Oil and Gas Investor

JUNE 2021

Appalachian operators look to grind out copious cash flow.

HARTENERGY

OIL AND GAS INVESTOR APPALACHIAN BASIN / DIVIDENDS / POWDER RIVER BASIN JUNE 2021/VOLUME 41/NUMBER 6

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

$500 MILLION TALOS ENERGY SENIOR SECURED NOTES Senior Co-Manager	$560 MILLION MARTIN MIDSTREAM PARTNERS HAS SUCCESSFULLY CONSUMMATED ITS DEBT EXCHANGE, FINANCING, AND CASH TENDER Financial Advisor	$535 MILLION LONESTAR RESOURCES CHAPTER 11 RESTRUCTURING Financial Advisor	UNDISCLOSED NPR NP Resources, LLC DEBT RECAPITALIZATION Financial Advisor	UNDISCLOSED USA RAIL TERMINALS A PORTFOLIO COMPANY OF High Roller Group AND JIM DONNAN COMPANIES HAS BEEN ACQUIRED BY alpenglow rail AND CONNOR, CLARK & LUNN INFRASTRUCTURE Financial Advisor
UNDISCLOSED NORTH AMERICAN TRANSPORTATION AND SERVICE PLATFORM CORPORATE CARVE OUT Financial Advisor	UNDISCLOSED INTREPID HAS ACQUIRED CERTAIN ASSETS OF gyrodata Financial Advisor	$270 MILLION elkpetroleum ADVISOR TO THE AD HOC CROSSOVER LENDER Financial Advisor	$350 MILLION VIPER Energy Partners FOLLOW-ON OFFERING Co-Manager	UNDISCLOSED PETROFLOW ENERGY ASSET DIVESTITURE Financial Advisor
UNDISCLOSED Excalibur Resources, LLC ASSET DIVESTITURE Financial Advisor	UNDISCLOSED EAGLE FORD MINERALS PLATFORM PRIVATE PLACEMENT OF EQUITY Financial Advisor	UNDISCLOSED AETHON ASSET DIVESTITURE Financial Advisor	$28 MILLION VIKING MINERALS ASSET DIVESTITURE Financial Advisor	UNDISCLOSED ROSEWOOD RESOURCES JOINT VENTURE TRANSACTION Financial Advisor

ENERGY GROUP KEY STATISTICS

$54+ Billion
Aggregate Transaction Volume since 2009

$320 Million
Average Transaction Size

169
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME

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

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Oil and Gas Investor

JUNE 2021/VOLUME 41/NUMBER 6

Angelo Gordon provides energy companies with the capital required to refinance existing debt, bolster liquidity, fund growth, complete acquisitions and finance development drilling.

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Oil and Gas Investor

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ABOUT THE COVER: A Nabors rig drills for gas outside Utica, Ohio, in the Utica Shale. Photo by Marc Morrison.

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LATEST CONTENT

IEA: Narrow Pathway To Net-Zero Emissions By 2050
Hart Energy Staff
Huge benefits are possible, according to the IEA's special report.

Strong Q1 For Midstream Reflected In Payouts To Investors
By Joseph Markman, Senior Editor
Alerian's MLP/Midstream indexes reflect stability compared to other oil and gas sectors.

Eyeing Oil, Gas Exploration Trends
By Velda Addison, Group Senior Editor
Analysts discuss the state of oil and gas exploration as the year gets off to a not-so-smooth start for explorers.

Quantum Energy Partners Hires Keila Hand To Lead ESG Program
By Hart Energy Staff
In addition to the hiring of Keila Hand, Quantum Energy Partners also unveiled several other recent enhancements to its ESG initiatives.

Want to Monetize Your Energy Transition Efforts? Here's How
By Joseph Markman, Senior Editor
Experts discuss how emissions factor into profitability in the era of energy transition and the need for standardization in how to measure them.

Oasis Petroleum Exits Permian Basin In Sale Worth Over $480 Million
By Emily Patsy, Senior Managing Editor
Oasis Petroleum Inc. had entered the Permian Basin in 2017 with the acquisition of Forge Energy LLC for a mix of cash and stock equivalent worth approximately $946 million.

ONLINE EXCLUSIVES

Pickering Energy Partners Continues ESG, Energy Transition Expansion
By Hart Energy Staff
Recent hires Dan Romito, Rachel Racz and Ismail Hammami bring a combined 30-plus years of expertise to Pickering Energy Partners' consulting, ESG and energy transition business.

Pioneer's Recent Multibillion-Dollar Buying Spree Strengthens U.S. Shale, CEO Says
By Emily Patsy, Senior Managing Editor
Pioneer Natural Resources Co.'s acquisition of privately-backed DoublePoint Energy "helps the situation," CEO Scott Sheffield said in reference to rising fears of a U.S. shale drilling binge.

Laterals, Exports, Price Among Keys To Haynesville Shale Success
By Velda Addison, Group Senior Editor
Goodrich Petroleum COO shares insight on its operations in the gassy Haynesville Shale as forecasts show natural gas prices and LNG exports rising.

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.

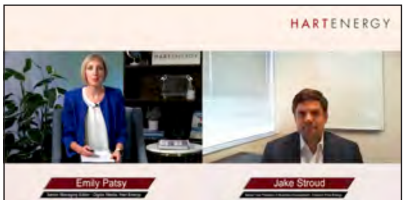
HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

hartenergy.com/videos/

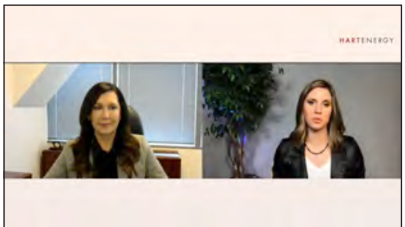
Forty Under 40 Honoree Interviews
For your introduction to these role models, we invite you to enjoy these video and audio interviews, extended narratives and personal insights.

hartenergy.com/videos/forty-under-40



Exclusive A&D Look From Privately Held Crescent Pass Energy
Crescent Pass Energy senior vice president of Business Development Jake Stroud provides Hart Energy with an exclusive look at A&D activity.

https://www.hartenergy.com/exclusives/path-forward-exclusive-ad-look-privately-held-crescent-pass-energy-194139



Energy ESG: Exclusive Look At EOG's Efforts To Reduce Flaring
In this exclusive video interview, EOG Resources Inc. vice president Pam Roth sits down with Jessica Morales to break down energy policies and how oil and gas producers can demonstrate their ESG plans.

https://www.hartenergy.com/exclusives/energy-esg-exclusive-look-eogs-efforts-reduce-flaring-193888

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GOLDEN AGE OF A&D

STEVE TOON,
EDITOR-IN-CHIEF

A&D is back, and I'm not talking about corporate M&A where a favorite name waves goodbye and gets absorbed only to become tomorrow's memory. That's happened more than enough in recent months. I'm talking assets—production, wells, acres and maybe a pipe or two. After two years of deal drought, the A&D machine is coughing back to life and gaining traction.

I know this because a full day of live, in-person speakers at the A&D Symposium hosted by the Society of Petroleum Engineers Gulf Coast Group Business Development Section in May were practically giddy at the deals that transacted in the past few weeks.

Doug Reynolds, managing director with the energy and power team at Piper Sandler, went so far as to title his presentation "The Golden Age of A&D?" The question mark was only insurance in case his optimism was too hopeful.

"Before you think I am being ridiculous, before I got here, you ought to know there's $17 billion of transactions done so far this year, and we're only in the middle of May," said Reynolds.

Transaction activity is heating up quite well, he observed. Yet, while corporate mergers dominated the scene with $116 billion in deal value over the past two years, this year only $1 billion is attributed to such a marriage thus far, that one being the Bonanza Creek Energy Inc./Extraction Oil & Gas Inc. combo. "This is an asset market," he said.

Reynolds and his team have identified several billion of assets currently on the market actively pursuing a transaction. Of course, relative commodity price stability supports dealmaking, and in his last few deals he's advised on, "there's been no discussion as to commodity price. There seems to be alignment around the strip right now."

Interestingly, the buyers are predominately public companies, the same publics that wouldn't touch an asset over the past year-plus as they would get their stock slapped by Wall Street. It turns out investors really do like growth, just not by the drill bit. Growth by acquisition is far less risky in investors' minds.

And stock prices generally have responded well to recent acquisitions. "We haven't seen a company announce something and the market throw up all over it, which is refreshing. Asset deals have been well received by the market."

Another positive sign: Publics are stocking up on inventory, not just PDP reserves. "Public companies are running out of inventory," Reynolds said. Where last year 90% of a deal value might be attributed to PDP and 10% to inventory, now the value attributed to upside "is materially higher." Those who are still bidding on last year's valuations that don't include upside value, he noted, are getting outbid by 50%.

While conservatively staying in basin, publics are also looking to change their inventory profiles. "It's very interesting to see public companies repositioning themselves." Pioneer Natural Resources Co., Enerplus Corp., Oasis Petroleum Inc. and Laredo Petroleum Inc. have all fundamentally changed their profiles through acquisition within the past 12 months, he said. "These are not little bolt-ons for them. These are very significant transactions, even for a company the size of Pioneer. They've each changed the complexion of those companies rather significantly."

Though buying too, private equity-sponsored companies are the most active sellers, finding clear runways to land the investments and unload returns to stakeholders. After a year of buyer desolation and aging waterfalls, the sponsors of these stranded portfolio companies are more than willing to take stock to achieve an exit, and the public buyers are more than willing to transact a portion of the value with stock.

"The private equity guys are smart sellers," he said, and realize all-cash deals aren't going to work for most buyers. "It has to work for the balance sheets of the acquirer, so they have to take some stock as consideration." Forty percent of total deal value year-to-date has been paid in stock.

The good news for buyers is that—while the bank markets are tough and "are going to stay that way for a little while"—the bond markets are "super supportive. The return of the bridge is a phenomenon that's happened in the last 30 to 60 days."

Annualized, 2021 should end with some $50 billion in total deal value, he said, "which would be pretty significant." Of that, he foresees one or two more corporate consolidations.

However, Reynolds predicts some $30 billion to $40 billion in asset transactions alone this year, on par with 2016 to 2018 in terms of total dollar volume of asset transactions. For A&D guys, whether buyers, sellers or advisors in the middle, that's positive news.

"We see this as a heck of a year—and we may be about the same next year."

The hiatus is over. Time to do some deals.

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STREET FIGHTER

DARREN BARBEE,
SENIOR EDITOR

The hacking of the Colonial Pipeline and its subsequent shutdown in May unleashed one of the worst spills of schadenfreude—or delight in other's misery—in modern history.

The National Review, with clear glee, reported that "seventeen states and—oh, glorious irony!—the District of Columbia have declared states of emergency after the closure of the Colonial Pipeline."

This same article lamented how quickly the Texas ice storms that claimed 111 lives in February were forgotten.

Perhaps that's the cost of whimsy.

The "Colonial effect"—long lines of panic buyers at gas stations—was also captured on video, naturally. Footage included a nasty confrontation in which a woman exited her car and spat on a male driver. He retaliated with a saliva sample of his own. Inevitably, the two began brawling.

Instagram, we owe you so much. People now can judge for themselves just how awfully carried away people get over a silly little thing like fuel.

But what will be the takeaway from the Colonial Pipeline hack, other than bad puns? Perhaps that companies should harden cyber defenses? Or that paying cyber extortionists is a bad idea—although Colonial reportedly did cough up a $5 million ransom.

Nope. The object lesson is the collective shrugging of shoulders—a communal, "So what?" with an emoji added for emphasis.

On Capitol Hill, the woes of millions translated into debates about how to define infrastructure instead of actually doing the work. President Joe Biden hosted a playdate with Republican leaders in the Oval Office, which quickly devolved into who got the better of whom press conferences.

Texas Sen. Ted Cruz called the Colonial Pipeline hack Biden's "gas crisis." But those performative slogans won't add to the depleted ranks of qualified truck drivers to haul gasoline. And it won't give pipeline companies the ability to perform basic maintenance on their existing pipelines.

The "what's-in-it-for-me" gestalt just isn't healthy, even for the Cancun-enabled.

Drue Pearce, director of government affairs at Holland & Hart, said she's seen a self-centeredness at work for years when it comes to pipelines.

Pearce served as deputy administrator of the Pipeline Hazardous Materials Safety Administration and as a senior advisor to Secretaries of the U.S. Department of the Interior. She was a member of the Alaska legislature and an appointee of President George W. Bush.

Pearce said that infrastructure is quick to draw opposition from the 'Keep It In The Ground' crowd, but also from people who didn't support a pipeline because it doesn't directly benefit them.

"Americans don't recognize the benefits—I have to say, I've heard it in public testimony—they don't care how it affects their neighbor," she said.

After a stunned silence, Pearce said, "It is stunning."

Hurdles to building new pipelines or any transportation system, including railroads, roads or transmission lines, are easy to tangle up with lawsuits.

"Now we're seeing litigation when companies are merely trying to increase the flow or double the capacity of a line that's already in place," she said. "That's also discouraging because it is inefficient to put gasoline or crude oil into tanker trucks and put them on the highway."

Attempts by Dominion Energy Co., for instance, to increase capacity for a gas line crossing from Virginia into Maryland to its Cove Point LNG facility were fruitless.

"They were stymied by the local opposition," she said. "The way they were stymied was that they could not get the permits to build the compressor stations that they needed."

The local argument was that the community didn't want pollution in an area Pearce said was overrun by personal propane tanks.

The unneighborly attitude extends to New York, which will not allow pipelines in the state. The net effect is the importation of Russian gas into Boston Harbor.

"It's a very state-centric attitude," she said.

Biden's decision to cancel the Keystone Pipeline is perhaps the most prominent example of the irrational animus toward long metal tubes. Why not help Canada, our closest ally, export its crude? Opponents say, among other reasons, because it doesn't help the U.S.

Pipelines in the U.S. are owned by the private sector, of course. Whatever happens with the infrastructure plans of the current administration, dollars won't necessarily be going to pipelines. But Pearce said that even when there's bipartisan urges to address, say, cast iron pipes dating back to the Civil War, it's hard to make progress.

Every administration seems to recognize such problems, but "it hasn't been the top priority," Pearce said.

The Colonial Pipeline debacle was just another exercise in scoring points, ignoring the needed updates to 40-year-old regulations and keeping the problem underground.

Enjoy the street fighting. It's all we get.


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SCIENCE AND REALITY

JACK BELCHER,
CORNERSTONE
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They call it "sausage making" for a reason. Forging public policy is an ugly process, inexact, complicated and messy and often defies logic. This is not a process to which scientists and engineers, like those in the oil and gas industry, can easily relate.

Our energy complex, however, is also imperfect—composed of an intricate system of drilling, completion, production, gathering, separation, processing, pipelining, storage, refining, liquefaction, marketing, shipping, generation, transmission and distribution. Each segment has a complex series of laws and regulations requiring compliance. Each segment also is a target of politicians, NGOs and activist groups that initiate protests, permit challenges, lawsuits, legislative and regulatory challenges, shareholder proxies and media attacks.

Each section of the complex is also being scrutinized for its carbon content and carbon intensity. This is driving a thorough review of all the processes along the value chain to identify opportunities to reduce carbon. Many factors need to be considered when assessing these options: cost, availability, technical viability, as well as the impacts to quality, supply chain, regulatory frameworks, and ESG performance and the ability to recover or pass along costs.

Billions of dollars are being considered for capital investments in areas such as carbon capture and storage, renewable credits, carbon offsets and the creation of certified low carbon commodities.

Public policy, through new regulations, the reshuffling of tax incentives and the impacts to infrastructure will help decide which options are most viable and cost effective, and the timeliness of policy outcomes and their consistency with U.S. energy and climate needs will ultimately guide major technical and operational decisions on capital spending.

The European Union is currently going through a process to review all inputs—from energy to commodities like steel, aluminum and cement—to determine what constitutes acceptable carbon content. A border adjustment tax is likely for imported sources of energy or other commodities that fail to meet their targets.

The U.S. could be headed in a similar direction, but on a slower trajectory. U.S. legislative proposals such as the CLEAN Future Act that set forth new carbon targets, establish "clean energy" standards and reform energy markets, will likely pass the House but fail to advance in the Senate. The 50:50 split in the Senate is a safeguard against anti-fossil energy policy because, even under the budget reconciliation process where legislation can move under a simple majority, the presence of Sen. Joe Manchin (D-WV) and his opposition to an energy transition based on elimination rather than innovation means that sweeping anti-fossil energy bills are likely dead on arrival.

Still, a lot of questions remain unanswered: Will a package include a higher corporate tax rate? Will it eliminate the percentage depletion allowance and expensing of intangible drilling costs? Will there be new or enhanced incentives for carbon capture and other greenhouse gas reduction technologies? Will there be a carbon tax as part of a "grand deal" regarding carbon?

Unfortunately, the legislative process is often not aligned with what is needed to accomplish our goals realistically, economically and based on science. Instead, it is based on rhetoric and aspirations, emotional appeals and platitudes that fail to provide a realistic path to achieving the goals at hand.

All too often, what results is a hodgepodge of targets, mandates and demands without the roadmap, tools and incentives needed for success. In the case of energy policy, it results in a disconnect with science and reality. It is what someone I recently served on a panel with described as "The Trilemma," three qualities we would all like to have with energy: cheap, reliable and green. While it is fairly easy to achieve two of the three qualities, it is exceedingly difficult to have all three. Reliable, green energy is not cheap. Reliable, cheap energy is usually not as green, and cheap, green energy is usually not reliable. Achieving all three is virtually impossible without abundant natural gas.

This brings us to a fundamental question: Will the Biden administration and Congress recognize the role that natural gas needs to play in helping the U.S., the rest of North America and the globe meet our energy and climate needs? We need natural gas to continue to reduce greenhouse gas emissions in the U.S. We need it in North America and Europe as a baseload fuel to offset the intermittency of wind and solar as these markets increase their use of renewables. We need it in the emerging world to meet growing energy demand, offset energy poverty, reduce air pollution from burning coal and biomass, and meet climate goals in the places where carbon emissions are growing the fastest.

Let's hope our policy aligns ambitious energy and climate goals with science and the realities of our energy complex. In order to be successful, we have no other choice.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2021				
Energy Capital Conference	**June 1-2**	**Houston**	**Omni Hotel Houston**	**energycapitalconference.com**
Western Energy Alliance Golf Tournament	June 7	Parker, CO	Club at Pradera	westernenergyalliance.org
DUG East/Marcellus-Utica Midstream	**June 8-10**	**Pittsburgh**	**Lawrence Conv. Center**	**hartenergyconferences/ marcellus-utica-midstream**
Carbon Management Forum	**July 12**	**Fort Worth, TX**	**Fort Worth Conv. Center**	**hartenergyconferences.com**
DUG Permian/Eagle Ford/ Midstream Texas	**July 12-14**	**Fort Worth, TX**	**Fort Worth Conv. Center**	**dugpermian.com**
OOGA Annual Meeting	June 21-23	Columbus, OH	Hilton at Easton	ooga.org
Unconventional Resources Tech. Con.	July 26-28	Houston	George R. Brown Convention Center	urtec.org/2021
Western Energy Alliance Annual Meeting	July 28-30	Tabernash, CO	Devil's Thumb Ranch Resort	westernenergyalliance.org
Petroleum Alliance of Oklahoma Annual Mtg.	Aug. 4-7	Las Calinas, TX	Four Seasons	thepetroleumalliance.com
OGA Annual Conference	Aug. 9-11	Norman, OK	Embassy Suites	okgas.org
Energy Workforce & Technology Council 2021 Annual Meeting	Aug. 15-17	Santa Ana Pueblo, NM	Hyatt Regency Tamaya Resort	energyworkforce.org
EnerCom Oil & Gas Conference	Aug. 15-18	Denver	Westin Downtown	theoilandgasconference.com
Energy Summit Golf Tournament	Aug. 16	Littleton, CO	Arrowhead Golf Club	coga.org
Offshore Technology Conference	Aug. 16-19	Houston	NRG Park	2021.otcnet.org
The Energy Summit	Aug. 17-19		Virtual	coga.org
26th Annual Gas Compressor Association's Expo and Conference	Aug. 17-20	Galveston, TX	Moody's Garden Hotel	gascompressor.org
NAPE Summit	Aug. 18-20	Houston	George R. Brown Convention Center	napeexpo.com/summit
DUG Bakken and Rockies	**Sept. 8**		**Virtual**	**hartenergyconferences.com**
Energy Transition Capital Conference	**Sept. 15**		**Virtual**	**hartenergyconferences.com**
GPA Midstream Convention	Sept. 26-29	San Antonio	Marriott Rivercenter	gpamidstreamconvention.org
A&D Strategies and Opportunities	**Sept. 28-29**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Minerals Forum	**Sept. 28**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Digitalization in Energy Conference	**Oct. 6**		**Virtual**	**hartenergyconferences.com**
Offshore Executive Conference	**Oct. 20**		**Virtual**	**hartenergyconferences.com**
USAEE/IAEE North American Conference	Oct. 31-Nov. 3	Austin, TX	Sheraton Capital	iaee.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Thursday, odd mos.	Forth Worth	Forth Worth Petroleum Club	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., 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
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Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
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NewsWell

Summer outlook favorable for U.S. natgas production

Rebounding rig counts, recovering oil and gas prices and growing global demand signal an improved outlook for the natural gas sector with production forecast to rise.

But don't rejoice yet.

There are risks to summer U.S. gas production, analysts say.

"Three things that come to mind are pipeline maintenance and outages, economic curtailments and hurricane season related to shut-ins," Eugene Kim, director of Americas gas research for energy consultancy Wood Mackenzie, said during a recent webinar.

A planned facility modification as part of The Williams Cos. Inc.'s Leidy South Project in Pennsylvania, for example, might impact some production. Add to this the potential for low gas prices to prompt some producers to curtail volumes. Plus, another active Atlantic Basin hurricane season could shutter coastal LNG facilities while impairing Gulf of Mexico production and possibly operations farther inland, impacting demand, he said.

Despite potential risks, current conditions appear better than a year ago when the COVID-19 pandemic slowed global demand, forcing producers to shut in wells.

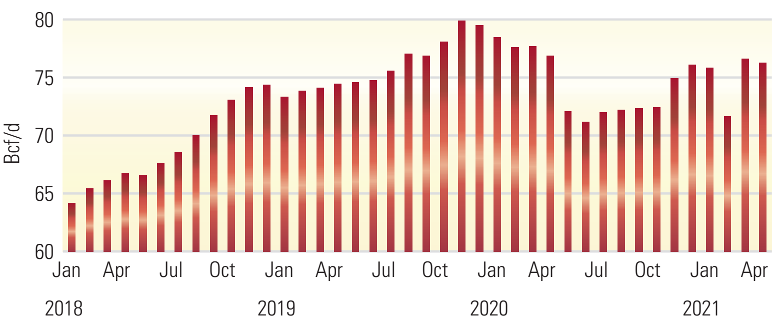
Though still below pre-collapse levels, rig counts have recovered as producers work to climb even steeper treadmills brought on by extended periods of low activity when oil prices plummeted along with gas prices.

Analysts at Wood Mackenzie forecast a year-on-year supply increase of nearly 2.1 Bcf/d this summer, including about 400 MMcf/d of Canadian imports. The growth is not considered meaningful. It's essentially a recovery from last summer's price-related production shut-ins, according to Eric Fell, research director of short-term gas for Wood Mackenzie.

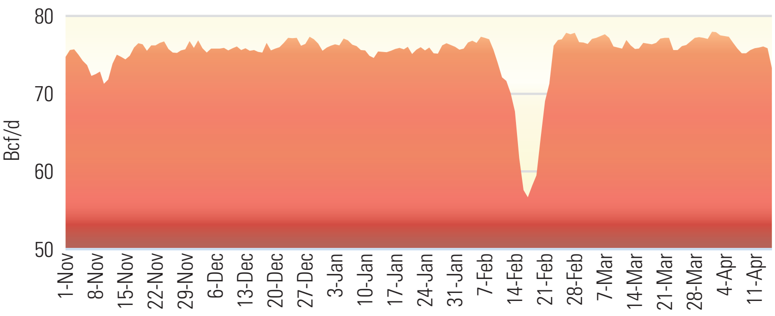
"That's really what is driving that 1.6 Bcf a day of production increases," Fell said. "It's more about the weak comps or weak production last summer than outright growth in the current summer from where we are today."

Forecasts show burgeoning Haynesville production. Of the seven main hydrocarbon-producing regions in the U.S. tracked by the Energy Information Administration (EIA), the Haynesville is

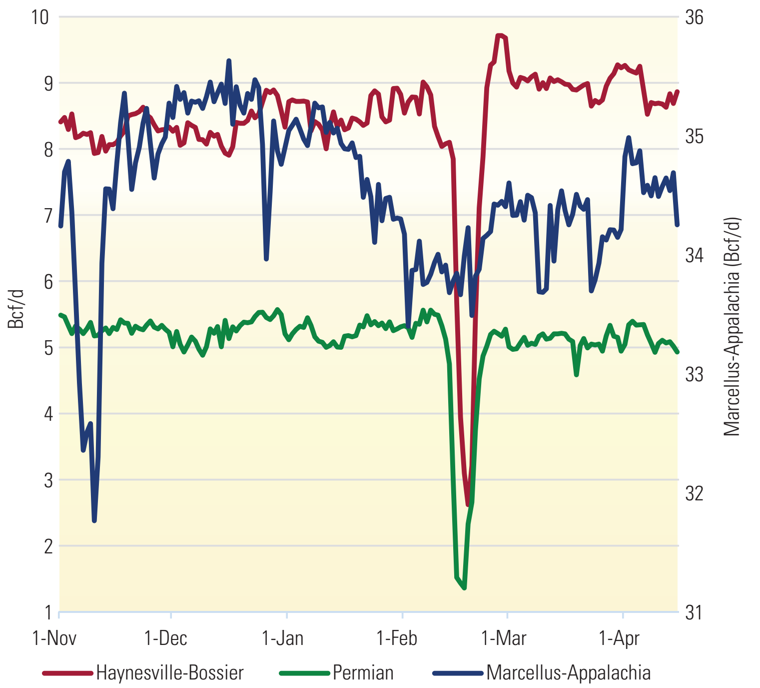
U.S. Lower 48 Gas Production Monthly Sample Flows



U.S. Lower 48 Gas Production Daily Sample Flows



Gas Production Daily Regional Sample Flows



Source: Wood Mackenzie On-Demand Dashboard powered from NatGas Analyst & RT

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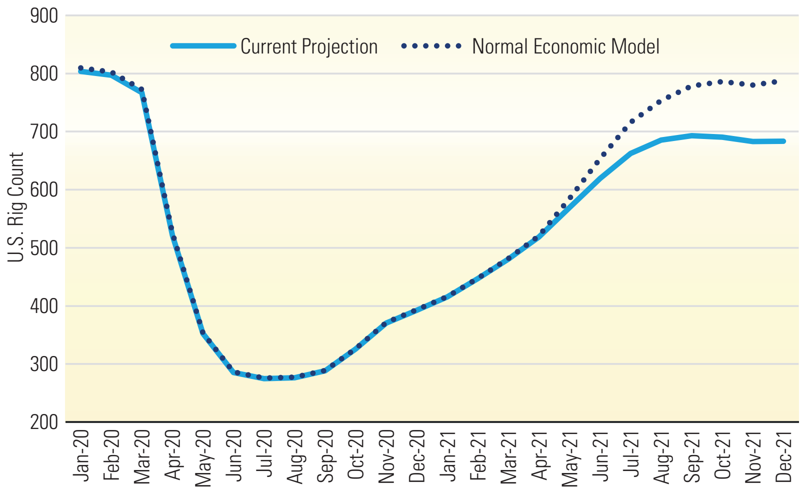
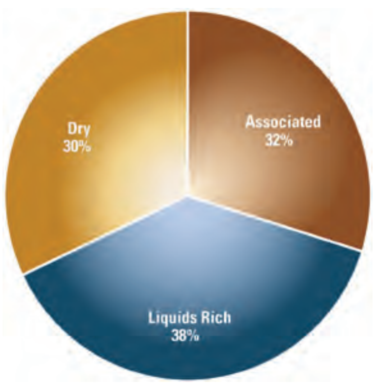
U.S. Rig Count Forecast



Source: Wood Mackenzie, Rig Data

2021 U.S. Gas Production Forecast By Type



Source: Wood Mackenzie, Rig Data

the only one forecast to see gas production growth in May. The EIA's latest Drilling Productivity Report shows gas production in the Haynesville up by 104 MMcf/d to about 12.2 Bcf/d.

"Haynesville production has been gradually increasing and is expected to continue through the summer with higher gas prices and less investor pressures from a larger subset of producers that are PE backed or private," Kim said. "Rigs here have been steadily increasing and back above pre-collapse levels."

Also, back to pre-collapse levels is the oily Permian Basin, which produces enough associated gas to make it the second-biggest gas producer. Considering only about one-third of gas production in the U.S. comes from dry gas plays, eyes will be on associated gas production from liquids-rich plays such as the Permian and oil prices.

However, "it's getting really difficult to monitor due to significant production volumes flowing on recent intrastate pipelines such as Gulf Coast Express and Permian Highway. And this summer, even more so when Whistler is expected to start up," Kim said of Permian production. "Those three pipes alone represent 6 Bcf a day of Permian gas takeaway capacity."

Appalachian production, though still off record highs, "has been outperforming our expectations as of late," he added.

This comes as the producer landscape changes. Consolidation could shrink overall investments and limit growth, analysts say.

"A large universe of the producers are either in the distress or de-lever category and are unlikely to grow production anytime soon in order to create stronger balance sheets," Kim said. "Those that can deliver growth have also maintained capital discipline and are only projecting modest growth rates. … Many have already pledged to reinvest only 70% to 80% of cash flow back into the fields and some even less while the balance is put toward debt production and shareholder returns. Continued investment pressure could drive this even lower."

Focus on emissions reduction and responsibly sourced gas, he added, "will undoubtedly slow down the pace of getting a well drilled, completed and eventually hooked into the gas grid. These changes are good for tackling mounting investor pressures, but ultimately deter the rapid production growth rates we have witnessed in the past at similar prices."

Industrial demand is expected to rise about 0.8 Bcf/d, Fell said, after pointing out summer power demand down by more than 3 Bcf/d.

For what it's worth, the world wants more natural gas and LNG feed gas.

"We're anticipating U.S. pipeline exports to Mexico to be up by approximately 1.2 Bcf a day, which is a huge jump that will be one of the biggest summer-on-summer increases we've ever seen," Fell said. He attributed the surge to production declines in Mexico, increasing demand and new pipeline infrastructure enabling more exports to Mexico.

Wood Mackenzie forecasts show U.S. gas demand of about 10 Bcf/d for the summer, which is about 4.3 Bcf/d more than 2020.

"We had some small increases in U.S. liquefaction capacity through 2020, but the majority of the change is due to the recovery of U.S. exports after the 2020 cancellations," explained Eric McGuire, director of Americas gas research for Wood Mackenzie.

Unlike last summer when profit margins for U.S. exports were negative, profit margins for exports this year are more than $2 for the summer, he said. "That's more than enough incentive to keep shippers moving LNG all summer."

So, can the market absorb the year-on-year increase in U.S. LNG exports?

Yes, according to McGuire.

"When we look at total global supply outside of the U.S., we expect total LNG supply to be relatively flat," he said. "So, the primary change in global LNG supply this summer will be a result of increased exports from the U.S."

Elevating confidence is growing Asian demand as the region, like other parts of the world, recovers from COVID demand destruction. Low European gas storage levels are also fueling opportunity for U.S. LNG exports, according to McGuire.

"Ultimately, when you put together our current base case for production, for domestic demand and for exports to Mexico and LNG, it points to just a little bit over 3.5 Tcf end of October balances," Fell added, noting that would be the second-lowest seen since 2012. The lowest was in 2018. "You're going to need higher prices to kind of get you there."

U.S. natural gas futures were down 1.9% the morning of April 21 to about $2.674/MMBtu.

