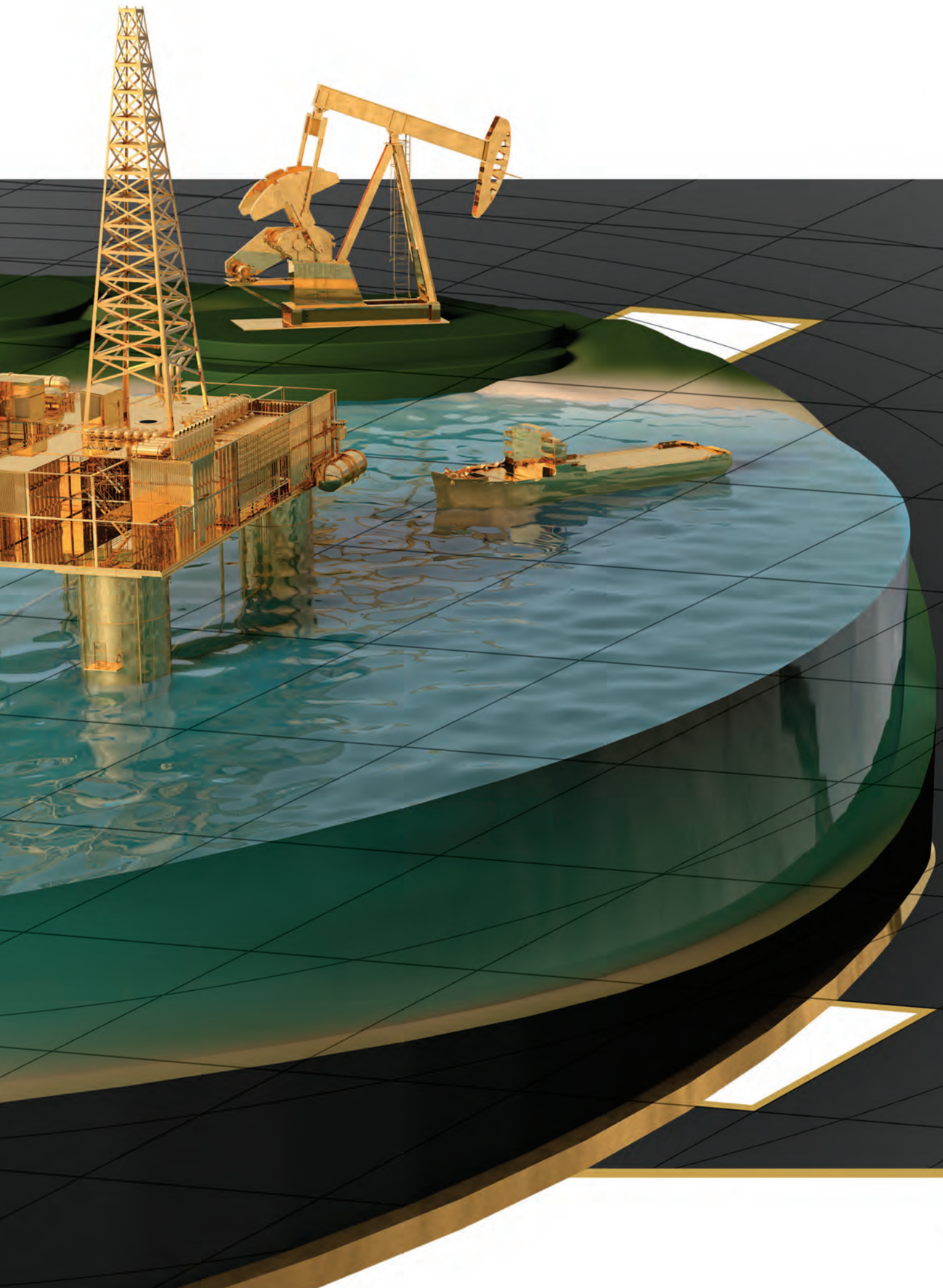
Oil and Gas Investor

SEPTEMBER 2020

Producers look for positive signs to restart curtailments and rigs.

HARTENERGY

OPPORTUNE OUTSOURCING



With limited exit and financing alternatives, the current environment requires lower costs, free cash flows and deleveraging.

While most companies have taken initial steps to address G&A, our multidisciplinary team will help you identify and realize opportunities to materially reduce cost and enhance efficiencies through the back-office, procurement and infrastructure.

OPPORTUNE OUTSOURCING SERVICES

- Financial Reporting – Public & Private
- Operational Reporting
- Process & Technology
- Technology Platforms
- AP & JIB
- Land
- Revenue
- Treasury
- Production & Regulatory Compliance
- Mapping
- Tax
- Reserve Engineering

BENEFITS OF OPPORTUNE OUTSOURCING

- Reduced headcount and infrastructure
- Reduced implementation costs with in-house software and hardware
- Quantified lower G&A
- Integrated and automated business processes in place within 30+ days
- Dynamic team of seasoned professionals matched to fit client needs - ability to scale

Carl Wimberley
Partner, Opportune LLP
cwimberley@opportune.com | 713.237.4983

Contact us today | Opportune.com/outsourcing

OPPORTUNE

unconventional thinking produces

EXCEPTIONAL RESULTS

Aethon Energy is a leading North American owner-operator Private Equity firm looking for exceptional individuals to join our team.

AethonEnergy.com/Careers

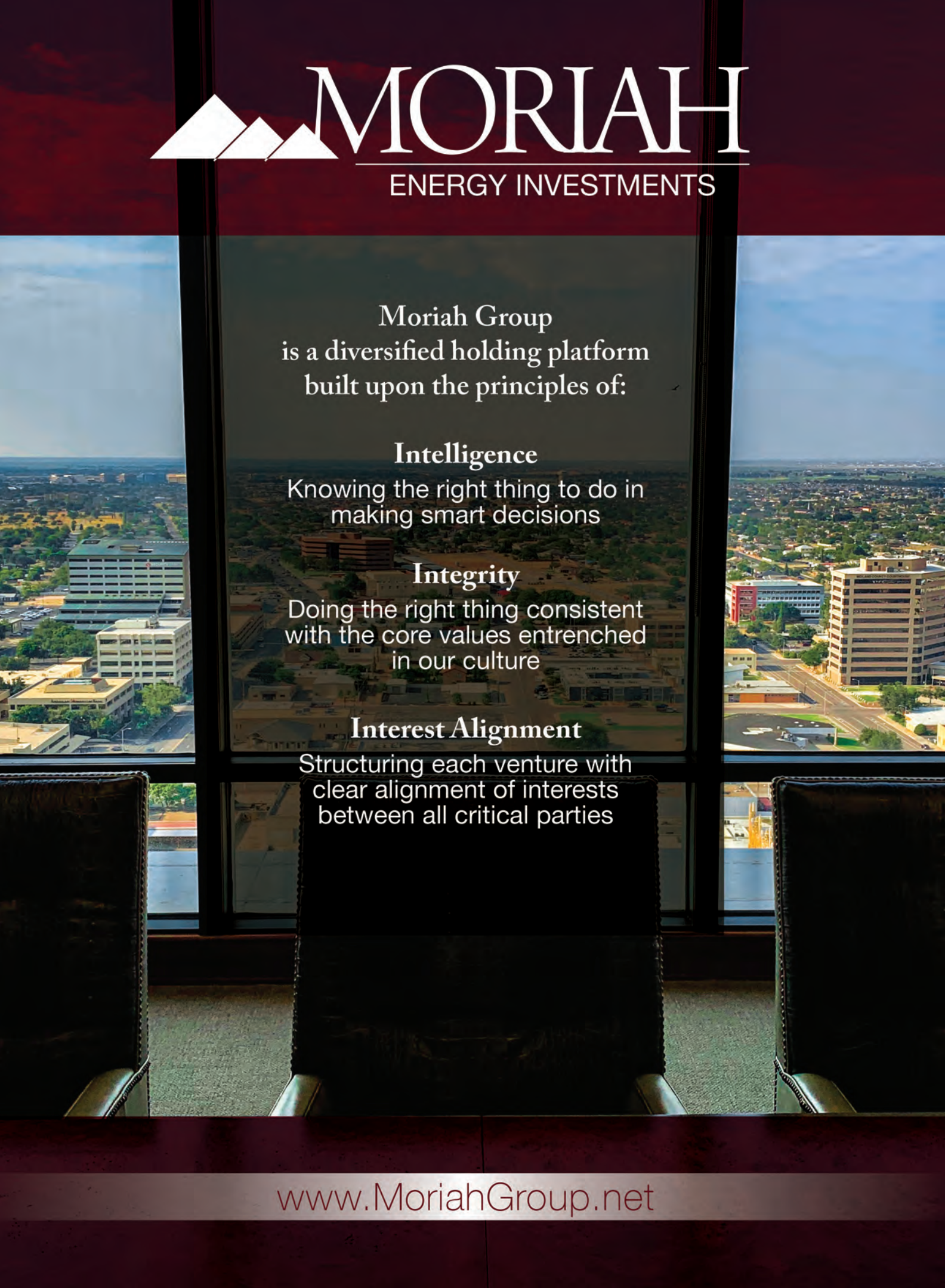
AETHON

sequitur superbia excellentium

HARTENERGY
EVENTS | MEDIA | DATA | INSIGHTS

Oil and Gas Investor

SEPTEMBER 2020/VOLUME 40/NUMBER 9


MORIAH
ENERGY INVESTMENTS
Moriah Group
is a diversified holding platform
built upon the principles of:
Intelligence
Knowing the right thing to do in
making smart decisions
Integrity
Doing the right thing consistent
with the core values entrenched
in our culture
Interest Alignment
Structuring each venture with
clear alignment of interests
between all critical parties
www.MoriahGroup.net

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

COLUMNS

DEPARTMENTS

ABOUT THE COVER: Patterson Rig No. 565 drills the CBR 27-335H well for WPX Energy Inc. on the Texas side of its Delaware Basin Stateline holdings. Photo by and copyright Jim Blecha; courtesy of WPX.

Oil and Gas Investor (ISSN 0744-5881, PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX. Ride-along enclosed. Advertising rates furnished upon request. **POSTMASTER: Send address changes to Oil and Gas Investor, PO Box 5020, Brentwood, TN 37024**. Address all correspondence to Oil and Gas Investor, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Telephone: +1.713.260.6400. Fax: +1.713.840.8585. oilandgasinvestor@hartenergy.com

Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepayment required). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

REPUTATION. EXPERTISE. SERVICE.

Netherland, Sewell & Associates, Inc. is one of the most respected names in independent reserves reporting. For over 50 years, we have provided high quality engineering, geological, geophysical, and petrophysical consulting services to petroleum and financial concerns worldwide.

Our clients use our reports for regulatory agency filings, stock exchange offerings, project financing, equity determinations, and acquisitions and divestitures. Each evaluation is based on technical expertise, sound professional judgment, and accepted practices.

With NSAI, you get our team of experts and a reliable, respected report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Serving Our Clients For Over 50 Years

Dallas 214.969.5401, Houston 713.654.4950
www.netherlandsewell.com
email: info@nsai-petro.com

LATEST CONTENT

Experts: oil and gas industry suffers a credibility gap
By Joseph Markman, Senior Editor
The message about abundant, affordable energy and lower emissions is lost because of a lack of trust, say panelists at a recent Colorado conference.

Analysts see frac crew, activity growth ahead for US shale sector
By Velda Addison, Group Senior Editor
Most of the growth over the next year or so is expected to come from the Permian Basin and Eagle Ford Shale along with notable growth this year from some gas plays, analysts say.

Oil and gas financing: back to the bootstraps
By Darren Barbee, Senior Editor
Investors can be lured back to oil and gas, but free cash flow has to be returned to shareholders and not sunk back into the ground, say panelists during Summer NAPE.

E&P bankruptcy sales: pros, cons of stalking-horse bidders
By Mary Holcomb, Associate Editor
The opportunity to acquire oil and gas assets out of bankruptcy has grown in the current downturn, however, a panel of experts say buyers should be prepared to act early and quickly.

Analysts hopeful for US GoM production recovery
By Velda Addison, Group Senior Editor
Companies operating in the U.S. Gulf of Mexico made about $4 billion in capex cuts as the coronavirus pandemic slowed demand and oil prices dropped.

ONLINE EXCLUSIVES

States' fights: why local elections are critical to oil and gas
By Joseph Markman, Senior Editor

In Colorado, E&Ps watch the SB-181 rulemaking progress; in Alaska, the ballot issue concerns higher taxes for North Slope producers.

Analysts forecast about 150 more E&P bankruptcies by end-2022
By Emily Patsy, Senior Managing Editor

Even at $40 WTI, about 150 more E&Ps in North America will need to seek Chapter 11 protection through 2022, according to Rystad Energy analysis.

Exploration outlook: key oil, gas prospects to watch post-COVID-19
By Velda Addison, Group Senior Editor

Despite spending cuts made across the oil and gas industry, some companies are moving ahead with plans to drill exploration wells.

Hart Energy's Unconventional Activity Tracker
By Larry Prado, Activity Editor

Updated weekly, Hart Energy's exclusive rig counts measure drilling intensity. They exclude units classified as rigging up or rigging down, and also exclude rigs drilling injection wells, disposal wells or geothermal wells. They are designed to offer the most accurate picture of what is actually occurring in the field.

HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

HartEnergy.com/videos

Grant Thornton's Bryan Benoit talks oil industry recovery
After a rough second quarter that included a historic collapse in oil prices, Bryan Benoit, a principal at Grant Thornton Financial Advisors who also leads the firm's energy advisory practice, says he's starting to see green shoots ahead for the industry.

ESG roundtable: Is oil and gas ready for the expectations, opportunities?
If the industry wants continued capital investment, it will have to up its game. Our virtual panel discusses what you need to know to be ready for increased scrutiny and requirements of an ESG future.

Babst Calland attorneys target oil and gas political issues to watch
As the November election draws closer, Babst Calland's Kevin Garber and Jean Mosites analyze the stance of major party candidates on key environmental issues and what the oil and gas industry can anticipate, depending on the victors.

TAILWATER
CAPITAL

PRESENCE.
PARTNERSHIP.
PRECISION.

130+
Years Combined
Investing Experience

$3.7B
Committed
Capital

40+
Professional
Dedicated Team

$20+B
Value of Tailwater's
100+ Energy Transactions

214.269.1183
tailwatercapital.com

MAJOR STIFF ARM

STEVE TOON,
EDITOR-IN-CHIEF

After 98 years the venerable Exxon Mobil Corp., the king of U.S. oil companies, was tossed out of the Dow Jones Industrial Average like a fallen billionaire out of a country club. "You're not welcome here, anymore. You don't meet our standards anymore. You're not who you used to be." The club of 30 high-flying American companies comprising the stock index oft used to reflect the health of the U.S. economy said don't let the door hit you on the butt on the way out.

Exxon first joined the Dow in 1928 as Standard Oil Company of New Jersey, originally formed by 1880s industrialist John D. Rockefeller. More recently, in 2007, it owned the honor as the world's largest oil company with a market cap of more than $500 billion, and in 2013 it briefly topped Apple as the largest company in the world.

Today it is the U.S.' 33rd largest company with a market cap of $173 billion.

Still, Exxon is no slouch on the oil playing field. It remains a prominent oil and gas and chemicals producer worldwide—second in revenue behind Sinopec—but in the course of a year its stock has halved from $80 to $40. Hasn't everyone's in the sector?

Chevron Corp. remains on the Dow, the sole representative of the energy industry. Its market cap is $159 billion—below Exxon and 38th on the list—but its stock price is twice Exxon's at $80, and the Dow weights price over cap.

What does Exxon's exile after nearly a century say for the industry? Simply that the wolves of Wall Street find no upside in energy.

And who can blame them? In April, at the depth of the downturn, energy represented just 3% of S&P 500, almost an afterthought in a portfolio. And that's all energy, not just oil and gas. In 2008, the energy sector reached 15% and couldn't be ignored.

We've now concluded second-quarter conference calls in which domestic E&Ps painted bleak pictures of shut-ins and rig abandonment in defense of prices that fell like a dove in a hunter's sights. Now the survivors are regrouping and replanning for an uncertain future on both the supply and demand sides of the equation, although it's pretty clear where Wall Street investors stand.

But where most oil soothsayers foresee prices in the $40s and $50s for a protracted time, there is one voice in the fray with a rather more optimistic view of the macro landscape for oil and gas companies. Marshall Adkins, managing director and head of energy investment banking for Raymond James, thinks by this time next year the pendulum is going to swing back, fast and high.

Adkins gave his perspective as part of Hart Energy's virtual DUG Midcontinent conference in August. He believes the supply and demand dynamics are going to flip-flop, with global demand quickly ramping back to 3% shy of where it was pre-COVID-19, and oil inventories evaporating rapidly in lieu of offline supply as rigs remain sidelined.

"I think we're going to see global oil inventories fall below what I would call a normalized level sometime in early 2021, and it will take us years to get back to an oversupplied market without a meaningful increase in oil prices. And when I say meaningful, I'm not talking five or ten bucks, but oil prices doubling from where we are today over the next 12 to 18 months."

Did Marshall just say $80 oil? "I think you're going to exit this year above $50/bbl. I think we'll see oil in the $80s next year, depending on that pace of demand recovery. Triple digits is not out of the question in my mind. It really starts to accelerate in the back half of '21."

$100.

He also said OPEC will need to produce at full bore and the U.S. rig count will need to average 800 rigs again by year-end 2021 to make up for the projected global undersupply.

If prices do spike up as fast as they spiked down this year, that will leave E&Ps with a hard choice: ramp up to meet the call to produce or return cash to shareholders as Wall Street dictates. That outcome remains to be seen, but in either scenario the relevance of the oil and gas sector will be on full display. And who couldn't use the oxygen?

And the granddaddy ExxonMobil? With guidance to produce 5 MMbbl/d by 2025—750,000 from Guyana and 750,000 from the Permian alone—at $100 oil that's a tidy profit, no doubt boosting the stock price. And may the Dow sit in envy.

To see Marshall Adkins' full remarks from Hart Energy's virtual DUG Midcontinent, go to DUGMidcontinent.com. And you won't want to miss the upcoming DUG Permian and Eagle Ford conference, also virtual, Sept. 29-30. Go to hartenergyconferences.com/dug-permian-basin.

CENTERED IN TRUST AND LONG-TERM RELATIONSHIPS

Stephens maintains a long history of raising private capital for oil & gas companies. In recent years, we have been particularly active raising capital for mineral acquisition businesses.

Recent Private Financing Transactions

UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED
Haynesville Minerals Platform	**Diversified Minerals Aggregator**	**Midland Basin Operator**	**Eagle Ford Minerals Platform**
EQUITY PRIVATE PLACEMENT	STRATEGIC PARTNERSHIP	ASSET ACQUISITION	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Sole Placement Agent	Financial Advisor	Sole Placement Agent
$100 MILLION	**UNDISCLOSED**	**$22 MILLION**	**UNDISCLOSED**
PRODUCERS MIDSTREAM	ROSEWOOD RESOURCES	Thunder Basin Resources	NOBLE ROYALTIES, INC.
EQUITY PRIVATE PLACEMENT	JOINT VENTURE TRANSACTION	EQUITY PRIVATE PLACEMENT	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Financial Advisor	Sole Placement Agent	Sole Placement Agent

Other Recent Minerals & Royalties Transactions

$28 MILLION	$28 MILLION	UNDISCLOSED	UNDISCLOSED
VIKING MINERALS	VIKING MINERALS	**Shadow Creek Minerals**	NOBLE ROYALTIES, INC.
ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

$350 MILLION	$66 MILLION	$104 MILLION
VIPER Energy Partners	KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS
FOLLOW ON OFFERING	FOLLOW ON OFFERING	INITIAL PUBLIC OFFERING
Underwriter	Underwriter	Underwriter

PRIVATE FINANCING STATISTICS	MINERALS & ROYALTIES STATISTICS
~$4.8 Billion	~$900 Million
Aggregate Capital Raised Since 2009	Aggregate Transaction Volume Since 2017
30 Closed Transactions since 2009	10 Closed Transactions Since 2017

Keith Behrens, Managing Director, Head of the Energy Group • 214-258-2762 • keith.behrens@stephens.com
Charlie Lapeyre, Managing Director • 214-258-2784 • charlie.lapeyre@stephens.com
Paul Moorman, Managing Director • 214-258-2773 • paul.moorman@stephens.com
Brad Nelson, Managing Director • 214-258-2763 • brad.nelson@stephens.com
Jim Wicklund, Managing Director • 214-258-2798 • jim.wicklund@stephens.com

300 Crescent Court | Suite 600 | Dallas, TX 75201

For the most recent list of our transactions, visit **stephens.com/buildingblocks**

Stephens Investment Banking

AT THE BRINK

DARREN BARBEE,
SENIOR EDITOR

As 2020 crawls through the third quarter, the strains on M&A and the oil and gas industry are beginning to take on albatross-ian levels.

China is abiding by its energy trade agreement with the U.S. quarter-heartedly (roughly one ventricle). The People's Republic committed to importing $18.5 billion more in U.S. energy products annually. Through June, China's purchases are an undazzling $1.3 billion, according to the Peterson Institute for International Economics.

As the election nears, fears that a Democrat president could institute fracking bans are matched only by the actual lack of fracking being done. The oil rig count has spiraled down to 172, the lowest since 2005, according to Simmons Energy.

And, of course, there's the coronavirus, which has definitively answered the age-old question, "If there was a COVID-19 infection party, what would you wear?"

Within this confluence of stupid and infuriating, M&A is becoming more an act of artistic license than profitability. Companies continue low premium, all-stock deals that have no immediate accretiveness, apart from tossing costs down the G&A garbage disposal.

The benefits of M&A arguably are still important but seem to lean more toward the macro side. Brian Singer, an analyst with Goldman Sachs, recently suggested shale industry M&A could function as a kind of self-imposed speed limit: Combined companies are likely to drive oil growth slower.

This comes as companies are already looking to put less money into operations and more into investor's pockets.

The deals themselves continue to show that high premium deals have far overshot their sell-by dates. Companies are courting each other but practicing safe sales. To paraphrase Rick Blaine, companies "stick their neck out for nobody."

Consider Chevron's merger with Noble Energy, for which the San Ramon, Calif., company threw in a little loose change in the form of a 7.4% premium.

Why accept so little? Noble Energy's internal deliberations may help explain. Noble held a July meeting with advisers to mull over its options: merge, acquire something or go it alone. Noble's go-it-alone option, even in a best-case scenario, would leave the company weakened with no ability to reach its pre-downturn metrics of 1.5x debt/EBIDAX—by 2029, Wells Fargo Securities analyst Roger Read said.

Gas deals, curiously, have shown some recent strength. Southwestern Energy's merger with Montage Resources, however, was viewed by analysts as only slightly needle moving. And Tudor, Pickering, Holt & Co. viewed it as another data point in the continuing trend of low-to-no premium merger.

But several companies also moved smaller assets. Antero Resources found a buyer for its dry gas production stream in West Virginia to the tune of $220 million over the next seven years. Range Resources will collect up to $335 million for the sale of some of its gassy assets in North Louisiana. And Kalnin Ventures LLC, backed by Banpu Plc of Thailand, agreed to move up its purchase of Devon Energy's Barnett Shale assets.

Christopher Kalnin, CEO of BKV Corp. and Kalnin Ventures, said in a brief interview that his company pushed for a quicker closing.

"The main rationale for the timing change is that we have become more bullish on the gas markets for Q4 2020 and FY 2021," Kalnin said.

The emergent gas deal emerges from a backdrop of confusion, according to Enverus founder Allen Gilmer.

Gilmer said in an interview that deals are bogged down by uncertainty—not just of pricing but consternation over what's really of value.

"People are scared," Gilmer said. "They don't have a grasp as to whether [acreage] is valuable or not."

Gilmer said Enverus is already seeing companies become more aggressive on acreage they already own and the acreage around them. Deals center on extended lateral lengths or companies just buying what's near them.

But even smaller companies with strong balance sheets and free cash flow, such as Magnolia Oil and Gas Corp., PDC Energy Inc. and Comstock Resources Inc., could be looked over by picky buyers because of limited inventory or, in PDC's case, the mental state of Coloradans.

As Gilmer noted, the M&A market is cold, at least for now.

"With regards to people going out and doing that kind of on a speculative basis, it hasn't started yet," he said. "But I suspect some money will go into that."

EnCap Investments L.P.

The leading provider of growth capital to the independent sector of the U.S. energy business.

Houston Office: 1100 Louisiana Street, Suite 4900, Houston, Texas 77002 | 713.659.6100
Dallas Office: 3811 Turtle Creek Blvd., Suite 2100, Dallas, Texas 75219 | 214.599.0800
www.encapinvestments.com

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
16th Annual Ryder Scott Reserves Conference	Sept. 16-17		Virtual	ryderscott.com
PIOGA Fall Conference	Sept. 22-24	Seven Springs, Pa.	Seven Springs Mountain Resort	pioga.org
TIPRO Summer Conference	Sept. 23-24		Virtual	tipro.org
DUG Permian/DUG Eagle Ford	**Sept. 29-30**		**Virtual**	**dugpermian.com**
North American Crude Oil Exports Virtual Summit	Oct. 1		Virtual	spglobal.com
DUG Haynesville	**Oct. 28-29**		**Virtual**	**dughaynesville.com**
Executive Oil Conference/ Midstream Texas	**Nov. 3-4**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
Petroleum Alliance of Okla. Annual Meeting	Nov. 5-8	Las Colinas, Texas	Four Seasons	thepetroleumalliance.com
DUG East/Marcellus-Utica Midstream	**Dec. 1-3**		**Virtual**	**dugeast.com**
Privcap Energy Game Change	Postponed to 2021			energygamechange.com
SPE Sustainability Innovation & Technology Convention	Dec. 10-12	TBD	TBD	spegcs.org/events/5739/
2021				
IPAA Private Capital Conference	Jan. 23	Houston	JW Marriot Houston	ipaa.org
Energy ESG Conference	**February**	**Houston**	**Omni Galleria**	**energyesgconference.com**
NAPE Summit	Feb. 8-12	Houston	George R. Brown Conv. Center	napeexpo.com
Innovation & Entrepreneurship Summit	Feb. 24-25	Houston	Norris Conference Center, CityCentre	spegcs.org/events/4637/
CERAWeek by IHS Markit	Mar. 1-5	Houston	Hilton Americas-Houston	ceraweek.com
DUG Bakken and Rockies	**Mar. 25-26**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
Williston Basin Petroleum Conference	May 11-13	Bismarck, N.D.	Bismarck Event Center	ndoil.org
Veterans In Energy Luncheon	**November**	**Houston**	**The Westin Memorial City**	**impactfulveteransinenergy.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

Email details of your event to Bill Walter at bwalter@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

VIRTUAL CONFERENCE

DUG PERMIAN BASIN

DUG EAGLE FORD

September 29-30, 2020

Two Powerhouse Plays Driving the U.S. Shale Market

An extraordinary conference experience awaits you when Hart Energy combines two of its biggest events into one virtual program!

Circumstances prohibit large gatherings, yet the oil and gas business marches on. Now the combined **DUG *Permian Basin* and DUG *Eagle Ford*** program delivers a potent mix of market intelligence from expert speakers – and you can view it all when and where it suits you best after **Sept. 29-30**.

Register today to:

- Gain critical insights from producers about increasing operational efficiencies
- Hear about best practices and key metrics from 30+ executives and influential leaders
- Review technologies and identify solutions that support your goals

Join your peers and colleagues as the industry re-starts during a chaotic year. Register for the **DUG *Permian Basin* and *Eagle Ford*** virtual conference for an unparalleled program blending business strategies, technology insights and operational best practices.

FEATURED SPEAKERS

Dan Pickering
Founder & Chief Investment Officer
Pickering Energy Partners

Clay Gaspar
President & COO
WPX Energy Inc.

Jay Graham
President & CEO
Spur Energy Partners LLC

Mike Henderson
Senior Vice President, Operations
Marathon Oil Corp.

Robert Anderson
President & CEO
Earthstone Energy Inc.

Chris Graham
President & CEO
Verado Energy Inc.

James Wicklund
Managing Director, Investment Banking
Stephens Inc.

Presented by: HARTENERGY MEDIA | RESEARCH | DATA

Hosted by: E&P plus, Oil and Gas Investor, MIDSTREAM Business

NewsWell

Karl Rove: Election results 'consequential' for industry

Energy is unlikely to be a major national issue in the 2020 presidential election campaigns unless President Donald Trump chooses to attack his Democratic opponents over their support of some elements of the Green New Deal, renowned political strategist Karl Rove said during his Summer NAPE keynote address on Aug. 12.

The president could leverage the positions of former Vice President Joe Biden and his running mate, Sen. Kamala Harris, to his advantage "If he tries to make those an issue of the economy, saying what they intend to do on energy, on climate, will affect the size of your utility bill, the quality of American jobs and quantity of American jobs, and affect America's role as [an] energy leader in the world," Rove said.

But he added a caveat: "Only if the Trump campaign—in a disciplined, directed, personal fashion—makes this an issue will energy be a part of the stage."

Rove, former senior adviser and deputy chief of staff to President George W. Bush, affirmed that the election will be of consequence to the energy industry but that energy policy would probably be relegated to an issue in certain states.

"For example, to the degree that Texans become aware that the Biden administration will immediately put a moratorium on new leases in the Gulf of Mexico and the Houston economy, the Texas economy would thereby suffer, the less likely it is that Biden's going to be able to carry Texas," he said.

In a recent poll listed on FiveThirtyEight, a website focused on poll analysis, Trump led Biden by six percentage points, 49% to 43%. That poll, by the Trafalgar Group, was conducted on Aug. 1-5.

Rove acknowledged that a Biden administration would have the regulatory authority to curtail hydraulic fracturing by stopping it on federal land and in federal waters. That presumptive vice presidential candidate Harris would support a ban was a source of frustration to him.

"It's a sign of how unglued we are as a country to even be thinking about this," he said.

Rove also had blunt words for the oil and gas industry when asked how it should engage in the public debate on climate change.

"First, it's got to get its act together," he said of industry. "It seems there's a lot of disparate voices here, and that's normal. But through their trade associations they've got to find a way to make a case that they are contributing to climate solution, not climate problem."

Rove stressed that the U.S. is the only major industrialized country since Jan. 1, 2000, to be able to consistently grow its economy and reduce its absolute level of greenhouse gas emissions.

"We ought to be heralding that success and saying, let's take that American ingenuity and experience and innovation and spread it around the world," he said. "It's a good thing for us to be exporting American natural gas because it will, in some places, replace dung and coal and oil and wood as means of generating electricity. We ought to be proud of what we can do with our natural resource and how it can help the world address its climate concerns."

For those wondering what a second Trump term would mean for the oil and gas industry, Rove's advice is to expect more of the same.

"He would continue to do what he's been doing, which is finding ways to reduce regulation, incentivize and encourage production, export," he said. "He'd be an advocate and defender of what the energy industry is doing. And he recognizes this is a way to create good, high-paying jobs. Because it's not just the jobs in energy itself. It's the jobs in steel, chemicals and refining and transportation—all these things."

—Joseph Markman

Operators turn to DUCs for short-term oil productivity gains

As U.S. shale players focus on high-return, low-cost assets to regain strength amid the latest downturn, attention is turning to DUCs for short-term productivity gains as oil prices continue to stabilize.

However, a situation could arise—in terms of remaining core inventory—if DUCs targeted are in Tier 1 areas of basins, according to an energy data intelligence firm.

"For these operators with larger acreage positions, it's worth noting that we are going to be experiencing a core inventory location drill down, which is not ideal," said Sarp Ozkan, senior director of energy analytics for Enverus, "especially should these operators choose to not wait to complete these DUCs for cash flow purposes or going concern purposes in the coming months."

Speaking during a webinar on Aug. 11, Ozkan said the Lower 48 DUC count has increased by more than 20% since March. Enverus data shows the Permian Basin, for example, saw its DUC well locations rise by 28% to 3,725. He pointed out that DUCs in the Delaware sub-basin have largely been focused on the core.

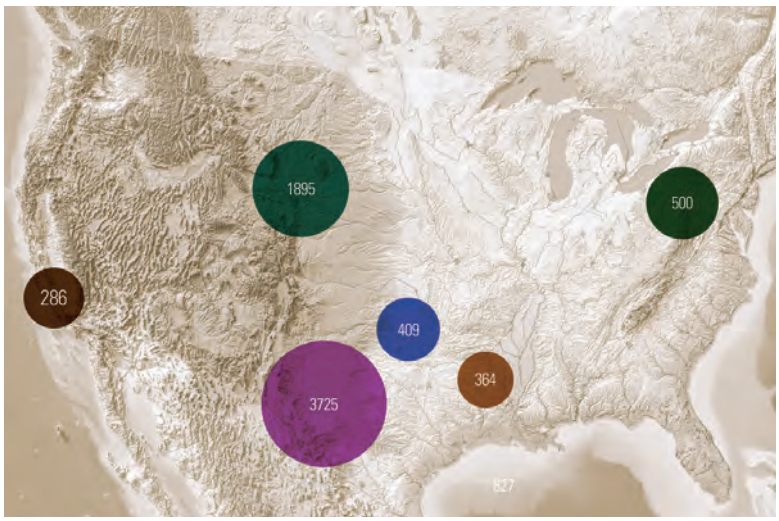
The inventory of DUCs continued to build this year as the COVID-19 pandemic slowed demand, consequently slowing drilling and completions activity as the oil and gas industry awaited improved market conditions.

"So as prices dropped not only did operators focus in with their rigs on these Tier 1 areas, but they also chose to drill and leave uncompleted wells in these regions," Ozkan said.

Tier 1 wells in the Delaware typically produce about 1.25x the EUR oil compared to Tier 3 across all formations within the type curve area, he explained. That means "The DUCs that are going to come online are going to be of the highest quality in terms of well productivity," he said.

The story is similar for the Midland sub-basin and Williston Basin, where Enverus data show Tier 1 wells respectively produce about 1.5x and 1.6x EUR oil compared to Tier 3 wells.

DUC Well Locations And Trends*



Numbers By Region

Ark-La-Tex	21%	Midcontinent	-3%	Permian	28%	West Coast	14%
Gulf Coast	0%	Northeast	11%	Rockies	7%		

* DUC counts have risen 21% across the Lower 48 since March 1.
Source: Enverus

"If commodity prices remain sort of where they are in this $40 range and uncertainty persists in the market, operators are going to continue to consolidate their activity into areas with the best well productivity," Ozkan said. "That means that that shift to top tier acreage across these major unconventional basins will provide an uplift to the average well level productivity that we might observe."

Data from the U.S. Energy Information Administration show the DUC count in major oil- and gas-producing regions jumped to an estimated 7,659 wells in June, up from 7,624 in May. Reported data at the time showed increases in the Permian, Bakken, Niobrara and Haynesville, but drops in Appalachia, Anadarko and Eagle Ford. An updated report is scheduled for release Aug. 17.

Several operators have said during second-quarter earnings calls they intend to start completing DUCs. These include international E&P Occidental Petroleum Corp. among others.

"In the D-J Basin, we will begin completing a select group of high-return drilled but uncompleted wells," Occidental Petroleum Corp. CEO Vicki Hollub said on the company's earnings call Aug. 11. "We will also selectively resume activity across other assets including completing key development sections in Permian Resources within Greater Sand Dunes and Silvertip during the fourth quarter."

Permian pure-play Parsley Energy CEO Matt Gallagher anticipates a "nice tailwind from the expected drawdown of about 20 to 25 drilled but uncompleted wells" in 2021.

"This is roughly a $50 million benefit," Gallagher said on the company's earnings call Aug. 6. "Additionally, our base decline shallows during 2021, requiring less replacement barrels in 2022, so all else equal $600 million would also be a fair assumption for a 2022 maintenance capital program."

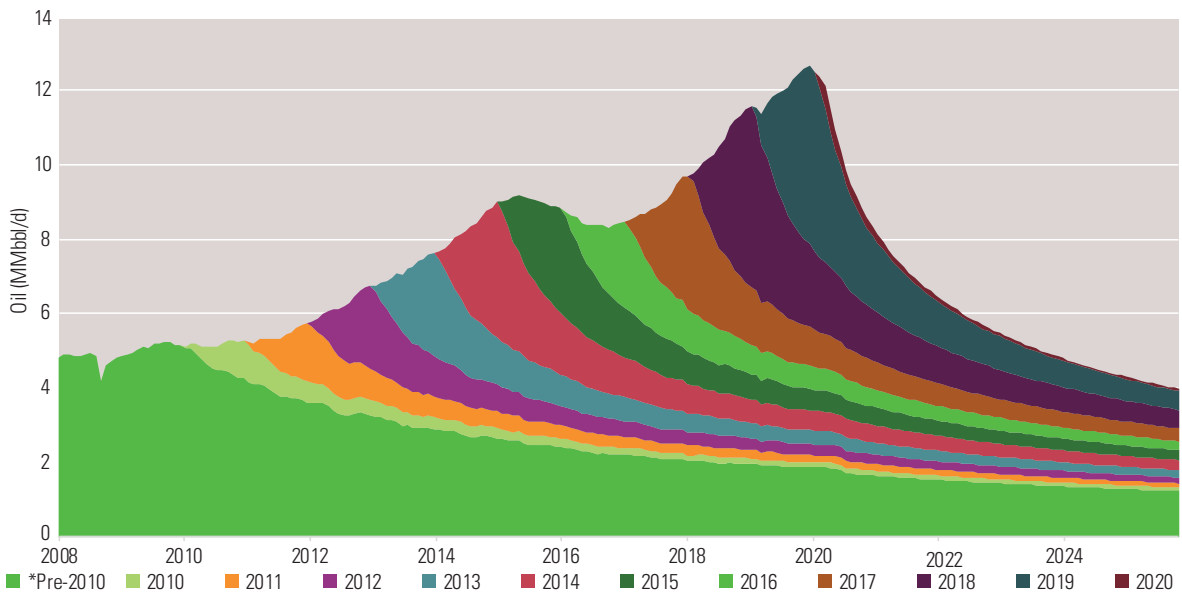
Exxon Mobil Corp. also spoke briefly about DUCs on its earnings call in late July. Neil Chapman, senior vice president for Exxon, said wells decline rapidly if there is no investment. He also pointed out the substantial number of DUCs.

"You're also aware [that] it's a much higher cost to frac than it is to drill," Chapman said when speaking about 2021 capital plans. "That's really important."

Enverus expects completion of DUCs in core areas will be prioritized by oil and gas companies, and the focus on top tier across could uplift decline rates across major U.S. unconventional basins.

Shale wells come on with strong production but decline

US Production Growth Forecast



Source: Enverus

Production Lending, LLC

Capital for Small E&P and Mineral Rights Companies

HIGHLIGHTED TRANSACTIONS:

Permian and Eagleford Minerals Firm **$7,500,000** **Mineral Interests Acquisition Loan** **2020**	Midland Basin Minerals Firm **$2,000,000** **Mineral Interests Acquisition Loan** **2020**	East Texas Operator **$1,000,000** **Equity Investment Facility** **2020**	Gulf Coast Texas Non-Operated Investor **$4,500,000** **Acquisition & Development Facility** **2019**
Permian Basin Operator **$10,000,000** **Development Bridge Loan** **2019**	Texas Minerals Firm **$7,500,000** **Mineral Interests Acquisition Loan** **2019**	Multi-Basin Minerals/Leasing Firm **$3,650,000** **Mineral Acquisition & Leasing Loan** **2019**	Uinta Basin Non-Operated Investor **$7,000,000** **Acquisition Bridge Loan** **2019**
Delaware Basin Minerals Firm **$2,500,000** **Mineral Interests Acquisition Loan** **2019**	Louisiana Operator **$1,350,000** **Acquisition Term Loan** **2018**	East Texas Operator **$3,500,000** **Acquisition & Development Facility** **2017**	South / East Texas Operator **$3,000,000** **Acquisition & Development Facility** **2017**
South Texas Operator **$2,000,000** **Acquisition & Development Facility** **2017**	Gulf Coast Texas Operator **$1,250,000** **Acquisition & Development Facility** **2017**	Central Texas Operator **$1,500,000** **Acquisition & Development Facility** **2017**	South Texas Operator **$1,000,000** **Acquisition & Development Facility** **2017**

Abhishek Kumar
Principal
(512) 853-0069 (direct)
ak@productionlending.com

Ryan W. Childs
Principal
(978) 828-1788 (direct)
rw@productionlending.com

10497 Town and Country Way, Suite 700
Houston, TX 77024
(832) 895-1086

productionlending.com

KILLAM OIL

RICH IN HISTORY. FOCUSED ON THE FUTURE.

For over 100 years, the Killam Family has helped shape and grow the oil and gas industry, beginning with the arrival of O.W. Killam in Laredo, Texas in 1919.

Looking to the future, the Killam Family has helped establish a new petroleum engineering degree at Texas A&M International University to inspire and educate whole new generations of future leaders interested in our industry.

TRUSTED FOR OVER 100 YEARS
1919 2019

KILLAM
OIL & GAS | REAL ESTATE | RANCHING | INVESTMENTS

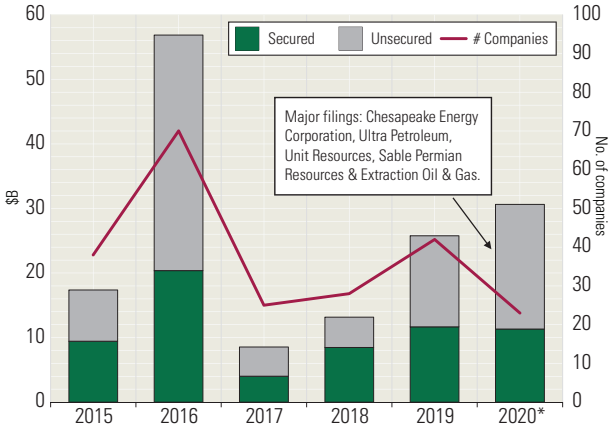
LETS MAKE A DEAL

The Killam Family is confident about the future of the oil and gas industry, and is actively looking to acquire properties and mineral rights across the US Lower 48. Please email us if you are looking to sell.

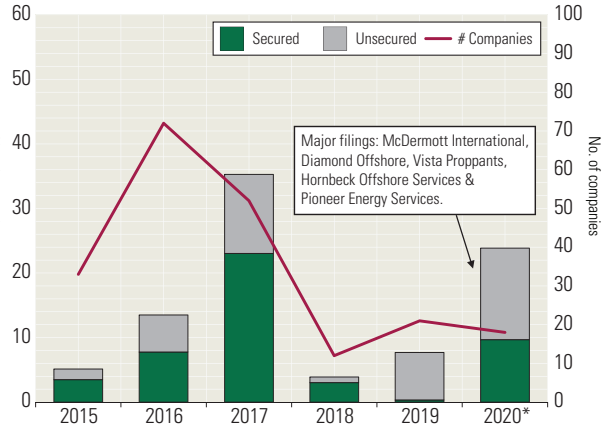
www.killamco.com | deals@killamco.com

Proudly Headquartered in Laredo, Texas

E&P Debt & Companies In Bankruptcy



OFS Debt & Companies In Bankruptcy



* YTD through June 30
Source: Westwood Global Energy Group

quickly, Ozkan said, leading to a need to drill new and better wells to offset steep declines. "These wells, in most cases, will decline about 60% to 80% in the first year of their production," he said. If drilling stopped today, the pace of declines would be "quite alarming," eventually dropping to levels seen in 2010, Ozkan added.

