfcamp, and uneconomic oil volumes in the Bone Spring. These hurdles discouraged oil companies and private-equity companies from being interested in this part of the basin.

The company received an equity commitment of $500 million from EnCap Investments in 2015 to go farther west, and made its initial purchase from Panther Energy in 2017. Scala is led by CEO Steve Hinchman, who formerly served as CEO of HighMount E&P. And the step-out is paying off, May said.

"You can see the density of drilling that's happened [since then], there are develop-

Scala Energy Snapshot

Net acreage	37,426
Counties	Culberson
Gross production (boe/d)	13,000
Backers	EnCap Investments

ments out here and there are multibench tests all throughout," he said. "We've drilled the most western well in the basin now, and it's an Upper Wolfcamp well. That's the sweet spot."

The western progression of increasing oil/liquids/gas volumes has risen rapidly: the average 12-month cumulative for wells drilled in 2012 was 100,000 boe compared to the average 12-month cumulative in 2018 at 400,000 boe.

The assets in the western basin are tightly held by three companies—Scala Energy, Chevron and Cimarex Energy.

Scala's first long-lateral well, the Norman, drilled in 2017 in the Upper Wolfcamp A, is an "awesome well that came on with a 30-day IP of 942 barrels of oil a day, 584 barrels of NGL and 3,607 Mcf per day of residue gas," May said. "It's a very strong well." After producing for the past two years, this well has been holding up "very well," he said, aided by the gas in production. In the first 12 months it produced 200,000 bbl of oil.

"Most people thought it was pretty much a gas play before this well was drilled."

The company is receiving 61% liquids from its wells with half consisting of oil and half gas liquids, while the remaining is "a lot" of residue gas. "Waha is really hurting us right now, but there are so many liquids in this that we're still making really good returns from the Mcfs on our wells."

Scala stimulations pump some 2,500 pounds per foot on 2-mile laterals. Scala has identified three landing zones in Upper Wolfcamp Sands, but the Lower Wolfcamp is even thicker, with two landing targets in C and two in D—"so that's playing out well."

The big question of pressurization has been answered, he said. "The Wolfcamp is overpressured all the way out to our western acreage," which also leads to lower declines.

Another advantage of the region is the 4,100-foot column of pay across 11 benches. "There's a lot of organic rock in there, and it's very rich," May said. But not all are created equal.

"The Upper Wolfcamp and Lower Third Bone are the most economic right now, but the C and the D are coming on really strong in the Wolfcamp. It will be a play that carries on for a very long time because of all these benches."

Neighbor Cimarex drilled a Third Bone Sand well last year, and "it's the biggest oil well on this west side right now. It's right next to us, so the Bone Spring is moving our way and we think that's going to play out well."

"We've drilled the most western well in the basin now, and it's an Upper Wolfcamp well," said Allen May, executive vice president of business development and exploration for Scala Energy. "That's the sweet spot."

Infrastructure is a challenge in the western desert, he confessed: there isn't any. "We've had to put everything in," including a gathering system and two saltwater disposal wells. "We do everything we can to avoid trucking water." The infrastructure is planned with the intent of developing the asset, he said.

Scala production reached 13,000 boe/d this year, including 2,800 bbl/d of oil and 4,400 bbl of NGL. The company plans to continue to delineate westward, including a test with Chevron upcoming, and to scale up development later this year and into next.

Cimarex and Chevron have moved into full development in several locations in the Upper and Lower Wolfcamp, and Scala Energy plans to move to full development in 2019.

"One of the challenges is how much do we put in the cube if we move into development?" he asked. A Scala cube development would include at least the Upper Wolfcamp zones, possibly Lower Wolfcamp as well, and potentially a Bone Spring well. "That cube [development] should start by the end of the year." □

Zarvona Energy LLC

Making a play on the Permian's Lower Barnett.

Zarvona Energy's bet on the Permian Basin Lower Barnett Oil Play is emerging as a lucrative decision.

The privately held oil and gas company, headquartered in Houston, was founded in 2010 by Kathryn MacAskie, who was previously senior vice president of acquisitions for EV Energy Partners. Zarvona Energy was backed through a joint venture with Salient Partners in 2011. The company currently holds interests in West and East Texas, Louisiana and western Oklahoma. It has invested over $600 million in acquisitions and capital projects since inception with more than 400 operated wells generating 19,000 boe/d.

"We're finding emerging plays in existing basins," said Rob MacAskie, Zarvona CFO and vice president of acquisitions. "We're looking to make them into highly economic developable opportunities."

Such is the case in the Lower Barnett play. Zarvona holds 25,000 net acres prospective for the Lower Barnett in Andrews County, Texas, with rights in three core areas: South Andrews, Big Max and North Andrews.

While the Mississippian-aged Barnett Shale Formation has historically been developed horizontally in the Fort Worth and Anadarko basins, the Permian has a large accumulation "that has not been produced almost at all," said MacAskie.

"We've found a way to produce economically, and it's been an execution-focused story."

Historically, companies faced hurdles drilling in the region because of the high clay content in the shale, he said. Wells that exhibited high IPs went to zero pretty quickly, he noted. Instead, Zarvona targets its landing zone 50 feet or so below the shale into the Upper Mississippian Lime, a shaley carbonate, also called the Lower Barnett.

"As long as you … stay below the Barnett Shale, you can typically make a pretty good well," MacAskie said. "It's highly frackable and very easy to complete." And though the lateral is below the shale, most of the production comes from the shale itself, he said.

The history of the south Andrews County Lower Barnett play began when Zarvona drilled its first vertical well, the University Cobra #3012, to test potential horizontal performance of multiple landing points from Clearfork through the base of the Mississippi Lime.

"We were very bullish on the amount of oil," he said. "We wanted to make sure we could execute it."

The company's process included fracking each potential landing point and performing tracer analysis to assess the long-term production performance. The log and tracer analysis indicated that the Lower Barnett play of shaley carbonate held the best potential for economic horizontal development.

Through the testing, the company chose to focus its drilling efforts on the Lower Barnett region.

"It's a phenomenal, low cost resource to produce," MacAskie said. "The economic viability is both on the topline and bottom line with high margin producers and very low maintenance. It's just a great asset to have."

In 2016, Zarvona, in partnership with Elevation Resources, drilled a discovery well in the Lower Barnett in Andrews County—University 1-30 #1H. The EUR for the well is 880 Mboe (60% oil; 75% liquids), with 350,000 bbl accumulated to date from a 5,500-foot lateral. Importantly, the well exhibited a mere 5% water cut.

Zarvona Energy Snapshot

Net acreage	39,000
Counties	Andrews, Ector
Producing wells	19
Other regions	East Texas/Louisiana, Oklahoma

Since, the Elevation/Zarvona partnership has drilled 19 Lower Barnett wells, which average 300,000 boe in the first 435 days (80% oil; less than 20% water post-flowback). Other companies that have drilled or permitted wells in the area include Occidental Petroleum, XTO Energy Inc. and Diamondback.

The company's 10 Lower Barnett horizontal wells are currently producing from the South Andrews and Big Max areas, with an additional six wells waiting on completion. Total gross production currently exceeds 6,000 boe/d (70% oil). Zarvona said that its future wells are planned for 10,000-foot laterals or greater.

Current EUR for a 2-mile lateral is 1.2 MMbbl of oil, and about 2 MMboe EUR (80% liquids). "That's a great resource from a single lateral. That gets you to an economic return of about $14 million net PV-10 and about 100% IRR on a 10,000-foot well." This is on a $10 million well cost, improving to $8 million on pad drilling.

But the Lower Barnett does not exist in just Andrews County, and MacAskie is confident it's present across the Permian Basin. Zarvona joined with Novo Oil & Gas in Ector County on a contiguous 14,000-acre position to test the concept. Geology and preliminary well tests indicate that this county could produce results similar to those achieved in the South Andrews area. The initial Zarvona test well (Cowden #602H) was spudded recently.

While MacAskie contends it is exciting to be part of an emerging play, he reiterates that the Permian Basin was itself emerging a decade ago. "This is one of the many opportunities to continue looking for new developed resources across the Permian and existing positions," he said. □

Rob MacAskie, Zarvona Energy CFO and vice president of acquisitions, said the Lower Barnett oil play has barely been tapped historically. "We've found a way to produce economically, and it's been an execution-focused story."

Occidental Wins Anadarko, Chevron Walks

THE TAKEAWAY FROM the **Anadarko Petroleum Corp.** merger sweepstakes depends greatly on perspective.

Occidental Petroleum Corp. prevailed with a cash-rich offer totaling $57 billion, including the assumption of debt. **Chevron Corp.** initially stirred the waters on April 12 with an agreement to buy Occidental for $48 billion, including debt. On May 9, Chevron declined to up the ante.

The Occidental camp saw its aggressive bidding—and in particular the wrangling of a contingency agreement with **Total SA** to buy Anadarko's Africa assets for $8.8 billion—as a creative bit of deal making.

Chevron, on the other hand, will pocket a $1 billion termination fee from Occidental, with **Wells Fargo Securities** senior analyst Roger D. Read saying the integrated oil and gas company won "by not overpaying."

Chevron has now shifted its plans, saying it would increase its share repurchase rate by 25% to $5 billion per year, according to a press release from the San Ramon, Calif.-based company.

Anadarko had originally agreed to be acquired by Chevron in a 75% stock and 50% cash transaction worth roughly $33 billion plus the assumption of $15 billion net debt. However, Houston-based Occidental, which had been rumored to be courting Anadarko, kicked off a takeover battle on April 24 by taking its roughly $57 billion offer, including debt, public. Occidental CEO Vicki Hollub even took to CNBC to make her case for why Anadarko was a natural fit for her company.

Chevron declined to enter a bidding war for Anadarko despite having the firepower.

"While it has the financial capacity to match Occidental Petroleum's offer, had it raised the cash portion of the consideration to compete with Oxy it would have materially increased its financial leverage and weakened its credit profile," Pete Speer, **Moody's Investors Service** senior vice president, said in an emailed statement.

Instead, Chevron chose capital discipline and conservative financial policies, Speer added.

"Winning in any environment doesn't mean winning at any cost," said Chevron chairman and CEO Michael Wirth, in a statement. "Cost and capital discipline always matter, and we will not dilute our returns or erode value for our shareholders for the sake of doing a deal."

Drillinginfo Inc. M&A analyst Andrew Dittmar noted Occidental management "fought hard and pulled out all the stops" to make the deal with Anadarko happen, though he noted it all came down to Chevron's reputation for conservative decision-making.

Still, "losing Anadarko probably stings a bit, given how strong a fit those assets were for Chevron," Dittmar said in an emailed statement.

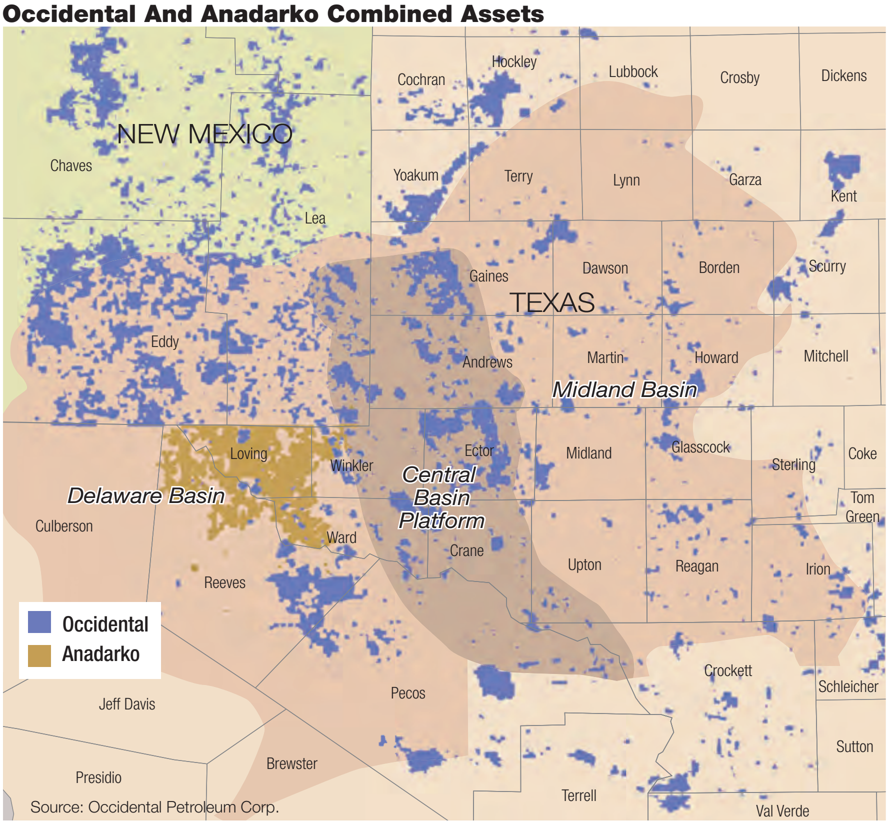
Largely believed to be key to the takeover battle is Anadarko's nearly 600,000-gross-acre position in the Permian's Delaware Basin. The portfolio of Anadarko—one of the world's largest independent E&P companies—also includes deepwater projects offshore Africa and in the U.S. Gulf of Mexico plus a position in Colorado's Denver-Julesburg Basin.

Dittmar doesn't see any pressure for Chevron to turn around and do another deal now that the company has walked away from the Anadarko acquisition.

"However, should Chevron choose to make a move, we expect they would initially be looking at the larger Permian-focused independents, especially those with substantial core acreage in the Delaware Basin," he said. "It's a relatively short list of companies there that can move the needle for Chevron."

Since taking its bid public, Occidental continued to sweeten its takeover offer for Anadarko by adding an up to $10 billion investment from Warren Buffet's **Berkshire Hathaway Inc.** plus agreeing to divest Anadarko's African assets.

Occidental And Anadarko Combined Assets



Source: Occidental Petroleum Corp.

The company also continued to revise its offer by boosting the cash portion of its bid to 78% on May 5. The increase—the equivalent of about $10.5 billion—made Occidental's bid 23% higher than Chevron's offer with a materially larger cash component, according to Greig Aitken, director of M&A research at global natural resources consultancy **Wood Mackenzie**.

"With added certainty around Oxy's ability to complete the deal, it will be very difficult for Anadarko not to accept," Aitken said in an emailed statement May 6. "Chevron has the firepower to increase its offer but will have to decide whether it also has the appetite."

Even though Occidental might have outmaneuvered Chevron, Moody's view of a weakly positioned investment grade outcome for Occidental after a merger with Anadarko does not change.

"With the proceeds of the sale of assets to Total directed to debt reduction defraying a significant portion of the $12 billion increase in the cash component of [Occidental's] revised proposal to acquire Anadarko, under the revised offer we continue to believe that [Occidental] would likely emerge from the review for downgrade with a weakly positioned investment grade rating," Moody's vice president Andrew Brooks said May 8.

Occidental had said it anticipated closing a merger transaction with Anadarko in the second half of 2019. The company's takeover offer for Anadarko does not require an Occidental shareholder vote.

Occidental also expects to close the African asset sale, which includes Anadarko's Algeria, Ghana, Mozambique and South Africa assets, simultaneously with the Anadarko transaction or "as soon as reasonably practicable afterwards."

The company's financial advisers for its Anadarko takeover offer are **BofA Merrill Lynch** and **Citi**, and **Cravath, Swaine & Moore LLP** is its legal adviser. **Evercore** and **Goldman Sachs & Co. LLC** are acting as financial advisers to Anadarko. **Wachtell, Lipton, Rosen & Katz** is Anadarko's legal adviser.

Credit Suisse Securities (USA) LLC was Chevron's financial adviser for the Anadarko merger transaction and **Paul, Weiss, Rifkind, Wharton & Garrison LLP** was the company's legal adviser.

—Emily Patsy

Amplify Energy, Midstates Petroleum To Merge

INDEPENDENT U.S. OIL and gas producers, **Amplify Energy Corp**. and **Midstates Petroleum Co. Inc**., agreed May 6 to a "merger-of-equals" through an all-stock combination expected to enhance their scale.

