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JUNE 2020

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ABOUT THE COVER: With associated gas production dropping as fast as the oil rig count in the Permian and elsewhere, Marcellus Shale players hope supply pause results in higher prices for all. Photo by Steve Toon.

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Oil CEOs Pen Open Letter Pushing for Climate Change Action
The letter addresses concerns that the COVID-19 crisis may push oil and gas companies and governments around the world to delay action on climate change.

Opinion: Oil Industry Needs Mindset Makeover to Weather Skills Storm
The oil industry needs to emerge from this crisis having changed forever—not solely driven by cost but by a commitment to values way beyond a corporate statement, writes James McCallum, chairman of Xergy Group.

Looking for Economic Intervals in the Permian Basin?
Experts at RS Energy Group say electrofacies could prove beneficial for oil companies considering vertically unbounded wells in the Permian Basin.

Coronavirus Will Create New Opportunities in the Midstream Sector
East Daley analyst: One clear lesson is that energy cycles are a force for creation as well as destruction.

Lending a Helping Hand to Oilfield Workers
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US Energy Department Continues Efforts to Help Oil Companies
Companies of all sizes have been coping with lower oil prices caused by a supply-demand imbalance fueled by the global COVID-19 pandemic.

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Shutting In Shale Oil, Gas Wells? Review Lease Provisions or Risk Loss

If the producer does not comply with terms needed to maintain an oil or gas lease, the lease could be terminated, an attorney says.

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Will Debt-Laden MLPs be the Next Oil, Gas Takeover Targets?

Private-equity firms are on the prowl for valuable assets at a discount, investment executive says.

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Parsley CEO Matt Gallagher Talks US Shale, Tech, ESG
Fresh off the end to proration discussions in Texas, CEO Matt Gallagher shares how Parsley Energy is responding to demand loss plus the Permian shale producer's focus on technology and ESG.

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Videos

KPMG's Regina Mayor Says 'It's Grim' But Shale's Not Dead
KPMG's Regina Mayor gives a look at how U.S. shale producers will respond to demand loss and who is getting hit the hardest in the energy industry amid the current pandemic.

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Oilfield Service Companies Turn to International Market for Survival
As oilfield service companies adjust operations in response to the COVID-19 pandemic, many are planning to invest internationally rather than U.S. onshore, says energy investment banker Jim Wicklund.

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THE FORWARD MONTHS

STEVE TOON,
EDITOR-IN-CHIEF

The specter of minus-$100 oil is behind us. Admit it, you felt a touch of morbid curiosity to see if the price would plummet to new record depths, just to say you were there when it happened and only if it were as short-lived as in April. As the June prompt month contract for WTI approached in May and Cushing storage was anticipated to reach tank tops simultaneously, a harder repeat of the April sell-by date—when WTI plunged ever-so-briefly to minus $37—was feared.

It didn't happen. In fact, on that day, WTI settled at $32/bbl, a much sunnier day than the predicted storm. In January when oil was comfortably above $60, $30 would have sounded atrocious. Now, after WTI languished in the teens and low $20s for the better part of a month, $30 is a welcome reprieve. At the minimum, it signals price stability. At best, it represents a mile marker on a steady if slow upward trend.

The April historic sell-off will have to stand alone as that remember-where-you-were-then moment, a once-in-a-lifetime anomaly, let's hope. Mizuho Securities analyst Paul Sankey, who postulated the possibility for a worse and deeper sell-off in May, said the April negative-price event was a result of "panic and blind algorithms." Fortunately, the financial results were suffered mostly by Chinese retail traders, Sankey noted, to the tune of $1 billion lost. On the flip side, it was a good day on the arb for traders with physical storage.

Preceding the June contract date May 19, U.S. inventory levels did indeed ride "straight up and to the tops of tanks and then rolled off the final limit," he said, "bang on schedule, especially at Cushing, which drew inventory, hugely significant on the pricing of WTI."

Cushing drew. No one expected that. Some 10 MMbbl left the Oklahoma tank farm in the two weeks prior to the contract date. Some speculate that oil might have gone to the Strategic Petroleum Reserve or to floating storage in the Gulf. But it left Cushing, and WTI survived.

Indeed, the month of May might be the turning point. Since the global coronavirus pandemic undercut demand by tens of millions of barrels per day and the ill-timed market share spat between Saudi Arabia and Russia pushed unneeded barrels into a flooded market in March, prices have stabilized—finally.

U.S. producers certainly did their part. It's been said the American shale industry is the world's new swing producer because it can react to market conditions quickly, and it did for this test. When the bottom fell out of prices in March, local E&Ps almost instantly slashed capex, rigs and completions.