Operators working with service companies have made strides in gaining efficiencies, drilling wells faster and modernizing completions with longer lateral lengths and higher proppant intensity. These moves have contributed to productivity gains. However, Ozkan noted such gains have slowed as other challenges—such as spacing and parent-child well interaction—emerged. It's led to changed development methods for some and pushed others toward areas with better productivity and economics.

"As commodity prices remain flat and uncertainty persists in the market," Ozkan said in his presentation, "operators will continue to consolidate their activity into areas with the best well productivity."

—Velda Addison

Oil analyst sees more challenges ahead for growing bankruptcies

E&P and oilfield service (OFS) companies looking to refinance debt amid continued volatility and a global pandemic may find themselves facing another challenge.

"What we're seeing today is that it's not only very expensive, but it is actually very challenging to refinance this debt," Arindam Das, group head of consulting for Westwood Global Energy Group. "As a consequence of that, we are likely to see a lot of debt restructuring and defaults in H2 2020."

About $140 billion worth of debt is due to mature between 2020 and 2022 in the U.S. oil and gas market. At more than 55%, the majority of the debt is noninvestment or speculative grade. This comes as the oil and gas industry endures an unprecedented downturn and tough market conditions give rise to more bankruptcy filings.

Speaking on the refinancing costs during a recent Westwood macro outlook webinar, Das said the average yield at the end of first-quarter 2020 was about 4% for all U.S. corporate entities. However, looking at investment-grade E&Ps and OFS the yields being asked are about 7% to 10%. That increases to between 12% and 17% for noninvestment grade, he said.

"But more importantly, as you get into highly speculative—B+ [and below] credit rating, you can start to see that it gets really high," Das said, up to a 21% average bond yield for OFS companies with such ratings in today's environment.

In addition to high refinancing requirements, the sector faces limited access to capital, according to Moody's Investors Service.

A "vast majority of sub-investment grade OFS issuers face limited access to capital markets and restructuring and defaults are accelerating in the sector," Moody's said in a July report. The bond credit rating business added: "Corporate default rates are rising, and oil and gas is among the hardest-hit sectors. E&P companies have less availability under bank facilities after the spring redetermination of their borrowing bases, raising their liquidity and credit risk, especially for lower-rated issuers with restricted access to capital markets."

Moody's reported 15 corporate defaults in the oil and gas sector during the first half of the year. Expectations are for "distressed exchanges to continue to rise in tandem with corporate defaults," with many firms opting to file for bankruptcy.

Data show that is already happening. Citing a report from Haynes and Boone LLP, Das said there were about 23 E&P and 18 OFS bankruptcies as of June 30.

Those numbers have already increased with Chapter 11 filings in July by service company BJ Services, California Resources Corp. and frac sand supplier Hi-Crush Inc.

"It's not all-inclusive, but it's a pretty good reflection of what's happening in the U.S. market," Das said. He pointed out there has been a lot of unsecured debt and speculative issuances, resulting in a significant amount of debt that is at risk.

Haynes & Boone forecasts about 100 bankruptcy filings will happen in 2020. The firm said in the report that although oil prices have stabilized around $40/bbl, after plummeting from $63/bbl in January to negative territory in April, it is not enough for the majority of the heavily leveraged shale producers.

"So, we expect to see a lot more defaults over the course of

H2 2020 if things don't improve," Das said.

—Velda Addison

2020 drilling activity forecast to hit 20-year low

Oil and gas drilling is set for a "staggering" decline this year, said Rystad Energy which expects global drilling activity to reach at least a 20-year low in 2020.

Rystad Energy released analysis on July 14 showing the number of drilled wells globally this year will reach around 55,350—the lowest level since at least the beginning of the century, according to the energy consulting firm.

"The decline is a staggering 23% fall from 2019's number of 71,946 wells," the firm said in its release.

Previously, Rystad Energy had expected total number of wells drilled globally in 2020 to rise year-over-year to 74,575. However, its previous forecast was made prior to the COVID-19 pandemic, which has largely stymied oil and gas activity for the year.

Although a modest recovery from the COVID-19 related downturn is possible in second-half 2020, Rystad still sees drilling activity remaining more than 50% below the levels seen at the same time last year.

Further, the firm not only noted the downturn's effect on the drilling market in terms of wells drilled but also the toll it has taken on demand for drilling equipment.

"Both new wells and drilling lengths will be pared down as E&P's scale down investments, affecting the entire supply chain associated with these services," Reza Hassan Kazmi, energy services analyst at Rystad Energy, said in the firm's release. "This includes drilling tools, which will decline by 35% in 2020 compared to 2019."

North America is likely to be the most affected, the firm added noting the region's rig count has already sunk to historic lows.

Looking forward, though, Rystad said onshore markets are expected to recover as early as 2021 and grow at a rate of 7% annually toward 2025. Meanwhile, offshore markets will see some highs and lows and will maintain an overall flattish level toward 2025.

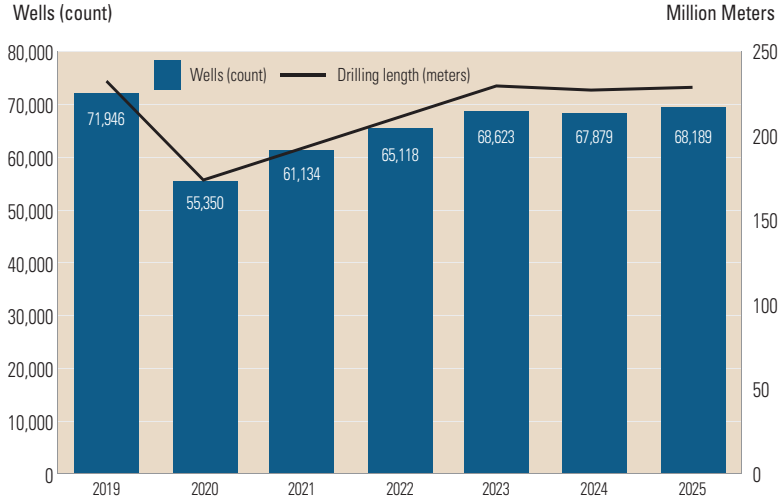
The firm also projects the U.S. to remain a "hotspot" for spending on drilling tools, with more than 80% of spending on shale drilling. The Permian Basin and the Appalachian Basin are expected to drive 60% of total shale spend on drilling tools followed by some conventional activity in other basins, according to the firm.

Offshore, Rystad said Norway is expected to top the list for drilling tools spending with Troll, Balder/Ringhorne and Johan Sverdrup driving the demand.

Rystad added that, despite the overall stagnant growth, Brazil, Australia and China will continue to offer "exciting opportunities" in the short-term with 20% to 40% growth prospects for offshore drilling in these countries. The firm also notes the U.K., Guyana and Mexico "look promising" in the medium- to long-term.

—Emily Patsy

Global Number Of Drilled Wells And Drilling Length Forecast



Source: Rystad Energy Wellcube

Westwood: Oil price 'painful but not terminal' for most

Though the near-term outlook for the oil market remains fickle, with demand being a key factor, analysts forecast the price for Brent crude could rebound to $60/bbl by 2022 to 2023.

That means the journey could be a long one with the price at just above $43/bbl July 17.

Speaking during a webinar on July 16, Keith Myers, president of research for the U.K.-based Westwood Global Energy Group, called the price "painful but not terminal for many companies," considering the price had recovered from historic lows of less than $10/bbl in April.

"The outlook still remains uncertain. In the short term, much depends on demand rebound and more."

A resurgence of COVID-19 cases, which sapped demand in recent months as the world locked down to slow the spread of the virus, threatens to decelerate the pace of the recovery. Some have called for the return of lockdowns, which had eased in parts of the world, and a rollback of reopening measures—specifically in the U.S.—adding uncertainty to demand for fuel and other products.

The U.S. Energy Information Administration (EIA) said it expects Brent crude to average about $41/bbl in second-half 2020, rising to $50/bbl next year and $53 by year-end 2021.

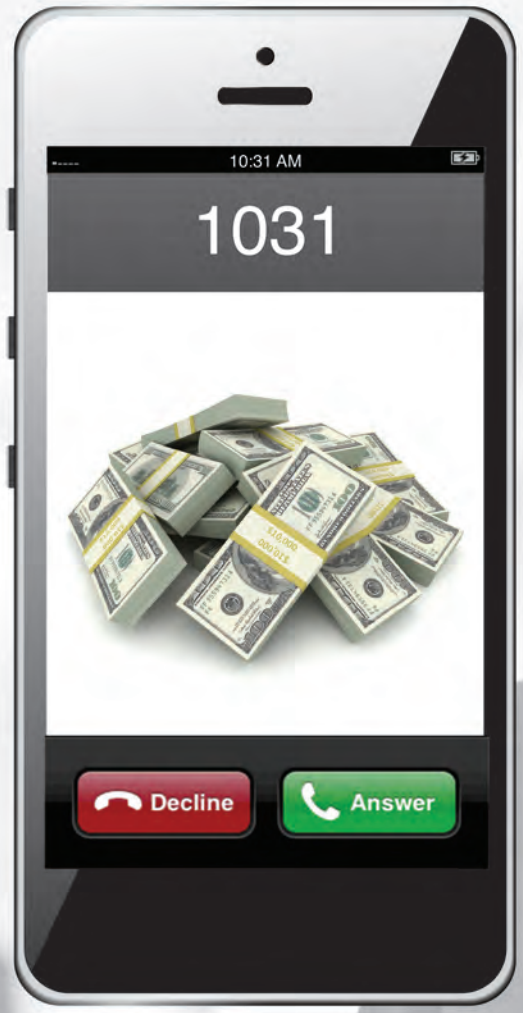
"However, this price path reflects global oil consumption of 96 MMbbl/d during the second half of 2020 along with relatively strict compliance to announced OPEC+ production cuts, both of which are uncertain," the EIA said in its latest short-term energy outlook. "Also, the degree to which the U.S. shale industry responds to the recent relative

VERADO ENERGY

Verado Energy has been expanding operations and creating value since 1986. We continue to increase the value of our properties through a history of successful leasing, acquisitions, drilling, and production techniques.

Come join and partner in the expansion.

www.VeradoEnergy.com



The company to call

BEFORE you sell.

A 1031 exchange or pay the taxes? Before you answer, talk to us. Since 1991 we've helped our energy clients use LKE's to successfully defer capital gains tax on over $35 billion of proceeds on large energy transactions. We've helped them regain control of their wealth. Our team is ready to do the same for you.

You can call on our expertise.

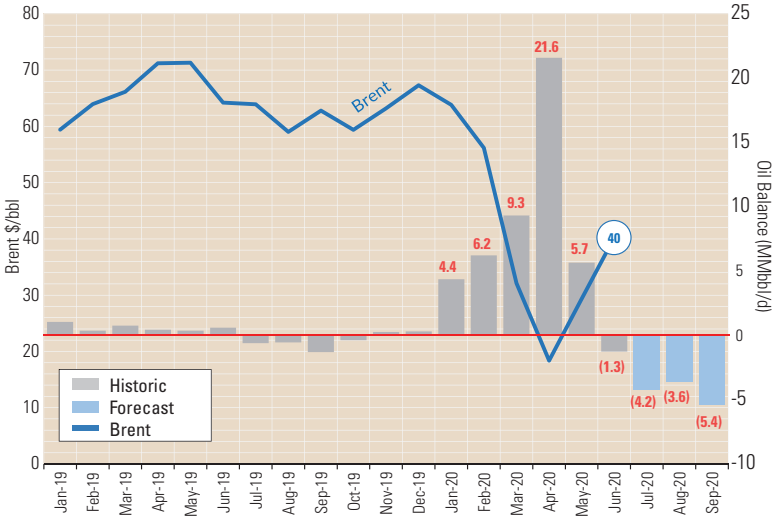
432.682.0292

www.petroleumstrategies.com

PETROLEUM STRATEGIES

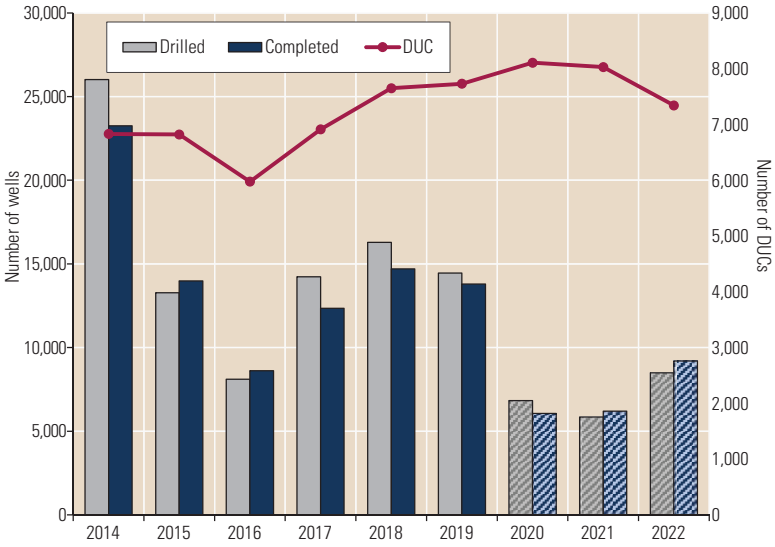
Your 1031 Exchange Partner

Global Oil Supply/Demand Balance



Source: EIA, IEA, OPEC, Reuters

Drilling And Completions Outlook



Excludes conventional basins
Source: Westwood Energent

strength in oil prices compared with their recent lows in April will affect the oil price path in the coming quarters."

Expectations are for WTI to average about $3/bbl less than Brent prices in 2020 and $4/bbl in 2021, reflecting lower U.S. crude oil production and export volumes.

"The oil market has continued its cautious recovery," having experienced unprecedented swings in supply and demand, added Thom Payne, head of offshore for Westwood. The industry had an oversupply of about 22 MMbbl/d in April due to the lockdowns and the dissolution of OPEC+ following the Saudi-Russia breakup, he said.

However, renewed OPEC+ commitments ushered in a new wave of cuts with high compliance rates. Though the 9.7 MMbbl/d of cuts will drop to 7.7 MMbbl/d, Payne noted that serial noncompliers—Iraq and Nigeria—would need to make up for their previous noncompliance, which could push up potential cuts for the next two months to 8.5 MMbbl/d.

This comes as U.S. oil production falls, dropping about 2.1 MMbbl/d since March, Payne said.

In all, "The oversupply for the first half of the year is now estimated at around 7.6 MMbbl/d," Payne continued.

Demand has also recovered some, and demand destruction wasn't as bad as feared. Westwood pointed out that June consumption rose by 10 MMbbl/d, compared to April.

Beliefs are that the market flipped to a net draw undersupply position of about 1.3 MMbbl/d, Payne said, pointing to the erosion of inventories, falling premium storage stocks and a drop in U.S. inventories.

"This undersupply is expected to continue through the balance of the year and average 4.4 MMbbl/d in the third quarter," Payne said. "This is going to be really critical in clearing the 1.2 billion barrels of excess crude that has been produced over the first half of the year, without that significant build position."

Looking ahead, the two burning questions on the supply side, he said, are: Will OPEC+ continue to comply with pledged production cuts, and will U.S. shale increase production to pre-crash levels?

"From 2019 to 2020, we're at least anticipating a 53% decline in the number of wells drilled," Todd Bush, head of onshore for Westwood, said of U.S. unconventionals. That would mark a drop below 10,000, a first since 2016.

"In '21, we're anticipating a slight drop, but then a recovery with WTI as well in 2022," he said.

Completion activity has also fallen below levels seen in 2016, down about 56%, he added. Improvement is expected next year and 2022.

The backlog of drilled-but-uncompleted wells is expected to fall from more than 8,000 in 2021 to 2022 to nearly 7,000 in 2022.

"That's certainly something to keep an eye on as we move into the $40 to $50 range for WTI," Bush said.

As for hard-hit frac crews, which Westwood satellite imagery show plummeted from 133 crews at the beginning of the year to 18 in the Permian Basin, a "rough" second half of the year is expected, according to Bush.

"But we do anticipate activity coming back in the third and fourth quarter of this year from a frac crew perspective," Bush said. "So, while 18 is probably the bottom that we're going to see, we are expecting that to increase probably to about the 30 to 40 range for the Permian."

—Velda Addison

Shale output growth to return, but far short of glory days

U.S. oil production will recover, IHS Markit analysts said in a July 7 webinar, but the post-COVID-19 industry will be forced to abandon its perch as driver of the global market.

Expect a profound change in the business model, as well.

"Our view is that the particular characteristics as of the North American shale-dominated system make this a disaster for U.S. oil and gas production," said Raoul LeBlanc, vice president for North American unconventional oil and gas.

The nature of the shale revolution—lightning-fast growth—also leaves the industry vulnerable to an extremely high base decline rate of about 37%, LeBlanc said. That's about four to five times the typical rate of other basins around the world.

"This is a beast that you can't stop feeding or shouldn't stop feeding or it falls away very, very quickly," he said.

Compounding the challenges for companies in this environment are long-term production forecasts that arrive wrapped in "fragile" stickers. Global economic uncertainty generated by COVID-19 has completely rearranged projections in place at the start of the year, though analysts are confident of one aspect: a significant decline in U.S. output.

Forecasts beginning in 2010 tended to overstate the impact of downcycles, meaning that demand exceeded expectations, said Jim Burkhard, vice president over IHS Markit's crude oil research, and energy and mobility research units. The exception was in 2005, when forecasts from both the International Energy Agency (IEA) and IHS projected demand to outpace what it turned out to be.

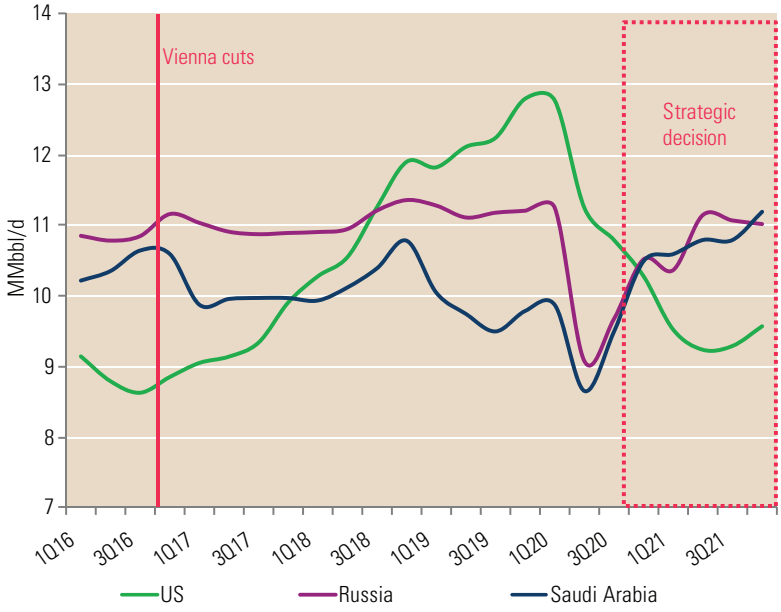
So, it's possible that contemporary forecasts are similarly cautious and global thirst for crude oil will compel suppliers to boost production to meet 2019 expectations of just shy of 115 MMbbl/d by 2030. IHS analysts have their doubts. The degree of uncertainty prevalent today is far greater than in 2008 to 2009, Burkhard said.

IHS expects a return to the 2019 global demand level of 101 MMbbl/d by 2022 in its base case 2020 forecast. Growth will continue after that, but, Burkhard warned, while the upward trajectory will return, the absolute level of oil demand will be lower by 3.5 MMbbl/d to 4 MMbbl/d in the late 2020s.

"That's because we've had lost economic output," he said. "That's not going to come back. There's not going to be more oil consumed in two years' time to offset what was lost this year." How much is lost? Burkhard equated the decline in global oil output to the total economic output of Germany, France and The Netherlands in 2019.

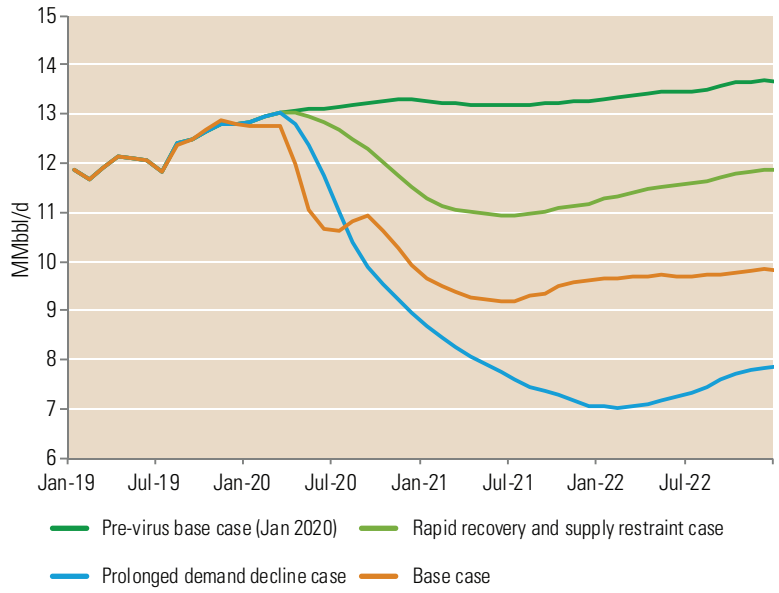
That is the base case, or what IHS terms the "rivalry" scenario case, however, which envisions evolutionary change and intense fuel competition. The "discord" scenario involves economic and political fragmentation and a slow energy transition. In that case, 2019 demand does not return until the mid-2020s. The "autonomy" scenario depicts accelerated change to a low-carbon world. In that case, demand rises to levels of the mid-2010s and then plateaus.

Big Three Production Outlook



Source: IHS Markit

US Crude Production Forecast By Case Scenario



Source: IHS Markit

2911 Turtle Creek Blvd., Suite 900
Dallas, Texas 75219
P: 214.272.2990
IOGCAPITAL.COM

IOG CAPITAL

NOW STREAMING ON-DEMAND

VIRTUAL CONFERENCE

DUG MIDCONTINENT

Respected Speakers and Relevant Content Available On-Demand

Presented by: HARTENERGY

Hosted by: E&P plus, Oil and Gas Investor

The **DUG *Midcontinent* Virtual Conference** is the fastest, easiest and safest way for you to stream relevant market intelligence on this dynamic region directly to your desk – no matter where your desk is today.

FEATURED SPEAKERS:

HAROLD HAMM
Founder & Executive Chairman
Continental Resources Inc.

MARSHALL ADKINS
Managing Director & Head of Energy Investment Banking
Raymond James

WARD POLZIN
CEO
Camino Natural Resources

TOM WARD
Founder & CEO
Mach Resources LLC

TOM PETRIE
Chairman
Petrie Partners

STEVE DIXON
Chairman & CEO
Tapstone Energy LLC

CALVIN CAHILL
President & CEO
Calyx Energy

FEATURED SPONSORS:

Kayne Anderson Energy Funds

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC. WORLDWIDE PETROLEUM CONSULTANTS

THRU TUBING SOLUTIONS

SIGNAL PEAK SILICA

ULTERRA

GR Energy Services

REGISTER TODAY FOR:

- ✔ *19 insightful sessions presented by an all-star roster of experts and executives*
- ✔ *Hours of on-demand content*
- ✔ *Convenient online access from the comfort of your home or office*
- ✔ *COMPLIMENTARY ACCESS courtesy of our sponsors!*

***Start streaming on-demand at* DUGMidcontinent.com**

LeBlanc drew a sharp contrast between this downcycle and the one experienced by the industry in 2015 to 2016. Then, shale producers were able to use a variety of tactics that are not available to them now.

"In 2015 to 2016, we were able to avoid a catastrophic fall in production because the industry was able to borrow, beg or steal or issue equity to the tune of $47 billion in 2015 and another $15 billion in 2016," he said. "Productivity increased from about 17,000 bbl/d for every $1 billion spent to about 49,000 bbl/d for every $1 billion spent over 2015, 2016 and 2017."

But with debt and equity markets for the most part closed, any substantial borrowing is tough to come by. Improvements in efficiencies have eased, too, and these changes mandate fundamental changes in the business model that were on their way before the crash.

"We think there is a reset here," LeBlanc said. "Going forward, we believe that the change in business model will mean that the companies are taking free cash out of the system, spending less than they have in cash flow and giving some of that back to shareholders to please the equity holders and make some returns."

That means that, even when shut-in wells are producing again, the underlying lack of investment due to low cash flows and low activity levels returns and the industry will find itself on a trajectory of slow growth through 2025 due to a harvesting of cash rather than reinvestment, he said.

"All this means, bottom line, that the U.S.—as a force that has been constantly guiding the global market—may change," LeBlanc said. "It may not be willing or able to provide those incremental barrels, and that changes the global pricing dynamic, we think, in the future."

—Joseph Markman

Deloitte: Staying competitive amid oil market uncertainty

As oil and gas companies await normalcy in new forms, agility and flexibility with an ability to grow production capacity to meet long-term demand are key to staying competitive, according to a new midyear industry outlook from Deloitte.

The firm gives oil and gas companies something to consider in the outlook as they navigate market uncertainties and fluctuating demand swayed by the global COVID-19 pandemic.

"In the coming months, they should balance the trade-offs between short-term cost-cutting and long-term investments so they are best positioned for the future," Deloitte said in its outlook released July 13. "Even if energy demand drops in the coming year and the energy mix begins to change, the long-term demand for energy overall will likely continue to grow."

In the next three months, a lower cost structure may be needed but without hindering the ability to scale production later, the firm said. This could come in the form of discharging debt and restructuring, moves several companies have taken in recent weeks.

Delaware Basin pure-play Rosehill Resources Inc. said earlier this month it entered a restructuring support agreement with its lenders and planned to file for Chapter 11 bankruptcy by mid-July. The company would join others on a list of recently declared bankruptcies that include Chesapeake Energy Corp.

Reduced spending could also come in the form of delaying certain projects or remote work such as videoconferencing and automated drilling and production processes, according to the outlook.

What is unlikely is more of the productivity gains previously seen across U.S. shale plays.

Longer lateral lengths and more sand pumped per foot led to production growth in the past, among other techniques, while simplified processes and standardization and technology along with lower service costs helped lower costs.

However, "Oilfield service companies remain financially and operationally stretched," Deloitte said. The insight was delivered as the industry continued to endure one of its worst downturns.

Natural gas markets, which has seen depressed prices, also face continued headwinds with power demand falling, including in Europe, and renewables displacing LNG imports in parts of the world, Deloitte said.

However, "Fuel switching could dictate the recovery" and "Natural gas still has a role to play in providing energy security in a lower-carbon world and can underpin economic growth in many developed and developing economies."

Low oil prices could prove advantageous for companies with gas-weighted portfolios. Deloitte points out that associated gas production could fall by about 10 Bcf/d this year.

"Even as global gas prices are low, operators in the Marcellus and Haynesville shale plays might see their revenues rise, providing an opportunity to consolidate the fractured shale gas industry through targeted M&A," the outlook said.

Market turmoil has not deterred some companies from goals to lessen their carbon intensity. There are still ways to invest in the energy transition, even during today's challenging times, and see benefits, according to Deloitte.

"Many oil and gas companies have been able to lower their operating costs and increase revenues by replacing older equipment, identifying sources of fugitive methane emissions, and boosting energy efficiency," according to the outlook. "In times of tighter margins, the benefits of those programs should increase. … [Larger] companies should consider expanding their research efforts into biofuels, carbon sequestration and power trading and services so that they are better positioned for the economic recovery."

—Velda Addison

E&P bright spots emerge despite little near-term optimism

Flexibility, location and scale are helping some oil and gas companies weather the current storm as the global coronavirus pandemic and economic consequences continue adding uncertainty to ongoing market volatility, energy experts say.

"At the price point that we're at right now, anywhere between $30 to $40 on a full-cycle basis,

there's really not very much that actually works if you take into account all of the costs that go into running assets," Vidisha Prasad, managing director of Adya Partners, said on a Kayo Conference Series webinar July 8. Clients of the energy consulting and financial advisory firm and other companies have been focused on half-cycle point forward economics. "And there are sweet spots in every basin."

Depending on the stage of development, infrastructure needed and required investment, some parts of the Permian Basin, for example, are coming out winners.

"Most of the independent players in the Permian did not shut in very much, which essentially indicates that from a point forward basis, they're making positive margins," Prasad added, "but it shouldn't be a surprise to anybody in the sector that $35 to $40 is really not a sustainable price no matter what basin you're in, and that certainly will have some snowball implications with certain companies."

That's come in the form of bankruptcies, something she said hopes will bring some supply relief and help prices rise.

In the Appalachian region, some operators have benefited from having diverse assets, giving them the ability to switch, for example, from oil to dry gas in the Marcellus Shale, noted Montage Resources Corp.'s Delvina Uka Oelkers.

"Even though the prices were low, it made a lot more economic sense, especially if the infrastructure's already in place," said Oelkers, adviser of operations, planning and technology for Montage. "For Appalachia, that was kind of a neat system to have in place [to] be able to make that swap fast."

In Canada, there are also a few oil sands projects that can generate free cash flow around $40 though growth is "out of the question" if prices stay around that mark or even in the low $50s, said Morgan Kwan, vice president of intelligence for Enverus, which acquired RS Energy Group earlier this year.

"Some of these projects are pretty low cost to just maintain production because it's very similar to a manufacturing plant," she said. "Once you have it built, you just have to keep it running." There is also risk of reservoir damage with steam-assisted gravity drainage wells.

On the gas side, the Canadian story is similar to Appalachia, she added. Operators focused on condensate when gas prices were low and then shifted focus to dry gas when condensate prices slid. "They have that flexibility," Kwan said.

Scale also matters, putting larger companies with larger balance sheets at an advantage, according to Prasad. "The ability to weather deeper storms was always valuable, but it's become even more valuable," she said, comparing valuations of majors like Exxon Mobil Corp. and independents like Pioneer Natural Resources Co. to smaller companies. "There needs to be more and more consolidation."

However, the challenge she sees is that most of the consolidation needs to happen among smaller players and those on the lower end of the quality curve.

"I'm hoping that this sort of very rude second quarter is going to create a little bit more impetus for more mid-caps and small-caps to come together," Prasad said. "I fully expect some large-cap consolidation, but there's only a handful of large-cap buyers," including five majors—two of which have not done a deal yet. "So, we shouldn't be expecting too many $50 billion transactions."

Meanwhile, companies that haven't already done so are eagerly awaiting oil price improvement to bring back shut-in production. And rigs that are already running must be part of lean drilling programs.

"It is imperative that we're doing leaner drilling programs, using better tools, getting the wells done efficiently, effectively and on time and on cost," Oelkers said. "We're not going to have more dead time and sitting around time; that is never the goal," she added. That is highlighted even more now.

In Canada, about 200,000 bbl of oil sands production shut-in since April has come back online. Shut-in production in the Lower 48 is also returning. However, storage remains an issue, given demand has not risen dramatically.

"I don't think there are a lot of economic storage solutions out there for these operators," Kwan said. "In a sense, shutting in production—keeping the oil in the reservoir—is the best storage solution at this point. I think it will remain tight as long as demand hasn't fully recovered."

Though she doesn't expect shut-ins to last much longer, Kwan doesn't foresee a complete recovery given COVID-19 numbers.

On the supply side, OPEC+'s decision to extend production cuts helped; however, "How disciplined they are in those cuts remains to be seen," Kwan said. "And then as U.S. producers start to bring that production back online, I think you'll be in this constant ebb and flow fighting against storage capacity and draws on demand. So, not an optimistic outlook, at least in the near term."

—Velda Addison

Experts offer grim outlook for upstream bankruptcies

As the impact of the COVID-19 pandemic accelerates through all the segments of the shale patch, experts foresee the upstream sector to continue to be hit with an inevitable wave of bankruptcies. Through the first seven months of 2020 alone, 32 U.S. E&P firms have filed for bankruptcy protection, according to Haynes and Boone's Oil Patch Bankruptcy Monitor report, representing some $50 billion in affected debt.

"During the first half of the year, the majority of bankruptcy filings have come from companies that had financial issues and unattractive assets pre-pandemic. … However, during the second half of the year, we are going to see a significant increase in bankruptcies from companies that weren't as challenged last year but are suffering financial distress due to the current market conditions," Brian Williams, partner at investment bank Carl Marks Advisors, told Hart Energy.

Williams added that despite the rebound in oil prices, the next few months could be extremely tough for the energy industry mainly

WINSTON & STRAWN LLP

950+	15	1853
TOTAL ATTORNEYS	OFFICES WORLDWIDE	FOUNDED

WHAT WE DO

**ACQUISITIONS AND DIVESTITURES \\ M&A \\ CAPITAL MARKETS \\ PRIVATE EQUITY \\ ESG \\ OIL & GAS \\ MIDSTREAM \\ OFS WATER MANAGEMENT & INFRASTRUCTURE **

DOUGLAS C. ATNIPP
PARTNER
+1 (713) 651-2688
datnipp@winston.com

MICHAEL J. BLANKENSHIP
PARTNER
+1 (713) 651-2678
mblankenship@winston.com

CHRIS A. FERAZZI
PARTNER
+1 (713) 651-2655
cferazzi@winston.com

ISAAC E. GRIESBAUM
PARTNER
+1 (713) 651-2714
igriesbaum@winston.com

J. ERIC JOHNSON
PARTNER
+1 (713) 651-2647
jejohnson@winston.com

ALEX M. NIEBRUEGGE
PARTNER
+1 (713) 651-2739
aniebruegge@winston.com

JAMES E. VALLEE
PARTNER
+1 (713) 651-2646
jvallee@winston.com

RICHARD L. WYNNE
PARTNER
+1 (713) 651-2656
rwynne@winston.com

YOU HAVE OUR DATA-DRIVEN EVALUATIONS.
YOU HAVE OUR TRACK RECORD.
MOST IMPORTANTLY, YOU HAVE OUR WORD.

LongPoint Minerals has a commitment to finding exceptional opportunities through our proprietary data technology. We not only have a reputation for finding value others miss, we have a deep and trusted record of doing what we say we are going to do. Our word – and our results – are rock solid.

Contact us directly at **303.290.0990** or visit **longpointminerals.com**

LONGPOINT
MINERALS

because investors and lenders are skeptical of capital investment in oil and gas companies due to a historic underperformance during the market downturn.

A recent Reuters analysis outlined that oil and gas lenders have restricted the borrowing abilities for shale producers by 20% so far this spring lending season. Even major companies are seen limping into the second quarter with high debts and default interest payments.

"We're seeing massive amounts of production shut-ins in North America, which is driving bankruptcies," he said. "While many conventional producers like Chesapeake Energy have public stories of bankruptcy, hundreds and hundreds of smaller conventional producers—who don't have millions of dollars of debt and were surviving by drilling a couple of wells a year—are also in a really bad situation."

According to a recent Deloitte report, E&P companies could write down the value of their assets by $300 billion, with significant impairments expected in the second quarter as they struggle to break even in a lower-for-longer oil price environment. The write-offs could have a significant impact on the sector's access to credit, which might force more drillers to file for bankruptcy.

Although each company has its own impairment assessment criteria and follows different accounting methods, Deloitte envisions that impairments in 2020 would be close to 2015 levels.

As Williams pointed out, "Previous oil price declines and cyclical downturns were associated with a couple percentage points and dips in demand or oversupply relative to demand, which took several quarters for companies to work their way out. Today we're dealing with an event where 20% to 30% demand destruction happened nearly overnight."

"It's very different because the North American shale recovery process is completely driven by the global macroeconomic recovery, which seems to be going in the right direction with oil prices recovering to about $40 per barrel, albeit at a flat growth rate. … It will take about a decade to go up to the $50s range," he continued.

2020 Oil And Gas Bankruptcies YTD*

Date	Company/Debtor	Total Debt ($)
E&P		
Jun.	Extraction Oil & Gas Inc.	11,577,502,693
Jun.	Chesapeake Energy Corp.	9,169,000,000
May	Ultra Petroleum Corp.	5,556,148,072
Jul.	California Resources Corp.	5,235,010,656
May	Unit Corp.	4,808,182,228
Apr.	Whiting Petroleum Co.	3,566,815,493
Jul.	Denbury Resources Inc.	2,500,000,000
Jun.	Sable Permian Resources LLC	1,434,296,685
May	Gavilan Resources LLC	1,120,804,265
Jul.	Bruin E&P Partners LLC	1,077,000,000
Jan.	Southland Royalty Co. LLC	625,047,200
Mar.	Sheridan Holding Co. I LLC	618,485,147
Jun.	Lilis Energy Inc.	579,876,334
Jun.	Chisholm Oil and Gas Operating LLC	560,003,485
May	Templar Energy LLC	465,700,000
Jul.	Rosehill Resources Inc.	362,700,000
Apr.	Echo Energy Partners I LLC	91,260,516
Jan.	Bridgemark Corp.	53,663,450
May	Freedom Oil & Gas Inc.	49,629,345
Apr.	Yuma Energy Inc.	43,378,602
Apr.	Sklar Exploration Co. LLC	41,000,988
May	New Emerald Energy LLC	38,244,956
Jul.	Columbus Oil & Gas LLC	25,988,659
Apr.	Buzzards Bench LLC	23,106,196
May	Victerra Energy Holding Co. LLC	18,993,806
Apr.	Amazing Energy LLC	13,489,109
Jul.	Brahman Resource Partners LLC	12,200,000
Apr.	Temblor Petroleum Co. LLC	12,198,912
Jul.	MexTex Operating Co.	7,434,527
Jul.	Summit Gas Resources Inc.	6,239,733
Feb.	Dalf Energy LLC	1,218,273
Jul.	Bullseye Energy LLC	193,743
	Total 2020 E&P YTD	**49,694,813,073**
OFS		
Apr.	Diamond Offshore Drilling Inc.	11,821,584,682
Jan.	McDermott International Inc.	9,923,937,824
Jul.	Noble Corp. Plc	3,946,000,000
Jul.	Calfrac Well Services Ltd.	745,000,000
May	Hormbeck Offshore Services Inc.	668,500,000
Jul.	Hi-Crush Inc.	509,400,000
Jul.	BJ Services LLC	506,800,000
Mar.	Pioneer Energy Services Corp.	488,815,566
Jan.	Kingfisher Stack Oil Pipeline LLC	224,000,113
Jul.	Permian Holdco 1 Inc.	88,000,000
Mar.	Carbo Ceramics Inc.	82,031,346
Mar.	Tri-Point Oil & Gas Production Systems LLC	72,220,546
May	Entrec Corp.	72,000,000
May	BOS Solutions Ltd.	50,000,000
Jul.	Patriot Well Solutions LLC	36,700,000
Jun.	RWDY Inc.	22,304,048
Feb.	Capstone Oilfield Disposal Services LLC	14,158,390
Apr.	Eco-Stim Energy Solutions Inc.	11,308,921
Jul.	Boots Smith Completion Services LLC	9,995,711
Jun.	Vista Proppant and Logistics LLC	7,765,407
Jun.	J&R Valley Oilfield Services Inc.	4,815,236
Jun.	Naphtha Energy Solutions LLC	2,874,233
Feb.	Harvey Ost Oilfield Services LLC	1,453,529
Jun.	Total Oilfield Solutions LLC	1,334,670
May	Elite Infrastructure LLC	311,342
	Total 2020 OFS YTD	**29,311,311,570**
Midstream		
May	Permico Midstream Partners Holdings LLC	225,381,585
Jan.	Kingfisher Midstream LLC	225,200,595
Jan.	Maximum Elite Pipeline LLC	9,845,858
	Total 2020 Midstream YTD	**460,428,040**
	Total 2020 Oil & Gas YTD	**1,250,489,285**

* YTD through July 31, 2020

Source: Haynes and Boone LLP

Williams said it's obvious that E&P activity for the remainder of 2020 will remain slow with no expected increase in the number of active rigs or frac spreads. While analysts are pessimistic about oil price recovery during the second half of the year, the shortage of both cash and access to capital will limit rig recovery over the next few years.

Some in the industry take the level of distress many U.S. producers find themselves in as a sign that a reduction in capex will not be enough to survive the current low oil price environment.

"We expect the restructurings to continue as many smaller E&P companies remain over-leveraged and oil prices are at suboptimal levels," said James West, senior managing director and partner of oil services, equipment and drilling fundamental research at Evercore ISI.

"With economic uncertainty hanging over the industry and oil demand, the industry as a whole needs to be capitalized at lower leverage levels," West continued. "The U.S. shale industry was capitalized at oil prices well above current levels."

—Faiza Rizvi

Exxon Mobil, Chevron adjust in Permian amid market volatility

Near-term market woes caused U.S.-based majors Exxon Mobil Corp. and Chevron Corp. to slow activity in the Permian Basin, dropping rigs and taking other steps to preserve cash flow. However, the two are staying focused on key goals in the top U.S. oil field.

Exxon Mobil is sticking to its plan to grow Permian production to more than 1 Boe/d by 2024, despite second-quarter volatility brought by the global COVID-19 pandemic and oil supplies slowing spend and drilling.

The company, which holds more than 1.6 million acres in the Permian, reported July 31 its Permian production increased 9% during the second quarter, compared to a year ago.

Neil Chapman, senior vice president for Exxon, said 2020 Permian production is expected to be about 345,000 boe/d. That is down only about 15,000 boe/d from the company's March outlook and more than 700,000 boe/d above 2019 output.

"That really reflects the way we are developing the Permian with these large-scale developments and large cube developments," he said. "The capital you invest last year has a material impact on the results this year."

In all, Exxon reported about 330,000 boe/d in total production curtailments during the second quarter, including about 75,000 boe/d at its unconventional assets. Most of the latter was back online in July to what Chapman later described as the same position on the type curve.

"The short-cycle nature of our Permian assets also provides flexibility to pace development, reduce spend and preserve cash in the current environment," Chapman said.

However, low oil prices—which sank into negative territory in April before rising to the $40s—halted some projects.

Exxon pushed out the flowback of its 27-well cube development in the Midland sub-basin to the third quarter. The company also cut its rig count in half to 30 rigs. The rig count is expected to drop again by year-end to between 10 and 15. Chapman called the move a "short-term" one to manage capital.

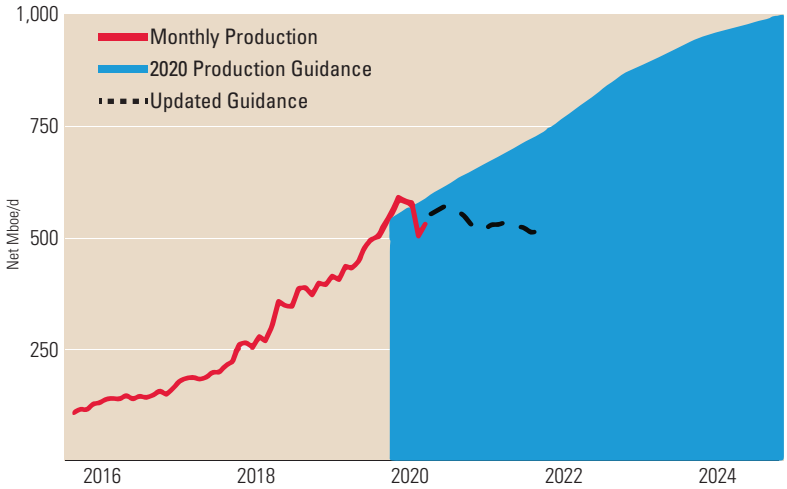
"Our activities for the rest of the year will be focused on Poker Lake [in Eddy County, N.M.] where we will continue to leverage our development scale advantage and utilize the above surface investments that we have pursued in the last 18 months, including Cowboy," Chapman said, referring to the Delaware sub-basin central processing and exporting facilities the company started up in the second quarter.