Amplify's operations are focused in the Rockies, offshore California, East Texas/North Louisiana and South Texas. Meanwhile, Midstates has a position in the Mississippian Lime play in Oklahoma. Combined, the companies produced about 40,000 boe/d during fourth-quarter 2018.

Pro forma, the total enterprise value of the combined company will be greater than $720 million with a market cap of more than $430 million. The companies expect annual G&A synergies of at least $20 million from the combination.

The combined company will be headquartered in Houston and trade on the New York Stock Exchange under the ticker AMPY.

Amplify's president and CEO Ken Mariani will lead the combined company. The new board of directors will include members who currently serve on the Amplify and Midstates boards.

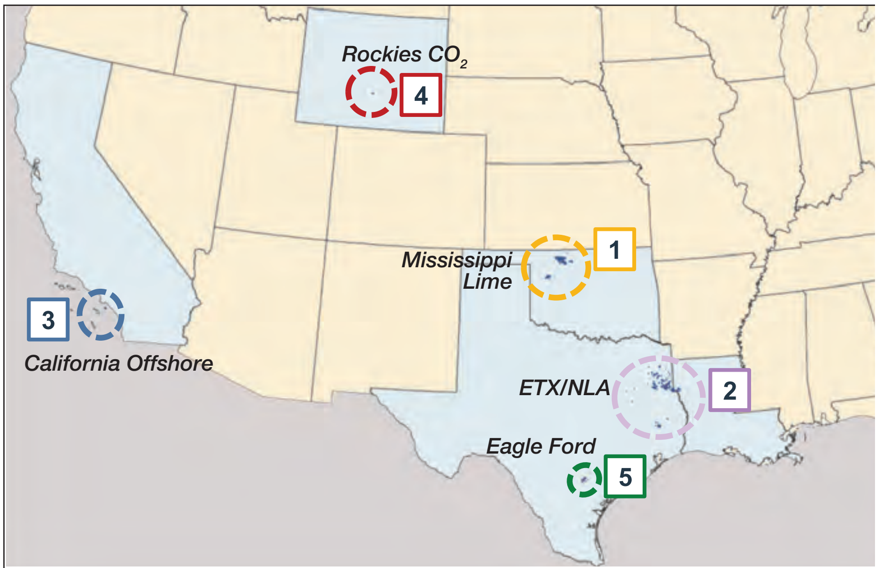
Under the terms of the merger agreement, Amplify stockholders will receive 0.933 shares of newly issued Midstates common stock for each Amplify share of common stock.

At closing, expected third-quarter 2019, Amplify and Midstates stockholders will each own 50% of the outstanding shares of the combined company.

Amplify's financial adviser for the transaction is **UBS Investment Bank** and its legal adviser is **Kirkland & Ellis LLP**. **Houlihan Lokey Capital Inc.** is Midstates' financial adviser, and its legal adviser is **Latham & Watkins LLP**.

—Emily Patsy

Combined Amplify/Midstates Assets



	Asset	SEC PD PV-10 ($ MM)	Strip PD PV-10 ($ MM)	Strip 1P PV-10 ($ MM)	Net Production (Mboe/d)
1	Miss. Lime	$433	$350	$444	16.4
2	ETX / NLA	$294	$230	$236	15.5
3	California Offshore	$257	$187	$270	3.1
4	Rockies CO_2	$253	$151	$194	4.1
5	Eagle Ford	$50	$42	$70	1.1
	Pro Forma	$1,288	$960	$1,214	~40.1

Source: Amplify Energy Corp.; Midstates Petroleum Co. Inc.

LLOG, Repsol Strike GoM Development Deal

LLOG EXPLORATION Offshore LLC signed a deal on April 29 to collaborate with an affiliate of Spain's **Repsol SA** on the development of deepwater assets in the U.S. Gulf of Mexico (GoM).

LLOG, based in Covington, La., is one of the largest privately owned E&P companies in the U.S. Its deal with Repsol follows a multibillion-dollar sale of deepwater assets in the GoM region to **Murphy Oil Corp.** announced April 23.

The agreement with Repsol covers Keathley Canyon blocks including the exchange of working interest in the Leon and Moccasin deepwater discoveries. The companies currently collaborate on the Buckskin development, also located within the Keathley Canyon.

Leon is a discovery drilled by Repsol in late 2014 on Keathley Canyon Block 642 and is located about 200 miles offshore Louisiana in about 6,000 feet of water. Meanwhile, Moccasin, operated by LLOG, is a discovery made on Keathley Canyon 736 in 2011 in more than 6,500 feet of water.

In part of the agreement, Repsol will acquire a 30% working interest in the Moccasin discovery with LLOG retaining a 31.35% interest. In exchange, LLOG will take a 33% interest in Leon while Repsol will have a 50% interest.

Moccasin and Leon are less than 20 miles apart, which Philip LeJeune, president and CEO of LLOG, said provides the "perfect" opportunity for co-development.

The agreement will provide for the drilling of a delineation well in the Leon discovery this coming summer, which will be operated by LLOG. Following the scheduled delineation drilling, potential development options will be evaluated for the field.

"We have worked well together at Buckskin and the delineation of the potentially significant discoveries at Leon and Moccasin is another perfect match for the deepwater technical knowledge and development expertise that both our companies possess," LeJeune said in a statement. "These highly prospective deepwater discoveries are in close proximity and are targeting the same Lower Tertiary Formation that we are exploiting at Buckskin."

The Leon discovery well was drilled to a total depth of about 32,000 feet and encountered nearly 500 feet of high-quality net oil pay in multiple sands in the Lower Tertiary Formation.

The Moccasin discovery well was drilled to a total depth of over 31,000 feet finding nearly 400 feet of net oil in the Lower Tertiary. LLOG subsequently licensed the block in a 2017 lease sale.

The transaction with Murphy, expected to close during the second quarter, included 26 deepwater blocks in the GoM's Mississippi Canyon and Green Canyon areas. Consideration for the transaction comprised roughly $1.4 billion in cash plus up to $250 million in contingency payments.

—Emily Patsy

Riviera Resources Jettisons Hugoton

RIVIERA RESOURCES INC. agreed to divest its Hugoton Basin assets on April 29 as the Houston-based company simplifies the multibasin portfolio it inherited from **Linn Energy**.

Riviera, an independent oil and gas company formed through a spin-off from Linn last year, said it agreed to sell the assets located in southwest Kansas to an undisclosed buyer for a contract price of $31 million.

The Hugoton assets comprise 2,300 nonoperated wells throughout the basin with proved developed reserves of about 74 billion cubic feet equivalent (Bcfe). The proved developed PV-10 value of the assets is about $30 million, the company said.

Earlier this year, Riviera closed the sale of its Arkoma Basin position for $68 million, which the company used to pay off its debt. When asked by an analyst about future asset sales during the company earnings call in February, Riviera COO Dan Furbee said the company will continue to be opportunistic.

"When you look at the upstream assets, we're in five different operating areas," Furbee said, according to a transcript of the call by Seeking Alpha. "I think that's something that you'd like to kind of simplify and have a story that's a little easier to understand."

Furbee didn't provide a timeline for any further asset sales the company might be targeting.

Through its spin-off from Linn in August 2018, Riviera added a portfolio of mature producing properties throughout the U.S. Additionally, the company took control of **Blue Mountain Midstream**, a midstream operator focused in the heart of the Merge play in central Oklahoma.

Riviera's portfolio currently includes positions in the Northwest Stack play, East Texas, North Louisiana, Michigan/Illinois and the Uinta Basin as well as the Hugoton Basin. During fourth-quarter 2018, the company produced about 274 million cubic feet equivalent per day (MMcfe/d) net. The company's assets have a roughly 10% base decline rate.

The Hugoton Basin, geographically centered in southwest Kansas, is Riviera's largest producing asset, according to the company website.

Riviera's wells in the Hugoton Basin primarily produce natural gas, NGL and helium from the Council Grove and Chase formations at depths ranging from 2,200 to 3,100 feet. The company produced roughly 130 MMcfe/d net from its Hugoton position in the fourth quarter of 2018.

The Hugoton production at its Jayhawk Plant, a cryogenic gas processing plant located in southwest Kansas, has roughly 450 Mcf/d of processing capacity. Production from Riviera's divested Hugoton properties will continue to be processed at the Jayhawk plant, the company said.

Riviera expects to close the sale in the second quarter of 2019. The transaction will have an effective date of March 1.

—Emily Patsy

Diamondback Shakes Loose Rattler Midstream

DIAMONDBACK ENERGY INC. launched the IPO of its midstream subsidiary on May 13 with proceeds earmarked to pay down the Permian Basin producer's debt.

Diamondback is offering about 33.3 million common units of **Rattler Midstream LP** priced between $16 and $19, plus a 5-million-share greenshoe option. The offering represents a roughly 22% limited partner interest, or 25% with the option exercised, in Rattler. The balance will be owned by Diamondback and its subsidiaries.

At the midpoint of the IPO range of $17.50 per unit, Gabriele Sorbara, principal and senior equity analyst with **Williams Capital Group LP**, estimates the enterprise value of Rattler Midstream at $2.64 billion, in line with the firm's valuation of between $2.4 billion and $3.1 billion.

Rattler Midstream was formed in July 2018 by Midland, Texas-based Diamondback to own, operate, develop and acquire midstream infrastructure assets in the Midland and Delaware sub-basins of the Permian Basin, where oil and gas production has soared.

Diamondback had initially planned for its Rattler Midstream subsidiary to make its public debut last year. However, despite filing the regulatory documents to take Rattler public in early August 2018, energy IPOs came to a full stop in the second half of last year thanks to commodity volatility, particularly in crude markets.

"Several IPOs were taken off the market," Christopher George, director of **Drillinginfo**'s Capitalize tracking platform, told Hart Energy earlier this year. "We had five S-1s across the sectors get pulled that did not go public. When price is the driver of valuation and the commodity price tanks, nobody wants to sell at a perceived discount."

As of March 31, Rattler Midstream holds 781 miles of pipeline with roughly 232,000 barrels per day (bbl/d) of crude oil gathering capacity, 2.720 MMbbl/d of permitted saltwater disposal capacity, 575,000 bbl/d of freshwater gathering capacity, 80 MMcf/d of natural gas compression capability and 150 MMcf/d of natural gas gathering capacity, according to filings with the U.S. Securities and Exchange Commission.

Additionally, Rattler Midstream owns equity interests in two long-haul crude oil pipelines—EPIC Crude Oil Pipeline and the Gray Oak Pipeline—which, upon completion, will run from the Permian Basin to the Texas Gulf Coast.

Rattler expects to list its common units on the NASDAQ Global Select Market under the ticker symbol RTLR.

Net proceeds from the IPO are expected to total roughly $546 million or $628 million with the greenshoe option fully exercised, Sorbara said. All proceeds from the offering will be distributed back to Diamondback, which he expects will be used to pay down a portion of the borrowings drawn on the company's revolver.

"While the [Rattler] IPO was expected to be commenced after [first-quarter 2019] results and the valuation was in line with our expectations, we believe the execution of the transaction will be viewed as positive, as it provides the paydown of debt and optionality going forward," he said in a research note on May 13.

During its first-quarter earnings announcement on May 7, Diamondback also revealed the sale of noncore assets with proceeds planned to reduce debt and fund a $2 billion share buyback program.

The noncore asset sales include 103,423 net acres in the Central Basin Platform, Eastern Shelf and the Northwest Shelf the company acquired in the Energen acquisition. Diamondback is also selling 6,589 net acres in the southern Midland Basin in Crockett and Reagan counties, Texas.

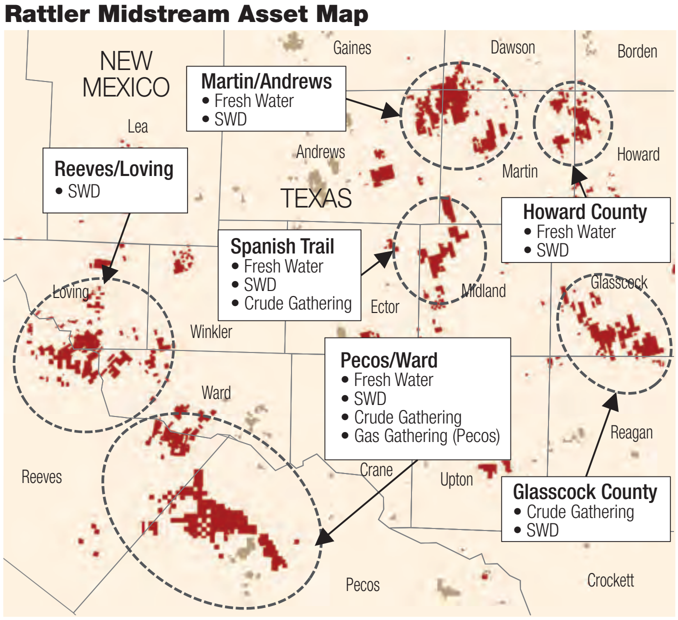
The assets for sale average estimated net production of about 6,500 boe/d for the full year 2019 from about 3,000 producing wells, according to a company press release.

Credit Suisse, **BofA Merrill Lynch** and **J.P. Morgan** are lead book-running managers for the Rattler IPO. **Barclays**, **Citigroup**, **Goldman Sachs & Co. LLC** and **Wells Fargo Securities** are also acting as joint book-running managers.

Capital One Securities, **Scotia Howard Weil**, **SunTrust Robinson Humphrey** and **UBS Investment Bank** are senior co-managers for the offering. **Evercore ISI**, **Morgan Stanley**, **RBC Capital Markets**, **Simmons Energy**, a division of **Piper Jaffray, Tudor, Pickering, Holt & Co.**, **Raymond James**, **Seaport Global Securities**, **Northland Capital Markets**, **PNC Capital Markets LLC** and **TD Securities** are also acting as co-managers.

—*Emily Patsy*

Rattler Midstream Asset Map



Activist Investor Pushing Carrizo Sale

CARRIZO OIL & GAS Inc. appears to be taking in stride an activist investor's demands, which include the company exploring a merger or sale.

In a regulatory filing, **Lion Point Master LP** disclosed a 5.1% stake in the company and said it acquired Carrizo's shares because they are undervalued and represent an "attractive investment opportunity," the filing said.

Lion Point contends that shareholder value would be enhanced, were Carrizo to pursue a potential merger or broader sales to other operators.

A merger, according to Lion Point, would:

- Build the size and scale of its Permian Basin operations;
- Increase cash flow through overhead reductions and operations cost reductions;
- Reduce Carrizo's leverage profile, improving its valuation while reducing risk; and
- Improve focus on core assets and exploring potential divestitures following a merger.

Lion Point's chief investment officer, Didric Cederholm, who is a founding partner, was behind a similar push at **Resolute Energy Corp**. **Cimarex Energy Co.** purchased Resolute on March 1 in a deal valued at $1.6 billion.

On May 6, Carrizo said the company would not comment on specific discussions with shareholders. In a press release, the company said it welcomes engagement with shareholders and "seriously considers all suggestions that may enhance shareholder value."

During the company May 8 earnings call, Chip Johnson, Carrizo's co-founder, president and CEO, said he supposed "anybody who has an activist [investor] needs to get some advisers that are used to dealing with activists.

"We have to engage the activists because they are shareholders, and they often have good ideas," he said. "That's all we can say about that."

Activist investors have sprung up in the oil and gas space in the past 18 months. Most recently, activist investor Carl Icahn took a position in **Occidental Petroleum Corp**., which has been negotiating its successful bid to acquire **Anadarko Petroleum Corp.**

This year, activists such as **Fir Tree Partners** forced management changes at **Halcón Resources Corp.** and called for the company to sell. On May 7, activist **Kimmeridge Energy Management Co.**, which owns 5.1% of **PDC Energy Inc.**, compelled the company to accept the nomination of three new board members.

Carrizo has targeted cash-flow neutrality by third-quarter 2019, with free cash flow beyond that targeted to debt reduction, **Capital One Securities** analysts said on May 8. The company also beat its oil production guidance in the first quarter by 3%.

