Oil and Gas Investor

APRIL 2019

Colorado sets a chilly bellwether as producers there seek a social license to operate.

HARTENERGY

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

UNDISCLOSED	$950 MILLION	$66 MILLION	UNDISCLOSED	$750 MILLION
AETHON	EARTHSTONE Energy Inc.	KIMBELL ROYALTY PARTNERS	ROSEWOOD RESOURCES	Matador RESOURCES COMPANY
ASSET DIVESTITURE	HAS AGREED TO ACQUIRE SABALO	FOLLOW-ON OFFERING	JOINT VENTURE TRANSACTION	SENIOR UNSECURED NOTES
Financial Advisor	Financial Advisor	Co-Manager	Financial Advisor	Co-Manager
$28 MILLION	$100 MILLION	UNDISCLOSED	$322 MILLION	$350 MILLION
VIKING MINERALS	LILIS ENERGY	PEARL ENERGY INVESTMENTS	SRC ENERGY	VIPER Energy Partners
ASSET DIVESTITURE	CONVERTIBLE PREFERRED STOCK	BUSINESS COMBINATION OF PORTFOLIO COMPANIES	FOLLOW-ON OFFERING	FOLLOW-ON OFFERING
Financial Advisor	Placement Agent	Valuation Analysis	Co-Manager	Co-Manager
$22 MILLION	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED
Thunder Basin Resources	PETROFLOW ENERGY	BEELINE COLORADO, LLC	ELM RIDGE EXPLORATION	EAGLE FORD MINERALS PLATFORM
PRIVATE PLACEMENT OF EQUITY	ASSET DIVESTITURE	HAS DIVESTED ITS COLORADO MIDSTREAM ASSETS	HAS DIVESTED ITS COLORADO UPSTREAM ASSETS	PRIVATE PLACEMENT OF EQUITY
Placement Agent	Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

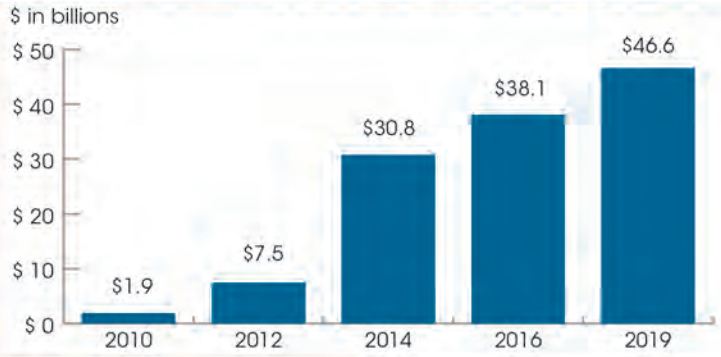
ENERGY GROUP KEY STATISTICS

$46.6 Billion
Aggregate Transaction Volume since 2009

$312 Million
Average Transaction Size

156
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



As an active participant in the energy industry with a principal mentality for over 50 years, we understand that capital and ideas are indispensable to a thriving oil and gas industry. Our advisory assignments demonstrate how an independent investment bank, backed by extensive industry knowledge and innovative ideas, can build stronger, more prosperous energy companies.

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Oil and Gas Investor

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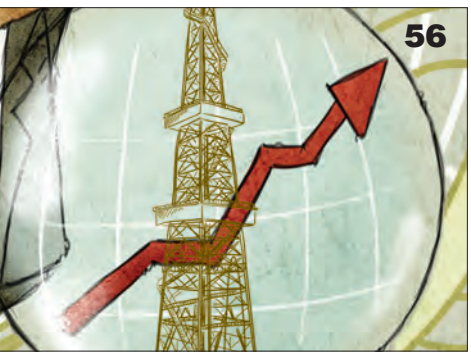
APRIL 2019/VOLUME 39/NUMBER 4



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LATEST CONTENT

Spain's Enagás To Partner With Blackstone, GIC For Stake In Tallgrass Energy
Enagás will partner with affiliates of Blackstone and GIC on the deal for a stake in Tallgrass Energy, a U.S. energy infrastructure company which owns several interstate pipelines.

Study: Half Of World's Future Workforce Eyes Digitizing Oil, Gas Industry
However, oil and gas faces stiff competition in attracting top STEM talent from other sectors since 77% of future workforce expressed interest in the technology industry.

Rosehill Resources Says David French To Join As CEO
David French will succeed industry veteran Gary C. Hanna, who has served as interim president and CEO of Delaware Basin operator Rosehill Resources since September 2018.

World Bank: Venezuela Must Pay ConocoPhillips More Than $8 Billion
The total award of $8.14 billion, plus an earlier arbitration award of $2 billion, makes the U.S. producer the biggest victor in claims from a wave of nationalizations last decade. However, Venezuela could still contest the award.

NextDecade Executes Site Lease For Rio Grande LNG Project In Brownsville
Investment could pump $15 billion into county's economy and create 5,000 jobs.

Moda Midstream Eyes Second Supertanker Berth At Texas Terminal
Ingleside expansion to coincide with launches of three pipelines in the second half of the year.

Apache Pushes Forward At Permian Basin's Alpine High
Apache aims to produce between 85,000 and 90,000 barrels of oil equivalent per day at Alpine High in the Permian Basin this year, running fewer rigs.

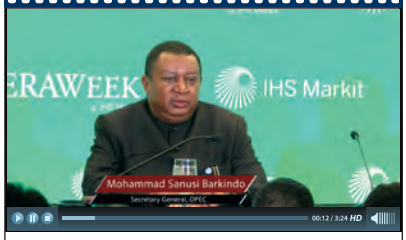
ONLINE EXCLUSIVES

Why Tellurian Loves Haynesville: It's Close, Prolific, Cheap
Tellurian Inc. is all in on the LNG trade, John Howie, president of the company's upstream arm, told attendees of DUG Haynesville.

Norway's $1 Trillion Wealth Fund Set To Cut Oil And Gas Stocks
Big groups have been reprieved as the Norwegian government recommends divestment from upstream oil and gas producers rather than large integrated groups.

OPEC Welcomes Forecasted Wave Of U.S. Shale Production
OPEC Secretary-General Mohammad Barkindo warned attendees of IHS CERAWeek that additional oil supply growth is still needed despite a second wave of U.S. shale production forecasted by the IEA.

Videos



CERAWeek: NOPEC, Carbon Capture, U.S. Shale Capital Outlook
OPEC Secretary General Mohammad Barkindo responded to questions about President Donald Trump's tweets.

www.HartEnergy.com/videos

What's Trending

1. TPG Capital Takes Control Of Goodnight Midstream With $930 Million Acquisition
2. Colorado's SB19-181 Impact: What Oil, Gas Should Expect
3. Anadarko Petroleum CEO Al Walker's Views
4. Noble Energy Prunes Permian Basin Position With $132 Million Sale
5. Innovation, Ingenuity Drive Changes In Handling Produced Water

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. Congratulations to our honorees!

OilandGasInvestor.com/fortyunder40

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: In the hostile terrain of Colorado's Rocky Mountains, a Helmerich & Payne hand braves blizzard conditions near a Laramie Energy well in the Piceance Basin. Photo by Ricardo Merendoni

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CONFERENCE & EXHIBITION

DUG ROCKIES

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Colorado Convention Center
Denver, Colorado

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- Get face-time with peers and other industry professionals during **8+ hours of dedicated networking.**

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CONFIDENCE EARNED.

M&A Advisory

PETROBRAS
Divestiture of 50% Ownership Interest in POGBV
Vitol, AfricaOil, Delonex
$1,530,000,000
Exclusive Advisor
Pending

NEWFIELD
Advised on the Combination with
encana
$7,700,000,000
Advisor
February 2019

HALCÓN RESOURCES
Divestiture of Delaware Basin Water Infrastructure Assets
WaterBridge
Up to $325,000,000
Financial Advisor
December 2018

ENBRIDGE
Corporate Simplification
ENBRIDGE, ENBRIDGE, ENBRIDGE, Spectra Energy Partners
C$22,730,000,000
Financial Advisor
December 2018

SIERRA, TALOS
Farm-out of Block 2 in Offshore Mexico
Pan American ENERGY
Undisclosed
Exclusive Financial Advisor
October 2018

BAYTEX ENERGY CORP
Advised on the Combination with
RRX
~C$1,900,000,000
Financial Advisor
August 2018

CIMAREX
Advised on the Divestiture of Delaware Basin Assets to
CALLON PETROLEUM
$544,500,000
Exclusive Financial Advisor
August 2018

SK
Acquisition of gathering and processing assets in the Delaware Basin as part of a $1.75 billion transaction
Brazos Midstream
$250,000,000
Exclusive Financial Advisor
May 2018

ExxonMobil
Advised on the Divestiture of 50% interest in Scarborough gas field to
woodside
$744,000,000
Exclusive Financial Advisor
March 2018

Cabot Oil & Gas Corporation
Advised on the Divestiture of Eagle Ford Assets to
VENADO OIL & GAS
$765,000,000
Exclusive Financial Advisor
March 2018

noble energy
Advised on the Divestiture of Lower 48 Mineral Interests to
BLACK STONE MINERALS
$340,000,000
Exclusive Financial Advisor
November 2017

VERESEN
Advised Veresen on the Acquisition by
PEMBINA
C$9,400,000,000
Exclusive Financial Advisor
October 2017

Capital Markets

ENERGY TRANSFER
Senior Notes
$4,000,000,000
Joint Bookrunner
January 2019

Matador Resources Company
Senior Notes (Add-On)
$300,000,000
Joint Bookrunner
October 2018

TALLGRASS ENERGY
Senior Notes
$500,000,000
Joint Bookrunner
September 2018

Apache
Senior Notes
$1,000,000,000
Joint Bookrunner
August 2018

Western Gas Partners, LP
Senior Notes
$750,000,000
Joint Bookrunner
August 2018

Matador Resources Company
Senior Notes
$750,000,000
Joint Bookrunner
August 2018

FREEPORT LNG
Secured Notes
$600,000,000
Joint Bookrunner
June 2018

EQT Midstream PARTNERS, LP
Senior Notes
$2,500,000,000
Joint Bookrunner
June 2018

ENERGY TRANSFER
Senior Notes
$3,000,000,000
Joint Bookrunner
June 2018

Shell
Has sold its shareholding in Canadian Natural Resources Limited
Canadian Natural
$3,300,000,000
Joint Bookrunner
May 2018

NEPTUNE ENERGY
Senior Notes
$550,000,000
Joint Bookrunner
May 2018

ENBRIDGE Income Fund Holdings
60NC10 Hybrid Notes
C$750,000,000
Joint Lead & Bookrunner
April 2018

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LOOKING TOWARD THE SHALE HORIZON

STEVE TOON, EDITOR-IN-CHIEF

One of the buzz topics at CERAWeek by IHS Markit in March was how U.S. shale oil has overtaken global supply dynamics and reset the traditional balance of crude flows worldwide. U.S. crude production grew by a whopping 1.8 million barrels per day (MMbbl/d) in 2018 year-over-year, to just shy of 12 MMbbl/d, a record. That fact propelled the U.S. into the pole position of global crude producers, topping Russia and Saudi Arabia.

However, off the main stage and in a room at the end of the hallway early one morning, one of the founders of the shale revolution harkened a warning: such a volume might not be sustainable for many more years. Shale production is destined to peak.

That prognosticator was Mark Papa, currently the chairman and CEO of Centennial Resource Development Corp., a Permian Basin-focused E&P, and the former CEO of EOG Resources Inc., the leading independent in shale oil development. Papa believes the industry is currently picking the low hanging shale fruit, and once that is gone, the effort becomes more challenging.

"I'm not particularly optimistic that over the next five years, the industry is going to be able to show year-over-year improvements in well recoveries that we've seen over the past 10 years," he said. "In fact, I think we're going to see evolutionary improvements, not revolutionary improvements."

That theory is first premised on shale quality and remaining inventory. For obvious economic reasons, shale producers today—in any shale basin—are drilling the core of the core quality acreage. And despite the perception that a shale is a shale, "there are quality differences," he emphasized. "It's not completely homogenous geology. And the industry has attacked the better quality shales."

And after a decade now of targeting the best-quality shale first, Papa asks, "What's left now? Tier 2 and Tier 3 quality shales."

Further, Papa believes the industry is reaching certain limitations in technology improvements. That is, lateral lengths for shale wells are "pretty much maxed out," if only by leaseline limitations; proppant intensity is at its maximum from an economic standpoint; and fracturing fluids have been well refined. "So as I look at the levers that we can pull today, I'd say we're in the seventh inning of a nine inning game of what we can do to maximize the recovery factor."

Additionally, Papa referenced the slew of shale operators who are up-spacing well locations from previously disclosed well counts per unit due to significant well interference occurring in pad developments—ultimately decreasing the number of wells that will be drilled.

Counterbalancing that argument, to a degree, was Greg Powers, vice president of innovation for Halliburton, the largest service provider in the world and the leader in oil and gas technology advances. "As a technology guy," he said, "I never give up on the notion that there is a lot more out there."

Even while we may now know all of the significant shale resources in the U.S., Powers emphasized that recovery only stands at 10% to 20%. "There's been a lot of technology expenditure this decade trying to figure out what's going on. What we ended up learning was experiential [i.e. trial and error], not fundamental. I think the fundamentals of what's actually happening are yet to be [illuminated]."

Thus far, the industry better understands the mechanics of hydraulic fracturing, "but the chemistry of hydraulic fracturing is still a little bit mysterious." Ultimate recovery will be a combination of both geophysics and geochemistry, he said.

"When you ask why we get 10% of liquids recovery, the answer is, we have no idea. The answer to what you have to do to make more oil come out has yet to be discovered. Ninety percent of the hydrocarbons are still waiting in a pore somewhere for their moment, and we don't know what that exit ticket is."

When pressed to make the baseball analogy as to what inning the shale cycle is in, Powers offered, "We might even be in the on-deck circle."

That would portend a lot more U.S. production for many years to come. Even Papa noted that the majors largely sat out the first decade of the shale revolution, and are now coming in "in a big way," particularly in the Permian.

"Once those big guys come in, you're going to see those R&D departments have high priorities to what you can do to improve shale oil recoveries with technologies in the shale plays. You can expect to see significant improvements. Time will tell how that plays out."

Yet Papa still believes the growth trajectory will flatten, even factoring in technology advances.

"I'm not proclaiming it's the end of the shale revolution," he said. "We will just have to expect that by 2025 the impact of shale oil for the U.S. will be less powerful than today."

For now, the shale revolution continues at DUG Permian in Fort Worth, April 15-17, where we will drill down to the core-of-the-core topics in the basin. Join us! DUGPermian.com.

A MANDATE IN MOTION

CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

There's no question that the vast majority of E&Ps now understand they have a mandate to prioritize returns to investors over growth. The problem is that the fine print detailing precise proportions—what level of returns is the right balance for a certain rate of growth—has been arriving slowly. As one analyst said, "The key question is: What will investors reward?"

The uneven response by investors to certain fourth-quarter earnings results would indicate that the ideal recipe is still in the making. Take Concho Resources Inc. for example. In announcing an admittedly weak final quarter, Concho cut its 2019 capex outlook by 17%, while lowering oil production by only 7% below prior guidance. Annual oil growth in 2019 was moderated at 26% to 30% from 35% to 40% earlier.

In a "show me the money" market, Concho's stock fell roughly 14.3% over the next two days, even as it projected generating close to $1 billion in free cash flow at $60 per barrel (bbl) in 2020. Analysts attributed the fall to management's reticence to specify how it planned to use the free cash flow. In addition, other things equal, the tempered growth meant the stock traded at a more expensive multiple.

At Hart Energy's recent Energy Capital Conference, VanEck Associates portfolio manager Shawn Reynolds countered the view that a slowdown in growth should necessarily result in a lower E&P multiple. Rather, the tempered trajectory can translate into stronger visibility, higher returns and a greater ability to pass on a portion of returns to shareholders.

For example, if an E&P can grow at 10% per year for 10 years and generate total shareholder returns in the high single digits, it should earn a greater multiple of enterprise value to EBITDA than the market's current 5.5 to six times, he said. "We haven't proved it yet. But we're on the cusp of giving the market something it hasn't seen before. It should trade at a much higher multiple."

To address efforts to strike the best balance between growth and free cash flow, Raymond James has developed a methodology to screen for E&Ps that can "efficiently grow reserves and production while spending within cash flow." It then takes the analysis "a step further to identify the optimal production growth and free-cash-flow combination for each operator," it said.

The base for the new Raymond James analysis is the time-tested recycle ratio, which compares an E&P's operating cash flow to its proved developed finding and development costs. The recycle ratio is then adapted to incorporate several changes.

First, the Raymond James analysis focuses on reserves developed in the first year of production, typically 20% to 25% of a well's reserves. Second, the adjusted recycle ratio is scaled so cash generated from current year production only needs to cover newly added barrels for an operator to achieve breakeven cash flow in the year. With these adjustments to the standard recycle ratio, "we can now effectively identify whether an operator is able to add first year reserves within cash flow."

The Raymond James study found that a group of E&Ps, with a compound annual growth rate (CAGR) in production of 10% or more at strip pricing, can generate a free-cash-flow yield in 2025 of 10% or more. The group is made up of Continental Resources Inc., Concho Resources, EOG Resources Inc., Diamondback Energy Inc., Oasis Petroleum Inc., Parsley Energy Inc., Pioneer Natural Resources Co. and Whiting Petroleum Corp. (Excluded from the study were E&Ps with significant non-U.S. operations, such as Noble Energy Inc.)

Despite deep skepticism that the energy sector can compete with the broader market, the Raymond James study also indicated that, assuming $55/bbl, its E&P coverage could grow production at a 15% CAGR over 2019 to 2025 to optimize a free-cash-flow yield of about 12.5%. This compares to the S&P 500 average growth rate of about 7% and a free-cash-flow yield of about 6%.

Raymond James said investor skepticism remained high as to whether the energy sector could "truly change its stripes." While the industry has "shifted its focus to corporate level returns/free cash flow," and balance sheets "have never been better," it said "sentiment is as bad as it's ever been."

Meanwhile, the meager multiples for E&Ps may re-awaken the long-dormant M&A market, according to a Tudor, Pickering, Holt & Co. report. With a 1.5 turn valuation gap between large-cap E&Ps trading at 5.4 times enterprise value-to-debt-adjusted cash flow (EV-to-DACF) and mid-cap E&Ps trading at 3.9 times EV-to-DACF, "the case continues to grow for a very active M&A environment in 2019."

CASH ONLY

DARREN BARBEE, SENIOR EDITOR

A surreal moment of this year's CERAWeek by IHS Markit: OPEC Secretary General Mohammad Barkindo sitting in the press room, questioned about presidential tweets.

Navigating carefully around a reporter's question of whether OPEC is influenced by President Donald J. Trump's digital screeds/bullying/self-congratulations regarding OPEC, Barkindo said the tweets add "uncertainty" to global markets.

Bumpiness ensues when the most powerful person on Earth writes, as he did on Feb. 25: "Oil prices getting too high. OPEC, please relax and take it easy. World cannot take a price hike—fragile!" Following the tweet, oil prices fell 3%, according to CNBC.

Barkindo noted that "the president doesn't give notice before he tweets."

Barkindo also said he has been meeting with shale oil producers to talk shop, though some of them probably wish he was just shopping.

Despite OPEC's corrective action last year, oil prices continue to be too rocky for buyers and sellers to find a middle ground to execute deals. In February, QEP Resources Inc. called off its deal with Vantage Energy Acquisition Corp., citing deterioration in commodity prices.

That volatility has helped cast A&D markets adrift. Experts and analysts talk a lot about nagging headwinds and eventual tailwinds. So far, though, E&Ps remain in a no-wind scenario.

At Hart Energy's Energy Capital Conference in Dallas, S. Wil VanLoh, founder and CEO of private-equity provider Quantum Energy Partners, said displacing the inventory of top-tier producers is a challenge. The top 10 producers, drilling at their current pace, have another 44 years of inventory remaining, he said.

That spells trouble for private-equity-backed companies. "In order for a public company to buy you, you basically have to displace some of their top quartile inventory. That's becoming a harder thing to do in the private-equity world," he said.

Jason Martinez, managing director and co-head of the A&D Group for BMO Capital Markets, took a slightly different view. He asked whether top producers' inventories are really that deep. Martinez, who also spoke at the conference, said the key is to think about A&D like Little League baseball. This analogy doesn't appear to extend to bitter parent rivalries, including a New Jersey mom who got probation for writing threatening letters to Little League officials (her son didn't make the team) or a former Florida policeman who gave a pitcher $2 to hit an opposing player with the ball (winning is not everything).

Martinez said Little League teams that go deep into the playoffs and eventually raise a championship trophy have great lineups—not just at the top of the order but in the sixth, seventh and eighth spots.

"You may not be able to compete and knock out top quartile production and inventory. That's OK," he said. "As you're building your companies, what we're telling people is to think about where you fit in the lineup of your target buyers."

Some companies may have strong and deep inventories. Others may just have strong inventories, or even some that are nearing retirement age.

BMO examined seven unnamed companies with high rates of return and their corresponding inventory. He singled out one company, which has IRRs of roughly 37% and about 100 remaining locations.

"If I'm that company, I'm thinking real hard about what else I can get out there, even if it's not the top of my batting order," he said.

Finding a buyer is one thing. Finding one who can close the deal is another.

"What we're seeing is a lot longer [marketing period] from the traditional process where you would go out, have your dataroom, get your bids, shoot your horse and go on down the path," he said.

Martinez said last year a buyer walked away from a materially higher bid because the ultimate buyer paid cash.

Though logic would suggest buying something requires money, "you'd be surprised … how many folks show up to a bid and really aren't cash closers."

Fellow panelist J.P. Hanson, managing director and head of the E&P group at Houlihan Lokey, said closing deals is causing companies to think more creatively.

"We become more creative if there isn't an immediate access to cash," he said. "We did an A&D deal that actually closed last month that was a combination of cash up front and a 5% override, which helped bridge a valuation gap between buyer and seller."

Final thoughts: Ignore Twitter, never bring an empty wallet to a cash fight and enjoy the game.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
TAEP Expo & Annual Meeting	April 2-3	Irving, Texas	Irving Convention Center	texasalliance.org
OGIS New York	April 8-10	New York	Sheraton Times Square	ipaa.org
PIOGA Spring Meeting	April 10	Pittsburgh	River Casino	pioga.org
DUG Sand and Water	April 15	Fort Worth, Texas	Fort Worth Convention Center	dugpermian.com
DUG Permian Basin	April 15-17	Fort Worth, Texas	Fort Worth Convention Center	dugpermian.com
Offshore Technology Conference	May 6-9	Houston	NRG Park	2019.otcnet.org
DUG Rockies	May 14-15	Denver	Colorado Convention Center	dugrockies.com
AAPG Annual Conv. & Exhibition	May 19-22	San Antonio	Henry B. Gonzalez Conv. Center	aapg.org
Louisiana Energy Conference	May 28-31	New Orleans	The Ritz-Carlton	louisianaenergyconference.com
Midstream Texas	June 5-6	Midland, Texas	Midland County Horseshoe Pavilion	midstreamtexas.com
CIPA Annual Meeting	June 6-9	Lake Tahoe, Calif.	TBA	cipa.org
IPAA Midyear Meeting	June 24-26	Colorado Springs, Colo.	The Broadmoor	ipaa.org
DUG East	June 18-20	Pittsburgh	David L. Lawrence Conv. Center	dugeast.com
Unconventional Resources Tech. Con.	July 22-24	Denver	Colorado Convention Center	urtec.org/2019
EnerCom The Oil & Gas Conference	Aug. 11-14	Denver	Westin Denver Downtown	theoilandgasconference.com
The Energy Summit	Aug. 20-22	Denver	Colorado Convention Center	theenergysummit.org
Summer NAPE	Aug. 21-22	Houston	George R. Brown Conv. Center	napeexpo.com
DUG Eagle Ford	Sept. 24-26	San Antonio	Henry B. Gonzalez Conv. Center	dugeagleford.com
A&D Strategies and Opportunities	Oct. 22-23	Dallas	The Omni Dallas	adstrategies.com
Executive Oil Conference	Nov. 4-6	Midland, Texas	Midland County Horseshoe Pavilion	executiveoilconference.com
IPAA Annual Meeting	Nov. 6-8	Washington, D.C.	Fairmont, Georgetown	ipaa.org
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
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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

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


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BACK IN THE SADDLE

STEPHEN G. BECK,
SENIOR DIRECTOR,
UPSTREAM

With earnings' season upon us, watercooler discussions are swirling around questions about shale. This month, Stratas is shining a light on the Bakken Shale, the granddaddy of shale oil. Our aim is to draw attention to new information arising from recent company announcements that could shape the play in the near term.

Recent activity and renewed guidance from operators suggest stable rig counts and lower production growth for the Bakken in 2019, a departure from stout growth in 2018. Hess Corp., the first major Bakken operator to report financial results this season, communicated that its production rose 7% from the third quarter to 126,000 barrels of oil equivalent per day (boe/d) despite some minor weather challenges in the final quarter of the year. Given the recent extreme weather conditions, Stratas expects another challenging quarter in the region. Fortunately, current prospects for spring flooding look low, according to National Weather Service reports. Snow packs and soil saturation levels are low due to dry conditions.

Stratas estimates 2019 year-end production of 1,693 Mboe/d for the Bakken, essentially unchanged from the 1,680 for December 2018. This stable production outlook reflects the play's relative maturity and expectations for operators to live within cash flow. Rig counts are expected to range between 60 and 70 during the next two years. Notably, rail exports of Williston Basin crude have been holding steady at roughly 20% of production, while refinery processing in the region dipped slightly, according to North Dakota Pipeline Authority reports.

Price volatility rose in 2018 on shifting upstream investments in shale, global trade uncertainty and risks associated with supply-demand fundamentals. As a result, leading operators adopted a variety of hedging strategies in different basins. This is also true within the Bakken community. Generally, Bakken operators have hedged around 60% of estimated 2019 production.

Since early 2008, when hydraulic fracturing began to take hold in the Bakken, operators in the top two categories (MVPs and All-Stars) controlled roughly 30% of all wells turned online. Recently, we have seen these top operators move to controlling nearly 90% of all wells in the play.

Stratas frequently refers to the following categories for producing wells: MVPs, All-Stars, Starters, Second-String and Benchwarmers. MVPs are wells which have achieved peak rates (30-day average rate) of 800-plus boe/d, All-Stars post 400 to 799 boe/d, Starters post 200 to 399 boe/d, Second-Stringers post 100 to 199 boe/d and Benchwarmers post zero to 99 boe/d.

What's behind the rising share of MVPs and All-Stars? Improving knowledge of geology and completions. Digging into completions a little further, MVPs averaged just less than 550,000 pounds per 1,000 foot of lateral length in 2013, while All-Stars averaged just over 420,000 pounds per 1,000 foot lateral.

Meanwhile, Starters typically used under 375,000 pounds per 1,000 foot. Since then, MVPs have been trending north of 1.2 million pounds per 1,000 foot, and All-Stars are trending just below at 1 million pounds per 1,000 foot, while Starters are using just over 600,000 pounds per 1,000 foot.

Looking into 2019, top operators are expected to continue pushing proppant thresholds, with completion techniques breaking the 1.5 million pounds per 1,000 foot bar.

The differences in proppant usage have led to improvements on peak rates of around 40%. Average peak rates for the MVPs increased from approximately 1,000 boe/d in 2013 and now trend north of 1,400 boe/d. The market share of MVPs in the Bakken has risen from approximately 20% of total wells turned online in 2013 to nearly 70% currently.

Lateral lengths in the Bakken have remained relatively unchanged for years. However, that is not the case with completions. Higher proppant loadings (pounds of proppant per thousand foot of stimulated rock) have become more common in recent years.

The Bakken rebounded in 2018, with operators putting more capital and rigs back into the play. Production of about 1,550 Mboe/d represented more than 10% of U.S. shale production in 2018. Going forward, we anticipate the Bakken to continue its transition into harvest mode. Rig counts are expected to range between 50 and 70 with capex ranging from $1- to $2 billion per year. Production is expected to grow 6% in 2019 to more than 1,660 Mboe/d, with an average production of about 1,750 Mboe/d during the next five years.

There is still running room for operators in the Bakken. By Stratas' estimates, the top quintile wells have enough locations to keep drilling into the early to mid-2020s with locations in the second quintile wells depleting in the early 2030s.

THE ROCKIES: WHERE NECESSITY DRIVES EFFICIENCY

Resource-in-place and lower LOEs attract robust activity.

Producers who drill the Bakken shale, develop new prospects in the Niobrara or other parts of the Denver-Julesberg (D-J) Basin, or are bringing unconventional wells and completions to the Powder River Basin (PRB) all share a common challenge: Wringing profits from production that lies at great distances from large end-use markets.

It's a dicey proposition to make money at today's crude oil prices, and it's even dicier facing large discounts to WTI. Yet best-in-class producers are doing exactly that—making money.

Bakken producers led the way on well pads and "factory drilling." DJ Basin players leveraged "lessons learned" from every U.S. shale play to find their own economic sweet spots. And lower land costs versus Permania-driven lease rates have renewed attention to targets within the PRB's stacked plays.

All three of these areas (and other plays in western states) provide the agenda topics for this year's **DUG *Rockies* Conference and Exhibition**, May 14-15 at the Colorado Convention Center in Denver. Hundreds of well-qualified oil and gas professionals, investors and technology providers will once again converge for this annual assessment of prospects, operations and economics from the Front Range into Canada.

Tapping producers' perspectives

Like Hart Energy's other DUG conference agendas, the speaker slate for **DUG *Rockies*** tilts toward producers. Nine of the 10 confirmed speakers (as of early March) are high-level executives with producing companies—and three of them (**Oasis Petroleum**, **Hess** and **Whiting Petroleum**) rank among the "Top 10" Bakken operators. (Invitations were pending with other key players as this went to press.)

Anschutz Exploration is a private E&P that's seeing exceptional results from horizontal wells drilling into as many as six targets within the PRB, where stacked pay ranges "from the Teapot all the way down to the Tensleep," according to an interview Anschutz President Joe DeDominic gave *Oil and Gas Investor* last year. The Niobrara and Mowry formations are pervasive throughout the basin, he said, and there's interest in the Turner and Parkman, too. (DeDominic will be speaking at DUG Rockies.)

Another private producer—Denver-based **DJR Energy**—is sending its VP for geoscience to the **DUG *Rockies*** dais. DJR invested near-

ly half a billion dollars last fall to acquire San Juan Basin assets from Encana Corp.—roughly 182,000 net acres.

Best practices arise from lessons learned

The potent blend of public and private company speakers—a hallmark of Hart Energy conferences—provides a full-spectrum view of what's working, what's not, and what lies ahead. For instance, when Brad Holly, president and CEO of **Whiting Petroleum**, takes the stage, he'll likely discuss how Whiting is reducing proppant use with new diversion techniques as well as other "tweaks" to the Williston Basin completion designs it's refined over the past eight years.

As North Dakota's second leading producer, the Whiting team gathers and analyzes data from a diverse roster of wells—and Holly likes what he sees. Last year he said, "If you take the labels off the wells, you'll see some of the best wells drilling in this country are in North Dakota and the Bakken."

Broader market issues

The Bakken's geology is well known and much of its acreage is HBP (held by production), so it can be difficult to optimize Bakken operations while finding room to grow. Yet the North Dakota operators' challenges pale in comparison to what faces Permian E&Ps. Additional Bakken infrastructure build-out is needed, but it's incremental relative to what Permian players must do develop the capacities needed to get oil their oil to market.

Portions of the **DUG *Rockies*** agenda will address infrastructure as well as the end-use markets driving demand for the region's surging production. Noted industry guru Tom Petrie, chairman of **Petrie Partners**, will be addressing America's renewed role in global energy security—and how Rockies and other U.S. hydrocarbon producers are changing the global geopolitical landscape.

Technology solutions and networking

Before and after conference sessions and during breaks throughout the day, the **DUG *Rockies*** exhibition floor will host attendees and provide outstanding networking opportunities. Exhibitors will be highlighting how their products and services can reduce operating costs and/or improve production results. The knowledgeable, high-level audience ensures tough questions will be asked—and promises outstanding business development potential.

Learn more online

New speakers are posted and firm agenda assignments can be viewed online at DUGRockies.com as the event approaches. If your business interests involve oil and gas activity in the Bakken, the Niobrara, or other areas within or around the Williston, D-J, Powder River or San Juan basins, you'll find uniquely actionable business intelligence by attending the 2019 **DUG *Rockies* Conference and Exhibition**, May 14-15 at the Colorado Convention Center in Denver.

NewsWell

Breakevens, lucrative acreage define basin winners

As oil prices appear to be settling at slightly lower prices than the hopeful peak periods achieved in 2018, industry players are bearing down on making the economics of plays work without a boom cycle.

Research and consulting firm Rystad Energy gave a look at top performers among oil and gas producers as well as the most lucrative acreage positions in U.S. shale plays. Those breakeven prices, tweaked by seasoned shale drillers, have responded.

Operators in the U.S. shale basins continue to prove they can make the economics work with WTI prices in more moderate ranges. In fact, during the past two years, breakeven prices on the best acreage generally ranged between $30 and $40/bbl WTI, with the top-notch acreage generating returns at below $20, according to Rystad.

Using the top 50 acreage positions with the lowest median breakeven prices, Rystad Energy partner Artem Abramov noted that even the acreage positions at the low end of the commerciality scale exhibit median WTI breakevens of roughly $46/bbl. This suggests that a $50 WTI environment will not act as a show-stopper for current U.S. shale oil activity, he said.

"Even at $45 per barrel WTI, 40% of U.S. shale oil projects will still thrive," Abramov wrote in the Feb. 13 report.

For example, Chevron Corp., one of the top performers per Rystad, had a median breakeven price on the Texas portion of its Delaware Basin operations at $18.90 WTI—the lowest noted in the Rystad report.

Still, the report found the majority of median breakevens concentrated in the $30- to $45-per-barrel range, which Abramov said were in areas where activity has evolved to the development phase.

He did note certain factors could make particular operators even more profitable. These included "excellent operational performance, outstanding acreage quality and unique features related to ownership of mineral rights."

"In many basins, operators that were not viewed as basin master several years ago have nevertheless managed to complete their way to excellence through high-grading, optimization of well design, cost structure and initiation of a full-scale development program," Abramov said.

He also cautioned that some of the largest players may not appear among the top performers because they have test programs on less prospective acreage.

Starting in the Bakken, the Rystad report found the top three performers were Marathon Oil Corp., WPX Energy Inc. and Newfield Exploration Co.

In the portion of the Delaware Basin in New Mexico, Mewbourne Oil Co. Inc., Occidental Petroleum Corp. and Devon Energy Corp. topped peers on the Rystad list. While in the Texas portion, top Delaware operators were led by Chevron followed by Rosehill Resources Inc. and Cimarex Energy Co.

Chevron also headed up the Rystad ranking of northern Midland Basin players followed by Endeavor Energy Resources LP and SM Energy Co. Meanwhile, the southern Midland Basin featured Apache Corp., Pioneer Natural Resources Co. and Concho Resources Inc. as top players.

Rystad divided the Eagle Ford Shale into Central Core and East Core groups. Chesapeake Energy Corp. led Rystad's Eagle Ford Central group followed by EOG Resources Inc. and Marathon Oil. Meanwhile, BP Plc and Devon Energy dominated the Eagle Ford East group followed by EOG Resources and Murphy Oil Corp.

In the Denver-Julesburg Basin, SRC Energy Inc., Anadarko Petroleum Corp. and Noble Energy Inc. led basin-wide breakevens, according to Rystad.

Lastly, Rystad found that Mid-continent Stack players faced higher breakeven hurdles. Still, Newfield Exploration held the lowest median breakeven at $44 with Alta Mesa Holdings LP and Devon Energy close behind.

The analysis included in the Rystad report looked at acreage with at least 30 horizontal oil completions drilled between 2017 and 2018 with more than three monthly production

Top 3 Performers Among Players By Basin*

Basin	Operator	Median WTI BEP	Median basin-wide WTI BEP
Bakken (core)	Marathon Oil Corp.	$35.1	$51.4
	WPX Energy Inc.	$38.7	
	Newfield Exploration Co.	$39.5	
Delaware NM	Mewbourne Oil Co.	$29.0	$42.5
	Occidental Petroleum Corp.	$29.1	
	Devon Energy Corp.	$43.7	
Delaware TX	Chevron	$18.9	$45.0
	Rosehill Resources Inc.	$31.3	
	Cimarex Energy Co.	$33.4	
D-J Basin (core)	SRC Energy Inc.	$23.2	$36.5
	Anadarko Petroleum Corp.	$25.1	
	Noble Energy Inc.	$31.6	
Eagle Ford Central (core)	Chesapeake Energy Corp.	$31.2	$52.4
	EOG Resources Inc.	$46.8	
	Marathon Oil Corp.	$55.0	
Eagle Ford East (core)	BP & Devon Energy Corp. (BH area)	$28.7	$41.6
	EOG Resources Inc.	$37.1	
	Murphy Oil Corp.	$38.2	
Midland North	Chevron Corp.	$30.8	$44.3
	Endeavor Energy Resources LP	$33.9	
	SM Energy Co.	$34.5	
Midland South	Apache Corp.	$38.6	$53.0
	Pioneer Natural Resources Co.	$43.8	
	Concho Resources Inc.	$45.0	
Stack	Newfield Exploration Co.	$44.0	$53.6
	Alta Mesa Holdings	$47.3	
	Devon Energy Corp.	$50.3	

*Top performers are selected only among acreages with at least 30 horizontal oil well completions in 2017-2018 (four production months). Source: Rystad Energy ShaleWellCube Premium

reports. The firm defined acreage as a combination of operator and sub-basin, looked at median, P-25 and P-75 WTI breakevens and discounted these calculations by 10%.

—Susan Klann

OPEC welcomes forecasted wave of U.S. shale production

A second wave of production growth from U.S. shale may have been forecasted by the International Energy Agency (IEA), but OPEC Secretary-General Mohammad Barkindo is not fazed.

Instead, Barkindo told attendees of CERAWeek by IHS Markit on March 11 he not only welcomes the revival of the U.S. oil and gas industry, but attributes its strong rebound partly to the cooperation between OPEC and non-OPEC producers led by Russia during the past couple of years.

Despite restored confidence in the U.S., Barkindo issued a warning for the need of additional oil supply growth, not only from the U.S. but other regions as well, in order to meet global oil demand, which he said will remain strong.

"What we need to focus on now is that this rebound, as the result of the short-cycle investment that pumped into the shale basins, should also now be reflected in the long-cycle projects around the world. … The shrinkage in investment in the last couple of years is still a huge challenge because this rebound is only in the U.S. Outside the U.S. we've seen just a trickling of investment capital coming back into the industry," he said.

Barkindo also said the rebalancing of oil markets is a "work in progress."

OPEC and its allies began new production cuts earlier this year, agreeing to reduce supply by 1.2 million barrels per day (MMbbl/d) for six months.

Barkindo indicated that OPEC and allies will continue supply adjustments through 2019. The producers will meet in Vienna in April with another gathering scheduled for late June.

Earlier in the day, the IEA released a report projecting the U.S. as leading future global oil supply growth, adding another 4 MMbbl/d of oil production during the next five years. The U.S. is currently the world's largest producer of crude, thanks to a boom driven by shale production, with record output of more than 12 MMbbl/d, according to data from the U.S. government. Production in the U.S. has risen by about 2 MMbbl/d in the last year alone.

The major finding from the IEA report, according to Fatih Birol, IEA's executive director who spoke alongside Barkindo on the panel during CERAWeek, was that the U.S. is entering into a second phase of the shale revolution.

The first phase was mainly the production of shale oil and gas for domestic purposes. "But now," he said, "the second phase is starting namely making the U.S. a major energy exporter, changing the direction of the trade flows in oil and gas."

Birol sees the U.S. overtaking Russia in the next three years and Saudi Arabia in the next five years in terms of oil exports. Also, in terms of natural gas, he said 75% of LNG exports will come from the U.S.

Global oil demand growth is set to ease as China slows, but will still rise by an annual average of 1.2 MMbbl/d by 2024 when it will reach 106.4 MMbbl/d.

Still, the IEA does not see a peak in global demand with Birol noting that moves such as greater adoption of electric cars will not put a cap on demand growth just yet.