The facility "enhances our integrated position in the basin through collection and processing of production from our Delaware Basin assets and enables efficient lower cost delivery to Gulf Coast markets," said Stephen Littleton, vice president and secretary for Exxon.

With a position of about 2.2 million net acres in the Permian, Chevron is also focused on growing production in the basin. However, like its peers, the company was also forced to make some tough decisions during the second quarter.

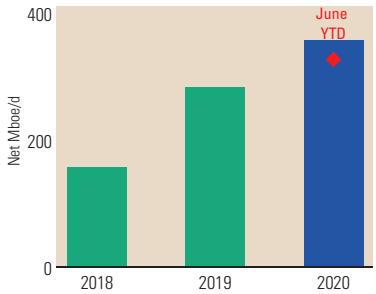
"In the Permian, [we] expect quarterly capital spend in the second half of the year to be about 75% lower than the first quarter," Jay Johnson, executive vice president for Chevron's upstream operations, said on the company's earnings call July 31. "As of July, we've reduced our

Chevron In The Permian



Midland and Delaware Basin production reflects shale and tight production only. Forecast assumes current activity through 2021 and excludes any impact from the Noble Energy acquisition.
Source: Chevron Corp.

Exxon Mobil Permian Production



Source: Exxon Mobil Corp.

Celebrating 20 YEARS

Energy Golf Classic benefitting KidLinks

Monday, October 5, 2020
Gleneagles Country Club • Plano, TX

The KidLinks Energy Golf Classic provides companies with a way to make a difference in little lives everywhere as well as a direct avenue for generating positive community awareness about the independent energy industry. The Energy Golf Classic is also one of the most effective energy-specific networking opportunities of the year.

Join your colleagues at the energy industry's premier event benefitting our most precious resource— KIDS!

REGISTER TODAY!

www.KidLinks.org
817.268.0020

SPECIAL THANKS TO OUR COMMITTED SPONSORS*

NAMING SPONSORS

KIRKLAND & ELLIS

PETRO-HUNT, L.L.C.

URBAN OIL & GAS GROUP

TAILWATER CAPITAL

MIRAMAR HOLDINGS

CHIEF OIL & GAS LLC

TEXAS CAPITAL BANK

SPECIAL EVENT SPONSORS

CAIMAN ENERGY

MEDIA SPONSOR

Oil and Gas Investor

EAGLE SPONSORS

Alliant

ASHER

FOUNDATION ENERGY MANAGEMENT

AE Energy, Inc. | Amegy Bank | Appalachian Mineral Partners LLC | BP Energy Partners | Brazos Midstream
Comstock Resources, Inc. | Crimson Energy Partners IV LLC | Edge Natural Resources | Hamilton & Squibb LLP
Haynes and Boone LLP | IMA, Inc. | Mettle Midstream Partners | Moss Adams LLP | Pegasus Bank | PetroCap LLC
Pinnacle Midstream | Purity Oilfield Services LLC | Silver Hill Energy Capital | Sterling Family Partners LLC | Thompson & Knight Foundation
WAFD Bank | Weil, Gotshal & Manges LLP

KIDLINKS

KidLinks is a 501(c)(3) nonprofit organization that provides healing, hope and happiness for children and families through therapeutic music entertainment and music therapy programs. For more than three decades, impacting more than 385,000 children and caregivers, KidLinks has provided healing experiences for the special needs of children through performing arts and media, funded therapeutic music initiatives, university-level music therapy training and free/low cost treatment programs for children in need. Funds raised directly support the growth of these direct services and the creation of content that can improve the daily experiences of hospitalized and special needs children when they need it most.

For more information on KidLinks, including services or news and events, please visit our website KidLinks.org or follow us on Instagram @Kid_Links.

supporters as of print deadline 08.05.20

operated rig count to four with one completion crew."

Less spending will impact production in the near term along with proved undeveloped reserves. Expectations are for current activity levels in the Permian to fall by 6% to 7% in 2021, he said.

"The near-term production profile for the Permian has changed, but our long-term view of the assets' attractiveness has not," Johnson said. "With our scale efficient factory drilling and royalty advantage, we believe we're well-positioned to maximize returns and deliver value."

Meanwhile, Chevron is striving to become more efficient. Among its goals: doubling the lateral feet drilled per rig and staying free cash positive at today's strip prices.

Neither Exxon nor Chevron gave specifics on 2021 capital spend for the Permian Basin.

"We're in the middle of our planning process," Chevron CFO Pierre Breber said. Details on next year's capex are expected in December. "There is a lot of time between now and then. … It'll depend on what the economic recovery is, what inventory levels (are). A number of factors will determine what our activity level in the Permian will be going forward."

Exxon's Chapman said wells decline rapidly if there is no investment. He also pointed out the substantial number of DUCs.

"You're also aware [that] it's a much higher cost to frac than it is to drill," Chapman said. "That's really important. So just looking at drilling rigs alone doesn't tell you the full story."

He doesn't expect Exxon's Permian volumes to fall next year. Plans will be shared during Exxon's investor day in first-quarter 2021.

Littleton shared sentiments similar as Breber.

"It'll also depend on what the business environment looks like and that's the beauty of the Permian," Littleton added. "We'll be able to flex up or down depending on what we see in terms of the market."

—Velda Addison

Is energy transition ready to kick shale to the curb?

A global economy struggling with the beatdown delivered by the COVID-19 pandemic has a chance to rebuild in a way that greatly accelerates the transition toward cleaner fuels and away from fossil fuels, experts said on a recent online symposium hosted by Reuters.

Whether it will is not a foregone conclusion, however, because the road from policy to practice is paved with contradictions. For example:

- The European Union has been moving toward adoption of renewables and a low-carbon economy for years and German lawmakers recently voted to abolish the use of coal—but not until 2038; and
- China has made a major push toward gas-fired power generation to combat its air pollution problems, but a movement is gaining traction to include construction of hundreds of coal-fired power plants in the country's next five-year plan.

"We are not seeing green, low-carbon programs emerge as the dominant method that policymakers are using in their COVID-19 response," said Jennifer Layke, global director, energy program at the World Resources Institute, a Washington, D.C.-based nonprofit focused on climate change and other issues. "I am a technology optimist, and I remain a believer that the [green energy] solutions … hold much more promise. Unfortunately, the institutional incumbency continues to make those political economy questions really, really challenging."

Stimulus funding is one clear indication. Layke said her organization had identified about $509 billion intended to be spent on high-carbon industries around the world with very few conditions for their use. Low-carbon industries, on the other hand, will likely be granted just $12 billion to $13 billion in funding, she said.

There is also a danger in assuming the U.S. will, or can, adopt the European model.

"I'm a little bit more cautious simply because what's happening in Europe right now is built on the back of momentum from things that have been going on for a decade," Kenneth B. Medlock, senior director of the Center for Energy Studies at Rice University's Baker Institute for Public Policy, told HartEnergy.com. "It's not like they just pivoted to unroll this EU hydrogen plan [to produce 40 GW of power by 2030], for example, that was laid out recently, and think about green stimulus. These are things that were already in play."

The movement toward green power is much more recent in the U.S., but Medlock sees opportunities to advance it through legislative action to support infrastructure development.

"One of the biggest problems with these grand bills is they end up rolling other things in that there's opposition to," he said. For example, when Rep. Alexandria Ocasio-Cortez (D-N.Y.) and Sen. Ed Markey (D-Mass.) rolled out their Green New Deal, its goals reached beyond reducing emissions to include ending poverty, income inequality and racial discrimination.

"Where you might have won some support, you just lost it in certain spaces," Medlock said.

On July 14, former Vice President Joe Biden, the Democratic nominee for president, unveiled his $2 trillion climate plan, one that was developed with input from Ocasio-Cortez and other progressive leaders. While the proposal could provide the government funding that Layke found lacking, it is anything but a sure thing. Passage would likely require Democrats to capture the White House and Senate in November as well as maintain its majority in the House.

Presidential influence is also limited even when a particular party is in control. Declarations at the start of the Trump administration that the "war on coal" was over have not kept coal production for power generation from falling 21% between 2016 and 2019.

Layke noted stimulus programs are not necessarily a good bet because they can be geared toward short-term measures that support a quicker political benefit, like immediate job creation, instead of a long-term strategy. Rather than rely solely on policy action, her organization also targets other economic players, seeking to encourage long-term investment.

Engie, the French utility with a market capitalization of about $30 billion, made the tough call to drop coal as a feedstock in 2015, at a time when it accounted for 10%

of the company's business, Judith Hartmann, the company's deputy CEO and CFO, said during the symposium. Since then, the company's internal doubters have affirmed the strategy, she said. Engie's power plants that are scheduled to be completed in the 2020s are designed to use renewable "green gases" such as biogas or biomethane, instead of fossil fuels.

"I believe that that is our responsibility and I hope other boardrooms are moving that way in terms of taking positions on what it means for the planet because those are related," Hartmann said. "If you don't build solutions for the future then, quite frankly, reality will catch up with you."

The oil and gas sector is in transition, Carbon Trust CEO Tom Delay said during the symposium.

"Whether it's peak demand this year, last year or next year is, frankly, anybody's guess," he said. "I think that transition is now clearly underway. It's being felt by different companies and different aspects of the sector very differently."

Delay's sentiments were similar to those of Parsley Energy CEO Matt Gallagher, who told Financial Times that U.S. crude production has already peaked. Delay does not minimize the challenges facing the energy transition.

"The world that we've built is hard to decarbonize," he said. "It's very sticky. We can make progress, but unbuilding what has already been built is hard. Working with economies where economic growth is still in place, where there's going to be an ambition, post-COVID-19, to build that, that's going to be an incredible opportunity to build differently and build better."

Driving the argument for cleaner fuels will be economics, Delay said. He sees renewables as a major growth market and, ultimately, as a profit center. In the medium term, Delay expects renewables to be a big driver of employment.

In the short term, jobs are driving the transition conversation. Biden's economic plan promises "millions" of jobs in the transition to cleaner energy.

Environmental Entrepreneurs (E2) and E4TheFuture released a report on July 15 estimating that $100 billion in stimulus would create 860,000 jobs and $330 billion in economic activity over five years in the sectors of energy efficiency, renewable energy and grid modernization.

Delay is convinced that energy transition makes a solid business case, if not a particularly sexy one.

"It's often a lot of hard work for a good return and a good sustained return," he said. "An awful lot of organizations want something big and shiny—a new market, a new product—and the alternative being energy efficiency is always hard to sell."

Now is a good time, with economic stimulus funds in abundance, to make that case, Delay believes.

"Where it's hard to get the leverage of the capital markets," he said, "that's where you can really bring in the benefits of longer-term thinking, more patient capital that governments can come up with."

—Joseph Markman

MEDITATIONS ON THE REVOLUTION

Shale operators have plans to restart production, but with OPEC seemingly satisfied with $40 oil prices, U.S. producers are facing the prospect of becoming 'zombie companies,' all dressed up but with nowhere to drill.


CACTUS

ARTICLE BY
DARREN BARBEE

Clay Gaspar, WPX Energy Inc. president and COO, said the company can return free cash flow with prices in the $40s but need to hit $50/bbl to $55/bbl "to get us to a confidence level to essentially restore activity to where we were before."

Call it an act of God, bad timing or an inability to read the room—the shale class of 2020 never knew what hit it, and that was the problem.

First came what pool hall players call "rearranging the furniture," with OPEC's price war making a mad scramble of the balls on the green felt. Then the pandemic, which the French might refer to as a *coup de foudre*—an unexpected event as shattering as a bolt of lightning.

Despite the clear threats posed by OPEC and the pandemic, much of the industry didn't react until oil prices began spiraling out of control.

The calamitous events of the winter and spring had, by March 8, dug a deep hole for U.S. producers. OPEC and Russia may have wielded the shovels as they cranked up production, but the pandemic might as well have been a backhoe.

After years spent pining for a revival—a sort of Great Awakening of oil prices—those hopes evaporated on April 20. That day, WTI crude sank to an almost unfathomable price of -$36.98 and spent the next 27 days below $30/bbl.

Clay Gaspar, president and COO of WPX Energy Inc., said prices have stabilized enough to give the company confidence in what comes next. He said the company is on firm footing after weathering the worst of the oil declines, at least so far.

"I think back to the day that oil traded in the negative range. Maybe that would be the deepest, darkest day. So we have recovered to the point where we're kind of in a low $40s price environment," he said.

Through July, WTI spot prices are averaging $37.19, the lowest average price since 2004, when oil opened the first seven months of the year averaging $37.46/bbl. Last year's nearly $57/bbl, by contrast, seems like a fairy tale.

WPX and its peers initially found themselves in stasis, like a patient in a medically induced coma. As they slowly begin to wake, they saw that shale is unlikely to return to the same width and depth of 2019. Instead, analysts and industry observers say, companies are likely to be winnowed down from the dozens to, ultimately, as few as 10 or 15 independent companies. These surviving companies will control profound inventory, a prudish attitude toward debt and a patient eye for consolidation.

All oil and gas activity depends on price, but current prices and oil futures simply cannot support a case for robust drilling by oily E&Ps. In contrast to the 15% (or more) oil production increases of 2019, flat is the new growth. Many E&Ps are aiming for either stable production or moderate increases well into 2021 and perhaps beyond.

Companies are likely to proceed cautiously, first by reversing their self-imposed production curtailments, then working on DUCs where they've already sunk money.

But adding rigs, for most companies, is still a far off and hazy prospect, like a math problem missing a variable. After a rig count that's gone, year to date, into a 70% uncontrolled descent, most companies need not only higher oil prices but also enough capital to hoist rigs back up.

Demand for oil remains weak. For 2020, the International Energy Agency (IEA) has forecast a 7.9 MMbbl/d-decline in oil demand. Bernstein Research, factoring in additional COVID-19 outbreaks, sees global oil demand contracting by 8.3 MMbbl/d.

Even as inventories appear to have peaked in the second quarter, shale producers are doubtful to return to pre-COVID-19 form in any meaningful way this year and likely not the next either. Rather, a crop of E&Ps seemed to have capitulated by the time they released their second-quarter earnings reports. Companies such as WPX, Pioneer Natural Resources Co., Diamondback Energy Inc., Devon Energy Corp. and Occidental Petroleum Corp. have started to "shift aggressively toward more returns and less growth," Devin McDermott, an analyst with Morgan Stanley, said in an Aug. 5 report.

More pointedly, excess capital will be focused away from reinvesting in the business and instead on paying debt and generous dividends.

"As oil and gas producers report historically weak earnings results, the industry has reached a turning point," McDermott said.

Reactivation fees

As COVID-19 swept the land earlier this year, WPX raced to downshift from what Gaspar calls "third gear to second" and then "first gear to zero."

WPX wasn't immobilized. But it wasn't moving, either. The company went from operating 15 rigs to nine, laying down five in the Permian and one in the Williston took a frac holiday. The remaining rigs kept running because of the company's careful plan of hedging and the strength of its balance sheet.

In the second quarter, the company even showcased its progress on the 58,500 net-acre Delaware position it acquired in February from Felix Energy for $2.5 billion. WPX completions have outperformed Felix completions by 35% in the first 50 days of production. WPX completion expenses were also down a remarkable $280,000 compared to Felix. The company's Permian well costs are also down 35% since 2018.

But like all oil and gas companies, WPX is mortal. The company withdrew capital and production in the face of the pandemic's oil demand destruction. WPX's projected 2020 capex has since been slashed by $640 million, or about 37%.

The company's previously forecast midpoint oil production of 160 Mbbl/d in the second quarter shrank to an actual total of 123.7 Mbbl/d. Weighted second-quarter sales price of $21.85/bbl illustrated the extent of duress in the market.

Now, WPX is proceeding with caution as prices have stabilized around $40/bbl.

At $40 per barrel, WPX estimated in July that it would generate $200 million in free cash flow for the year.

WPX and other independent producers aren't alone in questioning when to return rigs to

Facing page, H&P Rig No. 265 drilling WPX Energy's Shepherd FEE 401H well in Eddy Co., N.M.

the field. But the stark reality facing most oil and gas companies is that they cannot make money in the current environment, said Benjamin Shattuck, Wood Mackenzie's Americas Upstream Oil & Gas research director.

For much of the U.S. shale oil and gas sector, prices in the low $40s are unsustainable for any meaningful activity. "You probably need mid-$50s for the industry to sustain itself," Shattuck said. "Now that doesn't mean that the industry can't weather another 12 or 18 or 24 months, depending on the operator. But in terms of resuming shut-ins, most of the short run costs are covered onshore below about $35, $38 a barrel. And most of it's founded in the mid-$20s, which is why you've never seen shut-ins before, when we're in that $30 range."

WTI spot prices in July approached but never exceeded $42/bbl and, for the month, averaged $40.73. The outlook for next year looks equally grim. In early August, forward price contracts were mired in a $40 to $45 range for WTI. In early August, 2021 oil futures were trading at $43.80/bbl and look to climb to just $0.95 higher in 2022, according to KeyBank National Association.

Shattuck said that oil prices are now above the threshold that companies need to restore curtailed production, but rigs remain out of reach.

"In terms of working off the drilled but uncompleted backlog, you know, it depends on the area, but you're $7 to $15 a barrel lower," he said.

Completing DUCs also becomes possible, although many companies would simply be breaking even at $40.

"The bottom line is the companies are telling us if it's enough or not. Right now, the prices that we're seeing are somewhere around $40," said Elena Nikolova, senior analyst for U.S. Lower 48 supply at Wood Mackenzie. "It's enough to reverse containment, we suspect, and we assume it's enough to start completing some depths. "But in terms of new drilling, you're going to have to see a higher outlook over a sustained period of time."

Gaspar said prices would have to reach $50/bbl to $55/bbl "to get us to a confidence level to essentially restore activity to where we were before."

As the pandemic set in, WPX began to cut back on operations, though "not quite as aggressively as some of our peers," Gaspar said. "So [with] our ability to maintain our production rates and then being able to grow back in at the right time, I think we'll have a couple of steps ahead of many of our peers."

Gaspar said reactivating all of the moving parts of WPX is based on three tiers of decision making, including full cycle drilling that requires the highest level of capital and commitment. The second level is completing wells that have already been drilled.

"You already basically have half of the capital on the ground. It's a sunk cost. And the economics are usually very compelling even at relatively low prices," he said.

The third tier is one that seldom ever comes up: curtailment. WPX slowed down production because commodity prices fell so low

The stark reality facing most oil and gas companies is that they cannot make money to sustain their business at current prices, said Benjamin Shattuck, Wood Mackenzie's Americas Upstream Oil & Gas research director.

WPX completed the acquisition of Felix Energy in March 2020. Production from Felix wells is approximately 70% oil.

© WEST TEXAS AERIALS/COURTESY WPX ENERGY

© JIM BLECHA/COURTESY WPX ENERGY

Above, H&P Rig No. 314 on the WPX Energy CBR drilling pad. Facing page, WPX entered the Delaware Basin through its acquisition of RKI Exploration & Production in 2015.

that even already completed and running wells weren't economic.

"So we cycle through each one of those spaces in very, very short order," he said. "On the front end of March, early April [we were] really trying to figure out, 'Where's this whole thing going to shake out?'" WPX saw storage filling up and began looking at the implications of dropping rigs and completion crews and curtailing existing production.

June appears to have been the worst of the downturn, after which WPX management thought they would "be able to see the other side." Now, the company is unwinding in reverse order, first with curtailments.

"We seem to have some stability at the $40 range. We've checked that first box … [to resume] production that was already drilled and completed," Gaspar said.

The next hurdle was returning completion crews to the field to complete DUCs, which Gaspar said were largely drilled in the past six months. "In a $40 environment, clearly it's the right thing for us to do to get that production back online and start generating that very important cash flow to us."

The company said on its second-quarter earnings call that it is resuming completions and adding frac crews back into operation. However, the rigs that were brushed away remain unlikely to return to the field in the foreseeable future.

"The third box is when do we start adding rigs incrementally to this base plan that we have," Gaspar said. Elsewhere in the company's portfolio, legal matters still hang over the Dakota Access Pipeline, which was a factor, though not the primary one, in reducing rigs in the Williston Basin.

"The challenge, just to be completely honest, with our Williston position is the lack of depth of inventory," Gaspar said. "We have hundreds of wells there, and decades in the other [Felix and legacy] areas. We have literally thousands of well opportunities in the Delaware Basin. And so we need to be thoughtful and disciplined about the cadence of harvesting the remaining assets in the Williston Basin," Gaspar said.

A single rig in the Williston provides the right amount of output and free cash flow to help fund other basins and generate the returns WPX needs to deliver to investors. WPX intends to pick up speed in the Delaware Basin as it returns to a more active phase. The company has now shifted back from "zero to first, to second and then we're waiting on that third gear."

Paradigm shift

In the second quarter, E&P management teams delivered earnings that ranged from painful to appalling. This was understandable, given the whiplash caused by WTI abruptly plunging in April to an average of just $16.55 a barrel. Some company losses were also driven by colossal impairment charges. Across the board, even vaunted, high-quality operators struggled in the second quarter. By the third quarter, many of them were carrying a new playbook.

EOG Resources Inc. reported on Aug. 6 a second-quarter net loss of $909 million, which it attributed to low commodity prices and production volumes partially offset with reduced operating costs. Pioneer, Concho Resources Inc. and WPX all reported losses of at least $400 million.

Other companies were scorched with large-scale impairments, including Occidental, which came out of the quarter $8.4 billion dollars in the red. Likewise, Chevron Corp.'s earnings of $4.3 billion weren't able to overcome $8.3 billion in impairments and a $1.8 billion drop in commodity prices.

But a paradigm shift was evident in some of those companies and others, which said during earnings calls that growth would not

© JIM BLECHA/COURTESY WPX ENERGY

Liberty Oilfield Services on the Boxer 32-22-27 FEE 401H well frac for WPX Energy.

be a driver—or even a front seat passenger—in their businesses.

Morgan Stanley's McDermott noted that Pioneer and Devon both committed to upping shareholder distributions and reinvesting less of their cash flow into operations.

Pioneer president and CEO Scott D. Sheffield managed to deliver $165 million of free cash flow and to generate a total of $600 million for the year. While slashing expenses—including about $1.8 million, or 20%, off wells—the company has reoriented itself, he said.

Sheffield, in the company's second-quarter conference call, said the company will reinvest between 70% and 80% of cash flow into the company while keeping production growth to an annual average of about 5%. While he said the company is "built for 15% growth" in 2019, Pioneer's oil production increased by about 27%.

The company is slowing growth because the primary motivation should be returning capital to investors, he said. To that end, the company intends to adopt a variable shareholder dividend in 2021, payable in 2022. The company will base its capex on strip prices and hold to its 5% growth rate, even if prices rise.

"Even if it gets to $70 or $80, I just don't see us changing our policy," Sheffield said. "We'd have to have such an extreme shortage of crude oil in the world, which I don't see [happening] in the next three to five years."

Other CEOs were on a similar bandwagon during earnings calls: hold production flat and pay down debt or shareholders.

Diamondback said it expects further production declines in the third quarter and will continue to run six rigs for the remainder of the year. At the end of March, the company had dropped 14 of its 20 rigs and curtailed 5% of its production. If oil prices remain low in 2021, the company will maintain a maintenance capital scenario and continue to complete DUCs drilled in 2020.

Production growth has, by default, become almost taboo for companies such as Diamondback.

"Certainly, we're not seeing any signals that growth is needed from Diamondback or from our industry in general," said CEO Travis Stice. "So, growth in today's world is pretty much off the table."

Stice said Diamondback will "lean into" using excess cash flow to maintain its dividend and reduce long-term debt.

Vicki A. Hollub, president and CEO of Occidental, said the company will focus on debt reduction while capex will be designed to keep production flat. "I don't really see us growing next year," she said. "I see us optimizing and following our cash flow priorities, which is really the maintenance first."

Concho chairman and CEO Tim Leach, said July 30 that for most of his three decades in the oil and gas industry, companies would reinvest all their cash flow in operations and then demonstrate success by growing production. "That's how this industry worked for a long time. That's not how it's going to work in the future," he said.

The focus will now shift to the efficiency of oil and gas as a business—driving down costs, returns and how much total cash flow is reinvested into the business. Those measures will be compared against showing continued growth.

"The bottom line is the companies are telling us if it's enough or not. Right now, the prices that we're seeing are somewhere around $40," said Elena Nikolova, senior analyst for U.S. Lower 48 supply at Wood Mackenzie. "It's enough to reverse containment, we suspect, and we assume it's enough to start completing some DUCs."

© JIM BLECHA/COURTESY WPX ENERGY

WPX workers at the Lindsay Compressor Station.

Liberty Oilfield Services completing CBR 41-44, 5 well for WPX Energy.

David Ramsden-Wood, co-founder of OneEnergy Partners LLC and host of the #hottakeoftheday podcast, said Saudi Arabia is eager to keep prices deflated. "OPEC is kind of happy in the $35 to $40 market because they are able to watch drilling in the U.S. slow down dramatically," he said.

"I also mentioned that I thought our industry as a whole needed to be more aware of price signals and what was going on in the market," Leach said. "So as we entered this cycle, no one really thought that U.S. shales could grow as much as they did [or] add as much production, and that threw everything out of balance at a really bad time."

Leach said that as consolidation takes place and producers get their "shops in order," companies will need to pay closer attention to supply and demand fundamentals globally.

"I think what you're talking about is lower growth, bigger cash flow distributions [and] less percentage of your total cash flow reinvested into the business," he said.

Shattuck said that as companies hold production flat next year, "that represents a year-over-year decline. If you get to the end of this year and hold production flat, the new messaging will be promoting production flat is actually year-over-year decline."

Companies with clean balance sheets will have the best chance at surviving the downturn, provided they only spend 70% of cash flow, delever and pay down debt, he said. Smaller companies that quietly make up a large portion of total operations are more likely looking at restructuring in the future.

"For the most part the playbook is written. Some companies that maybe would have been able to weather the same set of circumstances in '16 and '17 even without the additional available capital that they had at that point in time" could have divested assets, Shattuck said. But that market has nearly dried up, leading companies such as Chesapeake Energy Corp. into bankruptcy.

Viva la revolución

Most technological revolutions have naysayers and rivals. Textile machinery in the 19th Century gave birth to vandal-prone Luddites. Early opponents of refrigerators argued they caused cancer and tooth decay. More recently, 5G cellular towers have been targeted by conspiracy theorists/arsonists who see a link between phone service and the coronavirus.

The shale revolution's adversary has long been OPEC.

The future of the oil and gas sector for the foreseeable future will include two relentless tugs on shale producers: the vast oil producing power of Saudi Arabia and the need to consolidate.

"It's not about oil. It's not about gas. It's about the Saudis," said David Ramsden-Wood, cofounder of OneEnergy Partners LLC and host of the #hottakeoftheday podcast.

Saudi Arabia is also eager to keep prices deflated, he said.

"The Saudis in my view want to keep oil at $40 because at $40 every E&P becomes a zombie company," he said. "Shale needs $50 to $60 to be economic full cycle anywhere."

Steve Hendrickson, president of Ralph E. Davis Associates, an affiliate of Opportune LLP, agreed.

"OPEC is kind of happy in the $35 to $40 market because they are able to watch drilling in the U.S. slow down dramatically," he said.

"I am very supportive of industry consolidation, but we're not going to be desperate. We will stand opportunistically like we've done before and look for the right move for us and shareholders."

Clay Gaspar,
WPX Energy

In mid-March, Ramsden-Wood argued during a CNBC interview that companies, then facing $20 WTI prices, should shut down production. He was among a few voices predicting that oil prices would hit $0.

"And then oil went to negative $37, so I admit that I was very wrong. It went way worse than I thought," he said.

Since then prices have recovered, but only to the point where they were when the OPEC-Russia price war began. E&Ps will resume production as a matter of survival.

"To me, there's really no choice, but every company is going to open up their wells because of $40 [WTI]. They need the cash now," he said.

Ramsden-Wood said that only larger, financially stable companies will weather the lower prices.

"If they can keep oil at $40, all of their competitors that are highly levered go out of business and into Chapter 7 [bankruptcy] or merge," he said.

Hendrickson said there's talk of potentially 254 bankruptcy and restructuring filings in the upstream and oilfield services sectors.

"That was a bit of a surprise to us," he said. "But this is a problem that probably pushes it to next year as well. It is consistent with my view: The trouble doesn't all hit at once for every company. Some have greater staying power. [But] 18 months from now, we'll probably continue to see companies basically as" poorly structured as they are now.

If low oil prices persist, Ramsden-Wood said consolidation and bankruptcy becomes more likely. Since March 23, 29 companies have filed for bankruptcy with $49 billion in debts, according to a July 31 report by Haynes and Boone LLP.

"The U.S. industry … drilled as long as it possibly could, as tight as it possibly could," he said. "Capital was going away. And the oil industry was in decline."

Even companies in the Permian will cease operations because "There's no purpose. They're running no rigs, not doing completions. They need to sell." Ramsden-Wood said there will be perhaps 10 E&P companies left in the U.S. at the end of the downturn.

Such views aren't out of line with other observers. Analysts at Tudor, Pickering, Holt & Co. (TPH) have also said the E&P space needs radical consolidation, a topic they raised in an August report following Chevron's buyout of Noble Energy Inc. for $5 billion in stock.

"We've argued that the [E&P] space needs to consolidate down to 10 to 15 high quality names to offer investors the scale and returns the market is seeking," TPH said. "But transactions have been hit or miss as [the] industry has narrowed down transaction metrics toward low- or-no premium MOE [merger of equals] deals with clear cut cost synergies."

In a mid-August filing, Noble said that after running analysis on various commodity price cases through 2029, the company found that Noble would "be unlikely to return to pre-downturn metrics of 1.5 times debt/EBITDA by 2029 even under [a] high case scenario," Wells Fargo analyst Roger D. Read said.

Also referencing the Chevron-Noble transaction, Shattuck argued that attractive opportunities exist in overlapping acreage as well as midstream infrastructure.

"For the big companies that are not overextended, there's a countercyclical opportunity here," he said. He expects larger independents with high credit ratings and low leverage to continue to consolidate.

"Now, there are a lot of challenges to that. It'll be probably more of a slow burn compared to what we saw with the manic 'Permania' M&A a number of years back."

The year 2020 may well be the Valley Forge of the U.S. shale revolution—a stretch in which the battered Continental Army battled cold and defeat to emerge as a true fighting force.

For now Sheffield sees the road ahead still blockaded by OPEC's meddling. Sheffield said that he sees some of his peer companies spending the next two- to three years deleveraging because equity markets are closed.

As oil prices fell into the $20s earlier this year, even Pioneer would have felt the pressure after several months, he said.

"We just can't depend on OPEC long-term," he said. "We've seen OPEC affect our business model for the entire industry worldwide, in 2014, 2015 and this year. It's an issue we're going to have to deal with."

He added that every company will have to run with the assumption of a lower price case and more and more companies will need to hedge.

Gaspar said it's not in WPX's nature to put its head down and ignore the opportunities around the company.

"I am very supportive of industry consolidation, but we're not going to be desperate. We will stand opportunistically like we've done before and look for the right move for us and shareholders."

Gaspar said he's flattered that the company is mentioned as a potential, major pickup by another company. "At the same time, that's clearly not our intention," he said. For now, the next big challenge for the globe and WPX is a return to activity.

But the economy and demand must return first. "I think we can get back into a full cycle environment," Gaspar said. "And as you know, there are a lot of question marks on when that exactly happens." □

Steve Hendrickson, president of Ralph E. Davis Associates, an affiliate of Opportune LLP, said prolonged, hundreds of bankruptcies and restructurings could be on the horizon that will continue into 2021.

WPX Energy employees William Durham and Craig Jarboe perform maintenance at the Lindsay Compressor Station.

DEFINING A SMART ENERGY FUTURE

Geologist Dr. Scott Tinker is on a mission to educate the world on the critical intersection of energy, environment and economics. Can he save the world's energy future by drawing players into the radical middle?

INTERVIEW BY
STEVE TOON

An icon of the modern oil and gas industry, geologist Dr. Scott Tinker is—perhaps unintentionally—rising up to be the global voice of reason in a world that is increasingly divided over the path of longer-term energy solutions. Through his nonprofit venture Switch Energy Alliance (SEA), Tinker is disseminating educational videos that explore the benefits and challenges of all forms of energy without political slant. Always the narrator, his calm voice and measured delivery make you want to trust him.

His first documentary, "Switch," has been viewed by 15 million people worldwide including in colleges, high schools and middle schools in 50 countries. In this film Tinker travels the world exploring the energy resources that sustain economies today, from coal, solar, hydro, biofuels, oil, gas, nuclear and more. In "Switch On," his second documentary, he again travels the world to countries with little to no access to energy, looking at the impact energy resources make on developing countries, even communities. Soon, a video-based, monthlong energy curriculum developed by SEA will begin being taught in high schools.

Just the latest iteration in the evolution of his career, Tinker is best known today as the director of the Bureau of Economic Geology at The University of Texas at Austin, a position he's been in for the past 20 years and ongoing. He is also the state geologist of Texas.

A long-time voice of expertise to the oil and gas sector, it's his nonpartisan, objective video resources featuring the role of energy in global societies that are now reaching the masses, particularly in schools. Tinker spoke to Investor *on why he is on a mission to spread a reasoned conversation about energy to the broader public.*

University of Texas geology professor and Switch Energy Alliance founder Dr. Scott Tinker wants to change the conversation around energy. "We're trying to help everyone to understand that there's not good and bad energy or clean and dirty energy."

Investor After years in the industry and in education, what motivated you to start Switch Energy Alliance?

Tinker At the time there were some other films coming out, so-called documentaries, in which I learned quickly that "documentary" doesn't necessarily mean all truthful. It just means whatever the filmmaker wants to have you believe. Some of those films were really quite misleading about energy. Part of the reason for "Switch" was to do an old school documentary—factual. That was the motivator.

Also, people aren't reading as much anymore. The way to communicate has gone to film to be seen online and on different devices. So part of the "why" for the Switch Energy Alliance was to go to the communication media that people are using now. And that's video of all sorts.

My partner in all things Switch is Harry Lynch, an independent filmmaker. We agreed over a decade ago to be fact-based, objective and nonpartisan and not to pit someone "good" against someone "bad."

Investor What is its mission?

Tinker To inspire an energy educated future.

When I formed the Switch Energy Alliance, we decided to push into film-based energy education at lots of different levels. We've got a museum film we're about to release, and we've got a classroom series called Switch Classroom that's two years in the making. It's going to go into the high schools for AP environmental sciences. Really cool. It is a balanced, objective curriculum on energy that people just don't get any more.

Every time I have educated conversations with young people, which is often, they ask, "Why haven't I heard this? I haven't seen this in my school. This is upsetting to me that I haven't been presented the full picture."

I think we're losing ground on critical thinking, partly because of political correctness. We aren't teaching critical thinking in university settings as much. And there is a push to criticize rigorous dialogue, to be afraid of it, to instead tell us what we need to think. We need to have those hard but civil conversations if real progress is to be made.

That's where my passion lies, looking at it through critical thinking. What are the pros and cons? Look at it from 360 degrees. We're trying to help everyone, young people in particular, to understand that there's not "good and bad" energy or "clean and dirty" energy. They all have their challenges, and they all have their positive impacts.

Investor Your second film, "Switch On," focuses on energy poverty around the world. What is energy poverty, and why is it so important to you?

Tinker It's a lack of access to energy that underpins a modern life. As you see in "Switch On," some indigenous communities are still living the same way they did 500 years ago. I'm not judging that. I'm not saying that's good or bad, but they themselves recognize now that they're being left behind. Young people are leaving their communities, and they don't come back. So the impact of energy poverty is strongly tied to economic poverty. And you see it in the simple things—clothing, education, food, shelter, health—when you don't have much energy.

Everybody thinks of energy, particularly fossil fuel energy and nuclear, as having negative environmental impacts, and solar and wind energy as positive. That's not the case. They all have negative environmental impacts, and they all have positive ones.

Energy is closely tied to the economy. The wealthier the economy, the more it can afford to invest in the environment, in clean up and regulatory and legal. And this isn't just some mythical relationship. Look at where the air is the cleanest: where it's rich. Look at where you can drink the water; where it's rich. Look at where the soils are not polluted: where it's rich.

And the exact opposite is true. I've been in 65 countries, and almost without exception the dirtiest environments in the world are poor. It's not their fault. They don't have money. They don't have an economic system to clean up their environment. And that's all about energy access.

I'm not saying it's solely tied to that; it's not purely correlation/causation. In fact, there's a paradox: energy won't end poverty, but you can't get out of poverty without energy. And that's a very important dilemma, but one that we have to understand. If we don't, then we risk leaving people and regions and countries in severe poverty for a long, long time.

Investor According to your documentary, more than 2 billion people have no or limited access to electricity. How can you make an impact?

Tinker What we're trying to do is through this media to shine a light on these issues and then make that information very accessible broadly in middle schools, high schools, universities, civic groups, museums, scout groups and churches. We're trying to make this energy information accessible with good background and peer reviewed statistics so that everybody can become a little bit more energy educated to inspire an energy educated future. If that happens, then that begins to change the conversation.

I believe political leaders' intentions are good. If they have an energy educated populace, then that populace will begin to require, through the vote and other means, smarter decisions to be made. Our part is getting those good, defendable, peer reviewed, fun and digestible packets of information out in a form that everybody can use to begin to lift their awareness levels around energy.

Investor What is a "smart energy future?"

Tinker It's one that recognizes that energy is a fundamental component of any modern economy and that it requires energy to clean up the environment. So "smart" recognizes that trilogy, the energy-economy-environment waltz. I call that overlap space the radical middle. You have to have all three of those things working together intelligently.

"Energy is closely tied to the economy. The wealthier the economy, the more it can afford to invest in the environment."

"Most of the world does not demonize fossil fuels; quite the opposite."

If you just try to pull out two of the three E's—for instance, tying energy directly to the economy—and forget the environment: disaster. On the other hand, if you tie energy directly to the environment, there is a name for that plan now in the U S.—disaster—because you can't do that without the economy participating.

So the smart energy future is one that looks at data, digests information in all three areas, compromises and then develops intelligent solutions. And those can be done. They're going to vary by state, country and global region because everybody's energy resources are different and everybody's political regime and educational resources are different. There's not one size fits all, if you will, but all three of those E's remain no matter where you are in the world. And so a smarter energy future recognizes that and brings in the economic and the environmental components.

Investor What role do fossil fuels, and specifically oil and gas, play in your vision of a smart energy future?

Tinker They play a huge role. Fossil fuels all-in still represent some 85% of the world's energy mix.

Coal still plays a remarkable role in the global energy future. The United States built its modern electric economy on coal. So did Germany and England. So has China and so is Vietnam and India.

If you put a dot on Bangkok, Thailand, and draw a circle where the diameter crosses through India, parts of China down into Southeast Asia, half of the world's population lives there today, and they get their energy from coal. This is phenomenal to think about. Part of the reason for that is coal makes electricity very cheap. And that part of the world is now manufacturing everything for the world, so we get our stuff from there.

Oil still has a considerable role to play because it's liquid and so dense. Liquids power our vehicles with dense energy. And the only byproduct is CO_2. There's no solid or anything else. You fill it up in three minutes and drive off again for 300 miles. It's very hard to replace that.

We can talk about battery vehicles. We can talk about fuel cell vehicles. Those are really the two other options to transportation, and they each have a role to play, but none of those are going to dominate the vehicle market for many, many decades. And, in fact, none of them really should. Options and choices are good in transportation.

Natural gas has a huge future role to play in the world. Natural gas is very versatile. You use it directly for cooking, you can make electricity with it, you use it to make plastics and other things. Methane, propane, butane, pentane and other forms of natural gas are so critical to the future.

Natural gas is really a hydrogen fuel. Methane is one carbon and four hydrogen molecules, so it's really a hydrogen fuel, at least molecularly. We can split it and get hydrogen from it. And this transition away from carbon into hydrogen has been happening naturally for over a century.

These are all fossil fuels, but they have very different roles to play.

Investor There is a growing, global mantra to replace carbon energy with renewables. How would eliminating fossil fuels affect energy impoverished nations?

Tinker That'd be a disaster, and it's not going to happen. If you add up the populations of the United States and Western Europe, that's 600 million to 700 million, so 10% of the world's population. That's where the loud, anti-fossil fuel voices are. Most of the world does not demonize fossil fuels—quite the opposite. They are actually looking toward fossil fuels as a way to grow themselves out of poverty then into developed nations. They're building their nations on fossil fuels just like we did.

Now, can we accelerate that such that they have more options like we have now? That's smart thinking. How do you accelerate into a portfolio of options rather than being limited only to coal, for example, as some countries are now? We as modern nations can help other nations to accelerate.

There's 7 billion people in the world that are not going to leave 85% of the world's energy in the ground. It's just simply not going to happen. And it shouldn't happen. That would be a disaster for the environment because you will leave people in poverty for much longer, and they would not be able to invest in the environment. It's not hard to link these things up and see, "Oh, right, where is it clean? Where it's developed." So do that without the unintended consequences of environmental destruction.

Investor Why do you think having a conversation about the future of our energy supply is so controversial?

Tinker There's a political component to energy, obviously. It underpins everything and because it does, the politics are, and always will be, real. Conversations that are fact-based

SWITCH ENERGY ALLIANCE

In the film "Switch On," Tinker turns his focus to populations that are energy deficient in search of solutions to access energy. Here, Tinker interviews the project manager of a mega dam being built in Ethiopia that will supply energy to half the country's population and into Egypt.

and candid and civil are powerful, but they also are worrisome to those who want to keep energy as a political tool. This concept of clean and dirty, good and bad, is very powerful. I'm not pointing my finger at the left or the right; they all use energy as a tool. It's just used differently. So that's a big piece of the concern over healthy civil discourse.

Investor How do you address climate change concerns if fossil fuels are needed indefinitely?

Tinker Ironically, perhaps the only country of any size that has met its Paris Accord targets is the United States. Our 2030 targets from Paris were based on 2005. We were going to reduce emissions from the power sector from 2005 to 2030 by 32%. That was our goal. We did that this year, 2020. We did it by replacing coal with natural gas, increasing our renewable energy through state portfolio standards and adding efficiencies.

And—one that is a shell game—by exporting our manufacturing to other countries. They put up our emissions, so that part doesn't really count. Along with all that very affordable product comes atmospheric emissions on a scale that is unprecedented. We might think we're being green by offloading our manufacturing to some other parts of the world, but there's only one atmosphere, so it's not green. It doesn't help the climate.