John Freeman, an analyst at Raymond James, said in a May 15 report that names under coverage with a market cap at or above $2 billion slashed budgets almost in half, while smaller companies cut about 27%. Smaller companies, he said, have larger volumes of production hedged or must consider debt covenant issues. Some private companies went all in at 100% stoppage.

"Activity reductions are coming fast and furious, with many companies cutting all completion activity in the second quarter and reducing rig counts by 50% to 100%," said U.S. Capital Advisors analyst Becca Followill in a May 20 report.

While chaos reigned in the commodities markets for two months, U.S. producers were quietly and furiously curtailing existing production as well as cutting capex, saving their wares for a better-priced day. Evidence of this showed up in first-quarter conference calls, with estimates that some 1.75 MMbbl/d to 2 MMbbl/d were pulled out of the market in no time.

But these emergency curtailments might be reversed as quickly as they were implemented. Several analysts expect about 1 MMbbl/d to come back onstream in June. "With June and July crude now back over $30/bbl, most are expecting these shut-ins/curtailments to be short-lived and the majority of it back on by August," Followill said.

For the same reason, prices are now at a level that might incentivize new activity. Above $30, Macquarie strategist Walt Chancellor said he sees a return to "meaningful levels of new completions" by July and August.

Tudor, Pickering, Holt & Co.'s (TPH) Matt Portillo said in a video report, "We've seen crude rally to a point where we are able to actually bring production back onstream. It's coming a little faster than the market expected. The crude market is off life support."

Fellow TPH analyst Mike Bradley suggested pricing will "go sideways" for a while, holding in the $30s as U.S. production is carefully added back in, closing the year at $40.

"I'm bullish because I think demand is going to come back stronger than people think; OPEC cuts are going to hold longer than people think, which will put the market in backwardation; and we're going to drain those inventories," he said.

The forward months look stable. Healing is prevalent. It's time to dust off and move forward.

NEGATIVE FUTURE

DARREN BARBEE, SENIOR EDITOR

April has become a kind of cliché for bad months, but what a mess this one left behind for May. Forget the hand sanitizer—this requires the magic of Clorox.

This is a tough environment in which to live, let alone make oil and gas deals. Still hanging in the May air is the raw sting of enmity, childish China-blaming and the constant uptick of coronavirus deaths.

The deals, such as they were, mainly involved last-minute reshoots, as bad a sign in M&A as in the movies. Devon Energy Corp. rebooted its Barnett Shale asset sale, potentially adding $60 million to the price from buyer Kalnin Ventures LLC. Alta Mesa Inc.'s editing room floor, already slick with price cuts, saw another $100 million leak out of its deal with Mach Resources LLC as the company struggled to escape from bankruptcy.

So it went with HighPeak Energy and blank-check company Pure Acquisition, which dropped plans to include Grenadier Energy Partners II in a new company. Same story with BP Plc's Alaska sale to Hilcorp Energy Co.

Even the once safe, if demoralizing harbor of bankruptcy is now showing symptoms that it, too, is within the pandemic's grasp. Fitch Ratings said on May 4 that recent bankruptcy cases have gone off the rails as exit financing begins to wobble.

Bankrupt EP Energy, for instance, was ready for takeoff in March following a federal judge's approval. The company's debt was set to be reduced by $3.3 billion with majority equity ownership falling to holders of certain lien notes. Then the oil and gas values that underpinned the reorganization fell into a pandemic-sized hole.

The rapid collapse of the EP Energy's bankruptcy plan stunned Judah Gross, an attorney and director at Fitch. "I've never seen that before in my history of practice," he said.

As if in step with handwashing guidelines, debt seemingly takes longer to scrub off now. Lender disinterest for equitized debt and a lack of "third-party interest in certain distressed assets" has also disrupted the previrus Chapter 11 bankruptcy world, Gross said.

Those disruptions are "most pronounced in energy and retail as opposed to all other sectors," he said. "Energy [has experienced disruptions] because of the [collapsed] oil demand and the abruptly falling oil prices and retail just because of the lockdown."

Worse still is the fate of oil and gas in the hands of its adversaries. In Sun Tzu's day, it was considered wise to leave a desperate and surrounded foe with an exit. Today's maxim: It's not enough to see an opponent beaten—they must be humiliated, too.