Despite the record number of electric cars sold last year, oil demand continued to increase. Birol said this was because cars only make up 19% of global oil consumption.

"When we look at the dynamics of the oil demand growth, cars are not the major drivers," he said. "Drivers are trucks, petchem, aviation and shipping—these are the main drivers."

—Emily Patsy

Quantum CEO: Welcome to shale 3.0

Public companies have set a promising stage for themselves during the next five years, Wil VanLoh, founder and CEO of private-equity provider Quantum Energy Partners, said March 5 at Hart Energy's Energy Capital Conference in Dallas.

E&Ps are entering a new stage in their development in which they extend cost cutting and efficiencies, while maximizing their profits with technology, logistics and marketing, he said.

"If you're a private operator in the room today, that should scare you," VanLoh said. "Shale 3.0 is about efficiency, it's about manufacturing, and the advantage of that often goes to the larger company that can bring economies of scale to the table."

The S&P and E&Ps: Percent Change Since 2016 Peak

S&P 500	23%
S&P E&P Index	(29.4%)
Permian	(31.8%)
Appalachia	(52.7%)

Source: Capital IQ, Quantum Energy Partners

Shale 3.0 is what VanLoh calls the third iteration of shale phenomenon. According to his nomenclature, Shale 1.0 represented the E&P land grab from 2007 through the end of 2011, while Shale 2.0 was the productivity phase from 2012 through 2016. Since 2017, operators have been embarking on increased efficiency through data analytics, logistics and procurement and commodity marketing.

As they've become more focused on process, public companies are in the process of consolidating acreage.

"If you look at the top 10 independents in the U.S. at their current rig cadence they've got a 44-year inventory," he said.

That doesn't include potential upside—just stated locations, he said.

To entice a public buyer, private-equity companies have to offer assets that can displace a public company's top-quartile inventory.

"That's increasingly becoming a harder thing to do in the private equity world. And in a world where public companies are going to be more and more disciplined about what they're going to buy" he said.

"A lot of that capital was spent inefficiently, really alienating a lot of investors, particularly

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EPIC CRUDE PIPELINE

The **EPIC** Crude Pipeline project includes terminals in Orla, Pecos, Saragosa, Crane, Wink, Midland, Helena and Gardendale, with connectivity at the Port of Corpus Christi with an **EPIC** marine terminal and four additional third-party terminals. The **EPIC** Crude Pipeline runs side-by-side with the **EPIC** NGL pipeline.

Pipeline construction is scheduled for completion in 4th Quarter, 2019

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in the public realm, that have supported this industry for so long," VanLoh said.

The result is "really almost a disdain for energy," in which frustrated investors have walked away, VanLoh said. While the broader S&P 500 has fared well since 2016, E&Ps in that universe continue to suffer, trailing the broader market by about 52 percentage points.

Public companies are in the process of trying to "heal that relationship" through capital discipline, returning capital to investors and reducing debt. "That's got pretty profound implications … for public investors but also creating opportunities for private companies to gain meaningful market share," he said.

The public markets remain a tough environment for private companies. In 2016 and 2017, private upstream exits averaged about $6- to $7 billion a quarter, VanLoh said. "In the past two years, it's averaged a little over $1 billion a quarter."

Public companies are also exploring large-scale development using pad drilling.

However, even for large companies, pad development involves risk and huge capital outlays. A 24-well pad may cost as much as $300 million. Even an eight-well pad consumes the equivalent of a quarter billion pounds of sand and 305 Olympic-sized swimming pools of water.

That makes logistics and procurement even more important to those companies. Public E&Ps are also increasingly relying on data analytics, robotics and commodity marketing. Embracing technology and other efficiencies could save companies $8 to $10 per barrel (barrel) of oil.

Even getting products to market has given public companies an advantage, with some prominent Permian Basin companies able to export their oil and NGL.

"There was a point last year at which there was a $15 to $20 delta between the companies really on top of the marketing side of their business [earned] and what private operators were getting," VanLoh said.

Private companies will be challenged to keep up while still making themselves attractive to would-be buyers.

"Logistics and procurement are a huge part of this business going forward," he said.

Ultimately, that means private operators will face a significant strategic shift in how they do business, one in which they hold land for perhaps twice as long as they did leading up to 2016 and focus more on cash-flow metrics than the net asset value (NAV) of undrilled locations.

Private operators have responded, increasing rig counts at a faster pace than publics and now they operate 37% of rigs compared to about 30% during the past several years, VanLoh said.

With among the best breakeven production costs in the world, VanLoh said the U.S. shale revolution has largely been won. In retrospect, that may have been the easy part.

—Darren Barbee

New E&P model emerges as belts tighten

The slowdown in the A&D market along with moderating commodity prices and repercussions from the most recent downturn have permanently changed the outlook for both public and private players in the upstream oil and gas industry.

A mid-February note from Tudor, Pickering, Holt & Co. (TPH) discussed the overall "health" of private E&Ps, which, ever since the portfolio-crushing downturn of '14, have had to shift their models—particularly their exit plans. In fact, today it's hard to identify a typical timeframe for build-up, hold and sell for private E&P companies. Similarly, the publics must also be more cautious and measured in their approach now, as investors demand lower debt, more free cash flow and less risk.

"All signs point to a lack of visibility on exit strategies [for private E&Ps] and the need to shift business models—enter the super privates," the firm said.

The TPH team observed that with the pressure now on public companies to produce free cash flow and to "moderate growth," private companies may no longer fit the bill as acquisition candidates unless they have also changed their models.

"This likely means a cut to activity to slow growth, mergers to create productive scale, cuts to overhead and line of sight to free cash flow while preserving undeveloped inventory for potential exit long term," the firm said, noting it estimates productive scale at 1.5 billion cubic feet per day (Bcf/d) for gas companies or 50,000 barrels per day (bbl/d) for oily drillers.

In looking at the broader implications for the upstream industry, with many having reported fourth-quarter 2018 earnings, TPH said that "it's clear that capital cuts have been steeper than initially envisioned."

Thus, the team looks for a 13% drop in drilling for the 2019 average vs. the year previous. This, combined with the stricter spending guidelines announced by public companies in their recent earnings reports, could eventually slow production, lower service costs and in turn raise prices … repeating a cycle that has been a familiar one through the years.

The TPH analysis observed that as rigs start to "precipitously fall" over the coming months, and activity levels drop across the industry, this "could create additional tailwinds on cost going forward."

In additional upstream trends analysis, TPH analysts focused attention in late February on the recent announcements of pared general and administrative (G&A) expense by companies such as Devon Energy Corp. and QEP Resources Inc. After looking at G&A expense in relation to a variety of metrics, TPH said that investors' focus on this expense may continue.

"Ultimately, low-cost operators like FANG [Diamondback Energy Inc.] and CLR [Continental Resources Inc.] are driving top-tier margins by continuing to focus on this expense line item year in and out, but there is a wide rift in metrics between industry participants, and ultimately investors may require higher-cost producers to pull in line with their lower-cost peers," TPH said.

The firm estimates Diamondback's G&A per rig in 2019 at roughly $3 million and Continental's at $6 million. This, TPH added, results in less than 1% G&A/market cap and less

than 5% G&A/EBITDA for both companies.

Devon announced it would sell its Barnett and Canadian oil sands holdings as well as make other cost reductions. Additionally, QEP said it would reduce its G&A expenses by about 45%, when comparing 2018 to 2020, with most reductions during the first half of this year.

The belt-tightening can only continue.

—Susan Klann

How oil bottlenecks bruise prices, deals and trade

Crude producers struggling with takeaway constraints might need to get used to the pain.

Getting the oil out of the basins isn't enough—it's all about market access. The infrastructure must be in place to move oil out of basins to coastal terminals for export, a Wood Mackenzie analyst told executives at the NAPE business conference in February. Until that happens, both commodity prices and M&A deal economics will suffer.

"The U.S. is really focused on hydrocarbon exports in general, especially in the crude space," said John Coleman, WoodMac's senior analyst for North American crude oil markets. "If you're looking to purchase an asset … the thinking needs to be on a global basis, not a regional basis, as your crude is going to be placed likely into an export market and has to be priced accordingly."

While NAPE markets itself as "where deals happen," some of them simply won't happen, at least for the moment, if the region in question lacks infrastructure support and market access doesn't exist or comes up short. In 2018, takeaway constraints in the Permian Basin dealt a blow to Midland Basin prices.

"With intense growth comes intense growing pains," Coleman said. "You saw that play out in the first level in the Permian Basin in 2018 without sufficient infrastructure to support some of that growth."

Pipeline constraints in the Permian, he said, may be in the rear-view mirror but troubles are emerging in other regions. Production growth in areas such as the Powder River and Niobrara areas in the Rockies, the Bakken and the Scoop/Stack area in the Midcontinent are expected to put substantial pressure on regional infrastructure systems. As those systems fill up, transport slows and access to markets becomes more difficult. The Cushing, Okla., hub, for example, is beginning to feel the pressure of the increased volumes.

And shifting a constraint from one part of the system to a point further down the chain creates its own problems.

"It's starting to show up in pricing distortions in Rockies markers, potentially Bakken markers and Cushing, the granddaddy of all pricing points for WTI, could start exhibiting these against Brent, as well," Coleman said.

In a recent report, Alerian echoed those concerns.

"With Permian crude pipeline capacity set to increase significantly, the question is if midstream is fixing one bottleneck just to create another one on the Texas Gulf Coast," wrote Michael Laitkep. "One potential destination for Permian crude is Texas refineries, but their complexity is a limiting factor in their ability to run light, sweet crude. In general, to balance crude supply and demand along the Gulf Coast, incremental barrels will need to be exported."

Permian producers struggled to move their crude to Gulf Coast export terminals in 2018, but once the oil made it to the coast, it had free-flowing access across the docks on its way to markets, Coleman said. That paradigm is changing.

Much of the newbuild capacity under construction targets Corpus Christi, Texas, Coleman said.

"This is somewhat of a problem because Corpus Christi has less-developed crude infrastructure relative to neighboring Houston and Beaumont, and also a smaller refining footprint," he said. "So, a lot of crude is coming into a market that might or might not be able to handle all that is coming in."

WoodMac and Alerian agree that, over the long term, export capacity is unlikely to be constrained because of how quickly the midstream is responding to the infrastructure need. The South Texas Gateway Terminal in Corpus Christi, a joint venture including Buckeye Partners, Phillips 66 Partners and Marathon Petroleum Corp., is on track to start up at the end of 2019. Expansion of Magellan Midstream Partners' Seabrook crude terminal is also scheduled for the end of this year.

Typically, the midstream part of the value stream follows upstream growth. Construction projects take time and many won't be ready until late 2020 or 2021. During that lag time, a lot of crude will be looking for ways to export in 2019 and 2020, Coleman said.

Until takeaway improves, deals in some regions might have to wait.

"Any deals you might be evaluating in those parts of the world, you might need to have a plan in place for firm market access or a hedging plan to mitigate any type of potential infrastructure shortfalls," Coleman said.

Or, learn to embrace the pain.

—Joseph Markman

Energy CEOs' total compensation up 5% in 2018

Average total compensation for CEOs and CFOs in E&P companies increased this year vs. 2018, primarily due to the value of long-term incentives (LTI). This is according to a report by Alvarez & Marsal's compensation and benefits practice, which reviewed the 2018 proxy statements of the largest U.S. E&Ps.

The practice also surveyed annual and long-term incentives for CEOs and CFOs; the benefits

CEO Annual Compensation

Market Capitalization Rank	Base Salary	Annual Incentives	Long-Term Incentives	Other Compensation*	Total
Top Quartile Average	$1,102,001	$2,125,873	$8,261,562	$713,936	$12,203,371
Second Quartile Average	$854,185	$1,356,029	$5,748,181	$349,308	$8,307,702
Third Quartile Average	$567,657	$781,396	$4,335,307	$115,724	$5,800,084
Bottom Quartile Average	$493,056	$455,488	$1,497,138	$161,650	$2,607,332
Average	$754,225	$1,189,352	$5,006,726	$335,154	$7,285,457
Year-Over-Year Increase / (Decrease)**					**5%**

CFO Annual Compensation

Market Capitalization Rank	Base Salary	Annual Incentives	Long-Term Incentives	Other Compensation*	Total
Top Quartile Average	$583,736	$900,354	$2,986,253	$387,168	$4,857,511
Second Quartile Average	$484,538	$523,083	$2,147,263	$145,613	$3,300,496
Third Quartile Average	$383,110	$469,093	$1,791,937	$130,551	$2,774,691
Bottom Quartile Average	$324,615	$309,524	$797,724	$43,805	$1,475,669
Average	$447,226	$557,027	$1,977,359	$179,002	$3,160,614
Year-Over-Year Increase / (Decrease)**					**12%**

*Other Compensation includes: change in pension value above market earnings, and "all other compensation" as disclosed in each company's proxy statement.
**Only includes executives in both 2018 and 2019 studies.
Source: Alvarez & Marsal

to which executives are entitled upon a change in control (CIC); and CEO pay ratios. Seventy-six companies were analyzed, ranging from $25 million in market cap to as high as $65.6 billion.

Overall, CEOs saw a 5% increase in average total compensation from the $7,285,457 average paid in 2018; CFOs enjoyed a 12% boost over the 2018 average of $3,160,614.

"On average, incentive compensation—including annual and long-term—comprises approximately 85% of a CEO's and 80% of a CFO's total compensation package," the report noted.

In terms of annual incentive plans where payout is determined on a purely discretionary basis, just 5% of companies in the top two quartiles use this method, while about a quarter of those in the bottom two quartiles use such metrics. The most common metric in determining annual plans is production/production growth, with 87% of companies following this path. In terms of long-term awards, time-vesting restricted stock/restricted stock units are used by 96% of companies.

Nearly three-quarters of companies grant long-term incentive awards where vesting or payout is determined by one or more performance metrics, according to the report, and of these, relative total shareholder return is the most common, and three years is the most common performance period employed.

When there is a change in control (CIC), the most common cash severance multiple is three times compensation or greater (48% for CEOs) and two to three times compensation for CFOs (66%). In this situation, the most valuable benefit received is accelerated vesting and payout of long-term incentives, making up 59% and 56% of the total value for CEOs and CFOs, respectively, according to the report.

Bankruptcy compensation is also highly relevant for energy firms given the industry's upcycle and downcycle. The report noted that more than 150 E&Ps have filed for bankruptcy since 2015, and even in 2018 energy had more than any other industry.

"Incentive programs, when properly structured, can help bridge the compensation gap between the onset of financial hardship and a healthy go-forward restructuring," the report's authors said. They noted that equity granted upon emergence from bankruptcy is also used to motivate and retain employees.

IPOs have been sparse of late in the E&P industry, with just five during the 2017 to 2018 period. When planning an IPO, the authors said, among the compensation practices to consider are selecting a peer group, compensation and design benchmarking and governance policies.

"By forming an IPO roadmap, however, a company can ensure that its executive compensation programs and policies are competitive with the market; within industry norms; compliant with various government requirements; and aligned with executive and shareholder interests."

—*Susan Klann*

Increasing women in STEM fields a must for U.S.

If the U.S. wants to remain competitive on a global scale, the nation must increase the number of graduates being prepared for STEM fields, said M. Katherine Banks, Texas A&M University vice chancellor of engineering and national laboratories.

Banks recently received the Pinnacle Award during *Oil and Gas Investor*'s 25 Influential Women in Energy Luncheon on Feb. 12. She told the audience of nearly 1,100 energy professionals that STEM fields need the creativity and diversity of perspectives for better product design and development.

"Studies reveal that men and women approach product design differently," said Banks, who also serves as dean of Texas A&M's College of Engineering. "If products are developed without the perspective of half of the consumer base, problems can arise."

Banks cited issues involving first-generation air bags for cars, which were designed and implemented by a group of male

engineers. The design was for male bodies, which resulted in production malfunction for both women and children. Also, early voice recognition systems were calibrated to only male voices, which resulted in poor results for women.

Banks said radical steps must be taken to identify, attract and nurture prospective women who may go into STEM and energy fields. The college of engineering has a goal of increasing its percentage of women from 24% to 32% as part of overall enrollment growth by 2025, she said.

According to a 2016 Forbes report, the share of women in the oil and gas work force was below 20%, while women in senior level positions hovered between 10% and 15%.

"We must provide young girls with hands-on, learn-through-doing opportunities and encourage each and every one of them to consider an engineering career," Banks said. "We need to tell them not only what we do but why we do it.

"There is a wide range of opportunities for women in energy and other STEM fields, and this must be communicated to girl students at all levels. It is time to thoughtfully embrace those who will follow in our footsteps and prepare the path for the female leaders of the future."

A pioneer herself, when Banks took over as dean of the college of engineering in 2011 she became the first woman to head Texas A&M's largest college. She leads one of the largest engineering schools in the country with more than 16,900 students and 500 faculties. Banks initiated the 25 by 25 program, which is a controlled enrollment program that has a goal of enrolling 25,000 engineering students by 2025.

As vice chancellor, she oversees coordination and collaboration among the engineering, academic and research programs at seven universities throughout the A&M system, as well as three state agencies: the Texas A&M Engineering Experiment Station (TEES), the Texas A&M Engineering Extension Service and the Texas A&M Transportation Institute. Banks also is the TEES director, overseeing research administration of more than 4,800 projects and $208 million in sponsored research awards.

As Banks looks at ways to grow her engineering program, she said she also feels a responsibility to increase the number of women in the field. Currently there are 1.5 million engineers working in the U.S. and only 14% are women.

She pointed out that women make up in excess of 45% of the student population in other critical professions such as medicine and law, while women receiving engineering degrees remain less than 20% nationally.

"This new approach to education will produce technology leaders who are uniquely prepared to address tomorrow's challenges, however, to meet the need for an expanded engineering work force it is essential that we increase our recruitment of women," Banks said. "I recognize that I'm preaching to the choir here, but the need to increase opportunities for women and to pursue degrees in STEM fields and energy is crucially important.

"Public awareness of the need for more women for STEM has never been higher. But the issue is more than just about disparity of numbers. The low number of women in STEM fields means we are lacking the perspective of half the population when creating high-tech economic development opportunities. Engineering relies on design creativity and diversity of perspective and that leads to better product design and development."

—Terrance Harris

Hunt sees value in international oil exploration

With economic cash engines in bountiful U.S. shale plays like the Permian Basin, Eagle Ford, Marcellus and the Bakken, why would a Dallas-based oil and gas company leave home where production levels are regularly shattered to explore internationally?

For Hunt Oil Co., a private E&P with assets spread across the globe, it's about opportunity.

"For us, the answer is really simple. It offers a great opportunity in a less competitive landscape with the potential for significant discoveries as we go forward," Mark Gunnin, president of Hunt Oil Co., told a crowd gathered Feb. 13 for the NAPE Business Conference.

While few could argue against U.S. unconventionals being a driving force in the industry today, the world has more to offer. The company learned this more than four decades ago when it first ventured into the North Sea before later spreading its wings to Yemen, where the company has produced more than 1 billion barrels of oil.

Hunt Oil has assets in Peru, where it owns and operates the only LNG export facility in South America and produces—with a partner—about 1 Bcf/d of gas and 90,000 bbl of liquids. The company has more plans in store for the South American country, having recently signed three new exploration agreements.

Add to this Romania, where Hunt Oil is gearing up to chase deep oil prospects, and the Kurdistan region of Iraq, where Gunnin said the company signed a contract a day after its petroleum law was passed in 2007. Today, Hunt Oil is producing about 10,000 bbl/d in the Kurdistan region and hopes to double that this year, he said, before turning to Yemen.

"[Yemen is] our large international discovery to date, noticeably 30 years ago, and we produced over a billion barrels from there," he said. "We recycled 12 Tcf [trillion cubic feet] of gas during that project and ultimately we have participated, as a nonoperator with Total, in an LNG project that this gas is still the feedstock for."

The company maintained its international presence when the market downturn forced many to stick closer to their home and opt not to pursue international exploration. Oil and gas companies drastically cut back spending, slashing exploration budgets and shelving projects until market conditions improved.

"The steady cash flows that we can get from our conventional assets really provide a buffer for us in times of volatile prices," Gunnin said, noting the company was still able to grow its production despite reducing its capex budget by 90% from 2015 to 2017, compared to 2012 to 2014.

Most of Hunt Oil's conventional assets are international.

The company is bullish on conventional production and believes that is what is needed to develop significant upstream resources. The shrinking field of international players only expands the number of opportunities for small- and mid-sized independents with the technical know-how and financial backing to chase global prospects, according to Gunnin.

But the company, which he said has always been a wildcatter, is mindful of the risks it takes. With a goal of finding "through the drill bit step-change resources," Hunt Oil is focused on oil-weighted potential and gas-serving premium markets, he said.

"We're looking to build around the areas we understand, where we have core institutional expertise that allows us to react quickly," he continued. These include places where there are stable fiscal and regulatory regimes, where the company can apply new technology or lessons learned elsewhere, with potential upside and plenty of acreage.

"We may not have an elephant in our sights when we get there, but we at least want to have the ability—based on acreage that may be available or acreage that we control—to at least get a wildebeest out of it," Gunnin said.

As an international explorer, it is important to understand opportunities and the rocks but it is also important to know what to avoid. That said, he still added that companies wanting to pursue international exploration should be open to opportunities "out of left field. A number of the best projects we've ever been involved in were not on our radar."

At present, Hunt Oil doesn't have its sights on deep water, Southeast Asia or the Arctic, but it has areas of interest in Mexico, North Africa, the Middle East and the Andean region of South America, among other areas.

"It's easy to run around the world chasing the next new deal. But what that leads to is distraction, a lot of time in data rooms and not a lot of deals and drilling," Gunnin said. "We've really refined our strategy in the last handful of years to focus on mature basins for the most part within oil-proven provinces and to build around areas where we have expertise."

—Velda Addison

Hedge funds find little love for energy stocks

Hedge fund billionaire investors frequently get media attention for their outsized paychecks, lavish lifestyles, amazing wins and woeful miscalculations. Bloomberg reported that in 2018, hedge funds posted an aggregate loss of 5.7%. Still, wouldn't it be useful to know what they are investing in?

To see where their money is going, WalletHub analyzed the SEC filings of over 400 hedge funds to determine their biggest equity holdings, new positions and largest equity sales in 2018.

Of the 25 most frequently held stock positions by these funds, Microsoft, Amazon and Apple were the top three. No surprise there. Mostly tech and financial or

bank stocks, and a few healthcare stocks, made the list.

The highest-ranked manufacturing company was Boeing at No. 13. No. 25 was billionaire investor Warren Buffett's own Berkshire Hathaway Inc.

Not a single energy-related company made the top 25.

WalletHub also took a deeper dive to identify the top three holdings of several celebrity billionaire hedge fund managers known for their investing acumen. Only Carl Icahn was listed as owning enough energy-related equities to make the top three list. He owned 9.4% of LNG leader Cheniere Energy Inc. as of Dec. 30. During 2018, the biggest new position he added was Diamondback Energy Inc., of which he owned 6.3% at year-end.

Despite the reputation of hedge fund managers, there is no guarantee of success. For example, last summer, Icahn took control of SandRidge Energy Inc., gaining five of its eight board seats and instituting broad changes. In January, a new CEO was named, Paul D. McKinney. At the time Icahn gained control, the stock was trading for about $17 a share; more recently it was around $8.

—Leslie Haines

Risk management makes, breaks producer success

What's the secret to running an energy company? Finding new reserves? Cutting costs? Admirable safety records? Keeping investors happy?

All of those challenges can be summed up in how management handles risks. That was a common theme in some two-dozen investor presentations given Feb. 27 to 28 at EnerCom's Dallas 2019 investor symposium.

"All we do is manage risk," Talos Energy president and CEO Timothy Duncan told conference attendees, echoing comments in other presentations as executives described how their organizations cope with an unsettled market.

Talos' focus has been on the Gulf of Mexico, both in the U.S. and Mexico. Duncan noted Talos' Zama discovery in Mexico drew Wood McKenzie's rating as the 2017 discovery of the year. Talos was a first mover into Mexico's upstream following that nation's constitutional changes that allowed private firms to enter exploration and production for the first time in 80 years.

In U.S. waters, the firm's extensive seismic footprint, coupled with advanced reprocessing, will allow Talos to develop its portfolio around deepwater infrastructure it now holds, including Green Canyon and Mississippi Canyon.

Likewise, GeoPark CEO James F. Park described his firm as "a risk management business." It's business model—creating and operating "a Texas-style independent in Latin America"—has been a challenge but has been successful, he said.

Park noted GeoPark production grew from 6,000 barrels of oil equivalent per day (boe/d) to 36,000 boe/d in nine years, from 2009 to 2018. Net present value has increased by a compound annual growth rate of 26%, he added. The firm has operations in Argentina, Brazil, Chile, Colombia and Peru.

GeoPark has had major finds in Colombia's Llanos Basin and Peru's Marañon Basin, as well as Chile's first oil production.

One of the industry's more diversified players, Tulsa, Okla.-based Unit Corp., must consider the risks and rewards of investing capital in its three businesses: exploration and production, drilling, and midstream gathering and processing.

"We are in as good a shape as we have been in the 38 years I have been in this business," Unit president and CEO Larry Pinkston told the conference, "because of a history of excellent capital stewardship."

Upstream, "our prospect inventory is very good," he added.

Pinkston said Unit's upstream portfolio offers high-return drilling opportunities, growing oil and liquids component and attractive full cycle. In the midstream, its Superior Pipeline subsidiary "enhances Unit's all-in drilling economics and provides a predictable cash-flow stream, supported by both Unit and third-party volumes." Meanwhile, Unit Drilling "has a high-spec AC rig fleet that is fully contracted."

Data, and its potential uses, allow producers to better manage risk through rapid development of artificial intelligence and machine learning, said Tom Chikoore, founding principal with Innovation Illustrated, a data management consulting firm.

Unfortunately, many energy firm data management projects "fail to get out of the laboratory," Chikoore said. Such projects "have got to marry the business objectives" of a firm to be a success. But the potential rewards can be tremendous when that happens, he added. Businesses "can leapfrog [competitors] because they have a lot of data" and know how to use it.

Brian Lidsky, senior director at Drillinginfo Inc., also had much to say about data and its impact on managing risk.

"We're a decade into the shale revolution," Lidsky reminded the conference, and the industry has a vast amount of financial and operational data to draw on to help executives make wise decisions. The challenge is to make all that information usable.

Although commodity markets have been unsettled, he pointed out "the good news in terms of prices is that, basically, we are where we were a year ago" despite ups and downs in recent months.

But Wall Street hasn't recognized that and energy stocks remain out of favor, he said. "Obviously, the sentiment for E&Ps has been challenging."

—Paul Hart

Turnham: Haynesville Shale remains a hidden gem

When calling plays for the natural gas game, the Haynesville Shale is often overlooked. But no one's rooting for the underdog more than the basin's own operators, citing favorable economics and scalability as the play's hidden gems.

While typically in the shadows of the Marcellus' and Utica's big muscles and the always popular Permian Basin, Haynesville players are adamant the shale basin is just as promising.

Speakers were sure to address their great success in the play at Hart Energy's DUG Haynesville conference in Shreveport, La., in February. But, the operators emphasized that a strategic game

plan is necessary to take on the Haynesville.

"We've got to educate the market, educate investors and get investors back to the space," Rob Turnham, Goodrich Petroleum's president and COO, said.

A lot of the resistance to setting up in the play, Turnham said, is due to "a bunch of guys that don't want to do the work, and they assume that the Haynesville and other basins have a high-cost structure.

"When you look at low-cost basins, the reputation use to be that the Haynesville was a high-cost basin, but not anymore. It's a low-finding cost."

Currently, Goodrich Petroleum holds 20,000 net acres in North Louisiana that is 100% HBP. In its leasehold position, the E&P company has drilled more than 102 wells that are both online and producing. Goodrich also holds an additional 3,000 acres in the Shelby Trough and Angelina River Trend.

"We don't have a huge footprint [but] it happens to be in the best rock in North Louisiana and what we call the Angelina River Trend," he said. "We'll spend about $100 million this year drilling in North Louisiana and that'll get us 10 net wells with an average lateral length of about 7,500 feet."

Turnham said that his company's continued interest in the play is mostly driven by its favorable economics.

This includes low lease operating expense, severance tax abatement from the state of Louisiana and ample service company capacity. And—his most emphasized factor—a high-price realization because it's "a big strategic advantage when comparing against the Marcellus."

"We know that the Haynesville is the basin of choice due to the close proximity to the Gulf Coast petrochemical plants in addition to LNG exports to Mexico," he said.

Additionally, on service company capacity he said Haynesville operators benefit from enough service capacity in the basin that it keeps a reasonable cost structure for them, so the service companies can generate sufficient returns.

"It's all about the economics and that is what we think is missing in the market. The assumption that it is gas and therefore you can't generate competitive rates of return is actually wrong," Turnham said. "If you take that 2.5 Bcf [gas production] curve, you bake in low-operating expenses, no severance tax … and you honor our early time outperformance of the curves—even the short laterals—you really start to see the benefit of the longer laterals to your rates of return."

"This competes with a lot of the Permian," he added.

Keeping this in mind, Turnham said that Goodrich hadn't drilled in the Haynesville for about three years prior to 2017. Despite coming in slow, Goodrich is projected to average 140 MMcfe/d of natural gas with the possibility of hitting 200 MMcfe/d of production exiting 2019. "The ability to grow is pretty obvious," he said.

"The completions recipe is working and the acreage is in the right zip code," Turnham added.

—Mary Holcomb

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Saulsbury Industries

Jeff Fulmer
Executive Vice President
CorEnergy Infrastructure

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BATTLEGROUND STATE

The Colorado oil and gas industry is on the state's endangered list, fighting a running battle with activists intent on stopping fracking. Just months after defeating a statewide proposition, the industry faces new challenges from lawmakers.

ARTICLE BY
DARREN BARBEE

PHOTOGRAPHY BY
RICARDO MERENDONI

In the fall of 2018, genuine fear ran through Colorado's oil and gas industry in the runup to the November election.

At first, the ballot initiative, ultimately referred to as Proposition 112, hadn't been widely viewed by the industry as a threat. The proposition was a superb piece of subterfuge. It appeared to be an effort to push back drilling nearly half a mile from homes and schools. The legislation's true, if masterfully veiled intent, was to kill off oil and gas on virtually all state lands.

An internal study group at one of the largest Colorado upstream companies concluded that the proposal lacked the signatures to bring it forward, according to a Colorado-based employee who is not being named because he was not authorized to speak on behalf of the company.

But environmental activists had set the stage in 2018 for an epic takedown of Colorado's oil and gas industry. By the time it was clear the proposition would qualify for the November ballot, "we were in scramble mode," the employee said.

A company leader delivered a blunt message to staff: "Look, this could be our jobs. This is a reality. You better start caring."

The industry, which in Colorado supports more than 230,000 jobs and pays $1 billion in annual state taxes, mobilized.

Companies contributed nearly $38 million to Protect Colorado, a committee opposed to the ballot measure. Rank-and-file and management-level employees stood on street corners, holding political signs that pleaded for their jobs. Companies raced to lock in drilling permits and grandfather in wells in case they lost the vote.

In the span of six months, from June to November, the Colorado Oil and Gas Conservation Commission (COGCC) recorded receiving 5,544 permit applications—nearly matching the total number of permit requests for all of 2017.

"This was do or die," said Tracee Bentley, executive director of the Colorado Petroleum Council.

"People didn't understand the impact that [Prop 112] would actually have," Bentley told *Investor*. "The industry, obviously, put a lot of resources in to it, but we felt like we didn't have a choice."

Prop 112 would have made 85% of Colorado's state lands inaccessible to future oil and gas development, according to COGCC. In the state's top five producing counties, an estimated 94% of land would be off limits to new development, according to the Colorado Oil and Gas Association.

The battle over Proposition 112 turned ugly and, at times, vicious. In the gutter of the Internet, oil and gas industry operations were compared to ISIS terrorists defacing sacred religious sites.

Robert S. Boswell, chairman and CEO of Laramie Energy LLC, a private E&P operating in the Piceance Basin, said Colorado families received social media messages and fliers saying fracking would pollute the planet and "your children are going to be exposed to contaminants that can poison your water," and other sorts of things that are just disinformation.

"Often these people then say, send us $100 and we'll fight these 'evil companies.' Ironically this is how they make their money," Boswell told *Investor*. "They're paying themselves by putting out disinformation to scare people while using some Earth-saving name."

High-profile supporters of Proposition 112 included former Vice President Al Gore, Vermont Sen. Bernie Sanders, and actors Mark Ruffalo and Leonardo DiCaprio.

The Colorado oil and gas industry went intensely local, countering with Hall-of-Fame quarterback John Elway, former Gov. John Hickenlooper, local mayors, pipefitters, and both candidates running for governor, who all voiced opposition to the proposition.

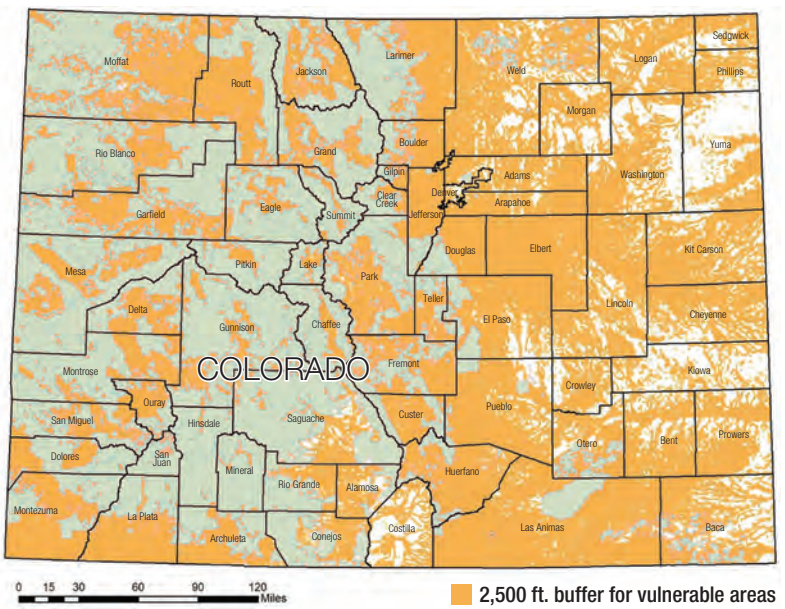
Prop 112's defeat in the November election was a victory for upstream companies, but ultimately an anticlimactic one. Less than four months later, it remains clear that the battle lines have simply shifted from voting booths to the courts and a legislature now controlled by the Democratic Party.

During its Feb. 28 earnings call, PDC Energy Inc. COO Scott Reasoner said the company was engaged with the new legislature and Democratic Gov. Jared Polis.

"We have full knowledge that there is an energy bill being drafted. We anticipate next month we are going to see something," Reasoner said on the call. "What that looks like we don't know."

The industry didn't know, either. On March 1, the day after PDC's earnings call, a senate bill was introduced, blindsiding Bentley and other Colorado oil and gas officials who had not been allowed to provide input.

Preceding page, Laramie Energy's work among the clouds takes them near the summit of Long Point Mountain, rising nearly 9,400 feet (2,861 meters) above sea level. At times, the cold creates challenges keeping fracking water warm and causing the company to spend more money for winter operations.



Source: Colorado Oil and Gas Conservation Commission

Promoted as a way to push back drilling from homes and schools, Proposition 112 also created buffers for "vulnerable areas" that would put 85% of Colorado's state lands unavailable for drilling.

In a matter of days, despite the protests of industry, the bill breezed through two legislative committees along party lines. If passed, the legislation would pose another crippling blow to many producers, industry advocates and other industry observers say.

Bentley warns that the bill's language calls for a halt to all permitting of existing and new applications until "every rulemaking outlined in this bill has been completed and each rule is in effect."

"The bill requires a minimum of six rulemakings, which could drain resources and take multiple years to conduct and implement. At a minimum, this could result in a multiyear ban on oil and gas development in the state," she said.

Even if the bill doesn't move to the governor's desk for signature, the new proposed law demonstrates the continuing risk for Colorado E&P companies, Moody's Investors Service analyst Arvinder Saluja said in a March 6 commentary.

"Though we still expect that the affected E&P companies and Colorado industry association will keep meeting with political leaders and regulators in the state to negotiate elements of the proposal, the bill was written without apparent input from the energy industry, and its sudden appearance for consideration in a committee hearing heightens the legislative and regulatory risks for Colorado oil and gas producers."

Collision course

In the remote lakes of the spectacular Rocky Mountain National Park west of Denver, protected from oil wells and gas lines, the water is dirty, the pollutants unmistakably human in origin.

In areas reachable by hiking, chemicals may threaten the reproductive health of aquatic species and the broader web of interconnected food chains.

Researchers writing in the "Science of the Total Environment" in 2018 said they detected caffeine, pesticides and the painkiller oxycodone among 149 pharmaceuticals, 22 hormones, 137 pesticides and dozens of other chemicals. Most were likely introduced into the area through urination or blown there by the wind.

In the Piceance Basin, oil and gas activity has been responsible for contamination, as well. In one of the few detailed studies of its kind, a 2018 U.S. Geological Survey (USGS) report found that a leaking gas well contaminated shallow groundwater with thermogenic methane. The source of the leak, which had been undetected at ground level, was a natural gas well drilled in 1956 before it was plugged and abandoned in 1990.

Where human activity and the environment intersect, there are always consequences. But trace amounts of steroids, hormones, drugs and pesticides found in Boulder Creek in 2006, for instance, are effectively invisible. Modern hydrocarbon production, with towering well derricks, rumbling trucks and much-reviled fracking, is not.

New communities and oil development in the Denver-Julesburg (D-J) Basin have inevitably brushed up against one another. Boswell said the meeting of industrial development and com-

Tracee Bentley, executive director of the Colorado Petroleum Council, said oil and gas companies had little choice but to commit resources, including $38 million spent by companies, to fight against state law. "This was do or die," she said.

Laramie Energy's operated produced water tank relies on solar panels to power the remote automation and telemetry for tank level gauging. Because of their remote location, about 95% of Laramie's 1,500 wells are automated and powered with solar panels.

munities was a factor that "precipitated a lot of the local concern."

Boswell said Colorado has also become a bellwether state in some ways as its demographics have changed. "We've gone from a red state to a blue state," he said.

An influx of people into Colorado's Front Range—an eastern mountain range that is part of the Southern Rocky Mountains—has seen population density increase with more government employees, union workers and teachers that are political organizing groups, Boswell said.

"There's been a stronger influence coming out of the population density and demographics of the Front Range vs. the overall state," he said.

The industry has tried to communicate with communities and listen to and address concerns.

ESG IS IN THE AIR

In early December, Royal Dutch Shell Plc took a bold but perhaps inevitable step in tackling climate change by becoming the first oil and gas company to announce it would tie executive pay to carbon emissions.

European companies are typically more sensitive to environmental matters and Shell had previously made commitments to reduce its carbon footprint by about 20% by 2035. But the Dutch company's move toward linking as many as 1,300 executives' pay to carbon measures has a strong incentive, according to Cowen & Co. equity research. The company developed its goals with Climate Action 100+, an investor initiative with more than $33 trillion in assets under management.

Climate Action includes more than 320 investors that are intent on engaging the world's largest greenhouse gas companies to improve governance, curb emissions and strengthen climate-related disclosures. Shell shareholders will vote on the plan and other reporting measures in 2020.

While there is disagreement over why climate change is occurring, most oil and gas executives believe it is and that companies ought to act to reduce emissions.

"It's clear the industry is trying to keep pace with investor demands and sentiments as well as what's happening on the global stage," said Matt Handford, senior manager, America Climate Change and Sustainability Services at EY.

A 2017 EY survey highlights the misperceptions of the U.S. oil and gas industry by consumers, with 67% of oil and gas executive respondents saying their companies "can and should be part of the climate change solution."

The disconnect is strengthened by consumer skepticism, with just 31% of consumers saying the industry wants to be involved and 29% who said don't believe the oil and gas companies want to help.

Environmental, safety and governance (ESG) reporting has become increasingly important to institutional investors, who want to see how companies are anticipating non-financial risks as governments transition toward a low-carbon future, Handford said.

"It's a risk exercise," Handford told *Investor*.