—Velda Addison

Report shows Big Oil's proved reserves dwindling

Six of the oil industry's biggest companies are not finding enough oil and gas to fully replace volumes produced, causing proven reserves to dwindle and threatening revenue needed to bankroll energy transition plans, analysts say.

The drop, according to Norway-headquartered Rystad Energy, could result in reserves running out within 15 years if large commercial discoveries are not made quickly.

The analysis comes despite proved reserve additions from Total SE and Eni SpA along with some massive oil finds in recent years, including more than 9 billion barrels of oil equivalent (Bboe) of recoverable resources discovered offshore Guyana by an Exxon Mobil Corp.-led consortium. It also comes as the world's near-term demand for oil and gas picks as COVID-19 vaccination rates and global economic activity rises.

About 10% to 15 % of the guided cumulative E&P capex of about $58 billion from the so-called "Big 6" is likely to be spent toward exploration, Palzor Shenga, senior upstream analyst for Rystad Energy, told Hart Energy.

Discovered volumes, so far, this year are down: first-quarter 2020 industry total of 1.2 Bboe, down from 2.7 Bboe a year earlier.

"Despite the modest exploration results recorded so far this year, 2021 has significant potential in terms of wildcat exploration, with South America and Africa among the key regions to watch," Shenga said. "Therefore, these wells will determine whether the majors will be able to maintain or improve their reserve replacement ratios."

Forecasts show demand growth through about 2030 as improving living standards create more need for oil in developing nations even as developed countries increasingly aim to add more alternative forms of energy to their mix.

"The ability of Big Oil to generate future revenues will continue to depend on the volume of oil and gas the companies have at their disposal to sell," Parul Chopra, vice president of upstream research at Rystad Energy, said in a news release. "If reserves are not high enough to sustain production levels, companies will find it difficult to fund expensive energy transition projects, resulting in a slowdown of their clean energy plans."

The report released May 5 by Rystad focuses on the proved oil and gas reserves of Exxon Mobil Corp., BP Plc, Royal Dutch Shell, Chevron Corp., Total SE and Eni SpA.

Combined, the companies' proven reserves dropped by 13 Bboe in 2020, according to Rystad. Contributing factors included less oil and gas exploration spend amid continued focus on capital discipline and the energy transition. The global pandemic also posed challenges.

Exxon Mobil: Proved reserves down about 30% to 15 Bboe. Rystad said the fall was mostly related to gas assets the company purchased from XTO Energy Inc. in 2009. Earlier this year, Exxon Mobil said its "year-end 2020 proved reserved are expected to have been produced by 2040."

Shell: Proved reserves down 20% to 9 Bboe. Declining gas reserves accounting for two-thirds of the drop, including a 600-MMboe revision in the company's Australian projects, Rystad said, while falling liquids reserves in the U.S. and South America accounted for the rest of the loss. Its reserves to production ratio dropped to 7.4 years, Rystad said.

BP: Proved reserves down about 5% to 18 Bboe as it sold some assets, including in Alaska. BP's annual report shows natural gas represented 41% of the reserves.

Chevron: Proved reserves down 3% to 11.1 Bboe, a U.S. Securities and Exchange Commission filing shows. Rystad said impairments were behind reserve losses for Chevron, though it gained some 2 Bboe of proven reserves through its acquisition of Noble Energy Inc.

Eni and Total: Both showed small drops in 2020, compared to the year earlier, according to the companies' financial reports. Total reported proved reserves of 12.3 Bboe, down slightly from about 12.7 Bboe, while Eni reported proved reserves of about 6 Bboe, down from about 6.3 Bboe.

"Total also enjoyed significant exploration success last year in the Guyana-Suriname Basin, while Eni did well thanks to success in Africa," Rystad said.

For the oil and gas industry as a whole, discovered volumes have declined.

First-quarter 2021 discovered volumes total 1.2 Bboe for the industry, down from 2.7 Bboe a year earlier, Rystad data show, as exploration success rates onshore and offshore fall.

"The lack of availability of easily exploitable prospects, combined with dying exploration activity in once rich onshore areas such as the Middle East, have led to the decline in the onshore success ratio," Shenga said in March. "Most of the easily mappable structural prospects with shallow reservoirs have already been thoroughly explored, leaving wildcatters to struggle primarily with technically challenging prospects."

Only 45% of the six majors' production have been replaced from new discoveries in the past six years, according to Rystad, which noted Exxon's 9 Bboe of discovered volumes offshore Guyana lifted it above its peers.

Though exploration has become more challenging with easy-to-find oil gone, companies are pursuing both infrastructure-led exploration campaigns and looking for hydrocarbon resources in frontier areas.

"There is a good balance between the prospects within the frontier and mature basins," Shenga said. "Hence, these companies are not shying away from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High-ranked prospects to be drilled this year provide hope.

Rystad put South America and Africa among the key regions to watch. These include a few wildcat and appraisals planned offshore Guyana and Suriname to be drilled by Exxon along with planned exploration activity by Total in the Guyana-Suriname Basin and Africa.

—Velda Addison

EOG embraces 'double premium' drilling strategy

EOG Resources Inc. said May 7 its shift to so-called "double-premium" wells is contributing to improved results as the Houston-based oil producer increases productivity and picks up exploration efforts.

The target, which focuses on wells that yield a 60% direct after-tax rate of return (ATROR) at $40/bbl WTI and $2.50 Henry Hub, is double the previous minimal sought-after return.

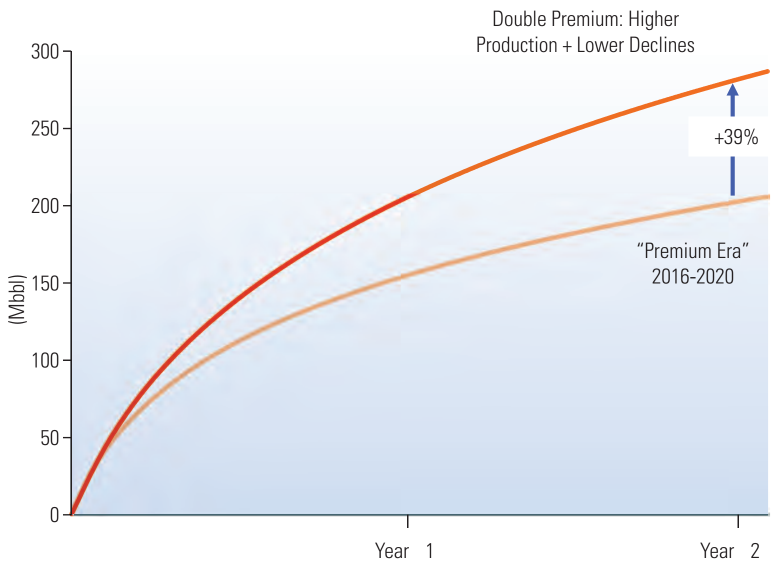
EOG's chairman and CEO, Bill Thomas, said the shift helped drive the company to record returns during first-quarter 2021. Notable achievements include an adjusted net income of $946 million, up from $318 million a year earlier, plus a quarterly record of more than $1 billion in free cash flow and an indicated annual total cash return to shareholders of $1.5 billion.

"As we drill more double premium wells, we expect our performance will continue to improve, our decline rate will flatten, our breakeven oil price will decline, our margins will expand, and the potential for free cash flow will increase substantially," Thomas said during an earnings call on May 7.

With assets spanning the U.S., including the Permian Basin and Eagle Ford, EOG said it has more than 5,700 double premium locations, which it equates to more than 10 years of drilling inventory.

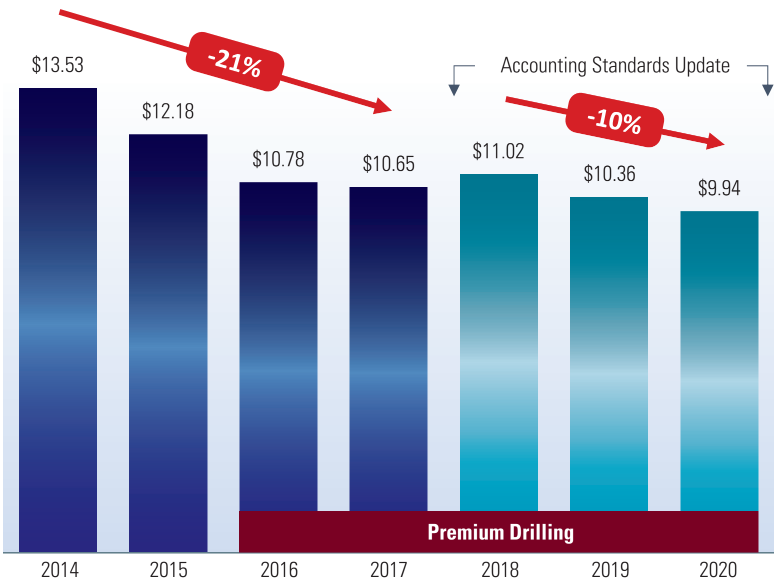
In 2020, EOG completed 290 double premium net wells. The company said it plans to complete about 375 this year,

EOG Cumulative Oil Production Comparison



Source: EOG Resources Inc.

EOG Cash Operating Costs



Source: EOG Resources Inc.

lowering WTI breakeven for more than 10% return on capital employed.

Prior to the shift, an oil price of about $80 was required to reach that level, but that has since fallen, said Ezra Yacob, EOG's president.

"That price is just $50 and we're not stopping there. We expect it will continue to fall as our well level returns improve," he said. "The impact of reinvesting at higher returns is also showing up in our free cash flow performance. We more than doubled the dividend over the last four years and improved our balance sheet, reducing net debt by nearly $3 billion."

CFO Tim Driggers added that since the shift to premium, EOG has retired bond maturities totaling about $2 billion. The company's plans are to retire another $1.25 billion in 2023 when the bond matures.

The focus on higher-quality assets comes as oil and gas prices improve following a dismal 2020 with pandemic-driven demand loss and oversupply.

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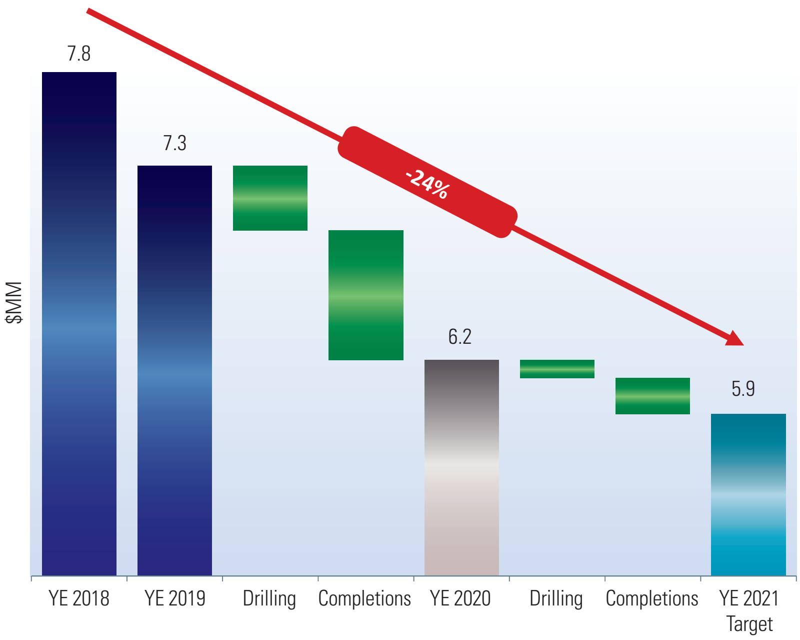
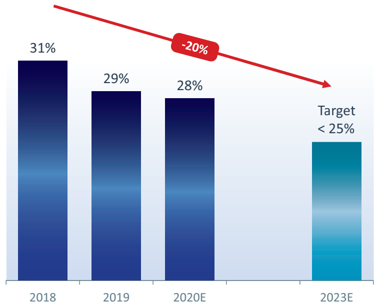


(1) Total LOE, transportation, gathering and processing and G&A expense.
(2) Reflects Increase in Gathering and Processing expenses primarily due to the adoption of Accounting Standards Update 2014-09 beginning in 2018, which required EOG to present certain processing fees as gathering and processing costs instead of as a deduction to natural gas revenues. In 2018, the adoption of Accounting Standards Update 2014-09 added $0.78/boe to gathering and processing expense. See Note 1 to financial statements in EOG's 2020 Form 10-K.
(3) Well Costs = Drilling, completion, well-site facilities and flowback. Normalized to 7,500' lateral.
Source: EOG Resources Inc.

EOG Annual Oil Base Decline Rate



Source: EOG Resources Inc.

EOG's average crude prices, for example, rose to $58.02/bbl in the first quarter, up from $41.81 in fourth-quarter 2020, contributing about 60% of the $1.40 earnings per share increase.

Total production, however, dropped to about 778,900 boe/d—courtesy of downtime related to Winter Storm Uri—from the prior quarter's 801,500 boe/d, though still above the guidance midpoint.

Quarterly oil production of 431,000 bbl/d was above guidance. Going forward, EOG said it plans to maintain oil production at about 440,000 bbl/d as it continues efforts to lower the base decline rate, reduce well costs by 5% and test across high-impact oil plays among other goals.

The double-premium strategy is also rooted in innovation, exploration and drilling teams focused on adding value by driving enhanced efficiencies.

COO Billy Helms highlighted some of the company's efforts. These included moving to larger wellpads and using "super-zippers," a completion technique crews began experimenting with in 2019 that has lowered well costs.

"This practice involves using a single spread of pressure pumping equipment to complete four or more wells on a single pad. We split the equipment's capacity in half, simultaneously pumping on two wells while conducting wireline operations on the remaining wells," Helms explained. "We piloted and perfected super-zipper logistics in our Eagle Ford play and the collaboration between operating areas has accelerated its adoption throughout the company."

In instances where four wells aren't feasible for a single pad, engineering teams are devising new ways to put the technique into practice, he added.

Sustainable well cost reductions combined with technology applications not only lead to well productivity gains but also enable EOG to move some existing inventory into the double-premium category, Yacob said.

So, what does the shift mean for the remaining non-premium inventory?

"We're always high-grading our portfolio and divesting of those properties with minimal double premium potential remaining," said Ken Boedeker, executive vice president of E&P for EOG. "We've actually sold about 7 billion in assets over the past 10 years, and we will continue to high-grade our assets as we see the market giving them fair value."

On the growth side, bolt-on acquisitions near existing developments and exploration efforts also provide opportunity. Such efforts are underway in the U.S. and abroad.

EOG has allocated about $300 million for exploration this year following a 2020 pullback due to the COVID-19 pandemic and the price downturn. The company's executives said they are drilling exploration wells at some prospects and appraisal wells at others.

The company is also looking to replicate shallow-water success offshore Trinidad and Tobago in Australian waters, where EOG recently acquired a stake in the Beehive oil prospect.

"The attractive thing about Australia is not only does it fit into our experience level from operations and a technical perspective," Yacob said, "but it has many offtake and oilfield service availability there and of course, the low cost of entry and an exciting amount of upside in the prospect."

EOG said it remains focused on adding low decline, high impact plays to increase returns, regardless of growth rate.

"When you're reinvesting in higher return opportunities and adding lower-cost reserves, you're driving down the cost base of the company year after year," he said, "and that's essentially what translates into our corporate financials and allows us to lower that price required for a double-digit ROCE every year."

—Velda Addison

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Peak oil? What about peak investment?

Could short-term capital discipline pressure lead to longer-term underinvestment in oil and gas as the energy transition to a low-carbon world unfolds?

"Our models suggest that investment will need to rise about 20% per year during the next three years to stave off a supply shortfall, and then roughly $500 billion in annual capex will be needed by the end of the decade to ensure sufficient production," said Rebecca Fitz, senior director and founding member of Boston Consulting Group's Center for Energy Impact.

The insight, shared during a recent webinar hosted by the Center for Strategic & International Studies, shifts the conversation from a focus on peak demand to whether the industry is nearing peak investment in oil and gas. The conversation on capital also comes amid heightened focus on ESG and a global push toward cleaner sources of energy as oil and gas companies try to attract and keep investors.

BCG, working with the International Energy Forum, released a report in late 2020 stating upstream spending dropped by about 35% in 2020 compared to 2019. However, Fitz said spending so far in 2021 has recovered somewhat, as energy demand picks up following COVID-19 vaccine rollouts and precautions. "We're still looking at about a $100 billion gap between 2021 and 2019," she said.

With all the easy to trim project management costs already cut, improving the cost curve will require more innovation technology solutions, she added.

Gaining access to capital remains tough for energy companies.

The chances of seeing rounds of financing into traditional oil and gas companies is low, according to Ashley Fernandes, natural resources sector leader and portfolio manager for Fidelity Investments.

"I don't think it's necessarily an indictment of the industry by any measure," he said. "I think it's more a question of the returns that have been put up over the course of the past decade."

Those haven't been so great during the past decade for many companies, though several showed strong profits during the latest earnings season as oil prices rebounded from demand loss due to the COVID-19 pandemic.

The influx of investment the U.S. sector benefited from in the last decade is not likely repeatable, according to Fernandes.

When considering oil and gas investments from a public equity's perspective, the formula is simple, according to Fernandes: It's all about returns, regardless of whether it's green or traditional oil and gas.

Still, "there's nothing that would excite me more if I saw a company investing in a market that serves the energy transition, which has a couple of different ingredients," he added. "The first

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is competitive advantage. Second is scalability and the third is returns. Those are the three magic things I'm looking for. It's tough to see right now, to be honest."

He used the offshore wind market, for example, saying rising steel and copper prices along with the potential for harsh weather conditions leave much room for error.

However, "Every time I go back to the spreadsheets and analysis I do, it tells me the supply curve will fall over quicker than the demand curve," he said.

Thinking about reinvestment in the core versus investment in low-carbon energy, Fitz said that some see the latter as future value creation. "Admittedly, we're not there yet. We're upstream oil and gas in large part funding a transition."

It's a balancing act that energy producers are facing, and it's one that has already led to portfolio adjustments or business model changes for some.

The cyclical nature of the oil and gas business brings with it volatility that's unappealing to investors, which have demonstrated an appetite for investments that keep environmental impacts in check.

The mandate of some companies—particularly the European ones—have changed and some can't return to traditional investments, Fernandes added.

Speaking on a separate panel, Shell Oil Co. president Gretchen Watkins spoke about Shell's renewables, low-carbon and core oil and gas business plus the importance of natural gas and carbon capture and sequestration in the energy transition.

Regardless of which energy source makes up the largest chunk of the mix in future years, understanding demand is key when allocating capital.

"About a third of the power that we buy and sell is renewable power," Watkins said. "So we have customers, frankly, like Amazon and Microsoft, that have their own net carbon footprint reduction targets that come to us and say, can you help us by providing us with a portfolio that that is mostly or all renewable energy."

Hydrocarbons are and will be still in demand, according to Watkins and Pioneer Natural Resource Inc. CEO Scott Sheffield, who joined her on the panel.

"We have a net-zero target by 2050, but that doesn't mean that in 2050 we won't be producing any hydrocarbons," Watkins said. "In fact, we believe the world will still need hydrocarbons in 2050 and probably far beyond that."

This outlook includes petrochemicals as well, she noted. "One of our biggest investments in the country right now is as at the Pennsylvania chemical plant," she said.

And as for the Permian Basin—Pioneer's primary asset, the prolific region will still be in play when it comes to oil production in Sheffield's opinion.

If forecasts by the International Energy Agency pan out and "we're down to 65 million barrels a day by 2050, then we think the Permian is still going

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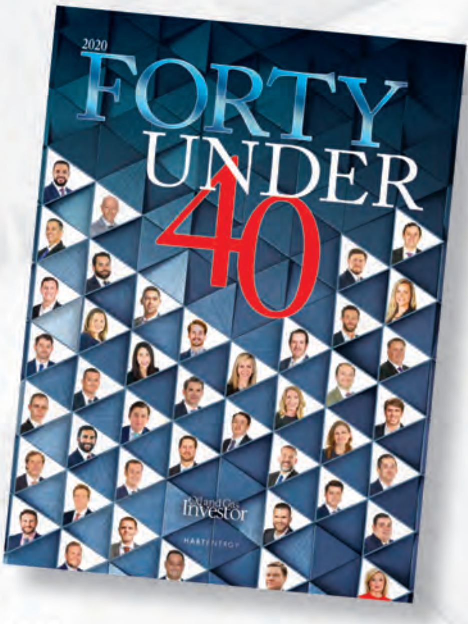

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to be producing at that point in time," he said. "It's still got huge potential."

But he warned the world should not look to U.S. shale to fill the gap if demand picks up faster than expected in 2022 or 2023.

"There is no shale to save everybody like it did in 2014 or 2019 when we grew over a million-million and a half barrels a day," said Sheffield. "I don't think the U.S. shale industry will ever recover to its peak of roughly 10 million barrels a day or U.S. producing 13 [MMbbl/d]."

Lowering annual growth rates today bodes well for shale underlying decline rates.

"We used to decline at 45% per year. It's moving down toward 30%," Sheffield said, "and over the next three or four or five years, it should move even lower because you're building up this great base of lower decline wells as wells get older."

For Permian-focused Pioneer, switching to what Sheffield calls the free cash flow model was needed for the company to survive through downturns and attract investors.

"Everybody knows we're the worst performing industry in the S&P 500 over the past 10 years, so something had to change," Sheffield said. He described the lows and highs of the company's stock price as it went through the last three industry downturns.

Pioneer, which recently reported first-quarter production up to 473,937 boe/d compared to a year ago with adjusted net income of $396 million, has committed to return about 80% of its free cash flow to shareholders and grow production at only 5% per year.

That's a change from the days when shale producers were growing at double digits, reinvesting more than 100% back into plays and growing rig counts. Back then, Sheffield pointed out, compensation was based on factors that included growth and reserve replacement.

Times have changed.

Like Sheffield, Watkins agreed the focus in the unconventional space has shifted to growing free cash flow. "It's a much more prudent way to run a business," she said. "We're very much a value over volume investor in shales and frankly, in the upstream in general, that's really what we're looking at, not out chasing barrels, but really chasing value and chasing cash."

She believes the industry is seeing the same with the recent consolidation wave, especially in the Permian Basin.

"I think that the industry will be less susceptible to creating some of this volatility," Watkins said, "but the markets, of course, no one knows what that's going to do."

—Velda Addison

Analysts forecast U.S. shale growth likely by year-end

U.S. light tight oil's base decline is almost half that seen pre-COVID-19, Rystad data show.

Before COVID, the base decline—defined as the difference between legacy production and the sum of legacy and new production in the previous month—was very high due to many new wells being drilled, which accelerated decline, Per Magnus Nysveen, head of analysis for Rystad Energy, said on a recent webinar.

"That contributed to base decline passing 600,000 barrels, but now we have seen some months with 300,000 barrels in base decline. Going forward, we think that … you need only half as many new wells as in the end of 2019 to keep the production level flat," said Nysveen. "This is important to understand the potential of shale to grow.

The analysis was given as the shale sector continues to rebound from a year that saw the global coronavirus pandemic squash demand, wreaking havoc on the oil market and slowing U.S. shale activity. Operators focused on core areas during the downturn and targeted drilled but uncompleted wells as conditions improved.

U.S. oil prices have since bounced back to about $65/bbl, compared to about $20/bbl a year ago, helped by moves by OPEC+ to calm the oversupplied market with production cuts and vaccine rollouts as travel picks up in parts of the world.

Rystad data show U.S. light tight oil activity—comprising horizontal wells in the Permian Basin, Eagle Ford Shale, Bakken, Niobrara and Anadarko Basin—is now about 15% above maintenance requirements. "There is potential for shale to continue growing through the year," Nysveen said. He pointed out that unlike supermajors, which have not begun adding rigs, some public independents have joined smaller private E&Ps in increasing rig counts.

Production, however, is expected to remain flat over the summer months, he added, noting there is also a typical dip in September as hurricane season impacts Gulf of Mexico production.

Though Rystad revised down its total U.S. oil and lease condensate production forecast in wake of the Texas freeze, which impacted production in the Permian Basin, the firm still sees production growing by year-end.

"I think this is fairly much in line with consensus," he said. However, "we think that the potential is a little higher given oil price and given activity level than some other analysts."

Higher oil prices, however, likely won't lead to a significant ramp-up in spending by most producers who remain focused on efficiency with investors watching closely. Hedging is also a factor, according to Alisa Lukash, a senior analyst for Rystad. Hedging is beneficial, particularly if a company wants to secure new financing, as it reduces investors' exposure to some risks.

"However, the floors are on $43 per barrel, and the ceiling is closer to $50," Lukash said. "So that is one of the reasons why for this year we won't see a huge overspending trend because many companies have ceilings or they kind of locked into a particular price.

"Most of them actually have swaps. Some of them have three-way collars and two-way collars, which allow a little bit more flexibility," Lukash said. For most, "it doesn't make sense from the cash flow perspective to significantly ramp up spending if you're still generating or securing your cash flow at $45 WTI."

Analysts also noted some other trends.

Consolidation continues, especially in Permian Basin. "And it's still a year when transactions are relatively cheap," Lukash said. Data show the U.S. average price per acre dropped to about $5,000 in 2020 from $17,000 in 2018.

Deleveraging also continues. Historically, the U.S. shale industry had attracted $37 billion annually through debt or equity financings, Lukash said. That, however, dropped to less than $13 billion in 2019 but rose to nearly $19 billion in 2020. It's about $8.3 billion so far this year.

"Some companies actually needed capital for drilling activities, while most usually did it for refinancing purposes," Lukash said. "In 2021, we noticed some companies actually issuing debt for transactional activity. So that's a little bit of a new trend here. ... But overall, the industry is still highly leveraged and companies are still focusing to not just refinance into the future, but reduce their total debt."

—Velda Addison

What's next for the global oil market?

Coronavirus is out of the driver's seat when it comes to the oil and gas market, leaving Saudi Arabia and Russia at the wheel, according to energy experts.

What's next could come down to what these two drivers want.

"If they want to keep prices rising, they can keep a tight rein on supply and push inventories even lower," Mark Finley, fellow in energy and global oil at Center for Energy Studies at Rice University's Baker Institute, said during a recent OTC Live webinar. "But at what point does that become counterproductive? At what point does higher prices push U.S. drillers back into the game?"

OPEC+ agreed in April to ease production cuts of about 7 MMbbl/d today by adding 350,000 bbl/d in May and again in June. By July, the group will add another 400,000 bbl/d as Saudi Arabia also phases out its additional voluntary cuts of 1 MMbbl/d.

The move was another step in the group's continued efforts to stabilize the oil market following last year's pandemic-fueled crash, which saw prices briefly turn negative. In the months since, vaccine availability had added to hopes for economic recoveries across the world as travel picks up and refineries, specifically those in the U.S., recover from harsh winter weather.

The OPEC+ production group, however, has a lot of surplus capacity.

"Even after this summer's planned output increase, the group's production will still be 6 million barrels a day below reference at pre-production levels. That's a lot of spare production capacity," said Finley, a panelist on the webinar moderated by the Baker Institute's Ken Medlock.

"What it means is that with our two new drivers at the wheel, the group can increase production anytime they want. That should help keep a lid on prices going forward, if that's what they want. It also serves as a warning deterrent to people who are considering investing at these prices."

Riyadh and Moscow learned from the April 2020 oil price collapse, and the two are cooperating closely despite disagreements about strategy, said Jim Krane, Wallas S. Wilson fellow for energy studies at the Baker Institute.

"Saudis are often over complying with cuts. Some of that's due to their own views of the market. Some of that's due to their willingness to retain that OPEC leadership and shoulder more than the burden," Krane said. "They're also allowing Russia to bring … Russian production online earlier than everybody else."

Russia also benefits from cooperating, he added, noting it gains increased influence in the Middle East, including countries with close ties with the U.S.

"We know Vladimir Putin likes to insert himself in between the U.S. and its allies, and he's doing a fantastic job of that here," Krane said, after also pointing out Russia's acceptance of Saudi's desire for higher oil prices despite Russia's low fiscal breakevens. "I would expect geopolitical drivers to keep Russia cooperating with Saudi Arabia and OPEC."

Market watchers are also paying attention to Iran.

Iran's production is inching up with exports, mostly to China, at about half of pre-sanction levels, Krane added. Efforts are underway to bring the U.S. back into the 2015 nuclear accord with President Joe Biden in office.

"It's a nice confidence-building measure if things are progressing, but a good way to put pressure on Iran if things start stalling," Krane said. "In doing that, reinvigorating those sanctions would create some stress, not just with Iran, but also with China, which appears to be more willing than usual to kind of test the U.S. these days and test Biden's, you know, get tough on China policy.

It could also create some stress with India, where Krane said refiners want Iranian crude as India has been "upset about the price hawkishness within OPEC and Saudi Arabia."

The U.S. Energy Information Administration's Short-Term Energy Outlook forecasts WTI crude oil averaging $58.89 for 2021, up from $39.17 in 2020 but set to fall to $56.74 in 2022. Brent is also forecast to see similar ups and downs, forecast to average $62.28 in 2021, up from $41.69 in 2020 set to drop to $60.49 in 2922.

WTI was hovering around $62/bbl on April 27, compared to about $12.17 a year ago.

Don't forget about U.S. shale.

"The rocks are still there," Finley said. "Under the right circumstances, domestic shale producers certainly have the potential to raise output significantly."

Will they resist temptation?

"Most analysts expect that at these prices, the rig count should drift higher, and along with that, later this year, we should expect to see a modest production increase," Finley said. "U.S shale could grow much more rapidly. The Dallas Fed's surveys, for example, show that a lot of U.S. shale operators are in the money at these prices. But even so, most producers and their investors seem determined to avoid temptation, seeking instead to maintain spending discipline and aiming to return cash to investors rather than plowing it back into growth."

Data from Baker Hughes Co. show the U.S. land rig count at 426 for the week ending April 23, down 22 from a year earlier, as drillers rebound from record lows seen at the height of the pandemic and global oil oversupply.

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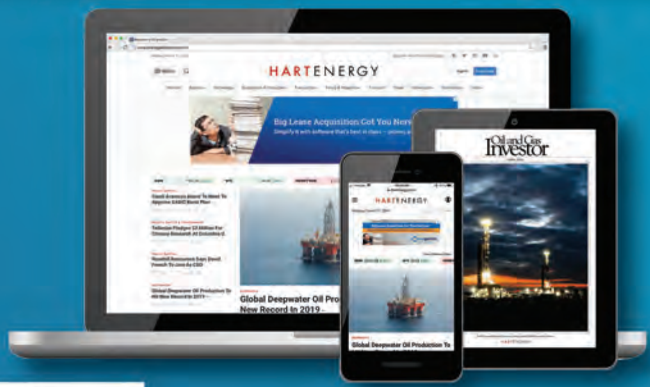

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In all, U.S. crude production is at about 11 MMbbl/d. Finley said there isn't much prospect for increased global oil production this year beyond the OPEC+ increases. The rig count increase in the U.S. has been supplemented on the shale side by a drawdown of DUC inventory, he said. Further, operators have been cutting costs and increasing productivity. However, "All of these positives so far have only served to offset the decline rate of the base of production, which is very high in the U.S.," he said.

Global oil demand could change everything. Emerging virus variants, vaccine uptake pace and how quickly travel returns, however, add to demand uncertainty.

After last year's monumental pandemic-drive demand declines, the world's need for more energy is picking up.

"The International Energy Agency [IEA] in Paris projects that after falling by 9 million barrels a day last year, which was the biggest decline ever recorded, worldwide oil demand this year is likely to grow by about 6 million barrels a day, which in turn would be the biggest increase ever recorded," Finley said.

Sequential growth is expected each quarter through 2021, with global oil demand just one million barrels below pre-COVID levels by the fourth quarter, he said, citing the IEA's forecast. "And by the way, the IEA is on the low side of forecasters. Other analysts are expecting growth this year to exceed 7 million barrels a day."

—Velda Addison

Report shows global flaring levels down in oil sector

Though seven of the world's top oil-producing countries together flared enough associated gas to power sub-Saharan Africa last year, the volume of gas flared by the oil industry fell by 5% as the coronavirus pandemic slowed demand and ultimately, oil production.