In a sign of this age's rancor, critics of President and Chief Medical Officer Donald J. Trump have taken to mimicking his chaos game theory. Consider Tom Sanzillo, director of finance for the Institute for Energy Economic and Financial Analysis, who argued on April 27 that qualifying oil and gas businesses shouldn't be eligible for loans that would enable them to pay employees.

Sanzillo sings to the choir about the sector's poor showing with investors and lenders the past couple of years. He delivers his TKO of the sector by arguing that any funding to the oil and gas industry is "a waste of taxpayer money."

As of May 11, nine public oil and gas companies had taken Small Business Administration loans—$29.7 million, or about two one-hundredths of the $1.2 trillion bailout program.

This Trumpian argument appears meant to inflame rather than persuade. It fits neatly with "windmill cancer" and "buy Greenland"—phrases more suited to safe words than talking points.

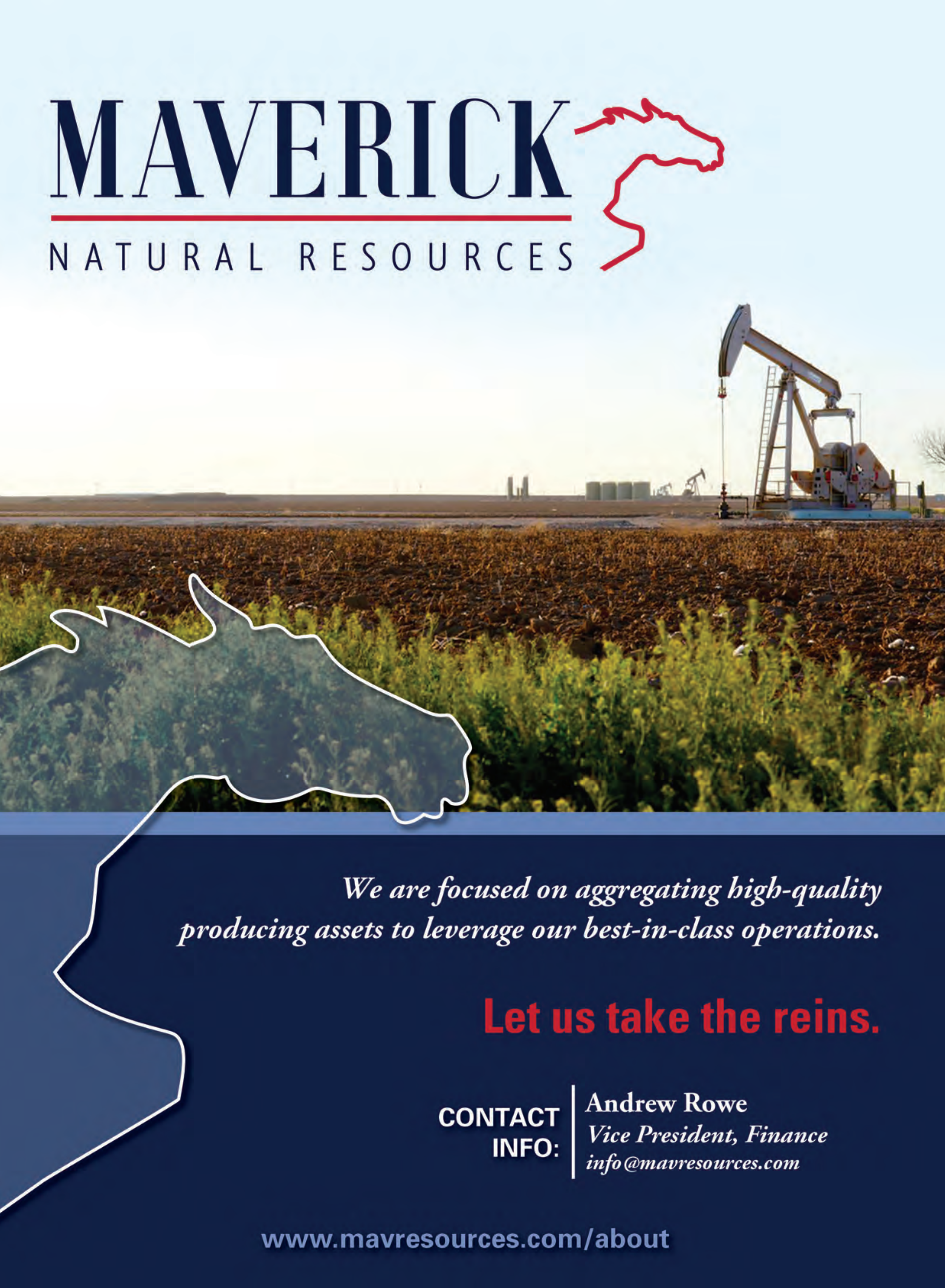
How far can this animosity, which threatens more than just oil and gas deals, go? The vibe is 1912, which isn't good.