The company also said that efficiency gains and cost savings have contributed to a 35% year-over-year reduction in capex. The company operates in the Eagle Ford Shale and Delaware Basin.

—Darren Barbee

Pioneer Takes Just $25 Million Upfront For Eagle Ford Assets

PIONEER Natural Resources Co. completed its transformation into a pure-play Permian Basin company with the sale of its remaining South Texas assets for up to $475 million.

Privately owned producer **Ensign Natural Resources LLC** agreed to buy Pioneer's Eagle Ford Shale assets comprising roughly 59,000 net acres located primarily in Bee, DeWitt, Karnes and Live Oak counties in South Texas. Net production from the assets averaged roughly 14,000 barrels of oil equivalent per day (boe/d) during the first quarter.

Ensign, backed by **Warburg Pincus LLC** and **Kayne Anderson Capital Advisors LP**, paid $25 million at closing for the assets. Pioneer expects to receive the remaining $450 million contingent on future commodity prices between 2023 and 2025.

At that price, Pioneer effectively gave away its Eagle Ford Shale assets, according to Gabriele Sorbara, principal and senior equity analysts with **Williams Capital Group LP**.

Sorbara noted he had estimated Pioneer's assets were worth between $200 million and $250 million. Though, he added that the sale reduced the company's cost structure burden and completed its pure-play transition.

"Overall, while the price tag is clearly disappointing, the company removed the significant operating costs from the minimum volume commitments [although, 80% of the forecasted remaining minimum volume commitments is carried as a liability on Pioneer's balance sheet] and transitioned the company to pure-play Midland Basin operator," he said in a research note on May 7.

The assets sold represent all of Pioneer's remaining interests in the field, including all of its producing wells and the associated infrastructure. With the divestment, Pioneer achieves its Permian pure-play goal, which the company has been working toward for over a year.

In total, Pioneer has sold roughly $1 billion worth of assets located outside the Permian Basin. As a result, the company is left with about 680,000 net acres in the Midland Basin with a resource base of more than 10 Bboe.

"With the Eagle Ford divestiture closed, Pioneer is now a 'pure-play' Permian company, with decades of high-margin drilling inventory," Scott D. Sheffield, Pioneer president and CEO, said in a statement on May 6. "The actions we are undertaking position us for success now and into the future, delivering strong results and increasing shareholder value. We plan to increase our dividend to approximately a 1% yield, underscoring our commitment to returning capital and continuing our journey of enhancing shareholder value."

Sheffield, Pioneer's founding CEO who had retired in 2016, returned to his former role earlier this year.

Pioneer also plans to sell its gas processing midstream assets during the year, which Sheffield said he expects will result in capital savings and increased free cash flow. The data room opened for Pioneer's 27% interest in the Midland Basin gas processing infrastructure operated by **Targa Resources Corp.**

Pioneer anticipates executing the sale of midstream assets this year. The sale of Pioneer's remaining South Texas assets to Ensign is expected to result in a pretax noncash loss of $400- to $550 million during the second quarter of 2019, according to the company press release.

Ensign was formed by CEO Brett Pennington, who previously served as senior vice president at **Murphy Oil Corp.**, in late 2017 in partnership with Warburg Pincus. As part of the acquisition from Pioneer, the company has also secured an equity commitment from the **Kayne Private Energy Income Funds**.

"We are excited to announce our first acquisition. These assets include both meaningful existing production and years of attractive drilling inventory," Pennington said in a statement May 7. "We will continue to evaluate additional acquisition opportunities in the Eagle Ford and look forward to working with our equity sponsors to create value."

BMO Capital Markets was exclusive financial adviser and **Kirkland & Ellis LLP** acted as legal counsel to Ensign for the transaction. In addition, BMO Capital Markets, along with **Citigroup Global Markets Inc**., provided an underwritten commitment for debt financing as part of the acquisition. Also, **Willkie Farr & Gallagher LLP** represented **Kayne Anderson Capital Advisors** in its equity commitment in Ensign. The Willkie deal team was led by partners Steven Torello and Michael De Voe Piazza.

—Emily Patsy

Pioneer's Eagle Ford Sale

Total potential proceeds ($MM)	$475
Upfront proceeds ($MM)	$25
Contingent payments ($MM)	$450
Acres	59,000
South Texas counties	Bee, DeWitt, Karnes, Live Oak
Production 1Q19 (boe/d)	14,000
Expected noncash loss 2Q19 ($MM)	$400 to $550

Source: Pioneer Natural Resources Co.

TRANSACTION HIGHLIGHTS

GOM

■ **Equinor ASA** boosted its holdings in deepwater U.S. Gulf of Mexico (GoM) on May 13 through a $965 million cash acquisition from a **Royal Dutch Shell Plc** subsidiary.

The Norwegian energy company, already one of the largest producers in the GoM, said it agreed to acquire an additional 22.45% interest in the Caesar Tonga oil field from **Shell Offshore Inc.**

The acquisition, made through an exercise of preferential rights, boosts Equinor's interest in Caesar Tonga to 46% from 23.55%. **Anadarko Petroleum Corp.** will remain the operator of Caesar Tonga with a 33.75% interest. **Chevron Corp.** also retains its 20.25% interest.

Caesar Tonga Field is located 180 miles south-southwest of New Orleans in the Green Canyon area and is one of the largest deepwater resources in the U.S. GoM, according to Equinor's press release. Equinor's current net share of production from Caesar Tonga is 18,600 boe/d.

PERMIAN

■ **PDC Energy Inc.** agreed to sell Permian Basin midstream assets on May 1 as the Denver-based E&P continues to face pressure from shareholder activist.

The sale included PDC Energy's gas and water midstream assets in the Delaware Basin through two separate agreements worth roughly $310 million of total cash proceeds. The company also authorized a $200 million stock repurchase plan, which along with the divestitures helped PDC offset a first-quarter miss, said Gabriele Sorbara, principal and senior equity analyst at **Williams Capital Group LP**.

PDC reported a net loss for the first quarter of $120.2 million, or $1.82 per share. The company's first-quarter production was 125,000 boe/d, an increase of 26% from first-quarter 2018.

SAN JOAQUIN BASIN

■ **California Resources Corp.** said May 2 it sold a 50% working interest in the Lost Hills Field of the San Joaquin Basin for about $200 million.

The buyer was not disclosed. The deal transferred operatorship of the field to the buyer, which paid $168 million in cash and agreed to a carried 200-well development program with a minimum value of $35 million, the company said.

California Resources said the value per flowing barrel of oil was $88,000. The company used the sale proceeds to pay down debt.

NORTH SEA

■ Israel's **Delek Group** confirmed on April 28 it submitted a proposal through its Ithaca unit to buy **Chevron Corp.**'s oil and gas fields in the British North Sea.

Reuters reported that Delek offered about $2 billion for the assets. Delek said it believed that if a deal is reached, it could be completed in 2019 and would be financed through bank loans and its own resources. Delek's strategy is to expand its international operations.

THE TWO SIDES OF CONSOLIDATION

RICHARD MASON, CHIEF TECHNICAL DIRECTOR

Occidental Petroleum Corp.'s $38 billion acquisition of Anadarko Petroleum Corp. revives the simmering conversation advocating for industry consolidation.

The deal's rationale includes acreage access, cost reduction and an opportunity to achieve manufacturing efficiencies long-promised but infrequently realized.

Shale plays evolve in a progression from discovery and delineation to optimization to full-field development. Each phase requires different management and technical skills. The ability to amass acreage or nimbly respond to geological and engineering challenges is different than the skills required to transition organizationally from geologic prospecting to reservoir engineering or full-field harvest, where supply chain mastery dominates.

The industry begins shale play development as Aubrey McClendon's Chesapeake model but exits on the long tail of gradual decline as the EnerVest model. Different management teams excel at different stages. Organizational challenges generally prevent a single management team from being the best across all phases of shale evolution, whether the benchmark is capital efficiency or technical proficiency. It took a village of multifaceted and diverse management approaches to accelerate shale development. Indeed, the absence of a diverse universe of players accounts for the slow traction of tight formation progress outside North America.

And that makes calls for industry consolidation a curious theory. Does the Haynesville need just two players instead of 12 to 15? How about the Marcellus, or the Permian? Reality suggests that one or two acreage conglomerates seldom yield the same stimulus to successful development found in a regionally Balkanized industry.

Outside the post-World War II move to bifurcate the industry into specialty sectors such as standalone oil service providers or E&P companies, the call for consolidation has been the main theme for the past six decades among those offering opinions on just what the industry needs.

When times were tough in the late 1990s, consolidation provided a way forward, giving us ExxonMobil Corp., Chevron/Gulf/Texaco, ConocoPhillips Co. and BP Amoco. The ensuing acreage spin-offs provided an opportunity for growth for the Devons, Apaches, Chesapeakes, Ranges and Continentals that spurred the tight formation revolution.

Later, the multinationals jumped into the shale revolution after the influx of cash from international joint ventures ran its course. Integrated international oil and gas companies injected nearly $100 billion in the 2006 to 2011 time period, illustrated by M&A involving ConocoPhillips/Burlington ($35.6 billion), ExxonMobil/XTO ($41 billion) and BHP/Petrohawk ($15.1 billion). All entered to pursue natural gas development.

Indeed, consolidation has been the recommended solution to every problem facing the industry regardless of circumstance, sort of the Aramco approach for developing oil and gas reserves. Obviously, the business model works for Saudi Aramco, the world's largest and most profitable business. But is consolidation the best model for U.S. oil and gas? After all, the last large consolidation round found Marathon and ConocoPhillips splitting upstream and downstream operations, Shell buying in and then exiting onshore U.S. tight formation gas, while BP sold out but is now buying back in. BHP, which spent $15 billion to buy in, exited with a $10 billion sale. Meanwhile, oil replaced gas as the main industry objective after all that IOC spending.

On the other hand, small, nimble independents provide disruptive change in all industries including oil and gas, a sector challenged by discontinuities between commodity price and technical prowess. At the end of the day, creative entrepreneurship stands separate from the benign evolutionary contributions in supply chain management and capital allocation by committee that find expression in the largest companies.

Furthermore, selling, general and administrative expense reduction doesn't mean net fewer players or result in aggregate sector cost reduction. Rather, consolidation spins out astute management teams who, with private-equity backing, deploy specialized technical knowledge to create the next round of industry progress. ConocoPhillips may have acquired Burlington Resources' assets, but displaced Burlington human capital begat Diamondback Energy Inc., Oasis Petroleum Inc. and skilled leadership for a handful of independents. For Anadarko Petroleum, the king is dead. For industry progress, long live the king.

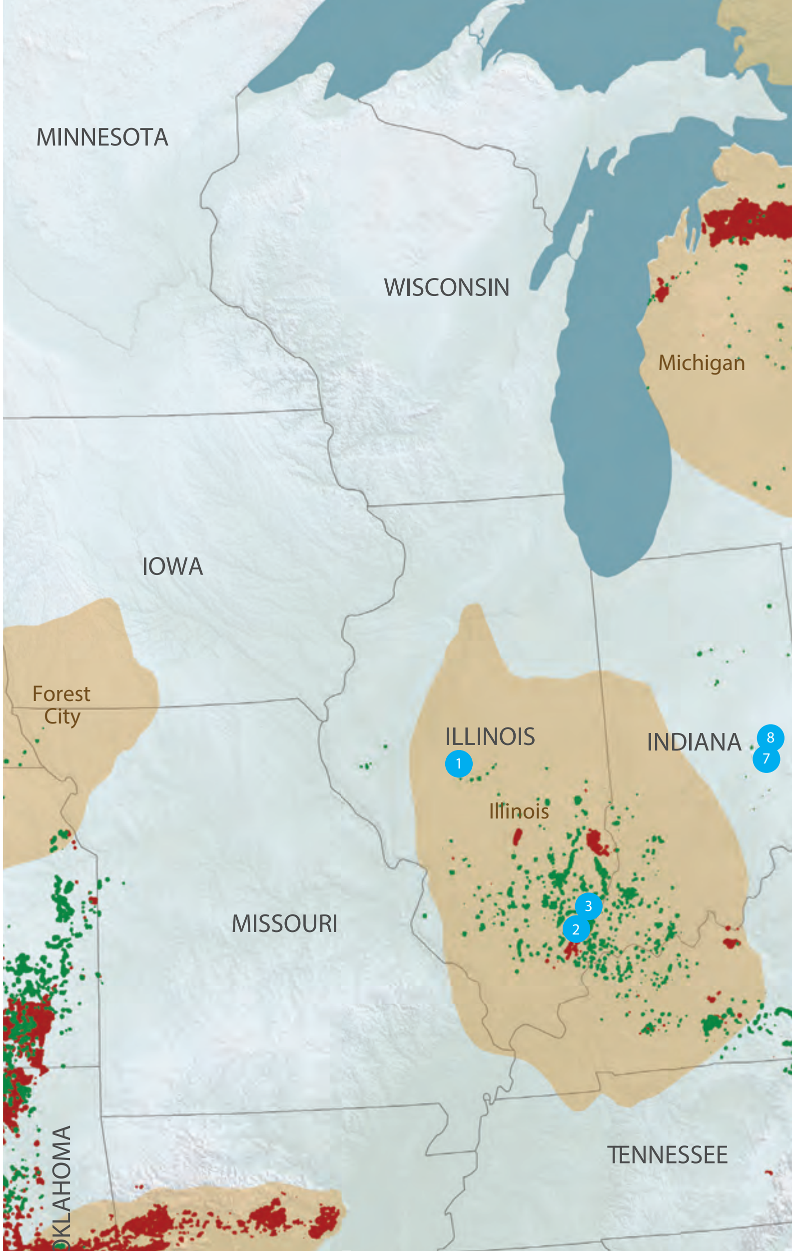
EASTERN U.S.

1 According to IHS Markit, ***Landgas Exploration & Production*** has set 5 1/2-in. production casing to 1,650 ft at the company's first two wildcats in Sangamon County, Ill. The #1 Theilen is currently waiting on completion tools. It is in Section 27-15n-6w and it was drilled to 1,998 ft. In Section 27, 5 1/2-in. casing has been set to 1,550 ft at #2 Theilen. It was drilled to 1,600 ft. Both of Landgas' wildcats are targeting oil pays in the Trenton. Few wildcats have been drilled in this part of Sangamon County. One earlier test, #1 Workman in Section 28, was abandoned in 1939 at 1,903 ft in Trenton. Nearby production is about 10 miles east of the Landgas program. Opened in 1960, wells in Springfield East Field yield crude from Silurian. Landgas E&P is based in Edinburg, Ill.

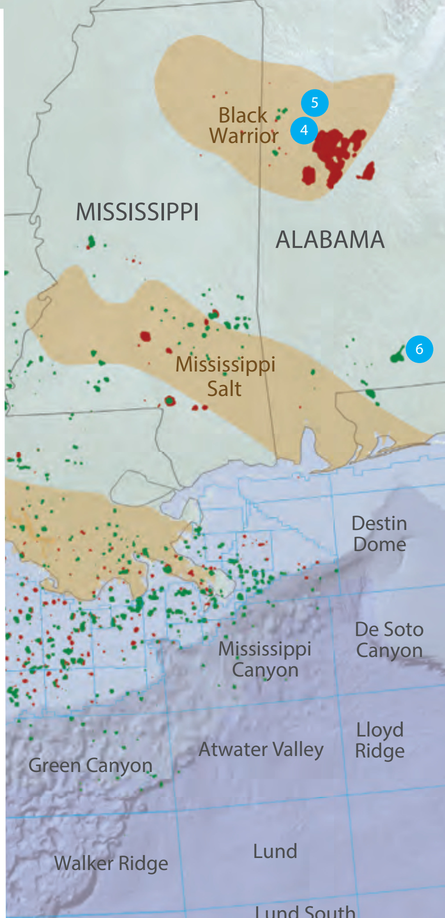
2 Carmi, Ill.-based ***Campbell Energy LLC*** has released plans for a 32-well program in Posey County, Ind. IHS Markit reported that the operator's scheduled tests are planned for various sites along the far southern edge of Griffin Consolidated Field. Each of the company's vertical development tests has planned depths of 4,200 ft and will be targeting oil pays in Fort Payne. The tests will be drilled from sites in sections 3, 8, 9, 10 and 17 in township 5s-14w. The first well to be drilled in the Ribeyre lease will be #16 Ribeyre. Numerous Griffin Consolidated Field wells have been drilled in the area surrounding Campbell's new locations. Griffin Consolidated Field, which came online in the 1930s, extends about 15 miles northeast of Campbell Energy's new locations on the lease. The company operates numerous wells in the field about 8 miles northeast of the new ventures. The field produces from multiple Mississippian pays. Southwest of Campbell's planned Posey County tests are several Fort Payne oil tests in Illinois' White County permitted by the company in 2019. Campbell's program in White County is designed to extend Fort Payne production into Maunie North Consolidated Field. The company's latest proposed deeper pool wildcats, #11, #12 and #13 Kempf, will be drilled in Section 19-5s-14w and the planned depths are about 4,400 ft.