That's according to a report released April 28 by The World Bank, which again named Russia, Iraq, Iran, the U.S., Algeria, Venezuela and Nigeria as the largest flaring countries. Combined, the countries accounted for about 40% of oil produced and about 65% of gas flared globally in 2020, according to the report based on satellite data.

Data in The World Bank's Global Gas Flaring Tracker showed 142 billion cubic meters (Bcm) of gas was flared globally in 2020, down 5% from 150 Bcm in 2019. The decline came partly due to oil production falling to 76 million barrels per day (MMbbl/d) as the COVID-19 pandemic slowed demand. Much-needed new pipeline infrastructure also became available, providing monetization opportunities for companies looking to capture the value of natural gas.

"These silver linings, against the backdrop of a dark year, give us hope that progress on gas flaring reduction will accelerate, particularly for those with the appropriate infrastructure, regulation and political will in place," Zubin Bamji, program manager of the World Bank's Global Gas Flaring Reduction Partnership World Bank, wrote in the report. "For our part, we will redouble our efforts to collaborate with high gas flaring countries, particularly in developing countries, and work closely with governments and oil companies to address the most common challenges to gas flaring reduction."

The U.S. was among the bright spots. The report showed gas flaring in the U.S.—mainly in the Permian Basin, Bakken and Eagle Ford—dropped by 32%, accounting for 5.5 Bcm or 70% of the overall drop in global gas flaring. Besides the oil production slowdown, the improvement was attributed to more gas infrastructure and takeaway capacity.

Regulators have also been taking steps to reduce emissions. New Mexico authorities passed rules earlier this year that require upstream and midstream operators to capture 98% of natural gas waste by year-end 2026.

Nigeria is also gaining ground in its efforts to reduce gas flaring volumes.

"Although the country has remained in the top seven flaring countries, it has nonetheless steadily reduced its flaring by some 70% over the past 15 years," the report said of Nigeria. "Flaring has declined from over 25 Bcm in 2000 to close to 7 Bcm in 2020, while oil production has remained essentially flat at around 2 million barrels a day."

Russia, however, remains the world's top gas-flaring country based on the report, which showed the volume here rose to 24.88 Bcm in 2020 from 23.21 in 2019. Still, the narrative is changing in parts of the country, including the Khanty-Mansi Autonomous Okrug (KMAO) region where the report showed gas flaring has fallen by 80% since the mid-2000s. KMAO gas flaring volumes were down to just over 4 Bcm in 2020, according to the report.

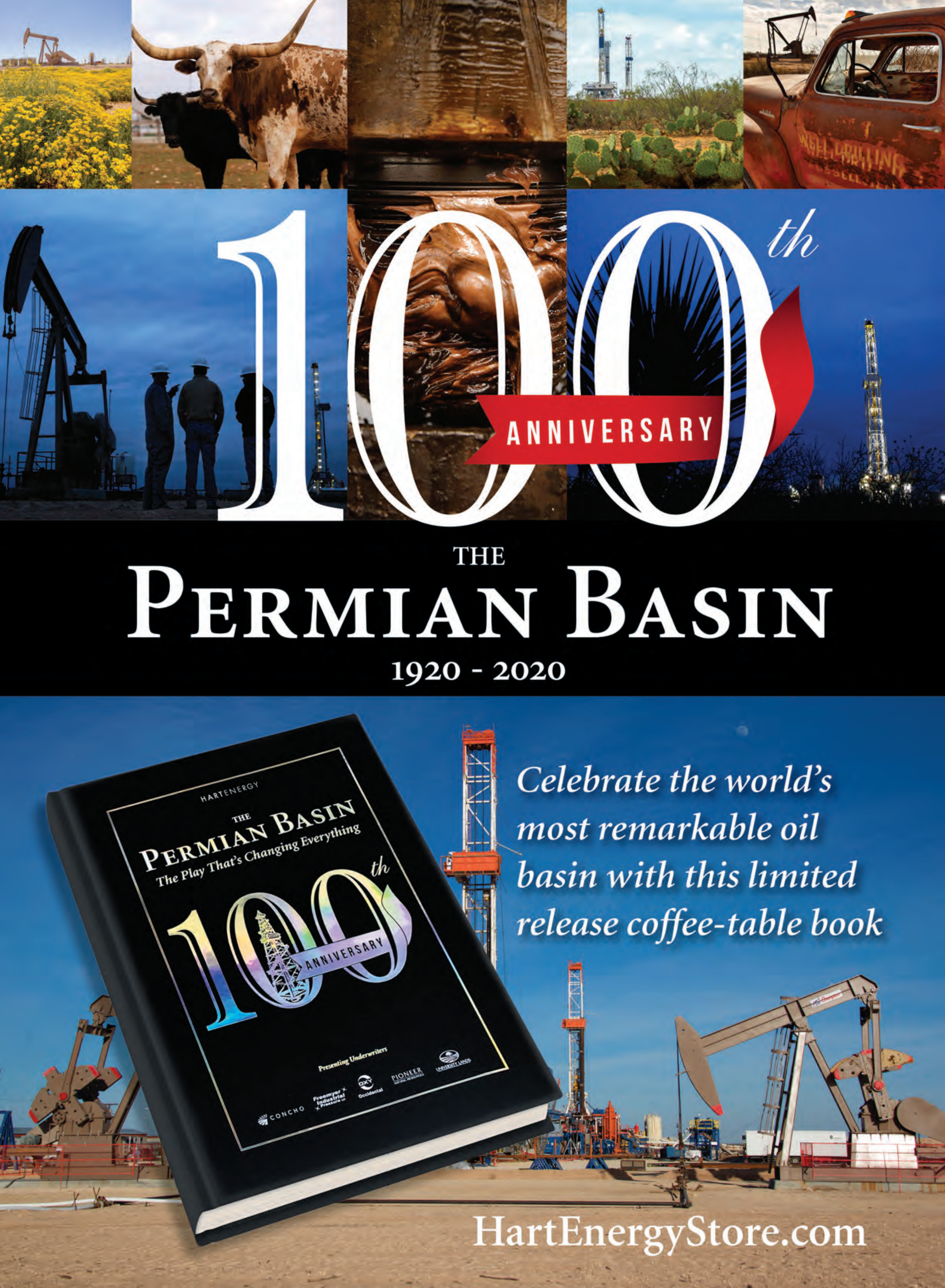
Surgutneftegaz was the most successful in bringing down emissions, having an associated petroleum gas utilization rate of 99.5% last year, Reuters reported April 9 citing a Russian document. Gazprom had 98.9%, while Rosneft stood at 73.1%.

The World Bank said its report utilized data from satellites operated by the U.S. National Oceanic and Atmospheric Administration and interpreted with assistance from the Colorado School of Mines' Payne Institute for Public Policy.

The organization also released a new metric called the Imported Flare Gas Index (IFG Index), that "aims to quantify the concept that if a country is importing crude oil from producing countries then it is also importing the flaring intensity of these producing countries in proportion to the amount of crude oil imported." The index identifies countries with indirect exposure to gas flaring via their large oil import volumes.

"Eliminating routine gas flaring is common sense because any action to reduce flaring profoundly reduces the direct or Scope 1 emissions of the oil and gas sector," the report stated. "In this sense, it is what we call a 'low-hanging fruit,' alongside other climate actions, like preventing and minimizing methane leaks, and eliminating routine venting. While there are certainly barriers and constraints, ending routine gas flaring represents a big 'win' for climate action."

—Velda Addison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ANTERO RESOURCES CORP.

APPALACHIAN BASIN SET IN STONE

Antero Resources Corp. says its days of growth are over, while other operators are still working to capitalize on growth after the pandemic slump.

BY DARREN BARBEE

PHOTOGRAPHY BY MARC MORRISON

The Appalachian Basin may be one of the most cutthroat shale plays in the world, grappling with global competition, pipeline constraints and a consistently disappointing commodity price.

Paradoxically, operators within the basin cannot seem to contain themselves. Even after a season of pandemic sapped demand, production in the Marcellus and Utica shales was seemingly in a world of its own.

While 2020's natural gas prices cut about 1% of U.S. natural gas production, the Marcellus and Utica shale states of Ohio, West Virginia and Pennsylvania produced 33.6 billion cubic feet per day (Bcf/d) in 2020, a 5% increase year-over-year.

Texas produced the most natural gas in 2020 among all of the states, but volumes decreased to 28.1 Bcf/d in 2020 from 28.4 Bcf/d the previous year, according to the U.S. Energy Information Administration, which bases its figures on gas supply withdrawals.

After outperforming the XOP by 39% in 2020, companies in the Appalachian Basin have seen a reversal, with oily names increasing by 27% in value through late April, said Cowen analyst David Deckelbaum.

The natural gas curve is now "off 10% since the highs of February, and East Coast basis has widened to 24%" below Henry Hub, Deckelbaum said in an April report.

Appalachia's song may seem somewhat familiar—a save-time-in-a-bottle melody. E&Ps are forced to keep gas in storage because of differential costs. Several major E&Ps are maintaining maintenance-level capex budgets this year. And rig activity is expected to change, perhaps by one or two rigs, according to Goldman Sachs.

Companies such as Antero Resources Corp. and privately owned Northeast Natural Energy LLC are both prepping for an immutable natural gas price.

"We expect to be in maintenance mode here going forward," said Daniel Katzenberg, Antero Resources' director of finance. "The growth era for Antero is complete."

Mike John, CEO of Northeast Natural Energy, has also cast out any magical thinking regarding commodity prices.

"I guess I've given up on thinking that we just need a price spike to bail us out," he told *Oil and Gas Investor*. "That was a key lesson for me and hopefully a key lesson for a lot of other folks. Because if you're not willing to put aside that aspiration, then I think you're subject to disaster."

If basin operators are resigned to a slower pace of activity, they are eager to capitalize on several inherent advantages. Operators are technologically advanced. Their teams have

Fog overtakes Tug Hill's West Virginia operations. The company expects to spend about $300 million on a 40-well campaign this year.

TUG HILL OPERATING

weathered multiple severe downturns and learned the rock beneath them.

Many operators say they are poised to generate hefty free cash flow even in a tough market. Many of the basin's operators also have an advantage over oil companies because of their early adoption of sustainability goals, such as reduced methane emissions.

The Marcellus Shale also suits the oil and gas industry's transition to Shale 3.0, a still nebulous phase in which E&Ps will attempt to deliver consistent shareholder returns via cash flow generation while balancing capex and environmental stewardship.

Tug Hill Operating COO Sean Willis said the Appalachian company has demonstrated that environmental stewardship and economic prosperity are not mutually exclusive decisions or outcomes.

"You're not compromising one for the other," he said. "We feel like we've made the right environmental decisions that, as a result, are also the right economic decisions."

As for repeatable cash flow, Antero Resources' Katzenberg sees the Marcellus' rock having enough uniformity, thanks to low natural fracturing, to support manufacturing-style repeatability. The shale also compares well against other gas producing basins, including those in Texas and Louisiana, Katzenberg said.

"That allows for all of your wells to be very consistent," he said. "You don't see that in other basins. If you look at other shale basins in the U.S., whether it's the Permian [Basin] or another natural gas basin like the Haynesville [Shale] you end up having natural faults that can cause disruptions in your drilling results and not allow for long lateral drilling. Repeatable drilling results deliver predictable operating performance."

Appalachia may be the basin to beat, not for production, but as companies turn back high-debt ratios and begin to throw off cash flow.

First blush

Perhaps the most important task Antero Resources had lined up in 2021 has already been accomplished. In the first quarter, the company reduced its debt by $433 million and expects its net debt to EBITDA to fall below 2x this year.

While Antero Resources' first-quarter production was 1% lower than expected, the company "still managed to crush Street EBITDA estimates by about 19% on the heels of higher NGL and natural gas realizations," Raymond James analyst John Freeman observed in an April report.

Antero expects to generate $600 million in free cash flow this year, which Freeman called

"We expect to be in maintenance mode here going forward," said Daniel Katzenberg, Antero Resources Corp.'s director of finance. "The growth era for Antero is complete."

THE LAST MVP

Whether another pipeline will be built in the Appalachian Basin, the curse of the region's great production strengths is a perpetual need to move natural gas cheaply and effectively.

Many operators doubt new pipelines will be built, leaving some operators' gas occasionally sidelined because of commodity prices and basis differentials.

Crestwood Equity Partners LP, which has midstream storage and transmission assets in the basin, has several enviable advantages in the Appalachian.

Ben Hansen, senior vice president of operations at Crestwood Equity Partners, said evidence of capacity constraints routinely turn up.

"What probably highlights that, first and foremost, has been the recent attempts by some of the Northeast FERC regulated transportation pipelines to develop, permit and obtain approval for new projects," he said. "They are trying to link the production area to the demand area."

Crestwood, which also operates in the Bakken Shale, Powder River Basin, Delaware Basin and Barnett Shale, isn't in the process of building a new major project in the region.

"Needless to say, it's been challenging for people to get new infrastructure built up there," he said.

Crestwood Equity Partners' largest customer in the region is Antero Resources Corp., which connects 250 wells to Crestwood Equity Partners' system. Crestwood Equity Partners has a 140,000-acre dedication which includes an inventory of 1,400 liquids-rich and 1,200 dry gas locations. The company's 875-MMcf/d capacity allows new wells to be connected without additional spending.

"The Northeast Marcellus, is the closest production area to a very huge demand center, being in New York and New England," Hansen said.

In conversations with customers, producers still heavily value northeast gas, while Antero Resources targets a more liquids-rich gas in the southwest.

"We see two different sides of the Marcellus Shale. The dry Northeast and then the rich southwest," he said. "We continue to believe that the Marcellus is going to play a very important role in the future."

Crestwood Equity Partners also maintains storage facilities, including Stagecoach Gas Storage in New York, which has 41 Bcf of storage capacity and combined transportation capacity of 3.1 Bcf/d.

"We think that it's a very valuable asset because it can never be replicated again. I don't think that there's going to be any new, large-scale gas storage facilities developed in New York, at least for the near future," he said.

The Appalachian Basin retains appeal for midstream operators such as Crestwood Equity Partners, which generates stable cash flow from predictable wells.

"We think that there's going to continue to be a demand for natural gas that's connected to the Marcellus Shale, particularly around our West Virginia asset and because Crestwood has made great strides in reducing its methane emissions, that will be of greater appeal to utilities who are focused on responsibly produced and processed natural gas," he said. "It's only a matter of time before growth resumes in the area, because there's profitable rock underneath our system."

The new $6.2 billion Mountain Valley Pipeline (MVP) project under construction may be the last pipeline to be built in the region for some time. Assailed by protestors and legal actions, the project calls for a 303-mile pipeline that stretches from northwestern West Virginia to the southern part of the state.

"In all likelihood, that is the last possible project in the Northeast," Katzenberg said. "What that leaves you with is the Appalachian Basin being capacity-constrained going forward."

The basin, with total supplies of roughly 33 Bcf/d, max out the long-haul pipelines.

With its long-haul pipeline contracts that deliver its natural gas to premium priced markets, Antero Resources sees its transportation capacity as a competitive advantage that allows it to consistently deliver realizations at premiums to Henry Hub pricing.

Antero Resources has access to long-haul pipelines that move 2.1 Bcf/d to the Gulf Coast and LNG corridor where it is sold at Henry Hub prices—a significant margin benefit.

From August to October, other Marcellus Shale operators had to shut in gas in some cases because of pipeline crowdedness or gas prices that couldn't justify transporting it. Basis differentials went as high as a $1.50 discount to Henry Hub at one point.

"Our expectation going forward, given that we see the basin becoming pipeline-constrained, is that producers without sufficient takeaway capacity will be forced to shut in gas during annual shoulder seasons or forced to accept significant discounts to Henry Hub pricing for their gas sales," he said. "There will be wide basis differential and potentially shut-in volumes, regardless of whether MVP gets finalized or not, based on our long-term outlook."

Like Antero Resources, Tug Hill Operating has benefited from its partnerships. The company develops in conjunction with an infrastructure partner, XcL Midstream. XcL has remained in lockstep with Tug Hill Operating's operations, allowing for timely connections to pipeline and water infrastructure that also has enabled the company to reuse all of the water it produces.

With the appropriate planning, the company has eliminated the need to truck any water.

"Water trucking is very expensive and inefficient. Additionally, it poses incremental risks of spills and potential negative environmental impacts," he said.

Hypothetically, every stage frac stage pumped requires 10,000 barrels of water. That would require 50 trucks, carrying 200 bbl of water, to make a round trip for each stage fractured during a day. "That's significant amount of truck traffic. And we have done that because it's the right thing for the environment, it's the right thing for the members of the community where we work and it helps to minimize any impacts we have on the conditions of the roads in those areas," he said.

Tug Hill Operating hasn't had to dispose of water since first-quarter 2018, and over that time the company has kept more than 45,000 trucks hauling produced water off the road. "When you consider the amount of fresh water we have piped to our sites for our stimulation operations, we have eliminated the need for over 9 million trucks from off the road," he said. "That's just fundamentally the right thing to do from every perspective."

By investing in the power infrastructure, the company has been able to eliminate generators from more than 70% of the Tug Hill Operating operated pads.

"Our cost profile would not be where it is" without those upgrades and could have diminished the company's overall ability to attract capital.

"As you look at the oil and gas sector broadly, the returns have not met expectations for the investors, which is why you see equity values of many companies destroyed over the past five years," he said. "We're very excited about what we built and how we've gone about realizing the value."

"conservative at first blush"—considering its first-quarter haul of $416 million. And by 2025, the company intends to be on the path to producing $2 billion in free cash flow.

Antero Resources puts the Marcellus Shale, and its assets, in an elite class among the resource basins of the world. Its footprint has thousands of locations, complimentary midstream assets and a built-in customer base that includes population centers in the Northeast, including New York City, Philadelphia and Boston.

Surviving to this point, and now pulling ahead in 2021, has required Marcellus operators to change their mindset—with their hands forced by supply gluts and sputtering demand.

In 2018, Antero Resources drilled and completed (D&C) 164 wells at a cost of about $1.5 billion. In each year that has followed, the company has spent fewer dollars on its drilling campaign. As of May, its 2021 D&C budget is an estimated $590 million—about 60% less than three years ago.

The company now claims a spot as the second largest NGL producer and third-largest natural gas producer in the U.S.

Among Appalachia operators, Antero Resources is the largest U.S. NGL exporter with the most international exposure through Mont Bellevue. The company's propane position continues to be a leading source of cash flow.

"Looking back at 2020, you saw a great example of how inelastic global propane demand is. As transportation fuels, specifically oil, saw significant demand destruction, there was little impact on demand for propane." Katzenberg said. "And that's because you see that baseline support from demand in China and India, which is significant."

With leasehold of about 451,000 net acres in West Virginia, the company is distinct from many of its peers in Pennsylvania. Antero Resources also holds about 91,000 net acres in eastern Ohio.

In West Virginia, Antero Resources has amassed a large, contiguous acreage position with current operations centered in Tyler and Wetzel counties, where the rock allows for drilling pads to operate side-by-side.

"The efficiencies that you get from being able to drill repeatable wells and pads right next to each other, while not having to do these large step outs, really helps drive down your well cost and leads to more efficient drilling."

The company has fine-tuned its drilling through multiple industry slumps, improving drilling and completion plans that have led to lower costs. This year, Antero Resources also reported a U.S. record for lateral drilling, crossing 12,118 ft in 24 hours.

This year, Antero Resources is completing more than nine stages per day compared to about eight per day last year.

"We continue to improve on our drilling metrics. In combination, all these improvements help accelerate the time that it takes to drill the well and ultimately reduces the well cost."

Mike John, CEO of Northeast Natural Energy LLC, has no expectations of a rosy natural gas price. "If you're not willing to put aside that aspiration, then I think you're subject to disaster."

Drilling in the Appalachian Basin will slow in 2021, analysts say, but many operators expect a boom in cash flow.

Tug Hill Operating COO Sean Willis said that environmental stewardship and economic prosperity need not be mutually. "You're not compromising one for the other," he said.

That improvement has helped drive down capex, which leads to free cash flow on a sustained basis, he said.

Marcellus operators are now beginning to hear questions about the region's service sector, where the deflationary environment surrounding prices is beginning to abate.

Katzenberg said Antero Resources has not itself seen cost inflation yet. The company is locked in at three gross rigs, even accounting for its recent joint venture with Quantum Energy Partners, which netted Antero Resources $500 million to $550 million in proceeds.

"We expect our operated rig count level to stay flat," he said. Our maintenance plan is about 65 net wells (drilled)."

Should prices increase, Antero is confident in its own efforts to cut costs and improve operational efficiency, which it pegs at 80% of the recent capex savings. Service companies will eventually have to boost their margins, but with few new rigs expected in the Marcellus Shale, inflation still appears to be a longer-term concern.

"We do not see rig rates climbing meaningfully in the Northeast, and we have a similar outlook on the completion side," he said. "So at least in the Northeast, we don't think that inflation will be a significant factor in 2021 and should be pretty minimal in 2022."

On the private side, however, some companies have different plans.

Three rig hill

Heading into 2020, Tug Hill Operating's management had bold growth plans for its Utica Shale/Point Pleasant stacked pay.

Initially, Fort Worth, Texas-based private independent, planned to run five rigs on its leasehold, drilling 3,000 ft deeper than the Marcellus Shale to reach the Utica Shale. Since 2018, the company had been actively codeveloping their leasehold and while driving a leaner operation.

The pandemic hit and Tug Hill Operating was forced to drop down to three rigs.

"While most operators are executing maintenance capex programs, whereby keeping their production relatively flat to enable their ability to generate free cash flow, we are able to grow our business at more than 20% CAGR while also generating high levels of free cash flow," Willis said.

Though Tug Hill Operating is private, the team benchmarks their performance each day and strives for continuous improvement. As such, Tug Hill sees itself as a best-in-class operator among its Appalachian peers, and it is proud of the reputation it has established within the communities.

"Every decision we make is underpinned by our commitment to environmental stewardship, deep technical analysis and economic returns," Willis said. "By focusing on becoming more efficient as our organization has grown, we have generated basin-leading margins that drive our economic returns. And because of that, we're able to develop our resources more effectively, which is what drives our investment decision to grow our volumes and continue to build the company for long-term value creation."

Tug Hill Operating expects to spend about $300 million on capex on its drilling program this year and turn in line more than 40 well.

M & APPALACHIA

While the Permian Basin has seen the lion's share of M&A activity, including a $22 billion fourth quarter last year, consolidation has taken hold in the oil and gas industry.

The Appalachian Basin is a more mature basin with fewer producers, but that doesn't rule out deals.

In early May, EQT Corp. said it would adding a new operating position in Pennsylvania through an acquisition of Alta Resources LLC valued at about $2.9 billion in cash and stock. The Alta Resources deal will expand EQT's acreage position to more than 1.6 million acres with the addition of Alta Resources' roughly 300,000 acreage position in the Northeast of the Marcellus Shale.

"We do think there will be further consolidation," said Daniel Katzenberg, Antero Resources Corp.'s director of finance. "Ultimately, I think economies of scale will be good for the industry. He added that larger companies are more likely to focus on maintenance capex and return of capital to investors.

"We certainly would expect to see more M&A activity. There were a number of them that we saw in and outside of the basin and over the past 12 months," he said. However, Antero Resources doesn't necessarily feel pressured to make a deal.

The company estimates it has an inventory of more than 2,000 core drilling locations, giving it a long runway at its current development pace of just 65 per wells.

"We feel very comfortable with the assets that we have in place, but we have always been a company that closely monitors all options," he said. "We're always looking at our peers and just making sure that we have a complete understanding of their assets."

At Tug Hill Operating, COO Sean Willis said the overall strengthening of E&P industry during the past 12 months bodes well for M&A as companies evaluate the benefits of consolidation and operational synergies.

"I think that there are significant benefits of consolidation, and there are opportunities to participate in M&A," Willis said.

"Since our company's inception in 2015, most of our efforts have been focused on our organic growth and executing on our operational plans. While most of our leasehold has been built through organic grassroots leasing efforts, Tug Hill Operating has complemented these efforts through the acquisition of Gastar Exploration in 2016."

Facing page, service companies will eventually have to boost their margins, but with few new rigs expected in the Marcellus Shale, inflation still appears to be a longer-term concern.

"Relative to 2020, where we turned in line 30 wells for the year, in 2021 we're planning to bring on nearly 50% more wells and continue to grow volumes throughout the course of the year."

Like most operators in the Appalachia Basin, Willis sees the basin as superior to the Barnett or Haynesville shales. While West Virginia has many unique challenges for Tug Hill Operating, tapping into the Utica Shale was also a multi-year long process of refinement.

"We have unlocked a vast resource in the Utica," he said.

The ability to economically drill in the Utica Shale/Point Pleasant took time, skill and science.

"We've learned a ton about the Utica, the rock, the reservoir, and not only the resource in place and how to produce it, but how to drill there economically," he said. "We were very methodical, data-driven, and we have brought fit-for-purpose practices."

Early on the Utica Shale was considered a promising play with a lot of unknowns. While many company's early appraisal efforts of the Utica Shale/Point Pleasant across West Virginia and western Pennsylvania came at a very high price, with well costs frequently exceeding $30 million, the reservoir demonstrated strong production performance. In 2018, Tug Hill Operating's first Utica Shale/Point Pleasant well served as a platform to collect the necessary data that was required to provide the level of conviction necessary to move into full scale development. The company took a pressure core that allowed it to directly measure the rock properties and really understand how best to develop to reservoir.

"We have direct measurements of the gas in place, which tells us a lot of things that you can't get without years and years of production data from wells. It also gave us data on where we land our wells, why we frac them the way we do. It supplied us with a whole spectrum of data that has been a key factor in our ability to unlock the potential of this world-class resource."

Tug Hill Operating has now developed about 40 Utica wells and proven the prolific play underlying the Marcellus.

"It is a game changer for the asset and the acreage," he said.

The Utica Shale/Point Pleasant also affords Tug Hill Operating optionality between dry gas and liquids-rich development across the same asset footprint that allows the company to shift the development focus as commodity prices change.

"I know some of our peers talk about combo development, whereby developing adjacent units in a common reservoir in a systematic manner to gain development efficiencies and overall capital efficiencies," Willis said. "We do that too, but we also do it in three dimensions. We have a whole different reservoir down below that we're codeveloping from common pads."

Tug Hill Operating plans call for pads that can accommodate up to 30 wells. The company currently operates 20 well pads that have led to successful development and the efficient use of space that it has to work with, Willis said.

The company is set on making the right decisions for itself and the environment ensuring it's stewarding the capital of their investors in a responsible manner.

"I think that we have a responsibility, especially as it relates to some of the ESG, because the industry has a long way to go. But we want to be part of that journey and sharing lessons as well."

Marcellus marvel

The ongoing marvel of the Marcellus Shale is not so the abundance of gas but that there seems to be no stopping it.

But the economics of the Appalachian Basin require the strictest attention to every part of an operation. Everything from acquisition costs to artificial lift must be scrutinized to ensure success. What's clear to operators such as Northeast Natural Energy, which has been explored for more than 150 years, is no country for fantasists.

John, the company's CEO, said the talent and ingenuity of the people in the Marcellus Shale has led the way in lowering the costs associated with producing natural gas so that the company can continue to make a profit.

"There's no shortage of natural gas in our part of the country. Cost control is what we've focused on and will continue to focus on. I call it margin. We've got to keep our cost structure extremely low. We're drilling wells for $600 a foot, all in—drilled and completed. And, our lifting cost is less than a quarter."

"It was all about shale," John said, while reminiscing about the path that brought him to start Northeast Natural Energy. In 2009, coming off a stint as vice president for operations at Chesapeake Energy Corp., it was clear from his private equity connections that the time was right to create another private exploration company. He had a successful track record, as the company he helped form was purchased by Chesapeake Energy in 2005.

"In 2009, we put together Northeast Natural Energy with the clear vision that we would easily be able to turn and sell the company in three or four years," he said, adding in a deadpan voice, "So here we are in 2021 having not done that yet."

What Northeast Natural Energy did instead is build a focused area footprint that efficiently taps natural gas in the Marcellus Shale.

"One of the things I'm really fond of saying about the company and the work we do in northern West Virginia, is 'we're from here, and this is where we've always been.'"

Northeast Natural Energy's brand recognition is based on being a group of people who are successful doing what they love. "We're really lucky. We get to do what we want to do [and] where we want to do it," he said.

The company has continued to drill horizontal, dry gas Marcellus Shale wells, primarily in Monongalia County, W.Va. Northeast Natural Energy has 103 wells online, producing 400 million cubic feet per day (MMcf/d) of natural

Christopher Nielsen, Antero Resources Corp.'s director of sustainability, said IEA projections see gas demand stable through 2040 as coal and oil start to decline.

gas. The company has about 50 employees and a relatively compact acreage footprint.

Asked about the recent large mergers in the Permian Basin, John said scale is fine. But Northeast Natural Energy is more focused on its margins.

In particular, the company focuses on efficiently deploying capital and the timelines required to acquire land rights. Buttoning up large undeveloped land positions in large transactions has been impractical, John said. It's takes special focus and "mental understanding" that the tract sizes are small, the mineral interests are fragmented and the ownership records are complex.

"It takes a lot of time and research to put together the land that you need to develop long length laterals that are drilled today," he said. "We're comfortable drilling 15,000- to 18,000-foot laterals—five or six in each direction from a pad. So there's a lot of land that has to be accumulated."

But the Marcellus Shale geology has made longer-reach wells essential for operators to maximize profits. John described Northeast Natural Energy as a one-rig shop that will drill 20 to 25 wells a year—a drilling program not dramatically different than some other major operators in the Appalachian Basin.

"You can't drill 3,000-foot horizontal wells and expect to make money," John said. "You've got to drill longer wells, and you've got to be very efficient with your water. You've got to be efficient with your sand handling, all those things."

As for the future of the Marcellus Shale, John looks to the past. For the first 20 years of his career, the Appalachian Basin produced 15 Bcf/d or less. Today, even with COVID-19 and enhanced capital discipline, the basin is still churning out 32 Bcf/d.

With the underperformance in the sector during the past few years, there's been a noticeable slowdown in the deployment of capital toward D&C wells in the Northeast, he said.

"Over the course of my career, there has been a tremendous upheaval in the way natural gas pricing in Appalachia works," he said. "For many years, our gas sold for a 25 cent to 50 cent premium to Henry Hub. And now with the world class reserves in Appalachia we need to sell our gas at a 60 cents to 70 cents discount to Henry Hub—some months the discount is as much as a buck."

But capital discipline from large companies like EQT Corp., Cabot Oil & Gas Corp. and CNX Resources Corp. should make a difference in controlling the locational price differential, even as Northeast looks to grow.

"But Northeast Natural Energy is a small company. If our production grows from 400 million a day to 500 million a day, that should not move the needle regarding locational price differential," he said.

A lingering sustain

A significant advantage for Appalachian Basin operators has been their first-mover status as proponents of natural gas emissions protocols. Though not limited to one basin, such companies are already finding themselves graded above the curve compared to their oilier peers.

Operators in the Marcellus and Utica shales are increasingly proficient at drilling money-making wells and 15,000- to 18,000-foot laterals.

Christopher Nielsen, Antero Resources' director of sustainability, told *Oil and Gas Investor* he continues to see pressure on producers to reduce their methane and greenhouse gas (GHG) emissions.

"At the same time, many Northeast gas companies have been leading the way on reducing their emissions while establishing industry leading emissions performance," he said, adding that recent ESG scorecards by Credit Suisse and Wells Fargo have ranked Appalachian gas-weighted producers "much better on environmental metrics than their oily peers."

Antero Resources was an early member of One Future, a consortium of operators focused on science-based methods of reducing methane emissions to 1% or less of total natural gas production. Tug Hill Operating and Northeast Natural Energy are also members.

"We're a couple years into our sustainability journey and are well-positioned to take the next step," Nielsen said. "We feel that we have a great ESG story to tell and the leadership and proven performance to back it up."

Antero Resources has taken the initiative to develop 2025 goals that further reduce their already low GHG intensity by 10%, lowers its methane leak loss rate by 50% to under 0.025% and to achieve net zero Scope 1 carbon emissions through the implementation of operational improvements, technologies and the purchase of carbon offsets.