Roughly a century ago, presidential candidate Theodore Roosevelt took the stage at a gathering of Milwaukee Progressives whereupon he declared he'd just been shot.

"Fake!" a skeptical onlooker cried. Roosevelt, aggrieved by what he considered rigged or stolen elections, obligingly opened his coat to show blood oozing from a .38 caliber wound. An eyeglasses case and a 50-page speech had slowed the bullet's passage toward the center of his chest, according to History.com.

"It is a very natural thing," Roosevelt told his stunned audience, "that weak and vicious minds should be inflamed to acts of violence by the kind of awful mendacity and abuse that have been heaped upon me for the last three months by the papers."

Any of this sound familiar? If it helps, oil prices were probably about the same.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EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
CIPA Annual Meeting	Postponed	Santa Barbara, Calif.	TBA	cipa.org
AAPG Annual Conv. & Exhibition	Postponed	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
IPAA Annual Meeting	Canceled: June 29	Newport Beach, Calif.	Pelican Hill	ipaa.org
Unconventional Resources Tech. Con.	July 20-22	Austin, Texas	Austin Convention Center	urtec.org/2020
Western Energy Alliance Annual Meeting	July 29-31	Tabernash, Colo.	Devil's Thumb Ranch Resort	legacy.westernenergyalliance.org/annual-meeting
Summer NAPE	Aug. 12-13	Houston	Online	napeexpo.com
EnerCom The Oil & Gas Conference	Aug. 16-19	Denver	Westin Denver Downtown	theoilandgasconference.com
The Energy Summit	Aug. 17-19	Denver	Sheraton Downtown Denver	coga.org
TIPRO Summer Conference	Aug. 19-20	San Antonio	Hyatt Hill Country Resort	tipro.org
Energy ESG Conference	**Sept. 1**	**Houston**	**Omni Galleria**	**energyesgconference.com**
DUG Permian/DUG Eagle Ford	**Sept. 8-10**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugpermian.com**
DUG Midcontinent	**Sept. 22-24**	**Oklahoma City**	**Cox Convention Center**	**dugmidcontinent.com**
DUG Haynesville	**Oct. 13-14**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
A&D Strategies and Opportunities	**Oct. 27-28**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Executive Oil Conference/Midstream Texas	**Nov. 3-4**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
Petroleum Alliance of Okla. Annual Meeting	Nov. 5-8	Las Colinas, Texas	Four Seasons	thepetroleumalliance.com
DUG East/Marcellus-Utica Midstream	**Dec. 1-3**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Privcap Energy Game Change	Dec. 1-2	Houston	Houstonian Hotel	energygamechange.com
Veterans In Energy Luncheon	**Dec. 3**	**Houston**	**The Westin Memorial City**	**impactfulveteransinenergy.com**
2021				
IPAA Private Capital Conference	Jan. 23	Houston	JW Marriot Houston	ipaa.org
NAPE Summit	Feb. 8-12	Houston	George R. Brown Conv. Center	napeexpo.com
CERAWeek by IHS Markit	Mar. 1-5	Houston	Hilton Americas-Houston	ceraweek.com
DUG Bakken and Rockies	**Mar. 25-26**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.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
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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

NewsWell

Analysts forecast rise in US oil shut-ins, with Bakken in the lead

At least 300,000 bbl/d of U.S. oil production is expected be shut in during May and June, analysts at Rystad Energy estimated in an April 28 report, with low oil prices likely to force more production offline.

The outlook, which is up from about 100,000 bbl/d in projected cuts for April, was based on early communication from U.S. oil producers, including Continental Resources Inc., Cimarex Energy Co., ConocoPhillips Co., PDC Energy Inc., Parsley Energy Inc. and Enerplus Corp.

Though cuts will be spread across the Lower 48, the Williston Basin is expected to be impacted the most, according to Veronika Akulinitseva, vice president of North American shale and upstream for Rystad Energy.

"The Bakken play accounts for a high share of combined output, closely followed by the Permian's Delaware," Akulinitseva said in a news release. "Yet given the single-digit wellhead prices seen in the region recently, and overall commerciality, the shut-ins in Bakken are likely to be more pronounced."

Analysts said they believe shale producers will try to deliver the cuts mainly by lowering the number of new wells put into production with base decline making up a "material portion of the reported cut."