As the upstream sector is increasingly a focus of that reporting, ESG is something companies are increasingly thinking more strategically about, he said. Reporting on ESG matters has taken on a more prominent role as it's moved from fringe, activist movements intended to "create noise about a topic" by pushing environmental initiatives to proxy votes.

"The trend we are now seeing is institutional [investors] and large pension funds are now taking up those causes," Handford said.

A survey about ESG disclosures by EY found that investors increasingly rely on reports from companies' own sustainability reports, while the use of equity research from broker-dealers, press coverage and other external sources is decreasing or unchanged.

"Nearly all responders (94%) reported that integrated reports are very useful (88%) or essential (6%) sources of non-financial information," the survey found.

The oil and gas industry served as a pioneer in producing sustainability reports. Companies such as BP Plc have produced sustainability reports since the mid-1990s, long before other industries did so.

The industry also collects information about safety for internal performance to reduce lost time and avoid injuries or fatalities.

"It's also one of the most heavily regulated industries globally wherever they operate," Handford said. "Environmental compliance has always been a key focus. Industry majors, mid-size independents and even some of the smaller domestic operators are tracking this information internally."

Nevertheless, the current focus on climate change, flaring and other emission activities has the industry trying to wrap its arms around what investors want from the information they collect, he said.

"I think there's uncertainty about why investors want this information and what are they going to do with this information," he said. "And there's no real consensus on an external framework of reporting."

Handford noted multiple reporting initiatives, each requiring different sets of data, have created a challenge of pulling together a meaningful set of measures that investors can rely on while not placing companies in the position of playing fortune teller.

"There's a difference between just disclosing some numbers and saying, 'What does this mean to us as an organization?' and how does this affect our capital spending, strategic objectives, which plays we focus on, what states are doing, what regulations are doing," he said.

Industry is rightly cautious about how it approaches the reporting, particularly since scenario planning is more of a hypothetical exercise based on a complex world with various governments, The Paris Agreement and federal and state regulations, he said.

"I think oil and gas companies are typically saying 'Let's not jump the gun here. We want to provide a considered viewpoint to investors based on information we think will be relevant to them,'" he said.

Rather, companies should have an analytical view to demonstrate how they're able to manage non-financial risks.

"If you're able to articulate a strategic viewpoint about how government will impact your ability to operate as a going concern, now, in the near-term future and long-term future, you're better off to an investor than a peer that is unable to do that," he said.

The alternative, and perhaps the biggest danger for companies courting investors, is going on a roadshow where the CEO and CFO each have different answers about how they're tackling carbon risk.

Or, worse still, "they don't have answers," Handford said.

"So it's evolved and that's natural," Boswell said. "But part of what we've experienced is activism, and some of the activism has come from people who just take the position that hydrocarbon fuels are bad. They have said that they want to stop drilling and completions, and the use of hydrocarbon fuels in the state of Colorado."

Boswell said that some money spent in support of Proposition 112 came from out of state and from various contributors that "are difficult to trace." Potentially, even some foreign parties may have contributed, "and you wonder what influence these outside parties may be having on energy policy in the states," he said.

Foreign interests have taken aim at the oil and gas industry in the past. In August 2018, Renee DiResta, director of research for New Knowledge, told the U.S. Senate Intelligence Committee that the oil and gas industry is among two specifically targeted by state actors.

"We have seen evidence of campaigns targeting agriculture and energy as two industries of interest to foreign powers," she said. "On energy, we've seen anti-fracking narratives, anti-fracking bots, by countries affiliated—countries with strong oil interests. In agriculture, that's taken the form of spreading fear about GMOs."

An *Investor* analysis of contributions to Colorado Rising shows nearly a third of its contributions—roughly $525,600 out of $1.6 million—originated from out of state residents and organizations. Colorado Risings' largest single contribution—$170,000—appears to be connected to the Sergey Brin Family Foundation. Sergey Brin is a co-founder of Google Inc.

The foundation's contribution is now under scrutiny by the Colorado Secretary of State's elections division following a complaint filed by Charles Heatherly, former policy director for Colorado State Senate Republicans. Heatherly's complaint calls the handling of the donation a "case about secret political spending" and accuses Colorado Rising of trying to hide the source of its contribution through a series of amended reports. In early February, the elections division said the complaint would be reviewed while the Secretary of State—whose candidacy was supported by Colorado Rising—will not be involved in the investigation.

The oil and gas industry has tried to correct what Boswell said is "disinformation" while also trying to point out the positives of hydrocarbon development in the state.

Colorado Rising, for instance, said that "99% of Colorado's state revenue is generated from industries other than oil and gas development." However, that leaves out local property tax collections. In fiscal year 2016 to 2017, local governments collected $496.7 million from oil and gas development—about 82.5% of all local property taxes, according to the Legislative

In a snow-covered gulch in Garfield County, Colo., red lubricator valves, 24 in all, stand atop wellheads drilled by Laramie through pad development. By summer, as ice and snow melts, the company expects considerable runoff to wind through these canyons.

Council Staff, the nonpartisan research arm of the Colorado General Assembly.

Still, Boswell said he's most concerned with the grassroots concerns expressed by Coloradoans and after offsetting what he calls "disinformation with correct facts and figures" he wants to point out the positives of hydrocarbon development, including jobs, cleaner power generation and the use of hydrocarbons in synthetics and transportation.

"Those are facts that are important, and we need to point out that the state of Colorado has ... regulations that have been put in place over the years that address most of these issues," he said.

August surprise

In art, advertising or storytelling, verisimilitude gives the appearance of something real, authentic or truthful. The book "Abraham Lincoln: Vampire Hunter" gives readers a certain realism to grasp as the 16th U.S. president wades through a comically absurd premise.

Proposition 112 was a similar recipe of fiction lightly sprinkled with truth.

"Remember, Proposition 112 is not a ban on fracking," Colorado Rising's website declared. "Even though the above-ground drill head might be 2,500 feet away, the horizontal part of a drilled well often travels underground for up to and perhaps exceeding 2 miles."

In fact, the proposed changes to state law were remarkably clever. Prop 112 delivered oil and gas an August surprise in the run up to the 2018 Colorado elections.

To get on the ballot, Prop 112's advocates gathered many signatures, not through broad consensus but by concentrating efforts in more receptive, heavily populated and left-leaning areas.

Bentley said proponents of Prop 112 "understand that it's really only a small, very populated part of Colorado who would ever sign on to something like this."

The proposition in Colorado was partly a result of the peculiar nature of the state's laws for getting measures on the ballot. Prop 112 proponents simply chose the path of least resistance.

In Colorado, ballots can include two types of initiatives: amendments to the state constitution and statutory initiatives that have the weight of laws passed by government. While amendments to the constitution require fewer signatures than statutory measures, constitutional amendments require far broader support.

Colorado's requirements for statutory ballot measures are, at best, esoteric or, as Bentley put it, "really goofy."

As Bentley recognized the strategy was to introduce a statutory initiative, "we knew that there was a very real possibility that they would easily collect enough signatures," she said.

By law, a statutory measure requires 5% of the number of votes cast for candidates running for Secretary of State. In 2019, for example, a statutory initiative could be added to the ballot by collecting 124,000 verified signatures.

A constitutional amendment, however, has a higher bar even though it requires fewer signatures—about 76,000. That's because constitutional amendments require at least 2% of registered voters from each of the state's 35 senate districts.

In the right locations, such as left-leaning Denver or Boulder, the signatures needed for statutory amendments can be collected in a matter of days, Bentley said.

The challenge was to inform enough of the state's independent voters and Democrats just how damaging Prop 112 could be and do so within a matter of a couple of months, she said.

The Petroleum Council, a division of the American Petroleum Institute, partnered with Coloradans for Responsible Energy Development, a nonprofit educational organization started by oil and gas operators including Anadarko Petroleum Corp. and Noble Energy Inc. and began working on a message that would resonate with voters. Chief among those was explaining just how ruinous the proposed law would be to the oil and gas industry and billions of dollars in economic activity.

Prop 112 was a web of trip wires connected that could incapacitate virtually any drilling in the state. It didn't place a "ban on fracking" as proponents declared. Like any good trap, it instead left oil and gas drillers with almost nowhere to go.

"As written, if you don't understand the technicalities that were very craftily put in there," the set-offs might seem reasonable, particularly for schools.

While the proposition set back drilling from homes, schools and hospitals by nearly half a mile, it also did the same for "vulnerable areas," according to an analysis by the COGCC, which regulates oil and gas drilling in the state.

Those vulnerable areas included playgrounds, permanent sports fields, amphitheaters, public parks, public open space, public or community drinking water sources, irrigation canals, reservoirs, lakes, rivers, perennial or intermittent streams and creeks.

Bentley said she's been involved in many campaigns during her career but the response to Prop 112 was the most thorough she's ever seen.

The chief counteroffensive consisted of two avenues: explain what Colorado would look like if Proposition 112 passed, but have local leaders do the talking.

"A lot of our research showed that if 112 were to pass ... certainly the oil and gas industry would take a direct hit, but when revenue ceased due to 112 coming in, the communities were really going to take it."

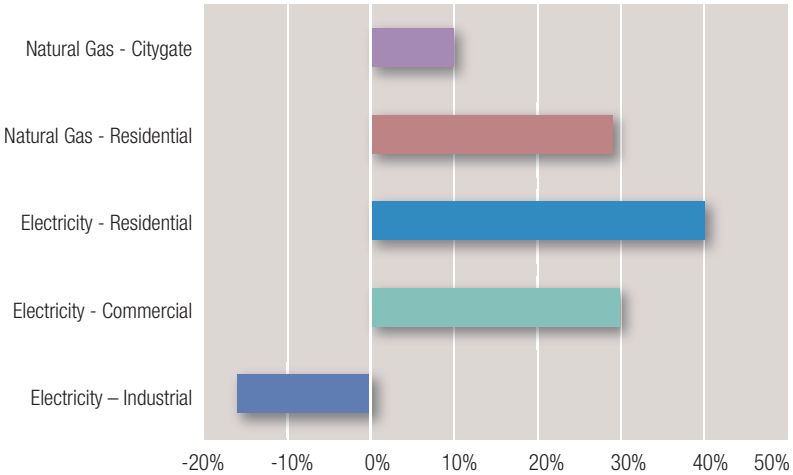
Healthcare, construction jobs, education and transportation would suffer as local tax revenue dried up.

"So much oil and gas revenue goes toward all of those services," Bentley said. "We literally had some schools we would have had to shut down because 99% of their operating budget comes from oil and gas tax revenue. And

Facing page, about 35 miles south of Grand Junction, Colo., Laramie Energy drills down 9,000 feet to the Williams Fork reservoir and the underlying Mancos Shale. The drilling here could have been affected had voters approved the state's Proposition 112.

Colorado has become a bellwether state in some ways as demographics have changed in urban areas now brushing up against drillers, said Robert S. Boswell, chairman and CEO of Laramie Energy LLC. "We've gone from a red state to a blue state," he said.

New York Price Differences From U.S. Average Most Recent Monthly



Source: EIA

New York's Clean Energy Standards, its ban on fracking and oppositions to pipelines result in the state's residents paying about 40% more for electricity than the average U.S. consumer.

when people heard that, they were like, 'Oh wow, this will devastate our communities.'"

Opposition to Prop 112 crossed party lines. Democrat Colorado governors, including 2020 presidential candidate John Hickenlooper, Bill Ritter and then gubernatorial candidate Jared Polis opposed the measure.

So did Pipefitters Local Union 208, which historically supports the Democratic Party but is a strong partner to oil and gas.

"Putting labor up on TV and asking a very well-known face, the head of the pipefitters, was very impactful," she said. Popular Colorado Springs Mayor John Suthers, who enjoys wide support from Democrats, Republicans and unaffiliated voters, also joined in opposition. "So of course, we put him on the radio asking people to vote no on 112," she said. "And we did that similar, you know, across the state, and then we did the same thing for digital."

Even though the proposition was defeated by Colorado voters by 10 points, "I definitely wanted a bigger margin. Nevertheless, with such a narrow divide in Colorado state politics, a 10 percentage-point win is sizeable."

Bentley said she believed the defeat of Prop 112 has been settled in the minds of voters. Still, in December, the oil and gas industry went further, working in collaboration with schools and community groups to expand drilling setbacks near schools.

Who rules: state or local?

Sloganeering, the lazy practice of using empty, rhetorical devices, has produced "drill baby drill" and "keep it in the ground," both of which have only made divisions over a difficult topic both simplistic and more acute.

A good slogan, however, is less costly and time-consuming than a practical policy debate—and more dangerous.

"Brexit is a great example," Matt Beckmann, managing director, Ascent Consultants, told *Investor*. "Remain vs. leave is very simple in form. In practice, though, it is a disaster. Voters

THE COLORADO EFFECT

Colorado Senate Bill 181 would make sweeping changes to the state's oil and gas industry—and drag energy companies in other states along.

"In addition to potential impacts on Colorado-specific investments, the proposed bill is illustrative of the way oil and natural gas may be regulated in other parts of the country," said Ali Zaidi, an attorney at Kirkland & Ellis LLP who focuses on identifying, mitigating and managing climate and environmental risks.

"The proposed bill is the product of a unique political confluence in Colorado—a series of big events and a set of new actors," said Zaidi.

Although Colorado's approach won't be carbon copied, elements of what Colorado does could become a reference point and starting place for new regulation in other states—particularly where development is taking place near population centers and elected officials are similarly aligned across the legislature and governor's mansion.

"Consensus processes in Colorado's past around methane, for example, served as a template for other states," he said. "It remains to be seen, whether these proposed changes, similarly scale."

Other states have taken similar action.

On Feb. 4, New Mexico State Sen. Antoinette Sedillo Lopez, D-Albuquerque, filed a bill that would place a four-year moratorium on oil and gas drilling.

In an op-ed in the Albuquerque Journal, Sedillo Lopez wrote that the bill is not a ban on fracking because it would only affect new permits. Her office did not respond to a request for comment.

"All existing permits will continue," she said. "The bill requires that relevant state agencies prepare reports on actual and potential impacts of hydraulic fracking on New Mexico's land, water, air and public health."

New Mexico's Legislative Finance Committee (LFC) estimates that the legislation would cost state and local governments a minimum of $3.5 billion in revenues during the four-year moratorium. Industry revenues are expected to make up 35% of New Mexico's total state general fund revenues for fiscal-year 2019.

"Substantial changes to how this industry operates in New Mexico—such as a temporary ban on hydraulic fracturing—would cause severe revenue losses," the LFC wrote in a Feb. 9 report. "Without a source of revenues to replace these losses, this bill would have a substantial negative budgetary impact."

Environmental activists have dismissed those concerns, noting that since New Mexico is already among the worst states in terms of education, oil and gas money hasn't helped. The bill is being pushed by a group called Pause On Fracking, an affiliation of social media and Internet platforms that lists no direct contact information. The group's website is registered to Jenni Siri, an activist and graphic designer for a group supporting Sen. Bernie Sander's 2020 presidential campaign.

The Pause On Fracking website encourages like-minded supporters to forward pre-written letters of support to New Mexico lawmakers and even fully written Twitter comments,

Despite assurances the moratorium is just a pause, supporters include WildEarth Guardians, a nonprofit organization which lists, among other goals, a transition to 100% renewable energy by 2035.

A crew runs a production log on a previously completed dry-gas well near a pad development. The snow makes for difficult travel while keeping lines and pumps thawed in the event of a drilling shutdown.

Keeping a low profile is a requirement of Bureau of Land Management regulations. Laramie operates produced water tanks and units and employs "visual mitigation" with a number of design and color choices.

were totally unaware of the real consequences of their vote."

Pro-energy supporters need to update and revise their communications strategy to include an environmental or green component, while opponents of fossil fuels need to recognize that an overhaul of the entire energy grid and economy is not realistic with current technological and commercial realities, he said.

While that message was hammered home in the fight over Prop 112, it seems to have fallen away as Colorado legislators again take aim at the oil and gas industry. New legislation will reorder not just the oil and gas industry in Colorado but the COGCC itself.

In his March 6 report, Moody's Saluja noted that Colorado's bill cedes state authority over oil and gas to local communities and alters the state's oil and gas commission, as well. Membership qualifications for the nine-member commission would reduce the number of commissioners who have industry experience from three down to one.

The bill also changes a key word in COGCC's mission to "regulate" rather than "responsibly foster" oil and gas development. As noted, taking out the word foster has massive implications. A similar effort by the out-of-state group Oregon Children's Trust argued in court that Colorado must first complete a health and environmental assessment to ensure no people are harmed in any way, shape or fashion before a permit is issued.

"There are some Democrats who would like to take that idea and take it legislatively," she said, foreshadowing the bill that emerged March 1. "That will have the exactly same effect as 112. That's probably one of the larger threats out there."

Outside of lawmakers' attempts to thwart oil and gas activities in the state, a campaign by local and professional activists has taken to the courts and government agencies to stall, frustrate and harass the industry.

Ursa Operating Co., for instance, applied for a state permit for its BMC A Pad in December 2017, followed by a land use change permit in Garfield County, Colo., on May 2018. The de-

velopment is near the Battlement Mesa community near Parachute, Colo. The pad is in the Piceance Basin.

Two groups, Battlement Concerned Citizens and Grand Valley Citizens Alliance, have filed a lawsuit against the COGCC in Denver District Court to halt Ursa's pad development. Ursa is not a named party to the suit.

The suit cites a number of concerns, including environmental impact, potential water contamination and "hundreds of comments asked the Commission to deny the project and approve a safer location," according to a copy of the suit on the Western Colorado Alliance for Community Action website.

The suit also notes that Battlement Mesa is a planned residential community marketed as "a quiet retirement community." However, the average age of residents is about 38 years old and many of the residents in the community work for Ursa or other oil and gas companies.

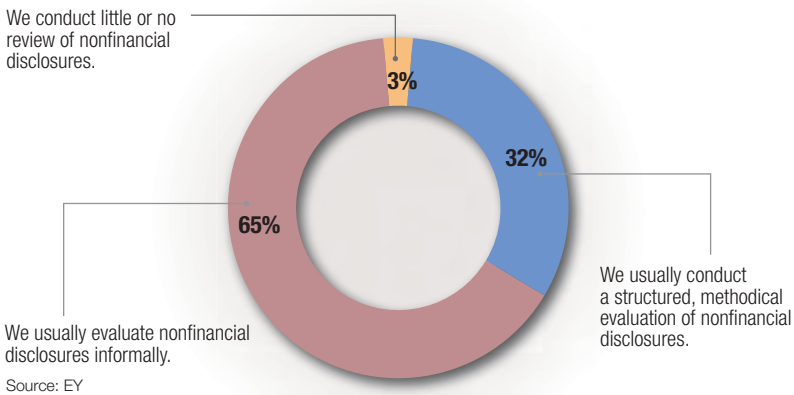
A letter by Ursa contends it has gone above and beyond its obligation to abide by state rules and regulations. The company held multiple meetings with local residents to share its plans to develop mineral resources and address local concerns. Ursa also worked with Garfield County to develop 27 conditions of approval as part of obtaining a permit.

Ursa also conducted site reviews, on-sites, and land assessments to ensure that the location complied with existing federal, state, county and local regulations and land use codes; including both cultural and environmental setbacks.

"If you overregulate us to a point where we start picking up and moving or we just can't get permits anymore, it's your state budget, governor, that's going to suffer."

—Tracee Bentley, Colorado Petroleum Council

Investors' Method For Evaluating Nonfinancial And ESG Disclosures



Source: EY

About 97% of investors conduct an informal review of nonfinancial standards and disclosures before making an investment decision, according to a survey by EY.

After a "Hail-Mary" attempt to reconcile residents' demands, the oil and gas commission approved the pad development only to see the lawsuit filed against the commission.

P. Kelly Muldoon, vice president of land and business development for Ursa Resources Group II LLC and an ad hoc advisory consultant for the Colorado Oil and Gas Association, said he's most troubled by the lack of scientific evidence that's been used to halt oil and gas projects, such as Ursa's pad development.

Despite that, "they almost shut down something that had been in the process and was one of the most reviewed pads in the state," Muldoon said.

Muldoon said he sees a political narrative driving the agenda instead.

"I think that the talking points are getting a lot more attention than the science, and I think that's a bit of a concern," he said.

Muldoon said the upcoming court battle feels like another attempt to delay development.

Over a phone interview, Muldoon's exasperation came through as he noted that the company had followed all established rules and regulations. The company spent 200 hours with local residents, tried to meet every community demand and spent hundreds of thousands of dollars in the process.

Yet, in the end, "a few individuals can still shut down an entire industry," he said.

"What's the scary part of it is, it's not the rules. It's the unpredictability of whether the rules are going to be enforced," he said. "Even if they don't shut us down, they'll slow us down enough that oil and gas companies are just going to leave the area. I can't plan a budget and a drilling program and an operations program if the rules that are already in place aren't going to be our guidelines to operate under."

The thought leads him to question why oil and gas would want to invest in a state governed by unpredictability.

"I think that's what it seems like, is that if they make it an inhospitable enough environment, the oil and gas industry will leave on their own, and not realizing the consequences of oil and gas leaving this state."

Oil and gas producers just want to follow the rules, though they continuously keep changing, said P. Kelly Muldoon, vice president of land and business development for Ursa Resources Group II LLC. "The scary part of it is, it's not the rules. It's the unpredictability of whether the rules are going to be enforced."

March surprise

Oil and gas advocates argue the primacy of oil and gas regulation belongs at the state level, where Colorado has funded and developed expertise for regulating development.

With Democrats in control of the state's legislature and executive branch, Bentley said she expects Gov. Polis to understand that as well.

"If you overregulate us to a point where we start picking up and moving or we just can't get permits anymore, it's your state budget, governor, that's going to suffer," she said. "And you're going to have to go explain to people why you let this happen. I think he fully understands that."

Yet a week after speaking with *Investor*, Bentley and the rest of the Colorado oil and gas industry were caught off-guard by surprise legislation proposed in the state senate that offered no input from stakeholders—including the industry, local governments, environmental groups and regulators.

"In my over 15 years of working with the Colorado state government, not having a thorough stakeholder process is unprecedented, especially for a bill that targets one industry but impacts every Coloradan," she said. "We are deeply disappointed that House and Senate leadership do not appear to value the stakeholder process nor the importance of having all stakeholders at the table on one of the most consequential proposals in Colorado history."

Companies such as Extraction Oil and Gas Inc. would be among the most at risk from the legislation because it produces in populated areas. Larger companies such as Noble Energy Inc. and Anadarko Petroleum Corp., each with about a third of their production in the D-J Basin, would be less affected, Saluja said.

"The bill is likely to most affect companies with production within Colorado's Front Range Urban Corridor, which includes the Denver metro region, allowing more restrictive measures from local governments, rather than companies," he said.

On March 3, Bentley and Dan Haley, president and CEO of the Colorado Oil & Gas Association (COGA), expressed dismay in a joint statement that "sweeping anti-oil and natural gas legislation" would head to a state senate committee a day after being introduced.

"No good can come out of legislation that is revealed on a Friday night and rushed through the legislative process," they said.

Beckmann said the preliminary text of the bill creates the opportunity for "subjectivity to influence both regulation and the permitting process."

"That will lead to inconsistent application of rules at the state level, and microjurisdictions of individual local communities creating a complex network of rules which will drive up compliance costs substantially," he said.

Months before the new legislation, the Colorado E&P employee said working in the state is becoming more and more difficult. And he expected something new to be thrown at the industry.

"Every two years it seems like we're facing some sort of attack against our industry," he said. □

The 697-16D "Cow Paddy" well development, with its hard-to-spot production tanks and units, is part of an effort by Laramie to blend structures and equipment with the environment. On federal lands, operators can choose from colors such as Carlsbad Canyon, Covert Green, Yuma Green and Carob Brown.

THE TREADSTONE IDENTITY

Treadstone Energy Partners co-founder Frank McCorkle is able to see oil and gas challenges in a different light with creative solutions. Just don't expect his operations to remain clandestine much longer.

INTERVIEW BY
STEVE TOON

After a successful exit with Treadstone I, CEO Frank McCorkle is building and delineating Treadstone Energy Partners II LP as an Austin Chalk/Eagle Ford unconventional player.

Frank McCorkle cut his teeth in the oil fields. The CEO and co-founder of Treadstone Energy Partners began working as a roustabout on his dad's homemade workover rig in southeastern Kansas at age 11 on Saturdays and holidays, and by age 13, full time in the summers. His father built the rig from an old truck, a tractor engine and piecemealed parts that serviced wells less than 2,000 feet deep. "I didn't know anything else," he said. "I had good field experience."

The family oil business, though instructive, couldn't be described as lucrative. The homestead in Sedan lacked air conditioning and heating, and during the winter McCorkle cut firewood on Sundays to burn in the wood stove in one room. "We were a poor family, but we had everything we needed," he recalled. He graduated at the top of his class with a love for math and science and a strong work ethic. With a scholarship in hand, he pursued a degree in petroleum engineering at the University of Tulsa nearby.

Following his sophomore year, BP offered him a summer internship in Alaska, which he accepted just a few days after marrying his wife, Kristin. "We were going to get married later, but we moved the wedding up so we could go to Alaska together for the summer," he said. "We loved Alaska, and we loved the people." When evaluating job opportunities at graduation, he had one question for interviewers: "Can you take us to Alaska? And BP was the only one that would."

McCorkle worked for BP as an engineer for a total of 23 years, beginning in 1988, and in its Anchorage office for 13 years, working the Prudhoe Bay and other Alaskan assets. He also worked on the North Sea, Midcontinent and Eagle Ford divisions while with BP.

In 2011, he and two BP colleagues broke off to form Treadstone Energy Partners I with $50 million in backing from Kayne Anderson Energy Funds. Treadstone I redeveloped the Fort Trinidad asset in East Texas before exiting for $715 million in 2014, a 16-times return. Oil and Gas Investor *recognized the program with its "Best Field Rejuvenation" award in 2012. (See, "What's Old Is New Again,"* Oil and Gas Investor, *July 2014.)*

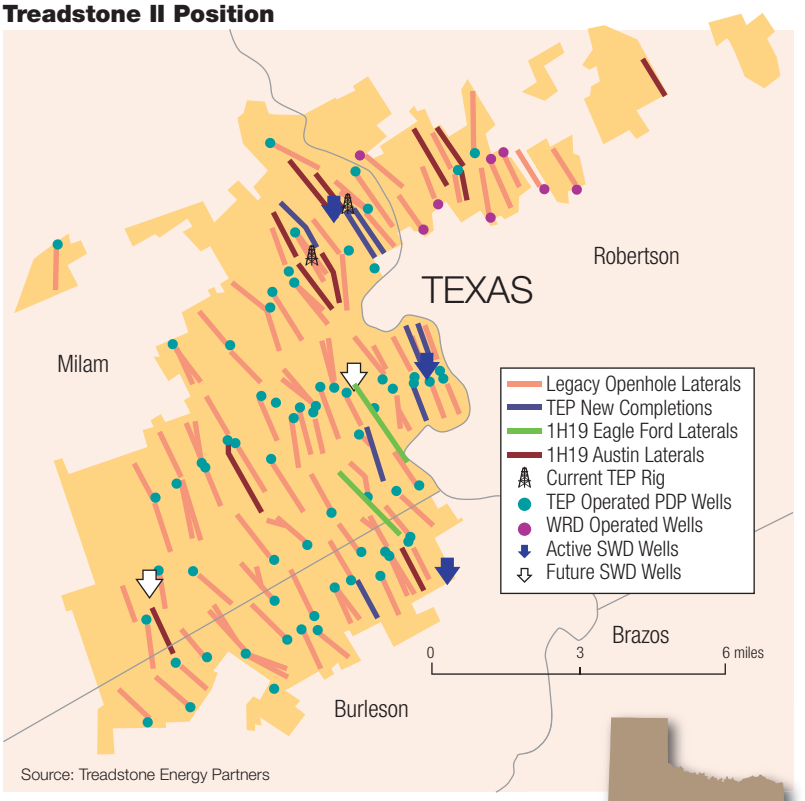
He and the same team formed Treadstone II in 2014, headquartered in Houston, this time with $100 million in commitments from Kayne Anderson. This second iteration holds some 40,700 net acres in the East Texas Austin Chalk and Eagle Ford Shale region in Milam, Robertson and Burleson counties in Texas. The position abuts the northwestern border of the WildHorse Resource Development Corp. position recently acquired by Chesapeake Energy Corp. for almost $4 billion. Treadstone II exited 2018 with approximately 2,700 barrels of oil per day net production, with seven wells waiting on completion.

McCorkle spoke to Investor *at his office near Tomball, Texas.*

Investor Tell me about your experience working in BP's Alaska unit, and what you learned from that.

McCorkle I learned so much working for BP up there. I started out in engineering, and it was a very active place. There were a lot of well workovers, drilling, field expansion,

Treadstone II Position



Source: Treadstone Energy Partners

waterflooding and miscible gas flooding. I got opportunities to work in all of those activities and obtained a broad background in engineering.

When I arrived, there were a lot of young engineers, and within a year and a half I was a senior engineer. Now, that's scary looking back, but at the time it's just how it was. You just didn't really think about it because everybody was young, and so you just did the work. You tried a lot of things that a lot of the big companies won't do anymore. They just won't do unique ideas often.

Investor Like what?

McCorkle I was involved with some of the very first horizontal waterflood injectors. Nobody believed it would work, but we tried it and it worked really well.

I was involved with some unique workovers to repair some wells. We had wells that would produce several thousand barrels a day, and we had some that broke, producing rocks to surface. And when I say rocks, I mean the size of your fist. They were big rocks. I came up with a unique idea to fix it, and we tried it and it worked. We actually pumped cement down there, shut it off, and then perforated three feet above [the cement plug]. Nobody thought it would hold, but it ended up making 8,000 barrels of oil a day.

Another thing, we had a heavy oil tar layer at the bottom of the reservoir. In the gassy area of the field, the horizontal wells were drilled just above the tar interval to minimize the gas. One well was drilled too deep, into the tar layer, which would not allow the oil to flow to the wellbore. We brought some bugs in—you know, microbes—to see if we could dissolve enough of the tar to actually allow the well to produce. And it did. So the well wouldn't produce until we put the microbes down there and let them eat out some of that heavy oil tar. My partner, Gene Roberts, worked this project with me.

So they just let us come up with ideas.

Investor What was your motivation to leave BP and form your own company?

McCorkle I'd always planned to have a company someday. Years ago I set a goal of having a company that produced 5,000 barrels a day before I was 50. Just something crazy that I wanted to do.

BP was getting to be a really big company and was starting to act like a really big company, so the BP I had grown up with was no longer the BP that existed. I just found it was not as much fun. I never really liked politics.

I was on the petroleum board at the University of Tulsa with Mike Heinz (managing director with Kayne Anderson), so one day I said, "Hey, Mike, one of these days I'm going to come ask you for a bunch of money to start a company." I was just throwing that out there. Then the next year we see each other again at the board meeting and he said, "Hey, you ready to go?" "Are you serious?" I said. "I'm four and a half years to early retirement. Can it wait four and a half years?" He said, "I can't make any promises."

I talked to my wife. It was a big risk, obviously, and I was probably overconfident. She said, "If you can find two crazy people to do it with you, I'll be okay with it." She knew I only had two people on my list of people to ask, and they both agreed.

Investor How did you form your team?

McCorkle I picked the best land person I knew out of BP and the best engineer I knew out of BP, and that's how we formed our team. Gene Roberts and Key Sanford.

Key was always up for a new adventure. He had worked at BP maybe 10 years. And Gene is an engineer's engineer, so working at BP had gotten very difficult, and he was ready for something different. I was his first boss at BP, and he says I'll be his last boss. They are both still part of the organization.

Investor What was it like coming out of BP after 23 years?

McCorkle We realized we didn't have any clue how to start up an oil company. That's the reality of it. We realized that there were a lot of things that just happened that we had no idea how they happened. So we started learning a lot. How do we get data? How do we get computers? Just everything. So it took us a few months to get oriented, and we started looking at a bunch of little deals. We were probably looking at all the wrong stuff, to be honest. They were way too small to make a private-equity company work.

We actually bought a little deal that ended up not working out, but fortunately it got us into an area where we finally started looking around. And that's where we found our first real asset.

We saw a series of wells in the Buda that had performed really well. We started to evaluate this area, looking at offset production, trying to figure out what was going on with it. About that time an asset comes up for sale in the area we were looking in, a deep-gas unit that had been formed for gas recycle—and it had an uphole oil zone that had never been exploited because of that.

Our bid was three times most of the other companies' because we were not bidding on the deep gas. Everybody but one company already working in the area was bidding on the deep gas, a little bit of PDP and maybe a little bit of upside. And we were bidding completely on the uphole oil zone. It had a great ending.

Investor If that differentiated you with Treadstone I, what differentiates you in Treadstone II?

McCorkle We're always looking for an asset that's in an area that's out of favor and in an area that we think is just overlooked. We're trying to find something that nobody else really sees.

On our current asset, we had tried to get Anadarko to sell it to us for over a year. Anadarko had a deal with KKR to drill Eagle Ford, and it covered certain acres and they wouldn't sell anything inside that deal. So when we kept bugging them, they ended up carving out part of their asset in this area and putting it on the market.

It was fairly competitive. Originally, the Austin Chalk and the Buda were all drilled with open laterals, so most people were bidding on PDP and maybe a few more infill wells. But we were looking at it from the standpoint of drilling horizontal cased-hole and fracked completions.

Investor Treadstone II was formed just ahead of the downturn in 2014. Did that affect your strategy?

McCorkle It didn't affect our strategy, it just made it very difficult to find anything. People were not wanting to sell anything during the downturn. We worked over multiple counties looking at stuff in areas that we liked trying to get a deal, and then people would just decide not to. It made it very hard to find something that we thought was attractive.

Investor Why'd you choose the Austin Chalk?

McCorkle The industry believes that if you drill into a fractured reservoir, you drain out all the fractures, and you're done. There's nothing left, and that's why your well goes on screaming decline. We take a different view on that. We believe there's a lot of reservoir that's not connected to those fractures, and by bringing in modern frack techniques, we can bust up the rock a little more and connect more of it.

Until fairly recently, people had not been doing that in these types of reservoirs. They are doing modern completions in the Permian; they are doing them in the Eagle Ford. But if you look at the Austin Chalk, it's been fairly recent.

Treadstone II Snapshot

Acres	50,000 gross/43,000 net
Net production YE 2018	2,700 bbl/d

Target zones

Austin Chalk	**175 locations**
Best well: Holden-Moore 3HA cum'ed 260 Mbbl in first 150 days with an IP90 of 1,930 bbl/d on ESP-managed flowback. Completed lateral length: 5,036 feet. Completion stats: 100-foot spacing; 65.7 bbl/ft; 2,200 lb/ft; 100 mesh, 40/70, 20/40. Well cost: $6.5 million.	
Eagle Ford	**200 locations**
Recent activity: At press time, completing Remi Rose 1HE with a plug-and-perf completion on a 10,000-foot lateral, 158-foot stage spacing, 70 bbl/ft and 3,500 lb/ft using 100 mesh and 20/40 proppant. Well cost: $8.1 million: IP30 1,300 bbl/d on ESP-managed choke.	
Buda	**30 locations**
Recently completed Holden-Moore 4HB with a peak rate of 1,000 bbl/d and 36 Mbbl cum'ed in first 120 days.	

Investor Your first three wells had mixed results?

McCorkle They were in three different reservoirs. We wanted to go out and test everything at once, so we tested the Georgetown, the Buda and the Austin—all three. The Georgetown was a bigger unknown out here. There's only a handful of Georgetown wells within a few miles, and for whatever reason, even though you look at those wells that are a few miles away, there's no water in them. But for whatever reason, ours is very high water.

We did the Buda, and because people are doing this wine rack pattern, we did the Buda and Georgetown close together. We ended up with a Buda well that was very high water too. It produced several hundred barrels of oil a day initially, but it was not what we were looking for. And the Austin well is the one that worked out really well.

Investor Let's talk about your Holden-Moore well.

McCorkle It's our best well. This well produces right now about 1,000 barrels a day, and it has produced a little over 300,000 barrels over six months.

This was our first plug and perf well. It was also in an area that historically was a little bit lower water cut. The carbonates tend to be 50% to 70% water cut throughout their life. It was significantly better than we would've expected it to be in this area.

Investor Is the Eagle Ford prospective on your acreage?

McCorkle It is. There's always been a debate in our area depending on whose map you look at as to whether our area is too far on the fringe, or inside the good area. And so we decided we had to drill a well to prove that up or not.

We drilled a 10,000-foot lateral and did a typical industry frack on it, and we did something slightly different that we think may help. Our first Eagle Ford well is at 1,400 barrels a day flat, and we can still draw it down anoth-

"The industry believes that if you drill into a fractured reservoir, you drain out all the fractures and you're done. We take a different view on that."

er 2,500 psi. We have it choked way back right now, so it should stay flat at 1,400 barrels a day for several months.

We're very excited about it. We have two more wells on the rig schedule coming up soon, and then we're planning more.

Investor Why is the Eagle Ford not the primary target?

McCorkle Because the area wasn't supposed to be very good. That's the bottom line. The reason we drilled it is because we would never get any value for it unless we took the risk to prove it up. So we decided to take the risk to prove it up.

Investor What's your plan for 2019?

McCorkle Near term, we're going to focus on the Eagle Ford. The next two wells in the Austin will get us clear across our acreage position to prove up the extent of it. The oil is proven productive and there's been recovery, it's just more about showing that our new completion technique will work across the whole acreage position.

We will end up drilling probably 30 wells this year, maybe a few more. We've been drilling with two rigs for a short period of time because we wanted to get certain wells done. We're going to drop the second rig for a while because we have such a large inventory of wells that need to be fracked and put online, then we'll probably pick up the second rig again midyear.

Capex will be close to $200 million from cash flow and debt. Later this year, we should be able to free cash flow two rigs quite easily. So even for a public company [looking to acquire], that should start to become attractive where they can pick up an asset that can cash flow however much development they want to do. A two-rig development out here is quite a lot.

Investor What is your exit strategy?

McCorkle I hope somebody wants to buy it.

Investor Do you see that as a problem right now? Do you think you're going to have to hold for longer?

McCorkle It could be a problem. We anticipate trying to go to market later this year once we've fully proven up our area in the Austin and the Eagle Ford. We don't want to go to market until we believe we've proven it because we don't want people to come in and say, "Well, we can't pay you for that." But we anticipate trying to go to market this year. If we don't get what we think is a reasonable price, we will keep it.

Investor Are you still aiming for a four-times return?

McCorkle When we evaluate something, that's our minimum target. We got a 16 on our first company. We won't get a 16 on this one. I'm not expecting that by any means, but I do think it's worth more than four times what we have in it.

Investor Do you think the drill-and-flip model is dead or dying?

McCorkle I hope not. There's a lot of debate on that right now; we think not if you get into the right area. Drill-and-flip is more drilling than it used to be, for sure. It used to be you'd drill a handful of wells and everybody agrees to it. Now we're drilling wells across our whole area to prove it out.

We had this internal debate on how much is too much. So midyear we're probably going to be at 10,000 barrels a day. At what point do we have so much production that it almost does the opposite that buyers don't want it? I don't know the answer.

Investor With exits being challenged in recent months, some private-equity firms are looking to transition to becoming a "yieldco," a longer-term company that produces dividends vs. an all-out exit. Is that option on the table?

McCorkle Not yet. And the reason I say that is we're still planning on trying to market it. If that doesn't work, then everything's on the table after that. If we don't sell it later this year, then I suspect the exit strategy's completely different, and we have no idea what that looks like. So by the time we bring all these wells online, assuming they are type curve wells even, we will be significantly above cash flow for one rig.

But the exit strategy's an issue that we don't have clarity on.

Investor What threats or opportunities do you think are being overlooked in today's marketplace?

McCorkle I see this market as still an opportunity to buy. We have Treadstone III started up already. We've got a good operational team in place, and we don't want to lose them when we're done with Treadstone II. We're working on some areas that we like, but we do not have assets in Treadstone III yet.

Investor What is your strategy for Treadstone III?

McCorkle At this point, our strategy is going to be the same. We're still looking for stuff that is overlooked by the industry, but it may be extremely difficult to find an asset that fits our strategy. And we know that. It was very difficult this time. So we have talked about that at some point we may have to go with a strategy that says maybe we're only looking for a two to three times return, but it's a much larger investment.