"Our position in low CO_2 intensity basins, combined with our commitment to achieve industry leading environmental performance, will allow Antero to continue providing low-cost, low-emitting energy to our customers in both domestic and international markets," Katzenberg said.

Natural gas companies have had a tough slog the past several years as prices have remained stagnant, but Antero Resources is confident in the demand picture it sees in the next two decades.

"If you look at IEA estimates and other third-party projections, you see that natural gas demand is expected to be stable under the base case through 2040 or increasing slightly as it takes market share through 2040," Katzenberg said. "You have coal and oil starting to see some decline in demand. But natural gas is expected to remain consistent."

Willis said the push toward a lower carbon future—including increased regulation and the perception of fossil fuels by a large cross section of society—will lead to more carbon-intense forms of energy being phased out. Any company that does not continuously adapt to ESG issues and demonstrate through performance, their commitment to methane emissions reduction will not have access to capital and it will compromise their license to operate.

"Our view is that natural gas will continue to play a significant role to a lower carbon future and that natural gas should be the fuel of choice given its abundant supply, reliability, affordability and emissions profile of it relative to other sources," he said.

With spending at maintenance levels for some E&Ps, operators will bank on repeatability, rather than more rigs, for cash flow.

"When you look at natural as demand, LNG is something that everyone continues to watch, and it is something that I feel we will be a key driver for the continued demand growth for our products we produce. That's what you see with the LNG demand, that there is a need for it. And I think we'll continue to see that as a growing global demand [source]," he said.

As an industry, we have an obligation to do a better job of explaining natural gas' role in the energy transition to a lower carbon future. "My view is that we have to build companies for the long term that work to ensure a responsible transition to net-zero emissions." he said.

In first-quarter 2021, Tug Hill Operating initiated a pilot project with Project Canary to bring transparency and verifiable date to complement their ongoing methane mitigation efforts. The company said it wants to lead by example in its environmental stewardship efforts. That includes taking part in a pilot project on four pads for Project Canary's TrustWell, which will give the company a responsibly sourced gas (RSG) certification.

Too many people, he said, tie environmental excellence to increased costs.

"From [Tug Hill Operating's] inception, we were focused on building the infrastructure to facilitate 100% water recycling and to facilitate our ability to utilize dual fuel … in our drilling and stimulation operations." The company has displaced diesel with natural gas as the primary fuel source.

"There is a cost if you get behind and you're playing catch up and if you haven't done things right." □

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Oil and Gas Investor

WASHINGTON WATCHER

Merely months into the Biden administration, energy policy is front and center with oil and gas on the defense. American Exploration & Production Council CEO Anne Bradbury is engaged with the policymakers rewriting the energy script and offers this primer of what's ahead for the rest of 2021.

INTERVIEW BY JACK BELCHER, CORNERSTONE GOVERNMENT AFFAIRS

Anne Bradbury, CEO of the American Exploration & Production Council, sees a divided Congress as a blessing in disguise. "I predict it's going to be a lot harder to continue moving big legislative packages through the Congress because of the small margins that exist."

Will the U.S. be able to lead the world in oil and gas production and emissions reduction? That quest is being put to the test as the Biden administration pushes to prioritize climate change in its energy policy.

Anne Bradbury, CEO of the American Exploration & Production Council (AXPC), whose membership is composed of 25 of America's independent E&P companies, joined Cornerstone's Jack Belcher for a segment of HartEnergy.com's Energy Policy Watch video series to discuss the already busy energy policy landscape merely months into the Biden administration.

Bradbury has served as a top leadership aide for over a decade for some of the most important leaders in Congress. As floor director, she guided the House majority's floor operations and advised the entire Republican leadership team on legislative strategy and policy development. She joined AXPC in 2019.

Belcher is a principal with Cornerstone Government Affairs Inc., a bipartisan public affairs and advisory firm.

Belcher We all know that there's a lot going on in Washington right now. We have a new Congress, a new administration, big policy changes and they all impact the oil and gas industry. Can you tell us a little bit about the specific policies that you're watching right now?

Bradbury We're about three months into this administration and this new Congress and there's been a lot that has been popping that affects the industry. Right off the bat we saw a very significant decision with regard to the Keystone Pipeline.

There were two sweeping executive orders out of the White House that contained a lot of provisions that affected the oil and gas industry. A lot of those policies were essentially directives to the agencies. And so right now we're in the process of engaging with the agencies as they develop what those policies are going to look like. So there's been a lot of talk about what the administration is doing, but it's important to remember a lot of this is very much a work in progress.

So the details remain to be seen what the Department of Interior is doing with their federal lands review, the EPA is developing regulations around methane, the Hill is looking at moving the climate and infrastructure packages. These are all issues that we're engaged with that we're really concerned about.

What we're trying to do is find areas where there is commonality. We want the U.S. to continue to lead the world in emissions reductions and to produce oil and gas at the highest environmental standards, but at the same time we want to make sure that policies ensure that we can continue to produce oil and gas here in America, and that we're supporting good paying American jobs.

Belcher You're the former floor director for two speakers of the House of Representatives so you have a lot of inside knowledge of how the system works. Can you give us some insight from your experience as to what you think are going to be the pieces of legislation that move? What can we expect?

Bradbury First of all, note the difference between where we are now and where we have been historically when you've had a president coming into office. The margins in the House and the Senate are effectively tied. The Senate

"There's been a lot of talk about what the administration is doing, but it's important to remember a lot of this is very much a work in progress. The details remain to be seen."

is completely tied with Vice President Harris being the tie breaker, and the House has just the smallest of margins it has seen in decades and is essentially tied.

While this Congress and administration saw great success in moving the first COVID-relief package through reconciliation, I predict it's going to be a lot harder to continue moving big legislative packages through the Congress because of the small margins that exist.

Policies that can move through reconciliation are going to need the support of everyone from Sen. [Bernie] Sanders to Sen. [Joe] Manchin in the Senate, and Rep. Lizzie Fletcher to Rep. [Alexandria] Ocasio-Cortez in the House. And that's a really challenging undertaking. I think they're going to do what they can to move forward the infrastructure package and the Biden agenda, but I personally think that there are going to be significant limitations on what they're able to accomplish. And at some point they're going to have to pivot to looking at what can be done on a bipartisan basis.

Belcher So what does that mean for specific pieces of legislation, for instance, the CLEAN [Climate Leadership and Environmental Action for our Nation's] Future Act that we just saw come out, and this infrastructure plan? What do those margins mean in terms of the legislative process?

Bradbury The infrastructure package unveiled by Biden, there are areas where I think you can find some bipartisan areas of support, particularly around the traditional definitions of infrastructure on roads and bridges, maybe even rural broadband. I think you're going to have a lot more trouble finding bipartisan agreement on some of the more expansive definitions of infrastructure. Some of those provisions may be able to move separately, but I don't know that they would be able to move under the rubric of an infrastructure package.

The CLEAN Future Act is one of the bills that I don't think Republicans view as infrastructure, and I do think Democrats view it as infrastructure.

But if you break that down, there are potentially some areas of agreement under the CLEAN Future Act, particularly provisions that support carbon capture research funding for innovation and new technologies. I think you see a lot of bipartisan support for that.

Then you also have the larger question of how are you going to pay for these things. The Biden administration has also put forward a plan on how to pay for it that included raising the corporate rate, getting rid of so-called subsidies for oil and gas as well as some other tax changes. We've even seen Democrats come out pretty early and criticize some provisions of that. So I think the question of how much of it is paid for and how it is paid for is, again, very much an open question that is going to take a lot of work to find consensus on, even if it moves on a partisan basis.

Belcher We've had the executive orders that direct agencies to look at their actions through a climate lens and a lot of talk about how it impacts the oil and gas industry. Can you tell us a little bit about what those impacts are and what AXPC is doing to try to avoid some of the negative impacts?

Bradbury One of the things that we saw from day one is this administration is very much taking a whole government approach to climate change. Because of that, we're seeing regulations that affect the oil and gas industry in places that traditionally we haven't seen. We would be very concerned with any policy that unfairly penalizes the domestic oil and gas industry and serves to essentially outsource production and outsource emissions, because emissions are a global issue.

By simply penalizing the domestic oil and gas industry, not only are you hurting jobs and families, but you're potentially actually increasing emissions because you're outsourcing it to places with higher, less stringent regulations. So we're looking at a number of agencies, certainly EPA and DOI, the more traditional regulators of oil and gas, but also Treasury, the SEC, FERC and DOT. All of these agencies are now really engaged in climate policy in ways that directly affect our companies and ability to operate. So we are going to continue to engage and advocate for policies that ensure that we can continue producing, and we continue to have access to capital.

Belcher Tell us about the importance of jobs in this debate, especially when you look at the razor thin margins.

Bradbury So much of this comes down to how this is impacting American workers. This is something that both parties care about a lot. President Biden is very close to a lot of the unions. We know that this is an issue that Republicans are talking about as well.

The administration's decision with Keystone [Pipeline] caused the immediate loss of jobs, unfortunately. It was an unfortunate outcome. A lot of the other policies that the administration is putting forward also potentially has that effect. It might take a little longer to be immediately obvious, but it certainly risks that particularly in areas like New Mexico, Texas, Colorado and across Appalachia where you have a lot of oil and gas operations.

It's also important to remember that it's not just areas where we employ oil and gas workers, but that domestic production supports jobs across the country both indirectly by (other job sectors) supporting our industry, but also simply through keeping energy prices low, energy supply stable, that's critical to a strong manufacturing base. Raising costs on American families as we're recovering from this pandemic is very concerning.

The worker angle is something that you're going to continue to see both parties talk about because it is a top-of-mind concern. [Former Obama Secretary Of Energy Ernest Moniz] recently put out a study that shows very clearly that oil and gas jobs pay more, have better benefits, are longer term and have better opportunities for advancement than opportunities in the renewable sector. We don't support picking and choosing. We're very supportive of an all-of-the-above energy strategy.

But it is just not credible to say that there's a one-for-one change that can be made for an oil and gas worker that may lose their job, that they can simply start manufacturing solar panels. It's not realistic. It's not credible. Oil and gas workers are proud of what they do, and they want to continue doing what they do. And the fact is they can as we support the economy. We believe that these jobs and environmental progress are not mutually exclusive; you can have both.

Belcher There are some financial regulations moving right now at SEC. Can you talk about those regulations and what their impacts are to the oil and gas industry?

Bradbury This is sort of a newer area of regulation that is going to affect all public companies, certainly the oil and gas industry, but really any public company. The SEC has put out a notice for public comment—not an official rulemaking; we think it's probably a precursor to that—that is seeking public input on a number of questions related to climate disclosure. That can give us a sense of what they're thinking about and where they're going.

So at a minimum, most people expect increased requirements around climate disclosure. But how far they intend to take this, I think, is an open question.

Are they going to try to force some sort of disclosure framework on industries? Will it be one size fits all or will it be unique to different industries? It's important to remember that the SEC is not an energy or climate policy expert. They're financial regulators, so it's a new area that they're exploring and one that I think a lot of folks do have some concerns about.

Our industry is really leading the way in terms of public disclosures around their ESG frameworks and metrics. One thing that we've been working on last year is developing a new framework for the upstream oil and gas industry to utilize when doing their reporting. It's now publicly available on our website. And so a lot of our companies will be utilizing this new, consistent, transparent framework for some of the key ESG metrics that our stakeholders care about. Industry is really leading the way here, and hopefully the regulators have a lot to learn on what industry is already doing here.

Belcher ESG is something that a couple of years ago a lot of oil and gas producers wouldn't know about, but now everybody's talking about ESG. Are your members moving quickly more in terms of disclosures?

Bradbury Our members are moving very quickly in the areas of disclosure. And you're exactly right that this area has evolved really rapidly over the past couple of years. And whether it's through the AXPC framework in addition to their sustainability reports they already do, our companies are responding to their stakeholders and their investors that want this transparent and consistent disclosure of information around ESG metrics. Some companies are ahead of others, but the entire industry is moving rapidly in that direction.

Belcher Looking at a lot of the regulatory actions that have taken place over the past few years—the methane rule, for instance, which has gone back and forth—ultimately these things end up in the courts. Can you tell us about the courts and how they're playing into some of the policies we're discussing today?

Bradbury There's just been so much regulatory back and forth of the pendulum, from the change of administrations, but also from what we have seen in the courts. And what we understand is that this administration is looking to push, they're exploring, what their legal authority is in a way that I think maybe goes beyond what some previous administrations have done. I do think this administration is going to play with the edges of what is legally justifiable. And if that is the course that they take, you're going to see this play out in the courts for potentially years to come.

Alternatively, perhaps taking a more collaborative approach and seeking more durable regulation that maybe isn't so questionable and stands on solid legal ground is another potential approach, because I know this administration also doesn't want to see its policies be unwound. We know that Sen. [Mitch] McConnell has made the appointment of Republican judges one of his big priorities over the past four years, and the Supreme Court has some new judges and is more conservative than it has been in the past.

A lot of these policies, if they are pushing the limits of what might be legally defensible, are going to end up before the Supreme Court, which might have a different view of how expansive their authority is under the law. That's something to think about, and to keep in mind that this administration is not necessarily the last word on regulatory policy.

Belcher How do you think some of these things are going to play out?

Bradbury For one, we know that [in] this administration there's a lot of cooks in the climate kitchen. Right off the bat, it seems like the center of gravity has been around the White House officials, particularly [U.S. Special Presidential Envoy for Climate John] Kerry, [National Climate Advisor] Gina McCarthy, because they didn't have to go through a Senate confirmation process. So they've been running the show for the most part in terms of climate and energy policy to date.

But now that [Interior Secretary Deb] Haaland and [Environmental Protection Agency administrator Michael] Regan are in place, it's going to be interesting to see if that center of gravity in decision-making shifts back to the agencies where it traditionally has existed, or whether or not the White House continues to try to drive all climate policy.

And then there are a lot of interesting members of Congress to keep an eye on, some young, fresh voices both on the Republican side and on the Democrat side. We all know Joe Manchin is somebody to keep an eye on, for sure, but some of your Texas colleagues, from Rep. Lizzie Fletcher and Dan Crenshaw, are interesting, new, younger voices that have a lot to say here and are up and comers in their party.

There's a lot to watch play out over the next six months, both on the congressional side and on the agency side. □

"Most people expect increased requirements around climate disclosure. But how far they intend to take this, I think, is an open question."

SHOW ME THE DIVIDEND

What is the preferred way to reward investors after achieving free cash flow? Dividends are becoming all the rage.

ARTICLE BY
LESLIE HAINES

To dividend or not to dividend? That is the question.

It's all about the investor: Put some money into his or her pocket.

Stock appreciation comes first. Since last fall, investors should be pleased: Most E&P equities have soared. Some have more than doubled or tripled, albeit rebounding from woeful lows. Stock buybacks also are a popular way to add value as investors now demand—and expect— returns from an energy industry that historically has performed badly on that score.

But paying a dividend is gathering a lot of traction. As free cash flow (FCF) is reached, more E&P companies can consider it. This makes sense because paying one is a key trait of mature companies in mature industries, which the shale world is becoming.

That's been true for the majors for decades. Some 65 companies make the S&P Dividend Aristocrats list, first published in 1989. This is a group that has raised their dividend for at least 25 consecutive years. Only two oil companies are on the list: Exxon Mobil Corp. and Chevron Corp. But even the mighty Exxon Mobil's cash flow last year only covered 70% of capex, and none of the dividend.

By one count, in fourth-quarter 2020 some 30 E&Ps paid a dividend, many because they had cut spending so much that they had the cash on hand. Companies that reduced or eliminated their dividend last year during the downturn are bringing them back now that the oil price is rising. Several other E&Ps are pledging to pay one soon.

"For a return of capital, I'd rather have a dollar in my pocket from a dividend than have a dollar to buy back stock," said Subash Chandra, analyst, Northland Capital Markets.

"The industry's coming around to the notion that growth scares the market, and investors prefer a dollar in their own pocket, not sitting in the company's pocket," said Subash Chandra, an analyst with Northland Capital Markets.

Morgan Stanley analyst Devin McDermott wrote that his E&P coverage group "has broadly embraced capital allocation frameworks, limiting growth while transitioning toward a model of sustainable FCF generation and shareholder return.

"Now, with these strategies in place and FCF set to inflect, we expect investor focus will shift toward initial uses of FCF. Leverage reductions will likely remain the priority for most … however, we could see incremental capital return announcements from others, including special dividends … and buyback optionality."

Many are setting the bar high by declaring a certain percentage of their FCF will be returned to shareholders. Exhibit A: On Pioneer Natural Resources Co. McDermott explained, "PXD proposes to reinvest 70% to 80% of cash flow (versus an average of 122% over the past five years) and target at least 10% total annual return to shareholders, which will include a new variable dividend (to be adopted in 2021) on top of growing the base dividend, while increasing oil production at least 5% annually (prior target of mid-teens). The company continues to maintain its commitment to a low leverage profile."

In March, ConocoPhillips Co. resumed its $1.5 billion share repurchase plan, and CEO Ryan Lance reaffirmed the priority is to return greater than 30% of cash from operations to shareholders annually—by its dividend and the repurchase plan.

In February, Cabot Oil & Gas Corp. announced a variable dividend and its intent to return 50% of all FCF to shareholders, adding to its current quarterly dividend. The variable plus the base will add up to 50% of FCF. The variable dividend will be paid annually starting in fourth-quarter 2021.

PDC Energy Inc. has said it will first pay down more debt and continue stock buybacks, but it may initiate a dividend by midyear. Executives at Cimarex Energy Corp. and Cabot Oil & Gas have told investors they are considering more payouts. Cimarex may institute a variable dividend, and Cabot may pay a base-plus supplemental payout to up its strategy for returning capital to shareholders.

Gabe Daoud Jr. of Cowen & Co. listed Cimarex as a top stock pick for 2021, citing the dividend as one of the reasons. "Overall, our model suggests XEC [Cimarex Energy] can deliver best-in-class FCF yield (about 12%) that supports a growing base dividend (about 3%), alongside retirement of the '24 notes ($750 million)."

Truist analyst Neal Dingmann expects that this trend will continue. "I view a variable dividend as a better alternative to common share repurchases seen in prior years," he wrote in an email to Barron's.

Hess Corp. and Murphy Oil Corp. said they plan to focus on maintaining free cash flow and paying down debt over production growth, to be followed later by dividend increases or share buybacks. Hiking capex with new-found cash flow is on the back burner now that investors do not want to see much growth.

Marathon Oil Corp.'s top priority of free cash flow is to continue to pay the base dividend and improve the balance sheet to its 1.0x to 1.5x leverage target, said analyst Gabriele Sorbara of Siebert Williams in a report. "Once these goals are achieved, we expect MRO to increase the base dividend or establish a variable dividend and consider buybacks."

"What is emphatically not a good idea is when companies borrow to pay the dividend on a sustained basis," said Pavel Molchanov, analyst, Raymond James.

Just before first-quarter conference calls began in April and May, KeyBanc analyst Leo Mariani said he anticipates more dividends to come. "Looking ahead to 2H21, we think COP could raise its dividend this fall, and we expect BRY [Berry Petroleum Corp.] to raise its dividend in 2H21 as well. Additionally,

Oil & Gas Companies That Pay A Dividend

Company	Ticker	Annual Dividend ($)	Share Price ($) (3/24/2021)	Yield
BP Plc	BP	1.26	24.75	5.1%
Chevron Corp.	CVX	5.16	104.7	4.9%
Exxon Mobil Corp.	XOM	3.48	56.34	6.2%
Royal Dutch Shell Plc	RDS	1.33	40.35	3.3%
Total SA	TOT	3.14	46.59	6.7%
ConocoPhillips Co.	COP	1.72	53.21	3.2%
EOG Resources Inc.	EOG	1.65	72.54	2.3%
Occidental Petroleum Corp.	OXY	0.04	27.06	0.1%
Pioneer Natural Resources Co.	PXD	2.24	161.3	1.4%
Hess Corp.	HES	1	69.08	1.4%
Cabot Oil & Gas	COG	0.4	18.23	2.2%
Devon Energy Corp.	DVN	0.63	22.34	2.8%
Diamondback Energy Inc.	FANG	1.6	74.39	2.2%
Ovintiv Inc.	OVV	0.38	23.81	1.6%
Marathon Oil Corp.	MRO	0.12	10.44	1.1%
Cimarex Energy	XEC	1.08	57.93	1.9%
Murphy Oil Corp.	MUR	0.5	16.75	3.0%
APA Corp.	APA	0.1	18.17	0.6%
SM Energy Co.	SM	0.02	16.37	0.1%
Matador Resources Co.	MTDR	0.1	23.3	0.4%
Whitecap Resources Inc.	WCP.TO	0.18	5.31	3.4%
ARC Resources	ARX.TO	0.24	7.44	3.2%
Tourmaline Oil	TOU.TO	0.64	23.18	2.8%
Blackstone Minerals LP	BSM	0.7	8.77	8.0%
Viper Energy Partners	VNOM	0.56	15.53	3.6%

Source: Yahoo Finance

Nothing is certain but if a company consistently raised its dividend over time, and hasn't disappointed, then that is more attractive than what the yield is," said Trey Cowan, oil and gas analyst, Institute for Energy Economics and Financial Analysis.

we think MGY [Magnolia Oil & Gas Corp.] may give numbers around its dividend by 3Q21, and we think CLR [Continental Resources Inc.] may reinstate its dividend in 2H21.

"Lastly, we think DEN [Denbury Inc.], WLL [Whiting Petroleum Corp.] and XOG [Extraction Oil & Gas Inc.] could initiate dividends in late 2021/early 2022 as return of capital restrictions roll off of their credit facilities post-bankruptcy."

How much do dividends matter?

People like dividends, but some investors and analysts continue to be a bit skeptical as well, given the boom-bust nature of the business.

"It's very important for signaling to the market that they are disciplined, but some of these companies are still not out of the woods," said Mark Lear, a Simmons Energy analyst who covers the large caps.

"It's a step in the right direction. But I've been a bit underwhelmed by those companies who introduce, increase or have a variable dividend. It's a bit of a 'show me' thing and then investors will begin to sniff around again. I think it's still early."

There is some question, too, of whether paying a dividend matters to a company's stock performance. "There is not a great correlation yet between paying a dividend and your stock price. I don't think the market knows what it wants yet," said Chandra.

"The stock performance has less to do with return of capital and more to do with NAV [net asset value] true-up. Antero Resources Corp. was probably one of the top stock performers last year, and they don't pay a dividend and aren't even close to paying one. The stock is up because of what it's actually worth [NAV]." Antero has said it will not pay a dividend, but rather, will plow cash flow back into the business.

First things first

In some ways paying a dividend is a luxury E&Ps cannot afford, although investors may think it's a necessity. In Chandra's mind, it is more important to use free cash flow to eliminate bank debt and fixed obligations. "Once you are at your debt target then you can think about how to pay out your return on capital."

Lear echoed that, saying, "First and foremost, companies should focus on their balance sheets and debt maturities. Cash burns a hole in a company's pocket, but it's not necessarily bad to have it on the balance sheet," he told *Oil and Gas Investor*.

He said stock buybacks can be very valuable as well, but some companies don't have a good track record on that score. If commodity prices rise and cash flow does too, deploying it to buy back stock occurs at a time when the stock is expensive. Buybacks are often ill-timed, he said.

Setting realistic expectations in an uncertain commodity environment plays a role. It's important to consider the overall health of a company and the direction it is going, said Trey Cowan, CFA, and oil and gas analyst for the

STEVE TOON

Pioneer Natural Resources Co. plans to increase its dividend by limiting reinvestment to 70% to 80% of its cash flow and targeting at least 10% total return to shareholders.

Institute for Energy Economics and Financial Analysis (IEEFA), which has reported on total shareholder return trends.

"Yield might be important and a nice bump, but there's more to it than that," he said.

Dividend yield is a function of the annual dividend paid, divided by the current stock price, which can vary wildly due to any number of factors that a company cannot control.

"What tends to happen is that investors don't look at a dividend yield. They instead ask the questions, 'Has the dividend grown over time and will it continue to grow? Are they confident that the company will continue to return a portion of its capital to investors?' Nothing is certain but if a company consistently raised its dividend over time, and hasn't disappointed, then that is more attractive than what the yield is," Cowan said.

A high dividend yield of 10%, 15% or more probably indicates that the stock has been beaten down and investors have lost confidence (or, that the company has not adjusted its dividend in response to tough times). A typical retail investor looks for a yield that is above the 10-year Treasury, which is currently less than 2%. Institutions are managing their portfolio to see what gives them a high enough return to meet their investing criteria, which is a stock appreciation game plus the dividend.

Devon Energy Corp. pays 19 cents per share on top of the base of 11 cents. On an annualized basis that translates to a yield of 5%, versus the 2% yield it had before.

"There is a subset of investment funds which only hold stocks that pay a dividend, even if it is essentially symbolic, such as one penny. I'm not aware of any data on how large these funds are, but they exist. So, all else being equal, it is better to pay one penny than nothing at all," Pavel Molchanov, a Raymond James analyst, told *Oil and Gas Investor*.

"That being said, investors that are truly focused on income typically prefer stocks with yields at least at the level of the S&P 500, which is currently 1.3%.

"What is emphatically not a good idea is when companies borrow to pay the dividend on a sustained basis. Of course, there can be temporary circumstances—perhaps one or two difficult quarters—when that is appropriate. But generally speaking, dividends should be funded from operating cash flow," he said.

Other benchmarks

How do payouts (dividends and buybacks) by oil and gas firms compare to the rest of the companies in the broad S&P 1500? In February, CFO magazine cited findings by Analysis Group, which looked at payout trends in the S&P 1500 from 1999 to 2019 (before the pandemic disrupted all financial metrics). Payouts have been increasing over the 20-year period.

"In 1999, for HPOCs (high payout companies in the S&P 1500), the median value for the ratio of payouts to operating income was 47%; in 2019, the median shot up to 69%. In other words, the typical HPOC in 1999 paid out a little less than 50 cents of every dollar of operating income. Twenty years later, the typical HPOC paid shareholders 69 cents of every dollar of operating income.

"For both HPOCs and non-HPOCs, the buyback portion of distributions increased much more dramatically than the dividend portion," the report found.

"Overall, the median shareholder payout ratio for non-HPOCs has been slowly converging toward the reinvestment ratio. That suggests that shareholder distributions are becoming a more important element of capital allocation strategies, even for businesses taking a more conservative financial path," the magazine said.

Simmons Energy compiled data that show that the average dividend yield varies by size of E&P companies. For the mega-caps on its list (BP Plc, Chevron, Conoco, Exxon Mobil and Occidental Petroleum Corp.), it is 3.6%. For the large-cap independents it studied (Apache Corp., Devon Energy, Pioneer, Murphy Oil, Cimarex Energy) it is about half that or 1.5%.

The oil-levered small and midcap group (SMIDs) included Centennial Resource Development Inc., Magnolia, Laredo Petroleum Inc. and Whiting Petroleum. Their average yield was zero. Gas-levered SMID companies fared little better, averaging 0.4%. This group included Cabot Oil & Gas, CNX Resources Corp. and EQT Corp.

Dividend, buyback or debt?

As CFOs contemplate how best to share cash flow with their investors, several choices are available. "Our view is that E&Ps have to find a way to return value (ultimately cash) to their investors, which they can do in one of three ways: stock appreciation, cash sale of the company or dividends," said Josh Sherman, partner in charge of the complex financial reporting group at Opportune LLP.

"Whether a company chooses to use available cash on development, paying-down debt, acquisitions or dividends says a lot about the current state and perspective of the company, industry and management team," he told *Oil and Gas Investor*.

"For a return of capital, I'd rather have a dollar in my pocket from a dividend than have a dollar to buy back stock," said Chandra.

Opportune looked at publicly traded E&P companies on U.S. exchanges (plus Shell and

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—Josh Sherman, Opportune LLP

Imperial Oil) with a market cap over $1 billion to analyze how their dividend policies affected their stock/total returns versus changes in commodity prices.

"Overall, it's not surprising that overall stock returns appeared mostly affected by commodity prices; however, we did note that companies that increased dividends fared slightly better in the 2020 downturn," Sherman said. Out of the 34 companies reviewed, 16 decreased dividends; 15 increased dividends; and three held dividends constant.

"The most surprising analysis was that the three companies that paid zero dividends in 2020 (EQT and Range Resources Corp. reduced their dividend to $0; CNX remained at $0) were the only companies that had a positive stock return in 2020," Sherman said.

"While dividends paid by other companies lessened the blow, the stock returns of these three companies are likely a market mandate for well-run companies focused on natural gas/ESG (versus oil)," the Opportune report said.

The decision to pay a dividend should be based on which choice will optimize a company's financial position and what is most cost-effective. There are mathematical formulas to help figure this out, Cowan said. Chandra said the market is looking for who can maintain production and throw off free cash flow, so companies must decide what the most robust approach is that enables them to do this, and at the same time, help them to survive any subsequent downturns.

IEEFA study

The IEEFA found that 30 shale producers generated $1.8 billion in free cash flows last year—after slashing capital spending by $20 billion from the previous year.

"During 2020, four of the world's five largest private sector oil and gas companies failed to generate enough cash from their primary business—selling oil, gas, refined products and petrochemicals—to cover their cash payments to shareholders," said the IEEFA report.

"Exxon Mobil paid $17.8 billion more to shareholders during the year than it generated from its core business operations; Chevron paid $9.5 billion more; BP paid $7.3 billion more; and Total SA rewarded its shareholders with $2.9 billion more than it generated. Only Shell broke from its peers, generating an $8 billion cash surplus. To do so, however, the company reduced dividends by two-thirds (the firm's first per-share dividend cut since 1945), while suspending share buybacks and slashing capital expenditures by 28% year-over-year."

Investor responses

"Energy investors like to see dividends—provided, of course, that they are adequately covered with cash flow—as a tangible manifestation of management's commitment to capital discipline. The days of growth for the sake of growth are long gone," said Molchanov.

"Return of capital—dividends and/or share buybacks—are much more highly prized. The difference between the two is that a share buyback can easily be flexed up or down from quarter to quarter, depending on (among other things) commodity prices, whereas a dividend is regarded as something that is more 'set in stone.'"

Lear told us it's difficult to decipher what the market thinks about the dividend versus the oil price leverage, and he noted some M&A activity has come into the picture too. "But it's very important for signaling to the market they are disciplined. Companies are still a bit concerned that they are not out of the woods yet, but a dividend is a step in the right direction," Lear said.