However, "Given typical shale operational patterns, the decline in started jobs that began in March will result in a lower number of wells put on production in May, which ultimately will not lead to a drop in peak production until June," Rystad said.

—Hart Energy staff

Texas grants oil producers regulatory relief, not proration

It's official: A request by two Permian Basin pure-plays for the Texas Railroad Commission to force oil companies to collectively cut 20%, or 1 MMbbl, of their production died May 5.

But commissioners unanimously agreed to waive certain fees for oil and gas companies, allow underground storage in nonsalt dome formations and temporarily grant exceptions for certain other rules for a year, giving relief to struggling Texas producers.

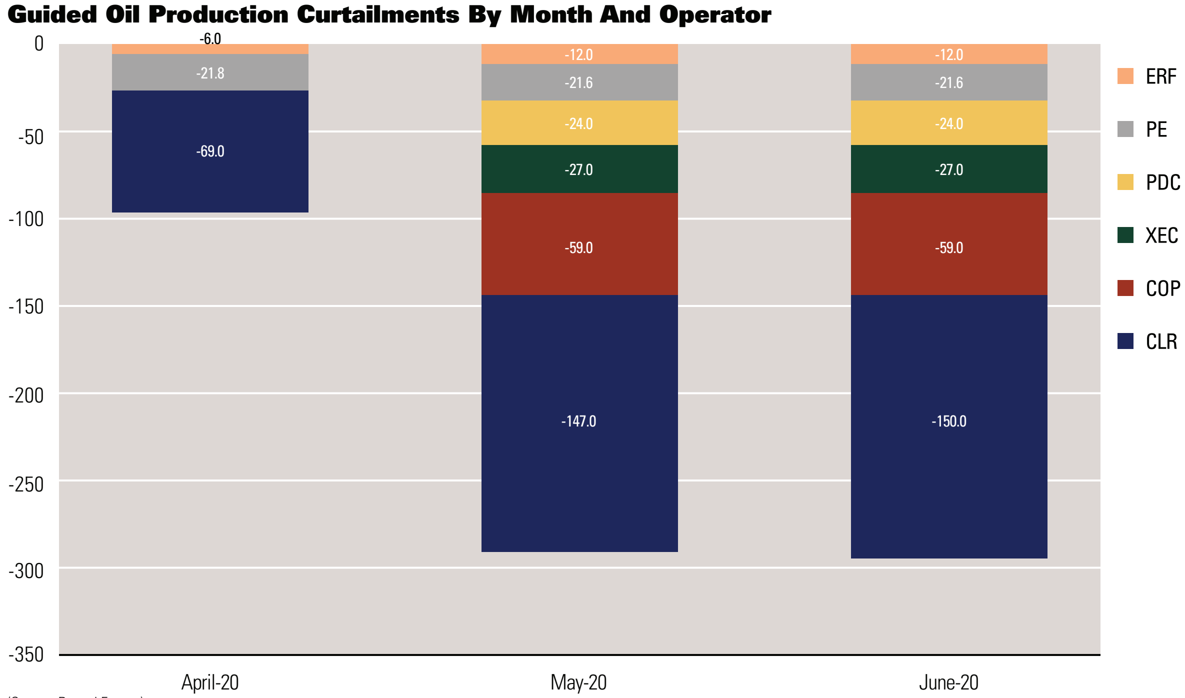
"I don't believe proration is the magic bullet that will save the industry," Chairman Wayne Christian said, noting a lot has changed since Texas last prorated oil in the 1950s. At the time, the Lone Star State controlled about 20% of the global oil supply compared to 5% today. "Given this, a government-mandated cut in oil production of 20% across the board will not have a significant impact on world supply," he said.

Fearing proration could make the situation worse, Christian said he refuses to implement an "antiquated policy," later adding "this problem is 90% demand."

The proration move would have aimed to stabilize low oil prices, which plunged to historic lows as a global pandemic slows energy demand for abundant hydrocarbon resources. It would have also been the first time in decades for Texas to unleash proration regulation to prevent waste.

Market forces, however, have pushed producers to make cuts, shutting in wells and laying

Guided Oil Production Curtailments By Month And Operator



(Source: Rystad Energy)

off thousands of employees, in an effort to salvage balance sheets. Opponents of the request, brought by Pioneer Natural Resources Co. and Parsley Energy Inc., have said market conditions have already led oil and gas companies to lower production at uneconomic well sites, negating the need for such a regulatory move.

"The industry and the market move a lot faster than we can as a regulatory body," Commissioner Christi Craddick said.

Commissioner Ryan Sitton delivered the lone no vote, saying the commission did not consider waste as is required by statute.