We have a $100-million commitment with Kayne, but if we bring them an asset that is really attractive and it's double that, they're going to be fine with that.

Investor How did Treadstone get its name?

McCorkle We found it difficult to come up with a name, so one of my partners liked the Jason Bourne series. [Treadstone is a secret organization in "The Bourne Identity" book and movie.] "We were just kind of an undercover company coming in and sneaking into places that nobody else was looking at and doing something with it. It gives us good name recognition, that's for sure. But no spy business stuff here. □

RIGHTSIZING FOR POSSIBLE OUTCOMES

Investor pressure is increasing for oilfield service companies to provide returns over growth. Opportunities may improve as the second half of 2019 unfolds.

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Capital allocation issues alone are hard enough to handle in a cyclical industry like oil and gas. In years past, producers would set budgets based on commodity price forecasts, and oilfield service (OFS) companies would typically take their cue from customer budgets. Much would depend on how well price forecasts held up, helping determine later tightness or slackness in an OFS sub-sector.

Today, the issues are much more complicated. Commodity volatility is in full force—witness the collapse of crude late last year—and producers are increasingly embracing a mantra of capital discipline. And like their E&P counterparts, OFS companies are coming under mounting pressure to prioritize returns to investors as they plan higher capex budgets aimed at capturing greater market share.

Earlier estimates of E&P capex for 2019 have already been subject to some notably steep revisions.

"Clearly, U.S. spending has been affected by the oil price collapse in the fourth quarter," said Colin Davies, senior research analyst, oilfield services, at AllianceBernstein LP. "E&P capital guidance in recent weeks shows 2019 spending expectations have come in much lower than back in November. It's a monumentally different position."

However, Davies doesn't exclude the possibility of an inflection in spending over the course of 2019.

"I would be surprised if we truly end up with a flat-to-down year-over-year picture," said Davies. "If we get a stronger macro environment into the spring and summer, which we've had for the last two years, it wouldn't surprise me if we see some of those numbers nudging back up again. But given pressure from investors to hold the line on capex, they could only do that if the macro is a bit stronger."

Lean into DUCs

"E&Ps will find ways to bolster production growth on constrained budgets. One way is to lean into some of the DUCs (drilled but uncompleted wells) that have been built up by the industry," he continued. "And then producers will start to frack more of those DUCs so they can get more production with relatively fewer dollars."

Historically, the OFS sector has felt less pressure from investors as regards capital discipline, but that is rapidly changing, according to Bernstein.

"What's happening is that the push to prioritize return on invested capital [ROIC] is coming across from the earlier move on the E&P side, and now it's really becoming part of the mantra on the OFS side, especially for large-cap names, like Schlumberger [Ltd.] and Halliburton [Inc.]," said Davies. "I think that's going to be the big investor push going forward—and quite rightly so, it's been long overdue."

According to Davies, there is "mounting investor frustration" at the successive years of declining ROIC metrics in the OFS sector. He attributed this to two main factors, with one being the "massive level of capacity overbuild" in earlier boom years. These investments are still sitting on balance sheets and are burdening OFS firms' income statements with high levels of depreciation, depletion and amortization.

'Very U.S. dominated'

The other is the degree to which the recovery during the past two years has been "very U.S.

Upstream Spending Update

	Barclays E&P Spending Survey (1-08-2019)			Post-Survey Update (2-19-2019)		
($MM)	NAM 2018A Capex	NAM 2019E Capex	2019 Y-Y Growth	NAM 2019E Capex	2019 Y-Y Growth	Change Vs. Prior Estimate
Large E&Ps						
Occidental Petroleum Corp. *	4,300	3,872	(11%)	3,889	(10%)	2%
Anadarko Petroleum Corp.	3,875	3,770	(3%)	3,650	(6%)	(3%)
Pioneer Natural Resources Co.	3,040	3,472	14%	2,950	(3%)	(15%)
Marathon Oil Corp.	2,300	2,436	6%	2,400	4%	(1%)
EQT Corp.	2,255	2,000	(11%)	1,950	(14%)	(3%)
Diamondback Energy Inc.	2,605	2,525	(3%)	2,525	(3%)	0%
Continental Resources Inc.	2,400	2,710	13%	2,200	(8%)	(19%)
Devon Energy Corp.	2,400	2,550	6%	2,550	6%	0%
Concho Resources Inc.	2,372	3,255	37%	3,255	37%	0%
Apache Corp.	2,176	2,300	6%	1,807	(17%)	(21%)
Noble Energy Inc.	1,900	1,831	(4%)	1,650	(13%)	(10%)
Actual, Estimate	15,770	15,505	(2%)	14,839	(6%)	(4%)
Estimate, Estimate	13,853	15,171	10%	13,987	1%	(8%)
Total Large Cap	29,623	30,676	4%	28,826	(3%)	(6%)
SMID E&Ps						
Antero Resources Corp.	1,500	1,620	8%	1,175	(22%)	(27%)
Southwestern Energy Co.	900	839	(7%)	814	(10%)	(3%)
PDC Energy Inc.	985	1,279	30%	800	(19%)	(37%)
CNX Resources Corp.	724	868	20%	600	(17%)	(31%)
Laredo Petroleum Inc.	575	613	7%	300	(48%)	(51%)
Parsley Energy Inc.	1,488	1,269	(15%)	1,269	(15%)	0%
WPX Energy Inc.	1,195	1,377	15%	1,050	(12%)	(24%)
Gulfport Energy Corp.	685	902	32%	538	(22%)	(40%)
Matador Resources Co.	663	772	17%	772	17%	0%
Callon Petroleum Co.	540	724	34%	513	(5%)	(29%)
Actual, Estimate	4,684	5,219	11%	3,689	(21%)	(29%)
Estimate, Estimate	4,570	5,043	10%	4,141	(9%)	(18%)
Total SMID Cap	9,254	10,262	11%	7,829	(15%)	(24%)

Actual 2018 Numbers, 2019 Estimate Estimated 2018 Numbers, 2019 Estimate *Total Company Capex

Source: Barclays

There is "mounting investor frustration" at the successive years of declining returns on invested capital in the oilfield service sector, according to Colin Davies, senior research analyst, AllianceBernstein LP.

dominated." The advent of U.S. unconventional resources has led to a lower technological intensity as well as fewer barriers to entry, which fosters "a very competitive dynamic, where people tend to chase economies of scale and market share to absorb fixed costs."

In turn, this has "driven a behavior of discounting prices," continued Davies, with the benefits naturally accruing to their E&P customers. "And if you take that very low pricing dynamic designed to chase market share, and combine it with the overbuild of capacity of the prior boom, you'll find you get very low return on invested capital."

That said, amidst ongoing uncertainty over E&P capex, Davies pointed to several sub-sectors that may offer attractive upside from a "tactical," or shorter-term perspective.

Super-spec rigs

Sub-sectors identified by Davies as attractive included "super-spec" rigs and, on more of a tactical basis, pressure pumping or hydraulic fracturing. In addition, although no "pure-play" vehicle exists, above-average returns are projected for rotary steerable tools, where a more concentrated set of suppliers means "you don't get the race to the bottom on pricing that exists in areas with low barriers to entry."

Super-spec rigs, which are required to drill very long horizontal wells, are concentrated in just a few hands. Leading operators include Helmerich & Payne Inc. (NYSE: HP), Patterson-UTI Energy Inc. (NASDAQ: PTEN) and, to a somewhat lesser extent, Nabors Industries Ltd. (NYSE: NBR). Another super-spec operator is Independence Contract Drilling Inc. (NYSE: ICD).

The relatively narrow ownership of super-spec rigs and rigs that can be upgraded to super spec has helped pricing remain "remarkably strong," according to Davies, whose favored stock in the group is Patterson. Patterson is rated outperform by Bernstein with a $19.50 target price. (Helmerich & Payne carries a market perform rating and a $63 target price.)

Following Patterson's release of its fourth-quarter results, Davies noted the company was able to cut its 2019 capex by 27% as it pared the pace of its super-spec upgrades to just one from 14 completed in 2018. While rig activity was slowing and "beginning to impact even the super specs," he wrote, pricing for super-spec rigs continued to be "strong with over 90% rig utilization."

With Patterson also having significant pressure-pumping operations, Davies described as "refreshingly differentiated" the company's strategy of managing near-term headwinds in the sector with lower capex and pricing discipline. Patterson opted to idle three frack spreads on top of two that were stacked in the fourth quarter, reflecting "a disciplined refusal to chase share at low margin."

As the year progresses, however, 2019 could be "a year of two halves" in the pressure-pumping market, according to Davies. "Very tough" market conditions are expected in the first half, but a "frack ramp" is likely to tighten the market in the second half as E&Ps step up activity in the Permian in anticipation of new pipeline capacity coming on and resolving bottlenecks in the basin. Conversely, as budgets swing back to fracking the DUCs, the rig market may weaken slightly in the second half.

Lure of 4 MMbbl/d of takeaway

"You can't dangle in front of the industry nearly 4 million barrels per day (MMbbl/d) of takeaway capacity out of the Permian through the end of 2020, and expect the industry not to frack those wells. They'll frack those wells," observed Davies. "And if you can get over 100 spreads coming back to work in a relatively short time, we believe that has to have a positive impact on pricing."

Beneficiaries include pressure-pumping leader Halliburton, as well as Patterson. The full impact of the potential uplift is "underappreciated in the marketplace, and that's likely to drive upside for both companies." The recommendation is "a bit more tactical," or short-term, in nature, and is premised on frack activity eventually catching up with new well drilling.

"We have a high level of conviction that some kind of frack ramp occurs in the second half of this year. It has to," said Davies. "And that's the basis for an outperform rating on Halliburton."

Bernstein's late January report on Halliburton carried a target price of $48 per share.

J. David Anderson, Barclays' senior equity analyst covering oilfield services and equipment, sees brighter days ahead for OFS—but only after recent performance left it among the lowest ranking market sectors.

"The worst is probably past for oilfield service," he said. "After four years, it feels like we've seen the final cuts on earnings estimates in the U.S. Earnings estimates have largely bottomed, and we can start thinking about growth in 2020 and beyond. Once the dust settles in the next month or so, people are going to say, 'Hey, these stocks are looking like they're priced at attractive valuations.'"

This presumes the market has by then factored in some hefty downward revisions in North American E&P budget estimates made as recently as early January of this year.

Analysts' Recommended OFS Stock Picks

Analyst	Stock Recommendation	Symbol	Rating Date	Stock Price	Target Price
Colin Davies AllianceBernstein	Patterson-UTI Energy Inc.	PTEN	Outperform - 02-13-2019	$13.58	$19.50
	Halliburton Co.	HAL	Outperform - 02-13-2019	$31.40	$48.00
David Anderson Barclays	Baker Hughes, a GE Company	BHGE	Overweight - 02-19-2019	$26.09	$31.00
	Tenaris S.A.	TS	Overweight - 02-19-2019	$26.90	$44.00
Marc Bianchi Cowen & Co.	Baker Hughes, a GE Company	BHGE	Outpeform - 02-13-2019	$25.13	$32.00
	Patterson-UTI Energy Inc.	PTEN	Outperform - 02-13-2019	$13.58	$19.00

Source: *Oil and Gas Investor*

Barclays' widely followed 34th Global 2019 E&P Spending Outlook, released on Jan. 8, showed increases in spending by large- and small to mid-cap (SMID) E&Ps of an estimated 5% and 11%, respectively, over last year's levels. However, by Feb.19, with additional data from earnings releases, the large- and SMID-cap spending estimates were revised down to minus 3% and minus 15%, respectively.

Depleting rock

The updated budgets for the SMID-cap E&Ps were "particularly shocking," said Barclays, citing a note in which it said SMID-caps were "stuck between a depleting rock and a hard place." Several "competing factors" might explain the budget reductions: accelerated base production declines, leasehold drilling obligations and pressure to spend within cash flow and return capital to shareholders.

"The SMID-cap guys are going to be faced with some very difficult challenges," commented Anderson. "Because they're at such an early stage of development, they have very high decline rates; they don't have tails of production from wells that have been producing for some time. The question is whether their production holds up. What are their 2020 production numbers going to look like?"

The SMID-cap E&Ps are likely to move their capex up if they see the opportunity, according to Anderson.

"SMID-cap E&Ps don't have a lot of options," he said. "You can't have it both ways. You can't cut your capex and still have your production. One of them has to give. I would not be surprised to see the SMID-cap E&Ps revise those budgets higher a little bit later in the year."

Capital discipline

By contrast, the large-cap sector is expected to be held to the 2019 budgets that are being announced.

"The big guys don't have a lot of wiggle room," commented Anderson. "They need to hit those numbers because capex is basically a proxy for capital discipline in today's E&P world."

Meanwhile, the majors, with a 15% budget increase, are set to play a stabilizing role in North America.

"I think the theme for 2019 is going to be about the majors reclaiming their stake in the U.S. market," said Anderson. "They're going to be ramping up activity and expanding their presence in the Permian."

If the OFS market is going to tighten later in the year, it is likely to do so partly due to activity on the part of the majors, especially with ExxonMobil Corp. and Chevron Corp. expanding in the Permian, he said. "They're the companies that could really take up a lot of capacity."

While those taking positions in the OFS sector are mainly energy specialists, "value investors are starting to poke around," according to Anderson. "And the reason they're poking around is they're seeing some interesting free cash flow stories. Admittedly, you have to look out a couple of years or more. People are asking me about midcycle multiples. I haven't had those questions in years."

Best of breed approach

Anderson said recent market conditions called for a "best of breed approach," focused on the "highest quality names." Two names sit at the top of his list: Baker Hughes, a GE company; and Tenaris S.A.

"Baker Hughes stands out from Schlumberger and Halliburton in that it has a differentiated business model," said Anderson. "The sweet spot for the company is its LNG business, which offers a huge opportunity. The company estimates that about 100 million tons of new capacity is going to be announced by the end of this year."

The critical advantage for Baker Hughes is that the firm's legacy GE turbine and compression business has an 80% or greater market share in these key components that are used in the construction of LNG facilities, according to Anderson. The business has a "longer cycle" in terms of returns, but offers "much greater visibility" over time. "It's a very attractive free-cash-flow story over the next several years."

Anderson also cited growth in Baker Hughes' Middle East business, where a contract has been signed to sell tools and equipment to ADNOC (Abu Dhabi National Oil Co.) Drilling, a major national oil company.

Anderson has an overweight rating on Baker Hughes with a $31-per-share target price.

Also favored by Barclays is Tenaris, considered the largest oil country tubular goods company in the world. Tenaris has operations in Italy, Latin America (Argentina and Mexico) and, more recently, the U.S., where it completed a new plant in Bay City, Texas, in early 2018. This coincided with the imposition of quotas and tariffs on imports of welded pipe from South Korea.

Tenaris has been a beneficiary of the restrictions on Korean supplies, which have enabled it to meet higher U.S. demand from its new U.S. plant. Further, if the planned replacement trade agreement for NAFTA is completed, Tenaris will be able to take further market share in the U.S. from its Veracruz, Mexico, plant, one of the lowest cost facilities in the world, according to Anderson.

Phenomenal free cash flow

Tenaris has "phenomenal free cash flow. It generates more cash flow on a revenue basis than any of the other big companies I cover," said Anderson. In addition, its balance sheet is "rock solid." Markets are being developed in new regions, with "toeholds" gained in the Middle East and Russia. Naturally, the company is already a dominant supplier to the Vaca Muerta play in Argentina.

Anderson has a top pick rating on Tenaris. His target price for the stock is $44 per share.

Marc Bianchi, a Cowen & Co. analyst covering oilfield services and equipment, also favors Baker Hughes as his top pick, while

"The large-cap E&Ps need to hit those numbers because capex is basically a proxy for capital discipline in today's E&P world."

—David Anderson, Barclays

"Value investors are starting to poke around," said David Anderson, Barclays' senior equity analyst. "And the reason they're poking around is they're seeing some interesting free-cash-flow stories."

"Until we work off the U.S. spare capacity, there's not going to be a real need for meaningful growth in the offshore and international sectors," said Marc Bianchi, analyst, Cowen & Co.

offering a number of selections across market cap ranges.

Away from Baker Hughes, these selections are in large part guided by a view of the U.S as "truly the swing supplier" and holder of the "biggest wedge of oil supply." However, supply can move up or down in a relative tight range, with production growth increasing above $50 per barrel WTI [West Texas Intermediate], but faltering at lower levels and falling "out of the money at $45 per barrel," according to Bianchi.

The implications for the OFS sector of this effective U.S. spare capacity—putting in a price floor at lower levels, but also a ceiling at higher levels—is that "it limits you mostly to U.S. onshore services, such as pressure pumping and land drilling," he said. "These areas can run at a healthy level of demand, but the rig count is not going to go to 1,500. It will probably stick around this 1,000 rate.

"Until we work off the U.S. spare capacity, there's not going to be a real need for meaningful growth in the offshore and international sectors," Bianchi continued. "That's unfortunate because offshore, especially deepwater, and international areas offer high-margin businesses with high barriers to entry. They're the sectors that the long-term investors want to own. But we just don't need it yet.

"Instead, we're stuck with relatively lower barrier-to-entry, lower technology U.S. onshore-levered businesses."

In the interim, the OFS sector is likely to see choppy market conditions, alternating between periods of tightness and slackness, according to Bianchi. This will make the sector "a little more volatile, but the amplitude of that volatility is going to be narrower. You won't have as big a swing up or down as the market corrects itself to a large degree."

The market's ability to adjust to changing conditions is reflected in Cowen's capex estimates for 2019 vs. last year. As with other surveys, an initial Jan.17 Lower 48 capex estimate of minus 2.9%, year-over-year, ceded further ground to minus 6% by Feb. 21. Data then indicated U.S. E&P capex down by 9%, while capex in the U.S. by the majors was estimated up 7%, for a blended 6% decline.

As investor focus turns away from recent weak sector earnings and toward a stronger 2020 outlook, which stocks offer the most attractive returns?

The super-spec rig area offers the best supply/demand fundamentals, although the question is how much is already priced into the stocks, according to Bianchi. For example, as regards Helmerich & Payne, the strong fundamentals are "largely reflected in its stock price," he said, while Patterson's mix of land drillers supplemented by pressure pumping offers greater upside.

'The swing piece'

"If you think activity is going to gradually increase over the course of 2019, there are areas that have more upside," he commented. "Drilling is not going to double, but pressure-pumping profitability could more than double. It's the swing piece. Patterson is guiding to $35 million of pressure-pumping gross margin in the first quarter. In the first quarter of 2018 it was $86 million gross margin."

Pressure pumpers are "very cheap on any of several metrics: free-cash-flow yield, EBITDA multiples, asset values, including replacement value—on all those metrics they look attractive," said Bianchi. His target price for Patterson is $19, based on midcycles multiples of 2020 EBITDA that are fairly modest: 6.5 times for the drilling component, and 4.5 times for the pressure pumping.

Other pressure pumpers favored by Bianchi include: ProPetro Holding Corp. (NYSE: PUMP), which he describes as the "easiest to own" in terms of quality and safety; Keane Group Inc. (NYSE: FRAC), which has a strong stock buyback program; and FTS International Inc. (NYSE: FTSI), which offers the most upside, but with more risk. Target prices are $24, $16 and $15 per share, respectively.

Massive intensity change

Pure-play pressure pumpers may also be poised to benefit from tighter market conditions driven by a "massive" intensity change on equipment from 24-hour operations and zipper fracks, noted Bianchi.

"I think we could reach a point around the end of 2019 or early 2020 when we've absorbed all the spare capacity that we have," he observed. "In the second quarter of last year, we were fully utilized on all the equipment. The rig count was about the same level as now, about 1,000 rigs, and we saw the same amount of pressure-pumping demand as in 2014. There's been this massive intensity change."

But, overall, Bianchi's top pick is Baker Hughes, offering a "buy and hold" type of business that should grow steadily "even in a flattish demand environment." In addition to its LNG exposure, the company offers products related to both upstream and downstream. However, with a lower level of capital intensity than its peers, it should generate greater cash flow.

In terms of timing of a purchase, the stock is currently weighed down by the "overhang" of GE's stock, which is set to come to market over time once a lock-up period expires in early May, according to Bianchi. "GE's exit from the stock probably happens at some point this year, and once that's gone I think the stock goes up as well."

As with the E&P sector, OFS companies are under pressure to move to a new business model. But what could that look like?

"If the sector isn't growing as fast, U.S. OFS companies should have fewer requirements in terms of growth capex, and they should be running mainly on maintenance capex," said Bianchi. "And in that world, if they're generating an OK margin, they'll throw off a bunch of free cash. And then they'll mature into more of a yield-driven, capital return vehicle rather than a traditional growth vehicle." □

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THE RETURN OF THE BAKKEN

North Dakota's production is setting new records, far exceeding the 2014 high. Bigger production volumes are coming from increasingly rubble-izing the rock.

ARTICLE BY
NISSA DARBONNE

PHOTO BY LOWELL GEORGIA

Completion operations in the Williston Basin were interrupted this past winter by extreme cold with some days at minus 20 degrees.

Fifteen miles west of New Town, N.D., along state Highway 23 and turning north about 7 miles toward the foot of the Antelope Creek State Wildlife Management Area, Continental Resources Inc. completed 13 wells at its Tarentaise Federal pad in the fall of 2017, in McKenzie County. Combined, the wells have produced more than 3.1 million barrels (MMbbl) of oil through this past January.

In Dunn County, on the Mountain Gap pad, 31 miles south of Mandaree on Bureau of Indian Affairs Road 12 and 5 miles west on Gap Road, 10 wells were completed in the spring of 2018. Through this past January, the drilling-spacing unit (DSU) had produced 1.8 MMbbl.

In a DSU just northeast, the Brandvik 9-25H has made more than 141,000 bbl in its first 73 days online.

North Dakota production figures during 2018—growing to a year-end exit rate of more than 1.4 million barrels a day (MMbbl/d)—defied some prognostications that the Williston Basin was on its way out. Rather, output from the Bakken and underlying Three Forks formations is on its way up.

It's in the completions, really, operators say.

Taylor Reid, president and COO for Oasis Petroleum Inc., said, "Yes, I remember a conference a few years ago where no one really cared about the Bakken. All everyone seemed to care about was the Permian. I opened my remarks saying that reports of the Bakken's demise had been greatly exaggerated."

At Oasis, good returns at $60 West Texas Intermediate (WTI) have resumed at even its leasehold on the Montana side of the basin,

The Williston Basin "continues to be a good place to do business," said Taylor Reid, president and COO for Oasis Petroleum Inc.

where the modern Bakken play began in 2000 in Elm Coulee Field. The Montana leasehold is back in Oasis' "Top Tier" category.

The Williston Basin "continues to be a good place to do business," Reid said. "It's great to see the recognition the past couple of years really play out [in the production figures]. The Bakken is as good as any of these other shale plays—or better."

The recipe

Until May of 2018, North Dakota's December 2014 oil output continued to hold the No. 1 spot in state records at 1,227,483 bbl/d, set at the beginning of a plummeting oil price that tumbled all the way down to less than $30 WTI in February 2016. That was just a month before Reid spoke at that conference.

Through year-end 2018, the December 2014 ranking was overtaken four more times, pushing it to the No. 6 spot, according to the state Department of Mineral Resources' count.

And the 2018 output was with a third (about 60) as many rigs as four years earlier.

Reid said that, besides advancement in the completion recipe in the Williston Basin, operators' focus on core leasehold, lower oilfield service costs that are making bigger fracture-stimulation jobs less expensive, and a decline in oilfield service demand that means the best crews and best equipment are at work in the field have, contributed to improved output figures.

Helping too is an improved price for Bakken oil as the Dakota Access Pipeline came online in early 2017. Prior, differentials for Bakken oil could be as much as $10 less than the Cushing-WTI price.

On the completions side, jobs are pretty much 100% plug-and-perf (PP) today, with Hess Corp. even quitting sliding sleeves (SS) in 2018 as the cost of a PP job declined.

So what's in that recipe? Chris Nichols, Continental's Northern region completions manager, said, "We used that downtime, with slower activity after 2014, to tailor our completions and evaluated what was working in different areas. Since then, we've transitioned from an enhanced completion to more of an optimized completion. Some of our drivers are perf-cluster spacing, volume of fluid and proppant per perf-cluster."

The stage interval has become a bit more of a secondary conversation today, he said. "We're starting to transition to treating slightly larger intervals, but we're *more efficiently* treating within that interval."

Many operators were pumping crosslinked-gel fluid to fracture the rock and deliver the proppant. Over the years, operators have been switching to slickwater fracks—big ones.

Oasis' Reid said, "It's really all slickwater at this point [for Oasis], and we're pumping 200,000 to 300,000 barrels of slickwater vs. 60,000 barrels in the crosslink jobs—the old-style jobs."

Proppant is a finer mesh too. "The majority is 100-mesh, depending on the job, and the actual volumes of sand are bigger, too. We went from a 4-million-pound job to now averaging 10 million pounds and with finer-mesh proppants."

Stages have grown from 36 to 50 in a 10,000-foot lateral. "And, then, the cluster-spacing is also tighter. The sets of perforations are about 25 feet apart now, where they used to be 50 to 75 feet apart. So we are doubling and tripling the entry points and amount of fractures in a wellbore."

The pumping rate has grown to as much as 90 bbl per minute vs. 30 to 35.

"And then we're also doing all cemented liners, all plug-and-perf, so all this is really designed to create more fractures, more complexity, really breaking up the rock and doing it more near-wellbore instead of making a frack that goes way out. We're just really trying to rubble-ize the rock around the wellbore."

Sleeve to perf

Barry Biggs, Hess Corp. vice president, onshore production, said the journey to reduce costs and improve productivity in the Bakken began in earnest in late 2010 but came into sharp focus in 2014 with the onset of a lower oil price. "Prices collapsed. You saw us, along with everyone else in the industry, really trying to figure out, 'How are we going to make money?'"

Many operators transitioned to PP completions. "At Hess, we took a different approach and one based on doing everything possible to drive cost out of the system," Biggs said.

Hess stayed with SS completions but started to aggressively implement its "lean manufacturing" method. Specifically, Hess increased sleeves from 30 to 60, while its well spacing was closer together than other operators' intra-DSU well spacing.

Well costs declined about 40% in that two-year timeframe. "Hess wells were about $4.8 million cheaper than our competitors' [wells]," Biggs said.

Other operators' PP jobs may have been getting higher production, but, to Hess, it wasn't worth the additional cost. "Our mantra was to maximize net present value at the DSU level."

The operator kept watching costs relative to productivity. "Come 2017 and '18, we trialed some plug-and-perf as we saw the cost of plug-and-perf dropping dramatically. We were able to get onto that learning curve and start the move to plug-and-perf at a cost point that made it incrementally more valuable to us," he said.

"And this approach is what is driving our significant growth outlook in the Bakken. It's simple, really: Lower-cost operations, combined with plug-and-perf, provide more entry points, more sand, which adds up to more efficient production.

"We expect to see 15% to 20% uplift on cumulative production over [wells' first] 180 days and 5% to 10% uplift in EUR. That generates about $1 billion in net present value for us over our remaining inventory at a $60 [oil] price.

"That's why we're moving to plug-and-perf and that's why we're moving now as opposed to earlier."

While Hess is transitioning to PP, Biggs said, "our overall goal remains maximizing net present value at the DSU level. This is what is driving the strong production outlook for Hess in the Bakken and one we expect to deliver approximately 200,000 boe/d [from Bakken operations] by 2021."

Transition to optimization

Original fracture-stimulated horizontals in the middle Bakken, beginning in Montana in 2000, were openhole; the fractures were created wherever there was the least resistance. As the play was brought to North Dakota, operators, including Continental Resources, began using SS to create fractures within intervals along the length of the lateral, rather than the job all going to a few areas.

In 2010, Continental began to transition to PP. Nichols said, "We saw where it was a more efficient way for us to complete the wells. We thought we were getting better completion and there was some operational flexibility we didn't have with the sleeves. We've been pretty much all plug-and-perf since 2010."

Through 2013, jobs were generally with crosslinked fluid and relatively less proppant. Stages were between 30 and 40 per well with about 3 million pounds of proppant. An infill project in 2013, though, suggested "we weren't effectively draining the reservoir," Nichols said.

Continental started testing slickwater and, in 2014, it was doing a lot of different things. "We basically set up a matrix of different completion parameters we wanted to test in different areas," Nichols said.

Pretty much everything was on the table. Among the variables: proppant volumes, proppant types, stage-interval perforation schemes. "I don't know if we could say we had a 'standard [job]' in 2014. But the average would come out to be about 5.5 million pounds of proppant per well and still around that 30-stage type of completion."

With the data, the Continental team tailored completions to what was working in different areas, transitioning from "enhanced completion" to more of an "optimized" one.

"Right now, we're looking at perf-cluster-spacing and volume per perf-cluster," Nichols said. "We look at that perf-cluster as a point of contact as to how we drain the reservoir. So the question becomes, 'How do we efficiently drain the reservoir at that point? How many points do we need? And how do we efficiently deliver proppant to those points?'

"We're starting to transition to where we're treating slightly larger intervals, but we're more efficiently treating within that interval."

How many entry points per thousand feet? Typically, 30 to 50. "Fifty, we're testing; we haven't done a lot of it," Nichols said. "Thirty is pretty common now. So we're setting those clusters every 20 to 30 feet, basically, within the wellbore."

The denser molecule

In Oasis' Wild Basin Field in McKenzie County, the operator brought 10 wells online in its Rolfson North DSU in August and September of 2016 about 7 miles north of Watford City, the county seat, and about an hour's drive west of both Mandaree and New Town.

Combined, the wells have produced some 3 MMbbl of oil through this past January. In particular, Rolfson North 5198 14-17 11BX made more than 194,000 bbl in its first 178 days online; production through this past January was 443,013 bbl.

The science-ing on where within the middle Bakken to land a lateral is brief—the zone is only about 30 to 60 feet thick. But Oasis' Reid said that drilling improvements have nevertheless helped contribute to growth in overall North Dakota output: Drill days for a 10,000-lateral-foot hole have decreased from about 24 to 12 for Oasis. It's less costly.

The best crews and best equipment working at both making the hole and completing it "just made the whole play super-efficient. If you look at statistics around production per rig, the Bakken is really one of the best plays."

The concern about a slickwater completion back in the earliest days of the play was that—while it worked in the Barnett, a gas play—Bakken production is about 90% oil, a much denser molecule. And fracture-stimulation jobs involved less proppant concentration at the time.

"We still have a 15-year inventory out there that can generate returns in excess of 50% at $60 WTI," said Hess Corp. vice president Barry Biggs.

Featured North Dakota DSUs

These DSUs are among those that have produced extraordinary wells, including one well that has made more than 140,000 barrels of oil in its first 73 days online, according to North Dakota Department of Mineral Resources records.

As a result, when first entering oil plays, operators switched to the more viscous crosslinked fluid that could deliver more proppant. By 2014, most of Oasis' jobs were crosslink, with 30/50 and 20/40 ceramic proppant and a little bit of 100-mesh—about 4 million pounds of it. Stages averaged 36 for Oasis and it tested some of up to 50, pumping about 30 to 35 bbl per minute.

Since 2014, though, all Oasis jobs are slickwater. Pumping is 200,000 to 300,000 bbl vs. 60,000 bbl of crosslink. The rate is between 70 and 90 bbl per minute. The proppant is mostly 100-mesh sand—about 10 million pounds of it.

Stages today are as many as 70, but most operators are doing around 50. "And then there are clusters," which came about over time and is "kind of a new advent." Cluster spacing is about 25 feet now vs. 50 and 75.

"In each of those stages, the spacing between groups of perforations is getting closer together," said Reid. "So we've gone from four to eight clusters in each stage. The entry points are now more dispersed along the lateral.

"There aren't always necessarily more actual perforations—because we're using limited-entry techniques. But they're closer together, so there are more places along the lateral that you have entry points now than we used to have."

Oasis Petroleum Inc.'s Rolfson North 5198 14-17 11BX in northern McKenzie County, N.D., has produced more than 440,000 barrels of oil.

Fine-tuning

Hunkering down in core leasehold has helped reduce cost, Reid said, "instead of moving [equipment and people] around to all these different areas. We moved into Wild Basin and have been drilling in Wild Basin four years. So we've had the same crews, the same rigs and all the infrastructure to support it."

Production Data For Rolfson North 5198 14-17 11BX

Date	Days	Bbl Oil	Date	Days	Bbl Oil
Jan-19	31	4,664	Oct-17	31	14,259
Dec-18	31	5,196	Sep-17	30	14,306
Nov-18	30	5,013	Aug-17	24	10,112
Oct-18	31	5,125	Jul-17	31	14,043
Sep-18	30	5,613	Jun-17	30	16,582
Aug-18	31	6,176	May-17	31	18,351
Jul-18	31	6,267	Apr-17	30	22,387
Jun-18	30	7,025	Mar-17	31	27,336
May-18	31	8,193	Feb-17	28	31,407
Apr-18	30	8,527	Jan-17	31	25,925
Mar-18	31	8,827	Dec-16	31	29,274
Feb-18	28	8,590	Nov-16	30	40,500
Jan-18	31	9,984	Oct-16	31	37,219
Dec-17	31	10,668	Sep-16	27	29,897
Nov-17	30	11,547			

Source: North Dakota Department of Mineral Resources

The big slickwater jobs mean moving more water—300,000 bbl per well—to the pad. "And then you need to dispose of it cheaply. It was a bit challenging" when operations were spread across the basin, he said.

But, "when you concentrate your activity and plan effectively, you're able to pipe all that water in at a low cost and then pipe it all out into disposal wells without it ever going into trucks."

The modern Oasis 10,000-footer is expected to cost less than $8 million. In 2013, a completed hole cost about $10 million and it was a smaller-intensity job. EUR today is between 30% and 50% greater.

Oasis finished 2018 with Williston Basin production of some 78,200 barrels of oil equivalent per day (boe/d), up 18% from 2017.

Hess' fourth-quarter 2018 Bakken production was 126,000 boe/d, up from 110,000 a year earlier. It expects 2019 Bakken production to average between 135,000 and 145,000 boe/d.

Continental's fourth-quarter 2018 North Dakota Bakken production was 177,358 boe/d, up from 158,640 boe/d in fourth-quarter 2017.

Hess' Biggs said, "We still have a 15-year inventory out there that can generate returns in excess of 50% at $60 WTI." The operator continues to fine-tune what works best in any given area. "There's no 'one size fits all,'" Biggs said.

A standard completion is roughly 10 million pounds of proppant, Biggs said, "but we're experimenting with wells that have 16 million pounds and some that have less [than 10 million] and experimenting with spacing and number of stages.

"Over the years, we've learned a lot, but we're not done yet. There's a lot more optimization that can come here with the hope that we can bring the economics up and extend that inventory to more acreage that sits outside the core of the core."

Continental's Nichols said there are some units in Continental's leasehold where the geology changes pretty rapidly. But, "for the most part, when a design change works in one place, it tends to work to some degree in another."

The company's average first-year production per well from 2013 to 2018 has roughly tripled and, it added, "we're still in early innings of developing our inventory."

And the early-days wells—might these be recompleted in the future with modern jobs? Hess' Biggs said, "Absolutely. We've seen others doing this in the basin. We're going to save that in our inventory. We're going to get a greater return on a new well [at this time]. We probably will not start to do a refrack program for probably another year or two."

Continental's Nichols said, "There are some options there [with refracks]. We're focused on new-drills right now; it's the best spend on our capital.

"But we're keeping an eye on recompletions. As technology evolves, there's always the possibility we can go back and develop those [old] wells further." □

NOTHING TOPS LNG

Above power, petrochem or even Mexico imports, LNG holds the key to U.S. natural gas demand growth and price recovery. And the Haynesville Shale is pole positioned.

ARTICLE BY
NISSA DARBONNE
AND
PAUL HART

U.S. LNG exports are key to balancing the U.S. natural gas market, according to Bernadette Johnson, vice president, market intelligence, for Drillinginfo Inc.

"Natural gas production continues to reach record levels," she told attendees at Hart Energy's DUG Haynesville conference in February in Shreveport, La. Dry-gas production through year-end 2018 was 24.6 billion cubic feet per day (Bcf/d) more than in 2010, according to Drillinginfo data.

The U.S. Energy Information Administration (EIA) reported that November 2018 alone was the 19th consecutive month of dry-gas production year-over-year increases. The November total was more than 88 Bcf/d, up some 9 Bcf from the November 2017 daily output. Yet, Johnson noted that "storage inventories remained at historical lows throughout summer 2018."

Working gas in storage entering withdrawal season Nov. 1 totaled 3.2 trillion cubic feet (Tcf), 15.3% lower, year-over-year, according to the EIA. Johnson said, "Demand for natural gas in the U.S. is increasing significantly. Some of it is domestic [consumption], but the biggest piece is LNG exports."

Growth in exports to Mexico has been meaningful, she said, "but it's not like LNG."

Drillinginfo is expecting 11 Bcf/d of U.S. LNG exports by 2023, an estimate Johnson said "is conservative" based on what LNG developers forecast. "Ours is based on the market. How big is the market out there?

"The global LNG market that moves around on ships is a 40 Bcf/d market. It's less than half the size of the U.S. [domestic market]," she said. "So can we grow to 11 [Bcf]? We think so. Can we grow much more than that? That's pretty tricky. How are you going to replace or add more than 25% of the existing market? This is the challenge."

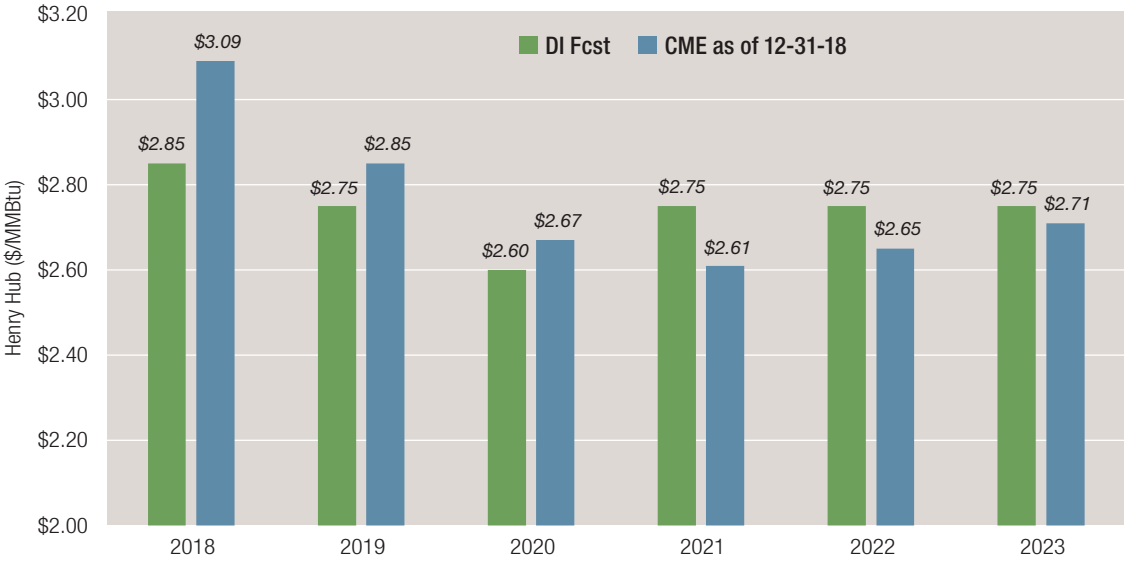
The EIA forecast for LNG exports at year-end 2019 is 8.9 Bcf/d (with year-end 2018 estimated at 3.6 Bcf/d) as new trains come online at Elba Island, Ga. (Kinder Morgan Inc.); Freeport (Freeport LNG Development LLC) and Corpus Christi (Cheniere Energy Inc.), Texas; and Hackberry, La. (Cameron LNG LLC).

Drillinginfo estimates 2018 exports averaged 3.4 Bcf/d from two facilities: Cheniere's Sabine Pass, La., export terminal and Dominion Energy Inc.'s terminal at Cove Point, Md.

Johnson said Drillinginfo data show January 2019 LNG exports set a record: 5.6 Bcf/d. The firm expects 2019 LNG exports will average 4.3 Bcf/d "as most [additional] facilities are not expected to be fully online until late 2019." In 2020, exports are expected to jump to 6.5 Bcf/d.