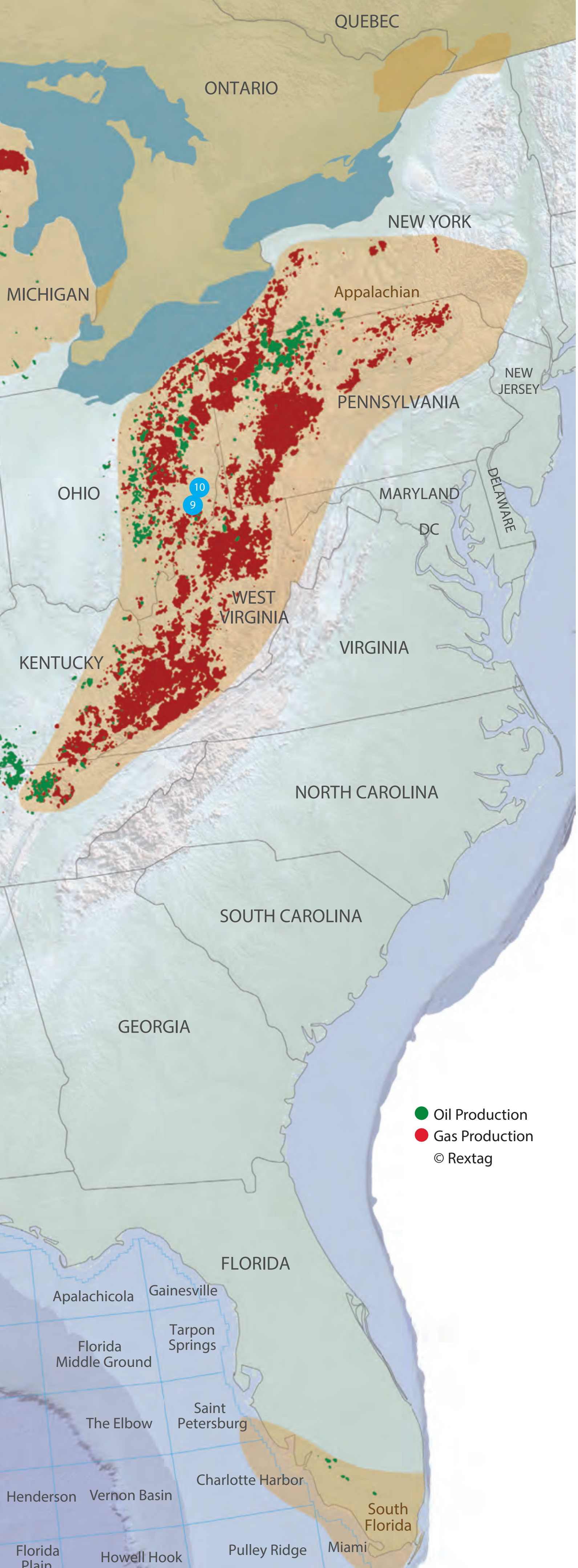
3 ***Campbell Energy LLC*** has been granted permits for four Ft. Payne tests in the White County, Ill., portion of New Harmony Consolidated Field Two wells, #1 Barger-Potter and #10 Cantrell Calvin Hon Unit, will be in Section 9-4s-14w. The #1 Barger-Potter has a planned depth of 4,300 ft. The #10 Cantrell Calvin Hon Unit has a planned depth of 4,200 ft. Two wells, #1 Barger-LP Cox and #2 Barger-LP Cox, will be in Section 8-4s-14w. The #1 Barger-LP Cox has a planned depth of 4,300 ft and the #2 Barger-LP Cox has a planned depth of 4,250 ft.

4 A 5,250-ft wildcat has been scheduled in Pickens County, Ala., by ***Jabsco Oil Operating Inc.*** The venture, #1 Carver 26-11, will be in Section 26-18s-13w. Nearby gas production in this part of the Black Warrior Basin is about 4 miles to the southwest in Elmore Creek Field. ***Land & Natural Resource Development***'s #1 Irvin 5-6 was tested in 2009 flowing 273 Mcf of gas per day from Lewis Sand at 5,216-32 ft. Three other Elmore Creek Field wells remain online, with two wells producing gas from Fayette Sand at 2,944-86 ft and one from Carter Sand at 4,987-5,000 ft. Through 2018, the wells have recovered a combined 358 MMcf of gas. About 5 miles to the northwest of Jabsco's planned wildcat is Lubbub Creek Field, which yields gas from Fayette Sand at around 2,250 ft and the deeper Lewis Sand. Jabsco is based in Tuscaloosa, Ala.



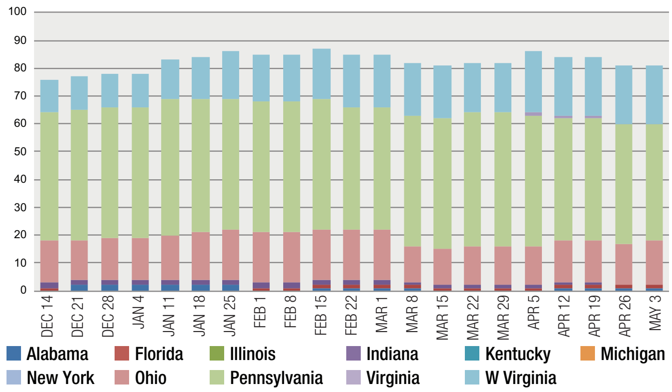
5 In Fayette County, Ala., ***Natural Gas & Oil Inc.*** plans to re-enter a Black Warrior Basin gas well. Located in Section 19-17s-12w, #2 Berry 18-4 will be re-entered to 3,460 ft. The McCracken Mountain Field well was originally drilled by the company in 1994 to 4,080 ft. It produced from Millerella at 3,588-3,610 ft flowing 81 Mcf of gas per day. It produced sporadically through early 2016 and to-date recovery is 13.2 MMcf of gas. Nearby production in the field is to the southwest at #1 Horace Berry 18-4. The 1981 completion in McCracken Mountain Field well was tested flowing 3 bbl of crude per day from Carter Sand at 3,662-70 ft and, during its one year online, it produced 1.228 Mbbl of crude. Fayetteville, Ala.-based Natural Gas & Oil recompleted the well in 2000 as a Lewis Sand gas well, and it produced 52 Mcf of gas per day from perforations at 4,024-36 ft—recovery through the end of 2018 was 124 MMcf of gas.





Eastern U.S. Rig Count

Dec. 14, 2018-May. 3, 2019



Data compiled from Baker Hughes

6 Dallas-based ***Ventex Operating Corp.*** has added a Smackover test to the company's program in southern Alabama. Located in Conecuh County, #1 Cedar Creek Land & Timber 16-2 will be in Section 16-3n-13e and has a planned depth of 12,500 ft—a successful completion would be the second producer in Sepulga River Field. The field was opened in 2014 at ***Fletcher Petroleum***'s #1 Hart 17-16 in Escambia County was tested flowing 400 bbl of 47.7-degree-gravity crude, 520 Mcf of gas and 18 bbl of water per day from Smackover at 12,038-52 ft. The completion is in Section 17-3n-13e and about 1 mile southwest of Ventex's planned venture. It has produced 56.268 Mbbl of crude and 11.2 MMcf of gas. Ventex and Fletcher have ongoing Smackover programs in this part of Alabama and are focused on extending Brooklyn Field to the southeast. Ventex also has received a permit for directional test at #1 Pate 12-12 in Section 12-3n-13e, and it has a planned true vertical depth of 12,200 ft.

7 A Trenton gas producer was reported in Decatur County, Ind., by Greenburg, Ind.-based ***Richard & Pam Morrow Co.*** The #1 Morrow is in Section 31-10n-9e in Trenton Field. The completion was drilled to 905 ft and produced 18 Mcf of gas per day from perforations at 881-905 ft. Additional testing is planned at the Cincinnati Arch Basin venture.

8 A vertical Trenton gas completion, #1 Miller, was completed by ***Timothy Miller Co.*** The Trenton Field well flowed 20 Mcf of gas per day and it is in Section 21-9n-9e of Decatur County, Ind. The well was drilled to a projected depth of 1,000 ft and production is from an openhole zone at 875-907 ft. Timothy Miller is based in Westport, Ind.

9 ***Eclipse Resources Corp.*** has scheduled two Cameron Field-Utica Shale wells in Monroe County, Ohio. The #4H B Pyles is in Section 20-4n-4w and it has a planned depth of 22,417 ft and it will be drilled to the southeast. The #8H Pyles C is in Section 13-4n-4w and has a planned of 22,462 ft, and it will be drilled to the south. In the same section as #8H Pyles C, the State College, Pa.-based company has a permit for another venture, #6H A Pyles, and it has a projected depth of 22,441 ft and it will be drilled to the southwest.

10 ***Gulfport Energy Corp.*** has received permits for three horizontal Utica Shale-Key Consolidated Field wells in Belmont County Ohio. The ventures will be drilled form a drillpad on a 665-acre lease in Section 18, Armstrongs Mills 7.5 Quad. The #2A Fankhauser 210035 has a projected depth of 26,150 ft. The #3B Fankhauser 210035 has a planned depth of 24,300 ft. The #4A Fankhauser 210735 has a planned depth of 24,300 ft. Gulfport Energy is based in Oklahoma City.

GULF COAST

1 In the Hawkville Field portion of Webb County (RRC Dist. 4), Texas, ***Pursuit Oil & Gas*** has tested an Eagle Ford Shale completion. The #1H La Santa Cruz-Rachal initially flowed 16.118 MMcf of gas and 922 bbl of water daily from acidized and fractured perforations at 11,476-19,445 ft. The well is on a 2,167-acre lease in Section 1364, C&M RR Co Survey, A-2553. It bottomed 2 miles to the northwest in Section 1367, C&M RR Co Survey, A-417, and was drilled to 19,578 ft. The true vertical depth is 10,660 ft. Pursuit's headquarters are in Houston.

2 A Wilcox gas well in Lavaca County (RRC Dist. 2), Texas, was tested flowing 3.4 MMcf of gas and 163 bbl of 51-degree-gravity condensate per day from perforations at 9,680-9,700 ft. Houston-based ***Lavaca Canyon Petroleum LLC***'s #1 BTK is a 9,900-ft sidetrack that was drilled in on a 352-acre Central Texas Coast lease in Samuel G. Hanks Survey, A-220. The original hole was abandoned at 8,802 ft. It was tested on a 12/64-in. choke and the flowing tubing pressure was 3,418 psi. It was placed in Campbell Creek Field.

3 ***Chesapeake Operating Inc.*** has tested two offsetting, extended-lateral Haynesville Shale wells in DeSoto Parish, La. The Caspiana Field wells were drilled from offsetting surface locations in Section 10-15n-14w and both bottomed about 2.5 miles to the north in Caddo Parish in Section 34-16n-14w. According to IHS Markit, #1-Alt Brown 10&3&34-15-14HC was completed in an acidized and fracture-treated interval at 12,142-23,203 ft flowing 31.241 MMcf of gas and 600 bbl of water per day. It was drilled to 23,249 ft, 11,721 ft true vertical, and was tested on a 30/64-in. choke with a flowing casing pressure of 7,442 psi. The offsetting #2-Alt Brown 10&3&34-15-14HC was tested flowing 30.924 MMcf of gas and 744 bbl of water per day. It was drilled to 22,909 ft, 11,626 ft true vertical. Production is from acidized and fracture-treated perforations at 11,902-22,868 ft. It was tested on a 29/64-in. choke and the flowing casing pressure was 7,692 psi. Chesapeake's headquarters are in Oklahoma City.

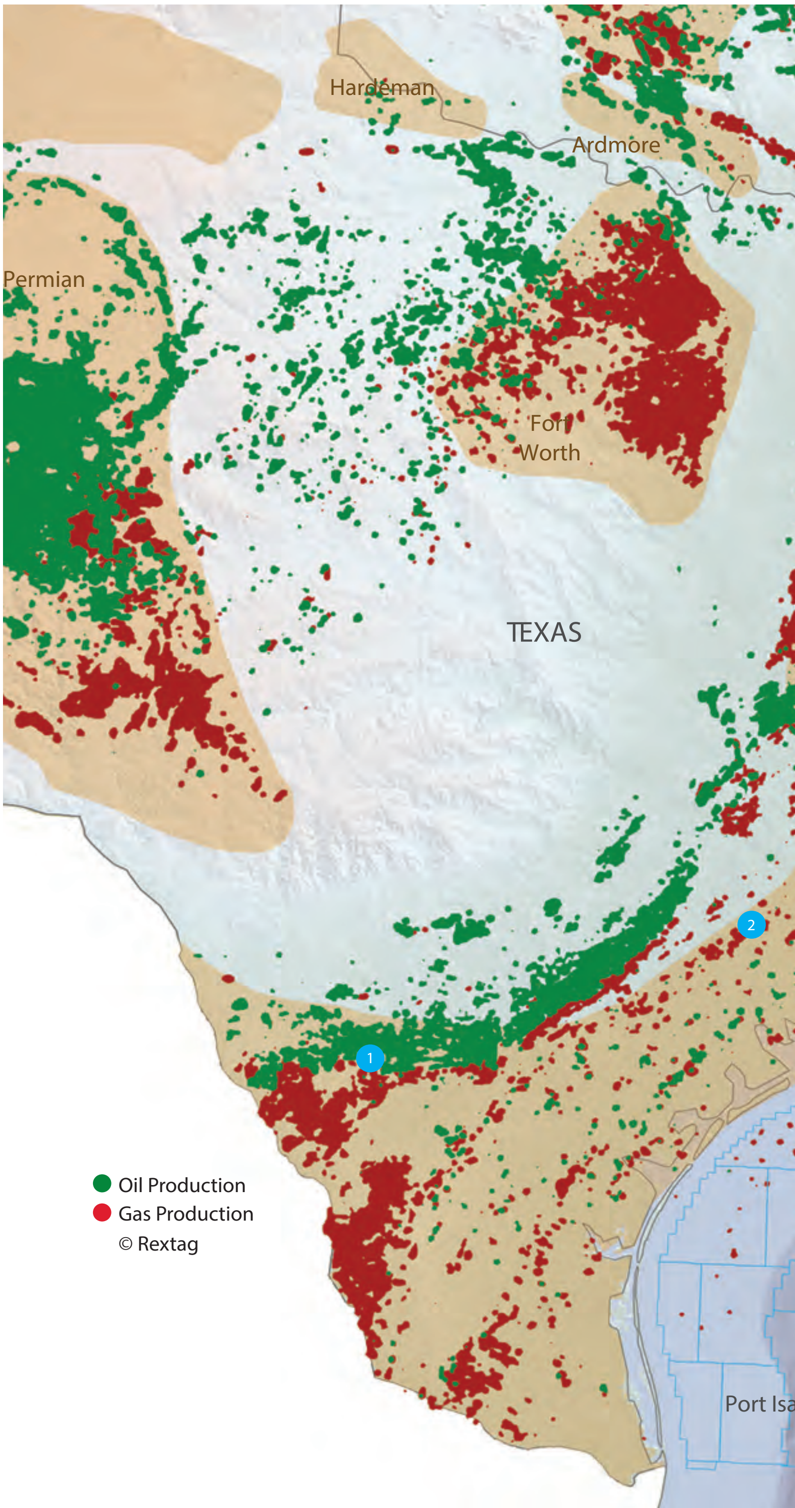
4 ***LLOG Exploration*** has filed a supplemental exploration plan to drill up to four tests on the company's Buckskin project. The development tests will be drilled from offsetting surface locations on Keathley Canyon Block 829 (OCS G25814)—two tests will bottom in Block 829 and two tests will bottom to the east in previously undrilled Block 830 (OCS G25815). Area water depth is 6,650 ft. The Buckskin discovery, #1 (BP) OCS G25823 on Keathley Canyon Block 872, was completed in 2009 by ***Chevron Corp.*** The deepwater find hit more than 300 ft of net pay in Lower Tertiary zones. Total depth is 29,404 ft. LLOG was the designated operator of the Buckskin leases in 2016 after Chevron decided to end the prospect's development. LLOG's headquarters are in Covington, La.