"My big fear is that in two or three years as market demand comes back [lower] … is that most of that production loss will come out of the United States," Sitton said. "Proration may not have been the answer. I would've liked to have a more analytical answer as opposed to philosophical."

The vote to dismiss the complaint brought by Parsley and Pioneer came after a marathon 10-hour meeting in April when commissioners heard from people voicing opinions on the matter.

It also comes after the formation of a Blue Ribbon Task Force for Oil Economic Recovery, which presented recommendations that were unanimously approved by commissioners May 5.

The task force, formed at the request of Christian, is comprised of Texas energy trade associations that include the Texas Alliance of Energy Producers, Texas Oil & Gas Association (TXOGA) and Texas Independent Producers & Royalty Owners Association among others.

Providing regulatory relief in response to the COVID-19 pandemic, commissioners agreed to waive some fees and surcharges for the rest of the calendar year and allow crude oil storage in formations other than salt formations for a year. Formations must be confined to prevent the waste or uncontrolled escape of crude oil.

These exceptions do not suspend other rules to protect public safety, health and the environment. Oil stored in non-salt formations must be removed within five years. Though a hearing is not required, the storage must be approved by RRC staff and protests will still be allowed. If there are protests and staff have concerns, a hearing would take place.

Craddick also proposed additional relief measures, which also passed. These exceptions, for a year, will:

- Allow deadline extensions for operators of authorized pits to de-water backfill in compact authorized pits;
- Extend the 180-day limitation on administrative approvals of alternative casing and tubing programs to allow administrative approvals exceeding 180 days;
- Allows the RRC's legal enforcement section to exercise discretion in assessing penalties for violations of commission rules occurring between March 1, 2020, and March 1, 2021, that do not implicate health, safety or environmental concerns; and
- Extend the one-year deadline to plug wells to two years for wells reporting production in February 2020 and subsequently shut in with no reported production from March 1, 2020, to March 1, 2021. The exception, Craddick said, does not limit the RRC's authority to tell operators to plug leaking wells.

"I think certainty, while difficult in this market, should be something the commission strives for," she said.

Todd Staples, president of the TXOGA, said the group was pleased with the RRC's decision.

"The market is a much better arbiter of production than artificial government mandates," Staples said in a statement.

He added that TXOGA, a member of the task force, is "encouraged that the commission today adopted some of the recommendations and believe their action will be meaningful to maintain jobs for employees and survival for employers."

The task force was also asked to return with suggestions on how the RRC can reduce flaring and whether the commission should adopt a new policy on flaring.

The regulator's moves came weeks after WTI future prices sank deep into negative territory in April. U.S. oil futures were inching toward $25/bbl by midday May 5, though still not high enough to justify production costs for some producers—many of which have shut in production.

—Velda Addison

Mexico's president AMLO threatens US gas exports as policies shift

The equation seems simple enough: Mexico's need for natural gas plus an abundance of cheap gas in Texas equals a boom of U.S. gas exports to Mexico.

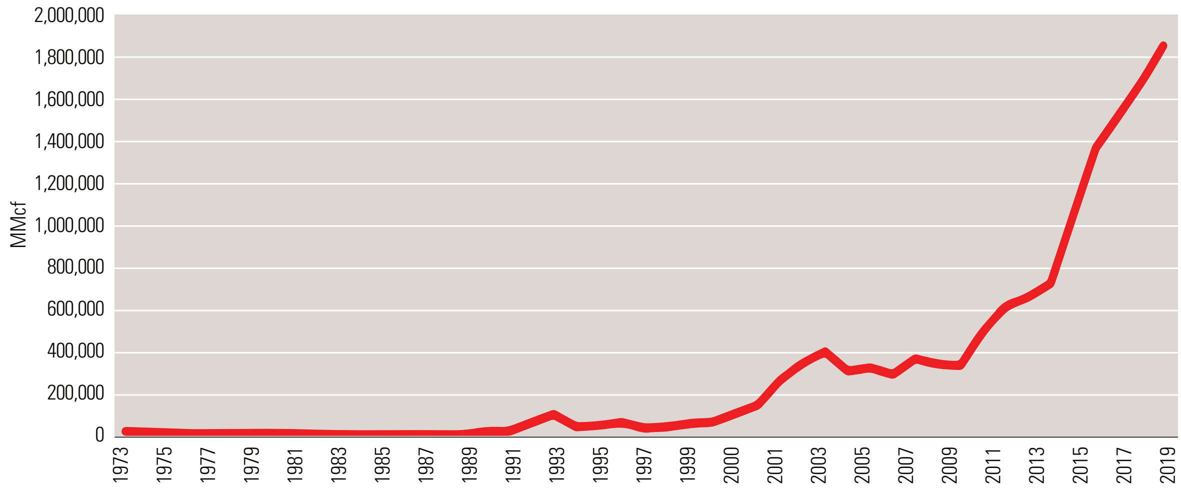
That is how it has added up, with pipelined U.S. exports to Mexico soaring 560% from 2011 through 2019. The equation is threatened, though, by the Mexican government's desire to achieve "energy sovereignty," a phrase akin to the Trump administration's goal of U.S. "energy dominance."