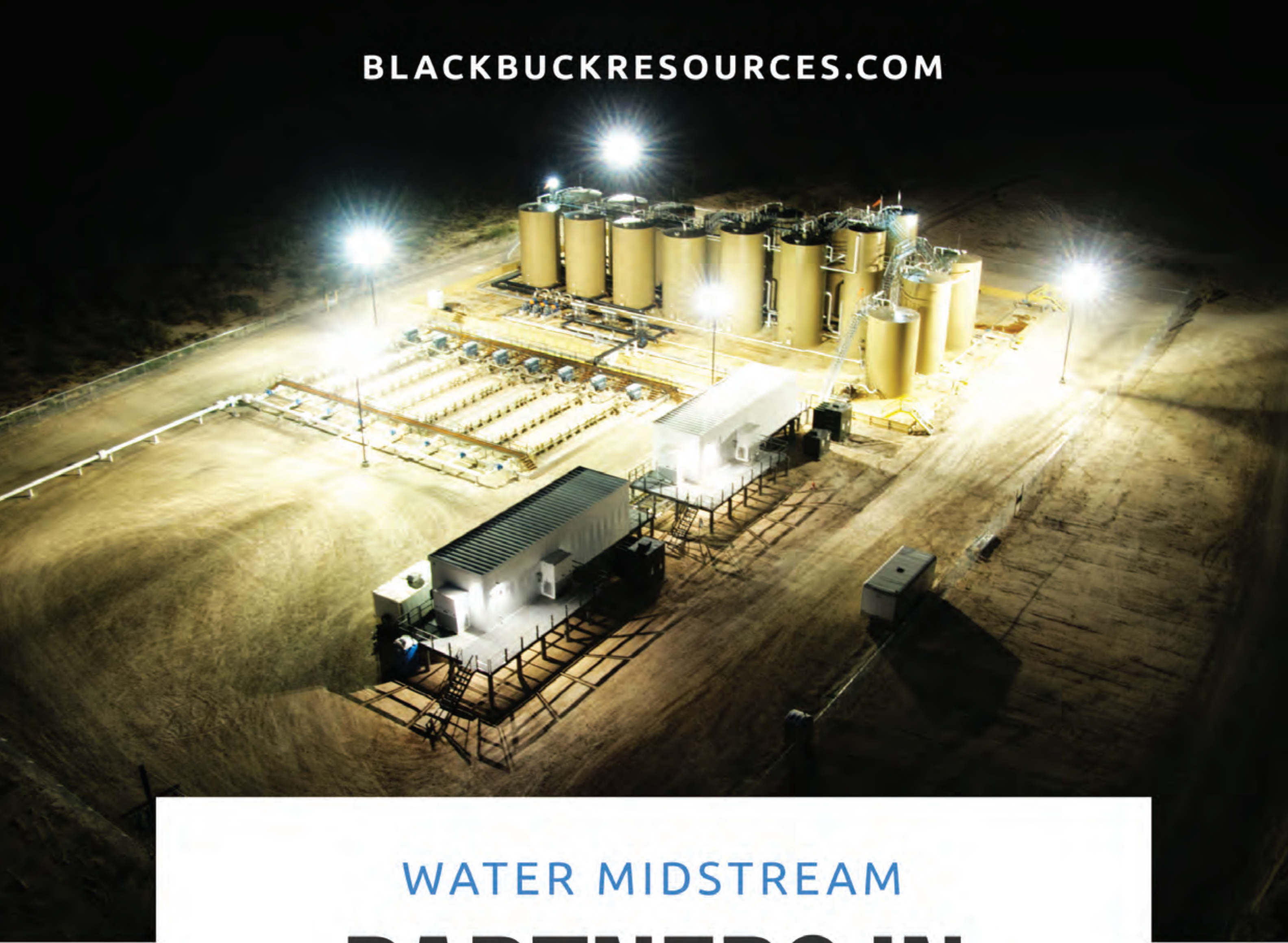
"We think the move toward a capital disciplined reinvestment approach and shareholder return model has been positively received by investors. The group has had a strong rebound starting in fourth-quarter 2020, but it's difficult to say how much is attributed to the anticipated economic recovery and the strategic shift to limit reinvestment and return capital," he told *Oil and Gas Investor*.

"We think the latter, paired with capped growth, has the potential to prolong the cycle for E&P. In terms of equity performance, we have seen higher leveraged names that provide oil beta outperform, and those that have the ability to deliver increased shareholder return rather utilize FCF for balance sheet repair have performed well, but they have lagged to some degree. We think over the longer term, a company's ability to deliver increasing shareholder return will drive outperformance."

The oil industry can be both a blessing and a curse to dividend investors, according to a comment on The Motley Fool website. "During rough patches such as those in recent years, it can be a challenging place for income-seekers, since weaker companies need to reduce or eliminate their dividends to make it through a downturn."

Paying a dividend may, in the end, be one way to mitigate the volatility inherent in a risky industry. "Companies can debate how to think about their future but there are some things you can't do. That's pretty clear," Northland's Chandra said. "This has always been a boom-bust industry but we're trying to take the bust away. It's too hard for investors to ride the boom-bust. So one way to do that is to pay down debt.

"Return of capital is important, whether it's a buyback, paying a variable dividend or a fixed one. I don't know what the mix is, but if you don't have free cash flow, it's a problem." □



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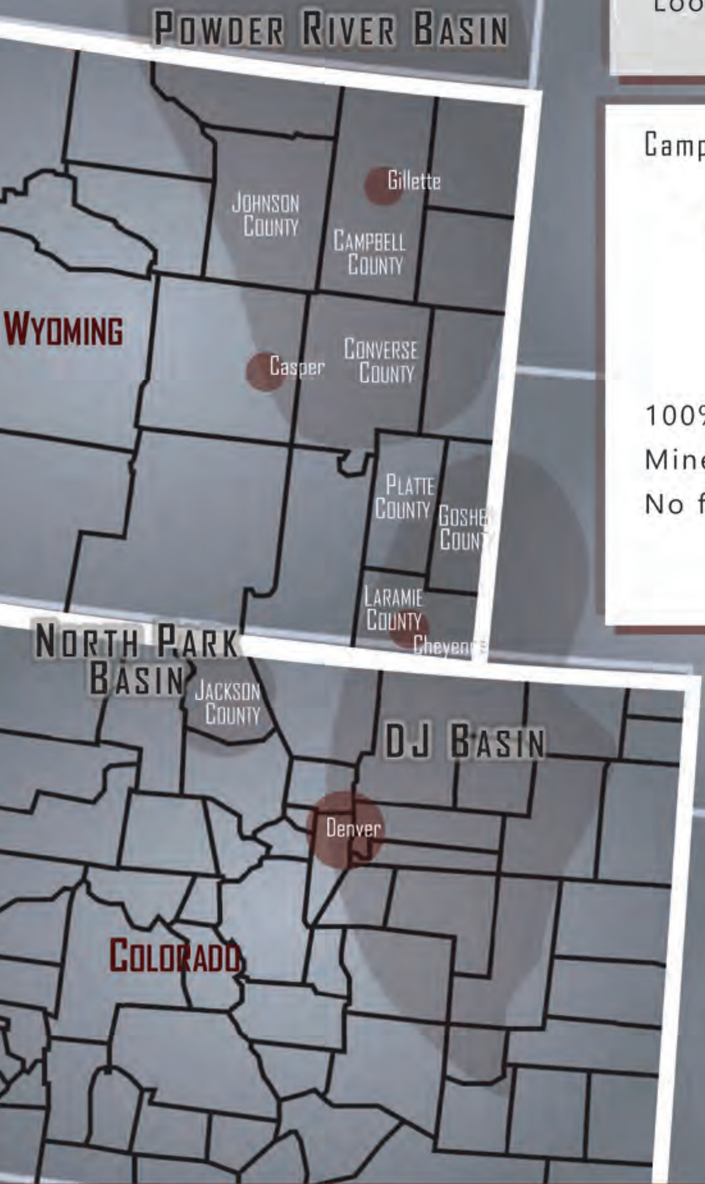

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POWDER RIVER BASIN PROMISE

The stacked pay basin has tantalized producers as technical advances started to tame high variability, costs and frustrations.

BY GREGORY DL MORRIS

Pat Bent, senior vice president of operations, Continental Resources Inc., said the company will be running two rigs through 2021. "We are expecting around 15 to 17 spuds and about 10 wells online for testing by the end of the year.

Major independents and many small private operators are close to solving the Powder River Basin in Wyoming. Historically a reservoir play, the stacked pay in deeper source rock has been known as much for its potential as notorious for its variability, thus complexity and cost. The players who have stuck with the basin, as well as those able to bring in their skills from other unconventional plays, are at last gaining traction, bringing costs down and consistency up.

Early this year Continental Resources Inc. achieved what Harold Hamm called a "homecoming," picking up Samson Resources II's position in the Powder River Basin. The move was widely seen as validation that the basin is finally ready for prime time.

"We completed the Samson acquisition in early March," said Pat Bent, senior vice president of operations at Continental Resources, told *Oil and Gas Investor*. "We have been diligently working to prepare for a two-rig drilling program for this year. We acquired 130,000 net acres that contain three of the top five wells in the play, two of which are operated. There is stacked pay with several horizons to target, including the Shannon, Frontier, Niobrara and Mowry [formations]."

Continental Resources' first rig was scheduled to be active in May, with the second online in June. "We will be running both rigs through 2021," said Bent. "We are expecting around 15 to 17 spuds and about 10 wells online for testing by the end of the year. That may sound like an ambitious schedule, but we've been developing a clear understanding of this basin for quite some time and have an excellent technical team."

Jack Stark, president and COO of Continental Resources, told *Oil and Gas Investor*, "As we studied this play, there are three things in particular that we liked: the stacked pays that produce 70% to 80% oil; the basin is in the early stages of its development with good running room; and early wells have demonstrated competitive economics even before we bring our operational expertise into play."

Powder River Basin wells tend to run 10,500 ft to 11,000 ft deep, with 2-mile laterals. From those standards, however, completion designs have been highly proprietary, as might be

ANSCHUTZ EXPLORATION CORP.

Anschutz Exploration Corp. is currently drilling two Niobrara wells and one Turner well on its multiwell Lucy pad in the Powder River Basin.

"The Powder has been on a lot of people's radar screen," said Jack Stark, president and COO, Continental Resources Inc.

expected early on for a stacked play with highly variable horizons.

Stark elaborated on his description of the play as being in its early stages. The basin was a conventional vertical play and thus was well-known. That was a double-edged sword, however, as it was understood to be challenging during early unconventional development.

"The Powder has been on a lot of people's radar screen," Stark said," but over the years it has not been a target. More recent technical evolution has started to bring the opportunity to the fore."

Several sources noted the entry of Continental Resources as a turning point for the basin. Bent remained modest, but did agree that the company's "operational excellence is not just in drilling and completing. It's financial and operational. All of the above. We have a record as being the low-cost operator on a peer basis for several years now with a demonstrated ability to reduce costs and improve efficiency."

By way of example, Stark noted, "At our operations in the Bakken and in Oklahoma, we have driven down costs by 25% in the last three years. We will be able to transfer that to the Powder."

All that said, getting hydrocarbons to the surface is hardly the end of the story. With any developing play, especially one in the middle of the continent, the midstream is always essential. "There is good midstream capacity," said Bent, "including sufficient takeaway in place for this year."

Continental Resources acquired some in-field gathering with the Samson operations and will continue to make use of that. Bent and Stark said that the company is comfortable building out or having midstream operators build in to its wellheads, whichever makes the most sense field-by-field.

"One of our strengths is that we tend to lease and operate contiguous blocks," said Bent. "That makes development more economical, including all aspects of infrastructure—water, gas and oil."

Compelling, yet consolidating

The basin is mostly federal minerals, said Austin McKee, a managing director at Eagle River Energy Advisors, based in Denver. "That means operators have more regulatory hoops to jump through with the BLM [Bureau of Land Management], especially with the challenges our industry is facing with the Biden administration. It was originally an extremely prolific conventional basin with multiple pay zones, including the Parkman, Teapot, Sussex, Shannon, Frontier, Turner and Muddy formations. Horizontal drilling kicked off with operators initially targeting the Frontier/Turner sands and has subsequently shifted to targeting the Niobrara and Mowry source rocks."

Broadly speaking, well costs associated with 2-mile laterals were as high as $10 million to $12 million when unconventional development began. Improved drilling efficiencies and service-cost reductions have brought that range down significantly. Drilling and completion costs are now in the range of $6 million to $9 million depending on the operator, completion design, depth and target formation. In the core areas of the basin, operators can generate compelling internal rates of return at $50 WTI.

The Powder River Basin is a focus for Eagle River, which has facilitated a variety of transactions in the basin including operated, nonoperated, mineral and royalty assets.

"The basin is dominated by a few large publicly traded operators," Michael Stolze, partner,

MERITAGE MIDSTREAM

In March, Meritage Midstream commissioned its Steamboat Natural Gas Processing Plant in Wyoming's Powder River Basin.

told *Oil and Gas Investor*, "including EOG, Devon, Chesapeake, Occidental [through its acquisition of Anadarko Petroleum Corp.] and now Continental Resources through its acquisition of Samson. But there are also a large number of private equity-backed portfolio companies that entered the basin over the past five years given the nascent stage of horizontal development and stacked pay potential."

There has also been some consolidation among operators, though not in the usual sense of M&A. Given the large number of private equity-backed operators, sponsors have consolidated their portfolios under fewer management teams to reduce G&A costs.

All the effort above ground speaks to the prize underground. "This is some of the best rock in the country," said McKee. "There are six Cretaceous intervals that come and go throughout the play and can be highly economic to develop, but what the Powder really needs from its larger operators is the delineation of the source rocks to provide repeatability. That will also assist in further driving down D&C costs. EOG has been great to watch over the years, as they have brought forth their industry-leading technology and cost structure to the basin and have proven the source rocks are viable targets. The Continental entry is great for the Powder. Continental brings scale and operating expertise along with the ability to further consolidate the smaller operators in Converse and Campbell counties."

Despite the challenges associated with federal minerals, Eagle River expects the Powder River Basin to see robust A&D activity driven by the consolidation of private operators and a return to drilling activity in the basin related to higher oil prices and lower drilling and completion costs.

Evolving midstream approach

"We are excited to welcome Continental to the game," Michael Woodward, senior vice president and chief commercial officer at Meritage Midstream, told *Oil and Gas Investor*. Noting that several mid-majors and large independents have been active in the Powder River Basin for some time, he added that this is a propitious moment for an additional well-known public company to raise the profile of the play.

As the basin has grown there has been an evolution of the midstream approach. "When we bought Thunder Creek Gas Services in 2013, we would usually build gathering pipelines to the wellhead," said Woodward. "Those were the early innings for the play—2013 and 2014—and producers wanted to focus on finding the best recipe for the sandstones. As the play progressed, we have seen some producers do some of their own in-field gathering. We do it all. We meet producers where they want us to be, by gathering at the wellhead or a central delivery point. This is a decision new entrants will have to make."

In some cases, the initial developers in the basin were portfolio companies backed by private equity, so their approach was to prove a field and make it ready for sale to a larger operator. "They wanted every well, prior to completion, to have a gas pipeline connected," Woodward explained. "In some cases, if producers had midstream assets, we would purchase and operate the midstream facilities so the producer could focus on drilling."

Those arrangements continue. For example, EOG announced plans for its own in-field gathering and handling for gas, water and oil to support a two-rig program that is part of its commitment to the Powder River Basin. Devon, however, has elected not to do its own in-field gas gathering, and Meritage goes directly to the company's wellhead.

"Everyone loves to compare the Powder to the Permian in terms of several thousand feet of stacked pay," said Woodward. "And that is true. There is also a great deal of variability from the sandstones reservoirs to the source rock. In addition to multiple depths, there is also a menu of oil, gas and liquids content. And each zone has its own technical challenges.

"The sandstones are fairly delineated at this point," he continued, "but the source rocks such as the Niobrara and Mowry still have some work to be done. That will take time, money and some appetite for risk. The play is more complex than the Permian or the Bakken. But the good news is this means there is more room to drive breakeven costs down and drive internal rates of return up."

The challenge for midstream operators is how to accommodate the variability with which producers are coming to grips—what kind of molecules and at what volumes. "There can be a well with great oil that comes on at barely 200 Mcf a day of gas," said Woodward. "Then, just a mile away, or even from the same pad, the next well can come on at 10 million cubic feet a day and tail off, or anything in between. It's not just between zones either, we've seen that variability within the Turner, for example. It's important that we design flexible systems that can handle variability and also allow our customers to grow."

Having established relationships with many of the blue chip producers in the Powder River Basin, Meritage has been able to plan its development in collaboration with shippers. "We will continue to invest and provide capacity as needed and optimize our assets. Communication and collaboration are key," said Woodward. "There is a fair amount of processing in place on the gas side, about 1 Bcf a day, of which about half is being used today. Producers know they can come to the Powder and grow with confidence in the midstream."

Lower well costs

In early 2017, private equity firm Kimmeridge began building a leasehold position in the central Powder River Basin in the core of the Niobrara and Mowry plays through its wholly owned operating company, Titan Exploration LLC. "We have accumulated around 56,000 NMA [net mineral acres] offset to large public operators including EOG [Resources

"There are also a large number of private equity-backed portfolio companies that entered the basin over the past five years given the nascent stage of horizontal development and stacked pay potential," said Michael Stolze, partner, Eagle River Energy Advisors.

"We will continue to invest and provide capacity as needed and optimize our assets. Communication and collaboration are key," said Michael Woodward, senior vice president and chief commercial officer, Meritage Midstream.

Inc.], Devon [Energy Corp.] and Continental [Resources]," said Alex Inkster, partner.

Kimmeridge has drilled seven operated Niobrara horizontal wells and participated as a nonop partner with EOG in nine Niobrara and two Mowry horizontal wells, reaching a maximum net production of around 5,500 boe/d.

"We believe that with limited remaining inventory in most established unconventional oil plays in the U.S. that the PRB will be the next major oil play to be developed and that it has the potential to be at the front end of the U.S. cost curve," Inkster said.

As the different Powder River Basin pay zones have been delineated over time with more wells, operators have optimized their drilling and completion strategies, said Inkster. "One of the biggest cost savings has simply been to reduce days-to-drill as operators have become more experienced with their target formations. Additionally, multibasin operators have brought best practices from other plays such as the Delaware Basin, which has shortened the learning curve in the Powder River Basin, resulting in lower well costs and better well performance. Another large area of improvement has been lowering completion costs through bulk purchasing and lower-cost sourcing of sand and water."

Kimmeridge believes that the basin is second only to the Permian Basin in terms of stacked pay potential. Inkster noted that "as the concept of upspacing is gaining traction across the industry, inventories have declined in all the major oil basins. Coupled with both their maturity and the lack of new unconventional basins being explored and delineated, we think that the PRB will be the destination of choice for cost conscious operators that have limited remaining inventory."

However, several issues have prevented the Powder River Basin from taking off and becoming the next hot unconventional play, Inkster cautioned.

"The perception that the PRB is structurally higher cost due to the regulatory oversight by the Bureau of Land Management, which has discouraged new entrants and thus more drilling activity," he said.

"Leases that are easy to hold-by-production, which allows multibasin operators to quickly reallocate scarce capital to other basins during lower oil prices where they have shorter duration leases.

"Highly variable well results in the Frontier and Turner, which were mistakenly characterized as resource plays, have been shown by different operators across the basin to have very low repeatability," Inkster said.

The variability in historic well performance is a function of the majority of Powder River Basin horizontal wells being drilled in conventional sandstone targets such as the Turner, Frontier, Shannon, Teapot and Parkman, Inkster noted. "That variability has hampered well economics and led operators to shift their focus to the shale plays where well performance is more repeatable. However, Powder River Basin operators were still able to realize economies of scale in these sandstone plays by drilling multiwell pads, with EOG, Devon and others publishing some very low well costs, such as $5 million to $6 million for the Turner. This gives us more confidence that the Niobrara and Mowry shale plays, which are much more repeatable, will see a material reduction in well cost and thus improvement in well economics once companies move to pad development."

An evolving basin

The Powder River Basin has historically been a more expensive basin in which to operate primarily because of lower rig count and associated activity and reduced service availability, said Glen E. Christiansen, president and COO of Peak Exploration and Production LLC, based in Durango, Colo.

"The targeted formations have additional drilling challenges, such as increased depth and overpressure compared to other basins, such as the Permian," he added. "Through time and experience however, we've seen costs associated with rigs, completion services and other operational services come down significantly. Drill times and completion days have dropped significantly as operators continue to optimize. For example, drill times have significantly improved through the use of surface casing preset rigs and bottom hole drilling assemblies tailored for the Powder River Basin while completion days and costs have been reduced with advances in coil tubing drill-out techniques.

Christiansen also said "there's been a lot of attention given to production variability in the basin. However, like all reservoirs, geology, quality, completion optimization and development strategy are all important drivers of productivity. Geologic mapping of net pay and saturation are important to well placement and larger casing design, which allows higher pump rates during the completion development strategy of the tight sandstone reservoirs. The shale plays tend to be more ubiquitous but subtle characteristics, like thermal maturity and fluid types, as well as tailoring completion techniques must be considered during development."

Anschutz Exploration Corp. is a prime example of how the Powder River Basin has evolved during the past several years from strictly delineation and appraisal to largely development mode, said Joseph DeDominic, president.

"We drilled and tested many different targets across our core operated areas, along with multiple spacing tests. It was a steep learning curve, not only for drilling, but also completions, to determine the optimal process and associated equipment, materials and people. Now that we have figured it out, we are taking advantage of a full-scale development by using multiwell pad and shared facilities including pipelines for oil and gas."

DeDominic confirmed that Anschutz, along with EOG and the majority of the smaller operators, are focused on the source rocks, mainly the Niobrara and Mowry. "Those formations are continuous across the basin, actually across multiple states, and eliminate the variably risk. As noted, we have also drilled enough wells in the Niobrara to significantly reduce the well costs."

As the Powder River Basin has moved to more development mode, DeDominic said, "I foresee consolidation potentially taking place if the oil and gas markets stabilize. There is a lot of running room. Development locations are already identified, and operators or investors looking to deploy capital and receive an above-market return over a longer period will have the ability to do so in the PRB."

While the operating companies get most of the credit for getting the basin sorted, they have lots of help. "Despite the volatile market in recent years, a number of dedicated service companies have kept their presence in the basin," said Bryce D. Ballard, vice president of engineering and operations at Ballard Petroleum. "As a result, there is a strong knowledge base to carry forward learnings from inside the basin."

The local support resource base is also starting to grow. "We are excited about the announcement of the PRB's first regional sand mine operated by Ramsey Hill Exploration," said Ballard. "The Niobrara and Mowry shale play both seem to need high volumes of proppant, and we're hoping local material allows us to pump those high volumes for a reasonable price. Another critical development in recent years has been the growth in the PRB's water disposal infrastructure. Recent disposal wells and evaporation pits will allow operators to dispose of water at a much lower cost than previously."

To date most development in the Powder River Basin has focused on the sand plays, said Ballard, "but we expect the vast majority of future development to focus on the shales. Early delineation of the Niobrara and Mowry shales has already shown each to have a much larger productive fairway than any of the sands. That leads us to expect less variability in the shales over the long term. We see the sand variability as an opportunity for exploration teams to generate additional returns beyond the baseline shale expectations."

As for consolidation, Ballard is circumspect. "Time will show the Niobrara and Mowry variability to be low enough to support consolidation. In addition to the major public players, the basin is full of privately backed companies designed for a build-and-flip business model. Obvious consolidation opportunities exists for each of the major players to purchase these private operators.

"Similar to other shales, the Niobrara and Mowry will require significant upfront capital to move from exploration to development mode. The inability of smaller private operators to secure this level capital may further drive consolidation." □

Peak Powder River Resources LLC's Iberlin Fed 1-6/2-7 Pad in Section 7-42N-74W, Campbell County, Wyo., in the Powder River Basin.

PEAK EXPLORATION AND PRODUCTION LLC

AN UPLIFTING CHOICE

The U.S. land artificial lift market continues to be one of the most dynamic segments as oil and gas operators strive to maximize production while optimizing lifting cost.

BY DAVID BAT

Since the 2015 market downturn, U.S. land operators have trialed using different forms of artificial lift to meet operational and financial objectives. It resulted in most oil and gas operators using two or three types of artificial lift during the life cycle of a typical unconventional well.

Before downturn, most U.S. land operators would complete and flow the well before placing on artificial lift, which was predominantly rod lift. Today, most land operators elect to use either gas lift or electric submersible pump (ESP) systems as their first form of artificial lift while rod lift is rarely used as the first form of lift for unconventional wells.

The preference of using ESP as the first form of artificial lift is driven by the desire to maximize IP rates, but these benefits were often offset with short run times and associated ESP failure due to sand, solids, debris, gas slugging and deposits such as scale.

During 2015, 2016 and 2017, it was not uncommon for U.S. land operators to experience multiple ESP failures within the initial six to nine months of operability. ESP providers, however, responded with improved designs and capabilities in the past few years, and today ESPs have improved mean time between failures (MTBF) performance dramatically with approximately 80% of U.S. land ESP users achieving up to nine months or longer run rates before failure.

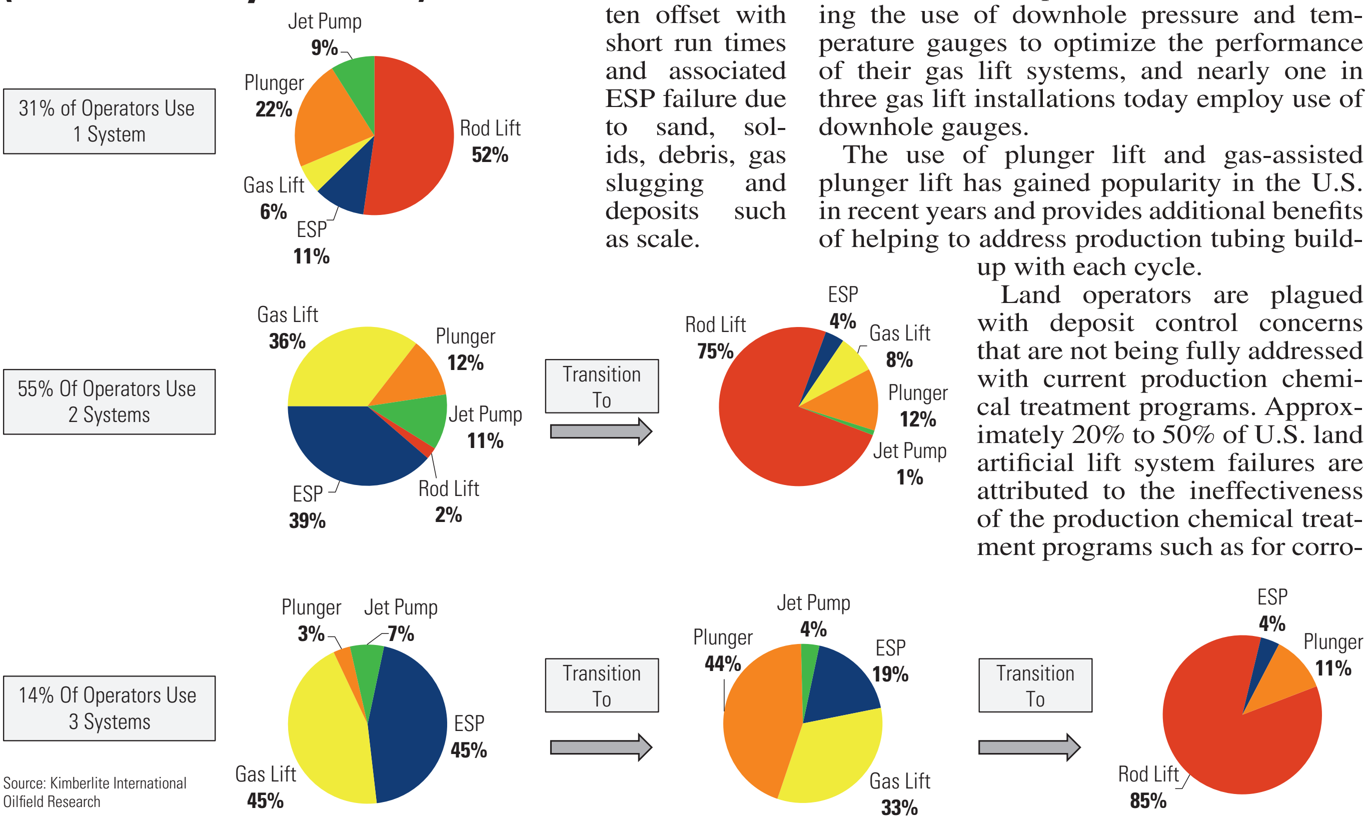
These performance improvements, along with attractive commercial leasing arrangements, continue to support use and adoption of ESPs as a preferred first form of artificial lift for unconventional wells in the U.S.

Gas lift is commonly preferred among U.S. land operators due to low cost and reliable performance with average MTBF rates of nearly 36 months. Land operators have been increasing the use of downhole pressure and temperature gauges to optimize the performance of their gas lift systems, and nearly one in three gas lift installations today employ use of downhole gauges.

The use of plunger lift and gas-assisted plunger lift has gained popularity in the U.S. in recent years and provides additional benefits of helping to address production tubing buildup with each cycle.

Land operators are plagued with deposit control concerns that are not being fully addressed with current production chemical treatment programs. Approximately 20% to 50% of U.S. land artificial lift system failures are attributed to the ineffectiveness of the production chemical treatment programs such as for corro-

Share Of Artificial Lift Installs By System Type (At Selected Life-Cycle Intervals)



Source: Kimberlite International Oilfield Research

sion, scale, wax, paraffin and/or H_2S depending upon the artificial lift system type.

Chemical and mechanical failures

Due to the integrated nature of the artificial lift systems and efficacy of the production chemical treatment programs, a significant opportunity exists in the market for suppliers that can help address both the chemical and mechanical failures in the market. These findings coupled with increasing interest to leverage digital solutions and remote operations to reduce environmental impact, respond to COVID-19 workplace concerns, improve safety performance and lower operating costs further create opportunities for innovative suppliers to deliver integrated production solutions.

Today, operators have to construct their own integrated production solutions approach leveraging multiple suppliers. However, it is entirely plausible that the market will continue to innovate and respond to these growing needs with integrated offerings and analytics to address the measurement and monitoring of emissions along with critical facility equipment monitoring and integrity as well as traditional production chemical pumping systems and artificial lift controllers and downhole sensors.

In the Kimberlite Production Solutions Business model, suppliers with strong digital footprints will be able to aggregate and analyze disparate data sets and integrate into a cohesive production solution to optimize production and financial results. Rather than simply monitoring a pump off controller to determine if a beam pump is operating properly, the analytics of the future will be able to integrate downhole well performance data, production chemical input data along with other sensors to predict not only future well failure events but predict downstream impacts on the production facilities, equipment and broader operation.

Headwinds for rod lift market

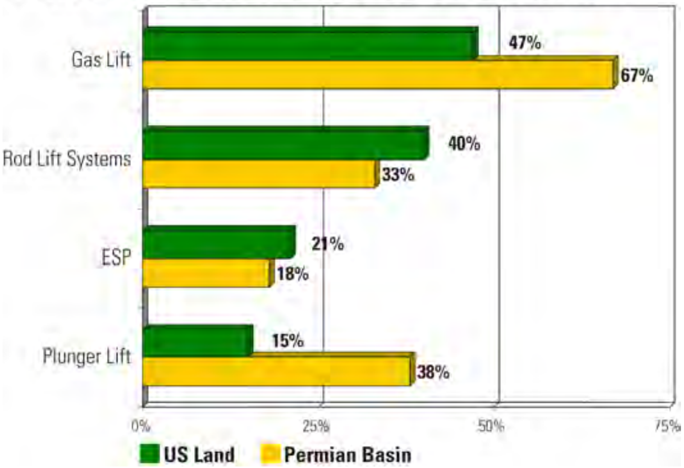
The rod lift market continues to innovate in response to the growth of gas lift, plunger lift and ESP in the early stages of land wells' life cycles with advancements in long stroke capability and continuous sucker rod technologies to address concerns and challenges with deviated wellbores and tubing wear.

The 2015 market downturn and the pandemic-driven market downturn created additional headwinds for the rod lift market, particularly the smaller-sized units, due to a surplus in used equipment as operators shut in wells and converted rod lifted wells to gas lift. This allowed operators to redistribute equipment in the field and the excess of used rod lift equipment also carried over into sucker rods where the used/inspected sucker rod business no longer looks like a niche market but rather a truly defined segment positioned to survive well into the future.

In the later stages of the well's typical life cycle, land operators continue to prefer the use of rod lift due to low bottomhole pressures. In other words, U.S. land wells will die on rod lift, not ESP.