5 IHS Markit reported that ***ConocoPhillips Co.*** has completed the first Austin Chalk well in the company's horizontal program in East Feliciana Parish, La. The #1 McKowen is producing 60 bbl of 36.4-degree-gravity crude, 34 Mcf of gas and 3.498 Mbbl of water per day from perforations at 15,048-18,745 ft. Gauged on a 24/64-in. choke, the flowing casing pressure was 1,748 psi and the shut-in tubing pressure was 4,806 psi. It is in Section 58-3s-1w and was drilled to 19,161 ft in a sidetracked hole that bottomed about 1 mile to the southwest in Section 61 with a true vertical depth of 14,990 ft. The Houston-based operator's completion has opened a new pool in Freeland Field, a Tuscaloosa reservoir last active in 1988.

6 ***EnVen Energy Corp.*** has received approval for its deepwater Ouray prospect. Up to four exploratory tests are planned on Green Canyon Block 723 (OCS G35003) and Green Canyon Block 767 (OCS G35409). Only a few tests have been drilled on blocks 723 and 767 under previous leases, including a deep 32,685-ft exploratory test abandoned by ***Noble Energy Inc.*** in 2009. Nearby production is the east at ***Anadarko Petroleum Corp.***'s Ticonderoga (Green Canyon Block 768) Field, which was brought online in 2006 and produces from Pliocene at 11,975-12,597 ft and Middle Miocene at 12,637-13,060 ft. EnVen's headquarters are in Houston.

7 The first of up to six development tests has been permitted on Green Canyon Block 200 by ***Fieldwood Energy LLC***. The first well in the block will be #9TA OCS G12209 and water depth in the area is 2,500 ft. According to an exploration plan, the Houston-based company could drill as many as five more tests on the tract. Fieldwood took over as lease operator in August 2018. Through 2009, five wells in the southeastern portion of the tract recovered 117 MMbbl of crude/condensate and 245 Bcf of gas from Pliocene at 15,140-17,840 ft.

8 Billings, Mont.-based ***Rovig Minerals Inc.*** is planning to drill a directional Middle Miocene test



in Louisiana's Lake Boeuf Southwest Field. The Lafourche Parish venture, #2 Libby & Blouin, will be in irregular Section 114-15s-17e and it has a planned depth of 12,631 ft (12,200 ft true vertical). It will bottom within one-half mile to the east in irregular Section 95. The offsetting #1 Libby & Blouin was drilled in 2018 to 13,791 ft with a true vertical depth of 13,737 ft. The Lake Boeuf Southwest Field test was perforated at 11,858-11,884 ft in Miocene and no other details available. A third directional test is planned from about the same surface location: #1 Calvin P. Boudreaux has a planned depth of 12,750 ft (12,300 ft true vertical) and will bottom within 1 mile to the southeast in Section 49.

9 ***Chevron Corp.*** is underway at a development test in Big Foot Field. The #4-A (ST) OCS G16942 is in Walker Ridge Block 27. The original hole was drilled in 2012 to 22,445 ft in Miocene. Chevron's venture was temporarily abandoned with no other details available. Discovered in 2006, the Gulf of Mexico reservoir is estimated to contain total recoverable resources of more than 200 MMboe. Originally expected to come online in 2015, the Big Foot start-up was delayed because of damage to several subsea installation tendons.

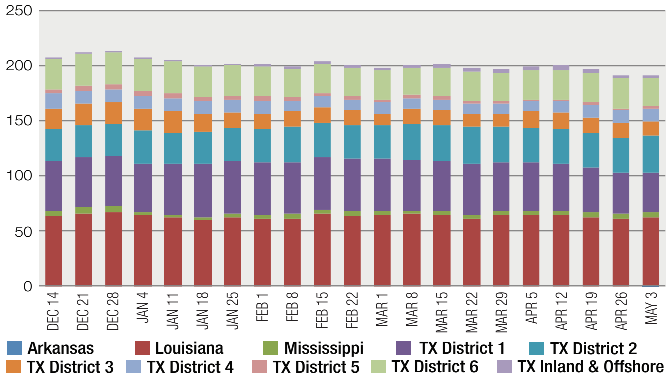
10 London-based ***BP Plc*** is underway at a development test as part of the company's Mad Dog Field expansion. The #9 OCS G09981 is in the northeastern portion of Green Canyon Block 825, and water depth in the area is 4,900 ft. BP discovered Mad Dog (Green Canyon Block 826) Field in 1998. The Mad Dog Phase 2 project is expected to come online in late 2021. The project will include a new floating production platform with the capacity to produce up to 140 Mbbl of crude per day.

11 ***W&T Offshore Inc.*** is underway at a deepwater development test in Mississippi Canyon Block 800 Field. The #2 OCS G18292 is in the southeastern portion of the tract and area water depth is 3,100 ft. The offsetting #1SS (ST) OCS G18292 was completed in 2008 at 16,870 ft and the lone producer on the lease has recovered 5.7 MMbbl of crude and 8 Bcf of gas from an Upper Miocene zone at 16,486-16,575 ft. The field is the only producing reservoir in this part of the Mississippi Canyon area. W&T is based in Houston.

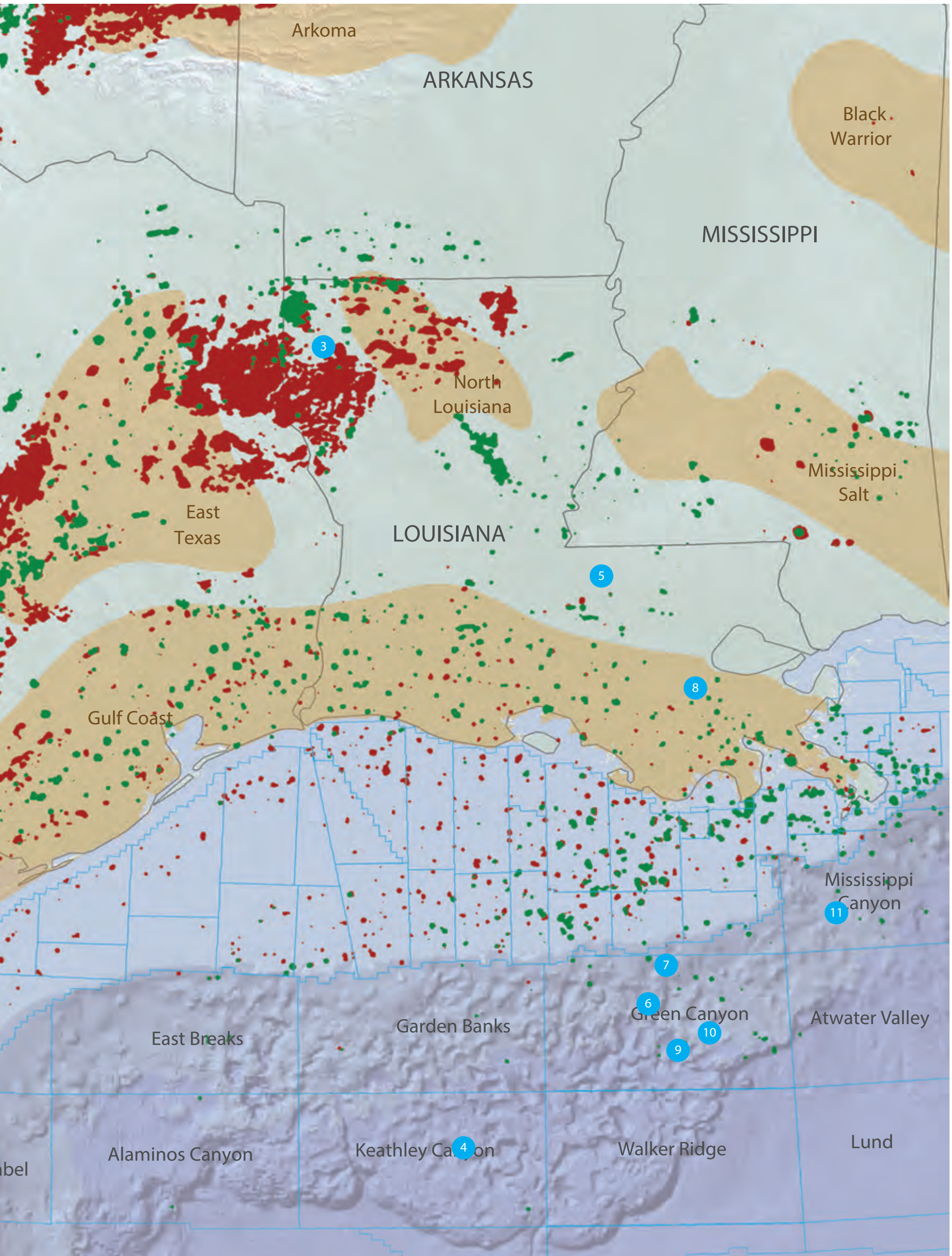
All data in the Exploration Highlights section are based on sources believed to be reliable, but accuracy cannot be guaranteed. In no way should publication of these items be construed as an express or implied endorsement of a company or its activities.

Gulf Coast Rig Count

Dec. 14, 2018-May. 3, 2019



Data compiled from Baker Hughes



MIDCONTINENT & PERMIAN BASIN

1 ***Oxy USA Inc.*** announced a Wolfcamp discovery in the Delaware Basin in Lea County, N.M. IHS Markit reported that the 22,047-ft #031H Lost Tank 30-19 Federal Com flowed 3.529 Mbbl of oil, with 6.854 MMcf of gas and 5.643 Mbbl of water per day. Production is from perforations at 12,097-22,048 ft following 50-stage fracturing. It is in Section 19-16s-032e, and it was drilled to the south with a true vertical depth of 11,778 ft and bottomed in Section 30-22s-32e. Tested on a 17/64-in. choke, the shut-in casing pressure was 2,131 psi. Oxy USA is based in Los Angeles.

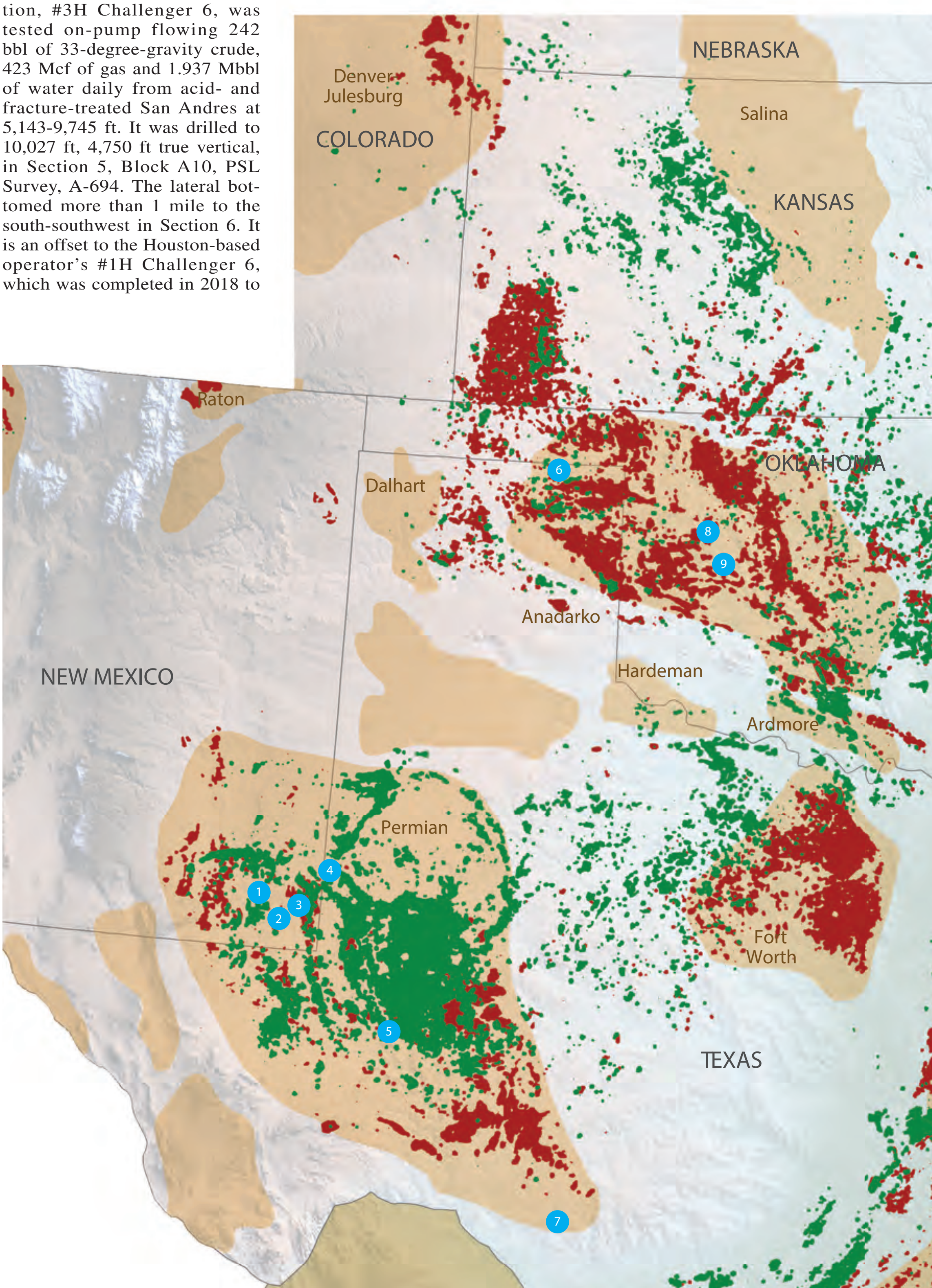
2 Two offsetting horizontal Permian Basin wells in Lea County, N.M., were completed from a drillpad in Section 28-24s-34e in Red Hills Field by ***EOG Resources Inc.*** The #301H Stonewall 28 Federal Com flowed 2.452 Mbbl of 39-degree-gravity crude, 3.761 MMcf of gas and 8.751 Mbbl of water per day from acid- and fracture-treated Wolfcamp perforations at 10,464-20,363 ft. It was drilled to 20,383 ft, and the lateral bottomed 2 miles to the south in Section 33 with a true vertical depth of 10,348 ft. The parallel #302H Stonewall 28 Federal Com flowed 2.733 Mbbl of 40-degree-gravity oil, 4.196 MMcf of gas and 7.297 Mbbl of water per day. It was drilled to 20,310 ft, 10,321 ft true vertical. Production is from acidized and fracture-treated perforations at 10,640-20,300 ft in Bone Spring. To the east on the same two-section lease, Houston-based EOG holds permits to drill 12 more extended-lateral Wolfcamp tests from four three-well pads.