Bernadette Johnson, vice president, market intelligence, for Drillinginfo Inc., said growth in natural gas exports to Mexico has been meaningful, "but it's not like LNG."

DI Natural Gas Five-Year Price Forecast: $2.60-$2.75



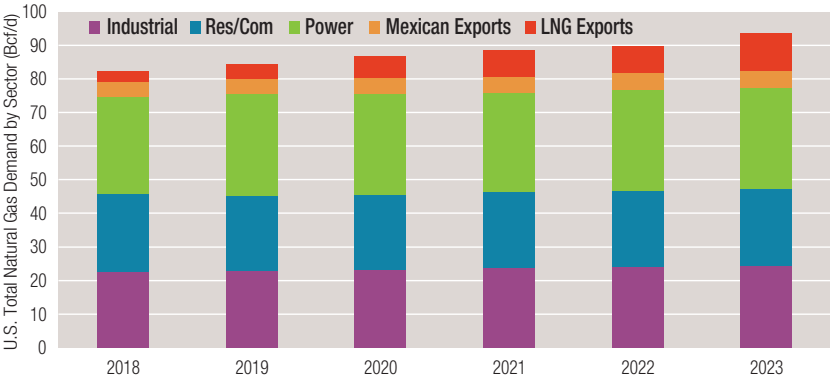
Source: CME, DI Analytics

Welles Fitzpatrick, managing director of E&P research for SunTrust Robinson Humphrey, said he expects gas prices to improve in 2019 and beyond. And when they do turn up, "the Haynesville will be one of the best-positioned plays to take advantage of that upturn."

The implicit rising connectivity of Henry Hub to the global gas pricing trend "is an exciting, transformational development for the U.S. fossil fuel sector generally, and especially for Haynesville production," said Tom Petrie, chairman of Petrie Partners.

"There's some growth [in natural gas demand] on the power side," she added, "but it's not dramatic. The biggest, most impactful … more than anything [to demand] is LNG."

Five-Year Outlook: U.S. Natural Gas Demand



Source: DI Analysis, EIA

Haynesville advantaged

Producers in all of the unconventional plays hope for a rise in natural gas demand—and gas prices—soon, but the Haynesville, more than other plays, depends on such a trend. The reborn play has multiple advantages, said Welles Fitzpatrick, but while markets have improved, they could be better.

Fitzpatrick, managing director of E&P research for SunTrust Robinson Humphrey, rated his firm "a little bit more optimistic on natural gas pricing" than many industry analysts. Also speaking at DUG Haynesville, he said, "Gas prices are depressed now, but we expect that to improve in 2019 and beyond. And when they do turn up, the Haynesville will be one of the best-positioned plays to take advantage of that upturn."

That will drive corporate capital efficiency, "writ large," he added, saying the play "will recapture its crown as the No. 1 gas play in the Lower 48."

The difference between a bull market and a bear market—$3.50 gas vs. $2 gas—is a comparatively small swing of 2- to 4 billion cubic feet per day (Bcf/d) of demand, he said. Current U.S. dry-gas production runs above 87 Bcf/d.

Net gas exports, as LNG and to Mexico net after Canadian imports, will be the big driver of future demand, Fitzpatrick said. "The change is going up and up, by 2.1 Bcf/d in one year. That's the equivalent of one Barnett [Shale]—that's huge. It's growing quicker than we expected. Industrial demand is positive, but the driver is exports."

The most significant shift in gas demand came in 2016 when Cheniere's Sabine Pass plant went on stream and "crystallized" the U.S. role as a major LNG supplier. "Now, we are supplying gas to the whole world."

The Haynesville enjoys a location close to the Gulf Coast, near Sabine Pass and other LNG liquefaction plants, as well as comparatively good midstream infrastructure. Proposed pipelines will make that infrastructure still better.

Fitzpatrick said Haynesville gas is oversupplied now, but "this will reverse as production growth slows dramatically in '19. Demand will accelerate this year and prices will respond positively as a result." Longer term, the supply/demand situation looks good for producers in the Haynesville and elsewhere, he noted.

"We haven't discovered a major new gas play since 2011," Fitzpatrick said. "Shale plays don't last forever, in fact they don't last long. Without new plays, you need higher prices. The Haynesville is unique in its rebirth, which provides huge advantages."

EIA figures show Haynesville gas production fell from above 6 Bcf/d to around 5 Bcf/d before starting a rebound in early 2017. Overall low prices and crowding from the Marcellus inhibited the play for a while. Late 2018 flows passed 8 Bcf/d.

Opportunity in abundance

Tom Petrie, chairman of Petrie Partners, seconded Fitzpatrick's emphasis on gas exports. He pointed to the "LNG infrastructure solution that is so critical to transform the gas pricing marketplace."

Petrie referred to a Massachusetts Institute of Technology gas production forecast published in 2010. It seemed optimistic at the time but in reality, "the productivity is more than twice what we thought we had." The nation expanded from five to eight unconventional plays, and the Marcellus, "because it became so successful, so quickly," gets credit for much of the increase, but the Appalachian play "became a competitive alternative to the Haynesville."

Petrie described Cheniere's announced plans nearly a decade ago to convert its LNG receiving terminal at Sabine Pass, La., to a liquefaction and export operation "the cornerstone" of LNG exports that transformed the U.S. gas business and the world's LNG market. Cheniere founder Charif Souki, who made that bet, is now chairman of the board at Tellurian Inc.

Additional trains at Sabine Pass combined with the Cove Point, Md.; Corpus Christi, Texas; and Cameron, La.; plants will push gas export demand to some 9 Bcf/d this year, he said.

Petrie noted the gas supply overhang "is not a problem, it's an opportunity."

Exports represent an exciting opportunity for all of the shale plays. He mentioned the surging associated gas flowing out of the Permian Basin in particular. But the Haynesville's proximity to many of the LNG liquefaction projects is a plus for the region's producers.

"The implicit rising connectivity of Henry Hub to the global gas pricing trend is an exciting, transformational development for the U.S. fossil fuel sector generally, and especially for Haynesville production," he said. ☐

BRIDGING THE DIVIDE

Oil and gas dealmakers are utilizing contingency payments to address the valuation gap.

ARTICLE BY
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ILLUSTRATION BY
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Since 2014, the domestic energy landscape has changed at a Usain Bolt type of pace. Whether it be the wave of E&P company restructurings, the continuing lack of public capital available to energy companies (and the prevalence of private capital replacing it), the U.S.' emergence as the world's top oil and gas producer or the "energy transition," change has been a constant in discussions regarding the oil and gas industry. Another constant has been commodity price volatility.

In 2018 alone, crude prices (West Texas Intermediate) began the year in the $50s, spiked into the $70s, and then ended the year in the $40s. In a similar vein, natural gas prices (Nymex) began 2018 in the $3 range, spiked above $4.50, and, by early 2019, dropped into the $2.50 range. This commodity price roller coaster has kept many dealmakers on the edge of their seats, and many others on the sidelines.

By most accounts, 2018 was a decent year for dealmaking in the oil and gas industry, with aggregate transaction value up year-over-year and deal count slightly down during the same period.

A slowdown in deal activity began during the latter part of 2018, especially noticeable when excluding one-time MLP simplifications and the handful of large M&A transactions that occurred during a two-week period in late October/early November. This slowdown has continued into 2019. Much of the slowdown has been attributable to the wild fluctuations in commodity prices occurring during the same period, which has often resulted in large valuation divides between potential buyers and sellers.

As most in the industry have experienced, it is quite difficult to make a competitive bid/offer, or accept a compelling bid/offer, when there is lack of predictability on commodity prices—arguably the most important variable in asset valuations.

One tool that is used by dealmakers to address this valuation divide is a contingent payment mechanism. While these types of mechanisms are more commonly used in other industries, there is an increasing appetite to consider their use in oil and gas transactions. This article highlights (1) certain situations in which the contingent payment mechanism may be useful, (2) structuring considerations for contingent payments and (3) industry-specific considerations for contingent payments.

Common uses

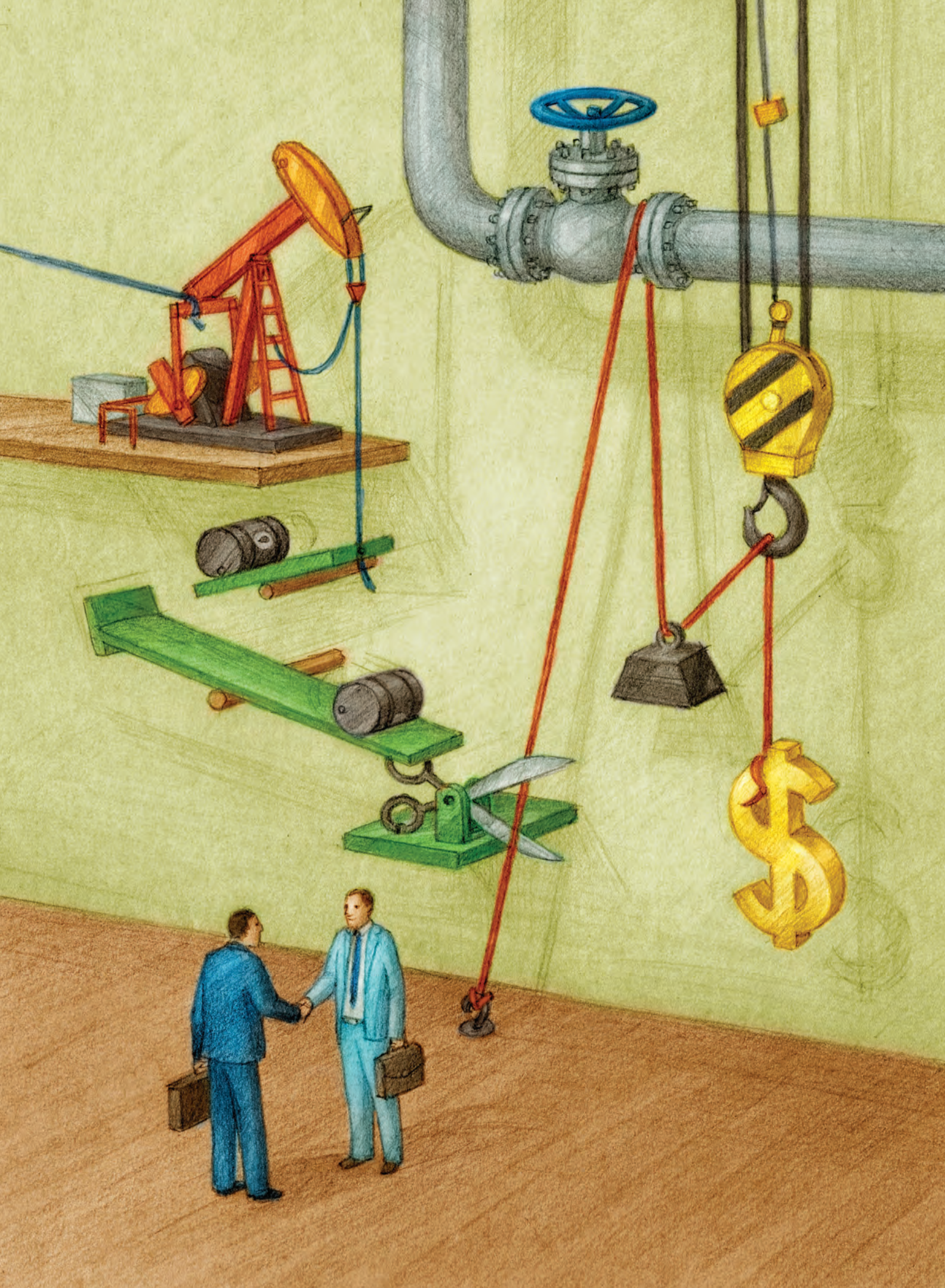
The form of contingent payment mechanism used in oil and gas is similar to the "earn-out" payment mechanism often employed in transactions in other industries. When using this mechanism, the buyer pays a base purchase price at a transaction's closing, and makes one or more contingent post-closing payments to the seller upon the occurrence of certain events (for instance, increases in commodity prices) or the satisfaction of certain predefined performance metrics (for instance, earnings for a midstream company). If such events do not occur or such metrics are not satisfied during the specified period, the buyer does not make the contingent payments to the seller.

Contingent payment mechanisms can serve as effective tools in resolving valuation divides

Recent Earn-outs: Upstream Transactions

	Transaction Summary	Earn-out Structure	Earn-out Term
Marcellus/Utica Transaction	Asset acquisition of Ohio natural gas assets	Up to ~5% of base & aggregate purchase price payable based on natural gas index prices during specified future time periods.	~1.5 years
North Texas/Oklahoma Transaction	Asset acquisition of North Burbank and Texas Panhandle enhanced oil recovery business	Up to 10% of base purchase price (~9% of aggregate purchase price (including earn-out amount)) payable based on target oil production volumes and average sales price therefor.	Three years
Marcellus/Utica Transaction	Asset acquisition of upstream assets in northern West Virginia and southern Pennsylvania	Up to ~9% of base purchase price (~8% of aggregate purchase price (including earn-out amount)) payable for achieving financial targets based on average natural gas index prices.	Three years

Source: Gibson, Dunn & Crutcher



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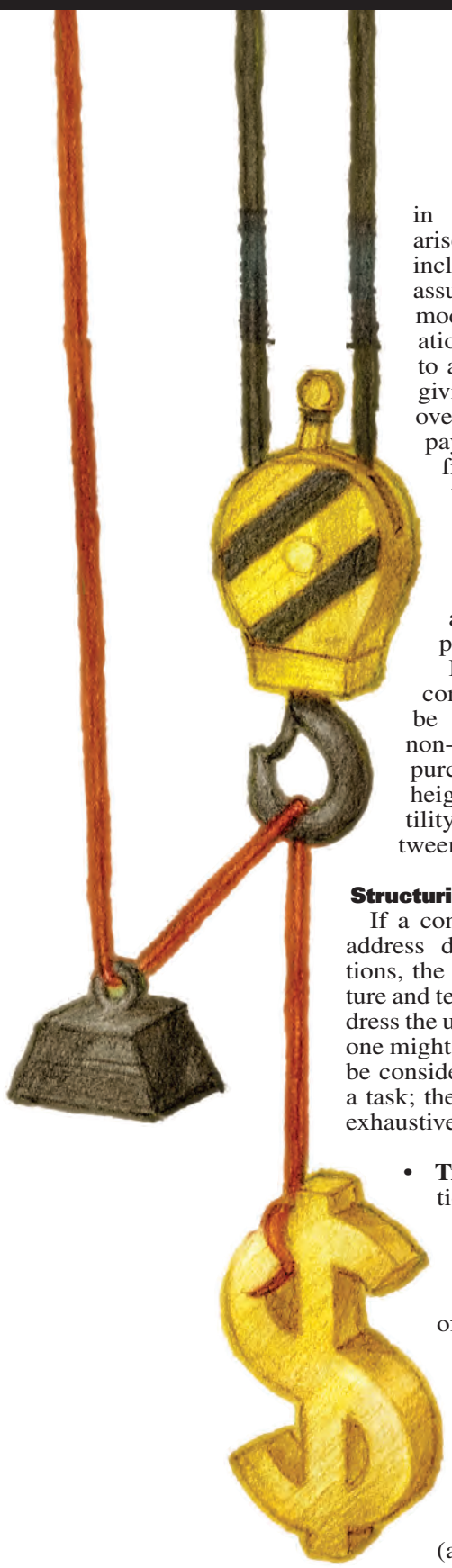

in transactions, which may arise for a number of reasons, including the parties' differing assumptions regarding commodity prices and future operational results. When structured to address the underlying issue giving rise to the disagreement over valuation, a contingent payment protects the buyer from bearing the risk of potentially erroneous valuation assumptions (and, thus, from potentially overpaying), while compensating the seller if its projections and valuation assumptions prove to be accurate.

In general, the size of the contingent payment tends to be larger (in relation to the non-contingent portion of the purchase price) when there is heightened uncertainty or volatility that creates a larger gap between the parties' expectations.

Structuring considerations

If a contingent payment is used to address differing valuation assumptions, the contingent payment's structure and terms should be tailored to address the underlying circumstances. As one might expect, several items should be considered when undertaking such a task; the following sets forth a non-exhaustive list:

- **Triggering events:** In addition to commodity price triggers, parties use a number of performance measures in contingent payment formulas based on the nature of a given industry and the entities being sold, as well as the interests of the parties to the transaction. Commonly used performance criteria include EBITDA, EBIT, sales, net income, profit, the occurrence of a specified future event or (as discussed below in the upstream and midstream context) industry-specific criteria. In many of these instances, the parties should address the proper application of accounting principles to the chosen criteria, including whether it will be consistent with the seller's or the buyer's prior application, and should address any relatively unique calculations or business-specific items upfront to avoid controversy.

- **Payment amounts/consideration:** The contingent payment mechanism can provide for such payments to be fixed or prorated in amount, paid in one lump sum or incrementally, and subject to varying time periods and time limitations. Additionally, the consideration paid as a contingent payment can take various forms, with different forms raising different sets of issues. With the use of stock consideration, for example, additional issues include how and when the stock is to be valued, what voting and registration rights the seller will have, what protections the seller will have with respect to changes in stock prices, and securities compliance matters.

- **Operating covenants:** When contingent payments are tied to the performance of the acquired business, the parties will likely need to specify post-closing operational parameters to protect each party's expectations, as the parties' objectives (and financial incentives) after closing may not be aligned. Specifically, the seller will almost be exclusively focused on the short term performance of the underlying assets/business (in the context of the contingent payment criteria), whereas the buyer will be focused on both the short-term and long-term performance of the underlying assets/business. Common covenants to address these concerns include requirements that the business be operated in substantially the same manner as before closing, as well as restrictions on specific actions that can impact the contingent payment (for instance, large expenditures and/or the retention of key employees).

- **Time periods:** Time periods during which contingent payments must be made typically range from one to five years following closing, depending on both the types of benchmarks chosen and the length of time that sellers are willing to forgo full compensation (and buyers are willing to provide continued incentives). Such periods can also be structured to continue until terminated upon the occurrence of specified events, such as the buyer's change of control or the attainment of certain nonfinancial benchmarks, including the introduction/opening of new projects or the securing of certain regulatory approvals.

- **Security:** Finally, the use of contingent payments may necessitate that the seller insist that the buyer provide some form of post-closing security with respect to the contingent payments. The financial wherewithal of the buyer, along with its post-closing capital structure, should be considered in evaluating whether such assurances are necessary. Forms of such assurance may include the provision of security (for instance, parent company guarantees), the post-closing escrowing of funds and the use of the acquired assets as collateral, among many others.

Industry-specific considerations

In addition to using the traditional contingent payment structures, companies engaged in upstream and midstream transactions can employ industry-specific mechanisms that may help the parties more accurately value the transaction:

- **Upstream:** Commodity price volatility will almost always be a concern for parties looking to accurately value certain assets in upstream transactions. This is especially true in higher-value transactions, where months of additional negotiations (and post-execution activities) following the initial agreement on a purchase price may allow for significant commodity price fluctuations, resulting in a purchase price that no longer accurately reflects the parties' initial valuation of the assets. Parties may attempt to solve this issue by tying contingent payments to specific commodity price hurdles on established exchanges. Bidders in a competitive process may also sweeten their bid by offering some post-closing upside to sellers in the event commodity prices increase. When this type of contingent payment mechanism is implemented, an index is typically specified, with the price hurdle as an average price on the applicable index over a period of time.

  Buyers concerned with the future (or continued) productivity of an asset, or wishing to address a value dispute with the seller for assets that are not yet de-risked through development, may base contingent payments on the performance of specific wells. Where the subject assets are at least partially developed and the parties have allocated value in the purchase agreement on a well-by-well basis, this can be accomplished using performance metrics for existing wells; in the case of substantially undeveloped acreage and/or value allocation on a lease or unit basis, more contingencies in the payment structure may be needed to satisfy both parties (for instance, sticking to predetermined drilling schedules or agreeing to earn-out well locations ahead of time).

- **Midstream:** In the midstream space, a large portion of a target midstream company's value is based on revenues attributable to existing contractual delivery commitments from upstream producers or other shippers. In the case of a target company with existing contracts containing such delivery commitments, the parties may structure contingent payments to be based on expected gross volumes at specified future dates (or over specified periods of time) in an effort to limit the risk that contract counterparties fail (for one reason or another) to meet their delivery obligations to the target company—a risk that may be compounded in situations where the target company has its own downstream commitments to satisfy.

  Similarly, in the case of a target company that does not yet have any such contracts in place, the parties may agree on contingent payments based upon the target company entering into such contracts (or upon the initial deliveries of volumes under those contracts to the target company) after closing and implement covenants requiring that the target company make reasonable efforts to obtain such commitments during the earn-out period.

  More (and more) dealmakers are continuing to see that, when carefully drafted, contingent payments can provide a useful tool to help bridge divides in transaction valuations, including in the context of valuation assumptions unique to the oil and gas industry. ☐

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Recent Earn-outs: Midstream Transactions

	Transaction Summary	Earn-out Structure	Earn-out Term
Appalachia Transaction	Acquisition of 100% of Target's equity interests	Up to ~14% of base purchase price (~12% of aggregate purchase price [including earn-out amount]) payable if certain firm natural gas transportation agreements executed meeting specified criteria.	Dependent upon in-service dates of specified pipeline segments
Permian Transaction	Acquisition of 100% of Targets' equity interests	Up to ~165% of total base purchase price (~62% of aggregate purchase price [including earn-out amount]) payable for achieving financial targets based on delivered volumes of crude oil or natural gas under certain contracts.	Two separate one-year periods
Eagle Ford Transaction	Acquisition of 100% of Target's equity interests	Up to 10% of base purchase price (~9% of aggregate purchase price [including earn-out]) payable for achieving financial targets based on financial performance and capex thresholds relating to anticipated expansion products.	Not publicly disclosed

Source: Gibson, Dunn & Crutcher

THE FIRST 100 DAYS

Here are key considerations when making oil and gas asset transactions.

ARTICLE BY
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AND
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OPPORTUNE LLP

In today's world of technology and investment into best practices, it is surprising how unique each oil and gas asset transaction can be. Companies spend countless hours and investment into standardizing a process for bringing on or offloading assets in a given time frame. This article addresses not only the unique requirements of an oil and gas transaction, but also the variables associated with the integration of hardware and software systems, all while adhering to strict implementation deadlines.

Asset integration

Project management and timing are critical to successful asset integration. There is a laundry list of activities that need to be accomplished correctly and within a set timeframe to ensure a smooth transition from negotiating and drafting a purchase and sale agreement (PSA) to post-acquisition activities, such as management and staffing. Here are the primary elements that directly impact the complexity of the cut-over:

- (Stage/life cycle) Start-up vs. existing organization;
- Location of assets relative to existing portfolio;
- Transition services agreement (TSA); and
- Software and hardware.

These activities are in a set time frame to ensure a smooth transition from negotiating and drafting a PSA to post-acquisition activities.

Start-up vs. existing organization

The biggest challenges are typically limited systems and minimal staffing for a start-up company. There is usually a strong case to outsource back-office functions such as land administration, operational accounting and financial reporting. The case to outsource is especially compelling if management's goal is a quick exit in three to five years.

If management determines that outsourcing is not the model it wants to take, the next question should be: "Is the seller allowing staff to transition with the assets?" If critical roles are made available to the buyer, then the systems and processes become the next focus.

There are many back-office systems available; most have a base configuration that works for 80% of the business cases. There is often the thought that if one keeps the systems the seller is using, the conversion will be easier. This is usually not the case. Whether outsourcing or hiring, the reporting requirements to external stakeholders should be a central focus for the software configuration regardless of what vendor is chosen.

Key decisions related to successful asset integration are different for an existing company with systems and processes in place and the necessary internal controls already defined. Typically, a review of the processes and controls to determine any necessary enhancements is sufficient. The question then becomes: "Can this acquisition be absorbed and, if not, how quickly can we hire?" And again: "Is the seller allowing any critical back-office positions to move with the sale?"

TSA and cut-over

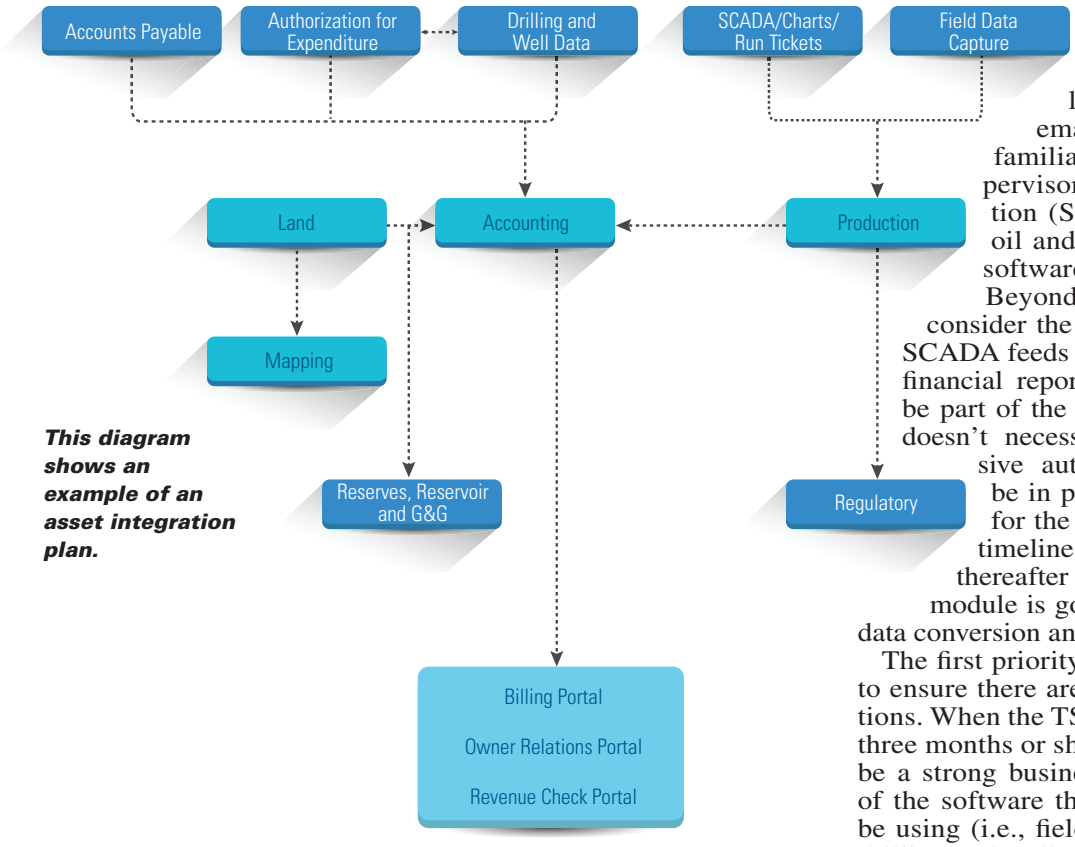
The TSA defines the type of services the seller will perform to support the asset integration, and the period those services will be provided before they are transitioned to the buyer. Timing of cut-over is a key consideration concerning the TSA because of the inherent lag between production and account-

Representative Upstream Oil And Gas Transaction

0-60 Days	Definitive Agreement	30-75 Days	Closing	30-180 Days and Ongoing	
Land Analysis		Full Due Diligence (land, EHS, financial)		System Selection & Implementation	FP&A
Reserve Engineering		Buyer Obligations		Financial Carve-Out	Purchase Price Allocation
Geoscience		RBL Support		Settlement Statement	Impairment Testing
Assessments		Data Conversion & Integration		RBL Support - Final	IPO Readiness
Quality of Earnings		Hedge Advisory		Land Admin	Tax Compliance & Provisions
Acquisition Model				Back Office Outsourcing	Divestitures
Risk Identification				Reserve Reports	Special Projects
PSA/TSA Support					
Pre-PSA		Pre-Closing Due Diligence		Post-Acquisition/Ongoing	

Source: Opportune LLP

System Considerations Example



This diagram shows an example of an asset integration plan.

ing. Generally, this lag is about 30 days for oil and 60 days for gas. For example, assume the TSA indicates the buyer will take over accounting and support processes in January. In January, the buyer will be accounting for December oil production and November gas and NGL production. Cut-over can be driven by either production month or accounting month; however, accounting month will result in a more aggressive timeline.

TSAs are often extremely detailed about the services the seller will provide and, of course, they cover the associated fees with those services and available timeline. The cut-over type, however, is not typically described in the TSA and often will be interpreted as "calendar month." Therefore, it is important that the buyer and seller work together as soon as a purchase agreement is executed in order to define exactly how the transfer of services will occur.

Hardware and software

It is often the case that insufficient time is allotted to transition or procure new hardware and software. Inevitably, buyers do not want to spend money on resources prior to the transaction's closing date. This means a significant amount of work needs to be performed post-closing. Even when the seller is including all the hardware in the field, items such as email transfers and corporate cell phones take longer than expected.

In addition to hardware, if a company is using a third-party IT provider, it is important to engage a firm familiar with the needs of an oil and gas company. For example, a company that helped set up an office for a law firm may understand laptops and servers and email, but it is not going to be familiar with radio towers and supervisory control and data acquisition (SCADA) meters and all the oil and gas-specific hardware and software required.

Beyond hardware, a buyer must consider the software needed. From the SCADA feeds and reservoir systems to the financial reports, every module needs to be part of the asset integration plan. This doesn't necessarily mean a comprehensive automated solution needs to be in place on day one, but a plan for the critical modules and then a timeline to implement the rest soon thereafter is critical. Ultimately, every module is going to require some sort of data conversion and testing activity.

The first priority of all asset transactions is to ensure there are no interruptions in operations. When the TSA window is tight (such as three months or shorter), there is not going to be a strong business case for switching any of the software that the field personnel may be using (i.e., field data capture, production, drilling and well data, etc.).

When pressed for time, buyers often think, "Let's just implement exactly what the seller did." In theory, this sounds like the perfect plan and the path of least resistance for everyone. Additionally, software vendors often tout the ease of a "lift and shift" where, in a perfect scenario, the seller data would be upgraded to the latest software version and all the configurations and reports will already be in place. This type of effort can be successful on reservoir systems, well and drilling data systems, but for the back-office modules, it is never that simple.

Consideration and planning for these complexities will reduce several risks to the integration timeline. Even the simplest of transactions often have limited timelines and unique requirements. Engaging third parties—due diligence, project management, IT, etc.—familiar with both the oil and gas space and complexities associated with asset transactions will lead to a smoother overall process. ☐

Amy Stutzman is a managing director in Opportune LLP's upstream transactional advisory group. She leads teams that support executive management in understanding the structure and implications of complex transactions such as IPOs and acquisitions. Byrony Coan is a director in Opportune's upstream transactional advisory group. She has 18 years of experience in project management, oil and gas software, product management, process consulting and change management.

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Noble Energy Gets Leaner, Starting In Permian

NOBLE ENERGY INC. launched plans to pare down its portfolio with a sale of 13,000 net acres in Reeves County, Texas, for $132 million in cash, the company said in regulatory filings. The buyer wasn't disclosed.

The company has targeted 2019 divestitures of between $500 million and $1 billion in assets sales to support its ambitious, though frugal, plans for 2019. The company plans to spend 17% less on capex in 2019 than last year while growing U.S. onshore production by 10%.

On a February earnings call, Noble chairman and CEO David Stover declined to identify other assets the company is selling but said it will continue to divest noncore areas and added that "probably 15% to 20%" of the sales were already done.

Noble also disclosed two deals it closed in December 2018.

In the Delaware Basin, the company sold noncore acreage for $63 million, resulting in a pre-tax loss of $16 million.

In the Denver-Julesburg Basin, the company closed a cashless acreage swap, receiving about 12,900 net undeveloped acres within core areas of its Mustang and Wells Ranch positions. In exchange, Noble traded about 12,300 net undeveloped acres in the same area. No gain or loss was recognized.

"I'm confident we will have sold the things that makes sense, either from the standpoint that they're worth more to somebody else because of the way they look at it, or that it's an opportunity to highlight value that isn't highlighted and recognized in the company at this point. So, those are the things we'll continue to look at. But it's just part of the ongoing portfolio management."

The company may also, at some point, decide to monetize a portion of Leviathan project offshore Israel to help fund additional expansions over time, Stover said.

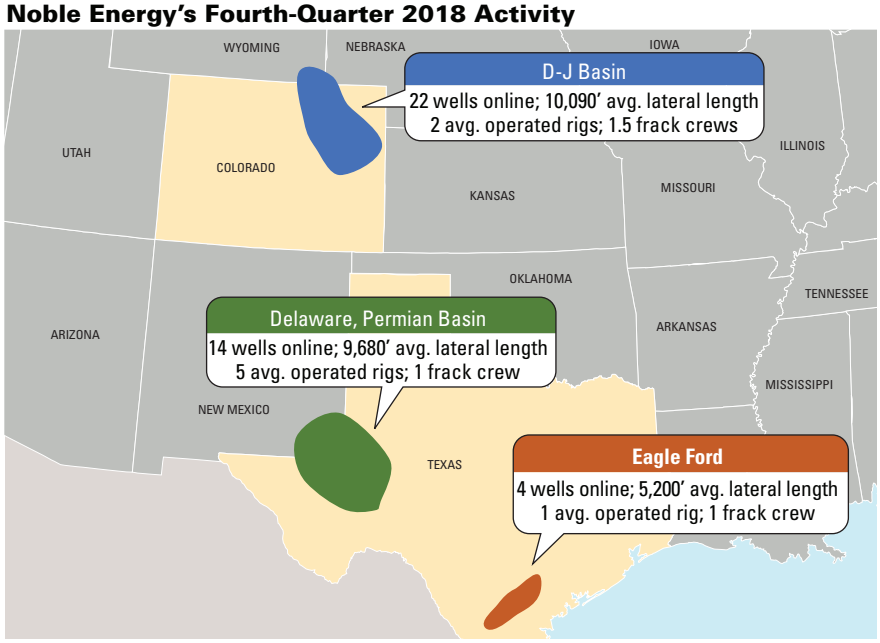
Devin McDermott, a **Morgan Stanley** analyst, wrote in a Feb. 20 report that the sales may unlock additional value for the company, which already trades at a discount to its peers despite 10% better year-to-date performance. Part of the company's asset sales could include a dropdown of midstream assets.

"Noble owns midstream assets that will generate $160 million of annualized EBITDA by 4Q19 [fourth-quarter 2019]," McDermott wrote. "Assuming an 8-times multiple implies about $1.3 billion of potential proceeds from sales" of its midstream affiliate.

The company's year-end results included a $1.3 billion impairment of goodwill, which was associated with the company's Texas assets, primarily resulting from the drop in West Texas Intermediate (WTI) forward strip pricing at the end of 2018, the company said.

Noble additionally said proceeds from asset sales in the fourth quarter totaled $226 million, including cash received for the divestment of 7.5% working interest in its offshore Israel Tamar area and other noncore U.S. onshore interests.

Noble Energy's Fourth-Quarter 2018 Activity



Source: Noble Energy Inc.

Ring Energy Pulls $300-Million Wishbone Acquisition

RING ENERGY INC. tacked on more Central Basin Platform acreage in the Permian Basin on Feb. 26 with the $300-million cash and stock acquisition from private-equity-backed **Wishbone Energy Partners LLC**.

Ring said it agreed to acquire Wishbone's North Central Basin Platform assets for $270 million in cash and $30 million of Ring common stock. The Midland, Texas-based company plans to fund the acquisition through an increased $1 billion senior credit facility led by **SunTrust Robinson Humphrey**.

Based in Houston, Wishbone was founded in 2013 with backing from **Quantum Energy Partners** to focus in select onshore conventional and unconventional reservoirs, with emphasis on the Permian Basin, East Texas and the Midcontinent, according to the company's website.

Wishbone's North Central Basin Platform assets consist of 49,754 gross (37,206 net) acres of mostly contiguous leasehold located primarily in Southwest Yoakum County, Texas, and East Lea County, N.M. The assets also include a base of 127 gross wells currently producing an average daily net production of 6,000 barrels of oil equivalent (boe/d).

The acquisition includes a 77% working interest and a 58% net revenue interest in the assets, which are roughly 96% operated by current production volume. Ring will be the operator.

"The future is very bright based on the great results from its existing wells combined with the exceptional results we are experiencing with our ongoing drilling and development program," Ring CEO Kelly Hoffman said in a statement on Feb. 26. "This acquisition doubles our daily production, adds another 37,000 prime acres to our horizontal footprint and nearly doubles our proved reserves."

In addition, Ring is also picking up infrastructure from the Wishbone deal, including 1,385 acres of owned surface rights, 21 saltwater disposal wells, 15 source water wells, five frack ponds and three caliche pits for road material and new locations.

Pro forma the acquisition, Hoffman added that Ring will also have more than 20 years of San Andres horizontal drilling inventory using a two-rig development program.

"We believe this acquisition is a major step toward achieving our stated goals to continue to generate strong annualized production growth and to become cash flow neutral/positive by the second half of 2019," he said.

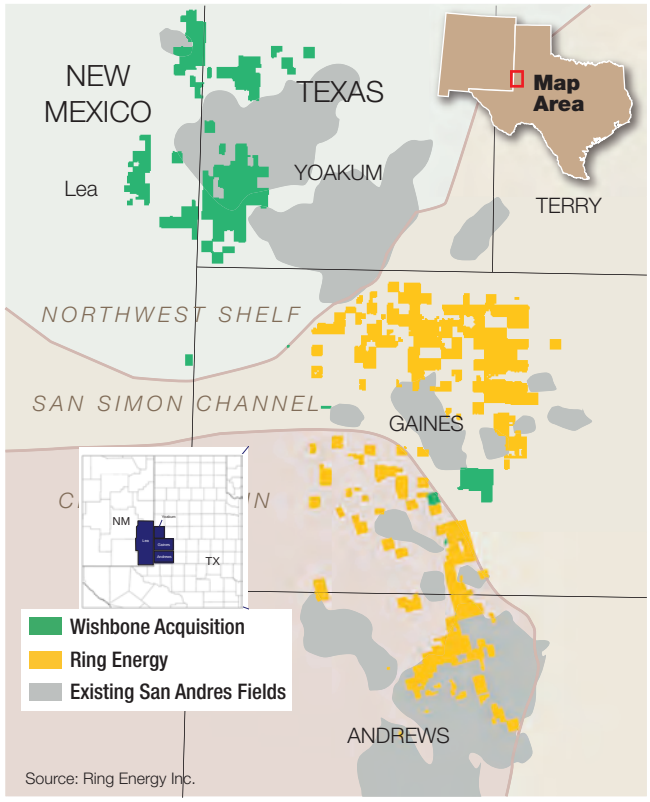
SunTrust Bank provided a financing commitment letter for the increased $1 billion senior credit facility, which has a borrowing base of $425 million. SunTrust Robinson Humphrey will act as lead arranger and book manager for the financing.

SunTrust is also Ring's exclusive financial adviser for the transaction and **Baker Hostetler** acted as legal counsel to Ring. Law firm **Vinson & Elkins** advised Wishbone Energy Partners in the sale of its North Central Basin Platform assets.

Ring said in the news release that it expects to close the Wishbone acquisition early in second-quarter 2019. The transaction will have an effective date of Nov. 1.

—Emily Patsy

Wishbone Acquisition



QEP Fails To Move Bakken Asset

QEP RESOURCES INC. launched a comprehensive review of strategic alternatives on Feb. 20, which the Denver-based company said could include a sale to activist investment firm **Elliott Management Corp.**

Additionally, QEP said it agreed to terminate the definitive agreement to sell its assets in the Williston Basin to **Vantage Energy Acquisition Corp.** due to the deterioration in commodity prices. The company had entered the sale late last year as part of its strategy to become a pure-play Permian E&P.

The strategic review could result in a merger or sale of QEP or other transaction involving the company or its assets, according to the company press release.

"QEP intends to engage in discussions with a variety of parties that have expressed interest in a potential transaction, including Elliott Management Corp.," the company said in the release.