We've also begun to slowly decommission our nuclear power, which is counter to the goal. But we maintained our nuclear power output by making our plants that were already on more efficient so they produced more. Nuclear has to be a part of this.

If you're going to meet climate targets, you've got to have a mix of natural gas replacing coal, nuclear power—small modular reactors as well as large reactors—renewable energy standards, efficiencies, and then geothermal has a role to play. It hasn't played much yet, but I think we're starting to see a lot of interest in that again, because it's scalable and it has no emissions and the technologies are catching up.

But if you're really going to begin to capture the emissions from combustion of fossil fuels of all kinds, including methane, then you've got to capture and do something with those emissions. Carbon capture, utilization and storage is still decreasing in cost, but we

haven't done it at scale yet. It adds a cost, but the cost is showing itself likely to be worth the benefit in terms of climate impact.

It's a portfolio; there are no magic bullets. It varies by region. But these are very doable and scalable in the timeframe that's needed if the climate models are correct. In 30 years a lot has to happen. It's vital.

Investor Do you believe politicized ideologies are leading to bad or misguided decisions regarding energy solutions?

Tinker Sure. They do it all the time. Without having that rigorous conversation, that critical thinking, you end up with well-intended policies with unintended consequences. There are so many examples of this.

Look at Germany, a very green-thinking populous. They were on a trend of decreasing coal, increasing nuclear, natural gas and wind. And CO_2 was coming down. Then the hydraulic fracturing revolution started and misinformation about fracking and health was rampant. Then Fukushima Daiichi happened in Japan, and legitimate scares about nuclear energy in that setting propagated to the whole nuclear energy industry. So Germany said no fracking, no nuclear.

Then they grew the wind energy industry, so now there are turbines everywhere, including areas that are not so windy. And they started putting in solar. If you look at a solar intensity map of Germany, it looks about like Seattle, Washington—it's rainy and cloudy. Solar and wind are intermittent energy, so you have to back it up with what? They're importing electricity, and they began to bring back coal.

So the CO_2 emissions, which were on a nice decline, flattened. The unintended consequence of a somewhat politicized dialogue on hydraulic fracturing and nuclear power had the opposite effect on the very thing that they were trying to solve for.

So this is California and New York. You can see case after case where a lack of rigorous and honest dialogue causes a public to believe something. They therefore vote in AOC [Rep. Alexandria Ocasio-Cortez, D-NY] and bring you the Green New Deal, which isn't green or new or a deal. But she's very popular in a state that is passionately misinformed. It causes Gov. [Andrew] Cuomo to not approve a $1 billion natural gas pipeline and instead put in a $3

Developing countries still look to fossil fuels—in this case coal—to build their economies. In the documentary "Switch," Tinker visits a Vietnamese coal mining corporation.

SWITCH ENERGY ALLIANCE

billion power line from Canada. These are the unintended consequences of a well-intentioned, but misinformed, energy understanding.

Investor Do you believe we've finally reached peak oil demand?

Tinker It's hard to know. As the economy is turned back on, we truly are learning what we can do remotely now. And it's real. There are things that can be done remotely, and that saves driving to work a couple days a week. We can do meetings online. It saves on a lot of the things we used to spend energy on.

We're going to see that dampen demand, and I think that's going to be a little bit lasting. That's not a bad thing to me as a citizen, as a caretaker of the environment, of someone who wants to preserve and protect our energy resources. That's not a bad thing. The thing that industry has to adjust to is in adjusting business models around that.

But it's not lower demand because of renewables. I don't think that oil and gas are going to be supplanted by other options anytime in the near future.

So you could see if we truly don't move ourselves around as much as we have in the past that will be a demand dampener. And we could have a plateau in oil demand. But, personally, I don't think that's going to happen. I think that developing nations, like we did, are going to want cars. It's a rite of passage for independence. And so you're going to see gasoline vehicles.

China is growing its vehicle manufacturing and sales remarkably; it blew by the U.S. India is just getting started, and they have that many people. If that happens, we have not reached peak oil demand because oil is going to go in those cars. They can't ramp up their electric vehicle fleet fast enough nor will they want to.

We've not seen the peak in natural gas, nothing close [to peak demand.]

We haven't yet seen the impact of solar and wind on the environment at scale. We're starting to see it in a few places. When these wind turbines get buried, the landscape is forever changed. And consider the mining to produce the batteries to back it all up.

Disposal of those batteries is nontrivial. These are giant numbers. At 1.3 billion vehicles in the world, if you electrify half of them by 2040 that's 650 million vehicles. You have to put 3,000- to 7,000 lithium ion batteries in each vehicle, or 3,000- to 7,000 cell phones per car in equivalent batteries. Where's that going to come from? How many mines do we have to open? How many battery manufacturing plants are we going to build? And where are all those toxic batteries going to be disposed?

So this is the environmental impact that we the people haven't processed yet. We're not ready for this. We haven't thought through all this. That's that radical middle.

Investor What might a Biden presidency mean for the oil and gas industry?

Tinker It depends on who he picks for his advisors in the White House and energy secretary. I know what he's signaling now, but part of that is just election politics. That all changes.

"We're not transitioning away from one form of energy to something else. … The transition includes oil, it includes a lot more natural gas, and it includes more renewables, more nuclear and more geothermal. A robust portfolio. What that allows is lifting the world out of energy poverty."

He's not been a particularly remarkable person in the sense of doing anything that would cause drama. He's managed to maintain his career over many, many decades. His roots are somewhere more moderate than others that were running in the party. One might hope that he would come back to those moderate positions as the president. So it might not be all good or bad. There could be some good components of it.

But if he went down the road of what he's promising—zero emissions by 2030 or 2035—I think he will quickly discover, like states and nations and other countries making those promises, that it's unachievable for many reasons.

But we'll see.

Investor What's going to be the subject of your next documentary?

Tinker Our third documentary film we're making now is called "Making The Switch." It's about the energy transition, the combination of economic health and environmental health, minimizing the impacts of energy on the environment and increasing the global economy. It's about the energy transition, but not in a way that is about fossil fuels or renewables. The successful transition is when nobody is living in energy poverty and the impact on the environment is minimalized. That's my vision.

Investor Does the energy transition imply eliminating fossil fuels?

Tinker We're not transitioning away from one form of energy to something else. Even if that happens, that's a century-long process, and it's toward ever more dense energy. In the next 50- to 100 years, the transition includes oil, it includes a lot more natural gas, and it includes more renewables, more nuclear and more geothermal. A robust portfolio. What that allows is lifting the world out of energy poverty. And what your readers need to do to make that happen is to minimize the impact of their form of energy, which is oil and gas. □

Special Viewing

Courtesy of the Switch Energy Alliance, Oil and Gas Investor readers are invited to a unique, on-demand online viewing of both "Switch" and "Switch On."

Be a part of the conversation!

Switch: https://switchon.org/watch/topic/switch

Switch On: https://switchon.org/films/screening/5upGT5wzGK/

THE 'SHADOW' BANKS

As commercial banks cautiously retrench—if not retreat—from energy, others have a growing appetite to provide debt solutions. Some call it rescue capital.

ARTICLE BY
LESLIE HAINES

ILLUSTRATION BY
ROBERT D. AVILA

Get ready. The RBL redetermination season that comes around every fall is fast approaching, but it could be more fraught than usual this year. Many E&P companies find themselves painted into a corner: They are fully drawn, or worse, overdrawn, on their revolving credit lines—just when the value of their reserves (collateral) has declined. Worse, their traditional bankers may not be apt to help, as many have pulled back from the space.

"The COVID-19 pandemic only accelerated what was already a challenged market in 2020. I think a lot of the 'fringy-ier' banks are getting out of energy, but just about everyone is trying to reduce their exposure," said one alternative debt provider. "Some banks find that the risks turned out to be bigger than they thought, and they are trying to consolidate or wind down their portfolio, and some are saying, 'Get me out of energy; I don't care what it takes.'"

What does it take? The natural buyer of a loan would be another bank or an investor with a higher hurdle rate and a long-term view. In any case, big discounts would be needed to attract a buyer.

"Even a healthy credit has to be priced attractively," said Phil Pace, senior advisor on the investment committee for Chambers Energy Capital, a debt provider that is an alternative to commercial banks. The high yield or term loan markets are also in relative disarray and will be more expensive than a reserve-based loan (RBL)—and more expensive than they used to be, he added.

Chambers provides debt structured as first- and second-lien credit, or unsecured debt, net profits interests and mezzanine transactions for small and medium-sized E&Ps.

Risk appetite has gone on a strict diet. Capital sources who were satisfied to be in subordinated debt positions before this crisis now prefer to be at the top of the capital stack or have "first-dollar-risk," said David Morris, managing director of Opportune LLP's restructuring practice in Dallas.

Debt analysis and debt repair has set in across the industry, probably taking up more executive time than figuring out how to solve problems between parent and child wells. The task is enormous. Recently JP Morgan Chase said U.S. banks hold some $650 billion in energy-related loans (only 3.5% of their total book, but still, significant).

In the retreat of the RBL, every other source of capital has been more expensive, and even more so now, said Phil Pace, managing director with Chambers Energy Capital.

Davidson Hall, head of the debt capital markets group at Stephens Inc., noted that while banks can be accommodating to some clients at a high level during the pandemic-induced economic slowdown, energy loans are another matter. "My guess is, banks feel they can be more aggressive with an energy company because some of these companies weren't doing all that well before the pandemic anyway.

"This gives the banks some 'air cover' to be politically correct while they clean up their own balance sheet. Otherwise, if big-balance-sheet banks are splashed across the media that they pushed a third-generation family energy company [into bankruptcy] that would not sit well with anyone on Capitol Hill."

Plan now

What should an E&P company do? It is never too soon to start planning for contingencies and thinking about alternative sources to replace or supplement bank debt, advises Jonathan Harms, director, senior debt, for Opportune. "If your RBL is changed and that just put you into a liquidity crunch, you can still pursue alternative capital sources, but it will likely be more expensive, and it might be too late.

"Starting early is the most prudent thing to do."

It's very important to be thinking ahead, agreed his colleague, Morris.

"One thing we've seen companies do is look for second lien financing, or a structure where junior debt is somewhere between the borrower's credit line and secured with a second lien on the collateral.

"But even junior debt shops are being much more disciplined these days. The days of taking an approach that they are agnostic as to oil or gas, or to play or location, are over," said Morris.

Rise of debt alternatives

Alternative lenders see increased opportunity in the current disarray. One grabbed headlines in July: Oaktree Capital Management LP., the largest distressed securities and credit investor in the world ($125 billion under management), acquired Hancock Whitney Corp.'s $497 million of energy loans, enabling the bank to clear its books of energy.

Oaktree acquired the bank's reserve-based loans (RBL), midstream and nondrilling service credits, for $257.5 million—roughly 50 cents on the dollar. A special provision for credit losses related to the deal of approximately $160.1 million (pre-tax) was included in the bank's second-quarter results.

The universe of opportunities that had scale no longer has the same scale, said Justin Moers, managing director with Munich Re Reserve Risk Financing Inc.

Risk appetite has gone on a strict diet. Capital sources who were satisfied to be in subordinated debt positions before this crisis now prefer to be at the top of the capital stack or have "first-dollar-risk," said David Morris, managing director of Opportune LLP's restructuring practice in Dallas.

"The primary objective of this sale is to continue de-risking our loan portfolio by accelerating the disposition of assets that have been impacted by ongoing issues within the energy industry, and have now been further complicated by COVID-19," said John M. Hairston, the bank's president and CEO, in a statement.

Another indicator of how much the financing environment has changed: A recent survey of E&P companies by Haynes & Boone law firm indicated that they expect to get 28% of their capital from cash flow and 20% from debt alternatives. Tellingly, bank debt was ranked third, at only 17%.

An example (although not in the energy space) shared by Stephens' managing director Keith Behrens emphasizes how much debt markets have changed: "It's really important to bring new sources to the energy market, because you can't go to the 10 guys you used to and get five term sheets anymore.

"We went to 210 capital providers for one deal and received only 20 term sheets, and ultimately, we let 10 into the next round. As soon as we did that, two of the 10 immediately

> Pre-pandemic energy credit problems give banks "air cover" to take stricter measures now, said Davidson Hall with Stephens Inc.

passed. They want to look like they are in business when actually, they are not. In a normal environment, I wouldn't have gone to 210 providers; I'd probably have gone to 30."

In unitranche deals, historically, providers advanced 80% to 100% of the PV-10 reserve value, but that's come down today to maybe 60% against PDP value, Behrens said. Credit for backing acquisitions is tough: While an E&P might be able to buy assets cheaply, unitranche lenders have also come down in the amount of PDP they'll loan against, he said.

A borrower looking for capital these days faces so much uncertainty. Companies find they can't necessarily rely on their existing bank relationships—but getting capital from a new lender is limited too.

"We got a call from an operator with no debt and a PDP reserve base with attractive upside, but he could not get a call back from any bank," said Justin Moers, of Munich Re Reserve Risk Financing Inc. "That really tells you the market is closed." Munich Re provides debt capital in a range of $75- to $250 million.

As one banker told *Investor*, "I have to reserve my capital to help my existing portfolio of energy companies. It's better to do a deal with the devil you know than the devil you don't."

Hedge fund investors that now want to invest in energy debt will charge a higher interest rate than traditional bank lenders, but "Once you put it to bed, it goes to bed and doesn't have to get reviewed twice a year," noted Ann Rhoads, a career energy banker who now advises Odinbrook Global Advisors, which advises companies in need of restructuring that may be too small for the likes of some of the bigger restructuring advisory names such as Lazard Partners, Alix Partners or Alvarez & Marsal. Odinbrook was formed in 2014 by Steven Strom, formerly a top restructuring advisor with Jefferies, Blackhill Partners and other firms.

"I do think some of these competitive alternative investment funds are probably more

Recent Alternative Debt Deals

Provider	Client	Amount ($MM)	Terms
Munich Re	Diversified Gas & Oil Plc	$160	Acquisition financing: Sr. secured, amortizing, 10-yr note., 6.5% coupon
Arena Investors	White Oak Energy	$26.3	3-yr. 1st lien, Sr. secured term loan to refi RBL & drill PUDs
Angelo Gordon	Abraxas Petroleum Co.		Refi of 1st & 2nd lien notes with PIK on 2nd note
Production Lending LLC	Moriah Energy Investments	$10	To drill Midland Basin PUDs (MEI Camp Springs LLC)

Source: Oil and Gas Investor, company reports

Debt Options

Source	Rates	Terms	Funding Time Frame
Bank	6-10%	3-7 years	14-30 days
Line of credit	5-15%	3-7 years	10-30 days
Alternative debt	6-25%	1-5 years	5-7 days
Cash advance	1.16-1.5%	3-24 months	1-3 days

conservative than they were two years ago. Nobody is going to do more than they have to do right now," she said.

Chasing illiquidity

The various alternative debt structures available typically fall between a traditional RBL from a bank and private equity or a mezzanine deal. They feature customized terms and often can be closed faster than a bank agreement. Like banks, they require a meaningful amount of flowing PDP (proved developed reserves that throw off cash flow), but "nonbank banks" can stretch more, assigning a bit more value.

A senior unitranche structure seems to be a preferred replacement for an RBL. It separates the collateral from the estate of the borrower, and it puts the lender in a senior first-lien position. The coupon is higher than for an RBL.

Despite various structures or options that are available, underwriting is now difficult because no one really knows when the energy business will return to normal, or what normal will look like.

"While times look tough right now and the industry is constrained, there is capital available, but the terms will not look like they did during the heyday of the shales," said Moers.

The run for the exits is creating a need for new capital sources, and fortunately, many of the alternative debt providers see growing opportunities to invest in oil and gas today, as market dynamics have been pushed and pulled by oil price volatility and demand uncertainty. They might buy bank debt, stock options or royalties; provide a volumetric production payment (VPP), or provide debtor-in-possession financing during a bankruptcy workout; or exit financing after a company exits bankruptcy. In a larger bankruptcy filing especially, there are a lot of moving pieces and distortions of value that create new opportunities to buy or sell.

"As banks move up their reserve levels, you'll see more banks exit this area," said Dan Zwirn, CEO of Arena Investors LP, a credit-focused investing group with about $1.5 billion under management. The company calls itself "a chaser of global illiquidity." It has acted as lead investor and structuring agent on nearly 20 deals in the last four years to June 30. It employs first and second-lien structures on producing assets, and provides VPPs, minerals financing and joint venture equity.

For Arena, investing in oil and gas is a great opportunity, just as long as hedging by the E&P borrower is part of the deal. It acts as a facilitator for companies that have the ability to move their PUD inventory to the PDP column (undeveloped reserves to proved, producing),

"If a bank says, 'We're just not underwriting another nickel,' the E&P still needs capital. Those assets don't come up out of the ground by themselves," said Dan Zwirn, CEO, Arena Investments.

Earlier this year Cibolo Energy Partners was cautious, but it thinks it's important to invest during the trough, so it's looking for deals, said partner J.W. Sikora.

and a borrowing base that is no more than 10% allocated to PUDs, Zwirn said.

Typical deal size ranges from $10 million to $50 million. Arena has also provided debtor-in-possession financing so that companies in bankruptcy, or even just prior to filing, have enough capital to keep employees operating the assets. "If a bank says, 'We're just not under-

While times look tough now there is capital available, but the terms will be different, said Chad Mabry, vice president, Munich Re Reserve Risk Financing Inc.

writing another nickel,' the E&P still needs capital. These assets don't get up out of the ground by themselves. So, we're kind of a 'Swiss Army knife' of solutions," Zwirn told Investor.

Now that the so-called shale gale is past and the accompanying financing frenzy has calmed down, the people with capital and the people who need it are reflecting on what went wrong, what went right, and the way forward.

"I'd argue that when everything is rosy, banks tend to over-advance [on reserve values] and when commodity prices drop they tend to under-advance, and with draconian terms," Zwirn said. "So, I think banks tend to do the wrong thing in each direction."

Arena's principals have entered, left and re-entered the energy space when and if the numbers dictated. In the 1990s when oil plunged below $20/bbl, Arena started investing, and in the early 2000s, it began looking again at buying energy loans from firms like Shell Capital, Duke Energy and Enron as the latter "nonbanks" exited.

At one time, Zwirn helped create and finance Petrobridge Investment Management LLC to provide debt capital, but by the late 2000s, commercial banks were returning to the energy space in a more aggressive way than ever before, as everyone rushed to join the shale revolution. By then, deal terms were becoming too frothy, and the numbers no longer worked, Zwirn said.

Indeed, repairing capital dislocation is an all-consuming chore. "There was way too much leverage in the shale boom," Zwirn said. "The leveraged finance world went to lending on P1 and P2, and it created a false sense of security. People were not making the distinction between PDP and PDNP reserves."

Today, "an E&P private-equity apocalypse" has set in (as Zwirn told Institution Investor magazine in April), and public financing and banks are redlining the industry. "These factors add up to a pretty interesting investment opportunity. There's a lot to be done out there… to step in and finance solid operators who have a view on prices or an ability to move reserves up to PDP," he said.

A case study

Zwirn cited a recent deal without naming names. A conventional bank group had financed a well-known, private-equity-backed company that was pursuing conventional assets. The bank line was $250 million. But then recently, the banks had to write off nearly 90% of that loan (although one member of the bank syndicate thought that there was still something worthwhile there, in spite of the write-down).

The remaining syndicate member rolled that debt into new equity, and Arena advanced 60 cents on the PV-10 dollar of the proved developed producing reserves, and it also took some penny warrants. In addition, Arena required the borrower to contract with a well-known hedger to buy forward for three years a portion of the E&P's production.

"We've focused on conventional, vertical production, with long-lived reserves that are operated. We might do a shale deal, but it will cost you," Zwirn said. Of about 25 transactions we've done in the last three years, we've been involved in only one shale deal."

Actively seeking deals

Cibolo Energy Partners LLC is actively seeking to deploy debt capital from its latest $260-million fund, which dates from 2018, and from which about half the capital remains, according to J.W. Sikora, managing partner

Comparing Debt

Bank RBL (Senior)	Mezzanine (Junior)	Munich Re (Unitranche)
Full recourse loan, Revolving credit	Full-recourse loan, Typically not amortizing	Limit recourse to collateral in SPV, Fully amortizing
Floating-rate debt	Floating-rate debt, often with equity kicker	Fixed-rate debt
Tenor of 3-5 years	Tenor of 3-5 years	Tenor up to 10 years
Availability per borrowing base	Typically single draw	Typically single draw
1st lien on all assets	2nd lien on all assets	1st. lien on all SPV assets
Price hedging may or may not be required	Hedging not required	Hedging required

Source: Munich Re

and co-founder. With co-investments and 22 limited partners, some $400 million was raised altogether, so the Houston company now has about $150 million in dry powder left.

The company prefers first-lien, senior secured, unitranche deals in the range of $20- to $80 million, with $20- to $30 million being the sweet spot.

These are backed-stopped by producing assets and conventional opportunities. It prefers to be the sole lender in each case, so there is no bank debt ahead of Cibolo and no second-lien debt behind it.

"For new deals, we haven't deployed any new capital, but we've deployed capital into our existing companies. On new deals, it's been a whole lotta lookin'," Sikora said. "We'd like to add one or two more companies this year and two or three next year."

Cibolo has five portfolio companies at present, and they are hedged. During the downturn some of their production was shut in, and none of their rigs has been stood up yet. In another sign of caution, the lender's covenant terms say that, in most cases, there are limits on how much vendor debt a borrower is allowed to have.

Like other sources we spoke to, Sikora wonders how and when private-equity players will re-emerge from their lockdowns to either buy assets or advance capital to E&Ps. Meanwhile, Cibolo and its existing portfolio companies are not focused on growth.

"I say, let's keep production flat, let's build liquidity, where can we 'manufacture' cash by reducing costs? Let's find rock we like, and then wait until we can get a 25% return. You don't want to stick a drill bit in the ground at $40 oil."

Other deals

In May Munich Re closed its second acquisition financing for Diversified Gas & Oil Plc, an active Appalachian consolidator. The first deal was done in November, but this time, everything was done remotely for the second term loan Munich Re has provided to the company. In aggregate it now has $360 million invested in DGO.

This was a 10-year amortizing, senior secured loan backed by working interests, with a 6.5% coupon. Those interests were placed in a special purpose vehicle (SPV) that was nonrecourse to the company. "The SPV becomes the borrower," explained Chad Mabry, vice president, Munich Re, and "This is a fixed coupon that doesn't float with LIBOR or other metrics."

> "You can't go to the 10 guys you used to and get five term sheets anymore."
>
> Keith Behrens, Stephens Inc.

Munich Re provides first-lien debt and some second lien, but only if the credit metrics are consistent with a first-lien borrowing transaction. Capital can be for an acquisition, general corporate purposes or a recap. Preferred deal size is $75 million to $250 million.

"We're seeing a lot of things that need some kind of restructuring or recapitalization, but the equity value is so depleted that there's not much we can do, because the oil price decline has affected reserve values," said Moers. "We still promote the same structures, but the universe of assets or opportunities that were of scale no longer have the same scale—and, the G&A drag is increasingly a problem."

E&P companies have to decide if they want to step into a term loan with a provider like Munich Re, with a term of five to seven, even 10 years, that comes with a higher coupon, or, stick with an RBL that has more restrictive covenants and has to be reviewed twice a year, said his partner, Mabry. In either case, interest rates are likely higher now than they were last year.

CSG Investments Inc. also lends in a structure between the RBL and private equity, in customized, senior secured loan and mezzanine debt. It provided a $65 million term loan to BJ Services and $100 million to Keane Group Holdings, for example. It participated in the $4 billion bridge loan made to Chesapeake Energy Corp. prior to its bankruptcy filing and in the $750 million loan to Chaparral Energy Inc. as well. It did so by buying certain amounts from the underwriters of these deals.

In the end, companies that face a large decrease in their RBL this fall have a good sense of that already, and what's more, they are already on the radar screens of the alternative debt providers, according to Jonathan Harms with Opportune. If they are overdrawn past their PDP or PV-10 value, that spells trouble in this environment. The time to act is now. □

Munich Re provides alternative debt financing to help fund your growth.

Learn more at www.munichre.com/mrrf/en

Justin Moers - (281) 203-5944 • Chad Mabry - (832) 592-0085

NOT IF, BUT HOW

Munich RE®

HORIZONTAL EASTERN SHELF

A conventional, stratigraphic trap in Scurry County on the Permian Basin's Eastern Shelf doesn't cover hundreds of thousands of acres like shale plays. But the wells are just as good. And, for private wildcatters, they're particularly great.

ARTICLE BY
NISSA DARBONNE

Just looking at it, this horizontal, fracked Strawn play wasn't supposed to work, but it does and "here we are," said Tyler Harris, CFO, Moriah Energy Investments LLC.

When Thunder Valley 2-1H was completed in Scurry County, Texas, on the Permian Basin's Eastern Shelf in September of 2016, there were five rigs drilling in the county, according to Enverus data.

That was up from one just a few months earlier and down from 28 in the summer of 2014.

With an intriguing new conventional, horizontal play demonstrated by Thunder's operator, Three Span Oil & Gas Inc., the count grew—totaling 10 this past winter. The count fell again to just one in July, but producers with leasehold for this hot spot of prolific Strawn section are planning to get back to work.

Conventional, vertical production in Scurry County began in the late 1930s from shallow wells, contributing 303,000 bbl of oil in 1944 to the war effort, according to the Texas State Historical Association (TSHA).

The deeper Canyon Reef, sitting on top of Strawn, was tapped in 1948, and county production grew to 94 MMbbl in 1974. By 1991, Scurry had made a cumulative 1.8 Bbbl of oil, according to the TSHA.

Recent E&P acquisitions on the Eastern Shelf indicate new interest in the area. Apache Corp. sold its Scurry and neighboring holding in the area earlier this year to a privately held firm. Additional details were not disclosed.

In early 2019, Mid-Con Energy Partners LP sold most of its Eastern Shelf property for $60 million to Scout Energy Group IV LP in counties north, east and south of Scurry.

There are about as many operators in Scurry today as the county's population per square mile.

To the maps

Among them, Midland-based Moriah Energy Investments LLC is part of the family office of father and son wildcatters Dale and Cary Brown. The latter left Legacy Reserves Inc. in 2015, and the family office got back into oil and gas.

On the Eastern Shelf these days, Moriah is drilling a single bench, the Strawn, born in the Desmoinesian stage of the Pennsylvanian period and sitting at between 6,000 and 7,500 ft.

"Geologically, it gets a little bit more complicated than that, but it is Strawn-aged, more specifically [Middle Desmoinesian] Odom Sand," said Tyler Harris, Moriah CFO.

"It's a fairly small play that's largely held by family offices. But it's fairly well delineated at this point, so we're now mostly focused on retaining leasehold and drilling it out."

Vertical Strawn production elsewhere was from conventional-porosity, coarser-grain sands in the second half of the past century. In Moriah's area, the sand is finer, thus the reservoir is tighter.

"People had tried to develop it conventionally, unsuccessfully," Harris said. "But, with the advent of horizontal drilling and frac technology, we made those tighter parts of the reservoir accessible and economic."

Moriah and other operators have landed 30 wells so far in the play; among them, Moriah has three, all of them 1-mile laterals. It had one DUC in mid-summer that it planned to complete this month.

"We haven't gotten to the stage where we are in a continuous development program," Harris said. The company is evaluating each well and learning more before it resumes drilling.

Moriah's portfolio on the Shelf includes some legacy horizontals and verticals. But "We took brand new leases for much of this," Harris said.

In 2015, another operator, privately held, Dallas-based King Operating Corp., tried horizontal technology in Strawn in a vertical well in Scurry County and found it to be prolific.

King followed that initial test with a second well. In 18 months, beginning in the summer of 2015, it closed three Scurry County Drilling Fund LPs, raising a total of $37 million to test Strawn as well as black Penn Shale.

"We leased what we thought was geologically similar to those [King] wells," Harris said.

Moriah's leasehold is 6,000 net acres with all but about 120 of them Moriah-operated, "and we're still adding a little bit here and there,"

Harris said, "increasing what's within our existing blocks.

"This is a stratigraphic play instead of having a blanket of several 100,000 acres out there. Depending on who you talk to, there are 30,000 to 50,000 acres that are going to be prospective in this area.

"So nobody's amassed a massive acreage block. That's lent itself to the family offices that are the developers out here. Everyone's kind of working from their own balance sheets as they're drilling these wells."

Moriah's 6,000 net acres—in Scurry and Fisher counties—aren't HBP yet except for the three wells it's drilled and completed so far. Two of the horizontals were completed in what's known as the Camp Springs Field with a $10 million loan last year from Production Lending LLC.

From well results Moriah has seen to date, "We think, on a one-mile lateral, you're going to get somewhere between 400,000 and 500,000 bbl of oil," Harris said.

Drilling and completion costs (D&C) were $5.5 million a well; Moriah estimates the cost today would be between $4.5 million and $5 million.

The first one, Tigger 1H, is public data now; its cumulative production is more than 150,000 bbl of oil.

"Your 24-hour max rate on these gets to be about 650 to 700 [bbl/d]. We've certainly seen rates north of that recently. But we think 650 to 700 is a somewhat predictable rate."

The 30-day average is about 600 bbl/d on Moriah's three wells to date.

From the results of the two play-opening wells by King, "We knew that there was something here that was going to work," Harris said.

Otherwise, it seemed unlikely. "When we were looking at it over and over, our geologist just kept saying, 'If you didn't have those two wells' results, I'd never drill this. There's nothing about this on a log that looks to me like it ought to be productive.'"

Among reasons: "The water cut would be too high. The pressure doesn't seem to be there."

The reservoir is normally pressured, and the operators in the play report a water cut of a third to more than 80%.

There were many reasons one wouldn't go after it, Harris said, "but here we are."

Enter and watch

Moriah picked up its entry leasehold in 2017 and waited, watching others drill 15 wells and trucks hauling oil from tanks on a consistent basis, suggesting the volume as well as that the wells weren't depleting.

"We sat on those acres for about as long as we thought we could," Harris said.

Moriah picked up a rig in late 2018. "By the time we put the drillbit in the ground, we didn't need to have a tremendous amount of faith that this was going to be productive.

"Maybe it wasn't 'proven,' but it was certainly in that 'probable' range."

Getting a frac spread and some other special services out to the Shelf had been challenging when the greatest demand for services was in the Delaware and Midland basins.

But getting a rig to the Shelf wasn't too difficult, he said. "We've really always been able to find somebody wanting to do it," Harris said.

This is due, in part, because the rig specs that are needed aren't as demanding as those needed for multipad development.

"The rigs [we use] really weren't designed to walk and be super-efficient in a way that a Pioneer [Natural Resources Co.] would need them to be," Harris said. "We really were a

VERADO ENERGY INC.

A Verado Energy Inc. lease sign designates a company location with a frac pond.

Double K Drilling LLC's Rig 8 drills Verado Energy Inc.'s Alpha 1H well on the Eastern Shelf.

VERADO ENERGY INC.

Verado Energy Inc.'s first well in this new play "came out spectacular. So we started to feel really good about it," said Christopher Graham, Verado president and CEO.

home for some of the rigs that couldn't compete for that work."

Completions are no different than in the Delaware and Midland basins, though. So "You were trying to find somebody who is moving a completion crew from one job to the next and happened to have a 20-day window."

With the Shelf play's target being at a shallower depth, Moriah's wells are economic at $40 oil with D&C at $4.5 million.

Adding oil

Also privately held, Verado Energy Inc. has been working on its horizontal program for the sandy Strawn beginning in 2015.

Allen, Texas-based Verado's history dates to 1968 in East Texas, and it currently operates about 150 wells there in 15,000 net acres and has an interest as well in 500 nonoperated wells.

"We've gotten pretty good at identifying areas that have potential for increased production and improved performance through horizontal development," said Christopher Graham, Verado president and CEO.

Graham joined the E&P in 2013, and it began looking to add property outside East Texas and at adding more oil to its 97%-natgas portfolio.

In Scurry County in the vertical Hermleigh East Field, it looked at logs on old wells. No horizontals had been drilled there yet.

"We thought the acreage had some promise for horizontals in the sandy, limey section of the Strawn," Graham said.

Verado drilled its first well, Dessie 91-1H, in 2015 and with a half-length horizontal test. "It came out spectacular. So we started to feel really good about it."

It landed two more wells—both of them full-mile laterals. "And they came in really great."

So it added leasehold. It operates about 4,000 net acres, mostly HBP, on the Shelf now and has 12 horizontals in its bag. It's looking at landing some laterals of more than a mile.

Water cut is about 70%. "Some people might say that's a pretty high water cut. But it's quite a bit of oil that we're getting out of it—about 500 [barrels per day]," Graham said.

"So I don't mind. I don't mind it at all."

The 1-mile laterals, D&C'ed, cost about $4.5 million now. As Verado typically drills a few wells at a time, it's been able to schedule back-to-back completions.

Except for one time when it had to wait, "We haven't had too much trouble getting them out to work with us," Graham said.

It has no DUCs. In 2019, it had paused drilling while watching earlier well results just to see, long-term, how the production would hold up and compare it to different areas.

The pause was fortunate as it was getting pre-March 2020 prices for its production and not paying pre-March 2020 service prices. "When we were ready to pick it up again in late 2019 and early 2020, [oil] prices had started to come down.

"So we intentionally held off [further] at that point. We were fortunate enough to have our pause while prices were still relatively high and all of our wells completed and online."

It shut in production for about two months this spring and had the wells turned back on by June 1.

Fracture length

Because Verado is inducing fractures in a conventional reservoir, it's especially mindful of well placement, as fracture lengths extend farther in less-tight rock than in tight rock.

"So how close do you want to space? I don't think the jury is completely out on that yet," Graham said.

"It takes some time to pull all the production together and see what the impact is on offset wells. But it's one of the things we're definitely studying."

For one-section laterals, Verado's proppant loading is about 1,200 lb/ft; pressure is with 30 bbl of water per foot.

"You don't need to frac these like a shale," Graham said. "The permeability is greater in the Strawn. It just doesn't need as many pounds per foot to stimulate it and get the kind of rates you'd like to get."

Remaining in debate, though, is whether to put a shale-size stimulation on one well and have the one well drain more area for less total D&C cost than that of multiple wells.

"Or do you put a relatively smaller frac on more wells in the field? It becomes a balance to try to optimize capital employed and what you think you'll get back," Graham said.

Carbonate Depositional Architectures In The Eastern Shelf Desmoinesian Succession

Architecture		Relative Age	Group (Formation/ Member)	Location
Ramp		Early Desmoinesian	Lower Strawn (Caddo equivalent)	Western margin of "Concho platform" facing the Midland Basin to the Eastern Shelf
	Shelf-interior banks Patch reefs	Middle Desmoinesian	Lower to middle Strawn (Odom) upper Strawn (Capps)	
		Middle Desmoinesian	Lower to middle Strawn (Goen) (e.g., Fuzzy Creek and Pony Creek fields, Runnels and Concho counties)	
		Late Desmoinesian	Upper Strawn (Capps)	
Shelf-margin/ rimmed shelf		Late Desmoinesian	Upper Strawn (Anson Bank) (e.g., Nena Lucia, Nolan County)	Eastern Shelf
Periplatform pinnacle reef (rare)		Middle-late Desmoinesian	Strawn	Parallel to the Eastern Shelf and Ozona Arch area

Source: "Depositional History of the Desmoinesian Succession (Middle Pennsylvanian) in the Permian Basin," Bureau of Economic Geology, University of Texas at Austin; author, Wayne Wright.

Overall, the horizontal Strawn has made a nice addition to the Verado portfolio. "We're excited about the Shelf. The horizontal wells are not as expensive to drill or operate as in other areas.

"So we get good reserves and better all-in economics. It's still economic—even at today's commodity price—to go after it."

In this downturn and as it has in-house capital access, Verado is looking at property to add to its inventory, Graham said, while, recently, "We may not have been as competitive, certainly not against the private-equity model."

And it is looking to pick up partners that "share the same long-term mentality." Among its past 125 drilled and operated wells—all but 12 of them in East Texas—only one was unable to reach TD. And only one was a dry hole, he said.

It's looking there and in the Shelf for portfolio additions, as "Our preference is to start with what we're the most familiar with.

"But we're definitely open to opportunities outside of that."

Word from Scurry

John Carr heard early on about a potential horizontal play in the Eastern Shelf. With an entry of 5,500 acres, its leasehold has grown to some 8,700 gross, 6,900 net, all in Scurry County, said Carr, president of Tyler, Texas-based Carr Resources Inc.

The company is targeting the Strawn A reef, but the sands in the Strawn B and C are also prospective, Carr said.

The overall reef play is up to 125 ft thick, about 10 miles north/south and about six miles wide. "It looks like a watermelon in shape. It's just a big patch reef, but it covers 60 square miles."

The targeted Strawn zones had oil shows when drilling through it with verticals in the past, he said, "but nobody ever completed in it. The first horizontal well that was [brought online] changed the game."

Carr's one well to date, the 7,000-foot-lateral Wolters 239-1H, was a 3,500-foot offset to Three Span's Thunder Valley 240 1H.

Carr's Wolters came in with 1,513 bbl/d in December and cumulative was more than 200,000 bbl, averaging 977 bbl/d, in roughly its first six months.

It plans to pick up a rig again this fall. D&C for a 1.5-mile lateral has declined from $5.8 million to about $4 million, he said. "So the economics are just about the same as they were last year [at a higher oil price] because of the fall in service prices."

Carr Resources had a string of exploration successes in the past decade in East Texas in what became the Woodbine Sand horizontal play, the Lower Woodbine Shale play (aka Eagle Ford) and, most recently, the deep, horizontal Austin Chalk gas play.

Carr was looking more recently for overlooked tight oil in conventional rock that could be developed with laterals. "The Strawn A reef fit with our plans not only for the reservoir but the depth and excellent economics."

Permian And Pennsylvanian Formations Of Central And North-Central Texas

Age	Formation	Character	Thickness (ft, +/-)
Permian	Double Mountain	Red and blue sandstone, shale, clay; some limestone, dolomite, gypsum; rock salt farther west.	2,200
	Clear Fork	Red and blue clay, shale; limestone, locally dolomitic; sandstone, gypsum, clayball conglomerate; probably contains rock salt farther west.	750-1,975
	Wichita	Red and blue sandstone and shale, with some clay-ball conglomerate.	1,000-2,000
Pennsylvanian	Cisco	Blue clay and shale, sandstone conglomerate; some thin beds of limestone.	750-1,000
	Canyon	Limestone, blue clay, some reddish sandstone, conglomerate, coal.	800-1,100
	Strawn	Sandstone, some conglomerate, shale, few limestones, some coal.	950-4,700
	Smithwick	Dark to black carbonaceous shale; some sandstone.	225-600
	Marble Falls	Bluish-gray to black limestone; limestone conglomerate or breccia at base.	450-650
Mississippian	Barnett Shale	Black fissile shale, highly bituminous; some limestone.	150
Ordovician	Ellenburger	Limestone	--

Source: USGS; author, H.W. Hoots, 1926

It's a Phylloidal reef. To describe it: "You think of a bowl full of cornflakes," he said. "The reef has all these irregular plates with void spaces between them. But they have a lot of structural strength.

"So, when they were buried, they held up, and the voids are preserved as porosity."

At 7,200 ft in depth and with a 7,500-ft lateral, well costs "are low for what will make in the range of 800,000 bbl of oil per well," he said. "We like the area and are currently doing regional mapping for other bypassed pays in all three of the Strawn intervals."

'So I bought it'

Two landmen had leased around Three Span's gusher "in kind of a horseshoe" shape. "I looked at the 5,500 acres they put together and said, 'There's nothing wrong with this.' So I bought it from them," Carr said.

Looking at old verticals that had been fracked in the Strawn, "They were little fracs and made 25 bbl/d." Fracking that section over 7,000 ft of lateral, every 200 ft, would be hundreds of barrels a day.

"And that's what we did. We've averaged almost 1,000 bbl/d since that well came on. It's still flowing," he said.

"That's what we were looking for: conventional reservoirs that hadn't been exploited because they were regarded as too tight, but could be completed with moderate-length laterals and multiple fracs."

Water cut is about a third—about 500 bbl/d with 1,000 bbl/d of oil. For now, Carr is sending it to a disposal well.

In its one well, the company used 8.5 million lb of sand and 188,000 bbl of water over the 7,065 ft of completion interval. "It's a lot like a shale frac," he said.

He's continuing to add to leasehold. □

Carr Resources Inc. used 8.5 MMlb of sand in its 7,065-ft completion. "It's a lot like a shale frac," said President John Carr.

GOING WITH THE FLOW

Water midstream companies are navigating the market downturn alongside E&Ps, eyeing possible opportunities ahead.

ARTICLE BY
VELDA ADDISON,
MARY HOLCOMB
AND
BRIAN WALZEL

When it comes to effective water management, forging strong relationships, being able to adapt and sufficiently meet the needs of E&P companies and having the ability to always be where the action is are proving to be crucial for water midstream companies.

The companies, just like the operators they provide services for, are using lessons learned during previous downturns and coming up with ways to survive when the work slows and thrive as it returns. Some are grateful for having secured access to equity capital, locked in long-term contracts and not having overleveraged balance sheets before market conditions soured.

Looking ahead, they already have sights on growth opportunities, eyeing where services will be needed most and ways they can provide an added benefit for operators.

As the oil and gas industry regains strength from a bleak moment in history—with a global pandemic, slowed demand, less production and record low oil prices on the 2020 timeline—Oil and Gas Investor profiles three water midstream companies that are pushing through challenging but improving times.

"It's safer. It's cheaper. It's more reliable to move produced water in a pipeline," said Goodnight Midstream CEO Patrick Walker. "And it's going to be more efficient for third parties to build those lines, because in virtually all cases, a third party is going to be able to utilize equipment more efficiently."

Goodnight Midstream LLC

For Goodnight Midstream CEO Patrick Walker, calling what the oil and gas industry has experienced during the past several months "unprecedented" is an understatement.

As the head of a water midstream company with operations in the Permian Basin, Williston Basin and Eagle Ford, he has seen U.S. shale players pump oil to record highs of an estimated 13 MMbbl/d. The growth has provided plenty of business for Goodnight's 500 miles of produced water pipelines with 1.6 MMbbl/d of throughput capacity and 60 saltwater disposal facilities, especially considering that most shale wells produce more water than oil in the Permian.

Like everyone else, Walker and the Goodnight team watched a global pandemic sap the world's demand for oil, prompting oil companies to shut in wells and halt new drilling. WTI prices briefly turned negative in April.

"All of a sudden the pandemic went from sort of a headline to the only news there was," Walker told Investor.

Between March 13 and April 3, petroleum products supplied to the domestic market plummeted by one-third, or 7 MMbbl/d, according to a Reuters report, which deemed the drop "equivalent to more than eight standard deviations for any three-week period since 1992."

Walker called some of the production curtailments that followed in North Dakota aggressive. Various difficult-to-predict scenes played out across the Permian Basin with "different producers doing different things," even within 5 or 10 miles of each other, based on their individual circumstances.

"Eagle Ford is pretty much a microcosm of that. There was some differentiation on curtailment based on gas-oil ratios in that region because of their economics," Walker said. "They were still finding markets for their natural gas, at least in May and somewhat into June. But again, it was very difficult to predict who was going to be curtailing or even which particular pad would be curtailed."