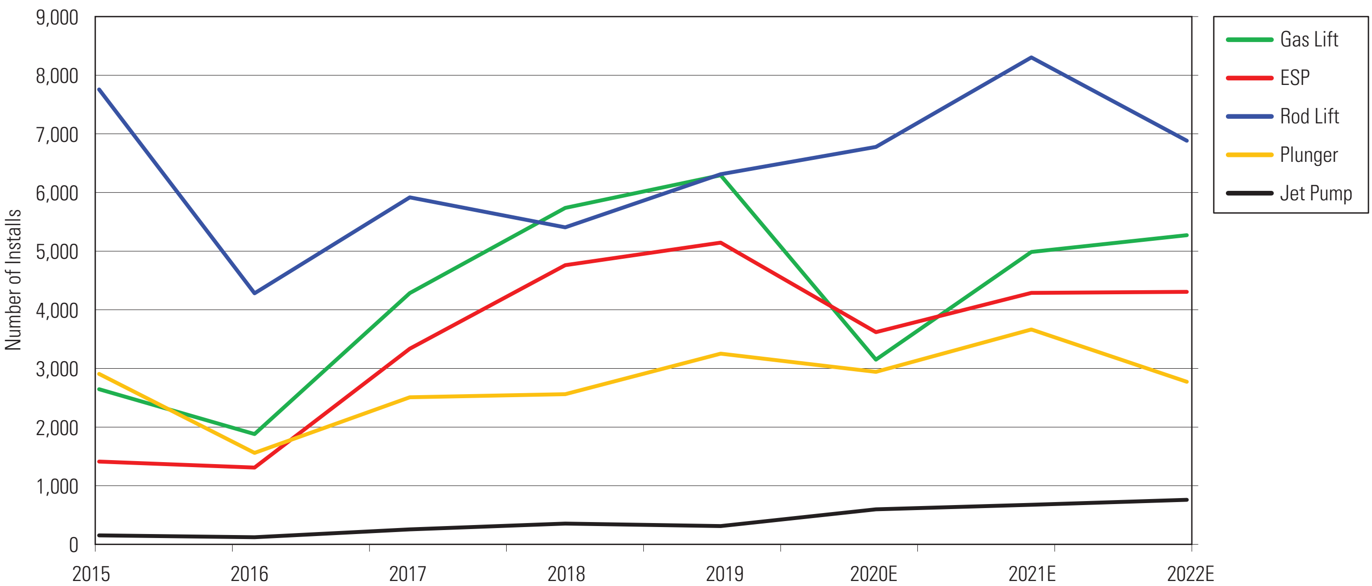
Looking ahead for U.S. land, rod lift installations will increase as wells transition from gas

Artificial Lift System Failures That Can Be Addressed By Production Chemicals



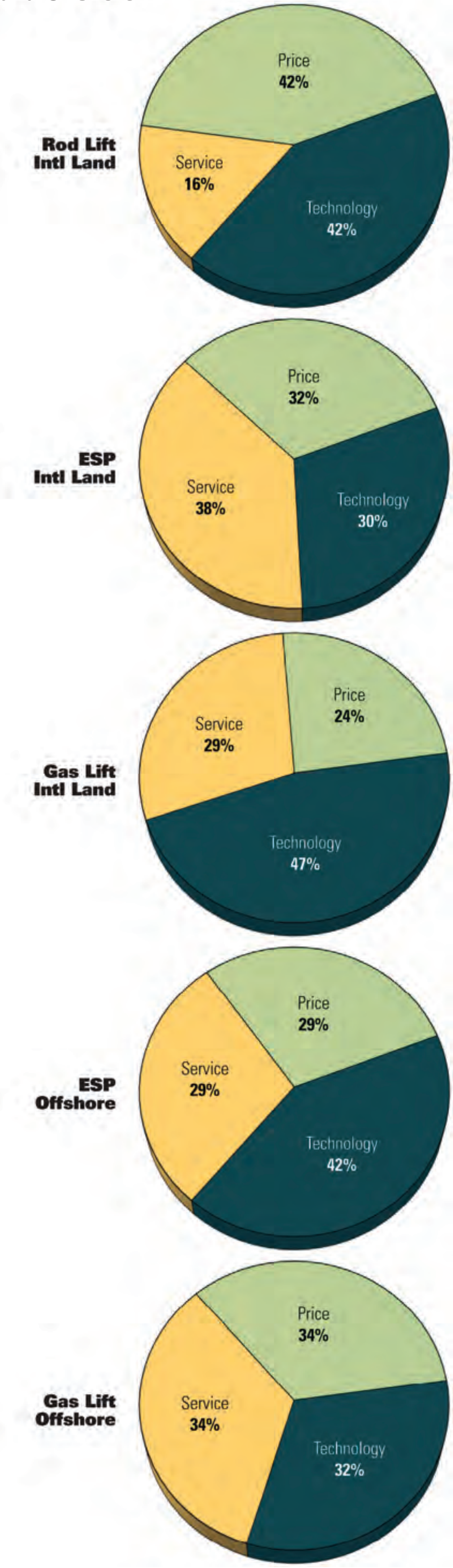
Source: Kimberlite International Oilfield Research

Artificial Lift Demand Estimates By Lift Type - U.S. Land



Source: Kimberlite International Oilfield Research

Artificial Lift Market Segmentation By Buying Behavior - International and Offshore



Source: Kimberlite International Oilfield Research

lift, plunger lift and ESP to rod lift. But again, the used rod lift market will continue to place headwinds on the rod lift business depending upon the size of unit required and future rate of well abandonment creating additional inventory of both surface units and used sucker rods.

Downturn impact on buying behaviors

The trends in artificial lift installations shown in the exhibit above reflect the impact of the market downturn in 2020 whereby gas lift and ESP installations declined due to fewer wells being drilled while rod lift conversions continue to occur from wells drilled in prior years.

The U.S. land market for artificial lift will benefit from improved drilling activity in 2021 with U.S. land operators projecting to drill approximately 9.6% more wells in 2021 versus 2020.

In addition, U.S. land buying behaviors continue to evolve. While some believe that the market is entirely 100% price and procurement driven, market data reveal otherwise based on the voice of the customer research conducted by Kimberlite. In fact, the U.S. land market is heavily influenced by service buyers for gas lift and plunger lift while rod lift buyers strongly value technology/performance in their recommendation and use of a supplier. ESP buyers tend to value technology/performance and price in their recommendation and use of a supplier.

Looking internationally and offshore, the artificial lift markets are a bit less dynamic than that of U.S. land with respect to switching of artificial lift systems, but these trends may change as the Middle East and other regions begin to look at unconventional trends for future resource development.

Currently, the offshore market remains dominated by gas lift and ESP, while the international land market is dominated by the use of ESP followed by rod lift.

Buying behaviors internationally and offshore also reflect segmentation among technology, service and price buyers depending upon artificial lift system type and market segment. Technology and service tend to play a higher role internationally and offshore in the recommendation and use of suppliers.

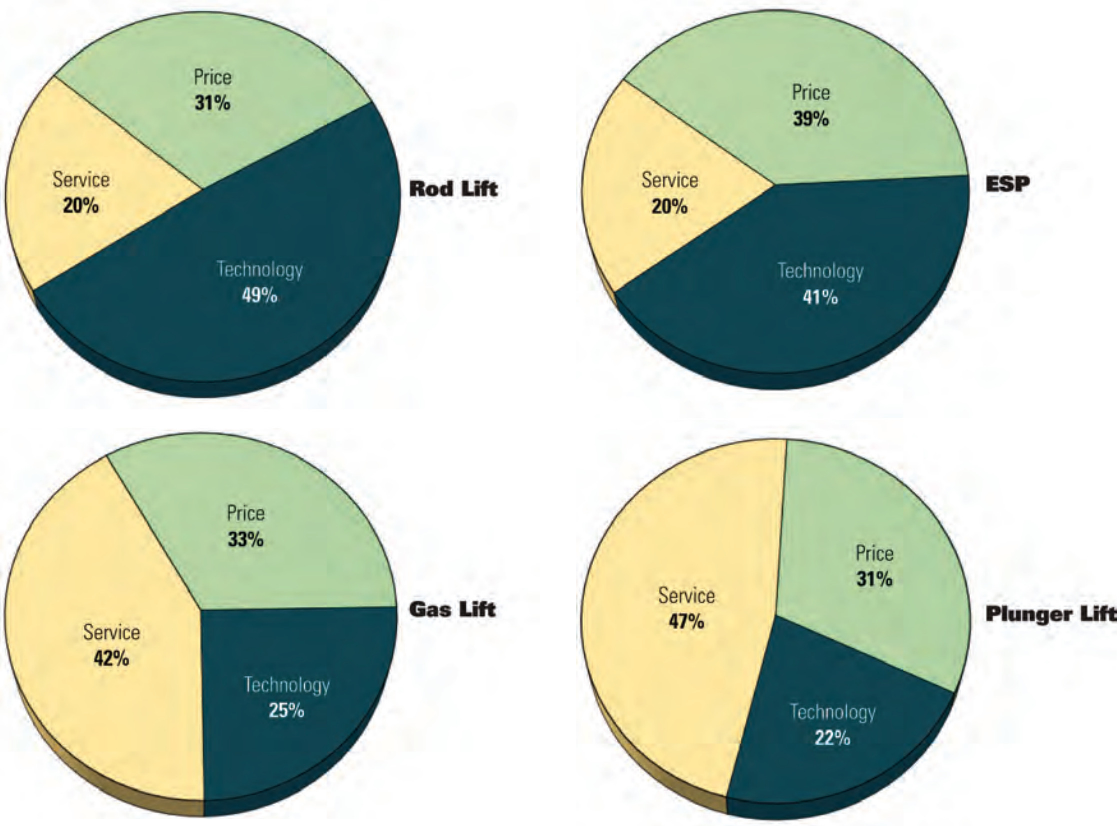
A promising year is ahead

The international artificial lift market will benefit from improved drilling activity in the second half of 2021 with international land operators projecting to drill 5.6% more wells in 2021 versus that of 2020.

The offshore market will remain essentially flat in 2021 with some observed growth projected to occur late into the year as offshore operators begin to take advantage of strong commodity prices and low oilfield service company pricing.

Next year will be the year for the offshore market to experience additional increase in investment and drilling activity that should translate into growth for the artificial lift market. It is common for offshore operators to take a more cautious approach and wait

Artificial Lift Market Segmentation By Buying Behavior - U.S. Land



Source: Kimberlite International Oilfield Research

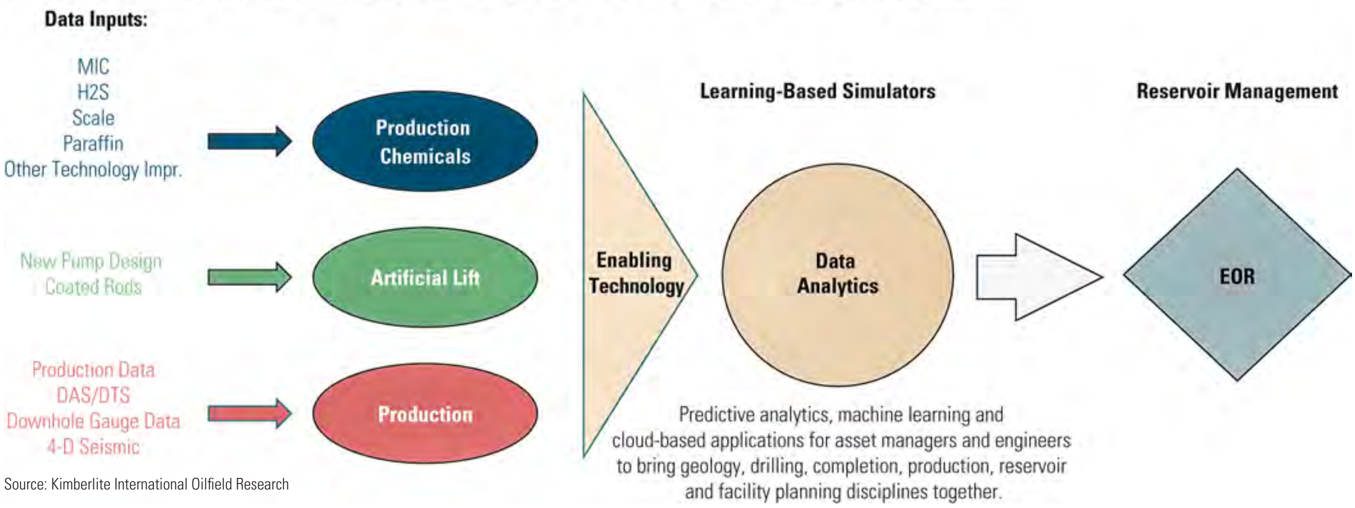
until the market is stabilized with favorable forward strips on three-year and five-year oil before making significant future investment commitments.

Oilfield service company pricing has taken a hit in 2020 and is currently at historic low prices that are unsustainable longer term. Oilfield service prices will trend higher in the second half of 2021 and into 2022 due to increased cost of shipping, steel and other commodities. Oilfield service companies are not positioned to absorb these additional costs and will be past through to the operators later this year and into 2022.

Whatever the future holds in the years ahead, the oil and gas industry has proven time and again the ability to innovate and adjust to challenging market conditions. One difference coming out of the COVID-19 pandemic is the realization that the use of remote operations and digital solutions will continue to grow and develop as operators seek to improve efficiencies and financial returns.

David Bat is president of Kimberlite International Oilfield Research and brings over 30 years of extensive energy and oil and gas experience. Kimberlite is a recognized leader in the industry for "voice of the customer" oilfield research tracking all facets of the upstream industry including technologies and supplier performance.

Future Business Model (Production Solutions-Focused Data Analytics Platform)



Source: Kimberlite International Oilfield Research

LENDER LIABILITY BEWARE

Energy lenders must keep borrowers at arm's length while they face COVID-19 challenges or risk lender liability.

BY JEFF ANAPOLSKY

ILLUSTRATION BY ROBERT D. AVILA

For thousands of middle-market companies with debt below $100 million, the borrower-lender relationship involves a relatively simple capital structure, with a bank loan secured by a first lien and a mix of preferred and common equity. Such middle-market bank loans typically involve one lead bank, which may partner with a few other banks, and are illiquid investments that are not traded like broadly syndicated leveraged loans for larger borrowers. Middle-market borrowers are typically owner-operated family businesses or portfolio companies of private equity sponsors. Therefore, upon default, neither the lenders nor the owners can readily exit their investment in these private companies, so they must find a negotiated resolution to avoid bankruptcy.

During these negotiations, lenders may find that they enjoy an unfair advantage where the troubled borrower relies on the bank loan for its liquidity to fund day-to-day operations, the owners are unable to invest additional capital and refinancing options are limited. While all parties will generally prefer avoiding bankruptcy, lenders may discover that borrowers' lack of familiarity with bankruptcy law often makes them deeply concerned about the stigma and risks involved in a bankruptcy filing, which leaves room for negotiation of an out-of-court solution. When lenders overreach at the negotiating table, however, they risk lender liability.

Rights and responsibilities

Equity owners of a business have the right to attend shareholder meetings, vote on strategic directions and/or elect members to the board of directors. The board of directors, in turn, selects officers to manage the day-to-day operations of the business, including hiring employees. For solvent companies, the directors and officers owe fiduciary duties to equityholders, including the duties of care, loyalty and good faith. For insolvent companies, the fiduciary duties of directors and officers flip from equityholders to creditors. The business judgment rule insulates directors and officers from liability as long as they observe their fiduciary duties, thereby protecting them from frivolous lawsuits.

By contrast, a lender forfeits the right to control a borrower's business in exchange for certain legal rights: liability protection from stakeholders, the right to seize underlying collateral, priority treatment in bankruptcy and predictable cash flows in the form of interest. As long as "the lender-borrower relationship is that of an arm's length transaction," lenders typically do not owe fiduciary duties to borrowers and other stakeholders.

However, if a lender acts contrary to its role as a passive investor by exerting excessive control over a borrower's day-to-day operations or effectively usurping or dominating the management function of the borrower's business, lender liability risks arise. Lender liability claims could include breach of contract, tortious interference, fraud, equitable subordination and breach of fiduciary duties. In lender liability litigation, a borrower (and creditors harmed by the lender exerting excessive control, such as vendors, counterparties, taxing authorities and other unsecured creditors) may bring causes of action against the lender, and the lender may be held liable for damages, thereby piercing its shield against such liability and jeopardizing its priority treatment in bankruptcy. Courts may consider whether the lender's conduct was inequitable, caused harm to the borrower's other creditors or conferred an unfair advantage to the lender.

Facing COVID-19 challenges

Stay-at-home orders driven by the COVID-19 pandemic have severely decreased demand across numerous industries, with the energy industry being hit doubly hard due to a simultaneous OPEC price war in the first quarter of this year. The subsequent decline in oil prices has caused energy companies to face plummeting revenues and diminishing liquidity. With the debt and equity markets largely closed to the energy sector, borrowers are pleading for liquidity from their banks.

The issue is exacerbated by the industry's decades-long reliance on asset-based lending. In asset-based lending, loan advances are limited to a percentage, called the "advance rate," of eligible collateral. "Eligible collateral" refers to assets that meet the bank-specified criteria for inclusion in the borrowing base. The "borrowing base" is the total amount of the borrower's eligible collateral, which may be significantly different from its total collateral due to customer concentration, aged receivables, slow-moving inventory and other factors. This lending model has proven problematic for energy companies because the very asset values that drive the company's credit lines are collapsing in tandem with oil prices.

A prime example of potentially problematic asset-based lending is "reserve-based lending," which was popularized in the 1970s amid rising oil prices. Reserve-based lending provides E&P companies with revolving credit facilities that are sized by the net present value of a portfolio of producing assets. Typically, only assets actively producing oil and gas are classified as eligible collateral. The borrowing base is periodically recalculated using updated reserve data and price projections, called a "borrowing base redetermination." With borrowing bases for upstream oil and gas companies adjusted twice a year to match the latest price projections, banks are notifying energy companies of large deficiencies, meaning that the amount drawn on the revolving line of credit exceeds the amount allowed per the revised borrowing base.

Often concurrent with collapsing collateral values, lenders can further restrict borrowing in multiple, subjective ways: (i) changing eligibility requirements and (ii) changing advance rates. The net result of these two variables may cause the borrowing base to suddenly fall below the borrowed amount. If so, the lender can cause the loan to become overdrawn, putting the borrower in default.

To cure a borrowing base deficiency or overdrawn loan, the borrower needs to pay down the loan, usually in six equal monthly installments, or add more collateral. In other words, the borrower may have been in compliance before the lender redetermined the borrowing base, but then the lender's new borrowing base calculation may create a surprise deficiency.

Figures 1 to 4 provide an illustration of this redetermination, as well as other issues that can arise from falling oil prices and declining asset values.

In Figure 1, the base case begins with $125 million of initial total collateral value of which the bank determines that 80% is eligible. The bank proposes to advance up to 70% the value of eligible collateral. Thus, $100 million of the collateral is eligible, and the maximum available loan is $70 million. In this scenario, since the borrower only borrowed $55 million, there exists a comfortable $15 million cushion of excess availability. However, presuming that oil prices collapse, the total collateral value subsequently becomes reduced to $100 million of which 80% is eligible with a 70% advance rate under the predetermined formula. Thus, eligible collateral has now decreased from $100 million to $80 million, and the maximum available loan has reduced further to $56 million. Since the loan amount remains $55 million, the excess availability cushion has shrunk from $15 million to only $1 million. This cushion was meant to absorb unexpected shocks, such as fluctuations in energy commodity prices, by shrinking the borrowing base in proportion to declines in collateral value. In this example, the formula worked since the borrower remained in compliance despite a 20% decrease in total collateral value.

An additional complication, though, is that a sudden drop of 20% of the total collateral value may alarm lenders. A nervous lender may overreact to sharp declines in collateral values across an industry and feel motivated to restrict credit exposure to that sector. Such overreactions may create deficiencies where there were none before, leading to preventable defaults.

In Figure 3, the lender responded to the sudden decline in collateral value by subjectively increasing the calculation of ineligible collateral to 30% of the total collateral value, causing eligible collateral to decrease from $100 million to $70 million (rather than $80 million) and the maximum available loan to be reduced from $70 million to $49 million (rather than $56 million). As a result of this one discretionary change, the borrower suffers a $6 million deficiency rather than having a $1 million cushion.

Lenders can further restrict borrowers by decreasing the advance rate in tandem with collateral value declines. In the figure above, the lender decreased the advance rate to 60% in addition to increasing the calculation of ineligible collateral

Figure 1: Asset-Based Lending Illustration – Excess Credit Available

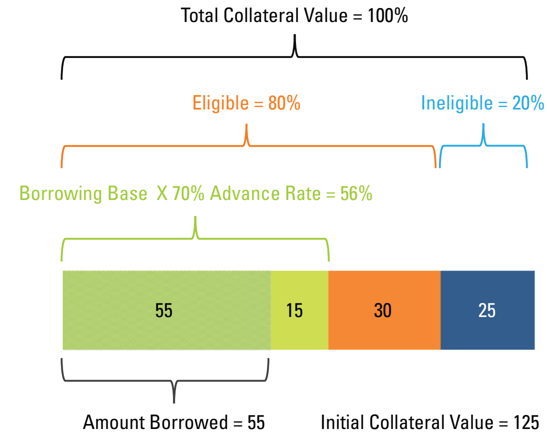
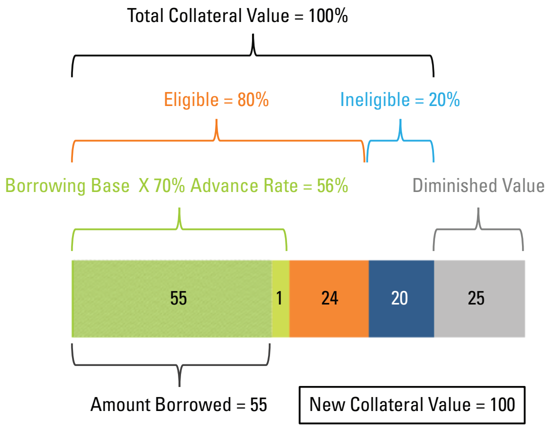


Figure 2: Asset-Based Lending Illustration – Redetermination, Compliance With Slight Cushion



Source: Crossroads Strategic Advisors

to 30% of the total collateral value. Accordingly, eligible collateral decreased from $100 million to $70 million (rather than $80 million), and the maximum available loan was reduced from $70 million to $42 million (rather than $56 million). As a result of this double whammy, the borrower suffers a $13 million deficiency rather than having a $1 million cushion.

These examples illustrate how reserve-based loans give lenders the power to deepen the distress for troubled upstream E&P borrowers to overcompensate for sudden drops in energy commodity prices.

Striking a balance for energy loans

Because lenders possess some discretion with borrowing base calculations, they may gain substantial negotiating leverage over such borrowers. During healthy periods for the energy sector, a borrower can usually find alternative lenders to escape an overbearing one. However, during troubled periods, alternatives may not exist. Without alternatives, the existing lender may attempt to coerce the borrower into strategic and operational changes in lieu of curing a borrowing base deficiency, which the lender used its discretion to create in the first place. Lender liability is designed to deter a lender from abusing its negotiating leverage to usurp the judgment of the borrower's officers and directors.

In fall 2020, approximately 65% of respondents to the Haynes and Boone Borrowing Base Redeterminations Survey said they believed borrowing bases would decrease by 10% or more. Indeed, according to a late-June S&P Global survey of 34 speculative-grade E&P companies, the average borrowing base redetermination was lowered by 23%.

Per the loan agreements for most asset-based loans, the lender has the right to take control of the borrower's cash if the borrowing base declines to a level below the loan balance. Specifically, most asset-based loans include a deposit account control agreement, which gives lenders control over deposit accounts should a default arise.

Excessive restrictions on liquidity, however, could compel borrowers to act in desperation—drastically cutting payroll, defaulting with vendors—and they may ultimately lose customers because of a hampered ability to fulfill orders. As a result, the lenders may inadvertently impair the value of their collateral, as well as alarm their other borrowers.

Typically, extreme financial distress reduces the ability of the company to collect receivables from its customers on a timely and full basis. Also, vendors may restrict the availability of critical goods and services if they fear that their outstanding invoices will never be paid.

Further, key employees tend to abandon a sinking ship.

Overall, keeping the business as a going concern is often the best way for lenders to maximize their recoveries. Accordingly, from a lender's perspective, engineering a discrete liquidation is often preferable to forcing an actual liquidation, although lenders should be cautious of adverse consequences for other stakeholders. Notably, harm to other creditors is part of the three-part test for equitable subordination.

When confronted with the harsh reality that customary remedies, such as foreclosing on collateral or sweeping cash accounts, will not maximize their recoveries, a lender usually realizes that it must continue funding losses for a business that may be in a death spiral. As J. Paul Getty, named the richest living American in 1957 by Fortune magazine, explained, "If you owe the bank $100, that's your problem. If you owe the bank $100 million, that's the bank's problem."

An aggressive lender risks that the borrower will ultimately declare bankruptcy to gain legal protection from its creditors, including the lender. Bankruptcy, however, may not advance the lender's objective. The costs of administering a bankruptcy case, such as paying for lawyers, trustees, creditors' committees and other administrative expenses, may diminish the value of the lender's collateral even further. In some circumstances, the court may approve post-bankruptcy financing with priority ahead of the lender's secured loan.

Furthermore, the bankruptcy process may prolong an inevitable sale of some or all of the borrower's assets. Finally, the breathing room provided by the bankruptcy process may allow the borrower to litigate lender liability as a way to improve recoveries for unsecured creditors and delay action by the lender.

The risks and uncertainty involved in bankruptcy often cause lenders to look for out-of-court remedies to protect their collateral via loan amendments, forbearance agreements and standstill agreements. These remedies, however, often come with strings attached for the borrower, such as onerous requirements to reduce overhead costs, put the company up for sale, provide more frequent financial reporting, waive potential claims against the lender and other lender-friendly terms and conditions.

When evaluating a troubled borrower, the lender faces the challenge of providing enough cash for borrowers to recover while limiting business activity that poses risks to the lender's collateral. This balancing act must be done while maintaining an arm's length relationship. If overreaching causes the lender to cross the line from passive to active investor, the lender may trigger lender liability.

Figure 3: Asset-Based Lending Illustration – Redetermination, Changes In Eligibility

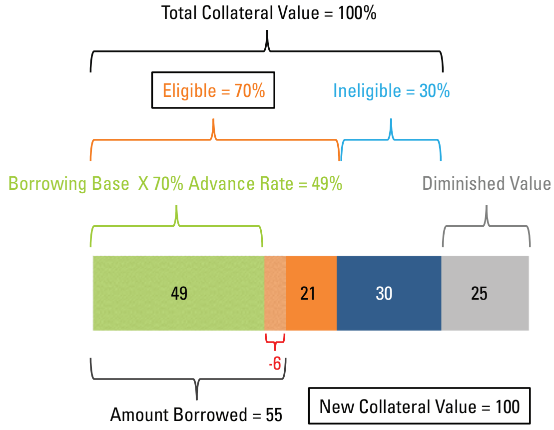
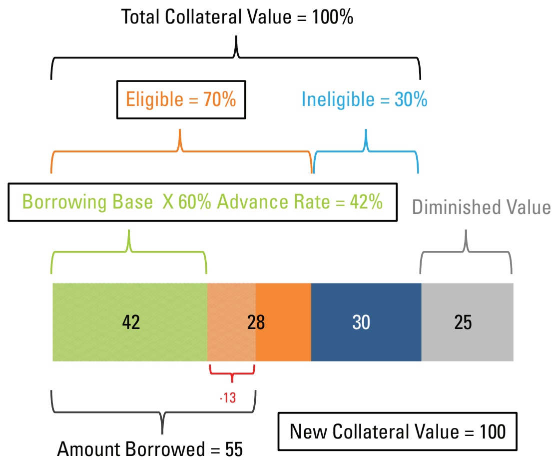


Figure 4: Asset-Based Lending Illustration – Redetermination, Changes In Eligibility, Advance Rate



Source: Crossroads Strategic Advisors

Breach of fiduciary duty

Mitigating strategy: Transparent communication with borrowers.

When a lender begins to pursue its remedies, the borrower may react unexpectedly. With the unfair benefit of hindsight, a court may determine that the lender exercised undue influence over the borrower by pursuing a specific remedy. To avoid surprises, and subsequent liability claims, lenders should create open and transparent lines of communication with borrowers. Ideally, communications should be documented, so consider asking questions via email rather than over the phone. Receiving frequent financial reporting from distressed or defaulted borrowers is also highly recommended. However, distracting executives from managing their day-to-day operations is generally counterproductive.

The need for communication and continuous financial reporting is illustrated in the New York Supreme Court case *U.S. Bank N.A. v. DCCA*. In the case, the lender refused to provide additional funding to defaulted borrower Doral Arrowwood Hotel and Conference Center. Without that liquidity, the company announced mass layoffs on Christmas Eve, effective on Jan. 12, 2020. The court determined that the lenders knew that their withholding funding would force Doral Arrowwood to close and that employees would not get the 90-day notice of termination required under the Worker Adjustment and Retraining Notification (WARN) Act. The bank was held liable for the cost to employees for Doral Arrowwood's failure to provide 90 days prior written notice of mass layoffs. The situation may have been avoided had the bank been aware of the borrower's payroll status. Given energy companies' reliance on banks for liquidity, it is easy to see how a similar scenario could play out in the oil patch.

If the borrower-lender relationship has soured, making meetings contentious, it might be the right time to hire a third party with experience in creating open lines of communication between borrowers and lenders. A restructuring advisor, turnaround consultant or independent director can work with troubled borrowers to restore the lenders' credibility.

Tortious interference

Mitigating strategy: Avoid any perceived or actual advisory role with the borrower.

In an effort to safeguard collateral, lenders may be tempted to provide advice to troubled borrowers regarding working capital management, overhead expenses, employee retention, marketing initiatives, agreements with customers and vendors, maintenance capex, potential asset sales and other topics related to day-to-day operations. However, history is replete with instances of lenders being found liable for providing advice to borrowers that resulted in damage to the borrower's other stakeholders.

Additionally, lenders should beware of relationships with borrowers that are atypical, i.e., what courts have deemed "special relationships," that can impose certain fiduciary duties on the lender if the lender is ruled to have exercised extensive control.

Avoiding advisory roles is of particular importance under the Paycheck Protection Program, whereby borrowers are only eligible for loan forgiveness if they meet certain criteria. Lenders should take particular caution that they do not advise borrowers in ways that could seem to manipulate borrower's eligibility for loan forgiveness.

Because lenders provide financing to many borrowers, they may have a good idea of typical industry practices. Therefore, it can be tempting

"Lender liability is designed to deter a lender from abusing its negotiating leverage to usurp the judgment of the borrower's officers and directors."

to offer proposed "benchmarks" or "norms." Lenders should make it clear to borrowers, in writing, that no advisory relationship exists between them. If a lender thinks that a troubled borrower would benefit from an outside perspective, then the lender should encourage the borrower to hire a restructuring advisor, turnaround consultant or independent director to maintain the arm's length relationship between the lender and the borrower. While the lender can approve of the person or firm being hired, the lender, as a passive investor, should not be the one making the final decision.

Duty of good faith and fair dealing

Mitigating strategy: Avoid providing assurances to the borrower, and communicate clearly and consistently the lender's obligations.

Given the federal "perks" provided to lenders that administer coronavirus relief loans, there may be an expectation from the courts that the lenders work with borrowers, rather than simply "canceling" the loan." For example, lenders under the Main Street Lending Program only retain 5% participation in any Main Street Loan, and federal banking agencies modified capital rules in favor of lenders participating in the PPP program. Even prior to the Coronavirus Aid, Relief and Economic Security (CARES) Act, there have been several cases where lenders' failure to work with borrowers, imposing steep penalties that borderline excessive control, has resulted in imposing additional liability. In *K.M.C. Co. v. Irving Trust Co,* K.M.C. asserted that Irving's refusal to fund without prior notice breached a duty of good faith implied in the agreement and led to the collapse of the company. Irving paid K.M.C. $7.5 million for its failure to act in good faith.

Irrespective of court expectations, it is often in a lender's best interests to negotiate with its troubled borrowers, providing them with amendments or forbearance agreements. In the case of energy asset-based lending, lenders would likely encounter severely depressed prices were they to foreclose and attempt to sell energy assets while values are low, like during the COVID-19 pandemic. Negotiations can maximize recovery. Regardless of the course of action, it is important that lenders communicate clearly about the current remedies sought.

Breach of contract

Mitigating strategy: Establish a fireproof loan application process.

Because lenders and borrowers have a contractual relationship, lenders could be held liable for breaching oral, implied and written contracts. Despite the enormous volume of applications lenders have received pursuant to the CARES Act, lenders still have a duty to process loan applications with reasonable care. If a bank's failure to process a borrower's loan application in a timely manner is to the borrower's detriment, the bank could be liable. Clearly, lenders should document the loan application process for both internal and external use to manage timing expectations among borrowers and prevent internal processing errors.