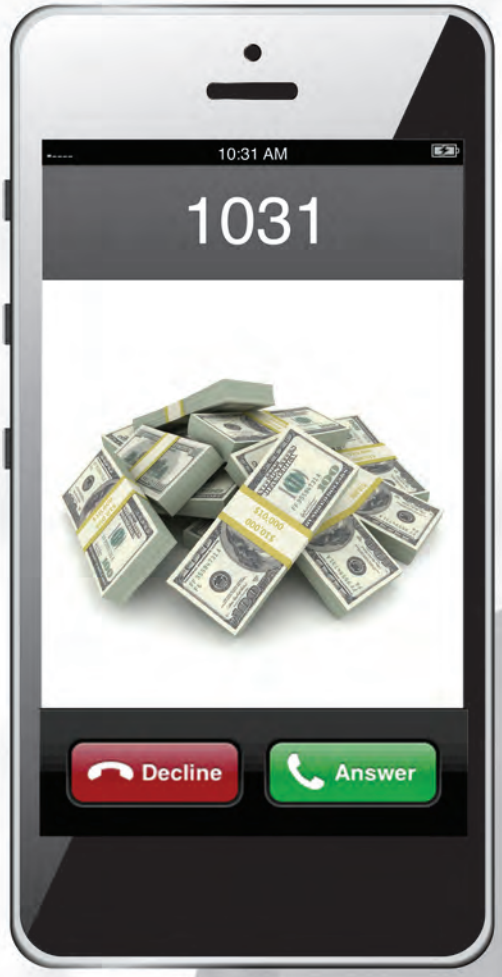
Earlier this year, Elliott offered to buy QEP in an all-cash deal valued at $2.07 billion, saying that the company is "deeply undervalued."

In addition to the strategic review, QEP also said Feb. 20 it plans to significantly reduce its general and administrative expense by roughly 45%, when comparing 2018 to 2020, in light of the reduction of the company's operational footprint during the last year. The company expects most reductions will be implemented during the first half of 2019.

Evercore and **BMO Capital Markets** are acting as financial advisers to QEP and **Latham & Watkins LLP** and **Wachtell, Lipton, Rosen and Katz** are serving as the company's legal advisers.

QEP will continue to operate and develop its assets in the Williston Basin, including the company's South Antelope and Fort Berthold leaseholds.

—Emily Patsy



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'New' Devon Energy Considers Canadian, Barnett Spin-offs

DEVON ENERGY CORP. launched plans on Feb. 19 to complete its transformation into a high-return U.S. oil growth business including the possible sale or spin-off of its Canadian and Barnett Shale assets.

Following completion of its transformation, Devon's business will hold core of the core positions with significant operating scale in four basins: the Delaware Basin, Stack play, Powder River Basin and Eagle Ford Shale.

"With our world-class U.S. oil resource plays rapidly building momentum and achieving operating scale, the final step in our multiyear transformation is an aggressive, transformational move that will accelerate value creation for our shareholders by further simplifying our resource-rich asset portfolio," Dave Hager, Devon's president and CEO, said in a statement.

In May 2017, Devon launched its "2020 Vision"—a strategic turn away from growth at any cost—with a focus on delivering "top-tier returns" to investors. As a result, the company set a $1 billion sales target and began shedding noncore assets, including divestitures in the Eagle Ford and Delaware Basin.

Devon expected to exceed its original $1 billion divestment target within a year to 18 months and eventually bumped up its asset sales goal to $5 billion.

With the steps announced on Feb. 19, Devon expects its U.S. oil business to generate 13% to 18% oil growth in 2019, with 10% less upstream capital than 2018, and is self-funded at $46 oil prices, assuming flat service and supply pricing relative to 2018, according to the company press release.

"New Devon will emerge with a highly focused U.S. asset portfolio and has the ability to substantially increase returns and profitability as we aggressively align our cost structure to expand margins with this top-tier oil business," Hager said. "The new Devon will be able to grow oil volumes at a mid-teens rate while generating free cash flow at pricing above $46 per barrel."

In the fourth-quarter of 2018, Devon's four core oil assets delivered light-oil production growth of 20% year-over-year, with total production averaging 296,000 boe/d.

Further, the company said the "new Devon" has operating margins that are 57% above the total company average in 2018 and has demonstrated well productivity that has exceeded the industry average by roughly 40% over the past three years.

With Devon's new, narrowed focus as a U.S. oil business, the company is committed to aligning the cost structure by taking steps to deliver at least $780 million in sustainable annual cost savings by 2021.

On Feb. 19, Devon said its board of directors authorized a $1 billion increase to the company's previously announced $4 billion share-repurchase program, bringing the total repurchase program to $5 billion.

Devon also reported a better-than-expected quarterly production on Feb. 19, aided by more output from its U.S. shale assets, according to a Reuters report.

The company reported production of 532,000 boe/d in the fourth quarter ended Dec. 31, while analysts had expected 527,060 boe/d, according to IBES data from Refinitiv.

The Oklahoma City-based company expects to complete the separation of its Canadian and Barnett Shale assets by the end of 2019. The company has hired advisers for each asset, and data rooms for the Canada and Barnett are expected to be open by second-quarter 2019.

Devon Energy said it anticipates using potential proceeds from the separation of these assets to maintain target debt levels of one to 1.5 times EBITDA and to continue share repurchase activity.

—Emily Patsy

Oil, Tech Titans ExxonMobil And Microsoft Partner

EXXONMOBIL CORP. struck a partnership with **Microsoft Corp.** to use the tech company's cloud technology on its Permian Basin operations, which the Texas-based oil major said will generate billions of dollars in value during the next decade.

The partnership with Microsoft includes an integrated cloud environment that collects real-time data from the field to enable ExxonMobil's **XTO Energy Inc.** subsidiary to make faster and better decisions on drilling optimization, well completions and prioritization of personnel deployment.

The value of the agreement wasn't disclosed but ExxonMobil said it expects the technology could expand its Permian Basin production by as much as 50,000 boe/d by 2025.

The company also added that the application of Microsoft's technologies across its Permian Basin acreage, which covers a 9.5 billion oil-equivalent barrel resource base and more than 1.6 million acres, represents the industry's largest acreage position using cloud technology.

Alysa Taylor, corporate vice president of Microsoft Business Applications and Industry, said ExxonMobil is taking a leadership approach in its digital strategy.

"ExxonMobil is leading the way for industry, grounding their goals in making data-driven decisions that will result in safer operations for their employees and more profitable activities for the company," Taylor said in a statement. "Our cloud infrastructure and business applications will continue to support ExxonMobil as it fully realizes its strategy across the Permian."

The application of Microsoft technologies by ExxonMobil's XTO Energy subsidiary includes Dynamics 365, Azure, Machine Learning and Internet of Things. The digital technology is a "fundamental enabler" for the company's Permian development, said Staale Gjervik, senior vice president of Permian integrated development for XTO.

"Through our partnership with Microsoft, we're combining our technical and engineering expertise with cloud and data analytics capabilities to develop the Permian resource in the most capital-efficient manner," Gjervik said in a statement. "Collaboration with Microsoft is key to our future development efforts, which include predictive maintenance capacities, innovative tools for employees, and artificial intelligence and machine learning integration."

ExxonMobil has pledged to increase its Permian Basin production to 600,000 boe/d by 2025. The company's fourth-quarter Permian production was 190,000 barrels of oil and gas per day.

—Emily Patsy

Mid-Con Energy's $87 Million In Deals Include Texas Exit

MID-CON ENERGY PARTNERS LP launched plans to exit Texas, it said on Feb. 19, as it concentrates on building its Oklahoma waterflood inventory in a series of A&D transactions. The Tulsa, Okla.-based company called the moves "liquidity enhancing."

Mid-Con Energy said it entered agreements to sell substantially all of its Texas properties and acquire producing Oklahoma properties in Caddo, Grady and Osage counties. The combined value of the transactions, which the company expects will significantly lower its total outstanding debt and leverage ratio, is about $87.5 million.

Scout Energy Partners purchased Mid-Con's Texas properties, which at $60 million was the larger of the two transactions. The deal includes properties within the Permian Basin's Eastern Shelf across Coke, Coleman, Fisher, Haskell, Jones, Nolan, Runnels, Stonewall and Taylor counties, according to a filing with the U.S. Securities and Exchange Commission (SEC).

The transactions "strengthen our financial position while enhancing the partnership's asset base with low-decline properties and an inventory of waterflood growth projects," said Mid-Con Energy CEO Jeff Olmstead in a news release.

Formed in 2011, Mid-Con Energy focuses on EOR in core areas located in Oklahoma, Texas and Wyoming with the Sooner State being the base of the company's operations.

According to an August company presentation, Mid-Con Energy's position in Texas comprised conventional oil assets held in 10 counties within the Eastern Shelf of the Permian Basin with four new waterflood developments in the past two years.

Scout, a private, Dallas-based investment firm focused on acquiring and operating mid-sized upstream conventional oil and gas properties on behalf of institutional investors, was also revealed in the SEC filing as the seller of the Oklahoma assets in a $27.5-million transaction with Mid-Con Energy.

The Oklahoma assets include 10 mature waterflood units with net proved developed producing (PDP) reserves of 6.2 million boe (96% oil), as of Jan. 1, and a PDP decline rate of less than 5%. Production from the assets was 1,313 boe/d during the third quarter of 2018.

"Like many of the other assets we have acquired in the past few years, we see significant opportunity in optimizing margins and the value of the new properties in a short time frame through a combination of operational efficiency improvements, reactivation of wells, and production enhancements," Olmstead said.

Pro-forma for the transactions, Olmstead said the underlying PDP decline rate for Mid-Con Energy will be less than 10%, with a portfolio of development projects for future growth.

Mid-Con Energy plans to continue to look for acquisitions of long-lived, low-decline assets with opportunities to enhance margins and cash flow or waterflood potential, according to the company's press release.

The company was expected to close both transactions in late March. The effective date of each transaction will be the same date as the closing date.

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Wednesday, April 17th, 2019

The Post Oak ✦ 1600 West Loop South

11:30AM Registration ✦ 12PM Luncheon

The World Affairs Council of Greater Houston is proud to recognize Jeff Shellebarger, President of Chevron North America Exploration and Production Co., as its 2019 International Citizen of the Year. The keynote address will be delivered by Ambassador Thomas Pickering, Former U.S. Under Secretary of State for Political Affairs.

Jeff Shellebarger

INTERNATIONAL CITIZEN OF THE YEAR

President, Chevron North America Exploration and Production Co.

Ambassador Thomas Pickering

KEYNOTE SPEAKER

Former U.S. Under Secretary of State for Political Affairs

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Matador Resources Enters Delaware Midstream JV

MATADOR RESOURCES CO. expanded its Delaware Basin midstream operations in a deal on Feb. 25 that analysts believe could help minimize outspend as the company considers selling upstream assets outside its core Permian position.

The company said March 1 that to narrow any potential difference between its 2019 capex and operating cash flows, "we may divest portions of our noncore assets, particularly in the Haynesville Shale and in parts of our South Texas positions" as well as mineral, royalty and noncore midstream interests.

Tudor, Pickering, Holt & Co. (TPH) analysts see the monetization of Matador's noncore assets as steps in the right direction with the "Eagle Ford as the most impactful monetization candidate in the near term.

"While the current A&D market is certainly tough, we expect management to take a surgical approach to a sale via many small packages vs. pursuing one large deal," TPH analysts said in a research note on Feb. 22.

The analysts estimate a sale of Matador's Eagle Ford position could generate aggregate proceeds of roughly $300 million.

The Dallas-based oil and gas company formed a second midstream joint venture (JV) in the Delaware with private-equity firm **Five Point Energy LLC** to be named **San Mateo Midstream II LLC**. The agreement is the second midstream JV between Matador and Five Point after the pair initially linked up in 2017 to form **San Mateo Midstream LLC**.

Similar to the original JV, San Mateo II will be owned 51% by Matador and 49% by Five Point and be responsible for expanding current gathering, processing and saltwater disposal capacity for Matador's northern Delaware Basin operations.

As part of the agreement, Matador will dedicate roughly 25,500 gross acres of its Arrowhead and Stateline asset areas to San Mateo II. In return, the company will receive a capital carry where it is expected to pay $25 million of the initial $150 million capital costs related to the expansion.

Matador will also receive firm capacity service for its Arrowhead and Stateline asset areas, up to $150 million of performance incentives over five years, plus retain operational control of the midstream assets.

> "It doesn't matter so much whether you are a single basin or multibasin; the point of it is to get into the best rock that you can with the best economics and that's what our primary focus is."
>
> — Joseph Foran, Matador Resources

Following announcement of the JV on Feb. 25, TPH analysts said the deal should help Matador management minimize outspend in 2019.

Matador had previously highlighted efforts to manage near-term outspend during its third-quarter earnings call in early November where management said it would consider any "really serious offer" for its Eagle Ford, Haynesville, minerals, royalty interests and midstream assets.

However, Matador CEO Joseph Foran indicated on the call that the company would not be pursuing the pure-play path several of its contemporaries have recently gone down.

"We have said for some time we're not a company that says we are a single basin company, and we are going to reduce ourselves down to whatever basin is most important," Foran said, according to a transcript of the company's earnings call by Seeking Alpha. "Clearly, the most important [basin] right now is the Delaware, but as you can see being in several basins has shown to be good strategy and that diversification leads to more options. ... It doesn't matter so much whether you are a single basin or multibasin; the point of it is to get into the best rock that you can with the best economics and that's what our primary focus is."

San Mateo II initially plans to construct a new cryogenic natural gas processing plant near Carlsbad, N.M., in Matador's Rustler Breaks asset area. The new plant will increase San Mateo's total capacity to 460 million cubic feet per day (MMcf/d) from the current, almost fully subscribed, 260 MMcf/d of capacity available from the nearby Black River processing plant built in 2016.

In addition, gas pipelines will be expanded north into the Arrowhead area and south into the Stateline area, which was recently acquired during a Bureau of Land Management sale in September 2018. Additional oil and saltwater disposal infrastructure will also be built in Eddy County, N.M., which TPH analysts believe could support Antelope Ridge development.

David Capobianco, CEO and managing partner of Five Point Energy, said the Houston-based firm has been proactively identifying management teams to partner with and build out world-class midstream infrastructure companies in the Delaware Basin.

"The Delaware remains one of the most promising producing basins in North America, yet it lacks sufficient permanent 'in-basin' midstream infrastructure," Capobianco said in a statement on Feb. 25. "Five Point's portfolio companies, including San Mateo Midstream, WaterBridge, EVX and Twin Eagle, are providing critical midstream infrastructure solutions for third-party producers, with unparalleled offerings and innovation."

The new cryogenic plant is expected online in mid-2020.

—Emily Patsy

Matador Resources Portfolio

Play	Net acres	Net drilling locations	Boe/d
Delaware Basin	132,000	2,472.2	45,237
Eagle Ford	28,900	206.9	3,158
Haynesville	12,000	100.2	3,417
Cotton Valley	18,600	49.2	316
Area total	22,800	149.4	3,733
Total	183,700	2,828.5	52,128

Source: Matador Resources Co. regulatory filings

BP's BPX Energy Pursues U.S. Shale Mission

IT'S NOT UNCOMMON for British supermajor **BP Plc** to publicly share information on its operations; however, its Lower 48 business—the recently christened **BPX Energy**—rarely makes such moves.

That changed when Mohit Singh, senior vice president of business development and exploration for BPX Energy, took the stage at Hart Energy's DUG Haynesville conference on Feb. 20. He spoke about how BP is transforming its U.S. onshore business, following its $10.5 billion acquisition of **BHP Billiton**'s Delaware Basin, Eagle Ford and Haynesville assets in 2018.

"For me to come out [on stage] was a little bit of a coming out party in some sense," Singh said. "One of the things we want to do going forward is be a little bit more visible externally so we can get our message out."

Starting March 1, the company was to take over operations from BHP on its quest to build a "premier independent onshore company focused on delivering free cash flow on a consistent basis," Singh said.

The acquisition, which closed in October 2018, marked a pivotal moment for BP, which already had U.S. onshore assets that include the Midcontinent's SWOOP, Anadarko and Arkoma as well as East Texas, San Juan and Wamsutter assets. The assets are among the $5- to $6 billion worth of property BP plans to divest during the next two years to pay for its acquisition of BHP's U.S. shale assets.

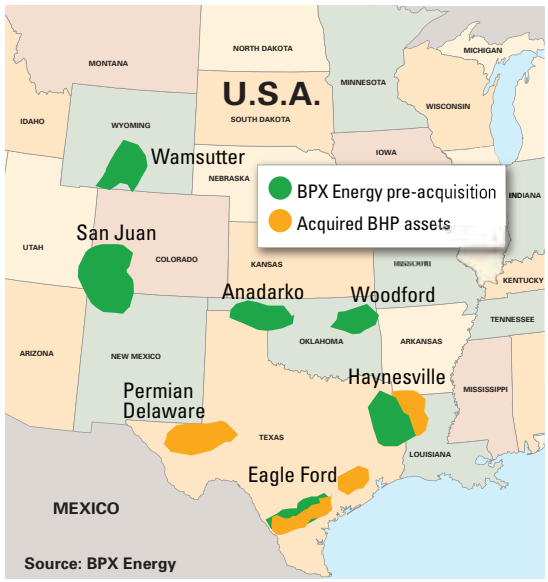
Referring to BPX's legacy portfolio, Singh said the company had several good opportunities prior to the acquisition, "but BHP clearly upgrades us. … We're talking about decades and decades of high-quality drilling inventory that will deliver phenomenal rates of return."

The deal includes assets in the Permian's Delaware Basin, adding about 41,000 barrels of oil equivalent per day (boe/d) in production with 3,390 gross drilling locations on an 83,000-acre position.

"We are seeing up to 240 rig years of drilling inventory just because of the stacked pay zones," Singh said, particularly in the Bone Spring and Wolfcamp A, B and C/D. The company put the after-tax internal rate of returns for the assets at between 28% and 50%.

The deal also gives BPX an opportunity to develop multilaterals in Eagle Ford benches and Austin Chalk. The acquired assets in the liquids-rich Eagle Ford included core acreage in the Karnes Trough and the shale play's wet gas window, Singh said. Current production is about 87,000 boe/d (71% liquids), and there are 1,402 gross drilling locations on the 201,000-acre position.

BPX Combined Assets



Source: BPX Energy

In the Haynesville, BPX tripled its footprint and doubled its production with the BHP deal. Singh said BPX is running six rigs in the Haynesville in East Texas this year and has plans to eventually start on the Louisiana side.

Once BP completes divestitures, which are being offered in seven packages, Singh said BPX will only operate in the Delaware, Eagle Ford and Haynesville.

"That's where all of the capital will go. Traditionally, we've spent about $1 billion of capital in this business every year," Singh said. "Going forward, that number will be $2- to $2.5 billion. It's significant investment by BP into the onshore business."

Meanwhile, marketing has already begun for assets being sold by BP.

"Suffice it to say the last 18 months at BP have been very, very hectic but a good kind of hectic," Singh said.

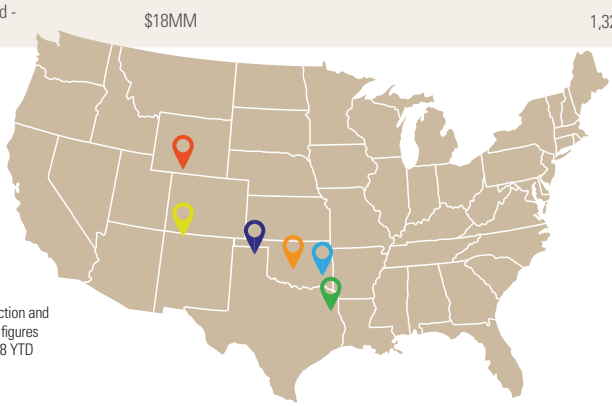
The Shallow Woodford Oklahoma Oil Play (SWOOP) near the Scoop and Stack plays and East Texas packages are already being marketed. The others, Singh said, are set to come out between the end of February and early March.

The biggest of the bunch are the San Juan Basin assets, which accounts for half of the nearly 200,000 boe/d of production being sold. Singh described San Juan as a "phenomenally robust play in terms of coal." Most of the production comes from coal seams in San Juan, he said, calling it world-class quality coal.

Here, BPX has drilled horizontal semi-laterals, dual laterals, tri laterals and quad laterals, which Singh described as horizontals coming from

BPX's Divestment Packages

	Mboe/d	OCF	% Gas	% NGL	% Oil	Wellbores (Vt%)	Acres
Shallow Woodford Oklahoma Oil Play (SWOOP)	4	$37MM	10	15	75	19 (0%)	35k
East Texas	6	$35MM	75	20	5	600 (77%)	45k
San Juan	102	$239MM	94	6	0	9,500 (99%)	567k
Wamsutter	38	$187MM	69	21	10	2,500 (99%)	500k
Anadarko	19	$91MM	62	31	7	3,600 (73%)	511k
Arkoma	34	$103MM	100	0	0	1,800 (67%)	440k
Legacy Non-Op Minerals/Leasehold - Multiple Basins		$18MM					1,320k



Note: Unless otherwise stated, all production and acreage figures are net to BP. Production figures 2018LE. OCF is annualized based on 2018 YTD Actuals through October.
Source: BPX Energy

one vertical on a pad. Such drilling methods have enabled BPX to reduce well costs, he added. Plus, "given the quality of the coal is so prolific, these wells come on and they stay flat for a year plus, which is incredible."

BPX produced about 100,000 boe/d from the San Juan Basin in 2018. Most of it was gas.

However, some oily acreage is also available, including in the SWOOP where BPX said well results have been strong.

"We were running four rigs prior to BHP happening. We were very, very bullish on this play," Singh said before highlighting IPs of nearly 90% oil. "Hopefully, it will end in the hands of someone who's going to get after it."

Other assets available include:

- Glenwood, Woodlawn and Oak Hill fields in East Texas, which comprise about 45,000 mostly contiguous acres. BPX says there are development and recompletion opportunities in the Cotton Valley, Haynesville and other horizons;
- Wamsutter in the northern Greater Green River Basin, where the company said "existing cash flow from liquids-rich low decline base production complements horizontal redevelopment of Lewis and Almond";
- Two large core gas positions in the Arkoma, where there is undeveloped horizontal potential in the Woodford Shale; and
- Anadarko Basin, a more than 500,000-acre position that Singh said might be divided into three packages.

BP is also divesting interest in legacy mineral and leaseholds in nonoperated assets in several basins, including the Powder River, Williston, Eagle Ford, Haynesville, Stack/Scoop and Denver-Julesburg.

Post-integration in 2021, BPX Energy expects to have 3,500 wells, down from 9,400 in 2018, and operate in three basins, down from six.

But the capital budget is expected to more than double as the company focuses heavily on the Delaware, Eagle Ford and Haynesville to bring combined production to about 500,000 boe/d, up from 315,000 boe/d in 2018. Oil is expected to make up about 25% of BPX's production mix, compared to 5% in 2018, as the company remains bullish on gas.

The acquisition of BHP's U.S. shale assets has been transformational, Singh said.

"It's given us very high rates of return and a depth of repeatable drilling inventory that is very, very exciting. … We are well on our way to building a premiere onshore business," he said.

—Velda Addison

TRANSACTION HIGHLIGHTS

UTICA

■ **Pin Oak Energy Partners LLC** said it closed an acquisition of nearly 70,000 net acres in the Northern Trend of the Utica/Point Pleasant play in Ohio and Pennsylvania.

The company said it closed a series of transactions in early February 2018 with multiple, undisclosed sellers. The transactions include the acquisition for the Utica and Point Pleasant assets, which are nearly 90% HBP. In addition to other areas, the transactions include leasehold acreage in Mahoning and Trumbull counties, Ohio, and Mercer County, Pa., all of which are part of Pin Oak Energy's northern Utica/Point Pleasant position.

Leasehold acreage in eastern Guernsey County, Ohio, was also included, which adds to Pin Oak's southern Ohio Utica/Point Pleasant activities. Also included were associated pipeline rights-of-way in and around Pin Oak's expanding acreage position. The company also acquired processing facilities and multiple taps into interstate pipelines across Pin Oak's northern Pennsylvania position.

BAKKEN

■ **Hess Midstream Partners LP** continues to build out its infrastructure footprint in the Bakken Shale play with a $60 million bolt-on acquisition on Feb. 26. The Houston-based company, an affiliate of oil and gas producer **Hess Corp.**, said it had entered an agreement to purchase the Tioga Gathering System from **Summit Midstream Partners LP**.

The crude oil and gas gathering assets include roughly 73 miles of crude pipelines and 79 miles of gas pipelines. Meanwhile, the water assets consist of 75 miles of produced water gathering pipelines. Hess Midstream said it expects that HIP will offer it a right-of-first offer to acquire the water assets in the event HIP decides to sell the assets in the future, according to the company press release.

DELAWARE BASIN

■ **Cimarex Energy Co.** closed its acquisition of **Resolute Energy Corp.**'s Delaware Basin position in a cash-and-stock transaction worth about $1.6 billion, including assumption of $710 million in debt.

The deal, announced Nov. 19, adds about 21,100 net acres in Reeves County, Texas, where Resolute held an average 79% working interest. Resolute's average third-quarter 2018 production was 34,752 boe/d.

MIDCONTINENT

■ **Encana Corp.** said Feb. 13 it completed its $7.7-billion acquisition of U.S. shale producer **Newfield Exploration Co.** and will proceed with a previously announced $1.25 billion share buyback program.

Encana acquired all outstanding shares of Newfield common stock in an all-stock transaction valued at roughly $5.5 billion. In addition, the Calgary, Alberta-based company also assumed $2.2 billion of Newfield net debt.

For Encana, the acquisition of Newfield, which analysts called Encana's "boldest move yet," will expand the company's "core four" portfolio to include a key position in the oil-rich Stack and Scoop plays of the Anadarko Basin.

"This acquisition creates North America's premier resource company with large-scale positions in the core of the Permian, Anadarko and Montney," Doug Suttles, Encana's president and CEO, said in a news release.

In November, Encana said it expected liquids production following the close of its combination with Newfield to contribute more than 50% of total company production, driving continued margin expansion and returns. Additionally, the company also anticipates the combination to result in $250 million of annual synergies through greater scale, cube development and overhead savings.

APPALACHIA

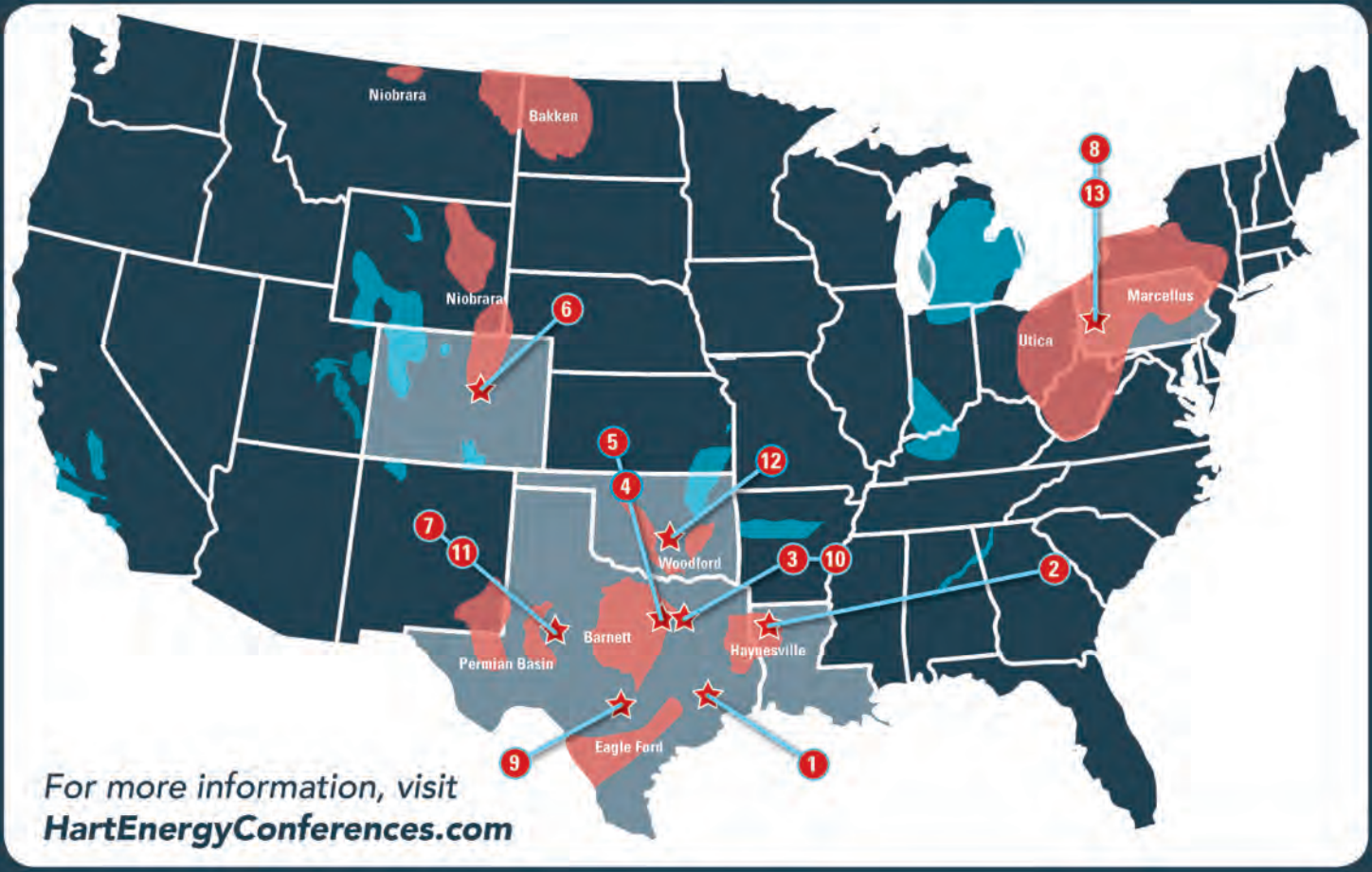
■ **Eclipse Resources Corp.** and **Blue Ridge Mountain Resources Inc.** completed a merger Feb. 28 and emerged as a new Appalachian Basin producer, **Montage Resources Corp.,** with 227,000 net effective undeveloped acres in the Utica and Marcellus shales.

In late August 2018, Eclipse and Blue Ridge Mountain agreed to merge in an all-stock transaction. Blue Ridge stockholders received 4.4259 shares of Eclipse common stock for each share of Blue Ridge stock. The transaction was then valued at about $345 million.

The resulting combination, holds acreage in southeast Ohio, West Virginia and North Central Pennsylvania.

Montage began trading on the New York Stock Exchange under the ticker "MR" with a 15-to-1 stock reverse split effective March 1.

2019 Hart Energy Events



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

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Feb. 19 – 20
Shreveport, LA
DUGHaynesville.com

CONFERENCE & EXHIBITION DUG PERMIAN BASIN
April 15 – 17
Fort Worth, TX
DUGPermian.com

CONFERENCE & EXHIBITION DUG ROCKIES
May 14 – 15
Denver, CO
DUGRockies.com

CONFERENCE & EXHIBITION DUG EAST
June 18 – 20
Pittsburgh, PA
DUGEast.com

CONFERENCE & EXHIBITION DUG EAGLE FORD
Sept. 24 – 26
San Antonio, TX
DUGEagleFord.com

EXECUTIVE OIL CONFERENCE & EXHIBITION
Nov. 4 – 6
Midland, TX
ExecutiveOilConference.com

CONFERENCE & EXHIBITION DUG MIDCONTINENT
Nov. 19 – 21
Oklahoma City, OK
DUGMidcontinent.com

MIDSTREAM EVENTS

From gathering and processing to transportation, storage and exports, the midstream conferences connect operators, service providers and their financial partners to core issues affecting midstream business.

CONFERENCE & EXHIBITION MIDSTREAM TEXAS
June 5 – 6
Midland, TX
MidstreamTexas.com

NEW DATES
MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION
Dec. 3 – 5
Pittsburgh, PA
MarcellusMidstream.com

FINANCE EVENTS

Investors and dealmakers converge at Hart Energy's finance events – and deals get done. Speakers analyze market trends, transactions and key drivers for future investment, and producers improve their skills to successfully access financial and asset capital.

energycapital CONFERENCE
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A&D STRATEGIES AND OPPORTUNITIES Conference & Workshop
Oct. 22 – 23
Dallas, TX
ADStrategiesConference.com

For more information, visit ***HartEnergyConferences.com***

THE RICE BROTHERS' NEXT ACT

RICHARD MASON, CHIEF TECHNICAL DIRECTOR

One good turn deserves another.

That's how Rice Investment Group (RIG) sees its role as a private-equity capital provider to oil and gas. The fund originated out of the multibillion-dollar 2017 sale of Rice Energy Inc. to EQT Corp. Now the Rice brothers are looking to fund investments that will further technology, best practices and data analytics—many pioneered at Rice Energy—in a capital-constrained energy space.

As it turns out, the strategy is about lowering cost, transferring technology, improving efficiency and hastening the day when the oil and gas industry regains favor in the public investment markets as a positive cash generator.

No one is speaking out of turn by noting the Rice brothers benefitted from oil and gas. The company was one of the great shale success stories during the last decade. Siblings parlayed a modest family investment into one of the more capital efficient and technically accomplished horizontal drilling Appalachian gas firms after 2007, culminating in a $1 billion IPO in 2013, followed by the $8.5 billion sale to EQT Corp., creating the largest natural gas producer in the free world.

According to Daniel Rice, former Rice Energy CEO and a board member for EQT, the merger was envisioned as a way to transfer best practices between two companies, implementing synergies that would make the surviving entity the lowest cost gas producer in the U.S. and a leader in further regional consolidation to create an even lower-cost structure to survive the brutal cyclicality in the natural gas space.

Maybe it should come as no surprise that the Rice brothers turned to private-equity investment as their follow-on act. RIG's $200-million investment fund focuses less on the time needed to turn an investment and more on whether a management team creates value and has the skillset to execute a longer duration investment plan. The latter is a necessity after the public capital markets dried up for energy and the old model of delineate, generate production volume growth and flip has turned into a model where management teams face fewer exit opportunities and must demonstrate the skills necessary to create value across the developmental arc and generate real dollar returns to investors over a longer time frame.

RIG is investing across the spectrum from E&Ps to oilfield services to alternatives. Investments include software data analytics for real-time hydraulic fracturing and methane production from landfills. Most investments fit within a $1- to $20 million range, though the fund will consider up to $40 million, according to its website. The fund is currently three quarters subscribed, split equally between oilfield services and E&Ps.

"The service side is an interesting way to play the industry going forward," Daniel Rice told attendees at Hart Energy's Energy Capital Conference in Dallas. "You know which plays work and which plays don't. As this industry evolves toward more pad drilling, longer laterals, more water, more sand, you can find companies that execute those plans or you can invest your capital into service companies that do those sorts of things."

Big data will also provide a way forward, Rice said. Analytics are now a commoditized feature, and what was once a competitive advantage for Rice has become commonplace in the industry.

"Everybody has the right information at their fingertips to make the right decisions," Rice said, "where you see the differentiation is less about the actual decision-making and more about the actual execution."

Additionally, the Rice brothers found that big data connects the entire work force within a common work environment, compressing the organizational structure so that everyone in the company knows what's going on across the company. That, in turn, offers a path toward further efficiency in oil and gas.

"The technology is there that allows us to have one or two companies operating all the assets in Appalachia," Rice said. "Certainly, the same goes for the Permian. You don't need 20 public and 50 private Permian companies. You need three or four who are doing things as efficiently as they possibly can. That's on the horizon for the industry and that gets us very comfortable with the industry being able to generate stable returns going forward."

The Rice brothers say their investment initiatives will provide practical operational solutions that lower cost and shorten the cycle to free-cash-flow generation.

The opportunity to regain investor confidence will turn out to be a good thing for energy.

EASTERN U.S.

1 IHS Markit reported that ***Landgas Exploration & Production*** has scheduled two Trenton oil exploratory wildcats in Sangamon County, Ill. The #1 Theilen will be in Section 27-15n-6w with a proposed depth of 1,999 ft. In the same section is the company's proposed #2 Theilen, which is permitted to 1,950 ft. There has been little wildcat drilling in the area in this part of Sangamon County. An earlier test, #1 Workman in Section 28 was abandoned in 1939 at 1,903 ft in Trenton. Another Trenton wildcat in the area, #1 Thorton Thomas in Section 23-15n-7w, was drilled to 1,811 ft. Nearby production is about 10 miles to the east of the proposed wildcats in Springfield East Field, which was opened in 1960 and produces crude from Silurian. Landgas is based in Edinburg, Ill.

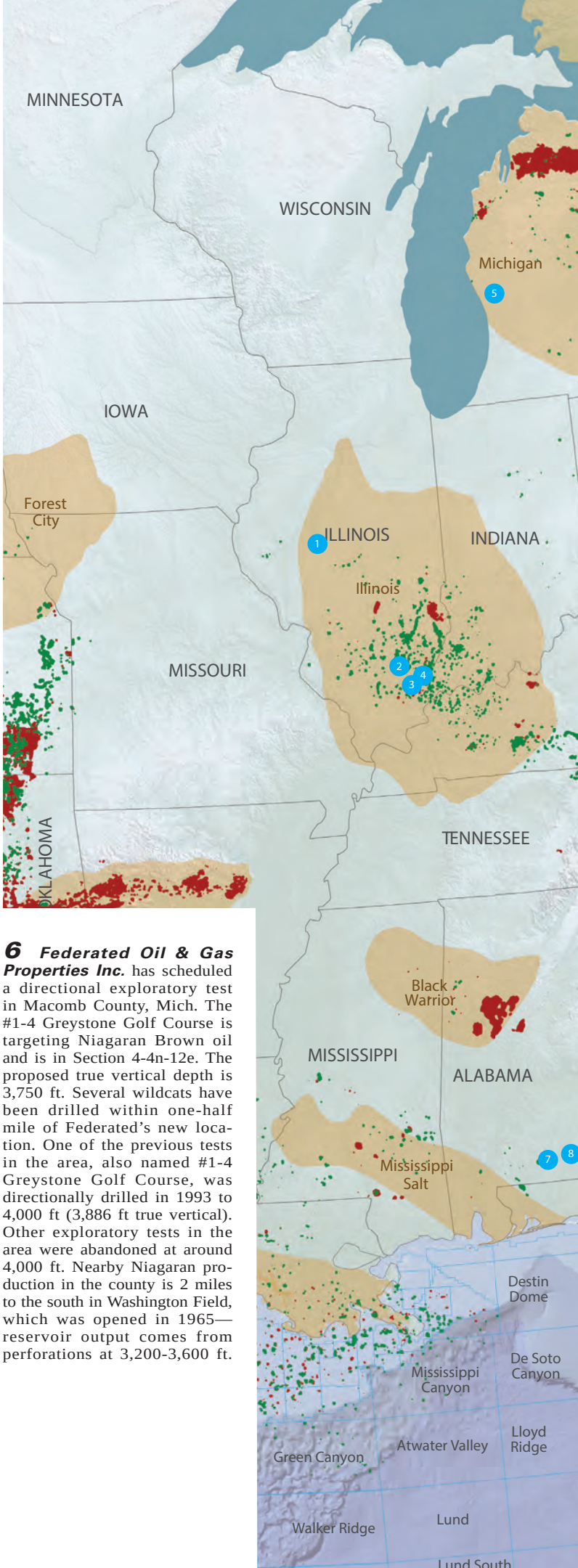
2 ***Palomino Petroleum Inc.*** has received a permit to drill a 5,700-ft wildcat in Wayne County, Ill., The #2 Dozier will test Dutch Creek in Section 26-2s-8e, and it will be in Barnhill Field. Nearby drilling in the field is at a ***Woolsey Operating Co.*** test at #1-110308-191 Simpson, which targeted Knox at 8,000 ft. Barnhill Field was opened in 1939. The Mississippian reservoir covers parts of Wayne and White counties. Wells drilled in the area reached total depths of 3,500-4,000 ft. Palomino is based in Newton, Kan.