3 ***EOG Resources Inc.*** completed two Third Bone Spring horizontal wells in Lea County, N.M., from a drillpad in Section 8-23s-35e in the northern Delaware Basin. The #601H Funky Monks 8 Federal Com flowed 1.412 Mbbl of 37-degree-gravity crude, 1.631 MMcf of gas and 4.492 Mbbl of water per day from 11,602-18,937 ft. It was tested on a 54/64-in. choke following 25-stage fracturing with a shut-in casing pressure of 373 psi. The Antelope Ridge North Field well was drilled to 18,938 ft and bottomed about 1.5 miles to the south in Section 17 with a true vertical depth of 11,483 ft. The parallel #602H Funky Monks 8 Federal Com flowed 1.172 Mbbl of oil, 1.344 MMcf of gas and 4.2 Mbbl of water daily from fracture-treated perforations at 11,570-18,921 ft. It was drilled to 18,922 ft, 11,516 ft true vertical, and tested on a 60/64-in. choke with a shut-in casing pressure of 391 psi.

4 A horizontal West Texas oil well in Gaines County (RRC Dist. 8A), Texas, was reported by ***Fortuna Resources Development LLC***. The Dempsey Creek Field completion, #3H Challenger 6, was tested on-pump flowing 242 bbl of 33-degree-gravity crude, 423 Mcf of gas and 1.937 Mbbl of water daily from acid- and fracture-treated San Andres at 5,143-9,745 ft. It was drilled to 10,027 ft, 4,750 ft true vertical, in Section 5, Block A10, PSL Survey, A-694. The lateral bottomed more than 1 mile to the south-southwest in Section 6. It is an offset to the Houston-based operator's #1H Challenger 6, which was completed in 2018 to extend horizontal production in Dempsey Creek Field.

5 An extended-lateral Wolfcamp well in the Spraberry Trend has been reported by ***Driftwood Energy Operating LLC*** in Upton County (RRC Dist. 7C), Texas. The #1H Sequoia had an initial daily pump rate of 1.018 Mbbl of 41.8-degree-gravity oil, with 573 Mcf of gas and 1.254 Mbbl of water per day, from acid- and fracture-stimulated perforations at 8,805-19,166 ft. The Midland Basin well was drilled to 19,272 ft. It is in Section 3, EL&RR Co Survey, A-136, and the true vertical depth is 8,503 ft. The well bottomed to the north in Section 25. Driftwood Energy is based in Dallas.

6 ***Amarillo Exploration Inc.***, based in Dallas, has completed two Texas Panhandle tests in Section 8, Block 1, WC RR Survey, A-700, in Hansford County (RRC Dist. 10), Texas. The #1MB Alexander was drilled to 8,650 ft and is producing from Mississippian St. Louis fracture-stimulated perforations at 7,514-7,685 ft. It flowed 82 bbl of 38-degree-gravity oil, 68 Mcf of gas and 515 bbl of water per day on gas lift. At a delineation test from the same pad, #2JG



Alexander produced 151 bbl of 38-degree-gravity oil, 234 Mcf of gas and 161 bbl of water during a 24-hour initial potential test run on gas lift. It was drilled to 7,861 ft and production is from a perforated and acidized St. Louis zone at 7,512-36 ft.

7 ***Sage Energy Co.***, according to IHS Markit, has completed a triple-lateral horizontal well in the western half of Pearsall Field. In the Dimmit County (RRC Dist. 1), Texas, portion of the reservoir, #1H Beeler flowed a combined 350 bbl of 38.9-degree-gravity crude, 175 Mcf of gas and 50 bbl of water per day through openhole zones at 5,575-10,376 ft, 5,575-10,653 ft and 5,575-10,691 ft. The well was completed in commingled zones in the Anacacho and Austin Chalk. One lateral bottomed about 1 mile to the northwest and was drilled to 10,653 ft (6,095 ft true vertical). The two other laterals bottomed within 1 mile to the southeast in Section 3, I&GN RR Co Survey, A-151. The Pearsall Field well is in Section 76, RT Co Survey, A-1464. Sage's headquarters are in San Antonio.

8 ***Continental Resources Inc.*** has completed two horizontal Meramec wells on a single-section unit in the Anadarko Basin-Stack play in Section 33-16n-13w of Blaine County, Okla. The #3-33H Lugene flowed 11.7 MMcf of gas per day with 1.884 Mbbl of 51-degree-gravity condensate and 2.418 Mbbl of water per day. Production is from acidized and fractured perforations between 11,650 and 16,283 ft. It was drilled to the south to 16,453 ft (11,758 ft true vertical). The initial potential test was run on a 36/64-in. choke with a flowing tubing pressure of 3,514 psi and a shut-in pressure of 4,712 psi. Within one-half mile to the west in Section 33-16n-13w, #2-33H Lugene was tested in a treated interval at 11,605-16,246 ft flowing 6.64 MMcf of gas, 723 bbl of 50-degree-gravity condensate and 8.301 Mbbl of water per day. It was tested on a 32/64-in. choke, and the respective shut-in and flowing tubing pressures were 5,439 psi and 2,848 psi. It was drilled to 16,417 ft and the true vertical depth is 11,736 ft. Continental's headquarters are in Oklahoma City.

9 A long-reach Meramec discovery by ***Devon Energy Corp.*** was tested flowing 23.4 MMcf of gas, 180 bbl of 52-degree-gravity condensate and 2.566 Mbbl of water per day. The Oklahoma City-based company's #1HX Mad Dog 31_30-14N-11W is in Section 31-14n-11w in Blaine County, Okla. Production is from a fracture-stimulated zone between 13,205 and 22,857 ft. It was drilled to the north to 23,082 ft, 12,911 ft true vertical, and bottomed in Section 30-14n-11w. Gauged on a 36/64-in. choke, the shut-in tubing pressure was 5,014 psi and the flowing tubing pressure was 2,850 psi.

10 Preliminary test results were announced by Tulsa, Okla.-based ***Trinity Operating & Production*** from two extended-lateral Woodford wells drilled on a common pad in Section 35-8n-17e of Pittsburg County, Okla. The #1-2/11H Marguerite is producing from acidized and fracture-stimulated zone at 8,360-18,560 ft flowing 7.8 MMcf of gas and 2.473 Mbbl of water per day. The flowing tubing pressure was 485 psi during testing on an open choke. The Arkoma Basin well was drilled to the south across Section 2-7n-17e to 18,730 ft (8,142 ft true vertical) and bottomed in Section 11-7n-17e. About 20 ft north on the pad, #2-2/11H Marguerite initially flowed 7.5 MMcf of gas and 3.427 Mbbl of water per day. It was drilled to 18,760 ft (8,117 ft true vertical) and was tested on an open choke. Production is from perforations between 8,366 and 18,598 ft in a parallel lateral that bottomed in Section 11-7n-17e.

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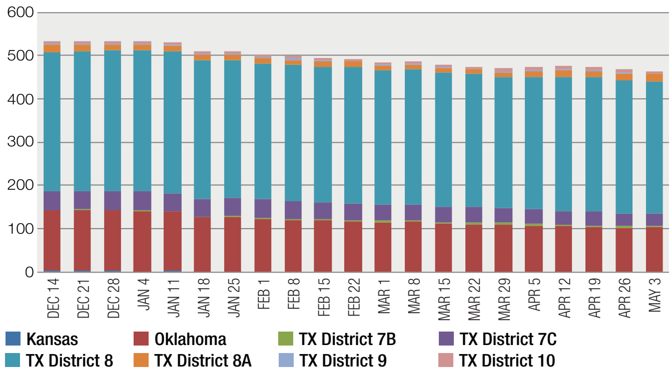
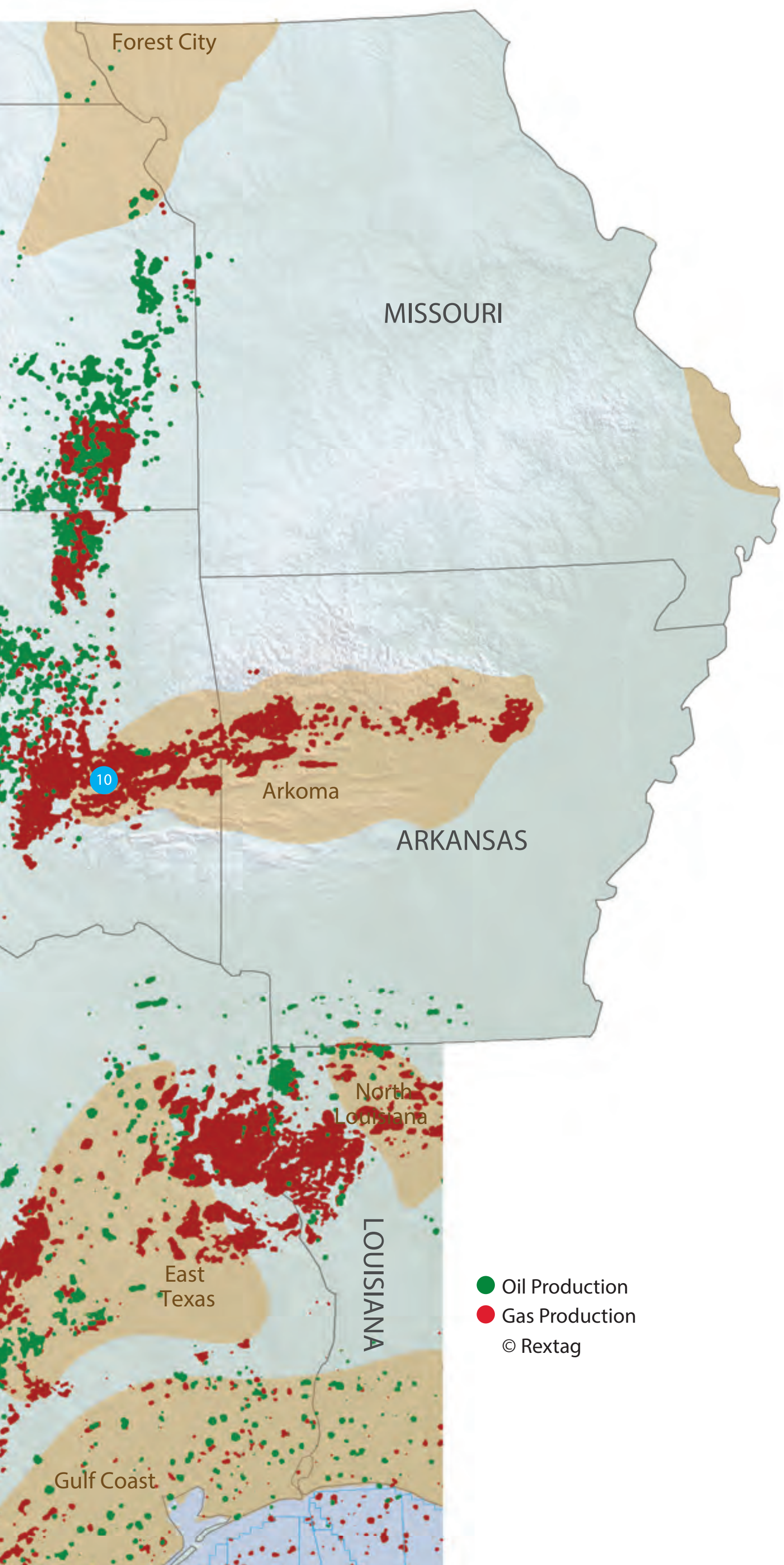
Midcontinent & Permian Basin Rig Count

Dec. 14, 2018-May. 3, 2019



Data compiled from Baker Hughes



WESTERN U.S.

1 ***Reabold Resources Plc*** reported a second oil discovery in California's Monroe Swell Field in Section 19-19s-7e in Monterey County, Calif. The #2B Burnett was drilled to 2,933 ft (2,850 ft true vertical) and hit the targeted Burnett and Lower Burnett sands. According to the company, significant oil and gas shows were seen within these formations and wireline logging has confirmed an estimated pay of 295 ft. A production test is planned for this well and the original discovery, #2A Burnett. London-based Reabold owns a 50% working interest in the well along with partner ***Sunset Exploration Inc.***

2 ***Ultra Petroleum Corp.***, according to IHS Markit, has completed a horizontal producer on the Pinedale Anticline that initially flowed 1.862 MMcf of gas, 48 bbl of condensate and 1.406 Mbbl of water per day. The #13-13-A-1H Warbonnet is in Section 13-30n-108w of Sublette County, Wyo. Production is from a lateral in Lower Lance extending from 12,173 ft eastward to 21,425 ft at a bottomhole location in Section 17-30n-107w with a true vertical depth of 12,157 ft. It was tested on an 18/64-in. choke following 30-stage fracture stimulation between 12,213 and 21,094 ft.

3 Casper-based ***Black Oak Energy LLC*** has received drilling permits for 117 extended-reach horizontal exploratory tests in the Wyoming portion of the Red Desert Basin in Sweetwater County. The horizontal projects will be drilled from common drillpads in sections 5, 6, 20 and 28-24n-94w, and 1, 4 and 24-24n-95w. According to IHS Markit, laterals will be drilled in Lewis, Fox Hills and the Almond member of Mesaverde on the company's Desert Rose, Marigold, Daisy, Lupine, Bitter Root, Buttercup and Elderberry leases. Measured total depths range up to 24,307 ft. The drillpads are 1-8 miles generally northwest of Battle Springs Field, which has produced gas from Lewis and Almond. Nearby production is at #1-31 North Battle Springs, Section 31-25n-94w. The 14,103-ft Almond gas discovery produces from treated perforations between 13,774 and 13,994 ft.

4 A horizontal Lewis F Sand producer by ***Southland Royalty Co.*** was tested flowing 482 bbl of oil, with 4.11 MMcf of gas and 518 bbl of water per day. The #5H-5-5H Chain Lakes is in Section 8-22n-93w of Sweetwater County, Wyo. Production is from a lateral extending from 10,527 ft northward to 16,434 ft at a bottomhole location in Section 5-22n-93w. The true vertical depth is 11,455 ft. It was tested on an 18/64-in. choke after 23-stage fracturing (plug-and-perf) between 11,711 and 16,314 ft with a casing pressure of 3,750 psi. Southland's headquarters are in Fort Worth, Texas.

5 ***Samson Resources Co.*** has completed a Powder River Basin-Niobrara exploratory in Converse County, Wyo. The #34-3031 39-74NH Allemand Fed is in Section 30-39n-74w. According to the Tulsa, Okla.-based company, it produced 2.248 Mboe (75% oil) and 228 boe per day per 1,000 ft of lateral and a maximum initial production rate of 3.326 Mboe/d (77% oil), during a 30-day test period. The well has 9,835 ft of stimulated lateral. The discovery was drilled southeastward to 22,000 ft and bottomed in Section 31-39n-74w with a true vertical depth of 12,275 ft. Further details are not yet available. Samson owns a 98% working interest and 81% net revenue interest in the well.

6 A Converse County, Wyo., Turner Sand discovery initially flowed 1.667 Mbbl of 41-degree-gravity oil and 3.089 MMcf of gas per day. According to IHS Markit, it is the first horizontal Turner producer in the township. ***Chesapeake Operating Inc.***'s #21H SFU (Sundquist Flats Unit) 12-34-72 USA B TR is in Section 12-34n-72w and is producing from a lateral extending northwestward to 20,790 ft with a bottomhole location in Section 1-34n-72w. The true vertical depth is 12,255 ft. It was tested on a 30/64-in. choke following 36-stage fracturing between 12,587 and 20,568 ft. Chesapeake is based in Oklahoma City.

7 ***Devon Energy Corp.*** completed a horizontal Parkman producer in the Powder River Basin that flowed 1.531 Mbbl of oil, 346 Mcf of gas and 547 bbl of water per day—the first two-section horizontal producer in the vicinity. The #31-063871-3XPH CWDU T-55 Fed is in Section 31-39n-71w of Converse County, Wyo. Production is from a Parkman lateral extending southward to 17,675 ft, 7,833 ft true vertical, at a bottomhole location in Section 6-38n-71w. It was tested on a 39/64-in. choke after 48-stage fracturing between 7,997 and 17,464 ft. Devon's headquarters are in Oklahoma City.

8 A horizontal Turner Sand discovery by ***Chesapeake Operating Inc.*** was tested flowing 1.037 Mbbl of oil, 5.337 MMcf of gas and 973 bbl of water per day. The #3H WCR 2-33-69 USA A TR is in Section 2-33n-69w of Converse County, Wyo. Production is from a lateral in Turner extending northeastward to 20,999 ft, and it bottomed in Section 35-34n-69w with a true vertical depth of 10,643 ft. It was tested on a 30/64-in. choke following 22-stage fracturing between 11,211 and 20,913 ft.