Essential to it all for Goodnight is being in good communication with not only producers but also peers in the water sector and being able to adapt to producers' needs.

"We're interconnecting with a lot of our peers and sending some volume in some cases and receiving some volume in some cases," Walker said. "I think that's a silver lining of the downturn that makes everybody a little bit stronger."

When producers slow down, so does activity for water midstream companies that handle the large amounts of produced water that comes up from oil- and gas-producing wells.

Though produced water volumes from U.S. oil and gas wells could increase by 1%, reaching about 21 Bbbl by year's end, compared to 2019, such volumes are expected to drop to about 20 Bbbl by year-end 2022, according to IHS Markit.

The lingering impacts of COVID-19, low oil prices and low demand will likely pose challenges to investment into water infrastructure going forward for some E&Ps.

Walker sees opportunity, particularly for big producers looking to outsource.

"One of the things that they would look to do is to access a third-party water system like ours to conserve their capex dollars for drilling and completing wells, which we obviously think is more efficient for all parties," Walker said.

The value proposition to build pipelines to move produced water is clear, given the density of development brought by horizontal drilling and hydraulic fracturing in shale plays.

"It's safer. It's cheaper. It's more reliable to move produced water in a pipeline," Walker said. "And it's going to be more efficient for third parties to build those lines, because in virtually all cases, a third party is going to be able to utilize equipment more efficiently."

Since its beginnings in 2011, Goodnight has steadily grown its footprint, expanding from the Williston Basin into the Permian Basin in 2016, where it has since constructed more than 100 miles of water gathering pipeline spanning seven systems. These include its Llano and Rattlesnake systems designed to carry produced water from the Delaware sub-basin to the Central Basin Platform for treatment and disposal into depleted zones.

Walker describes Goodnight as a "greenfield grower."

The slowdown in activity also has given Goodnight a chance to improve operations and catch up or get ahead on permits for new wells and work related to rights-of-way. It recently landed several permits in New Mexico to service Llano and contracts for well hookups in North Dakota and the Eagle Ford. Goodnight's control room in Dallas, Texas, also started operations in March, which Walker said continues to drive safety and environmental stewardship.

"Sometimes the slowdowns give you an opportunity to really reassess yourself, and we've spent a lot of time doing that," he said.

Admittedly, the construction workload is more modest than last year, Walker said.

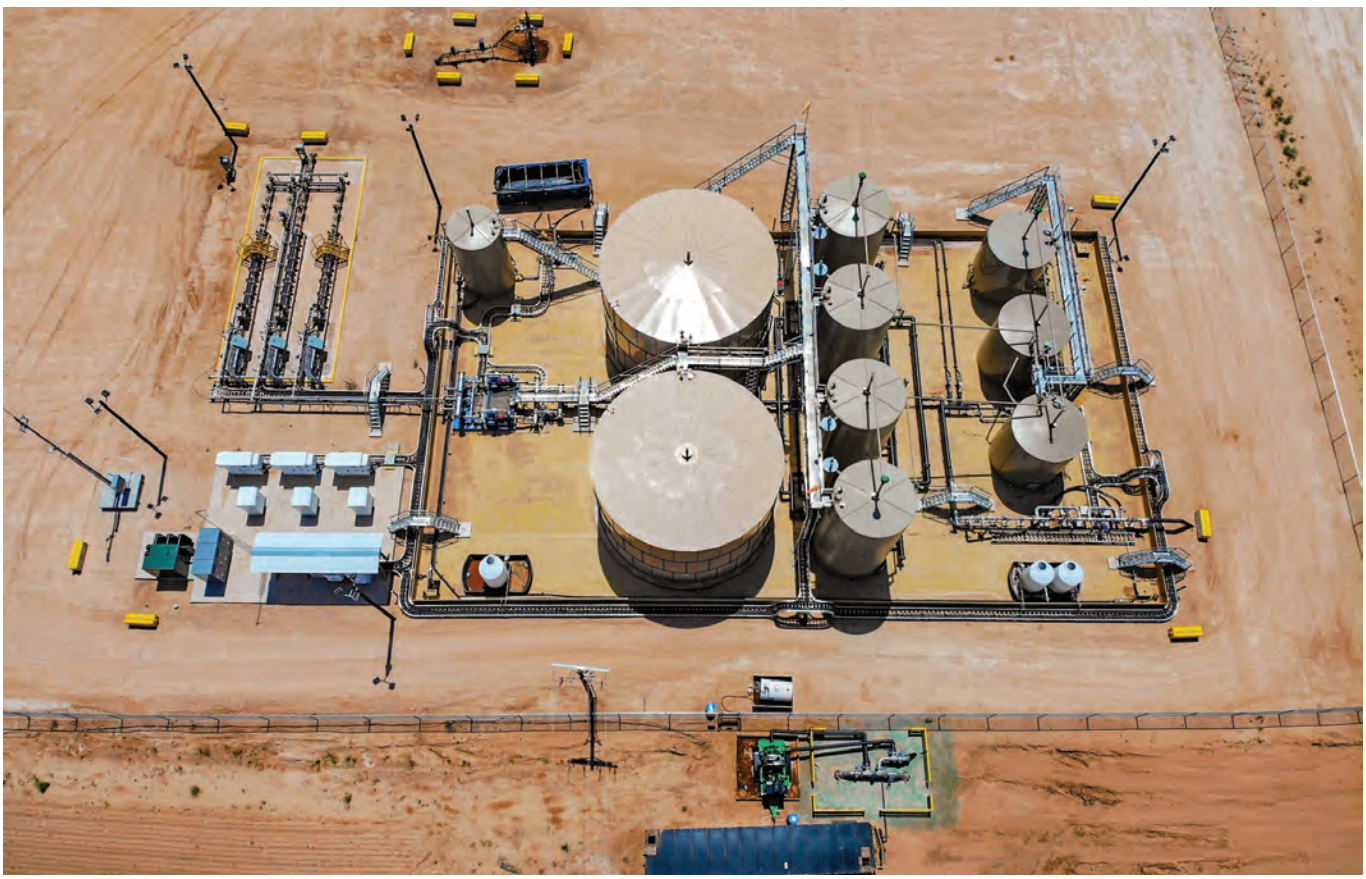
But the presence of Goodnight employees in fields in all three basins signals work is starting to pick back up. Producers are returning to DUCs and bringing wells back on production, he said, adding produced water volumes from previously shut-in wells starting back up have been consistent with what was seen before curtailments.

"Most of those producers, though, in North Dakota in particular, were cycling their wells to keep equipment running for even just a few minutes a day to make sure that they didn't have any issues coming back online," Walker noted.

Now that oil prices have stabilized, the return of activity gives Goodnight optimism—at least for the moment.

The U.S. Energy Information Administration forecast in August that U.S. crude oil production will fall by about 900,000 bbl/d to average 11.3 MMbbl/d this year, compared to 2019, due to less drilling activity and production curtailments connected to low oil prices.

"This 2020 production decline would mark the first annual decline since 2016," the EIA said in its Short-Term Energy Outlook.



H_2O Midstream owns and operates 1 MMbbl of produced water storage in the Permian Basin.

H_2O MIDSTREAM

"There are opportunities to use the assets and systems that are out there in this environment," said H_2O Midstream CEO Jim Summers. "I think that's a real opportunity for collaboration, just to add scale by putting multiple producers on common systems."

Production is expected to decline slightly through first-half 2021 until market conditions improve, making drilling more favorable for producers, the EIA said.

Despite the outlook and shale's decline, Walker is confident that drilling won't completely cease. So, there will be work for Goodnight to secure.

Looking beyond the U.S. level and into the county and township levels, he said, "You will see some areas that will continue to grow even though the total market will shrink."

Back during the 2015 to 2016 downturn, Goodnight—operating only in North Dakota at the time—tripled its volumes despite overall volumes in North Dakota being flat and later down. "What was happening is we ended up following our producers that were developing the basin," building facilities where needed.

Goodnight is fortunate that it has access to equity capital, Walker added. Dallas-based private-equity firm Tailwater Capital committed over $500 million in capital to the Goodnight Midstream platform last fall.

Though it is easier for a water midstream company to grow in a market that is growing, Walker said it will be "a little bit more difficult because the number of locations where you're seeing production growth will be declining."

Still, he has confidence in oil companies' ability to find drilling locations that are economic at $35/bbl to $40/bbl.

"That's the true test of their well economics," Walker said.

He added, "Hopefully, that means that we're building our facilities in the areas that are the most economic."

U.S. producers have been counted out many times before during challenging times, he said. "But for those of us that have the wherewithal to withstand it, I think there'll be bright days ahead. … U.S. shale is still the best short cycle, lowest cost oil resource in the world. You have to believe in the global economy. I think once we get back on track for global GDP growth, then there will be a call once again on oil resources."

H_2O Midstream

As energy demand slowly but steadily picks back up and producers cautiously eye new drilling, the challenges that existed pre-pandemic still remain. These include handling the massive amounts of produced water that come with oil and gas production, chiefly in the Permian Basin where for every barrel of oil produced, nearly four barrels of water come back with it.

Heading into 2020, H_2O Midstream was prepared to handle water needs for completions and production operations in both the Midland and Delaware basins after its August 2019 purchase of Sabalo Energy LLC's produced water infrastructure. The deal included a 15-year acreage dedication to provide produced water gathering, disposal and recycling services to Sabalo. The Midland Basin operator's water midstream assets were already connected to H_2O Midstream's assets, bringing the service provider's combined system to 435,000 bbl/d of disposal capacity, 240,000 bbl/d of deep disposal permits and 190 miles of water pipeline.

But, like every other upstream player, H_2O Midstream "took it on the chin" this spring, CEO Jim Summers said.

"Our initial reaction was to retrench a little bit and look at our business," Summers said. "We've streamlined our business some and made some changes as necessary to realign with the current market. That was our first reaction. And as time has gone on, we have really realized that our position, relative to our peers, has improved through this."

Summers attributes that advantaged position to the company's efforts toward acquisitions and operations to be a low-cost operator in Howard County, Texas.

GOODNIGHT MIDSTREAM

Goodnight Midstream's Nelson facility is located in McKenzie County, N.D. The company is among the water midstream sector's leaders in the Bakken.

"And further, we've been able to go out and actually renegotiate some agreements with landowners and with other folks that have lowered our cost structure even further," he said.

Darrell Bull, CCO, business development, for H_2O Midstream, works closely with operators in an effort to understand their needs.

Bull explained that during the onset of the downturn, many operators he interacted with were looking to renegotiate their service contracts for better rates. Many halted their drilling operations and held off on completing those wells, resulting in a large number of DUCs. Now, with oil prices leveling off in the $40/bbl range, Bull expects activity to soon increase.

"We're seeing optimism that volume will start to increase again in the fourth quarter this year," he said. "So that's been a positive. But [operators are all] a little bit different. They go from recycling water in the first quarter to not needing any recycling at all for two quarters. And they're going to want to start [recycling] again.

"So, when they're not recycling, that's business that we can help them with. But if we're not doing that, then we're disposing. I think they need providers like us who can do both of those kinds of things."

Although handling large amounts of water for their operations is nothing new for Permian producers, the advent of the water midstream business has established new challenges for those producers, particularly in relinquishing control of those operations, Summers explained. It was only a few years ago that operators moved from delineation to development. Producers typically invested their own capital in water management and worked in short-term commitments for costly trucking and disposal.

"I think producers are still getting comfortable [with water midstream]," Summers said. "Even though they've gotten comfortable with natural gas midstream being managed by a third party and crude oil midstream being managed by a third party, water is still relatively new.

"I think that's one of the big challenges the industry faces is assuring the producing community that [water midstream companies] have the ability to manage their water effectively, that best practices are shared across the industry, that they can do it as safely and reliably as a producer can themselves."

As is often the case in industry downturns, opportunities arise for asset growth and efficiency gains. For instance, following the post-2014 downturn, enhanced and tailored completion designs led to exponential cost savings and higher initial production rates. Summers said there are similar opportunities for greater efficiencies in the water midstream business.

"One of the things that's occurred as production or development has come off is if you look at the forward production curve over the next two years, a lot of new capacity needs to be built," he said. "I think people were trying to catch up to build that capacity. With volumes coming off, there's a lot of available capacity or more available capacity that's just not interconnected."

By connecting the multiple water midstream systems, companies have the opportunity to better integrate their operations and use existing capacity more efficiently, Summers added.

"There are opportunities to use the assets and systems that are out there in this environment," he said. "I think that's a real opportunity for collaboration, just to add scale by putting multiple producers on common systems."

Despite the slowdown and slow pace of recovery, Summers is encouraged by where he feels the industry, and the market, is headed. H_2O Midstream could be looking to build out more infrastructure to support their customer needs and perhaps add new areas of operations throughout the Midland and Delaware basins.

"We still have capital to deploy," Summers said. "We, unlike others, were not overly aggressive in acquisitions. We made the one strategic acquisition with Sabalo, and we've done a lot of organic growth. So, we still have a bit of dry powder to go out and look for opportunities as they come up in the market. We're hopeful the prices continue to stay strong, but we feel pretty good."

H_2O Midstream CCO Darren Bull said the company sees optimism for increased volumes in the fourth quarter of 2020.

Oilfield Water Logistics LLC

There's no doubt the water management sector will feel the ripple effects of the COVID-19 oil crash, especially on a long-term basis. However, already a seasoned veteran in the space, Oilfield Water Logistics LLC (OWL) is turning to familiar tactics to thrive.

Lessons learned from the previous downturn led OWL to place a heavy focus on geography, customer contracts and avoiding an overleveraged balance sheet, a strategy that leaves the Dallas-based company well-positioned this time around, CEO Chris Cooper said.

"In 2016, the downturn was the first time that we were able to get long-term water contracts, so there is a bit of a silver lining in a time like this—we all have to work together," Cooper said. "Luckily, we were able to prove ourselves through that period, and that's really helping us today with continuing our expansion."

OWL was formed in 2014 with private-equity firm NGP Energy Capital Management LLC. The partnership, along with strategic acquisitions, helped the company lay the foundation for a core position in the Permian Basin.

"We started forging the relationships with the Permian operators during that time and have since developed strong, long-standing relationships, which I think is critical to this industry and its evolution," he said. "It's just a matter of being focused where our customers are focused, where the best drilling economics are, and then it's about service. And, being well located in the Permian Basin, which is a real blessing that we don't take for granted."

In fall 2019, OWL recapitalized with North American infrastructure firm InstarAGF Asset Management Inc. and has grown its water footprint to include assets across Texas, New Mexico, Colorado, Utah and Wyoming. The

Oilfield Water Logistics CEO Chris Cooper said opportunities for large water companies to consolidate and move the sector forward are coming soon.

company operates over 400 miles of pipe, 38 saltwater disposal wells and four evaporation pond facilities in the Rockies.

Collectively, OWL owns and operates the largest commercial produced water gathering and transportation system in the Northern Delaware Basin, Cooper said. In January, OWL doubled its Northern Delaware footprint after acquiring a substantial infrastructure portfolio from EOG Resources Inc. in Lea and Eddy counties, New Mexico.

Despite already having a well-established position in the region, Cooper still sees an opportunity to expand OWL's water footprint further as the Permian Basin moves into its next phase of growth.

"As the Permian Basin moves from exploration to just pure production dynamics, I think we have an opportunity to be an important part of that process that can help reduce costs," he said. "And, we can use our capital for water and let our customers use their capital for drilling oil wells."

Generally, the Permian has some of the highest water-oil ratios in the market, resulting in large volumes of produced water. The Northern Delaware Basin, in particular, has at least four to seven barrels of water produced for every barrel of oil.

"If you take the low end of that range and production doubles, then that's eight times the amount of water that will be produced," Cooper said.

"With the produced water forecast being substantial over the foreseeable future," he continued, "there will be an opportunity for the healthy, larger water companies to consolidate water infrastructure and move into the next chapter of water midstream, which is pretty exciting."

Consolidation has also shown to be both a necessary and practical move right now for E&Ps that are examining better uses of capital. Cooper has taken an active interest in the water asset divestments, marking the new avenue as a "win-win" for OWL and its customers.

"Our customers cannot have their water shut in, so we are committed to providing the highest level of service possible and, in exchange, we're able to get longer-term contracts that have security, and that benefits all of us," he said. "Now is the time where the E&P companies can focus on drilling and let us handle their water and be confident with that decision."

Additionally, OWL has adopted technology on the reuse side of the water midstream business, according to Cooper. He said it is also actively working with a large international water company on water treatment equipment and that the first delivery of several large units will be delivered to its New Mexico assets.

"Having redundant full water lifecycle systems and infrastructure in place will be critical and that includes reuse, which, as drilling comes back, will be more substantial," he said.

OWL's overall goal coming out of this downturn is to maintain a healthy balance sheet. The key, Cooper said, is a positive capital structure that involves minimizing debt, not entering tertiary markets, and avoiding acquiring or placing operations in less ideal locations where drilling and production have stopped.

"We will continue operating conservatively and doing what we do on a day-to-day basis, which is to serve our customers and prepare for growth in the industry," he said. □

OILFIELD WATER LOGISTICS LLC

OWL's McCloy SWD is located at the corner of Highway 128 and Highway 1 in Lea County, N.M.

Great Golf for a Great Cause

Join us for the 25th Annual

SMALL STEPS GOLF CLASSIC

Monday, October 26, 2020
Champions Golf Club

The Golf Classic is one of the principal sources of funding for Small Steps Nurturing Center, an accredited early childhood program in Houston's First and Fifth Wards dedicated to stopping the cycle of poverty through education and early intervention. Small Steps provides a comprehensive program that addresses the needs of both the children and their families.

In its 24 years, the Small Steps Golf Classic has raised more than $15.8 million in support of early childhood education. Last year alone, the Golf Classic raised $891,000 for the students of Small Steps Nurturing Center.

2020 Title Sponsors

EnCap Investments L.P.

WELLS FARGO

Sign up for a day of great golf at Champions Golf Club, prior host to the U.S. Open, the Ryder Cup, and the PGA TOUR Championship, and future host to the 2020 U.S. Women's Open.

SMALL STEPS GOLF CLASSIC

To register, visit https://ssnc.org/events/golf-classic/registration/ today.
Contact Julianne Hickey at 713-236-0330 or jhickey@ssnc.org for more information.

HERE'S YOUR SECRET WEAPON

Get your FREE access to the LARGEST and MOST COMPLETE database on energy infrastructure assets in North America.

REXTAG
ENERGY DATALINK

Energy DataLink is the industry standard for accurate, up-to-date energy information and GIS data on energy infrastructure.

INCLUDES:

- Well Production & Completion Data
- Midstream and Downstream Data
- Visual Mapping
- and more!

Sign Up for FREE Access Today:

HartEnergy.com/datalink

HARTENERGY

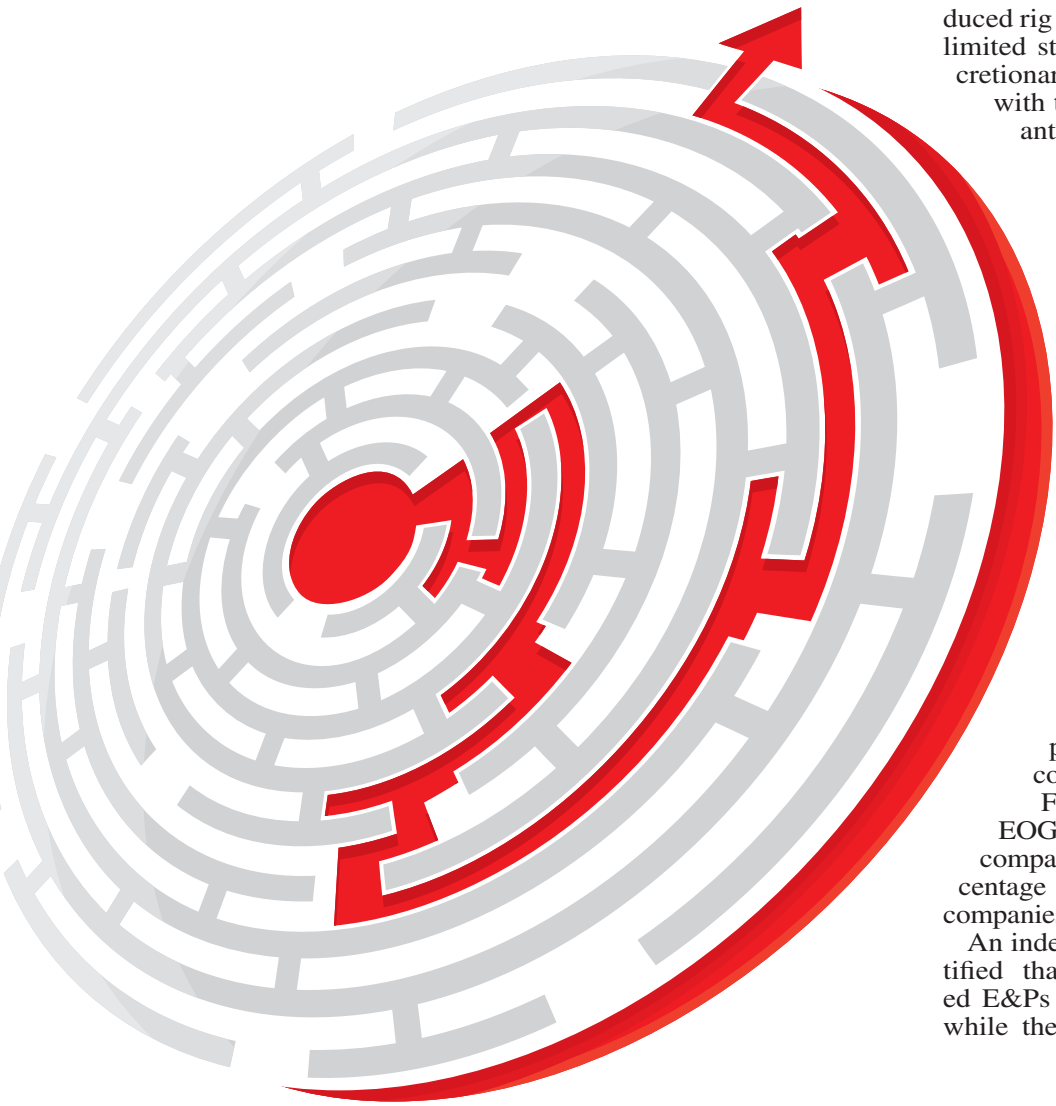
RIGHT-SIZING G&A

With limited exit and financing alternatives, oil and gas companies must take steps to address G&A and overhead costs to ensure the financial health of their organizations and their stakeholders.

ARTICLE BY
JOSH SHERMAN
AND
PETAR TOMOV

Dealing with market volatility and uncertainty, negative investor sentiment and depressed stock valuations isn't new to the upstream oil and gas industry, but today is different. The recent oil price rout has surpassed similar downcycles seen in the mid-1980s and 2014 to 2016 thanks to the one-two punch of coronavirus-related energy demand destruction and the collapse of the OPEC+ supply-management effort that, for more than three years, had propped up crude oil prices. In response, many E&Ps slashed their 2020 capital spending plans and have touted how much of their 2020 production levels are hedged.

The new reality is that most of the industry is in an asset preservation or "blowdown" business model: a focus on cost reduction and maintaining existing profitable production over converting undeveloped locations; reduced rig counts; shutting in higher cost wells; limited storage capacity; and little to no discretionary spending. Reducing G&A to align with this new reality is now more important than ever.



G&A costs: In focus

The days of growth (and debt) at all costs to maximize shareholder returns through an asset sale or IPO are now giving way to a focus on free cash flow. Historically, E&P cost structures increased dramatically as companies quickly added people and overhead to match the scale of current or expected operations. Companies like EOG Resources Inc. and Hilcorp Energy Co. are often lauded for the quality of their assets; however, competing management teams and boards may have lost sight of the fact that those companies also operate under a culture of running lean—they employ proportionately fewer people compared to their peers and align compensation to reward results.

For the year ended Dec. 31, 2019, EOG's G&A was 3% of its annual revenue, compared to the average and median percentage across all exchange-traded upstream companies of 25% and 10%, respectively.

An independent Opportune LLP study identified that G&A across all exchange-traded E&Ps increased 14% from 2018 to 2019, while their revenue declined 4% during the

SG&A Forecast And Assumptions

Current Realities	Discussion
Fewer capital projects	• Fewer new drills/completions, workovers; drillcos, JDAs, facility enhancements, etc. • Fewer internal transactions to address including AP, JIB, land, regulatory, HSE, treasury and technical support.
Less emphasis on converting undeveloped locations	• Reduced need for full asset development, subsurface, drilling and completion, facility and business development teams. • Technical, HSE and field teams need to be reviewed and rationalized.
Marketing efforts will be prioritized	• Shut-in and choked wells will become more prevalent as storage is constrained and take-away is limited. • Pricing scenarios must be rationalized.
All SG&A must be reviewed & rationalized	• Opportunities to outsource and seek new fee structures from existing service providers. • Compensation across the organization should align with new goals and objectives. • Review IT systems, software programs, hardware, data and subscriptions. • Review real estate holdings, including office buildings, field offices and yards.
Top-down approach—the people	• Review current organization, bios and functional support to determine appropriate staff levels and gaps, if any.
Compensation plan review	• Review current full compensation plans (base, benefits, bonus, stock/equity). • Compare to current market conditions and compensation plans. • Based on current environment and company goals/objectives, develop new compensation plans.
Review third-party professional service providers	• Identify areas where outsourcing is being used and/or may be appropriate—e.g., tax, subsurface, mapping, financial reporting, legal, HR, insurance/bonding, HSE, etc. • Identify current providers and review fee structures/bidding for negotiated fee negotiations or competitive environment review for potential cost-savings.
Review key field vendor service providers	• Identify key vendors—review agreements and associated spend to determine if appropriate to bid-out for potential savings.
Rent, vehicles, compression, etc.	• Review all options relative to highest fixed costs to determine what options are available, if any.
IT/data analytics	• Review IT schematic and all software for potential consolidation, renegotiated fee structures and savings through a negotiated or competitive environment. • On-prem vs. cloud-based solutions. • Review all subscriptions and data providers to identify must-have vs. nice-to-have.
Best practice review	• Conduct best practice review to determine accuracy and efficiency of certain agreed to activities (accounting, land, financial reporting, operational reporting, treasury, IT, etc.) • COPAS, netting, gas balancing, TIK, imbalance and pay-out reviews.

Source: Opportune LLP

Companies must take decisive steps to lead and make necessary changes to survive and be prepared for future opportunities. For the vast majority of E&P companies, the current environment is a "blowdown" business model. The primary emphasis will be optimizing production and lowering LOE and G&A.

same period. In 2020, the situation is clearly worsening, and many distressed public companies are starting to shed G&A via reductions in headcount and benefits. For example, another recent Opportune study of Form 8-Ks filed through May 2020 identified that about 15 public companies have announced specific cuts in executive compensation ranging from 10% to 20%.

The new reality

In the current environment, E&Ps should be optimizing production, lowering LOE and G&A and finding sustainable cost savings such as taking out layers of management or closing regional offices. Cuts to back-office accounting, IT, land administration and/or asset development departments are inevitable to better reflect the current environment.

The pertinent questions to current management are two-fold:

1. Have they accepted this new reality, and are they capable of cutting costs in a meaningful way?
2. Are they committed to aligning the company's goals to that of their current (or new) owners?

Ready, willing and able?

Capability vs. willingness may be semantics, but we've found that a management team's background (it's not just the CFO—change takes commitment from the entire C-suite) may determine their ability to succeed in this new environment.

Management teams that grew up in large public companies or transitioned to such entities after careers in banking, public accounting or other sectors outside of oil and gas often don't know any other way than what they've historically seen. Even under a blowdown business model, these executives consider large investor relations and human resources departments, maintaining a full back-office to continue managing antiquated accounting systems and keeping geology, drilling, completion and land departments intact a necessity. "We have to be ready for the rebound," they say.

Management teams that entered the C-suite by starting private-equity portfolio companies during the 2009 to 2014 boom years may potentially yield the same results. While some of these entities often begin lean, start-up portfolio companies by nature must be ready for sudden and rapid growth and often elect to preemptively hire a number of people across several functions rather than outsource until they reach a steady state. Fast forward to today, having missed the opportunity to monetize, these companies are now left with a headcount and associated G&A that's excessive when considering a blowdown business model. "But we don't need to cut G&A—we've always run lean," they say.

Representative entities may be ready for the rebound, but you (the C-suite) probably won't

be around to see it, as public companies are filing Chapter 11 and private-equity portfolio companies are being smashed together at a record pace. What was considered lean under an asset development model is likely bloated under a blowdown business model aimed at managing existing production to maximize free cash flow and pay down debt.

Committed to maximizing free cash flow?

Whether companies' performance incentives have historically been aligned to investor needs is debatable, but we're playing a whole new ballgame today. The field of play and goal posts have changed. Gone are the days of real estate speculation where the primary goal was to acquire acreage (at any price), drill a few wells to prove up the field and then flip the asset package or company for a pot of gold at the end of the contango rainbow.

Today's game is about maximizing cash flow to pay down debt and returning cash to investors. The A&D market is almost nonexistent, and no value is being given for proved undeveloped reserves (PUD) or unevaluated acreage. Even Chesapeake Energy Corp., which had skirted bankruptcy for a decade through asset divestitures, finally succumbed to the inevitable on June 28. Companies emerging from Chapter 11 and those hoping to avoid it must have a viable plan that generates free cash flow. Period.

A recent Kimmeridge whitepaper theorizes that an E&P trading at 3x EBITDA of $1 billion could generate a 9% yield to investors by reducing G&A by some 12% and reducing capex to approximately 75% of current year EBITDA. The whitepaper provides examples of two companies in the refining (Valero Energy Corp.) and tobacco (Altria Group Inc.) industries that have effectively generated such returns using similar G&A- and capex-reduction initiatives through years of volume, price and social pressures.

Kimmeridge stated, "We believe that by making these changes and following the same playbook, the E&P industry could reduce the risk of equity ownership for investors with visibility toward 100% of capital returned in a decade with a retained option on the asset base should energy demand continue to grow."

Right-sizing—a comprehensive approach

Right-sizing is a term that was first thrust into the mainstream by manufacturers and businesses of all sizes and industries during the 2007 to 2008 financial crisis. This principle applies to the upstream oil and gas industry today. E&Ps should consider implementing a comprehensive approach to right-sizing their organizational structure that better reflects the current market climate and aligns with company goals/objectives.

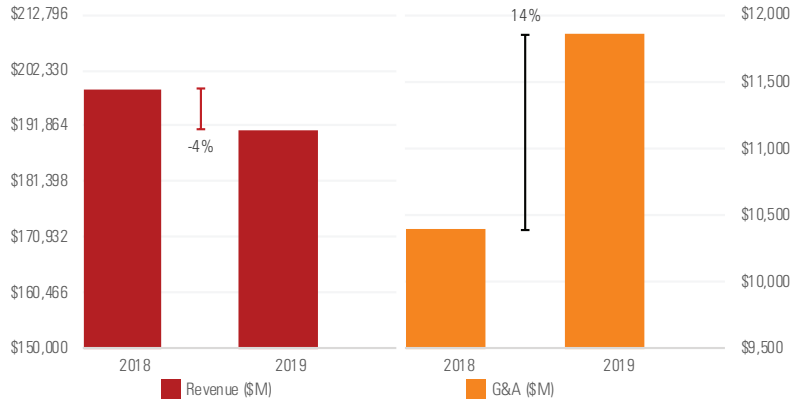
A comprehensive approach should start with a bottoms-up analysis to identify every department and employee position that's essential if, based on the current business model and environment, the company was starting up today. Positions not deemed essential should be eliminated immediately. For each current employee in an identified essential position, three questions should be considered:

1. Would you hire that person again?
2. What base salary would you pay them?
3. How would you incentivize them?

If the market turns around and expansion is needed in the future, quality employees can always be hired at the right price. Executive compensation packages should be predicated on capital preservation and returning cash to creditors and owners. Plans that tie performance to bonuses and/or incentive awards should also be rationalized and be based on current company goals and objectives. Personnel decisions are probably the hardest activity any leader performs and often involve uncomfortable conversations with friends, mentors and mentees; however, good people always find good work, and those employees may deserve a fresh start as much as their former employer's balance sheet.

Additionally, a top-down analysis of each G&A category and material contract therein should be performed to identify cost-cutting levers resulting from reduced personnel and business activities. □

E&P Revenues Vs. G&A



Source: S&P Capital IQ

Revenue and G&A based on total revenue and G&A for major U.S. exchange-traded E&P companies operating in North America as of Dec. 31, 2019, excluding integrated oil and gas companies and mineral and royalty companies.

Josh Sherman is the partner in charge of the Corporate Finance and Complex Financial Reporting groups of Opportune LLP. Josh has 20 years of experience in advising financial and accounting executives on the formation, support and analysis of their teams. Josh is currently an independent board member of U.S. Energy Development Corp., and previously served on the board of directors as audit committee chairman of JP Energy, Trans Energy and Voyager Oil & Gas.

Petar Tomov is a manager in Opportune LLP's Valuation practice and is one of the firm's leading experts on employee and executive compensation matters. Combined with his time as a manager at KPMG, Petar has nearly 10 years of experience focusing on the valuation of stock-based compensation, complex securities and intangible assets for financial and income tax reporting.

MAKE BETTER DECISIONS WITH A GROUP SUBSCRIPTION

A group subscription to HartEnergy.com equips your team with daily intelligence to stay ahead of the competition.

HartEnergy.com provides your business with daily intelligence about what is happening, why it matters and how it affects your company.

HartEnergy.com keeps your team abreast of business trends, energy markets, A&D&M transactions, E&P news, technology, policy changes, and midstream needs. And every issue of ***Oil and Gas Investor*** magazine, our playbooks, special reports, and ***E&P*** magazine (in a downloadable PDF) is included with each subscription.

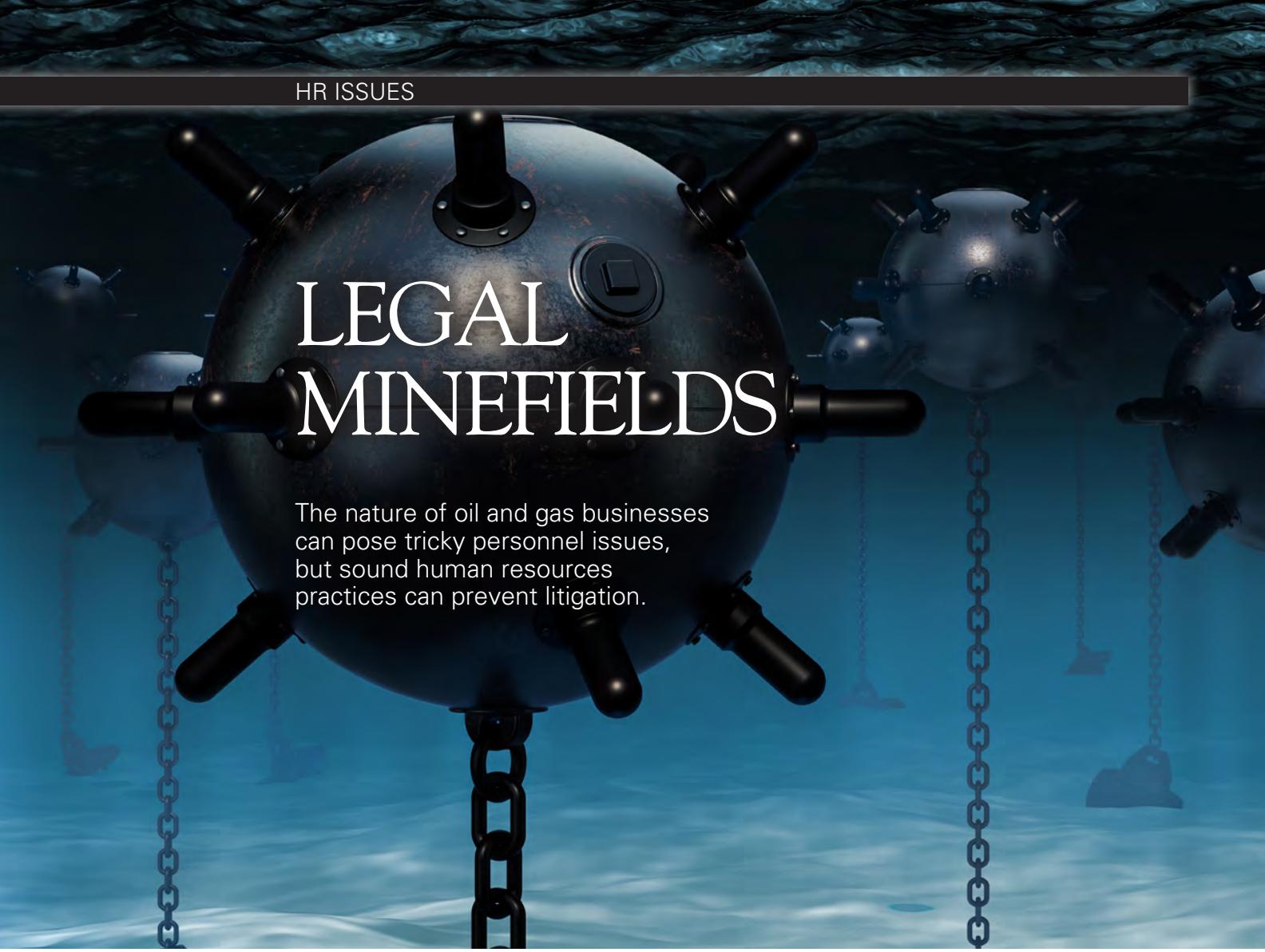
Equip your team or your entire company with a license to **HartEnergy.com**. Discounted group rates start with as little as two subscriptions.

To start your access right away or for more information contact:

Chris Rasch
crasch@hartenergy.com
713.260.4669

HARTENERGY.COM

Connecting You to the Global Energy Industry



LEGAL MINEFIELDS

The nature of oil and gas businesses can pose tricky personnel issues, but sound human resources practices can prevent litigation.

ARTICLE BY
ANNETTE IDALSKI
AND
BRIAN SMITH

Oil and gas employers face unique legal challenges. Because the nature of work in the oil field and on pipelines is cyclical and requires flexibility, it is often necessary for companies to rely on both independent contractors and employees. This novel compensation structure often makes companies targets for class action litigation by plaintiffs' lawyers, who do not always understand the industry and the nuances of the two professional roles.

To that end, oil and gas companies must be careful to not exert too much control over independent contractors so that they are actually deemed employees in a legal proceeding. By contrast, many highly skilled employees who are exempt from overtime must be paid a weekly guarantee and perform exempt duties to eliminate an employer's liability.

Given these complexities and the high salaries involved, plaintiffs' lawyers continuously look for ways to attack employers for perceived violations.

Because of this, oil and gas employers must examine their internal policies and procedures when it comes to arbitration agreements, job descriptions, offer letters, employee handbooks and other important human resources records. These documents often serve as the first line of defense against litigation, and if designed correctly, they can save oil and gas employers hundreds of thousands of dollars and preserve their business models.

Arbitration agreements

Arbitration agreements with class action waivers offer the best way for an employer to substantially limit the scope of litigation, and oil and gas companies, as well as their service companies, should require all their employees and contractors to sign them. These agreements must include not just the employer but also customers and vendors so that all businesses are protected against indemnification and additional litigation.

Arbitration allows additional benefits for employers, including limitations on the amount of public information available regarding the dispute and, in general, more efficient resolution.

However, the most important benefit of an arbitration agreement is its ability to foreclose a class action by prohibiting an employee from bringing such claims or joining any preexisting class action. Every oil and gas company should pay close attention to this risk management issue.

A properly executed arbitration agreement containing a class action waiver mandates an employee bring claims only in an individu-

al capacity. If the employee attempts to file a lawsuit in a representative capacity, a motion may be filed with the court whereby his claims will be dismissed and he will be compelled to arbitration.

Similarly, an employee subject to an arbitration agreement containing a class action waiver is ineligible for inclusion in a preexisting class in which he would otherwise be a member.

These waivers take on increased importance when an employer is faced with a class action under the Fair Labor Standards Act (FLSA) where court-approved notice is sent to individuals to inform them of the existence of the lawsuit and their right to opt-in. The recent trend among courts—including the influential Fifth Circuit covering Texas, Louisiana and Mississippi—is to disallow such notice from being sent to individuals who are subject to arbitration agreements containing class action waivers.

Class action waivers may be used when confronting any class action brought by employees—discrimination claims, etc.—not just those in the wage and hour context. Because of this, the successful use of an arbitration agreement requires careful drafting by experienced defense counsel consisting of employment lawyers that specialize in wage and hour class actions. Lawyers without this expertise often make mistakes when drafting these agreements, which can prove costly.

It is critical for companies to choose their employment lawyer wisely. They must consider their successes with litigation brought against oil and gas employers, experience drafting complex arbitration agreements and whether they have litigated against the plaintiffs' attorneys who typically sue oil and gas companies.

Arbitration agreements must be disseminated to employees for their review and, although not required, their signature. Courts frequently infer employee consent to the agreement at issue by continued employment, particularly when the agreement clearly states that continued employment constitutes consent.

However, to remove any doubt, employers are strongly recommended to secure an employee's handwritten or electronic signature. They should also remove arbitration agreements from handbooks and disseminate them instead as a separate document because arbitration agreements are contracts.

Employers in the oil and gas industry have long been a frequent target of plaintiff's counsel. A recent trend has emerged where plaintiff's counsel often seek to sue only the clients of service companies that contract for labor provided by the service company.

In many instances, the service company has arbitration agreements in place with its personnel. However, the agreements often do not explicitly include the client as an entity covered by the agreement. From the opposition's perspective, the rationale is clear: There is no money to be made litigating 50 individual arbitrations against the service company as compared to litigating a nationwide collective or class action against the client.

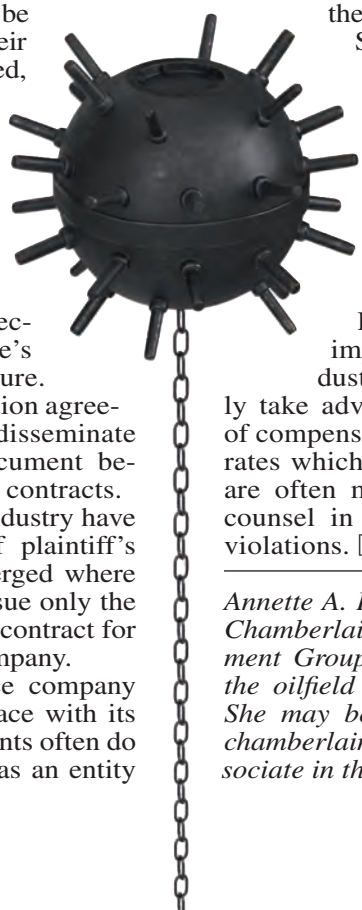
Of course, this ignores that it is the service company, not the client, that hired, paid and otherwise directed the work of the plaintiffs. Given this trend, it is more important than ever that service companies' arbitration agreements be drafted in a manner to explicitly include their clients as entities covered by the agreement.