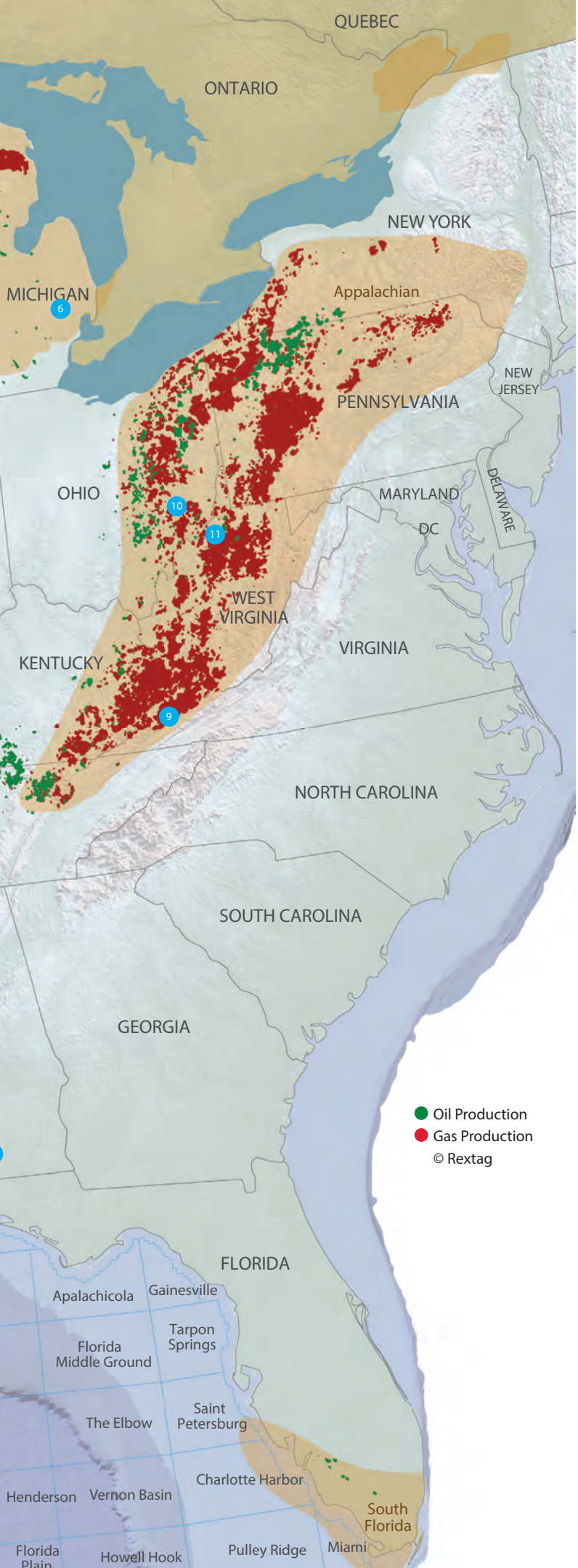
3 Carmi, Ill.-based ***Campbell Energy LLC*** has filed permits for three Fort Payne oil tests in White County, Ill. The program is designed to extend Fort Payne production into Maunie North Consolidated Field, where the operator began a drilling program in 2010. The deep-pool wildcats, #11, #12 and #13 Kempf will be in Section 19-5s-14w and all have planned depths of 4,400 ft. Most of the production in the field is from shallower pays in Pennsylvanian and several Mississippian zones. The deepest wells in the field produce oil from Ullin (Mississippian) at 3,950 ft. The field came online in 1941. The nearest Fort Payne oil producer is about 1 mile to the north-northeast in New Harmony Consolidated Field. In 2017, Campbell Energy received a permit for #5 Kempf in Section 18-5s-14w. Permitted to 4,200 ft and targeting Fort Payne, no activity has been reported at the site.

4 ***Citation Oil & Gas Corp.*** has received permits for two White County, Ill., oil ventures in New Harmony Consolidated Field. The #1 ES Greathouse will be in Section 04-5s-14w. It is a deep Warsaw test with a planned depth of 4,100 ft. About 1 mile to the southwest in Section 27-04s-14e will be #13C H C FORD. It has a planned depth of 4,100 ft and is also targeting Warsaw. Citation's headquarters are in Houston.

5 A Dundee Lime exploratory test is underway in Ottawa County, Mich. ***Trendwell Energy Corp.***'s #1-27 River Ridge Farms is in Section 27-8n-14w and the planned depth is 2,400 ft. According to IHS Markit, nearby Traverse Lime oil production is in Dennison Field about 1 mile to the northwest. The field was opened in 1963, with wells in the Ottawa County reservoir, producing crude from perforations at 1,800-1,900 ft. One of the deepest wells in the field, #1 Heckel-State in Section 21, was drilled to 3,202 ft. The nearest Dundee Lime oil producer is 6 miles west-southwest of Rockford, Mich.-based Trendwell's drillsite in Robinson Field where one well yielded crude from perforations at 2,096-2,102 ft.

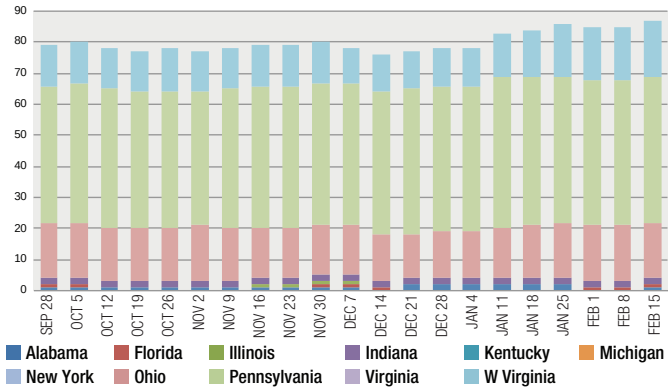
6 ***Federated Oil & Gas Properties Inc.*** has scheduled a directional exploratory test in Macomb County, Mich. The #1-4 Greystone Golf Course is targeting Niagaran Brown oil and is in Section 4-4n-12e. The proposed true vertical depth is 3,750 ft. Several wildcats have been drilled within one-half mile of Federated's new location. One of the previous tests in the area, also named #1-4 Greystone Golf Course, was directionally drilled in 1993 to 4,000 ft (3,886 ft true vertical). Other exploratory tests in the area were abandoned at around 4,000 ft. Nearby Niagaran production in the county is 2 miles to the south in Washington Field, which was opened in 1965—reservoir output comes from perforations at 3,200-3,600 ft.





Eastern U.S. Rig Count

Sept. 28, 2018-Feb. 15, 2019



Data compiled from Baker Hughes

7 In Conecuh County, Ala., ***Sklar Exploration Co. LLC*** has added a directional wildcat to the company's Smackover program. The #1 Cedar Creek Land & Timber 21-16 will be in Section 28-3n-11e and will bottom to the northwest in Section 21. There is no disclosed total depth. The wildcat replaces a test permitted by the company in 2018. Also named #1 Cedar Creek Land & Timber 21-16, the previously planned wildcat was permitted to 13,550 ft with a bottomhole location in Section 21. Nearby production is about 2.5 miles to the northeast at a directional Smackover discovery drilled by Sklar in 2014. The #1 Cedar Creek Land & Timber 14-9 in Section 14 was completed at 12,600-04 ft. The well produced sporadically for less than one year and well recovery totaled 372 bbl of crude and 1.056 Mbbl of water. Sklar's headquarters are in Shreveport, La.

8 ***Ventex Operating Corp.*** is drilling the southeastern-most test in Alabama's Brooklyn Field. According to IHS Markit, the Conecuh County-Smackover venture, #1 Cedar Creek Land & Timber 13-5, is in Section 13-3n-13e and will bottom to the southwest. Proposed total depth is 12,100 ft. The Dallas-based company's venture is the first horizontal activity in the southern Alabama field. Numerous directional wells have been completed in Brooklyn Field, including ***Fletcher Petroleum***'s #1 Anderson Johnson 11-9 in Section 11. The 11,988-ft well flowed 393 bbl of crude and 143 Mcf of gas per day from Smackover at 11,797-11,808 ft.

9 ***Dominiq Operating Inc.***, based in Plano, Texas, is underway at a vertical Knox venture in Cumberland County, Ky. The #11-AC Charles Garmon has a projected depth of 2,000 ft and is in the Cincinnati Arch Basin. Additional information is not currently available.

10 ***Ascent Resources LLC***, based in Oklahoma City, has received permits for three Guernsey County, Ohio, Utica Shale wells. The wells will be drilled from a drillpad on an 816.62 acre lease in Section 22-2n-1w in Barnesville Consolidated Field. The #7H Watson E MLW GR has a projected depth of 20,050 ft and will be drilled to the northwest. The #11H Watson E MLW GR has a projected depth of 23,300 ft and will be drilled to the northeast. The #9H Watson E MLW GR has a projected depth of 22,000 ft and will be drilled to the southeast.

11 Drilling permits have been granted to ***Antero Resources Corp.*** to drill three Marcellus Shale tests in West Virginia's Ritchie County. The Beason Run Field wells will be drilled from a drillpad on a 60-acre lease in Clay District, Pullman 7.5 Quad. The #1H Buzzard Run Unit has a projected depth of 10,000 ft and a projected true vertical depth of 6,800 ft. The #2H Buzzard Run has a projected depth of 20,200 ft and a projected true vertical depth of 6,800 ft. The #3H Buzzard Run has a projected depth of 20,900 ft and a projected true vertical depth of 6,800 ft. Antero's headquarters are in Denver.

GULF COAST

1 IHS Markit announced that ***Vitruvian Exploration LLC*** completed two horizontal Eagle Ford Shale wells in the La Salle County (RRC Dist. 1), Texas, portion of Hawkville Field. The wells were drilled from offsetting surface locations on a 5,423-acre Southwest Texas lease in Section 1, Refugio Charo Survey, A-914. The #1H Crescent C Ranch A flowed 6.041 MMcf of gas and 1.504 Mbbl of water per day from commingled, fracture-treated perforations in Eagle Ford Shale at 13,860 ft to Austin Chalk at 21,145 ft. Gauged on a 24/64-in. choke, the flowing casing pressure was 3,847 psi and the shut-in casing pressure was 5,728 psi. It was drilled to 21,327 ft, 12,881 ft true vertical, and bottomed about 1.5 miles to the northwest in Section 913, HE&WT RR Co Survey, A-890. The #2H Crescent C Ranch A was completed in a sidetracked, fracture-treated Eagle Ford Shale zone at 13,656-18,955 ft, flowing 8.014 MMcf of gas and 761 bbl of water per day. It was drilled to 21,195 ft (13,546 ft true vertical) and bottomed 1.5 miles to the southeast in Section 1, I&GN RR Co Survey, A-474. Vitruvian's headquarters are in The Woodlands, Texas.

2 According to IHS Markit, ***Shell Oil Co.*** has scheduled the first exploratory test on the company's Blacktip prospect in Alaminos Canyon Block 380. The #1 OCS G32954 will be drilled from drillship in the southern portion of the block and area water depth is 6,500 ft. The drilling plan for this block and Alaminos Canyon Block 424 (OCS G32964) to the south was originally filed in 2012 by Statoil (now ***Equinor***). Shell took over the lease and filed an amended drilling plan last year for the prospect. According to Shell's plan, as many as 17 tests could be drilled on the two tracts. Shell is based in Houston.

3 ***Chesapeake Operating Inc.***, based in Oklahoma City, has completed two high-volume Caddo Parish-Haynesville Shale wells in Louisiana's Bethany Longstreet Field. The discoveries were drilled from offsetting surface locations in Section 29-15n-15w and both bottomed about 2 miles to the north in Section 17. According to IHS Markit, #1-Alt Feist 20&17-15-15HC flowed 38.808 MMcf of gas and 774 bbl of water per day from acid- and fracture-treated perforations at 11,965-21,850 ft. Gauged on a 34/64-in. choke, the flowing casing pressure was 7,289 psi. It was drilled to 21,875 ft, 11,481 ft true vertical. The parallel #2-Alt Feist 20&17-15-15HC produced 38.232 MMcf of gas and 648 bbl of water per day. Production is from an acid- and fracture-treated zone at 11,852-21,759 ft. It was tested on a 33/64-in. choke with a flowing casing pressure of 7,564 psi. The well was drilled to 21,789 ft, 11,426 ft true vertical.

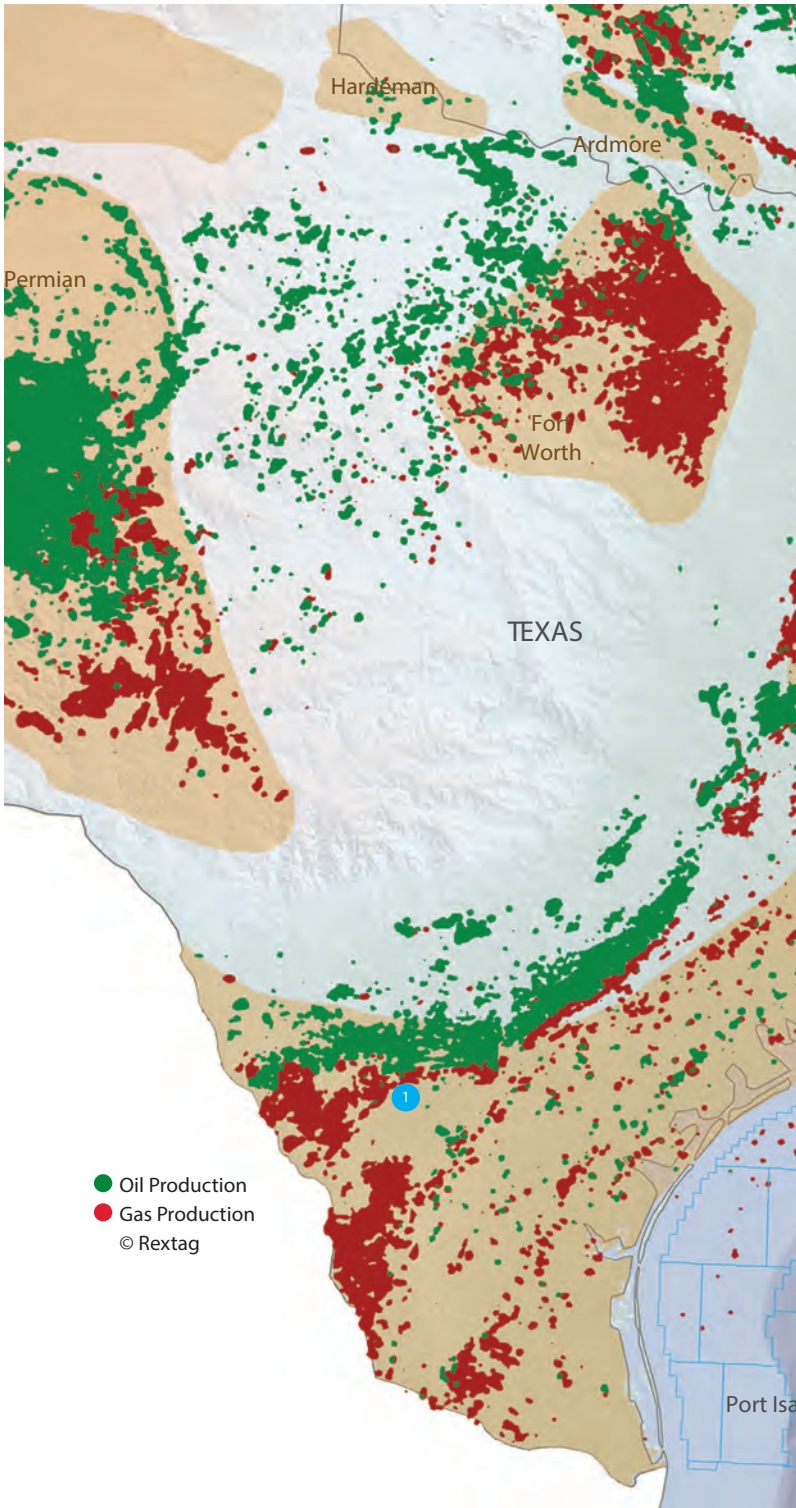
4 In Sabine Parish, La., Dallas-based ***Vine Oil & Gas LP*** has completed an extended-lateral Haynesville Shale discovery. The #1 Martin Timber 36-25H was tested flowing 25 MMcf of gas per day. Located in Bayou San Miguel Field, it was drilled to 22,420 ft, 12,186 ft true vertical, and is in Section 1-8n-13w. The venture bottomed about 2 miles to the north in Section 25-9n-13w. Production is from perforations at 12,667-20,470 ft and it was tested on a 16/64-in. choke with a flowing casing pressure of 8,755 psi.

5 San Antonio-based ***Zachry Exploration*** has completed a Hackberry gas well that extends southern Jefferson Davis Parish's Lake Arthur Field about 2 miles to the northwest. The #1 Adonis Martin Jr. flowed 2.194 MMcf of gas, 432 bbl of condensate and 5.079 Mbbl of water per day through perforations at 12,794-12,810 ft. The 13,360-ft well is in Section 17-10s-4w. Gauged on an 8/64-in. choke, the flowing tubing pressure was 8,784 psi and the shut-in tubing pressure was 8,896 psi. The nearest wells in Lake Arthur Field are 2 miles southeast of Zachry Exploration's completion.

6 An Acadia Parish, La., gas discovery in Richie Field was reported by ***Zachry Exploration LLC***. The #1 Indigo Minerals LLC was tested flowing 1.535 MMcf of gas, 173 bbl of 44.5-degree-gravity crude and 2 bbl of water per day from Tweedel at 9,759-85 ft. The completion was directionally drilled to 10,517 ft and is in Section 29-7s-1w. It was tested on a 16/64-in. choke with a flowing tubing pressure of 6,325 psi.

7 Covington, La.-based ***LLOG Exploration*** plans to drill up to five new exploratory tests near the company's Khaleesi and Mormont discoveries in the Green Canyon area. According to the plan, two tests are planned for offsetting surface locations on Green Canyon Block 478 (OCS G35662), bottoming to the north in Green Canyon Block 434 (OCS G 35868). Two more tests are planned in the southeastern portion of Green Canyon Block 389 (OCS G35864). A fifth exploratory test is planned for Block 389, bottoming beneath Block 434. Water depth in the area is 3,800 ft.

8 ***EnVen Energy Corp.*** has filed a drilling plan for a two-block prospect in Green Canyon Block 723 (OCS G35003) and Green Canyon Block 767 (OCS G35409). The plan indicates that EnVen could drill four exploratory tests from various surface locations on Green Canyon



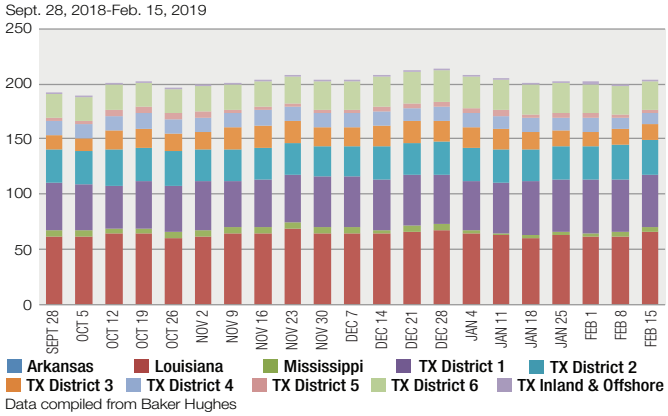
Block 723. Water depth in the area is 5,050 ft. Several tests have been drilled on blocks 723 and 767 under previous leases, including a 32,685-ft exploratory test drilled by ***Noble Energy Inc.*** in 2009. EnVen is based in Houston.

9 A Jones County, Miss., Cotton Valley completion produced 520 bbl of 48-degree-gravity crude, 1.029 MMcf of gas and 40 bbl of water per day. The ***Venture Oil & Gas Inc.*** discovery is in Section 22-8n-11w in Glade Crossing Field. The #2 Holifield 22-11 is flowing from acid- and fracture-treated perforations at 16,937-52 ft. It was directionally drilled to 17,600 ft, 17,568 ft true vertical, and was tested on an unreported choke size with a flowing tubing pressure of 1,790 psi. It is one of the strongest Cotton Valley producers in the county to date. Venture Oil & Gas is based in Laurel, Miss.

10 ***BP Plc*** has added another development test to the company's drilling program in Herschel Field at #5 OCS G09821. The venture is in the northeastern portion of Mississippi Canyon Block 520 and area water depth is 7,000 ft. First production from BP's Herschel project was reported in 2004 where two Middle Miocene wells produced from perforations at 16,413-16,567 ft and 17,136-17,248 ft. Approximately 25 MMbbl of crude and 30 Bcf of gas have been produced through late 2018. BP is based in London.

Gulf Coast Rig Count

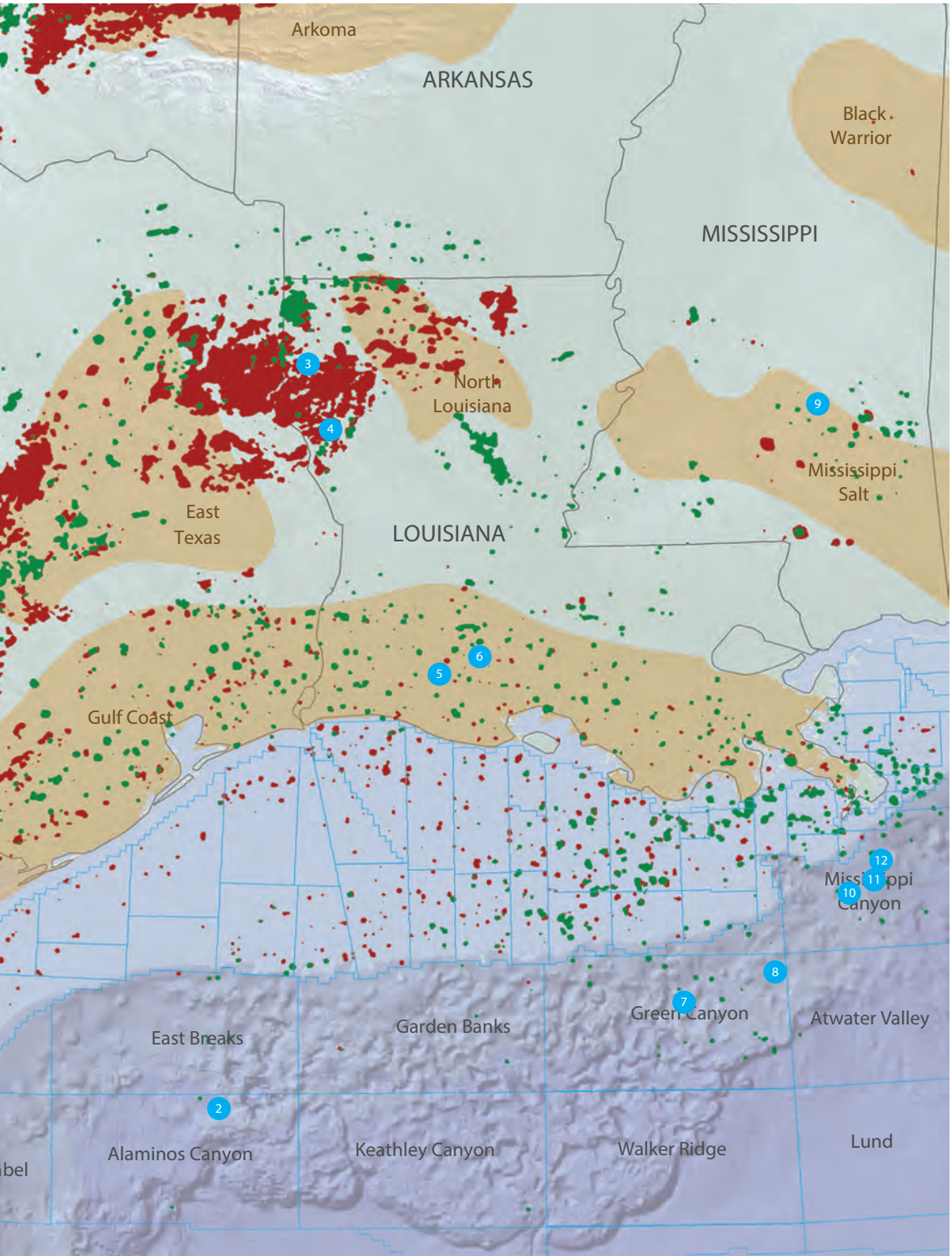
Sept. 28, 2018-Feb. 15, 2019



Data compiled from Baker Hughes

11 ***Chevron Corp.*** is underway at a second test on the company's Yarrow prospect. The #2 OCS G35971 is an exploratory Norphlet test and is in Mississippi Canyon Block 434. Water depth in the area is 6,900 ft. The venture is an offset to #1 OCS G35971, the first test on the prospect, which was plugged and abandoned. According to Houston-based Chevron's exploration plan, as many as nine tests could be drilled from various surface locations on Block 434.

12 ***Anadarko Petroleum Corp.*** is underway at a development test on the company's Horn Mountain Field expansion. The #8 OCS G18194 is in the southwestern portion of Mississippi Canyon Block 82 (OCS G35313) and will bottom to the south in Block 126. Area water depth is 4,300 ft. In 2018, the company won exploration plan approval to drill as many as 16 tests from various surface locations on Block 81 (OCS G35312), Block 82 and Block 126. There has been no production to date from blocks 81 and 82. Anadarko's headquarters are in The Woodlands, Texas.



MIDCONTINENT & PERMIAN BASIN

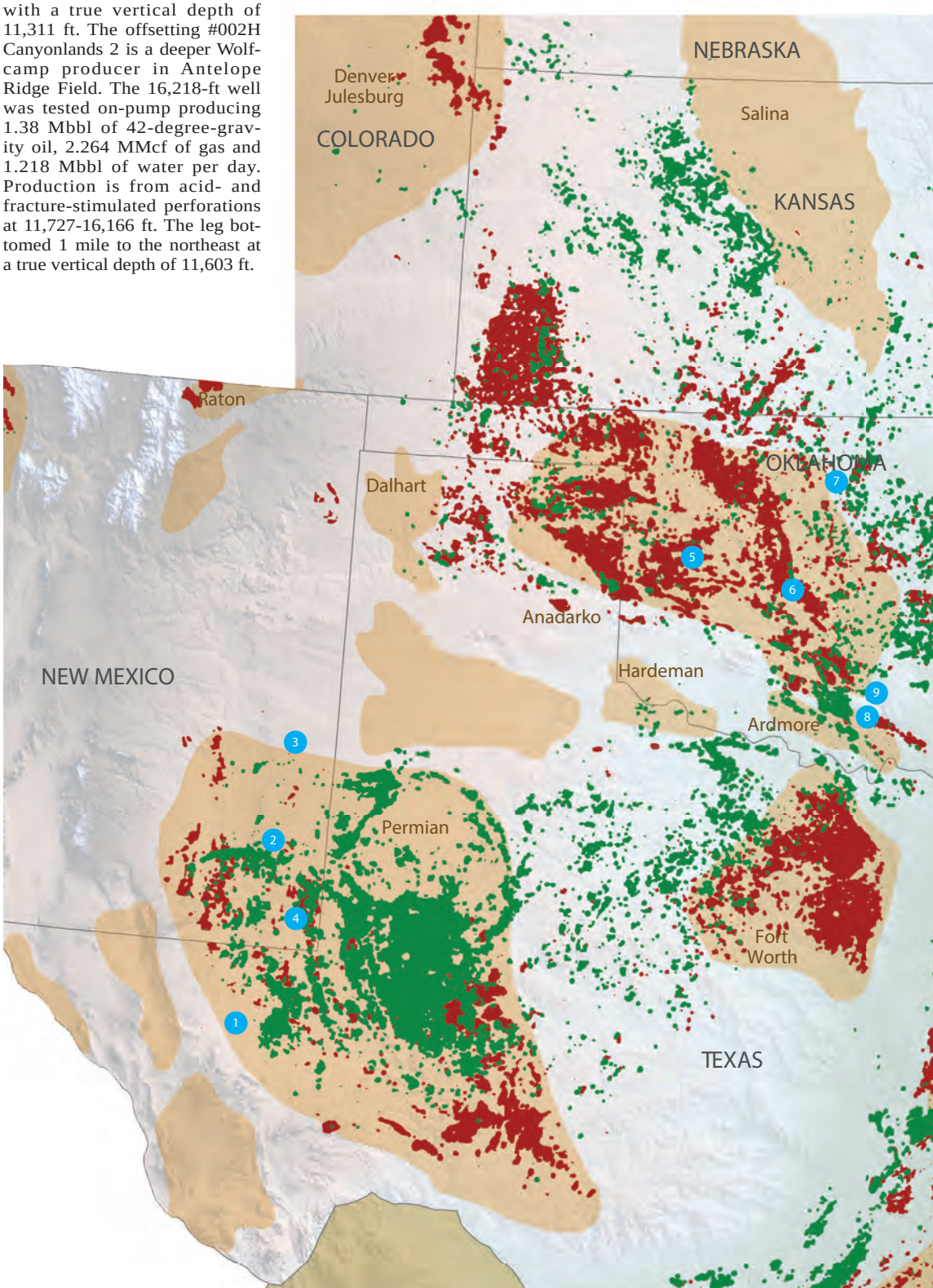
1 An ***Apache Corp.*** discovery in Alpine High Field was tested flowing 25 MMcf per day in Reeves County (RRC Dist. 8), Texas. The #104AH Mont Blanc was also reported producing 1.769 Mbbl of water per day. Production is from fracture-stimulated perforations at 12,093-16,950 ft in Devonian. The well is in Section 24, Block 57 T7S, T&P RR Co Survey, A-5615, and was drilled to 17,080 ft with a true vertical depth of 12,218 ft. It bottomed about 1 mile to the south. Gauged on a 28/64-in. choke, the flowing tubing pressure was 600 psi and the shut-in tubing pressure was 1,100 psi. Apache is based in Houston.

2 The first horizontal well in New Mexico's Kemnitz South Field has been completed by Denver-based ***Cimarex Energy Co***. According to IHS Markit, the Tatum Basin discovery is in Section 25-16s-33e of Lea County. The #001Y State 25 flowed 77 bbl of 39.6-degree-gravity crude, 83 Mcf of gas and 429 bbl of water per day from Cisco. The horizontal well was drilled out of a vertical pilot hole to 14,106 ft, 11,458 ft true vertical, and the lateral bottomed about 1 mile to the west. It was acidized and fractured then tested on a 2-in. choke with a casing pressure of 71 psi.

3 Roswell, N.M.-based ***Manzano LLC*** completed a Van Morrison-themed well in Roosevelt County, N.M. The #005H Domino 21-16 State Com was tested on-pump for 122 bbl of oil, 33 Mcf of gas and 1.638 Mbbl of water daily from San Andres perforations at 4,600-11,299 ft. It was drilled to 11,332 ft, 4,040 ft true vertical, in Section 21-6s-34e in Chaveroo Northeast Field. About 1 mile to the northwest, the company has permitted #942H Morrison San Andres. It has a planned depth of 11,350 ft and will be in Section 16-6s-34e.

4 Two horizontal oil wells have been completed by Denver-based ***Cimarex Energy Co.*** from a pad in Lea County, N.M. The #001H Canyonlands 2 State Com was tested flowing 1.063 Mbbl of 42-degree-gravity crude, 1.739 MMcf of gas and 1.388 Mbbl of water per day from fracture-treated perforations at 11,443-15,880 ft in Third Bone Spring. The 15,979-ft Red Hills North Field well is in Section 2-24s-34e, and the lateral bottomed about 1 mile to the north with a true vertical depth of 11,311 ft. The offsetting #002H Canyonlands 2 is a deeper Wolfcamp producer in Antelope Ridge Field. The 16,218-ft well was tested on-pump producing 1.38 Mbbl of 42-degree-gravity oil, 2.264 MMcf of gas and 1.218 Mbbl of water per day. Production is from acid- and fracture-stimulated perforations at 11,727-16,166 ft. The leg bottomed 1 mile to the northeast at a true vertical depth of 11,603 ft.

5 Preliminary information was released by ***FourPoint Energy LLC*** for two extended-reach horizontal wells completed at an Anadarko Basin pad in Section 24-10n-19w of Washita County, Okla. The #2HA Florence 25X36-10-19 flowed 9.81 MMcf of gas, 180 bbl of 47-degree-gravity condensate and 1.848 Mbbl of water per day from a treated Des Moines Granite Wash interval at 13,395-23,234 ft. Gauged on a 32/64-in. choke, the flowing tubing pressure was 2,000 psi. It was drilled to the south to 23,393 ft, 12,917 ft true vertical, and bottomed in Section 36-10n-19w. The #3HB Florence 25X36-10-19 was drilled about 20 ft to the east. It initially flowed 8.23 MMcf of gas with 102 bbl of 48-degree-gravity condensate and 1.182 Mbbl of water per day. The completion is producing from perforations between 13,220 and 22,974 ft in Granite Wash. It was tested on a 39/64-in. choke and the flowing tubing pressure was 1.400 psi. It was drilled to 23,171 ft, 12,890 ft true vertical, and bottomed in Section 36-10n-19w. The Burns Flat Field wells have parallel wellbores extending southward 2 miles across Section 25. FourPoint's headquarters are in Denver.



6 A Grady County, Okla., horizontal well completed by Austin-based ***Travis Peak Resources LLC*** flowed 1.128 Mbbl of oil, 1.54 MMcf of gas and 408 bbl of water per day. The #05-W1H Roberts is in Section 5-7n-5w and is producing from a treated Woodford interval at 11,907-16,310 ft. The Anadarko Basin prospect was drilled to the north to 16,467 ft. No additional information has been released.

7 IHS Markit announced that ***Lance Ruffel Oil & Gas Corp.*** reported preliminary test results from a new pool discovery along the western edge of Cherokee Basin in Oklahoma. The #1-33 Frailey is in Section 33-23n-1w of Noble County. It flowed 78 bbl of 42-degree-gravity oil with 400 Mcf of gas and 73 bbl of water per day during testing on an 18/64-in. choke. Production is from a fractured 1-ft interval of Red Fork Sand. Little additional information is available on the proposed 4,800-ft prospect. The Oklahoma City-based company's new well is in a section in the abandoned Fourdee Northeast Field that contains five inactive wells.

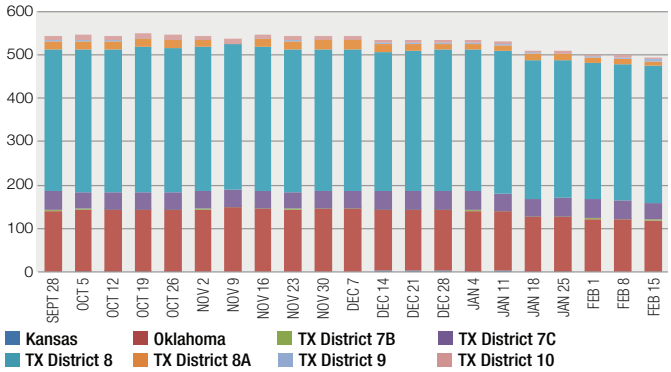
8 Two Arkoma Basin-Woodford producers were reported at a drillpad by ***Canyon Creek Energy Operating LLC*** in Section 7-2S-10E of Atoka County, Okla. The #1-8/17H Nacho was tested on a 128/64-in. choke, flowing 3.5 MMcf of gas, 9 bbl of 42-degree-gravity oil and 1.3 Mbbl of water per day. Production is from a fracture-stimulated zone at 6,354-14,072 ft. The 14,225-ft well was drilled to the northeast into Section 8, then south about 1.5 miles. It bottomed in Section 15-2s-10e and the true vertical depth is 5,572 ft. The respective shut-in and flowing tubing pressures were 610 psi and 300 psi. About 15 ft west on the pad, #1-7/18H Nacho was tested in a fractured lateral at 6,271-13,830 ft, flowing 3.04 MMcf of gas, 9 bbl of 42-degree-gravity oil and 2.5 Mbbl of water per day. This well has a parallel lateral extending to 13,920 ft (5,540 ft true vertical) and bottomed in Section 18-2s-10e. Tested on a 128/64-in. choke, the shut-in tubing pressure was 340 psi and the flowing tubing pressure was 235 psi. Canyon Creek's headquarters are in Tulsa.

9 An extended-reach horizontal well completed by ***Bravo Arkoma LLC*** initially flowed 2.35 MMcf of gas with 732 bbl of water per day. The #2-34/3/10H McGraw is in Section 27-2n-10e in Coal County, Okla., and is producing from a fracture-stimulated and acidized Woodford interval at 9,102-19,639 ft. The 22,040-ft Centrahoma Field well was drilled almost 3 miles south across sections 34-2n-10e and 3-1n-10e to a true vertical depth of 8,267 ft. It bottomed in Section 10-1n-10e and was tested on a 108/64-in. choke with 144-psi flowing tubing pressure. Bravo Arkoma's headquarters are in Tulsa, Okla.

10 Two horizontal Woodford producers were completed from a drillpad in the Arkoma Basin by Houston-based ***Trinity Operating LLC***. The pad is in Section 18-7n-18e, in Pittsburg County, Okla. The #2-7/6H Bernice flowed 13.9 MMcf of gas and 1.78 Mbbl of water per day. It was drilled to the north to 18,477 ft, 7,773 ft true vertical, and bottomed in Section 6-7n-18e. Production is from an acidized and fractured zone at 8,017-18,306 ft. About 15 ft north on the pad, #1-7/6H Bernice flowed 8.33 MMcf of gas and 1.318 Mbbl of water per day. It was drilled parallel to #2-7/6H Bernice to 18,555 ft, 7,698 ft true vertical, and also bottomed in Section 6-7n-18e. Production is from an acidized and fractured zone between 8,143 and 13,669 ft.

Midcontinent & Permian Basin Rig Count

Sept. 28, 2018-Feb. 15, 2019



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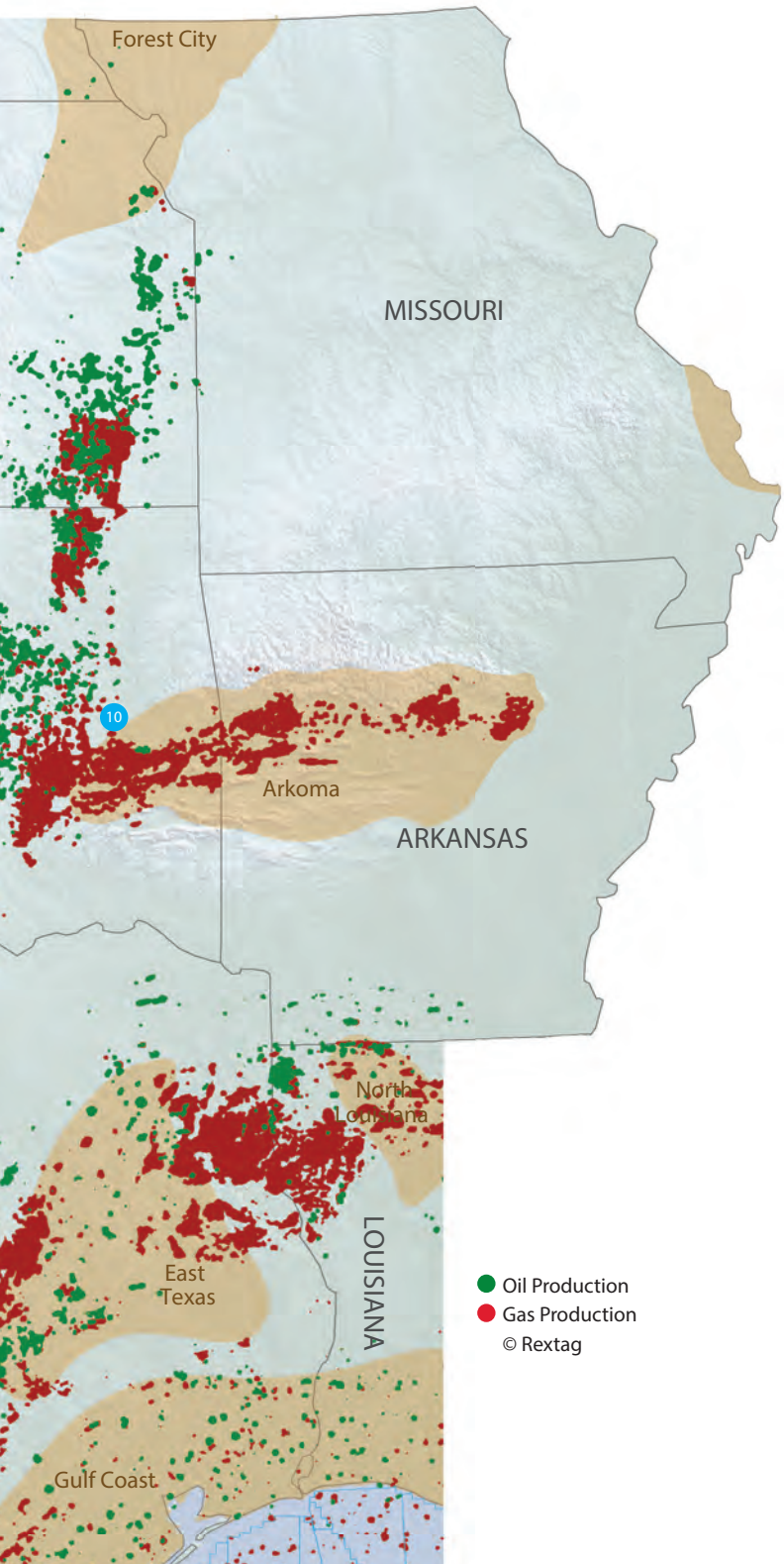


WESTERN U.S.