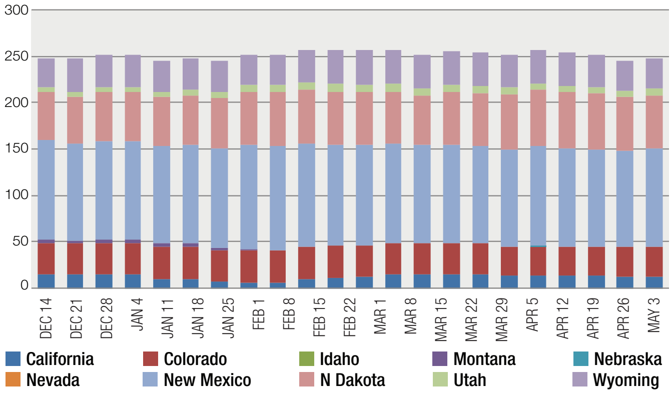
9 Permits have been issued for seven horizontal Niobrara/

Codell wells in Goshen County, Wyo., to Lakewood, Colo.-based ***EME Wyoming LLC***. The exploratory tests, three in Niobrara and four in Codell, will be drilled from a drillpad in Section 2-19n-65w on the company's Marsh & Ellis fee leases. Planned bottomhole locations are to the south and southeast in Section 11-19n-65w. Planned depths range between 19,003 and 20,406 ft with planned true vertical depths of 8,271 ft for the Niobrara tests and 8,466 ft for the Codell tests.

10 ***ConocoPhillips Co.*** is drilling at a delineation test associated with its Willow development project in the National Petroleum Reserve in Alaska. The #11 Tinmiaq is in Section 32-9n-1w and it is being directionally drilled to the northwest to a proposed bottomhole location in Section 30-9n-1w to Nanushuk. The Willow Field discovery is about 7 miles to the northeast at #2 Tinmiaq in Section 34-10n-1w, which was completed in 2017 to open the field. Testing established good reservoir deliverability with a sustained 12-hour test rate of 3.2 Mbbl of 44-degree-gravity oil per day from Nanushuk. ConocoPhillips is based in Houston.

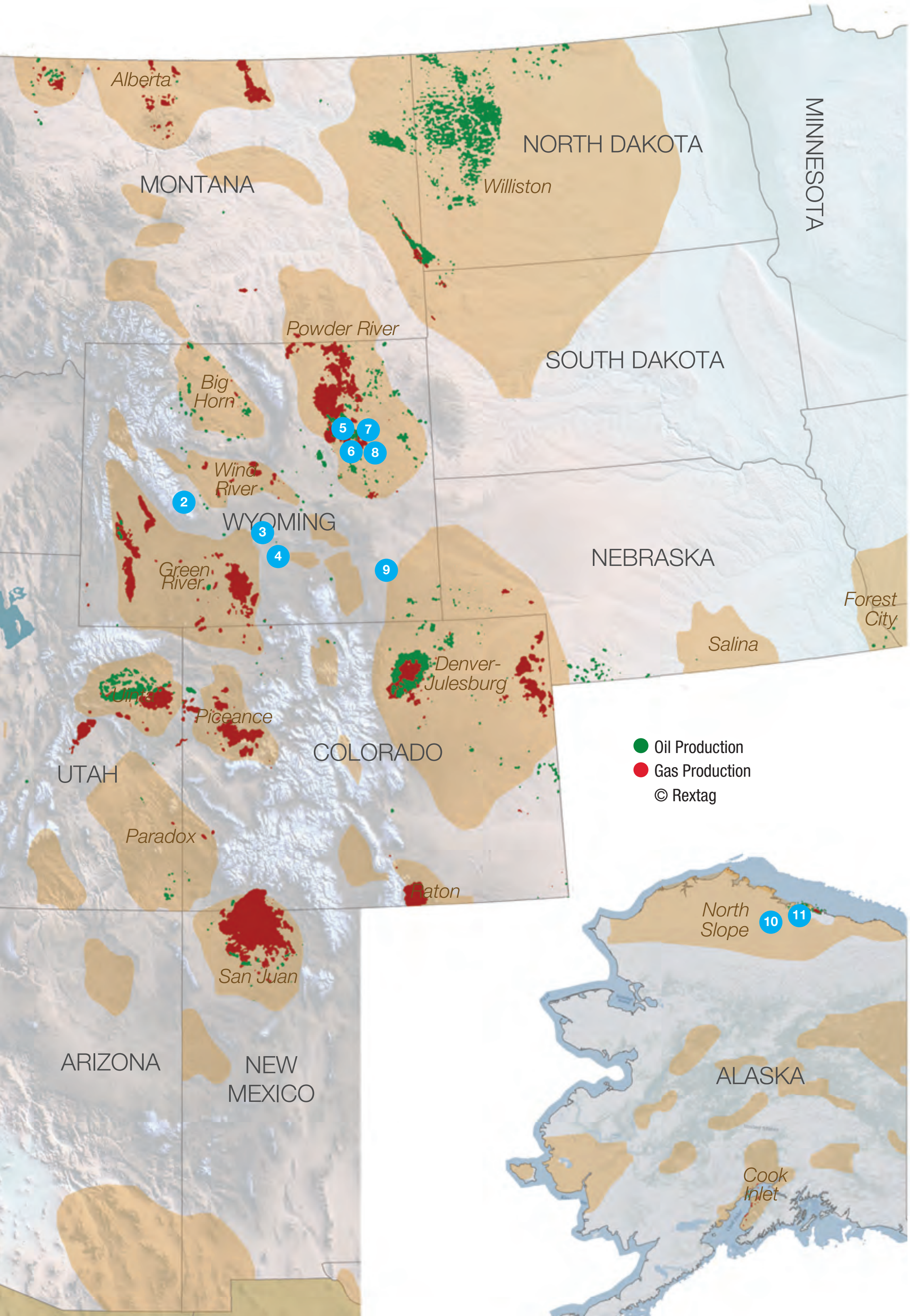
Western U.S. Rig Count

Dec. 14, 2018-May. 3, 2019

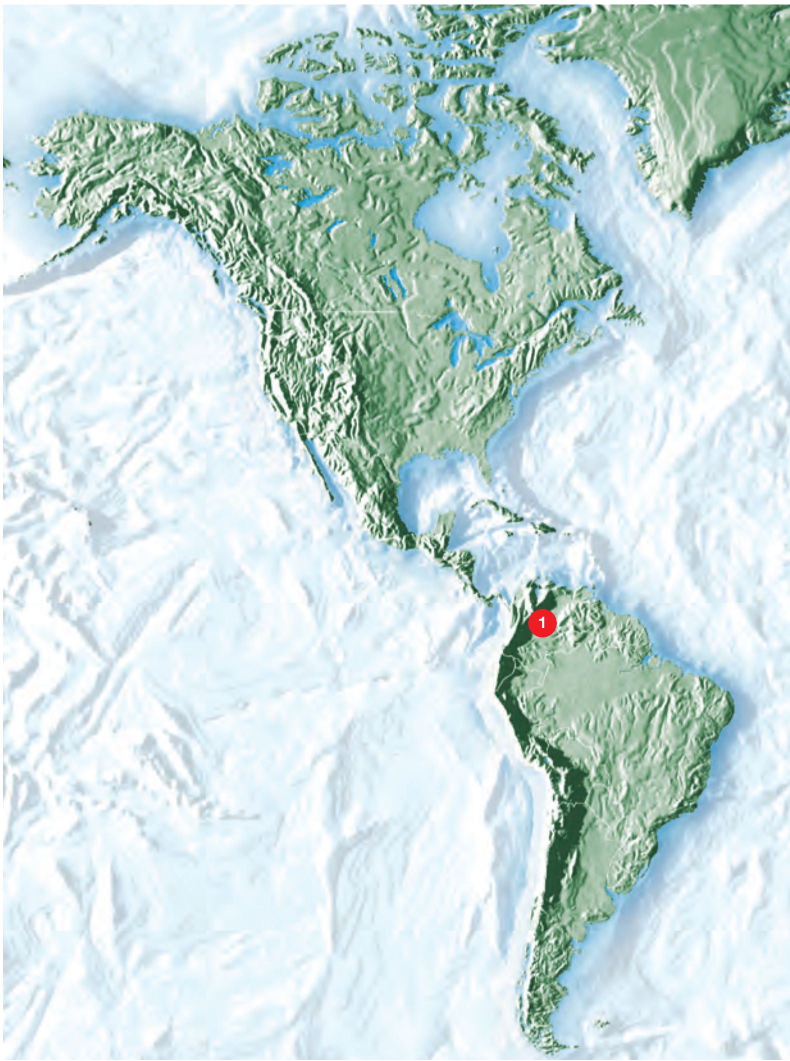


Data compiled from Baker Hughes

11 Sydney-based ***Oil Search Ltd.*** announced results from two tests in Umiat Meridian in Alaska's North Slope. A Nanushuk oil discovery flowed 2.4 Mbbl per day. The exploratory, #1ST Pikka-B, is in Section 35-11n-5e and was tested in a 71-degree-angle sidetrack in Nanushuk that was drilled to 8,600 ft. The company also reported that the flowtest was restricted by the test equipment capacity and that the productivity index calculations indicated a potential flow rate of approximately 3.8 Mbbl of oil per day. Prior to the flow test, Oil Search cut about 300 ft of cores in the sidetrack that had high-quality rock with similar qualities to that observed at Pikka B. The sidetrack was drilled westward to an approximate true vertical depth of 4,923 ft and bottomed in Section 34-11n-5e. The sidetrack was drilled off the company's #1 Pikka-B. Nine miles to the north-northeast, #1ST Pikka-C flowed at stabilized rates of more than 860 bbl of oil per day. The venture is a horizontal sidetrack in Section 16-12n-6e. It was kicked off #1 Pikka C from a depth of 3,210 ft and drilled with a 3,300-ft lateral in Nanushuk to 9,094 ft.



INTERNATIONAL HIGHLIGHTS



Power blackouts across Venezuela have practically paralyzed most of the country's oil wells and rigs. Oil output averaged less than 600,000 barrels per day (bbl/d) during the blackouts, which is what the country produced in the 1940s. The loss of production due to the blackouts deals another blow to Venezuela's already-crippled oil industry from years of mismanagement and recent U.S. sanctions.

The blackouts temporarily closed the Jose terminal, the Orinoco heavy oil upgraders and Sinovensa. The Orinoco Belt area has not fully recovered from the disruptions and is currently producing about 300,000 bbl/d. Near the Orinoco Basin in the east, where four out of every five barrels are pumped, heavy tar-like oil has begun to clog pipelines and tanks after the heating system lost power. According to a former Petróleos de Venezuela official, cleaning or removing the pipes could take months, and damage at the Orinoco Belt oil fields is substantial.

While pumping oil from fields in the Orinoco Belt requires some electricity, the bigger power demand comes from the upgraders—facilities that convert the extra-heavy oil to more commercial blends—located almost 200 miles away in the north near the coast. The country's four upgraders are still working to restart.

—Larry Prado

1 *Colombia*

Ecopetrol has announced a new gas discovery at a #1ST Arrecife well in Colombia. The 7,173-ft well was drilled to test Upper Oro Cienaga. During the initial tests, it produced between 3 and 10 MMcf of gas per day, with low condensate content and no formation water production. The Bogota-based company is planning additional testing.

2 *U.K.*

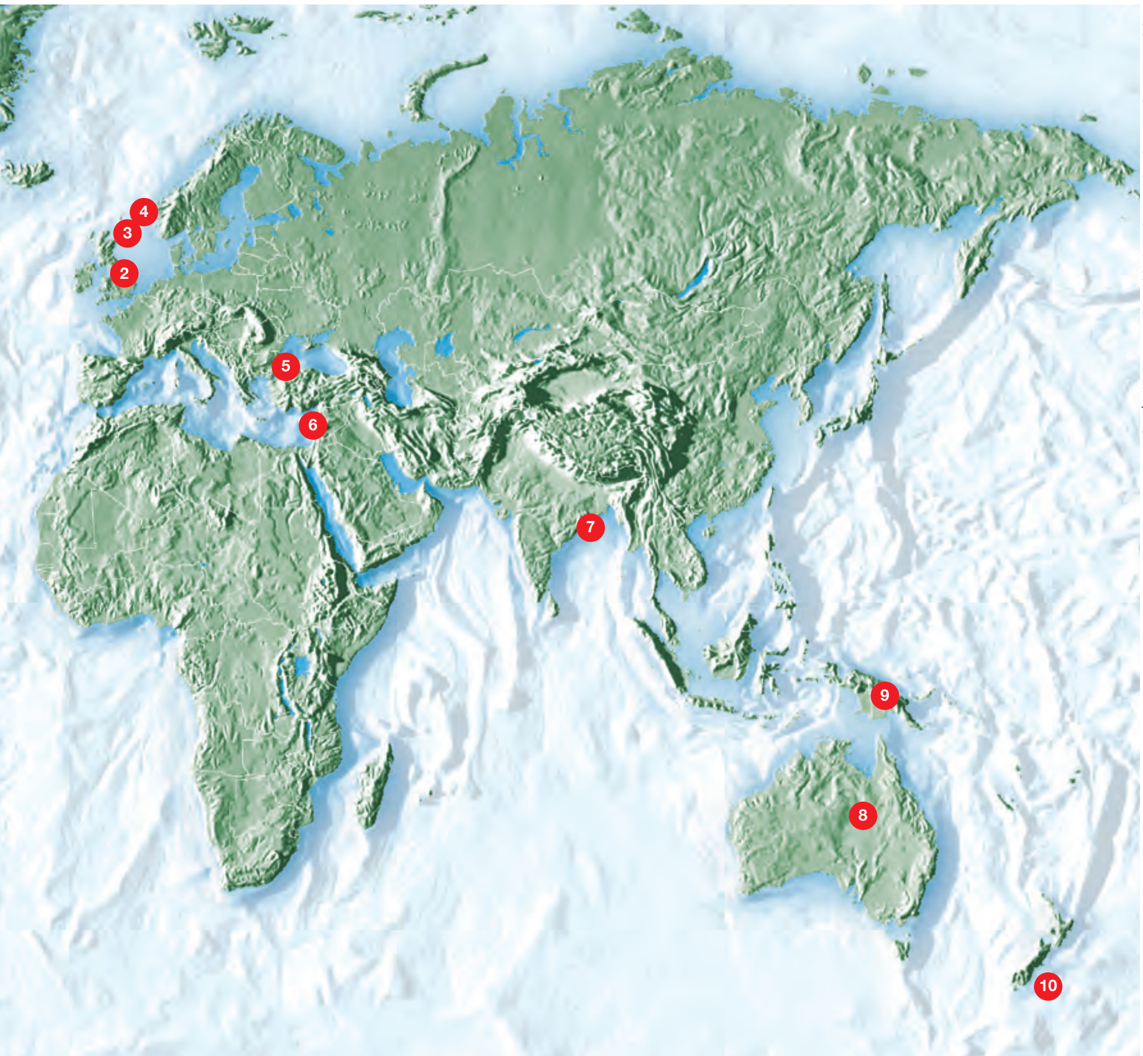
An appraisal well is planned by ***Rathlin Energy Ltd.*** in the onshore U.K. PEDL183 license in East Yorkshire. According to the company, the well is designed to test two targets with gross contingent resources of 189 Bcf (31.5 Mboe) at the #1-A West Newton gas discovery. The appraisal well at #1-A West Newton has two objectives—to appraise the Kirkham Abbey gas discovery and the second is to test a deeper Cadeby Formation reef flank oil prospect. The reef flank Cadeby oil prospect currently has a gross prospective resource of 79.1 MMboe. London-based Rathlin is the operator of PEDL183 with 67% interest, and partners include ***Reabold Resources***.