Other documentation

Handbooks and the policies contained therein are an effective means of preventing and defending against litigation and must be drafted with this purpose in mind. Accordingly, employers in the oil and gas realm should review and update handbook policies to reflect changes in the legal landscape and ever-evolving best practices.

For example, in *Bostock v. Clayton County* (published on June 15, 2020), the Supreme Court of the United States ruled that Title VII of the Civil Rights Act of 1964 prohibits employment discrimination on the basis of an employee's sexual orientation or gender identity. Employers should carefully review the equal employment policies contained within their handbooks to ensure they prohibit discrimination based on sexual orientation and gender identity.

Handbooks also provide an opportunity for employers to explicitly state the exempt or nonexempt status of employees. Listing the specific duties expected of an exempt employee is often helpful. Such evidence often proves critical in meeting the duties test, a requirement to establish exempt status under the FLSA.



Similarly, pay letters are critical in proving that the employee at issue is exempt from overtime or is a contractor rather than an employee. The letter should state that the employee will be paid a weekly guarantee not subject to reduction based on quality or quantity of work.

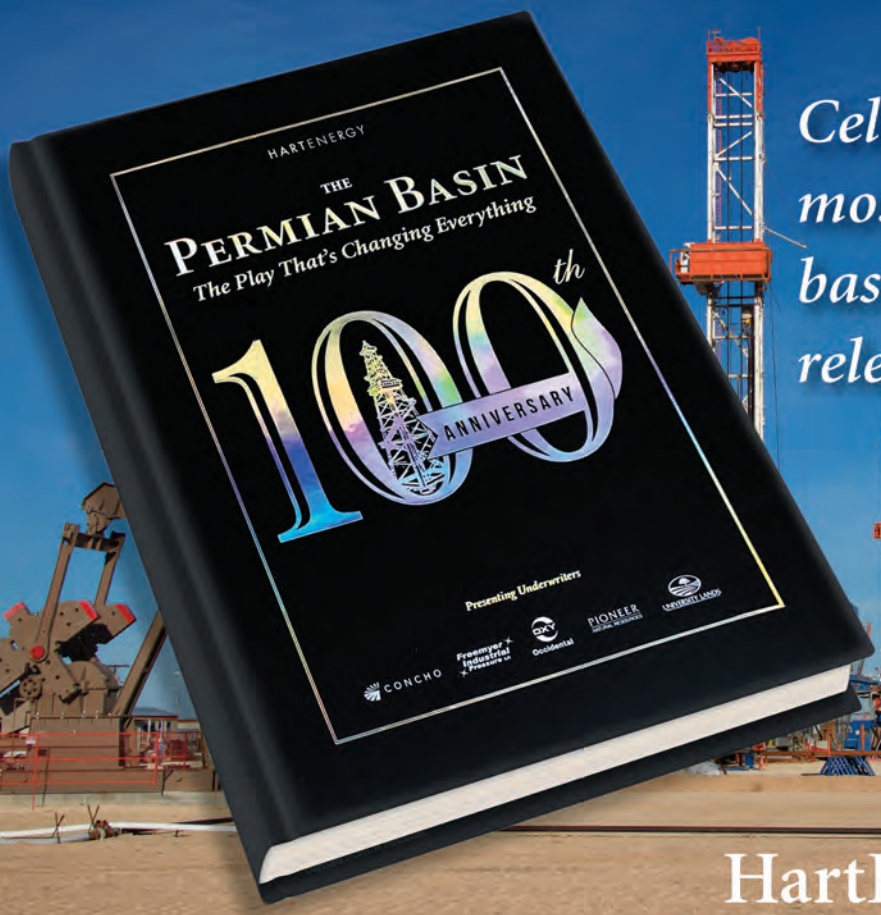
Pay letters take on increased importance in the oil and gas industry where employers frequently take advantage of alternative methods of compensation such as day rates or piece rates which, while legal under the FLSA, are often mischaracterized by plaintiff's counsel in an effort to pursue overtime violations. □

Annette A. Idalski is the National Chair of Chamberlain Hrdlicka's Labor & Employment Group. She represents employers in the oilfield throughout the United States. She may be reached at annette.idalski@chamberlainlaw.com. Brian Smith is an associate in the practice.

100th ANNIVERSARY

THE PERMIAN BASIN

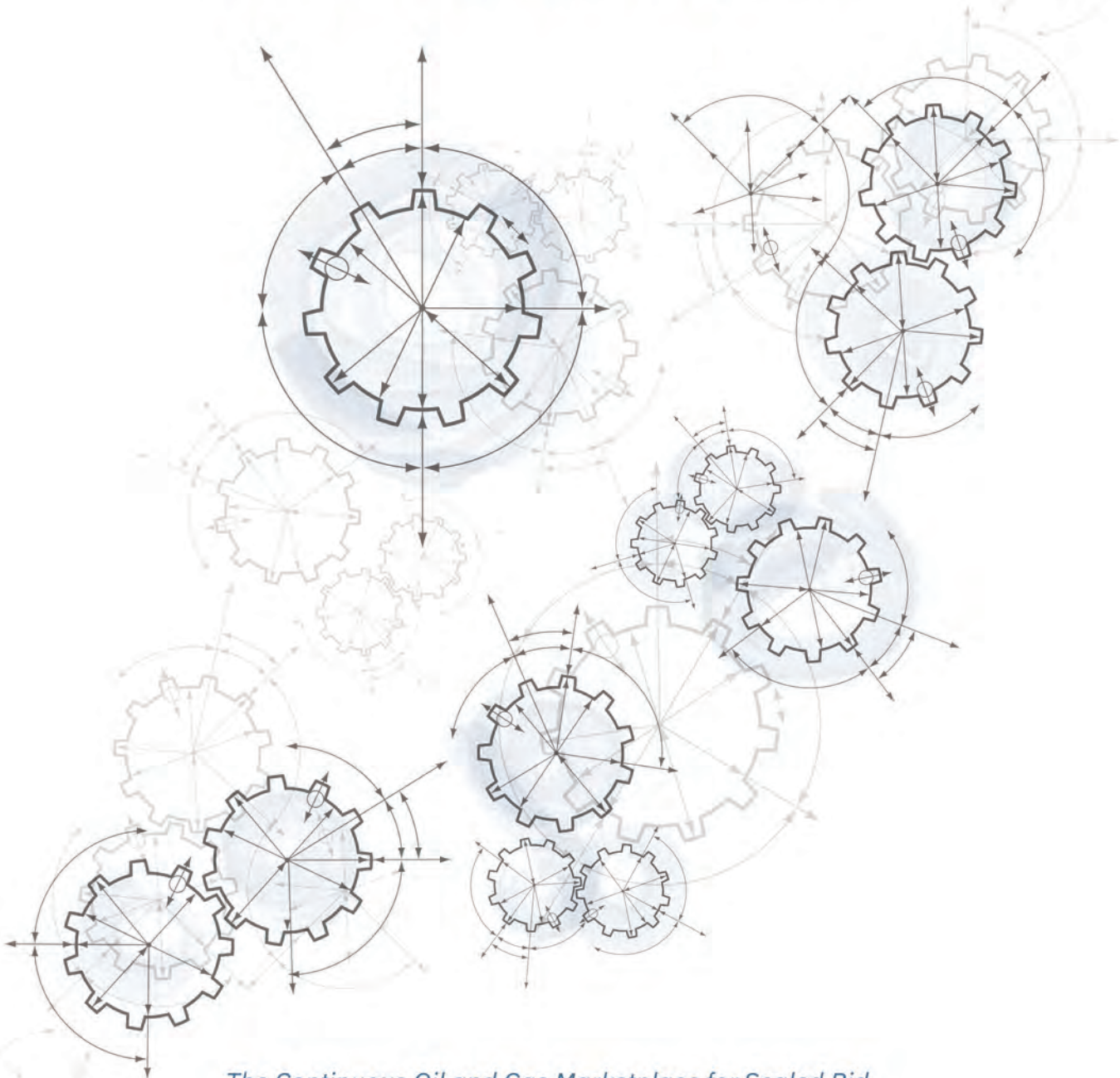
1920 - 2020



Celebrate the world's most remarkable oil basin with this limited release coffee-table book

HartEnergyStore.com

Competitive, Structured, and Fair Sale Processes for Oil and Gas Assets that Consistently Work



The Continuous Oil and Gas Marketplace for Sealed Bid and Negotiated, Auction, Federal and State Lease Sales

ENERGYNET

Your Trusted Advisor for 20 years

HOUSTON | DALLAS | DENVER | OKLAHOMA CITY | MIDLAND

877-351-4488 | EnergyNet.com

Southwestern Energy, Montage Join Forces In Appalachia

NATURAL GAS PRODUCER Southwestern Energy Co. said Aug. 12 it has entered a deal to acquire **Montage Resources Corp.** in an all-stock bolt-on to its positions in the Utica and Marcellus shale plays worth $883 million in stock and assumed debt.

The implied value of the stock transaction is $213 million, based on Southwestern Energy's Aug. 11 per share closing trading price, the company said in a filing with the U.S. Securities and Exchange Commission. Southwestern will also assume Montage's $670 million in debt, paced by $271 million in EBITDA for the trailing 12 months ending in June. As a result, the deal effectively reduces Southwestern's leverage to 3x from 3.1x.

The deal comes about a year and a half after Montage was formed by the combination of **Eclipse Resources** and **Blue Ridge Mountain Resources**. For Southwestern, the definitive agreement marks another step toward growing its Appalachian Basin business since it exited the Fayetteville Shale two years ago to become an Appalachian pure-play E&P.

"The transaction is expected to build on our financial strength and flexibility and is expected to be accretive to all per share metrics, delivering increased value to our shareholders," Southwestern Energy President and CEO Bill Way said on a call Aug. 12.

"With the complementary nature of Montage's high-quality assets, we expect to unlock additional value through increased scale, our demonstrated operational excellence and the benefits of our vertical integration all building upon the strong foundation Montage has built with this diverse portfolio."

The transaction, expected to close in the fourth quarter, starts a new chapter for Southwestern Energy, he said. The deal will add about 325,000 net acres to Southwestern's portfolio, boosting its total net acreage to nearly 787,000.

With the acquisition, the company said its total production will rise to 251 Bcfe with about 3 Bcfe/d of production, of which about 80% is natural gas, making it the region's third-largest producer.

In a news release, Way called the transaction value-adding for shareholders of both companies.

It's expected to bring about $100 million in annual free cash flow based on current strip pricing starting in 2021 and about $30 million in annual G&A savings, Southwestern said in the release.

The "transaction value highlights the industry's emphasis on low-to-no premium combinations," **Tudor, Pickering, Holt & Co.** (TPH) said in a note, which the analyst estimates "likely continues thematically in the space."

As part of the deal, Southwestern commenced a registered underwritten public offering of 55 million shares of its common stock. Proceeds, the company said, will be used to retire a portion of Montage Resources' 8.875% senior notes due 2023.

TPH pointed out that the exchange ratio of 1.8656 Southwestern shares for each outstanding Montage Resources share implies about $5.67 per share for Montage based on Southwestern's Aug. 11 close, which the analyst said is about a 5% discount to Montage Resource's close of $5.97 per share.

"This transaction creates a compelling opportunity for both Southwestern Energy and Montage Resources shareholders to benefit from the strength of the consolidated company," Montage Resources President and CEO John Reinhart said in a news release. "The combination creates a company of substantial scale with capabilities to enhance cash flow generation and a strong balance sheet that provides opportunities for enhanced shareholder value creation."

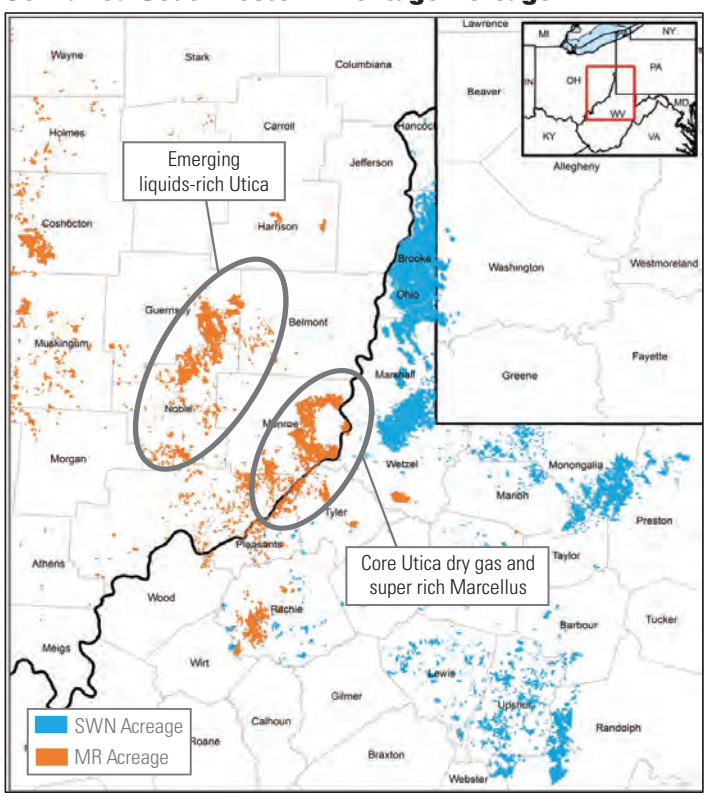
The transaction is subject to approval by Montage Resources shareholders and customary closing conditions.

EnCap Investments LP, which holds 39% of Montage's outstanding common stock, has already signed a support agreement, Way said on the call.

Based in Irving, Texas, Montage Resources' operating areas span more than 300,000 acres covering the Utica and Marcellus shales in southeastern Ohio, West Virginia and North Central Pennsylvania.

"The assets have

Combined Southwestern-Montage Acreage



Source: Southwestern Energy Co.

Southwestern/Montage Merger Metrics

	SWN	MR	SWN + MR
Production (Bcfe)	201	50	251
Net Acres	461,687	324,500	786,187
Proved Reserves (Bcfe)	12,721	2,730	15,451
Net Debt ($MM)(nonGAAP)	$2,447	$661	$3,108
Adjusted EBITDA ($MM)	780	271	1,051
Net Debt/Adjusted EBITDA	3.1x	2.4x	3.0x

exposure to natural gas, NGL and condensate, including the proven high return Marcellus, super rich and Utica dry gas windows," Way said. "The 2.7 Tcf of proved reserves and 520 remaining locations increase our already deep inventory and add additional portfolio optionality to complement our current diversified portfolio."

The acquisition news was delivered less than a month after Montage divested its Ohio Utica wellhead gas and liquids gathering infrastructure in exchange for a cash payment of $25 million to an international third-party. The Ohio Utica deal is also expected to close in the fourth quarter.

Spring, Texas-headquartered Southwestern Energy solely operates large-scale assets in Northeast Appalachia, where it is focused mostly on the Marcellus Shale, and Southwest Appalachia, where it's focused on the Marcellus as well as the Utica and Upper Devonian reservoirs.

The combined enterprise will also have over 15 Tcfe of proved reserves and more than 5,000 remaining locations as of year-end 2019, according to Way.

"The increased scale resulting from this acquisition is expected to improve the company's free cash flow sustainability, allow for greater capital investment optionality and facilitate further optimization of existing midstream commitments, offering a relevant and resilient value proposition for our shareholders," he added.

Citi and **Goldman Sachs & Co. LLC** are financial advisers while **Skadden, Arps, Slate, Meagher & Flom LLP** are legal adviser for Southwestern. **Barclays** is financial adviser with **Norton Rose Fulbright LLP** acting as legal adviser to Montage Resources. **Vinson & Elkins LLP** is legal adviser to **EnCap Investments**.

—Velda Addison

Antero Resources Adds VPP To Divestiture Goal

ANTERO RESOURCES CORP. inched closer to its divestiture target for the year with the announcement of a transaction on Aug. 11 for cash proceeds of $220 million. The transaction, with an affiliate of **J.P. Morgan**, is a volumetric production payment (VPP) through 2027 comprised of dry gas producing properties in West Virginia. The VPP deal follows Antero's sale in June of overriding royalty interest (ORRI) in its Appalachia position with proceeds earmarked to pay down debt.

"This morning's volumetric production payment transaction is another step toward de-risking the liquidity outlook," **Morgan Stanley & Co. LLC** analysts wrote in an Aug. 11 research note.

However, with Antero's leverage "still uncomfortably high," Morgan Stanley's rating of the stock remains "underweight" despite recently improving investor sentiment for natural gas. Assuming the full tender amount of an offering of debt repurchases also announced Aug. 11, the analysts estimate the company's pro-forma maturities would total about $1.4 billion, or roughly 70% of total debt outstanding.

"We maintain a cautious view of natural gas E&Ps and favor more defensive producers with relatively less leverage and stronger free cash flow profiles," Morgan Stanley analysts wrote. "For [Antero], strong execution on cost savings and hedge coverage insulate near-term cash flow, though [it] comes with significant execution risk ahead of a still onerous maturity schedule. Moreover, at strip commodity prices, we do not see a clear path toward leverage reduction and forecast meaningful downside to our intrinsic valuation."

Antero VPP Sale Snapshot

$220 MM VPP sale to an affiliate of J.P. Morgan
Composed of dry gas producing properties in West Virginia
Effective date of July 1, 2020, with 7-year term ending June 30, 2027
Net production of 60 MMcf/d for second half of 2020, 75 MMcf/d in 2021 then declines to 40 MMcf/d by the first half of 2027
Transaction value based on pricing of Nymex/Henry Hub, less $0.60/MMBtu (pricing is net of actual transport costs and basis differentials)
Attractive single digit cost of capital for PDP asset

Source: Antero Resources Corp.

The effective date of the VPP sale is July 1 with a seven-year term ending June 30, 2027. Associated net production includes 60 MMcf/d in second-half 2020, 75 MMcf/d in 2021 before declining to 40 MMcf/d by first-half 2027 prior to termination.

The VPP transaction brings Antero's asset sale proceeds for the year to $751 million, achieving the low end of its $750 million to $1 billion target range, according to Paul Rady, chairman and CEO of Antero Resources.

"The ability to monetize $751 million of assets in such a challenging market is a testament to the quality of Antero's substantial producing properties and acreage," Rady said in a statement.

Pro forma for the VPP sale and assuming $525 million of bonds are tendered and repurchased, CFO Glen Warren said Antero will have reduced near term bond maturities by over $1.4 billion since fourth-quarter 2019 when the divestiture target was first announced.

"We will continue to pursue additional asset sale opportunities and plan to use any future proceeds for debt retirement," Warren said in a statement.

Vinson & Elkins, led by partner Danielle Patterson, advised Antero Resources on the VPP sale. Antero's borrowing base under the credit facility remains unchanged at $2.85 billion following the VPP transaction, according to the company release.

Based in Denver, Antero Resources holds a position of about 536,000 net acres across West Virginia and Ohio in the core of the Appalachian Basin's Marcellus and Utica shale plays. Prior to the ORRI sale, the company's position included 84% net revenue interest.

—Emily Patsy

Riviera Resources On Course To Exit Upstream

After completing more than $500 million worth of asset sales since its spin-off from **Linn Energy**, **Riviera Resources Inc.** is now looking to exit the upstream space altogether.

In an Aug. 6 release, the Houston-based oil and gas company said it had started to shop its remaining upstream assets despite already narrowing its multibasin portfolio to focus solely in Oklahoma following a steady stream of asset sales.

Riviera Resources 2020 Divestitures

Transaction	Close Date/Status	Price ($MM)
Uinta – Drunkards Wash	Jan.	$5
East TX – Overton	Jan.	$19
East TX – Personville	Feb.	$34
OKC Building	Feb.	$21
North LA	Pending	$26.5
OK Anadarko	Pending	$15.8
Blue Mountain Midstream	Pending	$111
OK assets – EnergyNet	On the market	
	Total 2020	**$232.3**

Source: Riveria Resources

Riviera formed in 2018 through the spinoff of Linn Energy's portfolio of mature, low-decline assets located throughout the U.S. The company also owns **Blue Mountain Midstream LLC**, a gathering and processing business focused on the Merge, SCOOP and STACK plays of Oklahoma.

Since the spinoff, though, Riviera has gradually been monetizing assets from the multibasin portfolio it inherited from Linn. Last year, the company generated over $500 million in proceeds through strategic monetizations, returning more than $400 million of capital to shareholders, according to a release from late 2019.

Divestitures have continued into 2020. So far this year, the company has closed four transactions for proceeds of about $69 million. Divested properties include acreage in the Uinta Basin (closed January), the Overton Field in East Texas (closed January), the Personville Field also in East Texas (closed February), and its Oklahoma City office building (closed February).

The company also has two pending transactions—one a deal for its North Louisiana properties as well as an Aug. 6 agreement to sell interest in Anadarko Basin properties for $16 million. The Anadarko sale includes approximately 2,100 wells in 14 counties throughout central and northwestern Oklahoma averaging 28 MMcfe/d of production.

As for the company's remaining upstream portfolio, all located in Oklahoma, CEO David Rottino said Riviera had engaged **EnergyNet** to market those assets. Plans are for the transactions to close by fourth-quarter 2020.

"Once we close these remaining transactions, it will result in a complete exit from the upstream business," Rottino said in a statement on Aug. 6. "In addition, we continue to work closely with **Tudor, Pickering, Holt & Co.** to explore a potential sale or merger for Blue Mountain."

The North Louisiana asset sale is expected to close third-quarter 2020, while closing of the Anadarko sale announced Aug. 6 is expected for the fourth quarter.

—Emily Patsy

Japanese Gasco Takes Over Shale Producer Castleton

In its first acquisition of a shale gas operator, **Tokyo Gas Co. Ltd.** will take a controlling interest in **Castleton Resources LLC**, the Japanese company said July 29.

Through its subsidiary, **Tokyo Gas America Ltd.**, Tokyo Gas will pay about $620 million ($65 billion JPY) as it increases its ownership in Castleton Resources to 70% from 46%. Tokyo Gas said the investment was made in connection with the acquisition of additional oil and gas assets in Louisiana (see related story).

Tokyo Gas plans to purchase more Louisiana oil and gas assets through Castleton Resources with closing set for Aug. 14.

In December 2019, Castleton said it had closed on the acquisition of the East Texas and North Louisiana Haynesville Shale assets of **Royal Dutch Shell Plc** as the supermajor exited the play. The Anglo-Dutch company had previously sold off most of its Haynesville assets roughly six years ago to **Vine Oil & Gas LP** and its partner **The Blackstone Group LP** for $1.2 billion in cash. Shell's remaining assets in the Haynesville gas play consisted of a nonoperated position, according to its website.

With the Shell acquisition, Castleton Resources was expected to own about 222,400 net acres in the Ark-La-Tex region.

Castleton plans to fund the closing of the transaction announced July 29 with additional equity capital from both Tokyo Gas America and the global energy commodity merchant **Castleton Commodities International LLC** (CCI). After the funding, Tokyo Gas America will increase its ownership interest in Castleton Resources. Castleton will also change its name to **TG Natural Resources LLC** by March 2021.

Tokyo Gas acquired a 30% stake in Castleton Resources from CCI for an undisclosed price in 2017. Concurrent with the Shell transaction, Tokyo Gas increased its interest in Castleton Resources to about 46%.

Castleton and Tokyo Gas operate and develop acreage in East Texas and Louisiana targeting the Haynesville and Cotton Valley. Tokyo Gas said the acquisition announced July 29 will increase production of Castleton's production 1.6x to 473 MMcf/d from 296 MMcf/d.

In connection with the deal, Tokyo Gas's group management said that, by 2030, its overseas profits will increase by 3x. Tokyo Gas plans to continue to invest in expanding its business in North America.

In another energy deal in the U.S. announced July 29, Tokyo Gas also said it would purchase the Aktina Solar Project in Wharton County, Texas, which has been developed by **Hecate Energy LLC** of Chicago. That acquisition was set to close Aug. 5.

—Darren Barbee

Presidio Petroleum Tops Tapstone In Bid For Templar Assets

PRESIDIO PETROLEUM continued its expansion in the Anadarko Basin with the acquisition on Aug. 6 of **Templar Energy LLC**'s assets through a bankruptcy auction.

Templar Energy, backed by **Ares Management LLC**, held about 273,000 net acres located within the western Anadarko Basin of the Midcontinent region. The company's acreage spans Texas and Oklahoma, including into the STACK play of central Oklahoma.

Led by CEO Brian Simmons, Templar filed for Chapter 11 bankruptcy on June 1 with about $426 million in outstanding debt and sought a court-approved sale of its assets. The company previously completed a comprehensive restructuring in 2016.

The acquisition of Templar Energy's assets by Presidio Petroleum was worth about $91 million, according to **BMO Capital Markets**. The company's bid overtook a $65 million stalking horse bid made earlier by **Tapstone Energy LLC**.

The Templar transaction represents the second add-on acquisition for Presidio since Morgan Stanley Energy Partners' initial investment in the company in 2018 as well as its expansion into the STACK play.

Headquartered in Fort Worth, Texas, Presidio has assets located in the Western Anadarko Basin of Texas, Oklahoma and Kansas. The company was formed in 2016 by industry veterans Chris Hammack, formerly with **Trinity River**, and Will Ulrich, formerly of **Atlas Energy**.

Ulrich, who serves as co-CEO of Presidio alongside Hammack, said Presidio was founded with a differentiated strategy of pursuing attractive risk-adjusted returns through operational excellence and capital-efficient growth via acquisition, not drilling activity.

"At Presidio, we view ourselves as the leading custodians of mature, long-lived oil and gas properties in the U.S."

Presidio entered the Anadarko Basin in 2018 through the acquisition of **Midstates Petroleum Co. Inc.**'s position for about $58 million. Last year, the company bolstered the position with the multimillion-dollar acquisition of **Apache Corp.**'s western Anadarko assets.

According to a statement by Hammack, this extensive asset base, further enhanced by the Templar acquisition, makes Presidio the "logical consolidator of the Anadarko Basin."

"This acquisition is a logical extension of the asset optimization strategy we established upon founding Presidio, and we are excited to apply the knowledge gained from our previous two acquisitions in the basin and decades of operational experience to unlock value responsibly from the Templar assets," he said.

The Templar acquisition includes substantially all of the oil and natural gas producing properties of Templar Energy and certain affiliates in the Anadarko Basin.

Morgan Stanley Energy Partners is the energy-focused private-equity business of **Morgan Stanley Investment Management**.

—Emily Patsy

Pegula's SPAC: Buffalo Bills Owner's Blank-Check Company Seeks Deals

JEFF BUKOWSKI/SHUTTERSTOCK.COM

Billionaire NFL and NHL team owner Terrence M. Pegula's foray into the world of blank-check oil and gas companies has culminated in an IPO of $300 million in gross proceeds, according to federal regulatory filings. The newly public company, **East Resources Acquisition Co.**, plans to acquire assets after low commodity prices caused distress across the industry. Pegula will serve as the company's chairman, CEO and president.

Pegula largely made his fortune through deals in the early part of the last decade. In 2010, he sold **East Resources Inc.** to **Royal Dutch Shell Plc** for $4.7 billion. In 2014, he was majority owner of the assets sold by **HG Energy LLC** to Aubrey McClendon's **American Energy Partners LP** for $1.75 billion.

Those paydays allowed Pegula, worth an estimated $5 billion, to create what Forbes described as his "sports empire" of professional teams, including the Buffalo Sabres of the National Hockey League. He has continued to operate oil and gas interests through entities operating small assets in Texas, Colorado and Wyoming through **East Management Services**, of which he is owner and vice president.

With East Resources Acquisition Co., Pegula will also join other NFL owners, most notably Dallas Cowboys owner Jerry Jones, in making large new investments during a stagnant time for the oil and gas industry.

In keeping with other blank-check or special purpose acquisition corporation (SPAC) entities, East Resources has not specified a particular target for acquisition other than to say it will search for deals and combinations in the U.S. The company's executives and board have a broad scope of experience in several plays, including the Marcellus and Utica shales, West Texas and offshore Gulf of Mexico.

Guided by Pegula's 40 years of experience and relationships in the industry, East Resources will seek to acquire operational control and look for companies with the ability to reduce costs, increase production or optimize operations to create "improved economics and returns to shareholders." Further criteria for acquisitions include one or more companies with onshore oil and gas operations that have significant reserves, a history of production and free cash flow generation from existing operations.

The company said its deep industry knowledge and investing experience and the low values of assets makes the downturn an ideal time to buy.

"We believe that there is a unique and timely opportunity to achieve attractive returns by acquiring and exploiting oil and natural gas exploration and production assets in proven basins with extensive production history and limited geologic risk," the company said in a prospectus filed July 20 with the U.S. Securities and Exchange Commission.

The new blank-check company was sponsored by **East Sponsor LLC**. Its managing member is **East Asset Management LLC**, which is owned by Pegula and his wife, Kim S. Pegula, both of whom are managing members of the company. East Asset Management purchased up to $50 million interest in the new East Resources SPAC.

East Resources is also tied by common board members and management to **JKLM Energy LLC**, which was founded by Pegula. The independent oil and gas company operates a 120,000-acre position in Potter County, Pa., where it has targeted the Burkett, Marcellus and Utica.

Wells Fargo Securities LLC was sole book-runner for the offering. The company granted underwriters a 45-day option to purchase up to an additional 4.5 million units at the IPO price to cover over-allotments, if any. **Latham & Watkins LLP** represented East Resources Acquisition Co. in the offering with a corporate team led by New York partners Marc Jaffe and Ian Schuman and Houston partner Ryan Maierson.

In addition to his businesses, Pegula has been appointed by Pennsylvania governors to the Marcellus Shale Advisory Commission and the Penn State Board of Trustees. In 2020, he was appointed to serve on the National Petroleum Council by U.S. Energy Secretary Dan Brouillette.

—Darren Barbee

Range Resources Closes Louisiana Chapter

CASTLETON RESOURCES LLC said Aug. 17 it had closed on the purchase of **Range Resources Corp.**'s North Louisiana assets. Range Resources, based in Fort Worth, Texas, stands to gain potential proceeds of up to $335 million. The companies announced the deal on Aug. 3.

As part of a purchase and sale agreement, Range will divest its North Louisiana assets to Castleton Resources for gross proceeds of $245 million. Castleton Resources also agreed to pay an additional $90 million that is contingent on future commodity prices.

Range acquired the asset in 2016 through an all-stock merger with **Memorial Resource Development**, picking up about 220,000 net surface acres in the Terryville Field in Northern Louisiana. The transaction, which included the assumption of $1.1 billion in debt, was valued at about $4.4 billion.

"After the sale of our North Louisiana assets, Range's cost structure and capital productivity will take another meaningful step forward, driven by material improvements in our cash unit costs and a base decline solidly under 20%," Jeff Ventura, Range CEO, said in a statement Aug. 3.

According to the company website, Range has about 140,000 net acres in North Louisiana with stacked pay potential for the Lower Cotton Valley. At the time of the sale, the North Louisiana assets were producing approximately 160 MMcfe/d. Range did not have any drilling and completion activity planned for the assets in 2020.

Per the agreement with Castleton Resources, Range will retain certain commitments through their remaining term. Range intends to use $28.5 million of the sale proceeds to reduce a portion of the retained commitments.

Castleton Resources is an E&P company focused on being a consolidator in the Ark-La-Tex region. The company is owned by Castleton **Commodities International LLC** (CCI) and **Tokyo Gas Co. Ltd**.

Pro forma for the Range acquisition, Castleton Resources will own over 315,000 net acres of leasehold in East Texas and northern Louisiana with total daily net production of nearly 500 MMcfe/d.

Craig Jarchow, president and CEO of Castleton Resources, said in a statement the company is well-positioned to enhance the value of Range's North Louisiana assets through "further operational enhancements, among other activities."

"We are very pleased to be able to purchase quality assets at a low-point in the commodity-price cycle. ... We remain focused on strategically growing and diversifying our upstream and midstream assets, and broadening our portfolio with attractive opportunities that complement our long-term business strategy," Jarchow said.

Following close of the deal with Range, Tokyo Gas will increase its ownership in Castleton Resources to approximately 70% from 46%, with the balance to be held by CCI. Castleton Resources also agreed to change its name to "TG Natural Resources LLC" by late March 2021.

"Tokyo Gas America participated in Castleton Resources in May 2017, and has grown steadily with Castleton Resources by acquiring shale and tight sand assets since then," said Kazuya Kurimoto, president and CEO of Tokyo Gas America Ltd., a subsidiary of Tokyo Gas Co. Ltd. "We are pleased that Castleton Resources will join Tokyo Gas group companies, and with Castleton Resources as the base, we will continue to aim for further business expansion in East Texas and Louisiana."

The North Louisiana transaction was expected to close in August with an effective date of Feb. 1.

Greenhill is M&A adviser and **Kirkland & Ellis** as legal adviser to Castleton Resources. **K&L Gates** was legal adviser to Tokyo Gas America Ltd. **Bracewell LLP** was legal adviser to CCI.

Following the planned closing of the North Louisiana asset sale, Range's liquidity is expected to exceed $1.6 billion, according to the company release.

At the end of the second quarter, Range had $639 million drawn on its revolver and over $1.4 billion of additional borrowing capacity under the commitment amount. Range expects its $3 billion borrowing base to be unchanged following the sale of its North Louisiana assets.

—Emily Patsy

Thais To Texas: Devon Energy Aims For Early Barnett Exit

DEVON ENERGY CORP. has again fiddled with the timing of its Barnett Shale exit, saying on Aug. 4 that it will complete its deal with **Kalnin Ventures LLC** and backer **Banpu Pcl** of Thailand earlier than expected.

The deal, potentially worth up to $830 million, will now close at the beginning of October rather than the end of the year. The Oklahoma City-based E&P company said it expects to receive a net cash payment of $300 million at closing on Oct. 1, which will coincide with a special dividend to shareholders worth $100 million.

The companies had most recently postponed finalizing the deal until Dec. 31. The transaction, first announced in December 2019, was originally meant to close in the second quarter before a destructive oil price war and global pandemic threw the industry off-kilter.

Christopher Kalnin, CEO of **BKV Corp.** and Kalnin Ventures, told Hart Energy his company wanted to move up the timetable for closing with Devon.

"The main rationale for the timing change is that we have become more bullish on the gas markets for Q4 2020 and FY 2021," Kalnin said.

Devon said it has already collected a $170 million deposit. However, Banpu's costs at closing will be adjusted based on Devon's cash flow from the Barnett Shale asset since Sept. 1. The company may also have to pay contingency fees of up to $260 million based on future commodity prices.

Devon would receive the contingency payments at either a $2.75 Henry Hub natural gas price or a $50 WTI oil price. The payment period has a term of four years beginning Jan. 1, 2021. Payments are earned and paid on an annual basis.

Devon's footprint in the Barnett Shale includes more 320,000 gross acres and 4,200 producing wells comprising the birthplace of the shale revolution. After closing, Kalnin Ventures will take over as the largest natural gas producer in the Barnett Shale.

—Darren Barbee

ConocoPhillips Extends Montney Shale Position

CONOCOPHILLIPS CO. on July 22 tacked on additional acreage to its position in Canada's Montney Shale, giving the Houston-based independent "significant running room at a very attractive all-in cost," COO Matt Fox said.

In a company release, ConocoPhillips said it agreed to pay **Kelt Exploration Ltd.** roughly $375 million in cash for 140,000 net acres located in the liquids-rich Inga-Fireweed asset Montney zone. ConocoPhillips will also assume about $30 million in financing obligations for associated partially owned infrastructure.

Production associated with the acquired asset, which will add over 1,000 well locations, is approximately 15,000 boe/d. ConocoPhillips estimates the acquisition adds over 1 billion boe of resource with an all-in cost of supply of mid-$30s (WTI basis), the company release said.

Fox said ConocoPhillips has tracked and analyzed the acreage, which is directly adjacent to ConocoPhillip's existing Montney position, for some time.

The acquisition "represents a high-value extension of our existing Montney position, and we're pleased to capture this opportunity at an attractive cost of supply that meets our criteria for resource additions," Fox said in a news release.

Upon closing, ConocoPhillips' Montney position will expand to 295,000 net acres with 100% working interest, nearly doubling its total acreage in the play while also giving the company full control, according to analysts with **Tudor, Pickering, Holt & Co.** (TPH).

The analysts estimate the transaction has an implied acreage value of about $1,250 to $1,600 per acre, assuming a 3-4x cash flow multiple at about $42/bbl WTI next year.

"Overall, the transaction is consistent with the company's messaging regarding selective A&D for low cost-of-supply resource, with the strength of the balance sheet keeping the company positioned for future opportunities," the TPH analysts wrote in a July 23 research note.

Separately, ConocoPhillips on July 22 announced that it initiated production from its first mutliwell pad on its Montney position in first-quarter 2020.

Fox said ConocoPhillips is still in the process of bringing initial wells online, but noted early results are encouraging.

"We have confirmed the liquids-rich nature of the play and also confirmed that transferring the drilling and completion techniques we're employing in the U.S. Big 3 can add significant rate and recovery potential to the play," he said. "We view the Montney as a very attractive long-term asset and today's announcement gives us significant running room at a very attractive all-in cost."

The acquisition is subject to regulatory approval and is expected to close third-quarter 2020. The effective date for the transaction is July 1.

—Emily Patsy

TRANSACTION HIGHLIGHTS

WILLISTON BASIN

■ **Northern Oil and Gas Inc.** continued its buildout in the core of the Williston Basin, the company said July 31, through the acquisition of 400 acres primarily operated by **ConocoPhillips Co.**, **Continental Resources Inc.** and **WPX Energy Inc**.

In exchange for $3.2 million in cash and approximately 2.95 million shares of its common stock, Northern Oil and Gas will acquire nonoperated interests in producing properties, wells-in-process and acreage from multiple counterparties. The company also agreed to pay up to 450,000 additional shares tied to the fate of the Dakota Access Pipeline.

Earlier this year, Northern, which touts itself as being the largest Williston Basin nonoperator, agreed to a $1.5 million-cash purchase of nonoperated interests in core Williston Basin properties operated by WPX Energy. The transaction was expected to close July 1.

"We continue to add to our core inventory," Northern COO Adam Dirlam said in a July 31 statement commenting on the company's recent acquisitions. "Record levels of wells-in-process should drive strong volumes and improve upon our return on capital employed metrics in 2021 and beyond."

In total, Northern will acquire nonoperated interests in 0.7 net producing wells, 1.9 net wells in process and 1 net undrilled locations located in North Dakota's McKenzie, Mountrail and Dunn counties. Production from the acquisitions is expected to come online in mid-2021, averaging approximately 820 boe/d.

The transactions are expected to close within 60 days. Northern plans to pay back its acquisition costs and development capital expenses related to the acquired properties within three years while retaining additional future upside inventory, the company said.

GOM

■ Israel's **Navitas Petroleum LP** said July 28 that **The Blackstone Group LP** signed a preliminary deal to raise its stake in a drilling project in the Gulf of Mexico to 47% from 16%.

Navitas had partnered with U.S. oil firm **LLOG Exploration Co. LLC** and Blackstone's portfolio company **Beacon Offshore Energy LLC** in drilling at the Shenandoah discovery that holds 431 MMbbl of oil. Blackstone, through Beacon, is buying LLOG's 31% holding in the $250 million project while Navitas would continue to hold 53%, Navitas said.

It noted that the project is expected to generate $1.13 billion in cash flow for the company. Production is forecast to begin in 2024. The group recently signed a deal for drilling rig with Transocean Ltd.

"Blackstone's and Beacon's capabilities will help complete the project's financing and rapid and successful development," Navitas Chairman Gideon Tadmor said.

PERMIAN BASIN

■ **Black Stone Minerals LP** on July 27 said it completed its previously announced asset sales with cash proceeds of about $150 million boosting cash returns to shareholders of the Houston-based company.

In a June release, Black Stone Minerals had announced entering into two separate agreements to sell certain mineral and royalty properties from its position in the Permian Basin. The larger of the two agreements—worth about $100 million—involves **Pegasus Resources LLC**, a portfolio company of **EnCap Investments LP**.

On July 21, the company closed on the sale to Pegasus of undivided interests across parts of Black Stone's Delaware and Midland Basin positions. The effective date of the transaction was July 1.

The second sale, composed of mineral and royalty interests in specific tracts in Midland County, Texas, within the Midland Basin to a private buyer, was scheduled to close on July 28. The company anticipated total consideration for the Midland Basin transaction to be $54.5 million after customary closing adjustments.

Proceeds from the asset sales will be used to accelerate Black Stone Minerals' debt reduction goals by paying down the balance outstanding on the company's revolving credit facility.

APPALACHIAN BASIN

■ **CNX Resources Corp.** agreed to buy out its midstream affiliate, creating the "lowest-cost Appalachia producer," the Pittsburgh-based E&P company said July 27.

Under a merger agreement, CNX Resources will purchase the remaining public stake, comprising about 42.1 million outstanding common units, of **CNX Midstream Partners LP**. Total consideration for the all-stock transaction, which is valued at roughly $357 million, is about $8.47 for each outstanding CNX Midstream unit.

The exchange ratio of 0.88 CNX shares per CNX Midstream unit represents a 15% premium to the 30-day average exchange ratio or a 28% premium to close on July 24, according to analysts with **Tudor, Pickering, Holt & Co.** (TPH).

"At first blush, valuation represents relatively low premium paid for a one-off transaction to bring cash cost savings in house," TPH analysts wrote in late July.

CNX Midstream Partners is an MLP with gathering and other midstream energy assets to service natural gas production in the Appalachian Basin in Pennsylvania and West Virginia. The company formed in 2016, originally as **CONE Midstream Partners**, a joint venture (JV) between CNX Resources, operating as **CONSOL Energy** at the time, and **Noble Energy Inc**.

However, CNX Resources rebranded the company as CNX Midstream Partners in 2017 following the purchase of Noble's 50% interest in the midstream JV for $305 million in cash.

MONTNEY SHALE

■ **Canadian Natural Resources Ltd.** agreed to acquire Montney Shale producer **Painted Pony Energy Ltd.** on Aug. 10, continuing consolidation among E&Ps in the gas play located in the Western Canadian Sedimentary Basin.

In a company release, Canadian Natural Resources, Canada's largest oil and gas producer, said it will acquire smaller rival Painted Pony for about C$461 million (US$344.26 million) including debt. The offer includes the acquisition of all the issued and outstanding common shares of Painted Pony, for a cash consideration of C$0.69 per share, a premium of 17% to the closing price on the Toronto Stock Exchange on Aug. 7, according to the release.

Painted Pony holds a high working interest, contiguous land block covering 186,727 net acres of Monterey rights, according to the company website. The properties are located in Northeast British Columbia areas of Blair, Daiber, Kobes and Townsend.

Wildcatters Fund
the political action committee of independents

ENERGYINDEPTH®

Endangered Species Watch
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

DIVESTMENTFACTS.COM

IPAA/PESA Energy Education Center

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA | WWW.IPAA.ORG

EASTERN US

1 ***Resolve Exploration Corp.*** is under way at a northeast offset to an oil well completed by the company in late 2019. In Jefferson County, Ill., #2 Withrow is targeting Ullin oil and has a planned depth of 3,900 ft and is in Section 36-1s-4e. Within one-quarter of a mile to the southwest, the Mt. Vernon, Ill-based company's #1 Withrow was tested pumping 124 bbl of crude daily through Salem Lime perforations at 3,364-69 ft. It was drilled to 3,745 ft and extended Coil West Field more than 1 mile to the south. Oil production in Coil West Field is about 1 mile north north of the succesful field extension. Opened in 1942, the deepest wells in the Jefferson County Field yield crude from Salem Lime.