Fraud involving lender liability

Mitigating strategy: Communicate with caution about providing any guarantees of funds, amendments or forbearance when these cannot be assured.

When negotiating remedies, do not make promises you cannot keep. Lenders have been found liable for threatening borrowers with no ability or intention to follow through with those threats. Make it clear that you are in the midst of negotiations and that remedies have not been finalized.

Require borrowers to provide written confirmation that they recognize that their loan is in default and that they have agreed to engage in negotiations. A neutral third party can aid in quickening negotiations, and restructuring advisors are experienced in negotiating with all stakeholder groups. In some cases, advisors may provide borrowers with refinancing opportunities to move troubled loans out of lender portfolios.

The value of a third-party voice

Restructuring advisors are seasoned at dealing with distressed firms and can help you and your borrowers navigate an out-of-court workout or bankruptcy proceeding. Hiring a restructuring advisor can help mitigate lender liability risk by maintaining an arm's length relationship as well as:

- Improve reporting accuracy and transparency;
- Evaluate borrower liquidity and provide cost recommendations that do not violate the arm's length relationship;
- Provide paths to open, thorough, documented communication throughout the application and modification process; and
- Equip borrowers with effective benchmarking tools.

Bringing in an objective, third-party restructuring advisor to guide all players' next steps can help mitigate lender liability risk while working toward maximized outcomes for all stakeholders. During a distressed situation, the lender will likely resent "leakage" of cash going to fund interest payments on unsecured debt, bonuses to key employees, timely payments to vendors, management fees to sponsors, marketing initiatives, routine maintenance of equipment and professional fees to advisors or consultants, even though such expenditures may be needed to maximize valuation of the enterprise.

While the lender's desire to protect the value of its collateral may diverge from the interests of unsecured creditors and equityholders in rehabilitating the value of the business, lenders should be wary of overstepping their bounds. ☐

Jeff Anapolsky has more than 20 years of leadership experience in finance, law and operations, including more than 40 out-of-court workouts and bankruptcy reorganizations. As an industry generalist and functional expert, he has created credible forecasts, raised private capital, resolved multiparty disputes, determined complex valuation, managed transaction closings and delivered effective presentations for a variety of special situations.

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EQT Expands Its Marcellus Acreage In $2.9 Billion Deal

EQT CORP. IS expanding in the Marcellus Shale, adding a new operating position in Pennsylvania through an acquisition worth about $2.9 billion.

The Pittsburgh-based company agreed to acquire **Alta Resources LLC**'s Marcellus Shale assets, including its upstream and midstream subsidiaries in the northeast core of the play, according to a May 6 news release.

EQT, which bills itself as the nation's largest producer of natural gas, operates in the core of the Appalachian Basin's Marcellus and Utica shale plays. With an already formidable footprint in southwest Marcellus that stretches across Ohio, Pennsylvania and West Virginia, the company said its purchase from Alta will grow EQT's acreage position to more than 1.6 million acres with the addition of Alta Resources' roughly 300,000 acreage position in the Northeast of the play.

"The acquisition of Alta's assets represents an attractive entry into the Northeast Marcellus while accelerating our deleveraging path, providing attractive free cash flow per share accretion for our shareholders and adding highly economic inventory to EQT's already robust portfolio," president and CEO Toby Rice said in a statement.

EQT projects the Alta acquisition will increase its free cash flow by 55%, or $2 billion, through 2026.

Alta Resources is a private company headquartered in Houston. The private E&P's backers include the credit arm of **Blackstone Group Inc.**, according to a note by **Simmons Energy**, a division of **Piper Sandler**.

Founded in 1999, Alta has been a leader in the exploration and development of shale oil and gas assets including in the Fayetteville Shale of Arkansas and the liquids-rich Duvernay Shale of Canada. The company's current position comprises 300,000 net acres in the core of the Northeast Marcellus, 98% HBP, according to the EQT release.

The Alta Resources acreage consists of a 220,000 net-acre operated position with the remaining 78,000 net acres

Toby Rice

nonoperated. Net production is currently at 1 Bcfe/d, 100% dry gas.

"In addition to increasing our long-term optionality, we believe this transaction accelerates both our path back to investment grade metrics and our shareholder return initiatives," Rice added. "We look forward to applying our differentiated modern operating model to maximize the prolific value embedded in these premier assets."

Attaining an investment grade rating would bring EQT one step closer to returning capital to shareholders, noted the Simmons analysts in the firm's note on May 6.

"Well performance from the acquired position looks attractive based on 2020 data and the asset benefits from a low royalty position," wrote Kashy Harrison, senior research analyst at Simmons. "However, the asset does not fit hand-in-glove (i.e. CVX deal), effectively amounts to a new operating area for EQT, and possesses meaningful nonop exposure."

The total $2.925 billion purchase price for the transaction includes $1 billion in cash and approximately $1.925 billion in EQT common stock issued directly to Alta's shareholders.

EQT said it plans to fund the cash portion of the acquisition with cash on hand, drawings under its revolving credit facility and/or through one or more debt capital markets transactions, subject to market conditions and other factors.

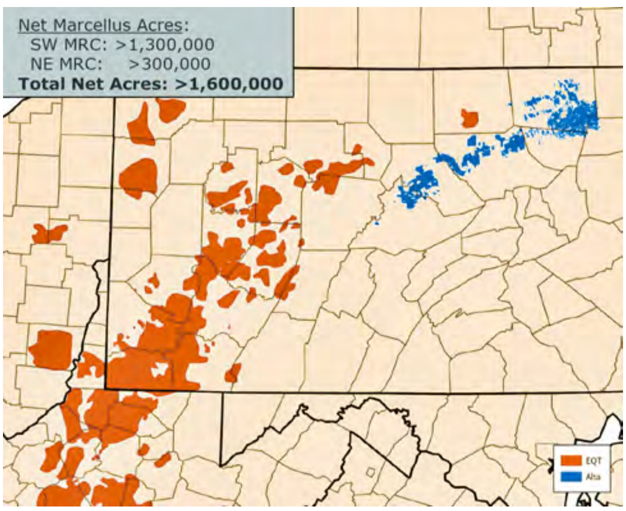
Bank of America NA and **JPMorgan Chase Bank NA** have jointly provided $1 billion of committed financing in connection with the transaction. The company said it also has access to over $1.4 billion of liquidity under our unsecured credit facility.

The transaction is expected to close third-quarter 2021, with an effective date of Jan. 1, 2021, according to the company release.

BofA Securities is financial adviser to EQT on the transaction. **Latham & Watkins LLP** is serving as EQT's counsel. Alta Resources retained **Citi Global Markets Inc.** as its exclusive financial adviser. The company is also receiving legal counsel from **Kirkland & Ellis LLP**.

—*Emily Patsy*

EQT Acquired Marcellus Assets



Source: EQT Corp.

Bonanza Creek, Extraction Merger Creates D-J Basin Behemoth

BONANZA CREEK ENERGY Inc. and **Extraction Oil & Gas Inc.** agreed to combine in an all stock merger on May 10 as the U.S. shale E&P landscape continues to consolidate.

The combined company, to be named **Civitas Resources Inc.**, will be the largest pure-play energy producer in Colorado's Denver-Julesburg (D-J) Basin, with an aggregate enterprise value of approximately $2.6 billion, the Denver-based companies said in a joint statement.

The transaction adds to a growing list of mergers among U.S. shale producers after upstream M&A activity took off beginning in the second half of 2020, including Bonanza Creek's merger with **HighPoint Resources**, which closed on April 1.

"Successful E&P operators will be those who place a priority on disciplined capital deployment, deliver operational and cost excellence, maintain a relentless focus on shareholder value and have governance standards that are aligned with the times," Eric Greager, president and CEO of Bonanza Creek, said in a statement on May 10.

Civitas aims to take the modern-day E&P business model of operational discipline plus a commitment to free cash flow generation and shareholder returns "to the next level" by also becoming Colorado's first net-zero oil and gas producer.

In the release, the companies said that at closing, expected in the third quarter, Civitas will be Colorado's first net-zero oil and gas producer (Scope 1 and Scope 2) through an intensive, continuing focus on reducing operational emissions and a multiyear investment in certified emissions offsets.

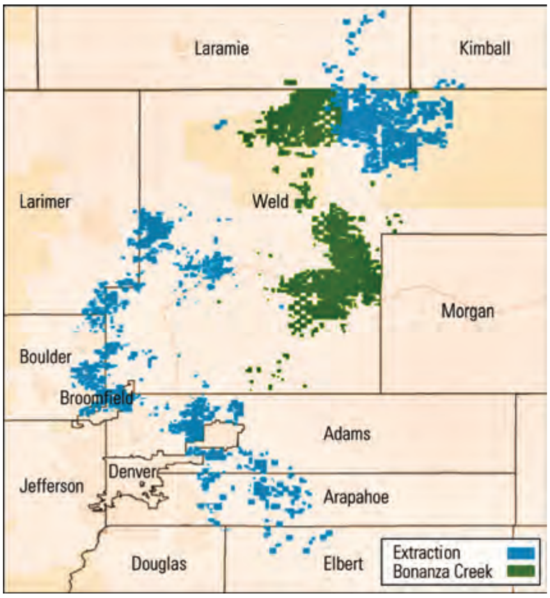
In a statement commenting on the merger, Extraction CEO Tom Tyree said, "We believe the combination of Bonanza Creek and Extraction will create one of the most durable, profitable and progressive producers in the D-J Basin, with premium assets at the front end of the cost curve."

The combined company will operate across approximately 425,000 net acres in Colorado, with a production base of 117,000 boe/d.

At closing, Civitas is projected to be one of most well-capitalized companies in the industry, with a leverage ratio below 0.3x pro forma first-quarter 2021 net debt/2021E EBITDA. Additionally, the companies expect to achieve annual expense and capital savings of approximately $25 million form the combination.

Greager will serve as president and CEO of Civitas, which will continue to be headquartered in Denver. Benjamin Dell, managing partner of **Kimmeridge Energy Management Co. LLC** who was appointed as Extraction's chairman following the company's emergence from bankruptcy in January, will serve as Civitas chairman.

Civitas Resources Combined D-J Basin Assets



Source: Civitas Resources Inc.

Remaining members of Civitas' executive team will include "demonstrated leaders" from Bonanza Creek and Extraction, the companies said, including:

- Matt Owens as executive vice president and COO;
- Marianella Foschi as executive vice president and CFO;
- Skip Marter as executive vice president and general counsel;
- Sandi Garbiso as senior vice president and chief accounting officer; and
- Brian Cain as vice president of external affairs and ESG policy.

Other senior leadership positions will be filled by current executives of Bonanza Creek and Extraction, the company release said.

Funds managed by Kimmeridge Energy own approximately 38% of the outstanding shares of Extraction and have entered into a support agreement to vote in favor of the transaction.

Under the terms of the merger agreement, Extraction shareholders will receive a fixed exchange ratio of 1.1711 shares of Bonanza Creek common shares for each share of Extraction common stock owned on the closing date. Upon closing, Bonanza Creek and Extraction shareholders will each own approximately 50% of Civitas, both on a fully diluted basis.

J.P. Morgan Securities LLC is financial adviser to Bonanza Creek for the transaction, and **Vinson & Elkins LLP** is serving as its legal adviser. Meanwhile, Extraction retained **Petrie Partners Securities LLC** as its financial adviser, and **Kirkland & Ellis LLP** is serving as legal adviser.

—Emily Patsy

Vencer Energy Acquires Hunt Oil's Permian Position

VENCER ENERGY LLC agreed to acquire **Hunt Oil Co.**'s Permian Basin position on April 30 in a splashy debut reportedly worth more than $1 billion.

The assets comprise 44,000 acres across five counties in the Midland Basin, with current daily production of approximately 40,000 boe/d, according to a statement by Vencer, a U.S. upstream company backed by energy trader **Vitol**.

The terms of the transaction—Vencer's first since its launch last year—were not disclosed. Analysts with **Truist Securities Inc.** pin the price tag of the Hunt Oil Midland assets at $1.4 billion, which they said is in line with recent transactions but materially more than deals just a year ago.

"We believe the latest deal suggests a new active formidable player/buyer in the U.S. M&A market going forward; this is just another reason valuations could stay elevated [in addition to strong oil prices]," Neal Dingmann, managing director of energy research at Truist, wrote in a research note.

The Truist analysts still consider a number of companies in the firm's coverage universe as potential acquiries, including **Pioneer Natural Resources Co.**, **Devon Energy Corp.**, **Diamondback Energy Inc.**, **Continental Resources Inc.**, **Marathon Oil Corp.**, **Ovintiv Inc**., **Whiting Petroleum Corp.**, **Northern Oil & Gas Inc.**, **Earthstone Energy Inc.**, **Ring Energy Inc.**, **Penn Virginia Inc.** and **SilverBow Resources Inc**.

Vitol established its Vencer Energy subsidiary in July 2020 led by Don Dotson who previously held executive positions at privately held E&Ps **Sable Bay Energy** and **Plantation Petroleum Co**. The initial target of the Houston-based company was to acquire mature, producing oil and gas assets, with a specific focus on key basins in the Lower 48.

"We are delighted with this acquisition which realizes our vision for Vencer as the owner of quality, mature, producing assets with attractive development opportunities," Vencer Energy president and CEO Dotson said in the company statement. "We look forward to working with our new colleagues."

Vitol is a leader in the energy sector with a presence across the spectrum; from oil through to power, renewables and carbon. It trades 7 MMbbl/d of crude oil and products and, at any time, has 250 ships transporting its cargoes.

In the statement commenting on the transaction, Ben Marshall, head of Americas for Vitol, said, "This is an important day for Vencer as it establishes itself as a significant shale producer in the U.S. Lower 48.

"We expect U.S. oil to be an important part of global energy balances for years to come, and we believe this is an opportune time for investment into an entry platform in the Americas," he noted.

Simmons Energy was financial adviser to Vencer for the transaction and **Latham & Watkins** acted as its legal adviser.

—Emily Patsy and Darren Barbee

Laredo Petroleum Buys Sabalo For $715 Million

LAREDO PETROLEUM INC. announced more than $1 billion worth of transactions on May 9, which the Tulsa, Okla.-based independent said will accelerate its strategic ambitions in the Permian Basin.

In a company release, Laredo said it had signed an agreement to acquire the assets of **Sabalo Energy LLC**, a portfolio company of **EnCap Investments LP**, and a nonoperating partner for approximately $715 million in cash and stock. Additionally, the company announced the partial sale of operated PDP reserves in gas-weighted legacy assets in Reagan and Glasscock counties, Texas, to an affiliate of global investment firm **Sixth Street Partners LLC**.

Laredo expects the $405 million of proceeds from the sale to partially fund its acquisition, which includes roughly 21,000 contiguous net acres directly offsetting Laredo's existing Howard County leasehold in the Midland Basin of West Texas.

"The transformational impact for Laredo of the combined transactions is significant," Laredo president and CEO Jason Pigott said in a May 9 news release. "Upon closing, we will be positioned for sustainable free-cash-flow generation and significant deleveraging, have more than 30,000 highly productive, contiguous net acres in Howard County and a near-term pathway to increasing our oil cut to more than 50% from the current 30%."

The current production on the acquired properties is about 14,500 boe/d (83% oil, three stream) with an estimated next 12-month oil decline of 35%, according to the company release. PDP reserves are approximately 30 MMboe (73% oil, three stream).

The transaction adds roughly 120 operated oil-weighted locations and 150 nonoperated locations to Laredo's drilling inventory, 83% of which, the company noted, are capital-efficient long laterals of 10,000 ft or greater.

In a statement commenting on the sale of Sabalo to Laredo, Doug Swanson, managing partner of EnCap, said, "This transaction complements Laredo's existing asset base and strategy and accelerates the company's transformation to becoming a leading independent operator in the Midland Basin.

"Laredo is well-positioned to maximize value from the Sabalo assets, and we view this transaction as compelling for Laredo shareholders, including EnCap, as part of this transaction," Swanson added in the statement, as the transaction was comprised of $625 million in cash plus approximately 2.5 million shares of Laredo common equity.

The company said both transactions are forecast to close July 1. **Citigroup** and **Houlihan Lokey** provided advisory services on the Sabalo acquisition. Houlihan Lokey also acted as financial adviser on the PDP sale to Sixth Street. **Akin Gump** and **Willkie Farr & Gallagher** served as Laredo's legal advisers. **Jefferies** was exclusive financial adviser to Sabalo, and **Bracewell** served as Sabalo's legal advisor. **White & Case** acted as legal adviser to Sixth Street.

—Emily Patsy

Diamondback Sells Bakken Asset To Oasis Petroleum

DIAMONDBACK ENERGY INC. agreed on May 3 to sell certain Bakken Shale assets it acquired through its roughly $2.2 billion all-stock acquisition of **QEP Resources Inc.** earlier this year.

Diamondback's sale to **Oasis Petroleum Inc.** includes select Williston Basin assets in a cash transaction valued at about $745 million. On May 3, Diamondback also agreed to divest noncore acreage from its Permian Basin position, the company's main focus, for a combined gross purchase price of $87 million.

Diamondback Energy closed out 2020 with the acquisition of publicly traded QEP Resources and private equity-sponsored **Guidon Operating** for a combined $3 billion. In addition to adding a foothold in the Williston Basin, the dual mergers helped Diamondback build out its position in the heart of the Midland Basin.

However, Diamondback had planned since announcing the acquisition of QEP to sell the Williston Basin with potential sale proceeds to be used toward debt reduction. The QEP transaction closed in March.

"We continue to be pleased with the seamless integration of both the Guidon and QEP assets, and we are achieving our synergy targets ahead of schedule and in excess of those highlighted during the acquisition announcement," Diamondback CEO Travis Stice said in a statement in a May 3 company release. "This progress only adds to our 'exploit and return' strategy of spending maintenance capital to hold oil production flat, while using free cash flow to reduce debt and return cash to stockholders."

According to its release, Diamondback signed definitive agreements in the second quarter to divest the Williston Basin assets and noncore Permian Basin assets for total consideration of $832 million. The assets being sold have estimated full-year 2021 net production of approximately 28,000 boe/d.

The Williston divestiture to Oasis includes approximately 95,000 net acres with estimated net production of approximately 25,000 boe/d for full-year 2021. Diamondback said the divestiture represents a complete Williston exit.

Meanwhile, the Permian asset divestitures, with undisclosed buyers, consist of approximately 7,000 net acres of noncore southern Midland Basin acreage in Upton County, Texas, and approximately 1,300 net acres of noncore, nonoperated Delaware Basin assets in New Mexico's Lea County.

Travis Stice

Diamondback expects to close its Permian divestitures in the second quarter and the Williston transaction in the third quarter of 2021.

In a separate release, Oasis said it anticipates closing the Williston transaction with Diamondback in July. According to the company, the purchase price represents approximately $28,000 per boe/d on first-quarter 2021 two-stream volumes.

"This exciting acquisition is a great example of how Oasis is addressing the needs of tomorrow, by taking action in our new industry paradigm, today," Oasis CEO Danny Brown said in statement.

Brown joined Houston-based Oasis in April to fill the CEO role that was left vacant following the retirement of the company's co-founder, Thomas Nusz. He has 23 years of experience in the oil and gas industry having spent his career with Anadarko Petroleum Corp. and one of its predecessors—Kerr-McGee—until Anadarko was acquired by **Occidental Petroleum Corp.** in 2019.

Oasis is one of the top producers in the Williston Basin, primarily targeting the middle Bakken and Three Forks formations. The acquisition of the Williston assets from Diamondback are expected by Oasis to significantly boost free cash flow, resulting in a notable bump to shareholder returns.

In anticipation of the increase in free cash flow per share, Brown said he sees Oasis declaring a 33% increase to the company dividend, raising the quarterly dividend to 50 cents per share with its quarterly declaration after the transaction closes later this year.

"This acquisition materially enhances scale in our core Bakken asset at an attractive valuation, with the purchase price almost entirely based on PDP and very little value attributed to the development of the top-tier inventory or potential synergies," Brown continued in his statement. "When combining the inherently attractive acquisition price with the prudent use of our best-in-class balance sheet this acquisition creates significant accretion for shareholders across all metrics, while maintaining pro forma leverage below target, and well below that of our peers."

Oasis, which completed a financial restructuring last year, plans to finance the Williston transaction through cash on hand, revolver borrowings and a $500 million fully committed underwritten bridge loan.

In connection with the acquisition, Oasis entered into a commitment letter dated May 3 with **J.P. Morgan** and **Wells Fargo** to provide the $500 million bridge facility. Wells Fargo is administrative agent on Oasis's credit facility. **Vinson & Elkins LLP** and **Kirkland & Ellis LLP** are legal advisers on the financing.

J.P. Morgan Securities LLC is strategic and financial adviser to Oasis on the acquisition, and **McDermott Will & Emery** is its legal adviser. **Goldman Sachs & Co. LLC** is exclusive financial adviser to Diamondback for the Williston deal, and **Latham & Watkins LLP** is serving as its legal adviser for the transaction.

For Diamondback's Permian Basin asset sales, **Tudor, Pickering & Holt Co.** is exclusive financial adviser to the company.

—Emily Patsy

TRANSACTION HIGHLIGHTS

COTTON VALLEY

■ **Diversified Gas & Oil Plc** acquired certain Cotton Valley upstream assets primarily in Louisiana from **Indigo Minerals LLC**, marking the addition of a new region to the portfolio of the London Stock Exchange-listed company.

Diversified's portfolio includes low-decline gas producing assets in the Appalachian Basin spread across West Virginia, Kentucky and Tennessee. However, the company hopes to repeat the success of that business model, which its CEO says is proven to generate shareholder returns, in its newly established "regional focus area."

"Our new regional focus area covers a multistate area in a similar size footprint to Appalachia, and meets our expansion criteria in terms of asset quality, infrastructure, market dynamics, opportunity set and supportive regulatory environment," Diversified CEO Rusty Hutson Jr. said in an April 30 company release.

According to the release, Diversified signed a purchase and sale agreement with Indigo to acquire producing gas assets consisting of 780 net operated wells and related facilities within the Cotton Valley and Haynesville producing area of northwest Louisiana and East Texas. The gross purchase price for the acquisition is $135 million.

AUSTRALIA

■ **EOG Resources Inc.** is making its debut in 'the land Down Under' through the acquisition in a giant oil prospect off the northern coast of Australia.

Australia-based **Melbana Energy Ltd.** said in a news release it had entered into an agreement to sell its WA-488-P permit containing the giant Beehive prospect in the Petrel sub-basin to a subsidiary of EOG Resources for $22.5 million. The Petral sub-basin is a shallow-water area of the Timor Sea southwest of Darwin.

EOG, which under the terms of the deal will acquire a 100% interest in the WA-488-P permit, intends to drill an exploration well targeting the Beehive prospect in 2022, according to the Melbana company release.

PERMIAN BASIN

■ **Chevron Corp.** is offering to sell about 73,000 acres (29,540 hectares) of oil and gas properties in New Mexico, according to documents viewed by Reuters, as oil firms accelerate divestitures in a rebounding oil market.

The properties could fetch about $100 million, according to one analyst who reviewed the parcels but declined to be named because he was not authorized to speak on the matter.

Sales in the Permian Basin of West Texas and New Mexico have jumped as shale producers and private-equity firms seize on a sizzling recovery in oil prices to buy companies or secure new drilling prospects.

Chevron set a May 20 deadline for bids on acres holding more than 1,000 producing wells with $1.1 million in combined monthly revenue, according to a sales document. Some of the properties are operated by **ConocoPhillips Co.**, **BXP Operating LLC** and **Providence Energy Services Inc.**, the document showed.

"Chevron has an ongoing and methodical program to evaluate and prioritize its assets," spokeswoman Veronica Flores-Paniagua said, confirming the New Mexico's Lea County offer. She declined to say what the company hopes to get for the assets.

SCOOP

■ **PHX Minerals Inc.** added to its mineral position in Oklahoma with a recent cash-and-stock acquisition in the SCOOP shale play valued at about $11.9 million.

Oklahoma City-based PHX Minerals said in an April 15 release it had agreed to acquire the mineral and royalty interests in southern Oklahoma from certain third parties. The majority of the acquired interests are focused within **Continental Resources Inc.**'s SpringBoard III project area located primarily in Stephens, Carter and Garvin counties, Okla., according to the release.

"This is an exceptional acquisition of mineral assets with excellent geology that fits well within our stated strategy to grow the company on an accretive basis," Chad Stephens, president and CEO of PHX Minerals, said in a statement commenting on the transaction.

The acquisition comprises a total of approximately 2,698 net royalty acres with 20.3 Bcfe of estimated reserves. With current net production of 529 Mcfe/d, the deal includes 103 PDP gross wells, 17 gross wells in progress and an estimated 613 gross undrilled locations.

PHX said it will pay roughly $9.5 million in cash and $2.4 million in PHX common stock in exchange for the assets. The company intends to raise the cash portion of the purchase price through an underwritten public offering of common stock announced concurrently with the acquisition.

PICEANCE BASIN

■ **Peregrine Energy Partners** agreed to acquire producing royalties in Colorado's Piceance Basin as the Denver-based company begins to see A&D activity pick back up.

In an April 8 release, Peregrine said it finalized the royalty acquisition comprised of over 100 natural gas wells under **Caerus Oil & Gas LLC** across Garfield and Mesa counties. The transaction with an undisclosed private seller follows two acquisitions Peregrine made last month in the Appalachian and Permian basins.

Peregrine, which focuses exclusively on producing oil and gas royalties, has been having more conversations with colleagues from the industry as deal activity begins to recover from the past year, according to managing partner C.J. Tibbs.

"With pricing coming back to above pre-pandemic levels," Tibbs continued in a statement, "there are folks in the royalty space now interested in potentially divesting pieces of their portfolios to return some liquidity to their investors and or simplify a bit of their back-office accounting challenges associated with the fractionalized interests."

BAKKEN SHALE

■ **Equinor ASA** on April 27 completed the sale of its entire position in the Bakken Shale, marking the Norwegian company's exit from the U.S. shale play.

Grayson Mill Energy LLC, a Houston-based E&P company backed by **EnCap Investments LP**, agreed in February to acquire Equinor's Bakken interests, along with associated midstream assets, for a total consideration of around $900 million.

The acquisition include all of Equinor's 242,000 net acres in North Dakota and Montana. Production from these assets in fourth-quarter 2020 was 48,000 boe/d (net of royalty interests).

PERMITS

Permitting activity in the U.S. during March was led by the Permian Basin with 382 new permit filings, which made the most amount of new permits issued in Texas. Karnes County, Texas, had 44 new permits for Eagle Ford and Austin Chalk wells, and Panola County, Texas, had 16 new permits for Haynesville Shale wells.

In Colorado, 22 permits were issued for Weld County ventures in the Denver-Julesberg Basin, with the most permits issued to Bayswater Exploration & Production. In the Piceance Basin portion of western Colorado, there were 28 Rio Blanco County wells permitted by Caerus Oil & Gas. The company recently completed five directional Grand Valley Field wells from a pad in neighboring Garfield County that produced from commingled Williams Fork, Ohio Creek and Cameo perforations. TEP Rocky Mountain has also had a successful program in Garfield County. A Trail Ridge Field well was completed in late 2020 producing gas from commingled zones at Williams Fork/Cameo; Cameo; Cozzette/Corcoran; and Corcoran (9,163 ft-9,379 ft).

Most of the new permits in North Dakota were for Three Forks or Bakken wells in Dunn County (21), followed by 17 permits for Mountrail County.

The majority of the new permits for West Virginia-Marcellus Shale drilling were issued to Tug Hill Oil for Marshall County.

Wells Permitted By Operator

Operator	Number of New Permits
Pioneer Natural Resources Co.	70
Anadarko Petroleum Corp.	57
Diamondback E&P LLC	40
EOG Resources Inc.	34
Endeavor Energy Resources	33
Birch Operations Inc.	28
Caerus Oil & Gas	26
CrownQuest Operating	25
COG Operating LLC	22
Bayswater Exploration & Production	20
Marathon Oil Corp.	19
Blackbeard Operating LLC	18

Permitting date range: March 1-March 31, 2021

Data source: Datalink

Wells Permitted By State

State	Number of Permits
Texas	743
Colorado	70
Pennsylvania	63
Oklahoma	54
North Dakota	53
West Virginia	23
Utah	17

Wells Permitted By County

County	Number of Permits
Midland, Texas	76
Loving, Texas	72
Howard, Texas	71
Upton, Texas	49
Karnes, Texas	44
Reeves, Texas	42
Glasscock, Texas	42
Reagan, Texas	35
Martin, Texas	30
Rio Blanco, Colo.	28
Weld, Colo.	22
Dunn, N.D.	21
Mountrail, N.D.	17
Panola, Texas	16
Washington, Pa.	13

Data from Rextag ENERGY DATALINK

RIG COUNT

According to Enverus, rig count increased by three but Baker Hughes data indicate that the rig count dropped by one.

However, the last week of April was the first week in 2021 to show an increase on a year-over-year basis, according to Enverus. The current count is up 7% in the last month and up 11% year-over-year.

At this point in 2020, crude spot prices went from averaging a closing price of $50.54/bbl in February to an average of $16.55/bbl in April, according to the Energy Information Administration.

U.S. crude futures were trading around $62/bbl on April 23, putting the contract on track to rise in April for a fifth straight month.

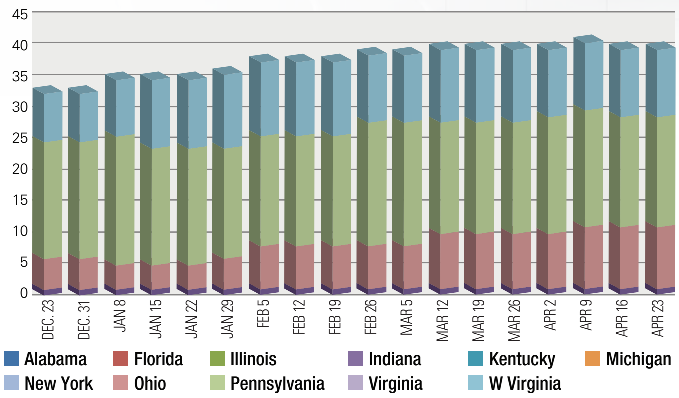
With prices mostly rising since October 2020, some energy firms said they plan to boost spending in 2021 after cutting drilling and completion expenditures during the past two years.

That spending increase, however, remains small as most firms continue to focus on boosting cash flow, reducing debt and increasing shareholder returns rather than adding output.

Oilfield activity in North America is expected to be at levels to maintain existing production, said top oilfield service provider Schlumberger NV CEO Olivier Le Peuch.

Eastern U.S. Rig Count

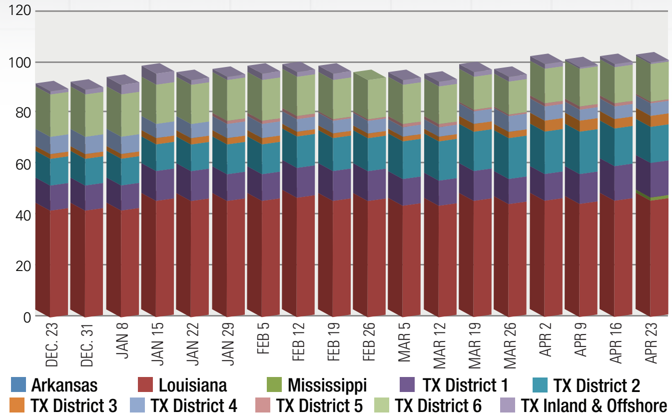
Dec. 23, 2020-Apr. 23, 2021



Source: Baker Hughes Co.