3 *U.K.*

i3 Energy has scheduled an exploration well on the Serenity Prospect on Liberator Field in the U.K. sector of the North Sea at appraisal well #3A in Block 13/23c of PL198. According to the company, the field in Block 13/23d extends northwest into Block 13/23c where the Serenity Prospect is located. The appraisal well in the Serenity Prospect will de-risk and confirm hydrocarbon volumes in the Liberator and Serenity structures, where company-estimated reserves are 314 MMbbl (Liberator) and 197 MMbbl (Serenity). The following wells in the program will be the Liberator Phase I L2 pilot well and appraisal well #1S. The exploration is also intended to determine the placement of a second Phase I production well in Liberator Field. Both blocks are 100% owned and operated by Westhill, Scotland-based i3 Energy.

4 *U.K.*

Stavanger-based ***Equinor*** announced results from the Verbier appraisal well #20/05b-14 on the U.K. Continental Shelf in the North Sea. It was drilled to 3,784 m and, based on preliminary observations during drilling, the well did not encounter Upper Jurassic sands as anticipated. The current resource estimate is 25 MMbbl of oil equivalent. The well results will be integrated with the processed data from the 3-D seismic survey acquired in 2018 to evaluate the upside potential for further Verbier appraisal activity. A large part of the mapped area of the Verbier discovery, located to the northwest of #20/05b-14, remains untested. Additional resource potential, which was not tested with this well or the discovery well, has also been identified in a deeper horizon beneath the Verbier discovery. Partners in the P2170 License are Equinor UK, 70%, ***Jersey Oil & Gas***, 18%, and ***CIECO UK***, 12%.



5 ***Bulgaria***
An exploration well has been scheduled by Houston-based ***Shell Oil Co.*** in an offshore Bulgaria block in the Black Sea. The #1-14 Khan in the Kubrat Block has a planned depth of 1,300 m. Partners in the project are ***Repsol YPF*** and ***Woodside Petroleum Ltd.*** Exploration in the offshore area is part of an effort by the country to end its dependence on Russian gas. Nearby drilling is underway in a neighboring block by ***Total*** and partners ***OMV*** and Repsol.

6 ***Israel***
Energean Oil & Gas Plc, based in London, announced results from exploration well #1 Karish North in offshore Israel. Preliminary analysis indicates the initial gas-in-place estimate is between 1-1.5 Tcf in a high-quality reservoir in the B and C sands. It was drilled to 4,880 m and hit a gross hydrocarbon column of up to 249 m, and a 27-m core was recovered to surface. Further evaluation is planned to refine resource potential and determine the liquids content of the discovery. The well will be deepened to evaluate the hydrocarbon potential of D4 Sands. After operations are completed the drillship will drill three more Karish Main development wells.

7 ***India***
Vedanta Ltd. has announced an oil discovery at exploration well #2H in block KG-OSN-2009/3 in the offshore Krishna-Godavari Basin in India. According to the company, multiple reservoir zones were encountered within the Mesozoic sequence between 3,310 m and 4,026 m with hydrocarbon indications during drilling and downhole logging. A drillstem test was performed in a zone at 3,403-31 m. Further appraisal drilling and testing are planned to establish the size and commerciality of the oil discovery in the Mesozoic sequence. The first exploration well in the block, #2-A3, was completed as a gas discovery. Evaluation is on-going based, and the results from #2-A3 and #2H will help finalize the prospect. Mumbai-based Vedanta holds 100% participating interest in the block and is the operator of #2H.

8 ***Australia***
Santos Ltd., based in Adelaide, announced that it has successfully completed the Moomba South Patchawarra Formation Phase 1 appraisal program in South Australia's Cooper Basin. The Moomba South Phase 1 appraisal program has confirmed a significant gas resource and resulted in seven new wells now producing in basin. The program also successfully targeted two new plays in Granite Wash and Fractured Granite, which have the potential to add significant new resources. Testing of both plays resulted in stable gas flows to surface. The Granite Wash has recently shown to be a proven producing horizon on the flanks of Moomba North Field. The majority of the Moomba South appraisal wells penetrated this interval and improved the overall understanding of this play. A number of the appraisal wells have been tested and flowed stabilized gas rates from intervals of elevated gas shows through Granite Wash. Stimulation and testing of the Fractured Granite in one of the eight wells has also demonstrated stable gas flows to surface. Santos is the operator of the Moomba South appraisal program and its PPL8 and PPL9 with 66.6% interest in partnership with ***Beach Energy Ltd.,*** holding the remaining 33.4%.

9 ***Papua New Guinea***
Oil Search Ltd. announced results from appraisal well #2-Murukin PDL 9 joint venture in Papua New Guinea's Highlands Province. According to the company, the venture has confirmed an extension of Muruk Field. A drillstem test in the Cretaceous Toro Sandstone reservoir have confirmed the presence of gas in the Toro A reservoir, with a similar composition to that tested in #1 ST3 Muruk. Pressure data from the appraisal indicates that the gas is on the same pressure gradient as that in #1 ST3 Muruk and confirms the extension of the field. The #2-Muruk is a stepout and was drilled to the northwest of the discovery well, and it penetrated gas-saturated Toro A sands in pressure communication with #1 ST3 Muruk. Additional flow testing is planned followed by an extended shut-in period to allow pressure build up, which will assist in constraining the gas resource volume in Muruk Field. Participants in PDL 9 are Oil Search, 24.4%; ***ExxonMobil Corp.***, 21.7%; ***Ampolex***, 21.7%; ***Kumul Petroleum*** 20.5%; ***Nippon PNG LNG***, 9.7%; and ***Gas Resources Juha No.1***, 2%. Oil Search is based in Sydney.

10 ***New Zealand***
OMV has scheduled an offshore New Zealand well in the Great South Basin off the Otago coast. The company is planning to drill three wells and up to seven appraisal wells in the program. OMV is targeting gas deposits and possible condensate in Tawhaki. OMV acquired its two permits, Block PEP4863 and PEP50119, in the Great South Basin in 2018 from ***Royal Dutch Shell Plc***. Vienna-based OMV holds 100% interest and is the operator.

OCCIDENTAL TURNS TO ORACLE OF OMAHA

To solidify the financing package for its $76-per-share bid for Anadarko Petroleum Corp., Occidental Petroleum Corp. turned to Berkshire Hathaway Inc. Led by CEO Warren Buffet, dubbed the "Oracle of Omaha," Berkshire Hathaway committed to invest a total of $10 billion in Occidental, subject to Occidental entering into and completing its proposed acquisition of Anadarko. Investments in the energy sector by Berkshire Hathaway have been relatively rare.

Berkshire Hathaway is to receive 100,000 shares of cumulative perpetual preferred stock with a liquidation value of $100,000 per share, together with a warrant to purchase up to 80 million shares of Occidental's common stock at an exercise price of $62.50 each. The preferred stock issued to Berkshire Hathaway will accrue dividends at 8% per annum.

Several days after its deal with Berkshire Hathaway, Occidental announced a binding agreement to sell Anadarko's African assets—its Mozambique LNG assets, as well as assets in Algeria, Ghana and South Africa—to Total SA for $8.8 billion. The latter deal is also subject to Occidental completing its acquisition of Anadarko.

An IPO, completed by Brigham Minerals Inc. (NYSE: MNRL), offered insights into possible similar offerings. After filing to sell 13.5 million Class A common shares at an expected range of $15 to $18 each, the IPO was upsized to 14.5 million shares and priced at the high end of the range. With a further 2.175 million shares sold via the overallotment option, net proceeds came to $277.4 million.

Stockholders in Brigham Minerals include affiliates of private-equity sponsors Warburg Pincus LLC, Yorktown Partners LLC and Pine Brook Road Advisors LP. Industry observers have held out the possibility of other mineral IPOs by firms backed by various private-equity sponsors, such as EnCap Investments LP, NGP and Quantum Energy Partners.

Reports from investment bankers leading the Brigham Minerals IPO indicate that, even with an increase in offering size and pricing at the high end of the range, the IPO was more than six times oversubscribed. Relative to its $18 offering price, Brigham Minerals' average closing price for its first five trading days was $20.79.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Occidental Petroleum Corp.	NYSE: OXY	Houston	US$10 billion	Announced that, in connection with the financing of Occidental's proposal to acquire **Anadarko Petroleum Corp.**, **Berkshire Hathaway Inc.** has committed to invest a total of $10 billion in Occidental. The investment is contingent upon Occidental entering into and completing its proposed acquisition of Anadarko. Berkshire Hathaway will receive 100,000 shares of cumulative perpetual preferred stock with a liquidation value of $100,000 per share, together with a warrant to purchase up to 80 million shares of Occidental common stock at an exercise price of $62.50 each. The preferred stock will accrue dividends at 8% per annum (or with respect to dividends that are accrued and unpaid, 9%).
Energy Transfer Operating LP	N/A	Dallas	US$700 million	**Energy Transfer Operating LP** a subsidiary of **Energy Transfer LP**, priced an underwritten public offering of 28 million of its 7.6% Series E fixed-to-floating rate cumulative redeemable perpetual preferred units at a price of $25 each, resulting in total proceeds of $700 million. The underwriters have a 30-day option to purchase up to 4.2 million additional Series E preferred units. Distributions on the Series E preferred units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2024, at a rate of 7.6% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Series E preferred units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 5.161% per annum.
Brigham Minerals Inc.	NYSE: MNRL	Austin	US$277.4 million	Announced that it priced an upsized IPO of 14.5 million shares of its Class A common stock at $18 each. **Brigham Minerals** granted the underwriters a 30-day option to purchase up to an additional 2.175 million shares of its common stock. It intends to contribute the total net proceeds of approximately $240.6 million, or $277.4 million if the underwriters exercise in full their option to purchase additional shares, to its subsidiary, **Brigham Minerals Holdings LLC**, in exchange for limited liability company units in **Brigham LLC**. Brigham LLC intends to use a portion of the net proceeds to repay borrowings incurred under its credit facility and the remainder to fund Brigham Minerals' future mineral and royalty interest acquisitions.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Tellurian Inc.	Nasdaq: TELL	Houston	US$200 million	**Tellurian Inc.** priced a private investment in a public equity offering with **Total SA** for about 19.9 million shares at $10.06 each for total proceeds of $200 million. In addition, the two companies have signed a heads of agreement for Total to make a $500 million equity investment in the integrated Driftwood project and to purchase 1 mtpa of LNG from Driftwood.
DEBT				
Crestwood Midstream Partners LP	NYSE: CEQP	Houston	US$600 million	A wholly owned subsidiary of **Crestwood Equity Partners LP** announced that it has priced $600 million in aggregate principal amount of 5.625% unsecured senior notes due 2027 in a private offering, which was upsized from the originally proposed $500 million offering. The notes will be guaranteed on a senior unsecured basis by all of **Crestwood Midstream Partners**' subsidiaries that guarantee its existing notes and the indebtedness under its revolving credit facility. Net proceeds from the offering are to be used to repay a portion of the outstanding borrowings under its revolving credit facility, which includes approximately $250 million of borrowings that were used to fund a portion of a 50% interest in **Jackalope Gas Gathering Services**.
Moss Creek Resources Holdings Inc.	N/A	Houston	US$500 million	A wholly owned subsidiary of **Surge Energy US Holdings Co.** announced that it has priced $500 million aggregate principal amount of its 10.5% senior unsecured notes due 2027 in a private offering that is exempt from registration under the Securities Act of 1933. The notes will be senior unsecured obligations of the company and will initially be guaranteed by each of the company's two subsidiaries, **Moss Creek Resources LLC** and **Surge Operating LLC**. The company intends to use the net proceeds from the offering to repay all outstanding borrowings under its revolving credit facility, with the remainder of the net proceeds to be used for general corporate purposes.

These deals and details on thousands more are available in real time in a searchable, sortable database at HartEnergy.com.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

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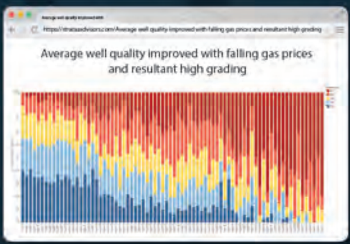

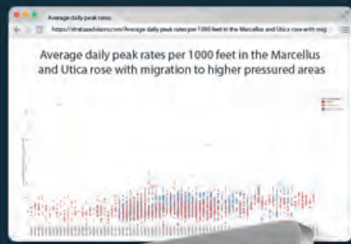

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CASH: THE NEW GOLD STANDARD

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Given that well costs are down and efficiency is up, it seems operating margins, recycle ratios and debt-adjusted production growth are reaching new heights for many E&P companies. If they can watch their tendency to outspend cash flow, things will finally fall into place, and they may then be able to meet the fervent desires of investors who chant, "Show me the money." Most of these metrics look better now for most E&Ps than they did back in 2014, when oil prices were rising to $100 per barrel (bbl)—ah, the good ole' days.

John Freeman, research analyst at Raymond James & Associates, said, in a report in the middle of E&P earnings season, that the energy industry is in the midst of a paradigm shift. It appears that growth for growth's sake is gone, he said, outmoded if not dangerous. Capital discipline, free cash flow (FCF) and returns are inescapable if one is to woo investors back to the sector. Many other analysts, and CEOs for that matter, are echoing these themes.

"We believe a tidal wave of free cash flow is set to engulf U.S. oil and companies in 2020. If correct, it would represent … the new gold standard," Freeman said.

Shout it from the roof tops. Figure out a way to make these trends pop up constantly on Instagram for the millennial generation of portfolio managers.

Analyst David Deckelbaum, who initiated on 20 E&P companies last fall when he moved to Cowen & Co., said at that time, "Even at $50/bbl, we see names capable of delivering sector-competitive production growth while manufacturing free cash yields that garner attention relative to other major S&P sectors …"

The list of E&Ps that promise FCF is growing. Whiting Petroleum Corp. is supposed to throw off $210 million of cash flow this year. Carrizo Oil & Gas Inc. was expected to make FCF in the third quarter, using it to reduce debt. Continental Resources Inc. is tracking toward $1 billion of FCF in 2019; having estimated that at $55 oil, it will make between $500- and $600 million so far. Parsley Energy said it would achieve "sustainable" FCF in the second half of 2019.

Diamondback Energy Inc. estimates $750 million of FCF in 2020 if $55 oil is sustained, and it has just authorized a $2-billion share buyback program that goes to year-end 2020.

But if companies are about to start generating FCF, what should they do with it? What do investors really want?

"Since corporations normally do not store treasure in a vault like Scrooge McDuck, they need to identify the best way to return this excess capital to shareholders," Freeman said.

He polled nearly 300 investors and management teams to ask these very questions. Obviously, the over-levered companies, whether E&P or midstream or oilfield services, will wisely pay down debt first. Therefore in his survey, he gave respondents these three choices: stock buybacks, payment of regular dividends, or one-time "special" dividends.

For investors in large-cap companies, the regular dividend was far and away the preferred choice, by 78%. Further breaking it down by sector, 70% of private companies and private equity want a regular dividend and 89% of those in the oilfield service group preferred to get a regular dividend.

For small-cap companies, however, 48% preferred share repurchases and 33% said they'd prefer to receive dividends. Some 19% said they'd prefer a special dividend. Why this choice?

There is relatively little history of small caps implementing a share repurchase program, or paying a dividend, for that matter. But Freeman explained that their highly variable cash flows make paying a dividend difficult, whereas larger companies with scale tend to be less volatile—if results are poor here, they can make up for it there.

Then too, small-cap investors normally seek tax-advantaged growth instead of a dividend, which could increase their tax liability and negatively affect total return over the long term. Freeman said large-cap investors are more likely to seek a mix of dividends and growth.

"Looking to our group analysis, share repurchases sustained a plurality in every group except midstream," he said. However, "Clearly from the results of the survey (both overall and by group) there is a growing distaste for share buybacks as a company grows larger," Freeman said.

The analyst looked at the S&P 500 to see what the preferred method is for those companies, and whether share buybacks during a five-year span (2013 through third-quarter 2018) made much difference. "It is clearly evident that S&P 500 stock buybacks have not improved earnings per share … relative to overall earnings," he concluded.