2 IHS Markit reported that ***Campbell Energy*** released information on three Maunie North Consolidated Field completions in White County, Ill. The deeper pool wells were drilled in irregular Section 19-5s-14w. The #11 Kempf was drilled to 4,130 ft and was tested flowing 30 bbl of oil and 150 bbl of water per day from commingled perforations in St. Louis (3,130-3,226 ft), Salem Lime (3,765-3,796 ft) and Ullin (4,036-4,050 ft). Within one-quarter mile to the north, #12 Kempf was drilled to 4,130 ft and was tested flowing 30 bbl of water and 149 bbl of water per day from commingled perforations in St. Louis at (3,265-3304 ft), Salem Lime at (3,760-3,954 ft) and Ullin at (4,051-61 ft). About one-quarter of a mile to the west of #11 Kempf, #13 Kempf was also drilled to 4,130 ft, and it produced 20 bbl of oil and 160 bbl of water per day from commingled perforations in St. Genevieve (3,055-3,104 Ft), St. Louis (3,200-3,283 ft) and Salem Lime/Ullin (3,888-4,056 ft). Campbell's headquarters are in Carmi, Ill.

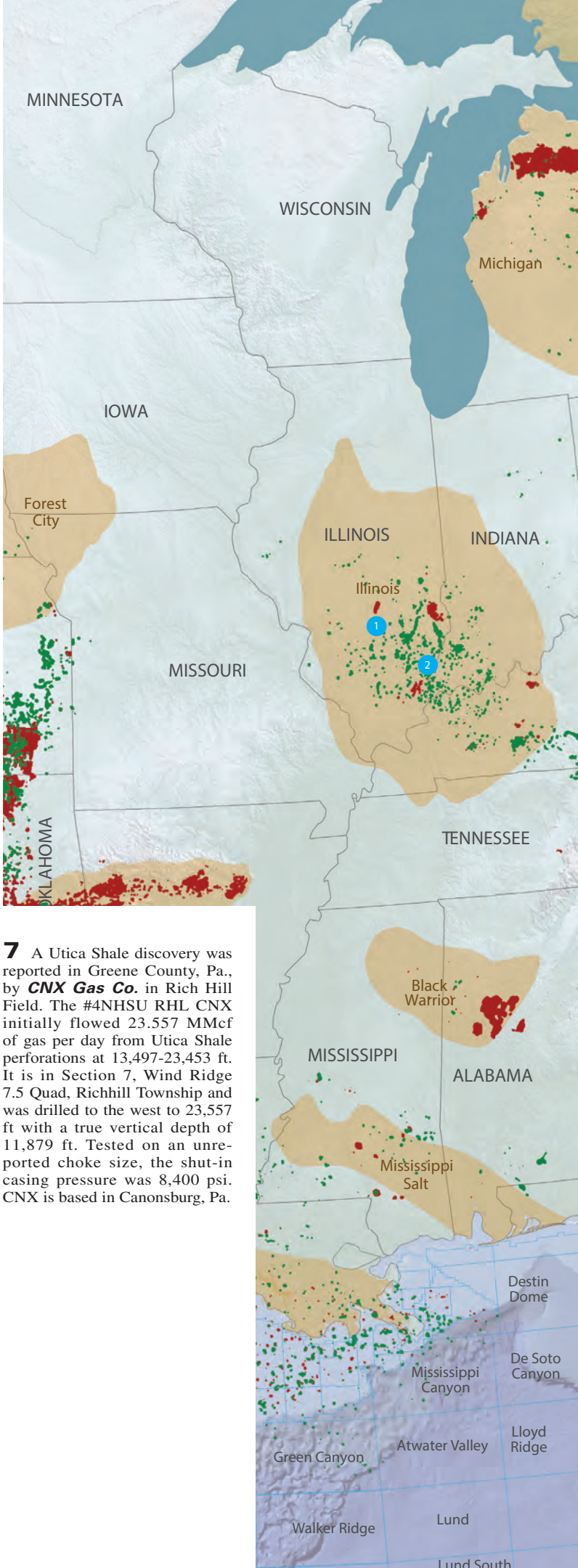
3 Two Belmont County, Ohio, Utica Shale discoveries were reported by ***Rice Drilling Co***. The Hunter Field wells were drilled from a pad in Section 23-7n-5w. The #12 Del Scorcho was drilled to 25,984 ft (9,298 ft true vertical). It was tested flowing 35.592 MMcf of gas and 2,303 bbl of water per day from fractured perforations at 9,302-25,895 ft. The #10 Del Scorcho was drilled to 25,981 ft (9,259 ft true vertical) and also bottomed in Section 8 flowing 30.72 MMcf of gas and 189 bbl of water per day. Production is from fractured perforations at 9,157-25,891 ft. Rice Drilling is based on Canonsburg, Pa.

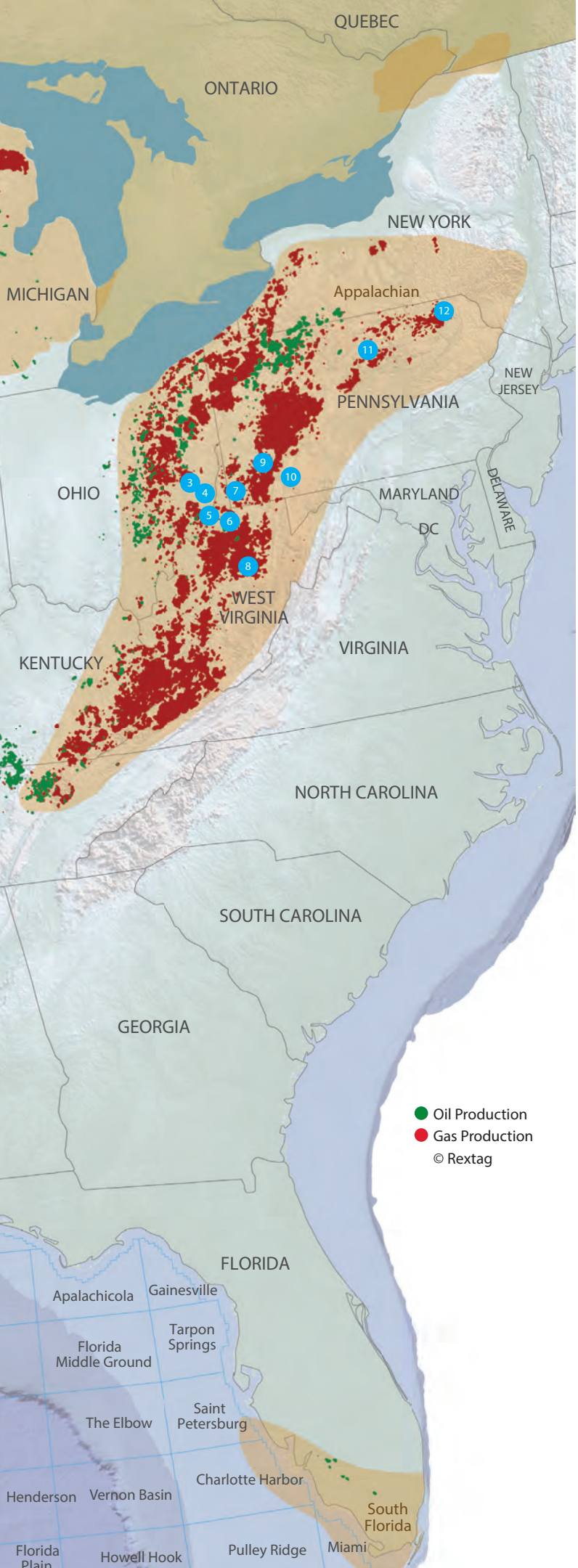
4 In Belmont County, Ohio, ***Rice Drilling*** completed a Utica Shale well in Section 16-7-5w. The #1H Krazy Train is in Morristown Consolidated Field. It was drilled to 27,888 ft with a true vertical depth of 8,802 ft. It initially flowed 2.202 MMcf of gas and 2,294 bbl of water per day. Production is from acidized and fractured perforations at 9,507-27,816 ft.

5 Results from a Woodsfield East-Utica Shale well were announced by Irving, Texas-based ***Eclipse Resources Co.*** The Monroe County, Ohio, well, #1H Bluebonnet A, is in Section 29-3n-4w and was drilled to 26,344 ft with a true vertical depth of 9,864 ft. It was tested after 104-stage fracturing flowing 14.849 MMcf of gas and 767 bbl of water daily.

6 ***Southwestern Production Co.*** completed a Marcellus Shale venture in Wetzel County, W. Va. The #5H SWN A WTZ was drilled to a total depth of 20,865 ft with a true vertical depth of 7,132 ft. It was tested flowing 89 bbl of oil, 13.4 MMcf of gas with 276 bbl of water per day. Production is from perforations at 7,645-20,815 ft. The well is in an unnamed field in Proctor District, Wileyville 7.5 Quad. It was tested after fracturing with a shut-in casing pressure of 1,707 psi. Southwestern's headquarters are in Spring, Texas.

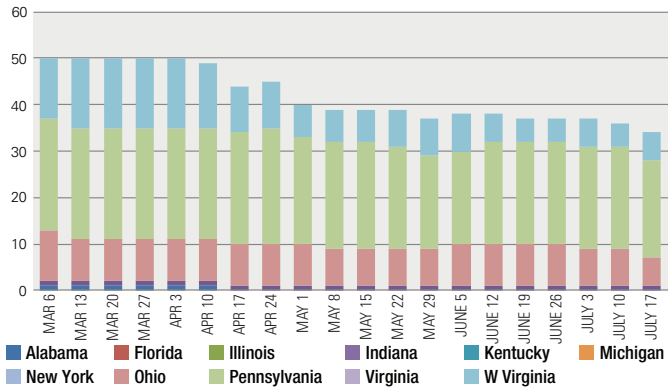
7 A Utica Shale discovery was reported in Greene County, Pa., by ***CNX Gas Co.*** in Rich Hill Field. The #4NHSU RHL CNX initially flowed 23.557 MMcf of gas per day from Utica Shale perforations at 13,497-23,453 ft. It is in Section 7, Wind Ridge 7.5 Quad, Richhill Township and was drilled to the west to 23,557 ft with a true vertical depth of 11,879 ft. Tested on an unreported choke size, the shut-in casing pressure was 8,400 psi. CNX is based in Canonsburg, Pa.





Eastern US Rig Count

Mar. 6, 2020-July 17, 2020



Source: Baker Hughes Co.

8 ***Dominion Exploration & Production Inc.***, subsidiary of ***CNX Gas***, announced results from recompletion in Jarvisville Field in Harrison County, W. Va. The #5030 Christopher Turner is in Union Dist., Milford West 7.5 Quad. It was tested flowing 60,000 cu ft of commingled gas from Fifty Foot Sand at 1,954-2,042 ft, Gordon Sand at 2,144-2,216 ft and Fifth Sand at 2,392-2,402 ft. It was tested on an unreported choke size with a shut-in casing pressure of 230 psi. The original well was drilled in 1989 by CNX, and it produced 490,000 cu ft of gas from Balltown Sand at 3,276-3,313 ft with a shut-in casing pressure of 500 psi.

9 Two Washington County, Pa., Lone Pine Field-Marcellus Shale wells were completed at a drill-pad in Section 7, Washington East 7.5 Quad, Amwel Township by ***Range Resources***. According to IHS Markit, the #7H Wager Unit was drilled to 20,035 ft (7,367 ft true vertical). It initially flowed 31.059 MMcf of gas with a shut-in casing pressure of 1,550 psi. Production is from fractured perforations at 8,320-19,959 ft. The #5H Wagers Unit was drilled to 20,948 ft (7,361 ft true vertical). It produced 35.612 MMcf of gas. The shut-in casing pressure was 3,095 psi. Production is from perforations at 7,778-20,879 ft. Range's headquarters are in Fort Worth.

10 Five Fayette County, Pa., Marcellus Shale wells were completed by Houston-based ***Chevron Corp***. The producers were drilled from a Luzerne Field pad in Section 2, Carmichaels 7.5 Quad, Luzerne Township. The #1H Yoder was drilled to 18,266 (7,920 ft true vertical) and flowed 3.803 MMcf of gas with a shut-in casing pressure of 4,619 psi. Production is from a perforated zone at 8,592-18,043 ft. The #2H Yoder was drilled to 17,268 ft, 8,000 ft true vertical and flowed 3.402 MMcf of gas per day from perforations at 8,406-17,043 ft with a shut-in casing pressure of 4,585 psi. The #5H Yoder was drilled to 16,899 ft, 8,100 ft true vertical, and produced 3.571 MMcf of gas per day from perforations at 8,641-16,701 ft. The #6H Yoder was drilled to 18,201 ft, 8,000 ft true vertical, and produced 5.906 MMcf of gas per day from perforations at 8,341-15,665 ft with a shut-in casing pressure of 4,425 psi. The #10 H Yoder was drilled to 16,834 ft, 8,000 ft true vertical, and was tested flowing 2.657 MMcf of gas per day from perforations at 8,739-16,600 ft with a shut-in casing pressure of 4.171 psi.

11 ***Chief Oil & Gas*** announced results from a Lycoming County, Pa., Marcellus Shale completion. The #5H Hemlock Ridge Estates E is in Eldersville Field. It was tested flowing 24,151 MMcf of gas per day from a perforated zone at 8,904-20,737 ft and with a shut-in casing pressure of 2,449 psi. The venture is in Section 8 Grover 7.5 Quad, McNett Township. Chief is based in Dallas.

12 In Pennsylvania's Susquehanna County, ***Cabot Oil & Gas Corp.*** completed a Marcellus Shale producer. The #8H Carey R is in Lenox Field and was drilled to a total depth of 16,853 ft with a true vertical depth of 7,411 ft. It was tested flowing 16.1 MMcf of gas per day from perforations at 8,206-16,791 ft. Tested on an unreported choke size, the shut-in casing pressure was 650 psi.

GULF COAST

1 ***Crimson Energy Partners IV*** completed an Eagle Ford Shale well that produced 548 bbl of 30° API oil, 365,000 cu ft of gas and 463 bbl of water per day. IHS Markit announced that the Briscoe Ranch venture, #10HL Bowman B 234 Unit, is in Section 7, &GN RR CO Survey, A-232 in Dimmit County (RRC Dist. 1), Texas. It was drilled to a total depth of 16,615 ft, and the true vertical depth is 7,215 ft. Production is from perforations at 7,801-16,611 ft. Crimson Energy's headquarters are in Fort Worth.

2 ***Marathon Oil Corp.*** announced more results from drilling at its Turnbull-Eagleville Field prospect in Karnes County (RRC Dist. 2), Texas. The wells were drilled from a pad in Section 603 Karnes CSL Survey, A-168. The #1H Turnbull Unit H was drilled to 19,105 ft (11,718 ft true vertical) and produced 2,828 bbl of oil, 4.195 MMcf of gas and 1,195 bbl of water per day from perforations at 11,647-18,982 ft. Gauged on a 28/64-inch choke, the flowing casing pressure was 3,453 psi. The #2H Turnbull Unit H was drilled to 19,063 ft (11,719 ft true vertical) and flowed 2,344 bbl of oil, 3.644 MMcf of gas and 1,062 bbl of water daily from perforations at 11,658-18,942 ft. It was tested on a 28/64-inch choke with a flowing casing pressure of 3,177 psi. The #3H Turnbull Unit E reached 18,726 ft (11,750 ft true vertical) and produced 2,408 bbl of oil, with 2.277 MMcf of gas and 1,340 bbl of water per day from a perforated zone at 11,459-18,595 ft. Tested on a 28/64-inch choke, the flowing casing pressure was 3,011 psi. Marathon is based in Houston.

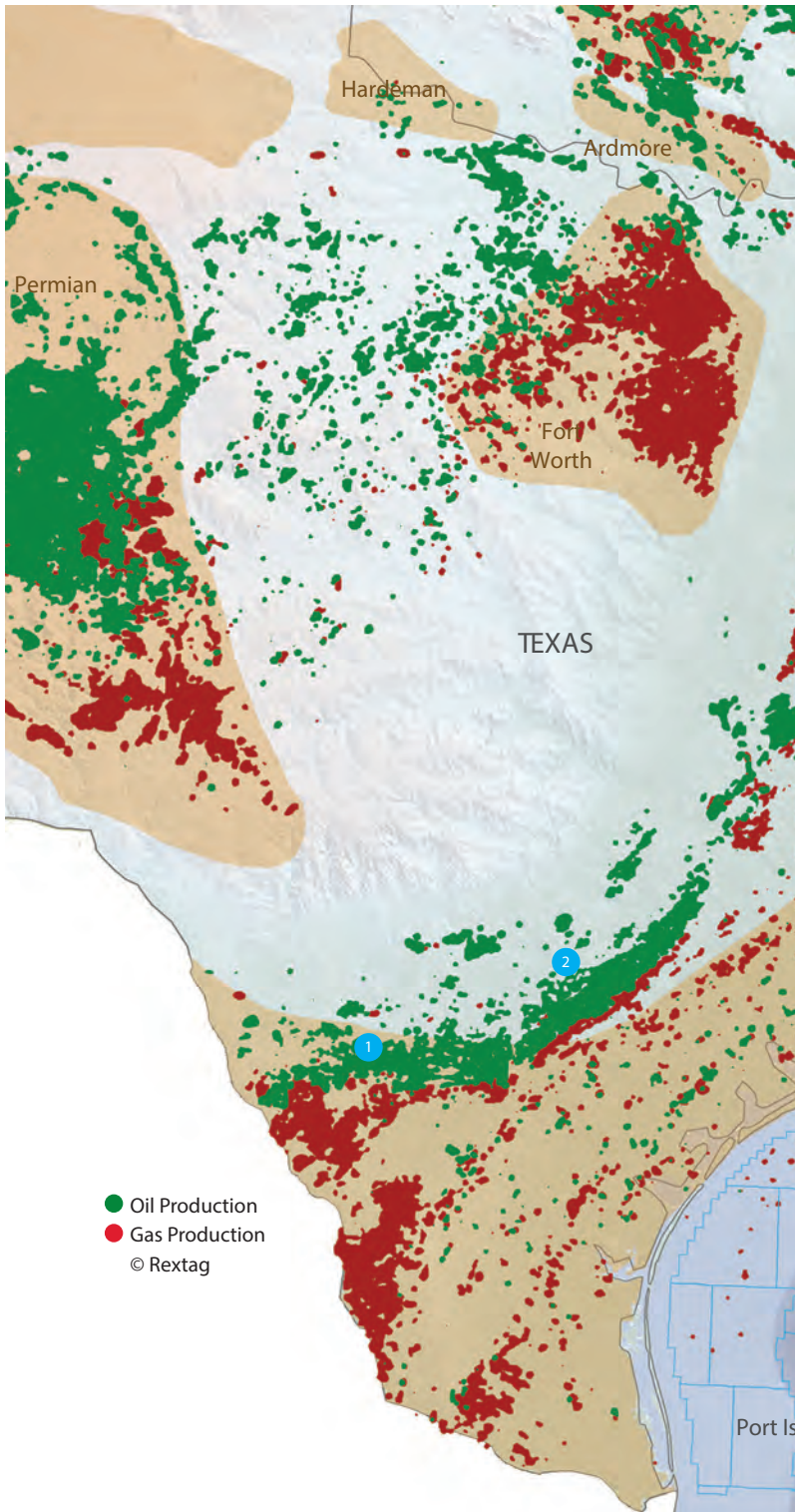
3 A Smith County (RRC Dist. 6), Texas, Cotton Valley well was announced by ***Breitburn Operating***. Located in Wiley J Parchman Survey, A-792, #1H Chapel Hill 5 was drilled to 17,975 ft, and the true vertical depth is 11,436 ft. It was tested flowing at a daily rate of 184 bbl of 48° API oil, with 9.492 MMcf of gas and 1,531 bbl of water. Gauged on a 40/64-inch choke, the flowing casing pressure was 2,186 psi, and the shut-in casing pressure was 2,665 psi. Production is from a perforated zone at 11,625-17,851 ft. Breitburn's headquarters are in Los Angeles.

4 Three Haynesville discoveries were completed at a pad in De Soto Parish, La., by ***GEP Haynesville***. The wells are in Section 30-13n-12w in Red River/Bull Bayou Field. The #001-Alt CMP LLC 30-31HC was drilled to 20,182 ft, 12,125 ft true vertical, and bottomed in Section 31. It initially flowed 40.953 MMcf of gas and 2,150 bbl of water per day from perforations at 12,461-19,972 ft. Tested on a 34/64-inch choke, the flowing casing pressure was 7,932 psi. The #1-Alt Robertson 30-31 HC was drilled to 20,050 ft, 12,151 ft true vertical. It produced 31.921 MMcf of gas and 1,992 bbl of water daily from perforations at 12,569-19,837 ft. Gauged on a 34/64-inch choke, the flowing casing pressure was 7,675 psi. The #001-Alt Blackmon 31-06HC was drilled to 18,303 ft, and the true vertical depth is 11,937 ft. It flowed 32.795 MMcf of gas with 1,799 bbl of water daily from perforations at 12,276-18,248 ft. Gauged on a 34/64-inch choke, the flowing casing pressure was 7,759 psi. GEP's headquarters are in The Woodlands, Texas.

5 In Louisiana's Bossier Parish, Dallas-based ***Aethon Energy Operating*** completed two Hayneville producers in Sligo Field. The #2-Alt Roy 18-19HC is in Section 18-17n-12w, and it flowed 13.376 MMcf of gas and 1,440 bbl of water from perforations at 10,860-20,777 ft. It was drilled to 20,823 ft, 10,763 ft true vertical, and was tested on a 24/64-inch choke with a flowing casing pressure of 6,956 psi. Within 2 miles to the west in Section 14-17n-12w, #1 Treat 14-23HC produced 15.504 cu ft of gas and 51 bbl of water per day from perforations at 11,125-21,102 ft. Drilled to 21,142 ft, 10,982 ft true vertical, it was tested on a 24/64-inch choke, and the flowing casing pressure was 6,905 psi.

6 ***Arena Offshore LP*** announced results from a Vermilion South Block 342 venture. The #0A03S0B1 OCS G33607 ST00BP01 was tested flowing 230 bbl of 27° API oil, 518 Mcf of gas and 11 bbl of water per day from Williana at 8,940-9,000 ft. The well was drilled to 9,829 ft, and the true vertical depth is 8,407 ft. It was tested on a 12/64-inch choke, and the flowing tubing pressure was 3,386 psi. Arena Offshore is based in The Woodlands, Texas.

7 An Iberia Parish, La., directional producer was reported by Houston-based ***Hilcorp Energy Co***. The Louisiana state waters well, #1 SL 03209; LSA Rob 5 RA SU, is in Lake Sand Field.



It was drilled to 15,078 ft. It initially flowed 91 bbl of 49° API oil, 6.061 MMcf of gas and 5 bbl of water per day. Production is from Robulus perforations between 14,440 and 14,516 ft. Gauged on a 12/64-inch choke, the flowing tubing pressure was 7,713 psi, and the flowing casing pressure was 100 psi.

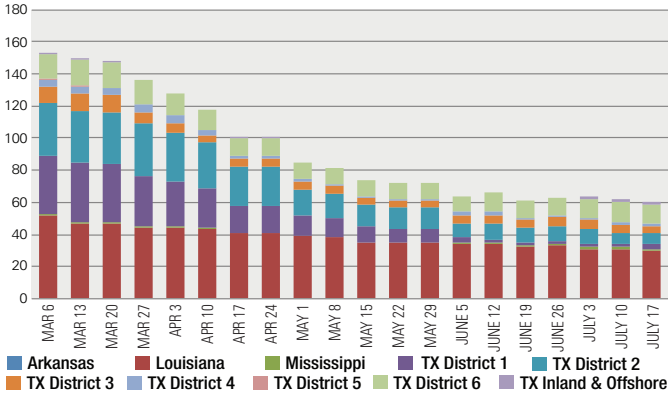
8 In Walker Ridge Block 584, ***Exxon Mobil Corp.*** announced results from a Wilcox discovery. The company's #1JU106S0B OCS G20351 was drilled to 31,910 ft, and the true vertical depth is 29,185 ft. It produced 9,278 bbl of 24.7° API oil, 1.058 MMcf of gas and 125 bbl of water per day from perforations between 30,672 and 31,630 ft. Tested on a 56/64-inch choke, the flowing tubing pressure was 8,037 psi. Exxon Mobil's headquarters are in The Woodlands, Texas.

9 ***Walter Oil & Gas Corp.*** completed a Pliocene discovery in Ewing Bank Block 910. The #3A00S0B0 OCS G24990 was drilled to 18,999 ft, and the true vertical depth is 13,504. It was tested flowing 1,896 bbl of 30° API oil, 3.624 MMcf of gas per day with no reported water. Production is from perforations between 15,850 and 15,860 ft. Walter's headquarters are in Houston.

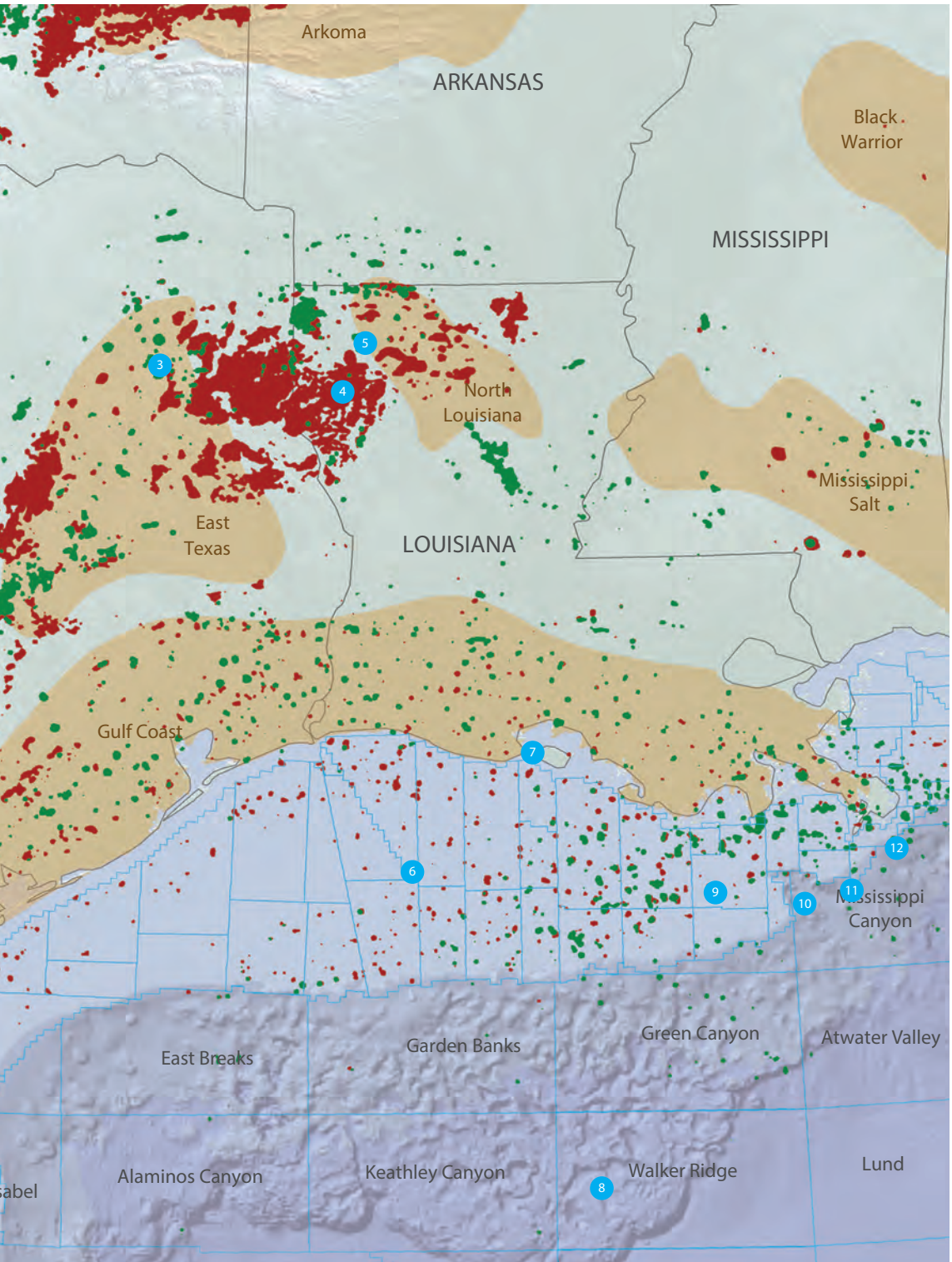
10 In Mississippi Canyon Block 934, Houston-based ***Shell Oil Co***. completed a deepwater Upper Miocene producer at #0A006S1B OCS G07976. The producer initially flowed 11,995 bbl of 26.7° API oil, with 10,000 cu ft of gas and no reported water per day. It was drilled to a total depth of 18,620 ft, and the true vertical depth is 17,826 ft. Gauged on an 88/64-inch choke, the flowing tubing pressure was 4,963 psi. Production is from a perforated zone at 18,423-65 ft.

Gulf Coast Rig Count

Mar. 6, 2020-July 17, 2020



Source: Baker Hughes Co.



11 ***LLOG Exploration*** announced results from a Taggart prospect discovery, #003S0B0 OCS G33178 ST00BP00, in Mississippi Canyon Block 816. The well was drilled in about 5,560 ft of water to 11,562 ft. According to the Covington, La.-based company, the venture encountered 97 ft of net pay in two Miocene objectives. Two subsequent appraisal wells were drilled—in 2015, it hit 147 ft of pay, and in 2019, it hit 84 ft of net pay. Processing of Taggart's reserves will be tied back to the Devils Tower Spar. LLOG also estimates that Taggart has reserves totaling approximately 27 MMbbl of oil equivalent. First production is expected in 2022.

12 ***Deep Gulf Energy III***, a subsidiary of ***Kosmos Energy***, announced results from a Mississippi Canyon Block 214 discovery at #002S0B1 OCS G24059. The well was tested flowing 11,070 bbl of 32.8° API oil, with 19.936 MMcf of gas and 83 bbl of water per day. Production is from Upper Miocene perforations at 16,215-45 ft. It was tested on a 36/64-inch choke with a flowing tubing pressure of 5,058 psi. The well was drilled to 17,835 ft, and the true vertical depth is 17,548 ft. Deep Gulf is based in Dallas.

MIDCONTINENT & PERMIAN BASIN

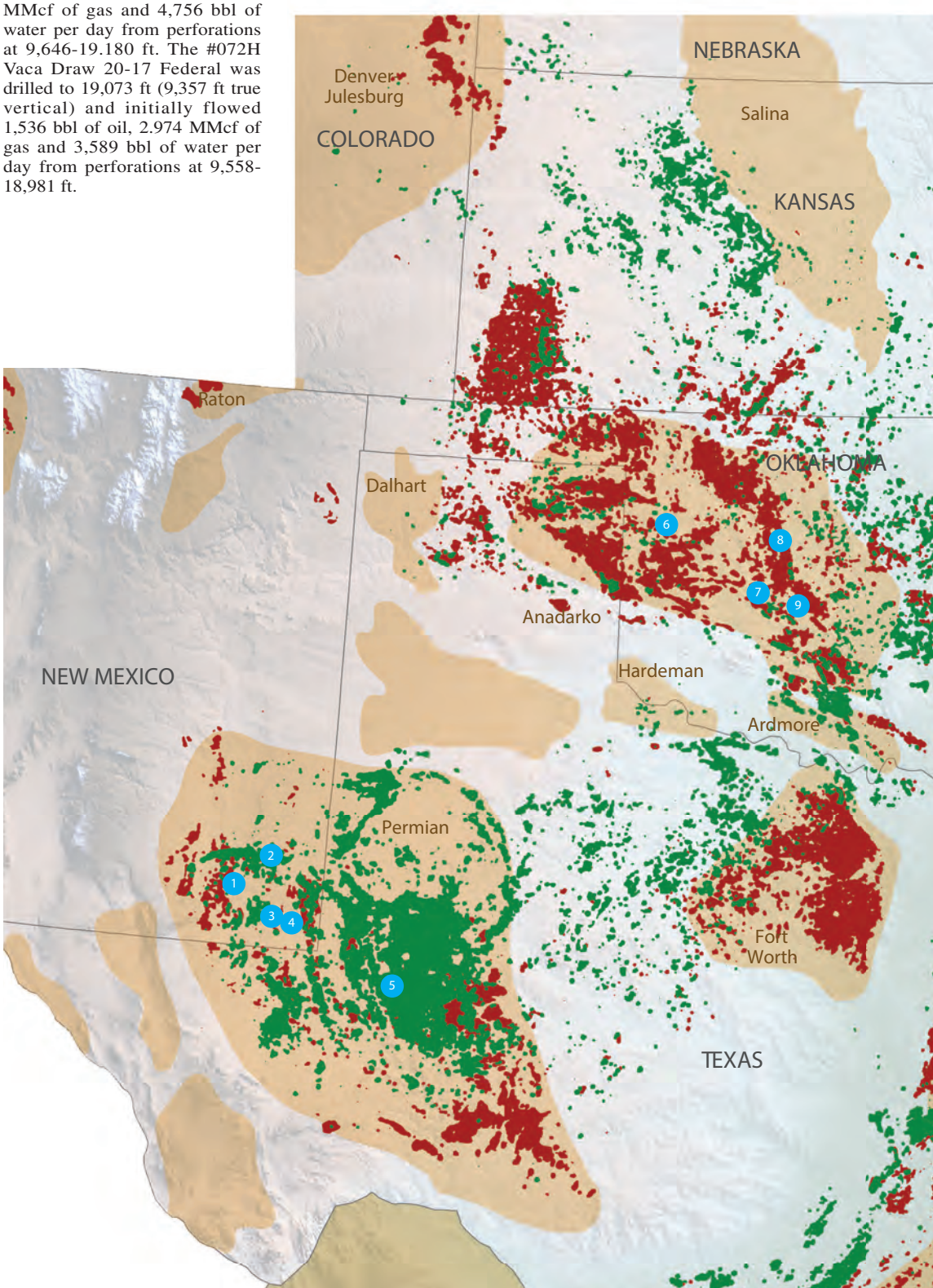
1 In Eddy County, N.M., Houston-based ***Oxy USA*** completed two more Purple Sage Field wells from a drillpad in Section 33-23s-31e. The #177H Sterling Silver MDP1 33-4 Federal Com was drilled to the southeast to 22,091 ft with a true vertical depth of 11,747 ft. It initially flowed 3,231 bbl of oil, 6.171 MMcf of gas and 12,202 bbl of water per day from Wolfcamp at 11,878-21,980 ft. About 1 mile to the northeast, #178H Sterling Silver MDP1 33-4 Federal Com produced 5,360 bbl of oil, 7.976 MMcf of gas and 5,367 bbl of water per day from Bone Spring perforations at 10,947-21,167 ft. It was drilled to 21,318 ft, and the true vertical depth is 10,779 ft. Oxy USA is a subsidiary of ***Occidental Petroleum***.

2 Three Red Tank Field discoveries were announced in Lea County, N.M., by ***Oxy USA***. The Bone Spring producers were drilled from a pad in Section 30-22s-33e on the company's Avogato prospect. The #032H Avogato 30-31 State Com was drilled to a total depth of 22,125 ft and had a true vertical depth of 11,948 ft. It initially flowed 4,742 bbl of oil, 7.824 MMcf of gas and 8,256 bbl of water per day from perforations at 11,850-22,031 ft after 51-stage fracturing. The #024H Avogato 30 31 State Com was drilled to 21,078 ft, 10,961 ft true vertical. It was tested flowing 1,492 bbl of oil, 1.704 MMcf of gas and 1,190 bbl of water per day from fractured perforations at 10,610-20,985 ft. The #025H Avogato 30 31 State Com was drilled to 20.988 ft, 10,785 ft true vertical, and produced 2,127 bbl of oil, 2.664 MMcf of gas and 9,976 bbl of water per day after 51-stage fracturing between 10,572-20,896 ft.

3 Three Lea County, N.M., Bone Spring wells were completed at a pad in Section 20-25s-33e by Denver-based ***Cimarex Energy***. The #043H Vaca Draw 20-17 Federal was drilled to 19,167 ft (9,353 ft true vertical) producing 2,442 bbl of oil, 4.92 MMcf of gas and 4,051 bbl of water per day from perforations at 9,638-19,075 ft. Within 50 ft to the east, #045H Vaca Draw 20 17 Federal was drilled to 19,226 ft (9,376 ft true vertical) and flowed 2,700 bbl of oil, with 3.63 MMcf of gas and 4,756 bbl of water per day from perforations at 9,646-19.180 ft. The #072H Vaca Draw 20-17 Federal was drilled to 19,073 ft (9,357 ft true vertical) and initially flowed 1,536 bbl of oil, 2.974 MMcf of gas and 3,589 bbl of water per day from perforations at 9,558-18,981 ft.

4 A Bobcat Draw Field-Wolfcamp discovery was completed in Lea County, N.M., by ***BTA Oil Producers LLC***. The #036H Rojo 7811 27 Federal Com is in Section 27-25s-33e, and it was tested flowing 1,155 bbl of 45° API oil, 2.9 MMcf of gas and 5,387 bbl of water daily. The proposed total depth was 17,856 ft, and the proposed true vertical depth was 12,929 ft. Gauged on a 41/64-inch choke, the flowing tubing pressure was 1,800 psi, and the shut-in casing pressure was 1,400 psi. Production is from perforations at 13,000-17,580 ft. BTA is based in Midland, Texas.

5 ***Parsley Energy*** announced results from an Upton County (RRC Dist. 7c), Texas, venture. The #4311H Reese 15E-10-F is in Spraberry Field, and it flowed 2,503 bbl of 42° API oil, 2.193 MMcf of gas and 2,989 bbl of water per day from Wolfcamp. It was drilled to 19,910 ft, 9,679 ft true vertical, and is in Section 15, Block 40, T&P RR CO Survey, A-459. Production is from perforations between 9,975 and 19,813 ft. Tested on a 128/64-inch choke, the flowing tubing pressure was 337 psi, and the flowing casing pressure was 107 psi. Parsley Energy's headquarters are in Austin.

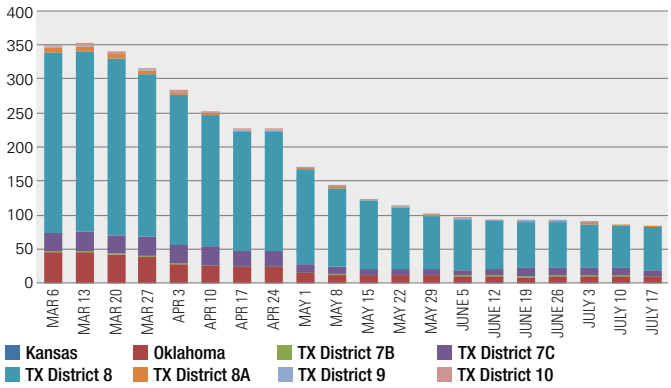


6 Three Ellis County, Okla., Cleveland wells were announced by Denver-based ***Fourpoint Energy***. According to IHS Markit, two of the Peek South completions were drilled from a pad in Section 19-17n-23w. The #1HA Spoonbill 20X17-17-23 was drilled to 20,261 ft (9,657 ft true vertical) and flowed 203 bbl of oil, 246,000 cu ft of gas and 813 bbl of water per day from perforations at 10,150-19,201 ft. Gauged on a 28/64-inch choke, the flowing tubing pressure was 300 psi. The #2HB Spoonbill 20X17-17-23 was drilled to 20,441 ft (9,574 true vertical) and produced 182 bbl of oil, 320,000 cu ft of gas and 1,235 bbl of water per day from perforations at 10,150-19,201 ft. It was tested on a 34/64-inch choke, and the flowing tubing pressure was 415 psi. In nearby Section 18-17n-23w, #2HD Blue Gill 18-17-23 was drilled to 15,196 ft with a true vertical depth of 9,734 ft. It was tested flowing 398 bbl of oil, 443,000 cu ft of gas and 1,215 bbl of water per day from perforations at 10,145-15,048 ft. The well had a flowing tubing pressure of 300 psi during testing on a 38/64-inch choke.

7 ***Citizen Energy III*** completed a horizontal Cherokee discovery in Oklahoma's Caddo County. According to IHS Markit, #1H-21-16 Bowling flowed 72 bbl of 50° API oil, 4.585 MMcf of gas and 559 bbl of water per day from acid- and fracture-treated perforations at 12,567-19,419 ft. Gauged on a 16/64-inch choke, the flowing tubing pressure was 4,695 psi. It was drilled to 19,474 ft in Section 21-10n-10w and had a proposed true vertical depth of 12,550 ft. The 2-mile lateral bottomed to the north in Section 16. There had been no previous horizontal drilling in the Anadarko Basin township, which borders Canadian County on its north side. Citizen Energy is based in Tulsa.

Midcontinent & Permian Basin Rig Count

Mar. 6, 2020-July 17, 2020

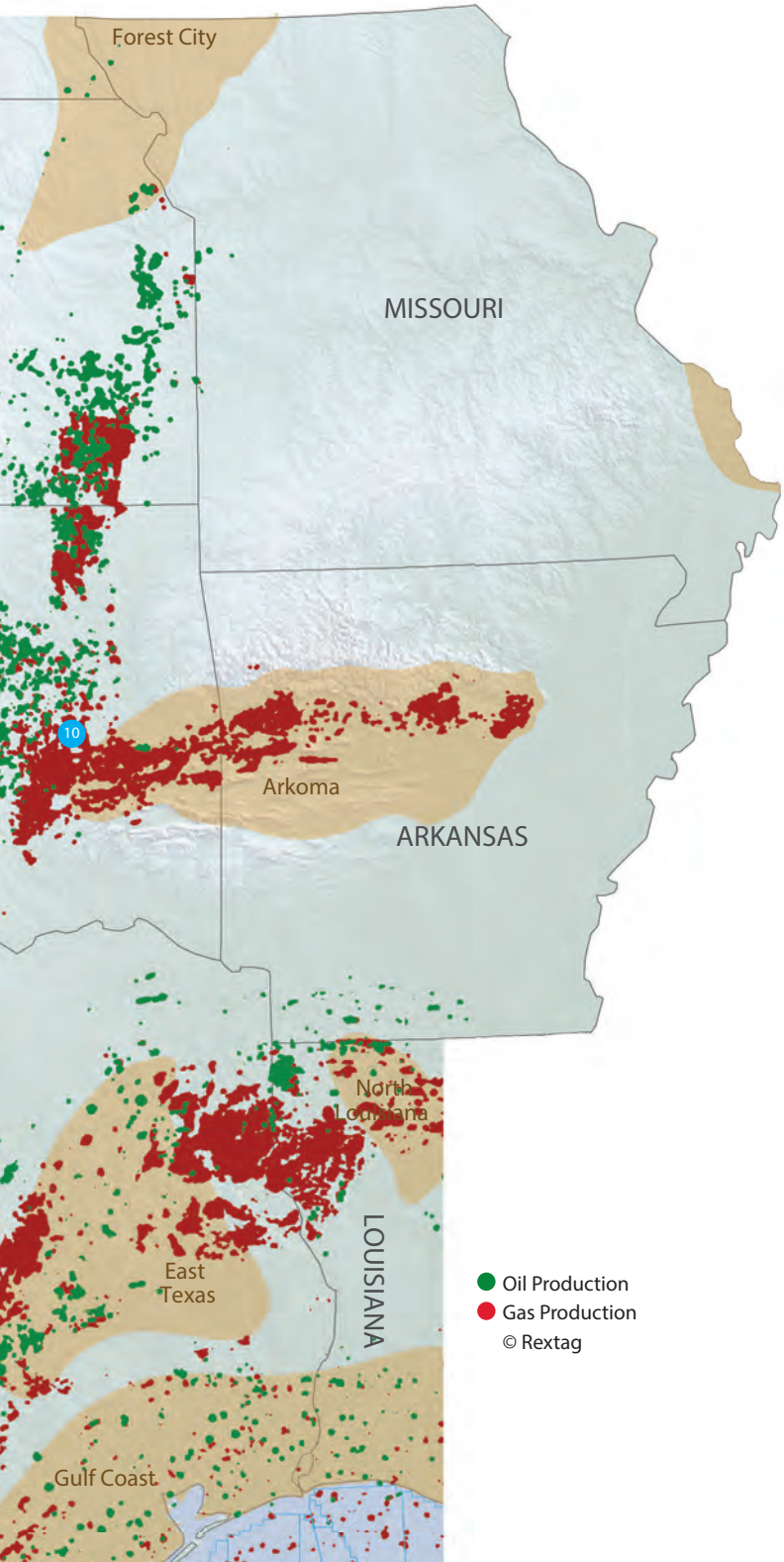


Source: Baker Hughes Co.