Gulf Coast Rig Count

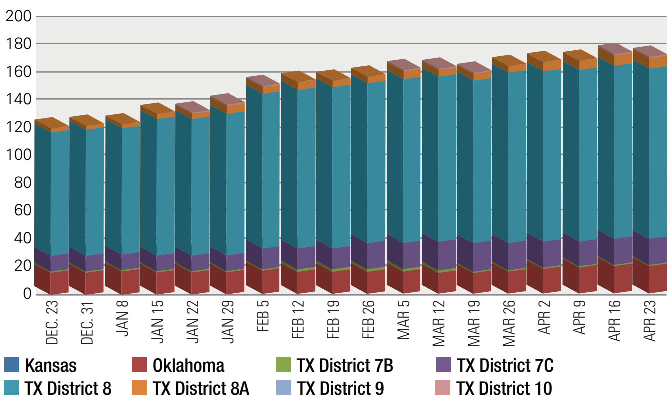
Dec. 23, 2020-Apr. 23, 2021



Source: Baker Hughes Co.

Midcontinent & Permian Basin Rig Count

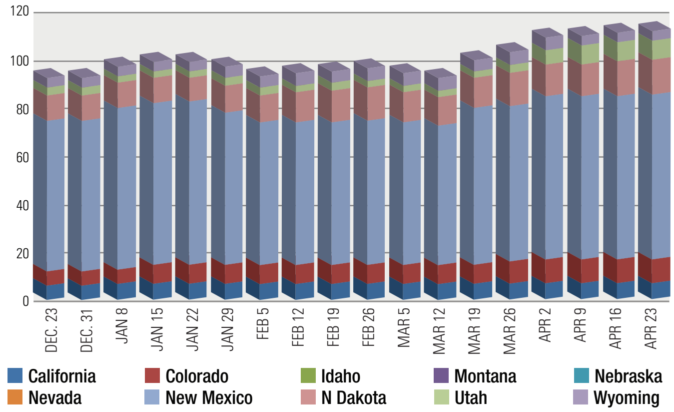
Dec. 23, 2020-Apr. 23, 2021



Source: Baker Hughes Co.

Western U.S. Rig Count

Dec. 23, 2020-Apr. 23, 2021



Source: Baker Hughes Co.

Data from Rextag ENERGY DATALINK

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FOCUS ON
Eagle Ford

According to EOG Resources Inc., the company's newly discovered Dorado gas play in South Texas could compete with oil assets for capital funding.

EOG began exploring what became the Dorado play, located in Webb County, Texas, in January 2019. Since then, the company has completed 17 wells and determined that Dorado is a cheap, well-positioned dry gas asset. EOG estimates low costs for developing the Austin Chalk (39 cents per Mcf) and Eagle Ford (41 cents per Mcf).

The company said that the Dorado play adds approximately 1,250 net well locations, and the company now has about 6,000 wells that produce 30% returns at either \$30/bbl oil or \$2.50/Mcf gas.

EOG recently completed two Eagle Ford Shale wells and one Austin Chalk well at a single drillpad in Webb County. All three producers were drilled to total depths ranging from about 18,000-19,100 ft. The #500H BFMT West flowed 16.416 MMcf of gas and 1,416 bbl of water per day from Eagle Ford perforations at 10,696-19,079 ft. The #501H BFMT West produced 15.144 MMcf of gas and 624 bbl of water per day from Austin Chalk at 10,257-18,025 ft. The #503H BFMT West flowed 16.44 MMcf of gas and 1,296 bbl of water daily from Eagle Ford at 10,639-18,832 ft.

Top 10 Eagle Ford Operators By Production

Operator	MMboe
EOG Resources Inc.	844.15
Chesapeake Operating Inc.	594.93
Burlington Resources Oil & Gas	576.87
Marathon Oil Corp.	466.36
Devon Energy Corp.	417.40
Lewis Petro Properties Inc.	296.62
Pioneer Natural Resources Co.	261.81
Anadarko Petroleum Corp.	248.99
SM Energy. Co.	246.26
Rosetta Resources Operating	190.30

Top 10 Eagle Ford Producing Counties

County	Production (MMboe)
Karnes	1,185.17
Webb	1,036.23
DeWitt	994.48
La Salle	866.11
Dimmit	842.16
McMullen	436.40
Gonzales	411.61
Live Oak	251.23
Atascosa	203.16
Lavaca	68.13

Eagle Ford Cumulative Production - Top Producing Wells

Operator	Well	Location	Total barrels of oil equivalent	Comp. Date
EOG Resources Inc.	3H Korth	Karnes County, Texas	1.726 MMboe	Dec. 2013
Devon Energy. Corp.	3H Wagner B	DeWitt County, Texas	1.706 MMboe	May 2013
Devon Energy Corp.	2H Wagner A	DeWitt County, Texas	1.688 MMboe	May 2013
SM Energy. Co.	A369H Galvan Ranch	Webb County, Texas	1.588 MMboe	July 2013
Devon Energy. Corp.	1H Immenhauser A	DeWitt County, Texas	1.552 MMboe	Feb. 2011
Devon Energy Corp.	2H Hamilton A	DeWitt County, Texas	1.526 MMboe	May 2013
Fasken Oil & Ranch	2H Loma Blanca	Webb County, Texas	1.525 MMboe	Aug. 2012
Lewis Petroleum Properties	27H Fasken State 1612	Webb County, Texas	1.512 MMboe	Mar. 2015
EPG Resources Inc.	1H Lynch Unit	Karnes County, Texas	1.503 MMboe	Mar. 2014
EOG Resources Inc.	11H Korth Unit	Karnes County, Texas	1.489 MMboe	Sept. 2016

Data from Rextag ENERGY DATALINK

INTERNATIONAL HIGHLIGHTS

India's current COVID-19 outbreak is creating unimaginable human suffering, with the country reporting more than 350,000 new cases per day. Lockdowns and shutdowns are more strict and widespread, which is reducing energy consumption.

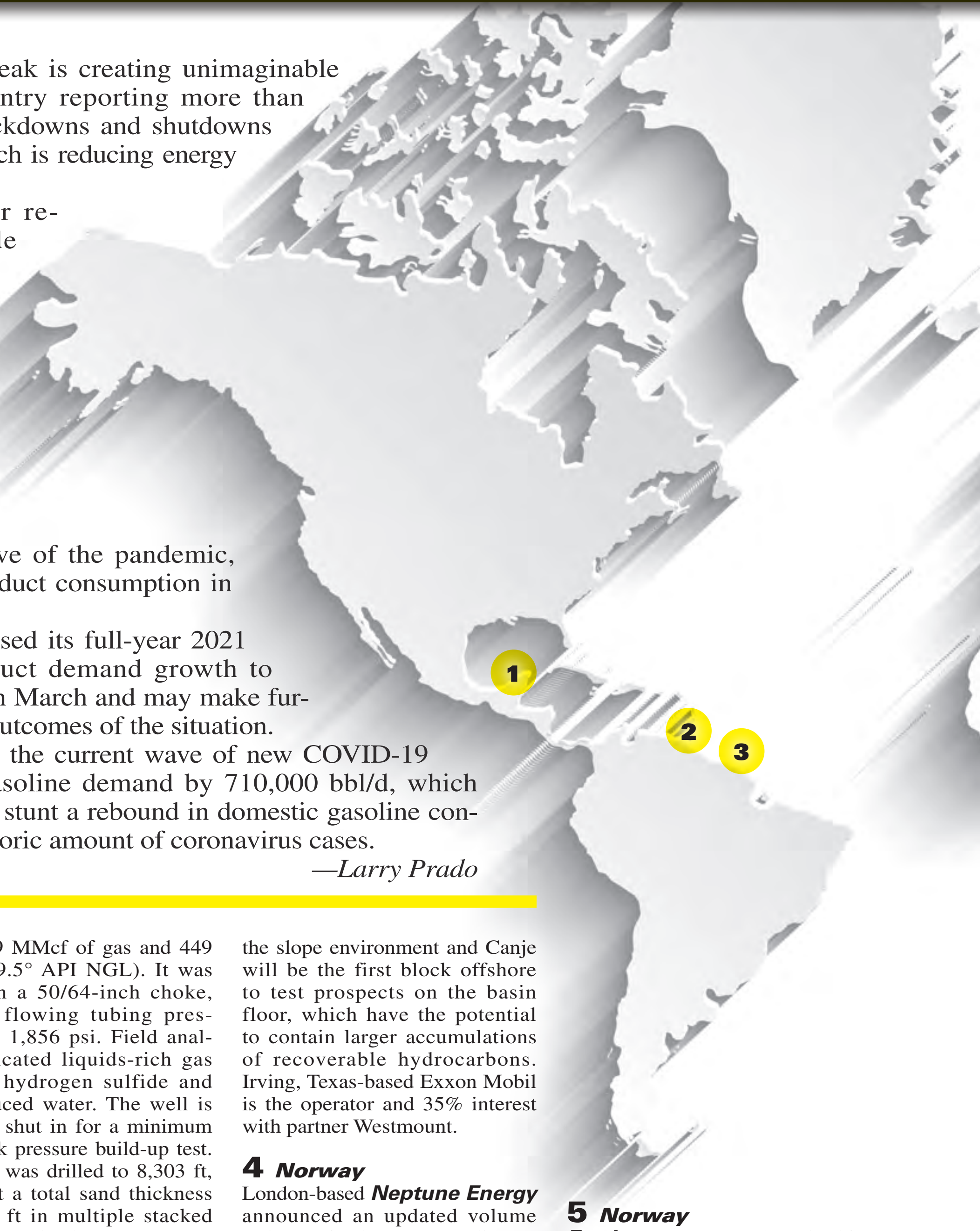
Indian oil refiners have so far refrained from cutting their crude capacity despite the increase in coronavirus cases. However, it may now be forced to scale back production.

As of third-quarter 2020, India's refining capacity was about 250 million metric tons, and it is the second-largest refiner in Asia. In 2020 alone, oil demand in India declined 470,000 bbl/d during the first wave of the pandemic, which is the lowest level of oil-product consumption in nearly 20 years.

S&P Global Platts Analytics revised its full-year 2021 outlook for India's total oil product demand growth to 400,000 bbl/d from 440,000 bbl/d in March and may make further adjustments depending on the outcomes of the situation.

According to S&P Global Platts, the current wave of new COVID-19 cases will reduce the country's gasoline demand by 710,000 bbl/d, which represents an 11.5% decline. It will stunt a rebound in domestic gasoline consumption before the current and historic amount of coronavirus cases.

—Larry Prado



1 *Mexico*

Pemex has received approval to drill in the offshore Tabasco Amoca Yaxche Block, in offshore Tabasco state. The planned well is #1EXP-Tenantli in the Amoca-Yaxche-06 license area in the Cuenca Salina Basin. This is the third exploration well that has been approved for the site including #1EXP-Itta in the same block and nearby #1EXP-Ichilanin the adjacent Amoca-Yaxche-04 Block. The combined prospective resource for the blocks is 185 MMbbl of light crude. The #1EXP-Tenantli has a planned depth of 3,400 m, and water depth is between 20 m and 50 m. Pemex is based in Mexico City.

2 *Trinidad*

Touchstone Energy announced results from flowback testing at #1-Cascadura Deep. According to the company, the results confirm a liquids-rich gas discovery on the Ortoire Block, onshore Trinidad and Tobago. The average flowback rate during the extended 24-hour test period was approximately 4,262 bbl of oil equivalent per day (22.9 MMcf of gas and 449 bbl of 59.5° API NGL). It was tested on a 50/64-inch choke, and the flowing tubing pressure was 1,856 psi. Field analysis indicated liquids-rich gas with no hydrogen sulfide and no produced water. The well is currently shut in for a minimum four-week pressure build-up test. The well was drilled to 8,303 ft, and it hit a total sand thickness of 2,100 ft in multiple stacked thrust sheets in the Herrera section. Calgary-based Touchstone has an 80% operating working interest in the well with partner ***Heritage Petroleum***, 20%).

3 *Guyana*

Exxon Mobil Corp. is underway at #1-Bulletwood in the Canje Block, offshore Guyana. The prospect at #1-Bulletwood is a 500 MMbbl oil prospect and is similar to the Liza prospect. It has a confined channel complex of Late Cretaceous, Campanian, age. Up to four wells are planned in the block. According to partner ***Westmount Energy***, most of the offshore Guyana discoveries have been made in the slope environment and Canje will be the first block offshore to test prospects on the basin floor, which have the potential to contain larger accumulations of recoverable hydrocarbons. Irving, Texas-based Exxon Mobil is the operator and 35% interest with partner Westmount.

4 *Norway*

London-based ***Neptune Energy*** announced an updated volume estimate for its Dugong discovery. Based on the results from appraisal well #34/4-16 S, the recoverable resources is 40-108 MMboe. The primary appraisal target for #34/4-16 S was to delineate the discovery made in Rannoch in wells #34/4-15 S and #34/4-15 A. A drill stem test on the well is planned at a later stage. The discovery is close to the existing production facilities of the Snorre and Statfjord fields. The reservoir lies at a depth of 3,250-3,500 m, and area water depth is 330 m. The Dugong license partners are Neptune Energy (operator and 45%), ***Petrolia*** (20%), ***Idemitsu*** (20%) and ***Concedo*** (15%).

5 *Norway*

Equinor announced a significant discovery on the Norwegian continental shelf. Preliminary estimates place the size of the discovery between 75-120 MMboe of recoverable oil equivalent. Exploration wells #31/2-22 S and #31/2-22 A in the Blasto prospect are in production licenses 090, 090 I and 090 E between Fram and Troll fields. The #31/2-22 S encountered a total oil column of about 30 m in the upper part of Sognefjord and an oil column of about 50 m in the lower part of Sognefjord. Exploration well #31/2-22 A hit high-quality sandstone in Sognefjord, but the reservoir is filled with water, and the well

is classified as dry. The #31/2-22 S was drilled to 2,379 m and #31/2-22 A was drilled to 2,207 m. Water depth in the area is 349 m. The wells have been permanently plugged and abandoned. These are the first two exploration wells in production license 090 I. Stavanger-based Equinor is the operator, and partners are ***Var Energi***, ***Idemitsu*** and ***Neptune Energy***.

6 *Angola*

Eni reported a new light oil discovery in Block 15/06, in offshore Angola. The well has been drilled on the Cuica exploration prospect located inside the Cabaca Development Area. The #1-Cuica NFW was drilled as a deviated well to a total depth of 4,100 m. The venture encountered an 80-m oil column with 38° API oil in Miocene Sandstone. Eni plans to drill an updip sidetrack, and the current estimated production capacity is approximately 10,000 bbl of oil per day. The find is estimated at 200-250 MMbbl of oil in place. This is the second oil discovery within the existing Cabaca Development Area where water depth is about 500 m deep. Eni is the operator of the block with 37% interest and partners include ***Sonangol*** (36%) and ***SSI*** (27%).

7 *Namibia*

ReconAfrica plans to drill an exploratory well in the Kavango Basin in the Kalahari Desert portion in Namibia. The well, #6-2, will be the first of a three-well drilling program intended to confirm an active, Permian-aged petroleum system in the basin. Core data and logging operations will be focused on conventional oil and gas reservoirs, which flow naturally under their own pressure. The venture will be in exploration license PEL 73, which covers the entire Kavango sedimentary basin (approximately 25,341 sq km). ReconAfrica has a 25-year production license. The Kavango Basin has both large-scale conventional and non-conventional play types. The Vancouver, British Colombia-based company acquired a high-resolution geomagnetic survey of the license area including reprocessing and reinterpretation of all existing geological and geophysical data. ReconAfrica holds a 100% interest in PEL 73 and in a nearby petroleum license, PEL 001/2020 in northwest Botswana, which comprises an area of approximately 9,921 sq km.

8 *Malaysia*

PTTEP completed an exploration well #1-Sirung in Block SK405B, off the coast of Sarawak, Malaysia. The well was drilled to 2,538 m, and it encountered an oil and gas column of more than 100 m in a clastic reservoirs. An appraisal well is scheduled to assess the upside resources. PTTEP also plans to explore nearby prospects in this production sharing contract including license areas SK410B; SK314A; SK438; SK417; PM407; and PM415. Block SK 405B. PTTEP, based in Bangkok, is the operator, and partners include ***MOECO Oil*** and ***Petronas***.

9 *Australia*

Buru Energy plans to begin a three-well exploration drilling program and a seismic survey in the Canning Basin in Western Australia. The program will be drilled in the Ungani oil field and two exploration wells in Block 391 are targeting two large, conventional oil prospects. Exploration well #1-Kurrajong in will be the first well in the drilling program and it has a planned depth of 2,500 m. Exploration well #1-Rafael has a planned depth of 3,800 m and it will be followed by development well #8-Ungani and exploration well #1-Rafael. About 1,200 km of seismic surveying is planned —the Celestine 2-D survey will be conducted across blocks EP 457 and EP 458 area to the southeast of Block 391. Buru Energy's headquarters are in Perth.

10 *Australia*

Beach Energy reported results from a gas discovery at #1-Artisian in the offshore Victoria portion of Australia's Otway Basin. The venture is in license VIC/P43. The well was drilled to 2,205 m and hit a gross gas column of 68 m in Upper Warre, including 62.9 m of net gas pay, with a gas-water contact intersected at 1,990 m. A gross gas column of 20.9 m was also intersected in the secondary target of Flaxman at 1,902.8 m, with net gas pay of 4.6 m. The well is being cased and suspended as a future producer. Adelaide-based Beach is the operator and holds 60% interest, and ***O.G. Energy*** holds 40% interest.

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EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
EnCap Investments LP	N/A	Houston	$1,200	Closed **EnCap Energy Transition Fund I LP** with proceeds used to invest in companies that advance the nation's transition to a lower-carbon future with a focus on creating wind, solar and energy storage enterprises. Committed capital from a diverse set of domestic and international investors including corporate and government-sponsored pension funds, sovereign wealth funds, family offices, endowments, foundations and high-net-worth individuals.
Orion Energy Partners	N/A	New York	$1,079	Announced final close of Orion Energy Credit Opportunities Fund III oversubscribed, exceeding the initial target of $900 million from investors across six continents. Proceeds will be used to provide flexible direct lending into private and public companies seeking to scale both traditional and new infrastructure solutions in energy transition and environmental innovation. **Asante Capital** was exclusive global placement agent, and **Latham & Watkins LLP** provided legal counsel.
Crusoe Energy Systems Inc.	N/A	Denver	$128	Closed Series B equity financing led by **Valor Equity Partners** with participation from **Lowercarbon Capital**, **DRW Venture Capital**, **Founders Fund**, **Bain Capital Ventures**, **Coinbase Ventures**, **Polychain Capital**, **KCK Group**, **Upper90**, **Winklevoss Capi-tal**, **Exor**, **Zigg Capital** and JB Straubel, the co-founder and former CTO of **Tesla** and founder and CEO of **Redwood Materials**. Proceeds will be used to pursues its mission to eliminate the routine flaring of natural gas and associated methane emissions while delivering low-cost computing infrastructure.
DMC Global Inc.	NASDAQ: BOOM	Broomfield, Colo.	$123.5	Closed underwritten public offering of 2.5 million shares of common stock and fully exercised overallotment option of an additional 375,000 shares. Proceeds will be used for general corporate purposes, which may include acquisitions. **KeyBanc Capital Markets** was sole book-running manager. **Stephens Inc.**, **Stifel**, **Tudor, Pickering, Holt & Co.** and **Roth Capital Partners** were co-managers.
Energy Transition Ventures LLC	N/A	Houston	$75	Launched the first venture fund in Texas exclusively dedicated to investing in energy transition technologies with anchor investment from two operating companies from the **GS Group** of Korea. Proceeds will be used to invest in early stage startups in North America focusing on companies driving or benefitting from the energy transition off fossil fuels, across categories including distributed energy, electrification, mobility and resource efficiency.
PHX Minerals Inc.	NYSE: PHX	Oklahoma City	$11	Priced an underwritten public offering of 5.5 million shares of its common stock, upsized from its initial offering of 5 millions shares, at a price to the public of $2 each. Underwriters granted a 30-day option to purchase up to 825,000 additional shares of stock at the same price per share. Proceeds will be used to fund a pending acquisition, subject to customary closing conditions, and for general corporate purposes. **Stifel** is book-running manager. **Northland Capital Markets** and **Seaport Global Securities** are co-managers.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Tullow Oil Plc	LSE: TLW	London	$1,800	Priced offering of 10.25% senior secured notes due 2026 at par. Proceeds will be used to repay all amounts outstanding under, and cancel all commitments made available pursuant to, the existing RBL facility, redeem in full senior notes due 2022, at maturity repay in full and cancel convertible bonds due 2021 and pay fees and expenses incurred in connection with the transactions, will be the general senior secured obligations and guaranteed by certain of its subsidiaries.
Kosmos Energy Ltd.	NYSE: KOS	Dallas	$1,250	Completed the amendment and extension of its RBL facility with the election to lower the overall facility size from $1.5 billion to reduce reliance on the RBL facility and commitment costs following the successful completion of the company's senior notes issuance in February. The amendment includes a two-year tenor extension, with the RBL facility's final maturity now in March 2027, and a mechanism for two ESG key performance indicators to impact the margin based upon delivering emissions targets and achieving certain third-party ESG ratings. The RBL facility is secured against the company's production assets in Ghana and Equatorial Guinea.
EQT Corp.	NYSE: EQT	Pittsburgh	$1,000	Priced a private offering of $500 million in aggregate principal amount of its 3.125% senior notes due 2026 and $500 million in aggregate principal amount of its 3.625% senior notes due 2031, issued at par. Proceeds will be used to fund the $1 billion cash consideration relating to its previously announced acquisition of **Alta Resources Development LLC**'s upstream and midstream subsidiaries.

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
CrownRock LP	N/A	Midland, Texas	$400	Priced a private offering of 5% senior unsecured notes due 2029. CrownRock, an oil and gas producing joint venture of **CrownQuest Operating** and **Lime Rock Partners**, intends to distribute the proceeds to **CrownRock Holdings LP**, its sole limited partner and sole owner of CrownRock's general partner, to fund its obligations under a partial and conditional redemption of CrownRock Holdings' Series A preferred units.
Penn Virginia Corp.	NASDAQ: PVAC	Houston	$350	Announced the deferral of a proposed private offering of its senior unsecured notes offering due 2028 after receiving indication from potential bond investors that the proposed new financing didn't materially differentiate from its financing in place currently, according to CEO Darrin Henke. Proceeds were intended to fully repay and terminate its second lien term loan, to repay a portion of outstanding borrowings under its reserve-based revolving credit facility and to pay related fees and expenses.
Southern Natural Gas Co. LLC	N/A	Houston	$300	Closed offering of 0.625% senior notes due 2023. Company is a 50:50 joint venture between **Kinder Morgan Inc**. and **The Southern Co. Citigroup**, **Barclays** and **Truist Securities** were active joint book-running managers. **Bracewell LLP** provided legal counsel.
Contango Oil & Gas Co.	NYSE American: MCF	Fort Worth, Texas	$250	Announced amendment and expansion of its senior credit facility led by **JPMorgan Chase Bank** under which the borrowing base has been increased by $130 million from $120 million.
Genesis Energy LP	NYSE: GEL	Houston	$250	Priced public offering of 8% senior unsecured notes due 2027, upsized from the previously announced $200 million and issued as additional notes, and are expected to rank equally with, and be treated as a single class of notes under the indenture pursuant to its currently outstanding 8% senior unsecured notes due 2027 on Dec. 17, 2020. Price to investors will be 103.75% of the principal amount of the notes, plus accrued interest from Dec. 17, 2020. Proceeds will be used for general partnership purposes, including repaying a portion of the revolving borrowings outstanding under the company's credit facility. **BofA Securities Inc.**, **Wells Fargo Securities LLC**, **SMBC Nikko Securities America Inc.**, **BNP Paribas Securities Corp.**, **Capital One Securities Inc.**, **Citigroup Global Markets Inc.**, **Fifth Third Securities Inc.**, **RBC Capital Markets LLC**, **Regions Securities LLC** and **Scotia Capital (USA) Inc**. are joint book-running managers. **Comerica Securities Inc.** is co-manager.
Centennial Resource Development Inc.	NASDAQ: CDEV	Denver	$170	Issued 3.25% convertible senior notes due 2028. Proceeds were used to redeem at par the $127.1 million 8% second lien senior secured notes due 2025, to repay borrowings under the revolving credit facility and to fund the cost of entering into a capped call transaction to minimize potential future dilution.
GeoPark Ltd.	NYSE: GPRK	Bogota, Colombia	$150	Priced offering of 5.5% senior notes due 2027 at 101.875% with a yield to maturity of 5.117%. Issued as an additional issuance of previously issued $350 million aggregate principal amount of its 5.5% notes due 2027. Notes will be fully and unconditionally guaranteed jointly and severally by **GeoPark Chile SpA** and **GeoPark Colombia SLU**. Proceeds will be used to purchase a portion of its outstanding 6.5% senior notes due 2024 through a concurrent tender offer and consent solicitation and for general corporate purposes.
Babcock & Wilcox	NYSE: BW	Akron, Ohio	$50	Commenced an underwritten registered public offering of shares of its Series A cumulative perpetual preferred stock, par value $0.01 per share with a liquidation preference of $25 per share. Underwriters expected to be granted a 30-day option to purchase additional shares of the preferred stock. Proceeds will be used for general corporate purposes, including clean energy growth initiatives, potential future acquisitions and reduction of net leverage. **B. Riley Securities Inc.** is lead book-running manager. **D.A. Davidson & Co.**, **Janney Montgomery Scott LLC**, **Ladenburg Thalmann & Co. Inc.**, **National Securities Corp.** and **William Blair & Co.** are joint book-running managers. **Kingswood Capital Markets**, division of **Benchmark Investments Inc.**, is lead manager. **Aegis Capital Corp.**, **Boenning & Scattergood Inc.**, **Huntington Securities Inc.**, **Incapital LLC** and **Wedbush Securities Inc.** are acting co-managers.
Crusoe Energy Systems Inc.	N/A	Denver	$40	Secured a non-dilutive project financing facility from **Upper90**. Proceeds will be used to pursue its mission to eliminate the routine flaring of natural gas and associated methane emissions while delivering low-cost computing infrastructure.
Natural Gas Services Group Inc.	NYSE: NGS	Midland, Texas	$20	Closed a new senior secured revolving credit facility with **Texas Capital Bank NA** as lender and administrative agent. Facility will be used to meet its working capital needs and pursue a wide variety of strategic, value-creating initiatives. **Enerecap Partners** was financial adviser, and **Jones & Keller LLP** provided legal counsel.

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You should know the steps we're taking to safeguard health in our venues as we prep relevant programs to help get our industry moving. From increased sanitation and social distancing to touchless registration and catering, safety for speakers, attendees and exhibitors remains foremost in our minds.

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Shreveport Convention Center

Sept. 28-29, 2021
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Fairmont Hotel – Dallas

IN PERSON
A&D STRATEGIES AND OPPORTUNITIES CONFERENCE

IN PERSON
energy capital CONFERENCE

June 2, 2021
Houston, Texas
Omni, Houston

Nov. 3-4, 2021
Midland, Texas
Midland County Horseshoe Arena

IN PERSON
EXECUTIVE OIL CONFERENCE & EXHIBITION

CO-LOCATED & IN PERSON
CONFERENCE & EXHIBITION DUG PERMIAN BASIN
CONFERENCE & EXHIBITION DUG EAGLE FORD
INCORPORATING MIDSTREAM TEXAS

July 12-14, 2021
Fort Worth, Texas
Fort Worth Convention Center

Nov. 29, 2021
Networking Reception
Houston, Texas
Westin Memorial City

VIRTUAL CONFERENCE
25 INFLUENTIAL Women IN ENERGY

VIRTUAL CONFERENCE
DUG BAKKEN AND ROCKIES

Sept. 8, 2021

Dec. 6-8, 2021
Pittsburgh, Pennsylvania
David L. Lawrence Convention Center

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Minerals Forum *with A&D Conference* **September 28, 2021**

Digitalization in Energy *Virtual Conference* **October 6, 2021**

Offshore Executive *Virtual Conference* **October 20, 2021**

Water Forum *with Executive Oil Conference* **November 3, 2021**

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LOVE THOSE PROCEEDS

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Boy howdy! It's investment time for E&Ps. The boom is on, but it is not a boom in drilling rigs or crazy investments. The only land grab that makes sense now is for snapping up contiguous acreage. This boom is about delivering free cash flow (FCF).

During their first-quarter conference calls, E&P companies showed they can deliver FCF and use it wisely—whether to pay down debt, buy back shares or distribute it. They are finally transferring wealth from their coffers to investors' bank accounts, a welcome and necessary outcome of the strategy that is capital discipline.

During investor presentations, the lead-off slides in the investor-targeted slide decks were all about money—how to make it and better spend it—and not about those boring old operational details such as acreage position, wells drilled, EURs and frac stages or water. No. Although important, those details came later in the presentations.

Higher commodity prices in the quarter provided a big boost, even as the petroleum engineers were tasked with holding production to a conservative 5% to 10% growth rate and absent acquisitions. In many cases, even with acquisitions made, buyers vowed to hold overall production nearly flat and reduce the pro forma number of rigs working.

Thanks to prudently reduced capex and more cash coming in the door from the commodity price recovery, the E&P industry is reporting more FCF. We hope, and we expect, that generalist investors sit up and notice, awakening like Rip Van Winkle from a long slumber.

In the first quarter, ConocoPhillips Co. delivered $900 million of FCF. Pioneer Natural Resources Co. reported $369 million of FCF, with an estimate of delivering an impressive $2.7 billion for the entire year. Diamondback Energy Inc. delivered $331 million in the quarter. Devon Energy Corp.: $399 million. EQT Corp.: $259 million. PDC Energy Inc.: $175 million. Magnolia Oil & Gas Corp.: $101 million

Marathon Oil Corp. hiked its dividend by 30% and is targeting $500 million of additional gross debt reduction in 2021, bringing the total to $1 billion, said Morgan Stanley. Devon Energy boosted its fixed-plus-variable dividend of 34 cents per share by 13% over fourth-quarter 2020 and paid down a boatload of debt.

And so on and on. There should be more to come.

PDC Energy, for one, said, "Assuming $55 per bbl WTI, $2.50 per Mcf Nymex natural gas and $15 NGL realizations, PDC now expects to generate more than $600 million of FCF in each of the next three years. The projected cumulative FCF of $1.8 billion to $2 billion equates to more than 50% of PDC Energy's current market cap and more than 40% of the current enterprise value.

"Under the same price assumptions, PDC Energy's reinvestment rate equates to less than 50% of its adjusted cash flows from operations in the development of crude oil and natural gas."

PDC Energy said it plans to pay down at least $850 million of total debt and return more than $650 million of capital to shareholders through its stock repurchase efforts and future dividend program.

Many companies are aiming for debt of only 1.0x or 1.5x by next year. We love the use of proceeds from these cash flow volumes. Magnolia said it expects to pay its first dividend in the third quarter and semi-annually thereafter. Meanwhile, it continues a slow but steady repurchase of shares every quarter.

EOG Resources Inc. delivered a $600 million dividend surprise of $1 per share, which brings its total dividend payout to shareholders to $2.65 a share by year-end (for a 3.4% yield). The sum of this year's regular plus special dividend totals $1.5 billion of cash returns, according to a report from Morgan Stanley.

Cimarex Energy Co. ($231 million in FCF) continued to reduce debt, all while it paid a dividend of 27 cents per share (it has paid dividends ever since 2006).

Many, many years ago in this column, we said the industry's thinking appeared to be changing from solely producing oil and gas in ever-greater quantities, to making money. In practice, the commitment to that has waxed and waned through the years.

For the rest of this year, E&P companies face rising labor, trucking, diesel fuel and steel costs, not to mention well servicing costs creeping back. "We continue to see attractive upside across much of our coverage, which we estimate intrinsically reflects average oil prices about 25% below the strip currently, despite offering FCF yields greater than 3x the broader market," said Morgan Stanley's Devin McDermott in a report.

Other analysts' comments were similarly upbeat. Stephen Inc.'s Jim Wicklund said in his weekly note: "Most E&P companies seem to beat expectations, and there is little question that budget discipline will hold. If you can only spend 70% of cash flow and oil prices go up, spending at some level is probable to be positively impacted. But don't expect a wholesale rush to spending. ROIC [return on invested capital] and FCF yield trump production growth. Take that to the bank."

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