In other words, despite the upheaval put into effect by its energy reform, the country's policy is drifting back toward a position in which hydrocarbons not "Made in Mexico," like imported gas, will not be welcome. For that matter, exports of Mexican oil may not be terribly in favor, either, and the role of Petróleos Mexicanos (Pemex) is expanding.

The early stages of a global oil collapse with the world tumbling into recession is hardly the best time for U.S. gas exporters to have to contemplate the potential loss of a huge and growing market. The American approach—both in industry and government—has been that, no matter the political leanings of Mexican leadership, it would make no economic sense to abandon cheap gas imports from its northern neighbor and ally just to develop expensive domestic production.

That is what the highly touted Mexican energy reform was all about: encouraging foreign investment and moving away from the Pemex monopoly over oil and gas. Conventional wisdom asserts it would be illogical to divert from that course. In the case of Mexican President Andrés Manuel López Obrador, however, illogical may be trumped by ideological.

US Natural Gas Pipeline Exports To Mexico



(Source: U.S. Energy Information Administration)

"In Mexico, even though the president has maintained the reform legally and he has committed not to change any laws prior to 2021, the reality of things is that the oil bids have been canceled, electricity options also have been canceled and the regulatory bodies have been undermined," Lourdes Melgar, a nonresident fellow in the Center for Energy Studies at Rice University's Baker Institute for Public Policy, said during a recent webinar.

"Pemex is working very hard at becoming a monopoly again, blocking all competitors, using old tactics and new tactics," said Melgar, who lives in Mexico City. She also expressed concern that the country is pivoting away from natural gas and toward the use of oil in electrical generation.

"This is actually, from my point of view, a tragedy because Mexico developed a broad network of pipelines under the past administration to be able to import natural gas from Texas," she said. “We have the pipelines, but we’re basically not using them as we should.”

Despite the commitment to Pemex from the López Obrador administration, the company is in trouble. Ratings companies, including Moody’s, have downgraded its credit rating to junk-bond status. The president pledged to increase Pemex’s production to 2.7 MMbbl/d by 2024, but 17 months after taking office, output is down 15% to 1.72 MMbbl/d.

And while the government believes Pemex can ride out the current crisis by producing more gasoline in domestic refineries, the global demand reduction induced by the COVID-19 pandemic and the subsequent plunge in prices may overwhelm the company.

Melgar doubts that the refining solution is viable.

“We have a huge problem with logistics because we don’t have [storage facilities] to put all this oil, which is, of course, very low quality,” she said, explaining that the high-sulfur content of Mexico’s heavy crude limits its potential markets.

“So, a big issue there is an attitude that Pemex does not have to revise its budget, which is really baffling analysts because we know that at the current price many of the projects that Pemex has are basically noncompetitive,” Melgar said, adding that despite this, López Obrador refuses to budge in pursuit of his plans.

“At some point there comes a reckoning, and I think it comes this year,” David Shields, an oil consultant in Mexico City, told the Washington Post.

The Mexican people, who took scant notice of global oil maneuvers in the past, were suddenly glued to their screens when news coverage of the market share war between Saudi Arabia and Russia evolved into a gripping telenovela. Then, Mexico itself was drawn into the plot.

At the April 9 meeting of OPEC and other producers, the Saudis and Russians agreed to reduce production, but only if other producers would cut their output by 23% of average production in October 2019. That meant a decrease of 400,000 bbl/d for Mexico. López Obrador balked, angering the Saudis and Russians and placing Secretary of Energy Rocio Nahle in a bind.

The president’s priority, Melgar said, “is that, no matter what, Mexico should keep its target of producing 2 million barrels a day by the end of the year, and this is why Secretary Nahle had such a hard time at that meeting. She would not agree to a cut. It’s very interesting because in the past Mexico never has agreed to cut production.”