8 In Kingfisher County, Okla., ***Devon Energy Corp.*** reported results from a Mississippi Lime discovery in Altona Field. The #2HX Cascade 14_23-16N-9W produced 629 bbl of oil, 828,000 cu ft of gas and 717 bbl of water per day. The well was drilled to 19,350 ft (9,139 ft true vertical) in Section 14-16n-9w. It was tested on a 26/64-inch choke, and the flowing tubing pressure was 599 psi. Production is from a perforated zone between 9,205 and 19,119 ft.

9 A Mississippi Lime completion was announced by ***Camino Natural Resources LLC*** in Minco Field. The #1MXH Sam Noble 0907 2-11 is in Section 2-9n-7w in Grady County, Okla. It initially flowed 200 bbl of 47° API oil, with 2.681 MMcf of gas and 4,620 bbl of water daily from perforations between 11,293 and 21,377 ft. It was tested on a 50/64-inch choke with a flowing tubing pressure of 768 psi. The well was drilled to 21,438 ft, and the true vertical depth is 11,409 ft. Camino is based in Denver.

10 ***Calyx Energy III*** completed two McIntosh County, Okla., commingled Woodford/Mayes wells at a pad in Scipio Field. The pad is in Section 7-8n-13e. The #3-18-19WH Edison was drilled to a total depth of 15,749 ft and a true vertical depth of 5,163 ft. It produced 8.854 MMcf of gas with 3,025 bbl of water daily. Production is from Woodford perforations at 5,645-15,582 ft and Mays at 9,822-13,495 ft. Tested on a 64/64-inch choke, the flowing tubing pressure was 480 psi. The offsetting #2-18-19WH Edison was drilled to 15,200 ft, 5,157 ft true vertical. It flowed 9.246 MMcf of gas and 4,106 bbl of water per day. Production is from perforations in Woodford at 5,476-15,107 ft and Mayes at 9,601-13,500 ft. It was tested on a 64/64-inch choke with a flowing casing pressure of 421 psi.



WESTERN US

1 Completion details have been released on two Altamont Field-Uinta Basin completions by ***EP Energy Co***. in Duchesne County, Utah. The discoveries were drilled from a pad in Section 33-2s-42. According to IHS Markit, #16-34-33-B4-4H Alpine Ranch flowed 329 bbl of oil, 193,000 cu ft of gas and 1,045 bbl of water per day from an apparent Uteland Buttes zone. It was tested after acidizing and fracture stimulation. The flowing casing pressure was gauged at 4,049 psi on a 12/64-inch choke. The well was initially expected to target Wasatch, and it was drilled to 20,563 ft. The lateral bottomed 2 miles to the west in Section 33-2s-4w. The true vertical depth is 10,174 ft. The parallel #16-34-33-B4-5H Alpine Ranch was drilled to 20,390 ft (10,109 ft true vertical). It initially flowed 257 bbl of crude, 202,000 cu ft of gas and 1,151 bbl of water per day from acid- and fracture-treated perforations in Uteland Buttes. Gauged on a 12/24-inch choke, the flowing casing pressure was 3,980 psi. E&P Energy is based in Houston.

2 In Sweetwater County, Wyo., ***FDL Operating LLC*** announced results from a directionally drilled Almond venture. The #38-34D Monell Unit produced 124.2 bbl of oil with 1.135 MMcf of gas and 23 bbl of water per day. It was drilled to 4,641 ft, and the true vertical depth is 4,626 ft. The Patrick Draw Field well is in Section 34-19n-99w. FDL's headquarters are in Irving, Texas.

3 Houston-based ***EOG Resources Inc.*** announced results from a Mowry and a Niobrara completion at a Johnson County, Wyo., drillpad in Section 12-47n-78w. The #53-1201H Orbit flowed 889 bbl of 51° API condensate, 2.712 MMcf of gas and 1,777 bbl of water per day from Mowry. It was drilled to 20,684 ft, 11,368 ft true vertical, and is producing from a perforated zone at 11,654-20,592 ft. Gauged on a 32/64-inch choke, the shut-in casing pressure was 1,733 psi. About 40 ft to the west, #61-1201H Orbit initially flowed 803 bbl of 45.4° API oil, 749,000 of gas and 777 bbl of water per day from Niobrara. Drilled to 19,115 ft, 9,929 ft true vertical, production is from perforations at 10,252-19,058 ft and it was tested on a 26/64-inch choke with a flowing casing pressure of 1,182 psi.

4 ***Titan Exploration LLC*** released details of a Niobrara venture in Converse County, Wyo. IHS Markit reported that #4075-1003-001NXH Ogalalla initially flowed 1,681 bbl of 43.3° API crude, 2.505 MMcf of gas and 852 bbl of water daily from acidized perforations at 12,251-21,718 ft. The interval was completed following a 50-stage fracturing. The shut-in tubing pressure was 2,687 psi during testing on a 24/64-inch choke. The discovery was drilled from a pad in Section 10-40n-75w with a total depth of 21,900 ft (11,816 ft true vertical), bottoming within 2 miles to the north in Section 3-20n-75w. Eight more horizontal tests have been permitted from the same pad, although no further activity has been reported. Titan Exploration is based in Casper, Wyo.

5 ***Navigation Powder River***, based in Houston, reported results from a Turner Sand discovery in Wyoming's Campbell County. Located in Section 25-43n-73w, #25-43-73-1h Adam Federal was drilled to 14,662 ft (10,406 ft true vertical). Tested on a 52/64-inch choke, the well flowed 1,626 bbl of 52° API oil 1.585 MMcf of gas with 957 bbl of water per day with a shut-in casing pressure of 525 psi. Production is from a perforated zone between 10,788 and 14,492 ft.

6 A Mowry well was completed in Campbell County, Wyo., by ***Ballard Petroleum Holdings LLC***. The #41-13-24 MH Dilts is in Section 12-42n-73w, and it was drilled to 21,678 ft with a true vertical depth of 11,549 ft. The venture flowed 870 bbl of 52° API oil, 6.226 MMcf of gas and 2,014 bbl of water per day. The K Bar Field well was tested on a 30/64-inch choke with a shut-in tubing pressure of 2,400 psi and a shut-in casing pressure of 400 psi. Production is from a perforated zone at 11,769-21,560 ft. Ballard's headquarters are in Billings, Mont.

7 Two Weld County, Colo., wells were completed by ***Anadarko Petroleum Corp.*** in Wattenberg Field from a pad in Section 1-1n-68w. The #1-16HZ Carson initially flowed 285 bbl of 65° API oil, 556,000 cu ft of gas and 1,952 bbl of water per day. It was drilled to 18,257 ft, and the true vertical depth is 7,696 ft. Production is from commingled Fort Hays (8,454-14,305 ft), Codell (8,472-18,208 ft) and Carlile (14,347-14,999 ft). It was tested on a 14/64-inch choke with a flowing tubing pressure of 1,800 psi and a flowing casing pressure of 2,100 psi. The offsetting #1-14HZ Carson was drilled to 19,399 ft, 7,636 ft true vertical, and tested after 42-stage fracturing. It produced at a daily rate of 297 bbl of 58° API condensate, 780,000 cu ft of gas and 470 bbl of water from Niobrara perforations at 8,184-19,364 ft. Gauged on a 14/64-inch choke, the flowing tubing pressure was 1,900 psi, and the flowing casing pressure was 2,600 psi. Anadarko is a subsidiary of ***Occidental Petroleum***.

8 ***PDC Energy Inc.*** completed a Wattenberg Field well in Colorado's Weld County. The #30C-30-M Sanford produced

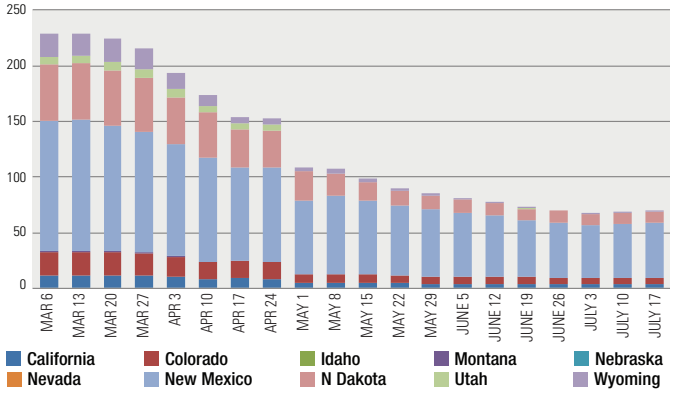
141 bbl of 53° API condensate, 1.211 MMcf of gas and 164 bbl of water per day from commingled Fort Hayes (7,856-7,956 ft), Codell/Carlile (8,006-15,421 ft) and Carlile (8,456-8,506 ft). The discovery is in Section 29-5n-66w and was drilled to 15,607 ft with a true vertical depth of 7,405 ft. Tested on a 16/64-inch choke, the flowing tubing pressure was 1,565 psi, and the flowing casing pressure was 2,131 psi. PDC's headquarters are in Denver.

9 A Middle Bakken completion was reported in Williams County, N.D., by ***Nine Point Energy***. The discovery, #152-103-9-11-12H Missouri S, is in Section 4-152n-103w. The Eight Mile Field well flowed 895 bbl of 41° API oil, 314,000 cu ft of gas and 6,051 bbl of water per day. It was tested on a 23/64-inch choke after 80-stage fracturing between 12,117 and 24,754 ft with a flowing casing pressure of 2,300 psi. Nine Point's headquarters are in Denver.

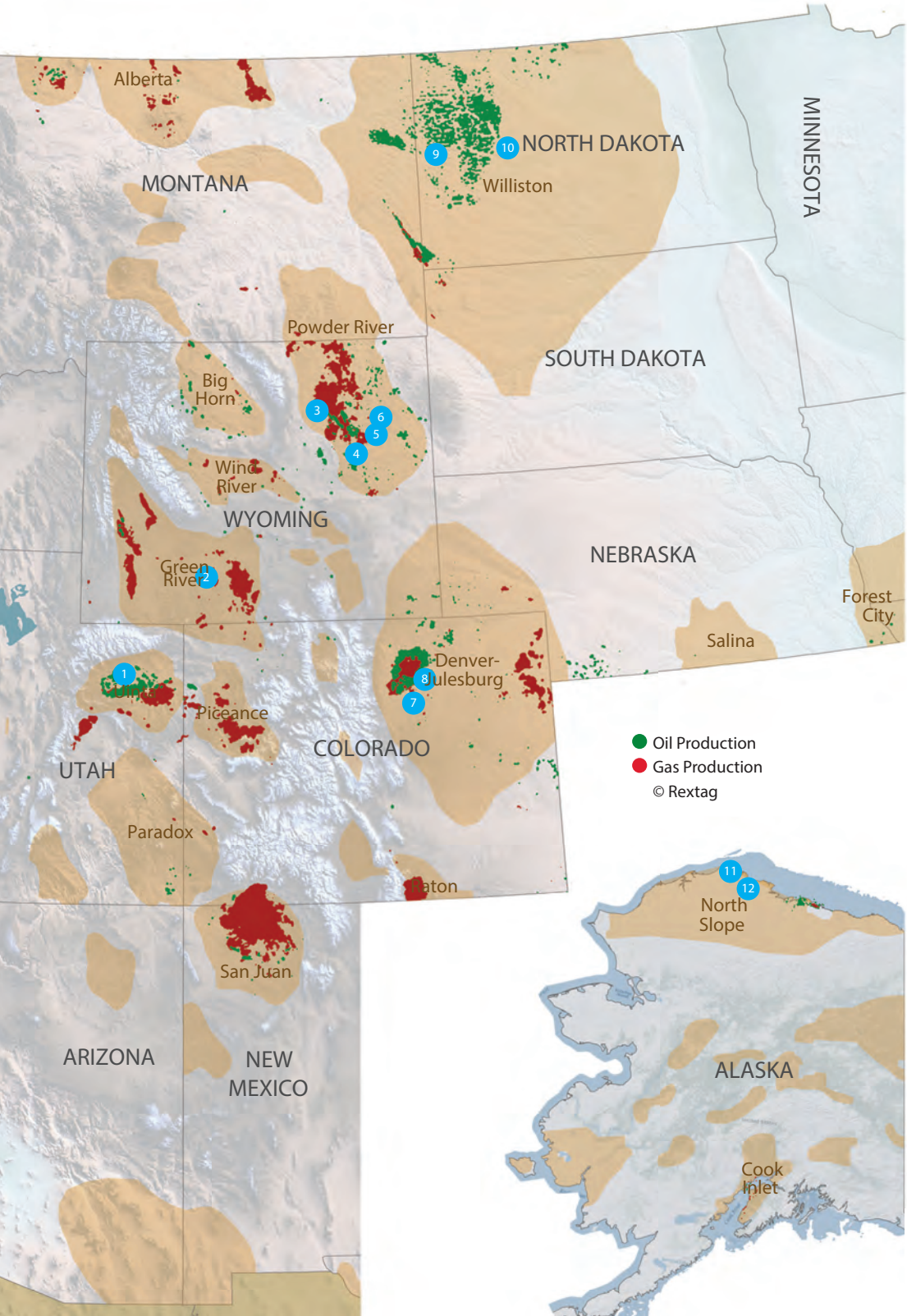
10 A Sanish Field-Three Forks discovery was reported by ***Kraken Operating Inc***. Located in Section 10-154n-92w in Mountrail County, N.D., #3TFH Ethan 15-22 initially flowed 732 bbl of 40° API oil, 589,000 cu ft of gas and 805 bbl of water per day. The 20,535-ft well has a true vertical depth of 10,459. It was tested after 60-stage fracturing and production is from a perforated zone between 10,340 and 20,459 ft. The Houston-based operator tested the well on a 48/64-in. choke and the flowing casing pressure was 265 psi.

Western US Rig Count

Mar. 6, 2020-July 17, 2020



Source: Baker Hughes Co.



11 ***Hilcorp Energy Corp.*** announced results from an offshore Milne Point Field completion in Beechey Point Quad in Alaska. The #116-F Milne Point Unit is in Section 6-13nn-10e and was drilled to 13,785 ft with a true vertical depth of 7,656 ft. It flowed 1,188 bbl of 22° API oil, 244,000 cu ft of gas and 378 bbl of water per day. Production is from commingled Kuparuk perforations at 13,354-58 ft; 13,362-13,400 ft; 13,438-48 ft; 13,456-74 ft and 13,485-13,540 ft. Hilcorp is based in Houston, Texas.

12 A Prudhoe Bay, Alaska, recompletion was reported by London-based ***BP Plc***. The #03-27A Prudhoe Bay Unit is in Section 11-10n-15e in Umiat Meridian. The discovery was tested flowing 839 bbl of oil, 6.952 MMcf of gas and 7,693 bbl of water per day from Sadlerochit perforations at 10,375-13,000 ft. It was drilled to 13,133 ft, and the true vertical depth is 8,794 ft. The original well was completed in 1985.

INTERNATIONAL HIGHLIGHTS

Iran is facing another crisis—storage tanks and vessels are almost completely full due to falling exports and refinery run cuts caused by the coronavirus pandemic.

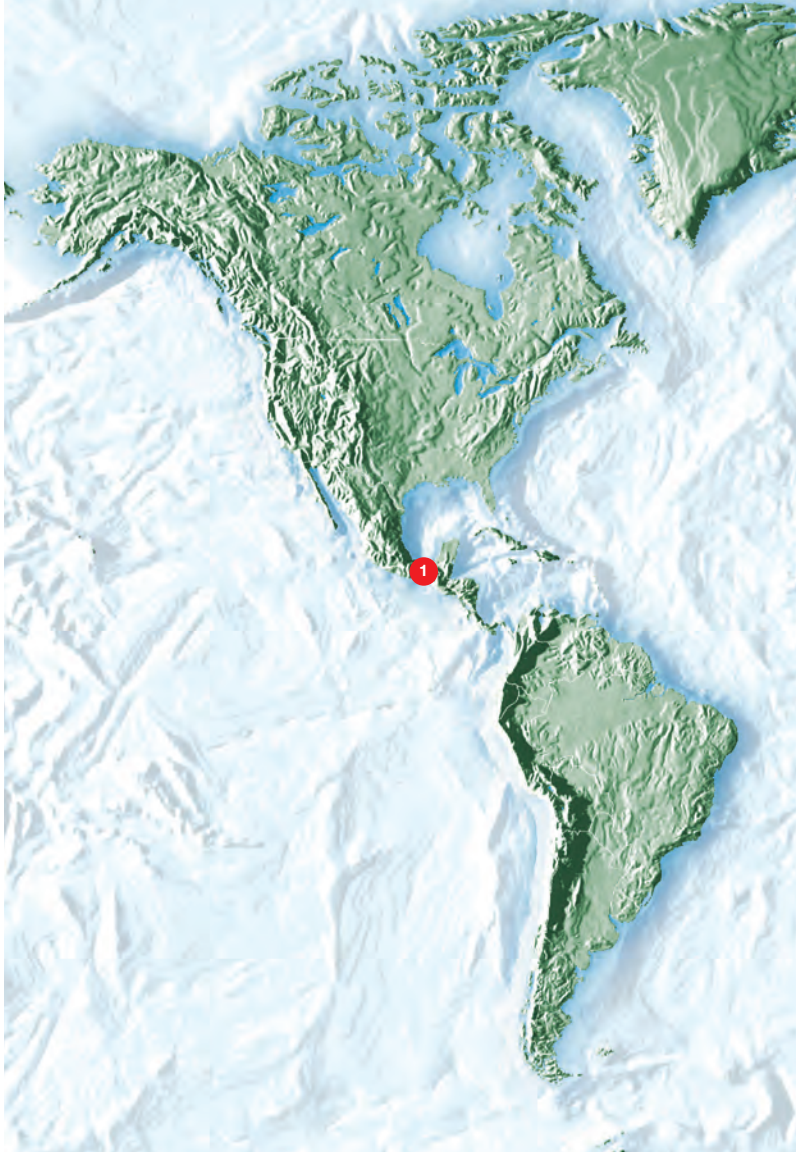
Total onshore crude stocks rose from 15 MMbbl in January to 54 MMbbl in April, and swelled further to 63 MMbbl in June, according to FGE Energy. Market intelligence firm Kpler estimated Iranian average onshore crude storage for June to be around 66 MMbbl, which is about 85% of the country's available storage capacity.

Iran's floating storage is also filling up. The country is estimated to be using about 30 tankers to store oil, most of them supertankers, each of which can carry a maximum of 2 MMbbl of oil. According to an industry source, the exact number of Iranian vessels on floating storage is uncertain since the vessels have all turned off their AIS (tracking transponder) signals.

The oil ministry is trying to manage crude stocks by shutting down more production.

The country's total liquid production, including crude oil, condensate and natural gas liquids, fell from 3.1 MMbbl/d in March to 3 MMbbl/d in June, and it is expected that July production will fall another 100,000 bbl/d.

—Larry Prado



1 Mexico

Pemex has received a permit to drill an exploratory test at appraisal well #2DEL-Quesqu in onshore Tabasco. The well is a follow-up of #1EXP-Quesqui and #1DEL-Queswqui. The appraisal well will be drilled in an 'S' trajectory toward an Upper Jurassic Kimmeridge (JSK) play, and the planned depth is 6,730 m. The well site is in AE-0053-4M-Mezcalapa-03, within the Cuencas del Sureste. Pemex noted the well will be a high temperature, high pressure well at 153-degrees C and 13,082 psi. The Mexico City-based company expects to encounter gas and condensate in total resources of 62 MMboe.

2 U.K.

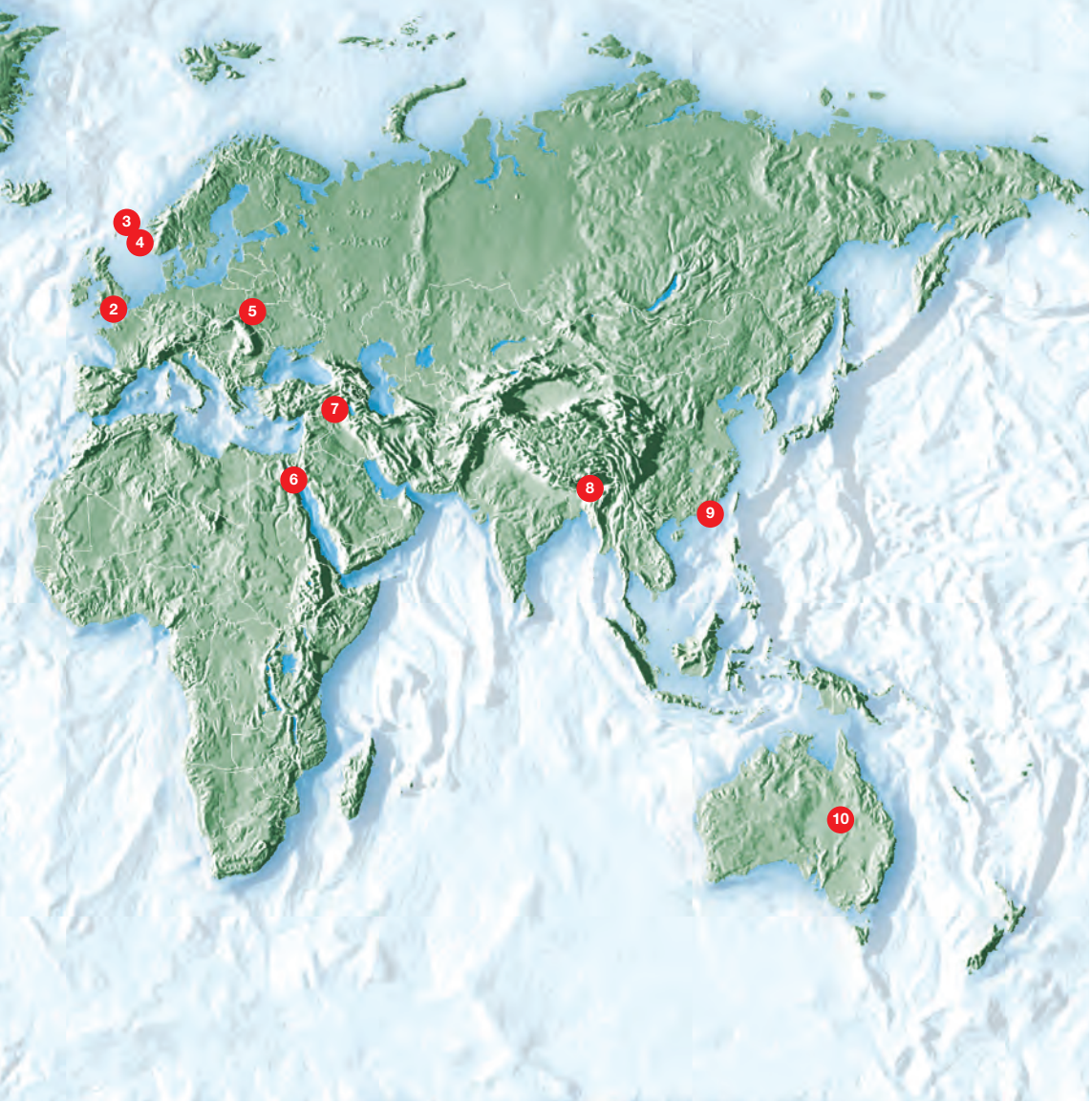
UK Oil & Gas has received a permit to drill and test its proposed #1-Loxley Portland gas exploration/appraisal well in the PEDL234 license area. A sidetrack well, #1z-Loxley, has also been permitted. The London-based company plans to appraise the Portland gas accumulation, which was originally discovered in 1982 by ***ConocoPhillips*** about 8 km to the west at #1-Godley Bridge. ***UK Oil & Gas*** is the operator of PEDL234 and #1-Loxley with 100% interest.

3 Norway

According to London-based ***Neptune Energy***, the company made a hydrocarbon discovery in the Norwegian sector of the North Sea in PL882 at exploration well #1-Dugong. The discovery was confirmed with well logs and drill cuttings, and a coring program is planned. Depending on the results, a sidetrack may be drilled to further define the extent of the discovery. Area water depth is 330 m, and testing indicates that the reservoir is at a depth of 3,250 m to 3,400 m. Neptune Energy is the operator of PL882, Block 34/4, and #1-Dugong well with 40% interest in partnership with ***Concedo*** (20%), ***Petrolia*** (20%) and ***Idemitsu Petroleum*** (20%).

4 Norway

Stavanger-based ***Equinor*** has completed a wildcat, #30/2-5 S, which is south of Kvitebjørn Field in the Norwegian North Sea. The objective of the well was to prove petroleum in reservoir rocks from the Middle Jurassic Age (the Brent Group). The venture encountered a gas column of about 160 m in Brent Group (Tarbert, Ness, Etive and Rannoch), of which 60 m make up an effective sandstone reservoir. Ness has 30 m of sandstone with poor-to-moderate reservoir quality, while Etive has 15 m of sandstone, primarily of moderate quality. The Tarbert has 10 m of sandstone with poor-to-moderate reservoir quality, and Rannoch has 5 m of poor quality sandstone. Preliminary estimates indicate the discovery between 3 MMcm to 10 MMcm of recoverable oil equivalents. No formation-testing was conducted, but volumes of data have been acquired, and samples have been taken and additional assessment is planned. This is the first exploration well in production license 878. The well was drilled to 4,390 m, and area water depth is 142 m and was terminated.



5 Romania

ADX Energy completed exploration well #1-Iecea Mica in onshore Romania's Iecea Mare Production License. According to the company, the well encountered gas across three zones with a combined total of 20 Bcf of 2C contingent resources. The Pannonian Basin well was suspended for future completion as a producer following testing. Testing has been deferred until downhole well production equipment is manufactured and has also been further delayed due to border closures caused by the COVID-19 pandemic, which has prevented testing operations until now. Testing will concentrate on the PA IV sand (Pliocene) which is a proven reservoir and has the greatest upside reserves potential of the three hydrocarbon-bearing reservoir intervals intersected in #1-Iecea Mica. The reservoir unit has a large stratigraphic upside potential, which will be further quantified in the near future with the planned high-resolution 2D seismic program scheduled for the third quarter. Perth-based ADX has a 100% operating interest in the Iecea Mare Production license and wells.

6 Egypt

Cheiron completed an oil discovery in Egypt's southern Gulf of Suez at exploration well #4-GNN in the Geisum & Tawila West Concession. The venture was drilled to test the prospect, and initially flowed more than 2,000 bbl of oil per day. It was drilled from the Geisum D platform. The discovery contains and estimated 260 MMbbl of oil in place. Two additional wells are planned from the D platform in the southern area of the discovery, and later the development focus will shift to the northern area of the discovery, The completion is the first to be made in Nukhul in the Geisum area and will open up further exploration potential, both within the concession and in the neighboring acreage. Cairo-based Cheiron holds a 60% operating interest in partnership with ***Kuwait Foreign Petroleum Exploration Company*** holding the remaining 40%.

7 Turkey

Trillion Energy has announced evaluation results from the Zagros Basin Derecik exploration licenses in the Hakkari area of Turkey. The company, which holds 100% interest in the Derecik Blocks, said today that the oil-rich Zagros Basin extends from Iraq into Turkey to include the Derecik licenses, which are now near several major producing oil fields in northern Iraq including Bijell; Atrush; Swara Tika; and Swara Tika East fields. According to the company, the Derecik Blocks have identical stratigraphy as the Zagros Field block in Iraq, with Cretaceous and Miocene compression. The #1-Balkayalar has a planned depth of 2,560 m in an anticlinal, four-way closure containing Jurassic and Triassic reservoirs. The #1-Derecik has a planned depth of 3,493 m, which is also an anticlinal four-way closure containing Cretaceous, Jurassic, and Triassic reservoirs. Trillion Energy is based in Vancouver.

8 Pakistan

MOL has made a new gas and condensate discovery in the TAL block in Pakistan's Kohat District. The exploratory test, #1-Mamikhel South, was drilled to 4,939 m. It was tested flowing gas and condensate from Lockhart and Hangu and a daily rate of 6,516 bbl of oil equivalent (16.12 MMcf of gas and 3,240 bbl of condensate). Gauged on a 32/64-inch choke, the flowing wellhead pressure was 4,476 psi. Additional well testing is ongoing. MOL is the operator and joint venture partners include ***Oil & Gas Development***; ***Pakistan Petroleum Ltd.***; ***Pakistan Oilfield Ltd.*** and ***Government Holdings Private Ltd.*** MOL is based in Budapest.

9 China

Chinese National Offshore Oil Corp. has announced a discovery in the eastern portion of the South China Sea at #26-6 Huizhou. According to the Beijing-based company, it is expected to become the first mid-to-large sized condensate oil and gas field in the shallow water area of Pearl River Mouth Basin. The well is in Huizhou Sag in Zhu1 Depression of Pearl River Mouth Basin. Area water depth is approximately 113 m. The well was drilled to 4,276 m and encountered oil and gas pay zones with a total thickness of about. 422.2 m. During a flow test it initially produced 2,020 bbl of oil and 15.36 MMcf of gas per day.

10 Australia

Vintage Energy is fracturing and preparing to flow-test exploration well #1-Vali ST1. The ATP 2021 venture will be fractured in six stages—five in the Patchawarra and one in the deeper Tirrawarra/Basal Patchawarra section, at depths of between 2,810 m to 3,140 m. The flow testing program will measure total stabilized gas rates, down-hole reservoir pressure and individual formation gas flow contribution. The certified gross 2C contingent resource is 37.7 Bcf of gas (18.8 Bcf net). The joint venture partners are Goodwood, South Australia-based ***Vintage*** (50%) and operators ***Metgasco*** (25%) and ***Bridgeport*** (25%).

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
East Resources Acquisition Co.	NASDAQ: ERESU	Boca Raton, Fla.	$300 million	Completed IPO of 30 million units at a price of $10 per unit. Each unit issued will consist of one share of Class A common stock and one-half of one warrant, each whole warrant entitling the holder thereof to purchase one share of the Class A common stock at an exercise price of $11.50 per share. Company intends to grant underwriters a 45-day option to purchase up to an additional 4.5 million units. Proceeds will be used for the purpose of entering into a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses in the energy industry in North America. Wells Fargo Securities LLC was sole book-runner.
Southwestern Energy Co.	NYSE: SWN	Spring, Texas	$137.5 million	Priced underwritten public offering of 55 million shares of its common stock at $2.50 per share. Underwriters have been granted a 30-day option to purchase up to roughly 8.3 million addition shares of stock. Proceeds will used to partially redeem Montage Resource Corp.'s issued and outstanding notes that it will assume upon the closing of its recently announced merger with Montage. Citigroup, Goldman Sachs & Co. LLC and J.P. Morgan are representatives of the underwriters and joint book-running managers. BofA Securities, BMO Capital Markets, RBC Capital Markets and Wells Fargo Securities are also joint book-running managers.
Tellurian Inc.	NASDAQ: TELL	Houston	$35 million	Entered a securities purchase agreement with certain institutional investors for the sale of 35 million shares of common stock at a price of $1 per share. Roth Capital Partners was placement agent.

DEBT

Apache Corp.	NASDAQ: APA	Houston	$1.25 billion	Priced underwritten public offering of $500 million of 2025 notes and $750 million of 2027 notes. Proceeds will be used to purchase a portion of outstanding senior indebtedness in cash tender offers, repay a portion of outstanding borrowings under its senior revolving credit facility and for general corporate purposes. Joint book-running managers for the notes are J.P. Morgan Securities LLC, BofA Securities Inc., BMO Capital Markets Corp. and Scotia Capital (USA) Inc.
Husky Energy Inc.	TSX: HSE	Calgary, Alberta	C$1.25 billion	Launched a public offering of 2028 notes. Proceeds will be used for general corporate purposes, which may include, among other things, the repayment of its $500 million unsecured nonrevolving term loan credit facility. Notes were sold through a syndicate of agents led by RBC Capital Markets, CIBC Capital Markets and Scotia Capital Inc.
Kinder Morgan Inc.	NYSE: KMI	Houston	$1.25 billion	Closed a public offering of senior notes, which included $750 million 2031 notes and $500 million 2050 notes. Proceeds will be used for general corporate purposes, including refinancing upcoming debt maturities. BofA Securities, J.P. Morgan, MUFG, RBC Capital Markets, Barclays, BMO Capital Markets, Mizuho Securities, Scotiabank, Société Générale and TD Securities were joint book-running managers.
Pioneer Natural Resources Co.	NYSE: PXD	Dallas	$1.1 billion	Priced a public offering of 2030 notes at 99.205% of the principal amount. Proceeds will be used for general corporate purposes, which may include, but are not limited to, the repayment or repurchase of 2021 and 2022 notes or other corporate obligations. BofA Securities Inc., J.P. Morgan Securities LLC, Wells Fargo Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Citigroup Global Markets Inc., Morgan Stanley & Co. LLC, MUFG Securities Americas Inc. and TD Securities (USA) LLC are joint book-running managers. Credit Suisse (USA) LLC, Goldman Sachs & Co. LLC, RBC Capital Markets LLC, Scotia Capital (USA) Inc. and U.S. Bancorp Investments Inc. are senior co-managers. BBVA Securities Inc., CIBC World Markets Corp., Citizens Capital Markets Inc., PNC Capital Markets LLC and Truist Securities Inc. are co-managers.
Cenovus Energy Inc.	NYSE, TSX: CVE	Calgary, Alberta	$1 billion	Completed public offering in the U.S. of 2025 notes. Proceeds will be used to repay short-term indebtedness outstanding under the company's $4.5 billion committed credit facility and other short-term indebtedness. BofA Securities Inc., BMO Capital Markets Corp. and Scotia Capital (USA) Inc. were active joint book-running managers. The offering was supported by additional advisers including RBC Capital Markets LLC, TD Securities (USA) LLC, ATB Capital Markets Inc., CIBC World Markets Corp., Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Desjardins Securities Inc., J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc., National Bank of Canada Financial Inc., SMBC Nikko Securities America Inc. and Wells Fargo Securities LLC.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Targa Resources Partners LP	NYSE: TRGP	Houston	$1 billion	Priced an upsized offering of 2031 notes at par. Proceeds will be used to fund a concurrent cash tender offer of 2024 notes, to pay fees and expenses thereof, and to redeem any 2024 notes that remain outstanding after consummation of the tender offer. Remaining proceeds will be used to reduce borrowings under its senior secured revolving credit facility.
Gibson Energy Inc.	TSX: GEI	Calgary, Alberta	C$650 million	Closed an offering of senior unsecured medium term notes consisting of $325 million of 2025 notes and $325 million of 2027 notes. Proceeds will be used for the redemption of its outstanding 2024 notes, reduce outstanding indebtedness under its revolving credit facility and for general corporate purposes. Notes were offered through a syndicate of investment dealers led by **CIBC Capital Markets** and **RBC Capital Markets**, as well as **BMO Nesbitt Burns** and **Scotia Capital**.
Boardwalk Pipeline Partners LP	NYSE: BWP	Houston	$500 million	Priced a public offering of 2031 notes. Proceeds retire all of the outstanding 2021 notes of Texas Gas Transmission LLC at or near maturity. Remaining proceeds will be used for general partnership purposes, which may include growth capex, repayment of future maturities of long-term debt and additions to working capital. Pending such use, proceeds will temporarily used to reduce borrowings under its revolving credit facility. **Barclays**, **J.P. Morgan**, **Mizuho Securities**, **MUFG**, **BMO Capital Markets**, **Citigroup**, **Regions Securities LLC**, **TD Securities**, **Truist Securities**, **US Bancorp** and **Wells Fargo Securities** are joint book-running managers. **BofA Securities**, **Goldman Sachs & Co. LLC**, **Morgan Stanley** and **RBC Capital Markets** are co-managers.
Concho Resources Inc.	NYSE: CXO	Midland, Texas	$500 million	Priced an offering of 2031 notes issued at 99.761% of par. Proceeds will be used for general corporate purposes, including, together with cash on hand, to redeem all of its outstanding 2025 notes. **BofA Securities**, **J.P. Morgan** and **Wells Fargo Securities** will act as joint book-running managers.
Helix Energy Solutions Group Inc.	NYSE: HLX	Houston	$200 million	Priced an upsized offering of 2026 notes. Proceeds will be used to fund the cost of entering into the capped call transactions and, together with cash on hand, repurchase outstanding 2022 and 2023 notes in privately negotiated transactions. **Wells Fargo Securities LLC** and **Evercore ISI** are joint book-running managers.

The **PERFECT GIFT** for COWORKERS

Autographed books by politicians, military heroes, and industry thought leaders.

HARTENERGY STORE

Available at HartEnergyStore.com

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

SEPTEMBER 1960

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

September 1960 will be remembered by baseball fans, political junkies and oil industry watchdogs. Here's why.

That month, Pittsburgh baseball fans were on fire. Their beloved Pirates had just clinched the pennant in Milwaukee and, thus, the team was on the way to its first World Series since 1925. Later that October, the players won it all in Game 7 over the New York Yankees, 10 to 9, with a walk-off home run. This has been labeled one of the most exciting Game 7s in baseball history, with the lead changing hands four times.

On Sept. 26, history was made in another, more serious way. Richard Nixon and John F. Kennedy faced off in a CBS studio in Chicago for the first-ever televised campaign debate between two presidential contenders. The symbiotic link between politics and television has never been the same since.

On a macroeconomic level, something even more momentous occurred, for on Sept. 14, some large oil producers met in Baghdad to discuss the sorry state of global oil prices. The result? The Organization of the Petroleum Exporting Countries was formed. The five founding members were Iraq, Iran, Saudi Arabia, Venezuela and Kuwait.

They met to figure out how to offset low oil prices caused by a supply glut—sound familiar? Starting in the mid-1950s, U.S. production had increased just as discoveries in the Middle East enabled those countries to ramp up oil production. The tug of war between the West and the Middle East began.

Sixty years later, is OPEC as relevant today as it was then? As powerful? During the shale boom from 2008 to 2014, it was fashionable to say no. Rising U.S. oil production and exports from our shores were remaking global oil flows, risk, storage fundamentals and prices. Before the pandemic hit, we were exporting about 3 MMbbl/d and producing about 12% of the world's oil. That's rookie-of-the-year star power.

But in 2019, OPEC collectively produced 42% of the world's oil, in a league of its own. Saudi Arabia produced about 12% at the height last year, Russia 11%. When adding Iraqi output, these three members of OPEC+ account for more than a third of the world's oil supply. That's hall of fame status that cannot be dismissed.

Since 1960, it's always been too easy to blame OPEC for the industry's woes whenever oil prices crash—even if it's because of a supply glut caused by others, or an unprecedented drop-off in demand caused by a virus. It's also been way too easy to wish OPEC would do something to fix the industry's troubles—even if that's really a matter of global economic or geopolitical factors instead.

The only real Band-Aids an individual producer has at hand are to hedge and cut costs. Bring on those swaps, collars and floors. Shut in producing wells and stop drilling. That has been done.

The EIA said that in May during the worst of it, U.S. oil production dropped by 1.9 MMbbl/d or nearly 17%, the largest monthly decline since 1980.

The top 25 public U.S. producers cut production by almost three-quarters of a million barrels a day, according to Rystad Energy. But OPEC has cut even more, some 1.2 MMbbl/d from January 2019. In May 2020 when repercussions from the pandemic and global downturn were severe and more visible, OPEC+ agree to cut by 9.7 MMbbl/d.

Oil is hovering around $44/bbl.

But let's face it—although we can debate the importance of OPEC, it's clear that we all hang on the organization's every word, perhaps never more so than this year, a year that will go down in infamy. Negative WTI? Global demand down more than at any time in history? Demand for OPEC oil supply fell to an astonishing 30-year low in April.

At press time, OPEC revised its 2020 energy outlook, saying world oil demand will fall by 9 MMbbl/d this year. It does not see demand in 2021 getting back to what it was in 2019, but it retained its forecast that demand will improve some next year, by 7 MMbbl/d. The International Energy Agency (IEA) reduced estimates for oil demand for almost every quarter through to the end of 2021.

"The energy market is still flashing the same warning signs it has been flashing since March," wrote Robert Yawger, director of energy futures, Mizuho Securities USA, in August. "The situation has improved some, but the market dynamics are still less than stellar. For starters, the stubborn contango curve continues to rule the WTI price curve. Contango curve implies the market is oversupplied."

The upshot seems to be that when U.S. producers vow to spend only enough to hold production flat, their place in the game may change. IHS Markit's Raoul LeBlanc thinks that a grand reset is unfolding, with shale possibly never regaining its former batting average.

A home for North American hydrocarbons

In North America, EDF specializes in commodity price risk management solutions with a focus on leveraging its downstream demand to serve the upstream oil and gas sector. We are part of the EDF Group of companies, one of the world's largest generators of electricity and a global consumer of energy including Natural Gas, NGLs, Crude Oil, and LNG.

www.edfenergyna.com

Chris Beyer
chris.beyer@edfenergyna.com
281-653-1068

Ben Rich
ben.rich@edfenergyna.com
281-653-1736

Oil and gas is here to stay. And so are we.

The last few months have challenged everyone in extraordinary ways as a virus temporarily crushed demand. As we begin to ramp back up, our country and the world will need oil and natural gas, especially the light, sweet crude and abundant, clean-burning natural gas our domestic producers provide. Our industry continues to demonstrate its ability to adapt and to succeed. At Continental, we are built to meet all challenges and seize every opportunity. You would expect nothing less from America's Oil Champion. To learn more about us and our new ESG approach, visit clr.com.

Continental
RESOURCES