1 London-based ***Reabold Resources Plc*** announced testing results from the completion #4-Venturini Ginnochio-4 in California's West Brentwood Field. The Contra Costa County well, in Section 17-1n-2e, was drilled to 4,570 ft and the projected formation was Massive. It flowed at a choked-back, 24-hour rate of 480 bbl, and the oil cut averaged in excess of 99.5%. In addition, the well averaged 742 Mcf of gas per day. It is now being prepared for production.

2 A Turner Sand completion by ***EOG Resources Inc***. initially flowed 1.296 Mbbl of oil, 3.724 MMcf of gas and 789 bbl of water per day. The #297-2436H Tiburon was drilled in Section 24-42n-74w in Campbell County, Wyo. Production is from a horizontal lateral in Turner extending from 9,787 ft southwestward to 21,363 ft at a bottomhole location in Section 36-42n-74w. The true vertical depth is 11,268 ft, and it was tested on a 22/64-in. choke following 32-stage fracturing between 11,678 and 21,243 ft. EOG is based in Houston.

3 Two high-volume Parkman producers were announced by ***EOG Resources Inc.*** in Section 9-42n-72w in Converse County, Wyo. The #407-0904H Bolt initially produced 2.208 Mbbl of oil, 1.904 MMcf of gas and 647 bbl of water per day when tested on gas lift. According to IHS Markit, it is the highest initial producing rate for a Parkman well in the Powder River Basin. It was drilled northward to 17,524 ft (7,361 ft true vertical) and bottomed in Section 4-42n-72w. It was tested following 35-stage fracturing between 7,981 and 17,378 ft. The #406-0904H Bolt produced 1.363 Mbbl of oil, 1.624 MMcf of gas and 607 bbl of water per day. It was tested following 35-stage fracturing between 7,746 and 17,066 ft. The lateral in Parkman extends from 7,785 ft northward to 17,167 ft (7,347 ft true vertical) and bottomed in Section 4-42n-72w.

4 A Niobrara completion in the Powder River Basin was announced by Oklahoma City-based ***Devon Energy Corp***. Located in Section 16-38n-70w in Converse County, Wyo., #09-043870-1XNH Conley Draw produced 1.506 Mbbl of oil, with 1.113 MMcf of gas and 1.223 Mbbl of water per day. Production is from a horizontal lateral in Niobrara that was drilled to the north to 20,492 ft, 9,893 ft true vertical, with a bottomhole location in Section 4-38n-70w. It was tested on a 38/64-in. choke after 41-stage fracturing between 10,360 and 20,367 ft.

5 ***Balidor Oil & Gas LLC*** has completed the first two Niobrara producers in a southern Powder River Basin township in Converse County, Wyo. Located in Section 8-35n-67w, #3567-8-20-2 NXH Lost Springs initially flowed 970 bbl of oil, with 767 Mcf of gas and 1.517 Mbbl of water per day. It was horizontally drilled in southward to 19,800 ft with a bottomhole location in Section 20-35n-67w and a true vertical depth of 9,075 ft. It was tested on a 42/64-in. choke following 51-stage fracturing between 9,432 and 19,715 ft, and the flowing tubing pressure was 495 psi. About 2 miles to the south in Section 29-35n-67w, #3567-29-32-1-NXH flowed 1.065 Mbbl of oil, 1.07 MMcf of gas and 1.609 Mbbl of water per day. Production is from a Niobrara lateral drilled to the south to 19,130 ft. 8,935 ft true vertical, and bottomed in Section 32-35n-67w. It was tested on a 42/64-in. choke after 49-stage fracturing between 9,476 and 19,039 ft. Balidor's headquarters are in Houston.

6 In Section 22-151n-94w of McKenzie County, N.D., ***Marathon Oil Corp.*** announced results from a Middle Three Forks producer. IHS Markit reported that #11-23TFH-2B Clara-USA was tested flowing 6.425 Mbbl of oil, with 7.271 MMcf of gas and 5.494 Mbbl of water per day. The West Myrmidon prospect was drilled to 23,871 ft, 10,926 ft true vertical, and bottomed in Section 19-151n-93w—it was drilled under the Missouri River. Production is from a lateral in Middle Three Forks (Three Forks B2 zone) extending from 11,238 ft eastward to 23,871 ft and tested on a 58/64-in. choke after 56-stage fracturing between 15,755 and 23,697 ft. Marathon's headquarters are in Houston.

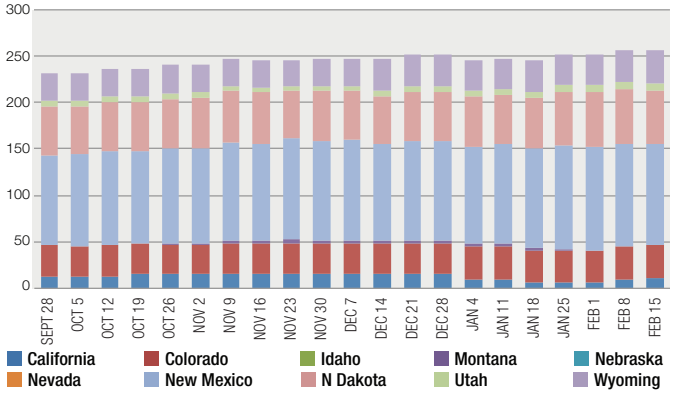
7 ***Marathon Oil Corp.*** announced results from two high-volume Three Forks completions and a high-rate Middle Bakken well at a six-well pad (Tat 13) at its West Myrmidon prospect. The Reunion Bay Field wells are in Section 22-151n-94w in Mountrail County, N.D. The #12-23TFH Jerome-USA was completed flowing 9.166 Mbbl of oil, 9.018 MMcf of gas and 7.107 Mbbl of water per day. Production is from a lateral in Upper Three Forks (Three Forks B1 zone). It was drilled to the northeast to 23,722 ft, 10,864 ft true vertical, and bottomed in Section 19-151n-93w. It was tested on a 60/64-in. choke after 56-stage fracturing between 11,214 and 23,588 ft. It was drilled under the Missouri River. The #13-23H Lamar-USA was tested flowing 8.887 Mbbl of oil, 10.628 MMcf of gas and 5.541 Mbbl of water per day from Three Forks. It was drilled to the northeast to 23,740 ft, 10,777 ft true vertical. Production is from an acidized and fractured zone at 11,266-23,603 ft. The #14-23H Whitebody-USA was tested flowing 8.702 Mbbl of oil, with 10.023 MMcf of gas and 5.818 Mbbl of water per day. Production is from a horizontal lateral in Middle Bakken extending from

11,017 ft eastward to 23,630 ft. It bottomed in Section 19-151n-93w and the true vertical depth is 10,706 ft. It was tested on a 64/64-in. choke following 57-stage fracturing between 11,114 and 23,499 ft with a flowing casing pressure of 2,150 psi. The discovery is on the Fort Berthold Indian Reservation and, like #12-23TFH Jerome-USA, its lateral extends under the Missouri River.

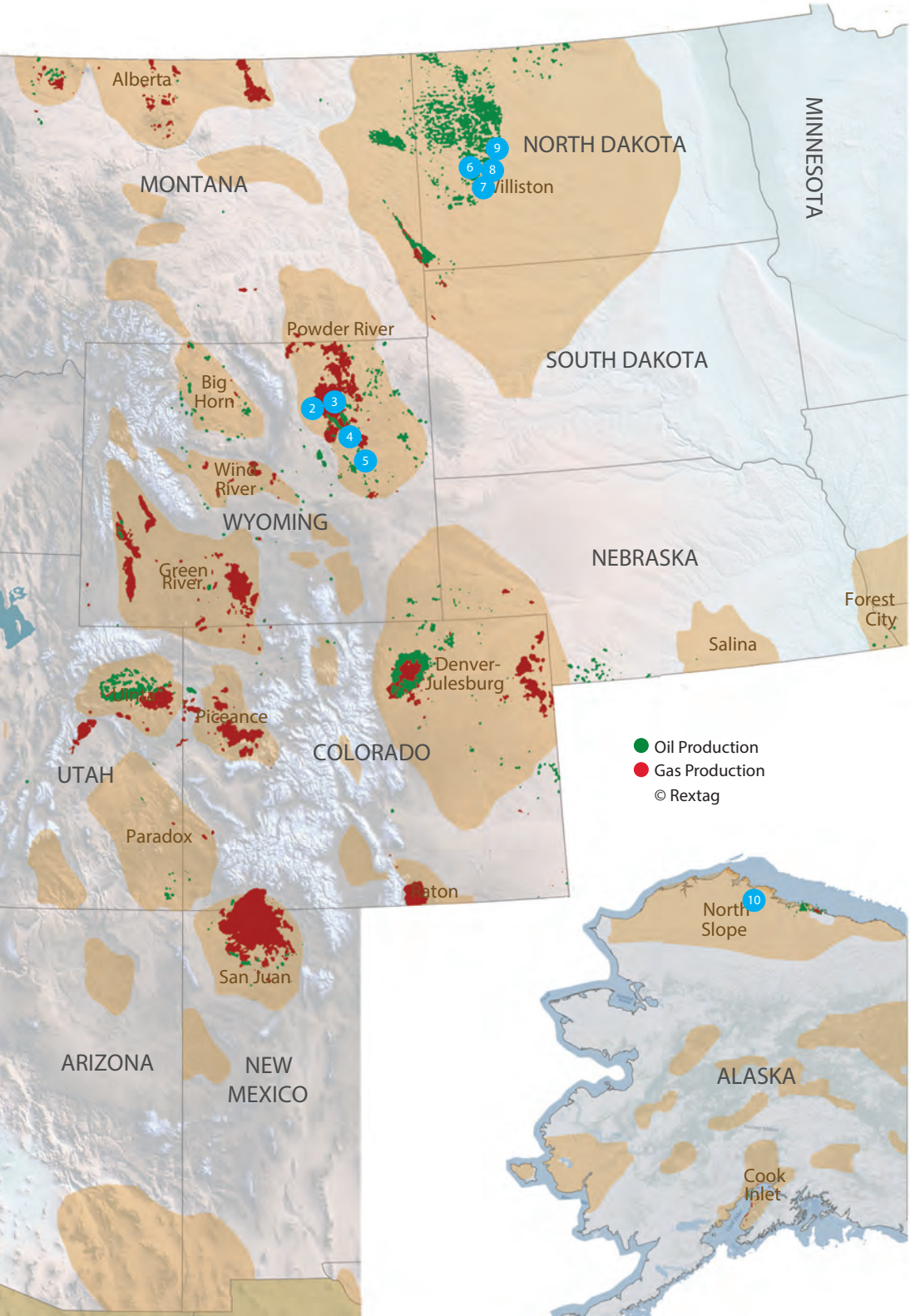
8 Two horizontal Upper Three Forks producers were reported by ***Marathon Oil Corp.*** from a drillpad in Section 30-151n-93w of Mountrail County, N.D. The #44-19TFH Sibyl-USA initially flowed 6.396 Mbbl of oil, 6.795 MMcf of gas and 4.694 Mbbl of water per day from 11,610-21,373 ft. It was tested on a 54/64-in. choke after 45-stage fracturing. The horizontal lateral extends from 11,505 ft northward to 21,558 ft and it bottomed in Section 18-151n-93w. The #44-19TFH Rue-USA produced 6.943 Mbbl of oil, 7.578 MMcf of gas and 4.293 Mbbl of water per day. Production is from a horizontal lateral extending from 11,408 ft northward to 21,441 ft, 10,833 ft true vertical, with a bottomhole location in Section 18-151n-93w. It was tested on a 1-in. choke after 45-stage fracturing between 11,507 and 21,308 ft.

Western U.S. Rig Count

Sept. 28, 2018-Feb. 15, 2019



Data compiled from Baker Hughes



9 ***Marathon Oil Corp.*** has completed a high-volume Bakken Shale producer in Mountrail County, N.D. south of Four Bears Village. According to IHS Markit, #31-17H Ness-USA flowed 7.956 Mbbl of oil, 7.897 MMcf of gas and 4.059 Mbbl of water per day. It is in Section 8-151n-93w and production is from a horizontal lateral in Middle Bakken extending from 10,979 ft southwestward to 21,121 ft, 10,592 ft true vertical, and it bottomed in Section 20-151n-93w. It was tested on a 1-in. choke following 45-stage fracturing between 11,074 and 20,983 ft.

10 Houston-based ***ConocoPhillips Co.*** has received drilling permits for five more delineation tests associated in its Willow development project in the National Petroleum Reserve-Alaska. The permits are for Nanushuk oil zone evaluation, and the wells are #10 Tinmiaq in Section 9-10n-1w with a bottomhole location in Section 15-10n-1w; #11 Tinmiaq in Section 32-9n-1w with a bottomhole location in Section 30-9n-1w; #12 Tinmiaq in Section 15-8n-1w; #13 Tinmiaq in Section 35-12n-2w and #14 Tinmiaq in Section 22-9n-1w. Earlier, the company received permits for two Willow area-Nanushuk delineation tests, #16 Tinmiaq in Section 8-9n-1w and #15 Tinmiaq in Section 9-10n-2w. ConocoPhillips in early 2017 opened Willow Field with the completion of #2 Tinmiaq in Section 34-10n-1w, and it had a sustained 24-hour test rate of 6.4 Mbbl of 44-degree-gravity from Nanushuk.

INTERNATIONAL HIGHLIGHTS

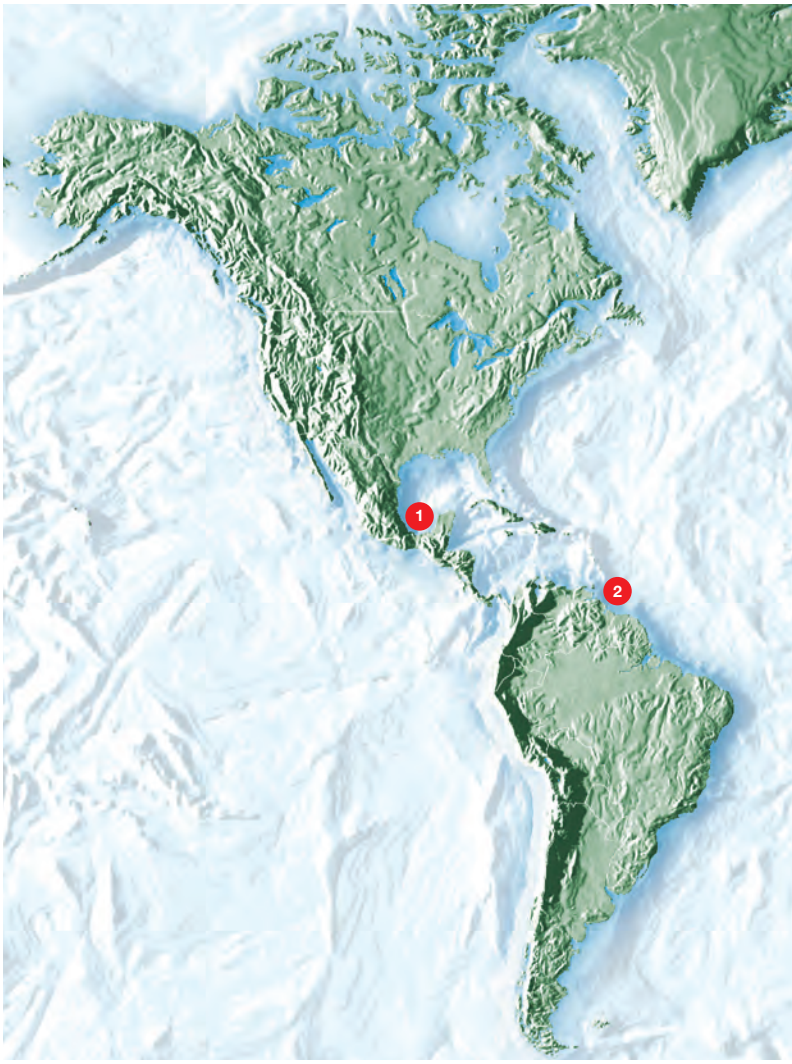
Control of Venezuela's oil industry is at stake in the face-off between the head of the Venezuelan National Assembly, Juan Guaido, backed by western interests, and Nicolas Maduro, supported most notably by Russia and Cuba.

While the current outcome is uncertain, a long struggle will likely accelerate the already steep decline in Venezuela's crude oil production of 1.1 million barrels per day (bbl/d). U.S. sanctions will reduce U.S. imports of Venezuelan crude oil to zero from recent levels of about 500,000 to 600,000 bbl/d. Also, the sanctions will cut off diluent supply from the U.S., which is blended with a portion of extra-heavy crude oil and made into Venezuela's diluted crude oil grade.

According to IHS Markit, a reversal of Venezuela's declining output will require money, equipment, experienced industry professionals, security and time. The global oil market is currently well-supplied with Organization for Economic Co-operation and Development crude oil stocks near the five-year average. There is currently no shock to the global supply, although there is a sharper impact on the heavy crude oil market.

A determining factor will be Venezuela's military and whether it sticks with Maduro, whose previous presidential term expired in January 2019, or whether it determines that a deal with the opposition holds better prospects than collapse under Maduro.

—Larry Prado



1 Mexico

Results from the first of three appraisal wells have been announced by ***Talos Energy*** on the Zama appraisal in Block 7 offshore Mexico. The #2-Zama was drilled in a downdip location to the north of discovery well #1-Zama to confirm the geological model and define the oil-water contact. According to the company, the well hit the top of the Zama reservoir at approximately 10,759 ft. A contiguous Zama sandstone interval of 1,676 ft was found and is thicker than at #1-Zama. The well also encountered several other thick, wet sands of similar age directly beneath the main Zama horizon for an aggregate total of approximately 2,350 ft of high-quality, Upper Miocene sands. The pressure data also indicates that this northern section of the reservoir is connected to #1-Zama. A vertical sidetrack is planned at #2-Zama with an updip vertical penetration in the reservoir. It will be cored and a drillstem test is planned. The second appraisal well, #3-Zama, will be drilled to the south of the original discovery well and will help delineate the reservoir continuity and quality in the southern part of the field. Houston-based Talos is the operator of Block 7 in a consortium with its partners ***Sierra Oil and Gas*** and ***Premier Oil***.

2 Guyana

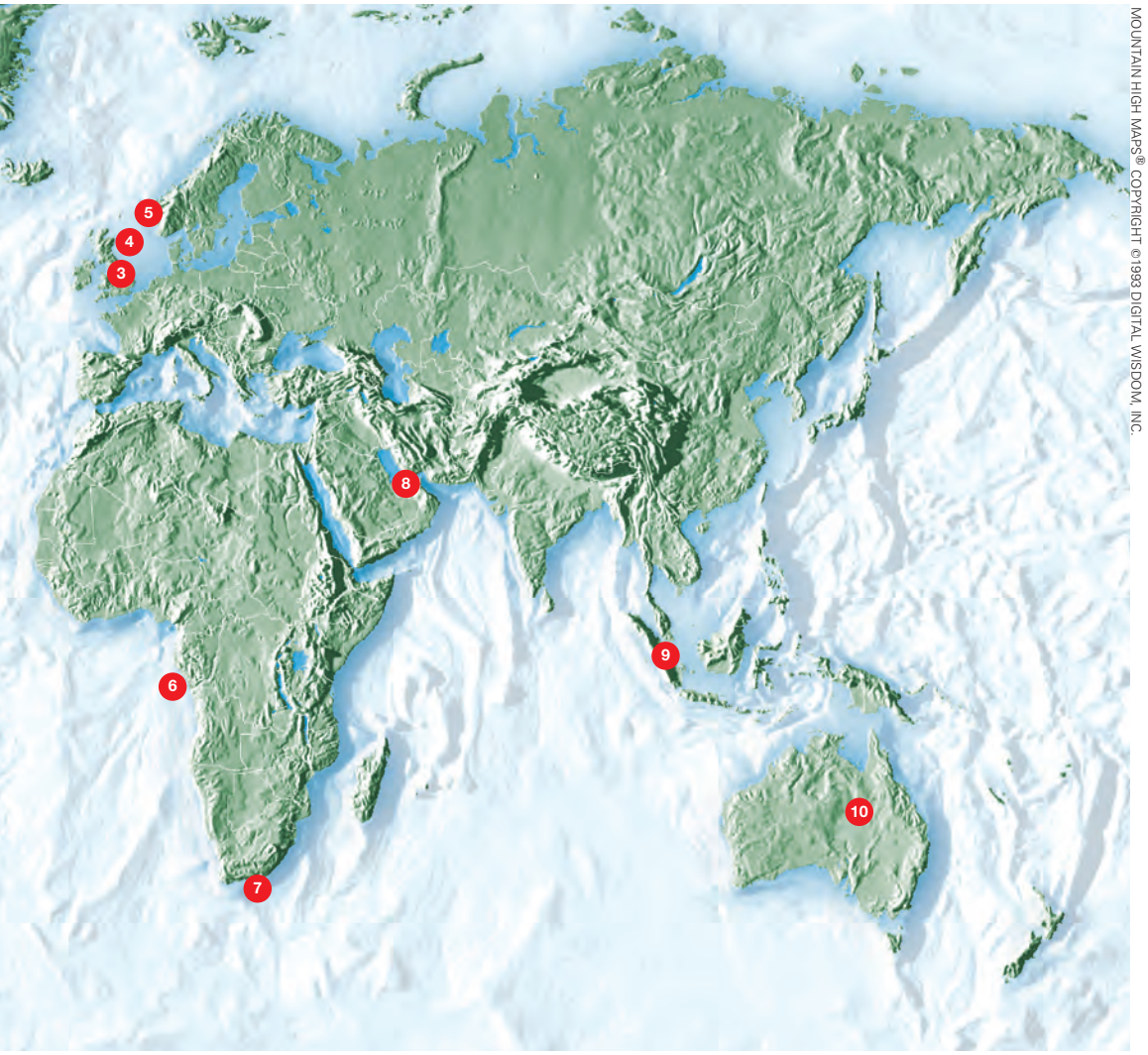
Two additional offshore Guyana discoveries were reported in the Stabroek Block by ***ExxonMobil Corp***. The #1-Tilapia hit approximately 305 ft of high-quality, oil-bearing sandstone reservoir. It was drilled to 18,786 ft and is in 5,850 ft of water. The well is about 3 miles to the west of #1-Longtail. The #1-Haimara hit approximately 207 ft of high-quality, gas-condensate-bearing sandstone reservoir. It was drilled to 18,289 ft, and area water depth is 4,590 ft and is about 19 miles east of #1-Pluma. According to the company, it is a potential new area for development. ExxonMobil is the operator and holds 45% interest in the block along with ***Hess Corp.***, with 30%, and ***China National Offshore Oil Corp.***, with 25% interest. ExxonMobil is based in Houston.

3 U.K

IGas Energy is underway at a Bowland Shale exploration well, #1-Springs Road, in North Nottinghamshire, East Midlands, U.K. It is the second well of an integrated exploration and appraisal program to define the Gainsborough Trough Basin. A previous well, #1-Tinker Lane, was drilled at the edge of the basin and encountered a shale interval before penetrating the targeted Dinantian Limestone. However, the shales encountered did not include targeted Bowland Shale. London-based IGas is the operator, and ***Total*** holds a 40% stake in license area PEDL 140.

4 U.K.

A new discovery at the Glengorm prospect was reported by ***China National Offshore Oil Corp***. (CNNOC) in the offshore U.K. portion of the central North Sea. The discovery is in License P2215 and area water depth is 86 m. The #1 Glengorm was drilled to 5,056 m and encountered net gas and condensate pay zones with a total thickness of 37.6 m. License P2215 comprises U.K. Central North Sea blocks 22/21c, 22b and 26d. CNOOC is the operator of License P2215, holding 50% interest. ***Total*** holds 25% interest and ***Edison Esplorazione e Produzione*** holds 25% interest. The recoverable resources are currently estimated at 250 MMbbl of oil equivalent. Additional testing and appraisal drilling are planned. CNOOC is based in Beijing.



5 Norway

Equinor announced results from a wildcat, #35/11-22S, in production license PL 248 C. The venture was designed to prove oil in Middle-to-Lower Jurassic reservoir rocks (the Brent Group and Cook Formation). It was drilled to 3,882 m and area water depth is 363 m. The secondary exploration target was to prove oil in the Statfjord Group in Lower Jurassic. In the Middle-to-Lower Jurassic reservoir, the well encountered 190 m in Brent Group with 90 m of effective reservoir rocks with moderate reservoir quality. The thickness of Cook is about 70 m, of which 50 m of effective reservoir rocks with poor-to-moderate reservoir quality. The secondary exploration target in the Statfjord group has a thickness of about 130 m, of which 60 m is aquiferous reservoir rocks. The well also hit a 30-m sandstone-dominated unit in Heather in the Middle-to-Upper Jurassic, with 15 m of effective reservoir rocks, mainly with moderate reservoir quality. No oil/water contact was encountered. Equinor is based in Stavanger.

6 Republic of Congo

Anglo African Oil & Gas Plc, based in London, reported a hydrocarbon find at #103C-TLP at its offshore Tilapia license in the Republic of the Congo. Wireline logging confirmed a 12-m oil column in Djeno, proving a functioning reservoir in the Tilapia permit area with a 4-m transition zone from 2,396 to 2,411 m in a dolomitic interval with high shale content in a Lower Cretaceous Neocomien. The well was drilled to 2,683 m. Another test is planned at #104-TLP and is targeting Vandju and a possible sandstone reservoir in Djeno. This discovery brings the combined total of oil encountered by the well to an aggregate of 56 m across the identified horizons.

7 South Africa

Paris-based ***Total*** announced a gas condensate discovery in offshore South Africa's Block 11B/12B in the Outeniqua Basin. The #1-Brulpadda well encountered 57 m of net gas condensate pay in Lower Cretaceous reservoirs. The Brulpadda-deep prospect well was drilled to 3,633 m. The discovery is currently estimated at between 500 MMboe to 1 Bboe in the Algoa-Gamtoos license. Total plans to acquire 3-D seismic this year and continue testing with four exploration wells in 2019. Block 11B/12B covers an area of 19,000 sq km and water depth ranges from 200 to 1,800 m. Total is the operator and owns a 45% working interest, with ***Qatar Petroleum*** (25%), ***CNR International*** (20%) and ***Main Street***, a South African consortium (10%).

8 Abu Dhabi

Abu Dhabi National Oil Co. has discovered more hydrocarbon deposits that increase existing oil reserves by 1% and an increase to gas reserves by 7.1%. Based on existing data from detailed petroleum system studies, seismic surveys, log files and core samples from hundreds of appraisal wells, estimates suggest these new blocks hold 11 Bbbl of oil and possibly 15 Tcf of gas. Abu Dhabi's Supreme Petroleum Council has approved a five-year capex plan for exploration and production beginning this year.

9 Indonesia

A significant gas discovery was announced by ***Repsol-YPF*** in Indonesia's onshore Sakakemang Block in Sumatra. Preliminary estimates at #2-Kali Berau Dalam are approximately 2 Tcf. The venture was targeting a Pre-Tertiary fractured basement play. Prior to drilling, the prospect was estimated to hold approximately 1.5 Tcf of gas (250 MMboe). Additional appraisal drilling and testing are planned and a second well is scheduled on the block. The find is the largest discovery in Indonesia since 2001. Madrid-based operator Repsol holds a 45% working interest. ***Petronas*** owns 45% and ***Mitsui Oil*** holds the remaining 10%.

10 Australia

Sydney-based ***Real Energy Ltd.*** has tested #3-Tamarama on the company's ATP927 permit in Queensland. The venture flowed 2.5 MMcf of gas per day from Patchawarra when tested on a 24/64-in. choke. The Cooper-Eromanga Basin well was drilled to 2,634 m. Additional data gathering and other reservoir parameters for #3-Tamarama and #2-Tamarama are planned and, according to the company, the main objective is to book a gas reserves for its Windorah Gas Project. The #2-Tamarama and #3-Tamarama were drilled as follow-up wells from the initial discovery well at #1-Tamarama and utilized a deviated wellbore design with optimal stress orientation to improve fracturing.

THAWING IN CAPITAL MARKETS

Evidence of a thawing in energy capital markets gained ground with an upsized offering by Viper Energy Partners LP (Nasdaq: VNOM). Having initially filed for an 8 million common unit issue, the offering was upsized to 9.5 million units and priced at $32 per unit. The offering price reflected a 5.4% discount to the market closing price.

The royalty/mineral interest area generally had better access to capital markets due to its income characteristics. Based on its recent dividend of $0.51 per quarter, Viper units offered a yield of about 6.3% on its $32 offering price. Gross proceeds from the $304 million offering (prior to the overallotment option) will be used to pay down its revolver.

In the credit sector of private equity, Sequel Energy Group II LLC was formed with a $500-million capital commitment from funds managed by GSO Capital Partners LP, the New York-based credit platform of Blackstone, and the founding partners of Sequel Energy Group.

Sequel's management team is led by industry veterans Doug York, Jeff Hemphill and Dave Kornder. The latest $500-million commitment in early 2019 brings the combined capital committed to the Sequel platform to more than $1 billion.

Sequel II is targeting "structured investments in non-operated oil and gas working interest in proven resource plays throughout North America." Its management added that drilling joint ventures provide "the ideal shareholder and balance sheet friendly capital solution" for oil and gas operators looking to maintain capex programs within cash flow.

Midstream players continue to access debt markets, with Antero Midstream Partners pricing an upsized offering of $650 million of 5.75% senior unsecured notes due in 2027.

In oilfield services, USA Compression Partners priced $750 million of 6.875% senior unsecured notes due 2027. In E&P, CNX Resources Corp. priced $500 million of 7.25% senior notes due 2027.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Viper Energy Partners LP	Nasdaq: VNOM	Midland, Texas	$304 million	Priced a public offering of 9.5 million common units representing limited partner interests at a price of $32 each. The offering represents a 1.5 million unit upsize to the originally proposed 8 million offering of common units. The total gross proceeds of the offering (before underwriters' discounts and commissions and estimated offering expenses) will be approximately $304 million. The underwriters have a 30-day option to purchase up to an additional 1.425 million common units from Viper.

DEBT

USA Compression Partners LP	NYSE: USAC	Austin, Texas	$750 million	Priced private placement to eligible purchasers and its wholly owned subsidiary, USA Compression Finance Corp., of $750 million in aggregate principal amount of 6.875% senior unsecured notes due 2027 at par. Will receive net proceeds of approximately $738.5 million, after deducting the initial purchasers' discounts and estimated offering expenses. The net proceeds from the offering will be used to repay a portion of existing borrowings under its asset-based revolving credit facility and for general partnership purposes.
Antero Midstream Partners LP	NYSE: AM	Denver	$650 million	Priced private placement to eligible purchasers of $650 million in aggregate principal amount of 5.75% senior unsecured notes due 2027 at par. It will receive net proceeds of approximately $641 million, after deducting the initial purchasers' discounts and estimated expenses, which it intends to use to repay a portion of the outstanding borrowings under its credit facility.
Sequel Energy Group II LLC	N/A	Greenwood, Colo.	$500 million	Funds managed by GSO Capital Partners LP, the credit platform of Blackstone, and the founding partners of Sequel Energy Group formed Sequel Energy Group II LLC with initial capital commitment in excess of $500 million.
CNX Resources Corp.	NYSE: CNX	Pittsburgh	$500 million	Priced $500 million of its 7.25% senior notes due 2027. The notes will be guaranteed by all of CNX's wholly owned domestic restricted subsidiaries that guarantee its revolving credit facility. Net proceeds of the sale of the notes will be used to purchase up to $400 million aggregate principal amount of its outstanding 5.875% senior notes due 2022 pursuant to the tender offer that commenced concurrently with the offering of the notes, with the remainder of the net proceeds to be used to repay existing indebtedness under CNX's revolving credit facility.

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ENERGY RIVALRIES

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

The theme for this year's CERAWeek by IHS Markit said it all: "New World of Rivalries."

Those include the U.S. oil tsunami eroding traditional OPEC market share, U.S. LNG exports competing with other LNG exporters and the U.S.-China trade dispute. Underpinning it all, fossil fuel emissions lead to cleaner renewables and the possibility of government mandates, vs. an industry that has vowed to police itself and contribute to cleaner energy solutions.

There is even a rivalry of sorts in thought, between an increasingly globalized world tied together digitally, where there's no boundary and no turning back, and rising nationalist or populist sentiment in nearly every country, noted IHS Markit senior vice president Carlos Pascual.

"There is a new world of rivals: a great power competition between the U.S., Russia and China. Obstacles and problems come with that," said Daniel Yergin, IHS Markit vice chairman and host of the conference.

Speakers on nearly every panel at the annual Houston event marveled at the global footprint of U.S. shale, which has created heated competition between the U.S. and OPEC. In a closed door session, according to Bloomberg, people from Carlyle, Morgan Stanley, Credit Suisse, certain producers and OPEC representatives discussed this rivalry. OPEC cautioned against Congress enacting a "NOPEC" act that would allow the U.S. to sue OPEC. This would backfire on American shale companies in a number of ways, including much lower oil prices, if President Trump were to sign it.

U.S. producers at the event vowed that they will continue, albeit in a more mature way, one that focuses on proper capital allocation, investor returns and environmental stewardship.

Energy Secretary Rick Perry told attendees how excited and proud he is about American innovation, the emission reductions we've achieved and what he called America's new era of energy. "Energy independence used to be a sound bite but now it's a reality. And, we've got more than enough energy to share with the world."

Hearing someone in a bilateral trade talk lean in and tell him, "We want to buy your LNG," is music to his ears, he said, admitting to being what he called "a traveling salesman for American energy."

When asked about the Green New Deal, Perry said, "Having a conversation about it is the right thing to do, and it needs to take place in a polite and thoughtful way. It's wise for us to have those conversations. We need more open and candid discussion and we need to face reality. We need to support smart technologies that are driving down emissions ... we need to keep saying yes to energy innovations."

One man saying yes is BP Plc CEO Bob Dudley, who just inked a new joint venture with the Environmental Defense Fund to use drone technology to find and reduce methane emissions. He said we are operating in a world that is no longer sustainable; how the energy industry responds is its future.

"We have to move from being pure-play oil and gas companies into broader energy businesses. Our focus has to be on developing an energy system that is cleaner, better and kinder to the planet," he said.

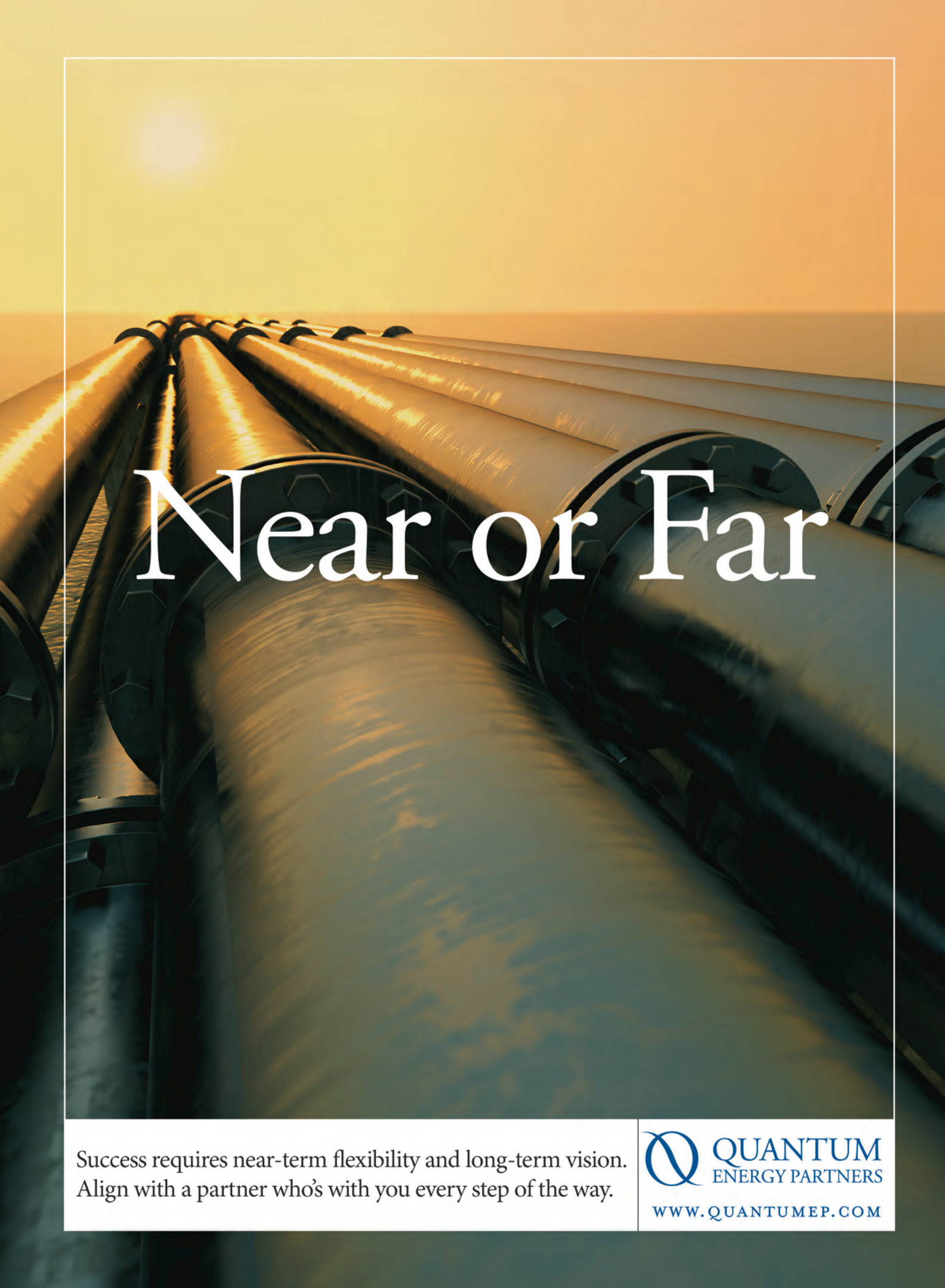
Dudley endorses low carbon solutions, yet at the same time, he said these must compete for investors' money. He recalled that BP was in the vanguard more than a decade ago, yet lost millions on its initial green efforts. Despite this, those efforts continue.

"We get our license to operate from society, but we get our capital from investors and it's our duty to spend it wisely and deliver the returns they expect, both shorter term and long term. In other words, we have to be progressive for society and pragmatic for investors. At the same time, we need to be ready to move fast as the market changes. We're not the big hulking ocean liners that some see us as."

Dudley said if we have cleaner energy tomorrow, it will be because we rely on the energy companies of today "incubating new ideas, adopting new innovations and integrating them into their business models and consumer offers.

"We have the relationships, the financial acumen and the engineering know-how to do that at scale and be pivotal in the energy transition. But in order for us to play that role we have to continue to evolve."

Numerous speakers addressing a variety of energy topics echoed these sentiments about environmental matters and community engagement. Peter Coleman, CEO of Australian LNG exporter Woodside Petroleum, said, "You can't hide behind government these days to make sure you have access to land rights" when seeking to build pipelines and LNG export facilities. He said companies have to communicate with First Nations, aboriginal groups and local stakeholders. "Citing the economic benefits is not always going to be enough. Think through what the benefits will be and talk with them, not to them and not at them."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