Under pressure, López Obrador eventually proposed to cut 100,000 bbl/d. President Donald Trump intervened on Mexico’s behalf, offering to cover the rest of OPEC+’s demand with a decrease in U.S. production.

Melgar, former deputy secretary of energy for hydrocarbons for Mexico, has plenty of experience dealing with OPEC and other international players. This time, however, she was not in the room. Still, she was able to perceive a significant geopolitical shift.

That Trump would intervene in a dispute to support the initiative of a cartel was a departure from the previous official U.S. position. What the deal means for Mexico remains unclear. What will Mexico owe the U.S. in exchange? Melgar isn’t sure.

“Something happened in there,” she said, “but basically the key point is, our president thinks that Mexico can continue to go on with business as usual even under this current scenario. It’s really surprising.”

—Joseph Markman

Want an oil price recovery? Simple—hit the road

Enough of the calamity, already. What will the recovery look like, and when can we expect it?

“If you look at what’s going to get us out of this recession, what’s going to drive U.S. oil demand back up, it’s getting people back to commuting,” said Michael Maher, senior program adviser for the Center for Energy Studies at Rice University’s Baker Institute, during a recent webinar.

Simple enough. Just hop in the car and head to work, right?

“The challenge there is the high level of unemployment, which means miles driven is probably not going to return for a while,” Maher said. Unlike the 1980s, when demand for oil dropped in large part because of the adoption of CAFÉ standards mandating more fuel-efficient passenger vehicles, this falloff in demand is related to economic activity.

But it is not the economic fundamentals that are askew in this recession, said Anna Mikulska, nonresident fellow in energy studies at the Baker Institute, during the webinar.

“It’s driven by external factors,” Mikulska said. “It’s driven by COVID, and it’s driven by governmental response to the pandemic and fear that the pandemic has instilled in people.”

Drawing parallels to previous downturns is difficult, primarily because this crisis is unparalleled.

“It occurred faster; it seems to be much deeper; it’s experienced by literally the whole world,” Mikulska said. “Consumption fell drastically, very quickly. OECD lost approximately one-third of its demand, non-OECD approximately 20% of oil demand for 2020, as projected.

“And the prices are not there,” she said. “So even if we see a recovery going forward, we probably won’t see $150 per barrel prices anymore. That’s something that has to be kept in mind.”

That’s because, unlike the Great Recession, demand is not primed for growth this time. As the world emerged from the economic shock of 2007 to 2008, the U.S. shale revolution dovetailed with a surge in international growth, particularly in Asia. But while that growth in demand continued in developing countries, it was not universal.

“Oil fell during the Great Recession and really, when you look at it later on, it didn’t recover,” she said. “Even in 2019, we hadn’t recovered in terms of oil consumption to where we were in 2007.”

Consumption in the 36 industrialized OECD countries remains lower now than it was in 2008, Maher said. Much of that reduction was balanced by an increase in non-OECD countries of 14 MMbbl/d, with China alone accounting for 6 MMbbl/d of that total.

"The Chinese averaged 9.1% economic growth between 2008 and 2013," he said. "That was a real driver for the world economy to start coming back from that recession, and especially a big driver for oil."

In 2008 to 2009, Maher said, there was a huge demand push coming out of Asia. During that same period, oil prices bottomed out in 2009 to about $61. By 2013, oil was back to $110/bbl, so the oil industry enjoyed enormous demand growth with very high prices coming out of recession.

Just don't count on it this time.

"That demand driver was not a result of what was going on in the United States or Europe," he said. "And that's something to keep in mind as we look at coming out of this next recession."

One sector in the oil and gas world that has been kneecapped and likely to struggle for a while is jet fuel.

"Is there a structural change there?" Maher asked. "Will Zoom really cut back on future business travel? Are individuals' fears of COVID meaning they're not going to fly, they're not going to go overseas? The airline sector is going to be a very interesting thing to watch."

The unprecedented nature of this downcycle makes it difficult to apply the standard economic models that analysts are accustomed to using, Mikulska said. Until the pandemic eases, and government restrictions and public fear are lifted, any kind of increase in demand or economic recovery will necessarily be limited.

"That's where this uncertainty exists," she said. "We really are not able to know how we can recover, and how fast we can recover and how we can come out of the recession."

—Joseph Markman

Understanding risk, relationships during oil crisis

The outlook for oil and gas may be cloudy, but what is clear is the need for companies to work together if they are to survive this crisis of crippled global demand, legal experts said during a recent webinar.

"Participants should be focused on the interrelatedness of the global upstream, midstream and downstream sectors, as the industry is more sensitive to events throughout the global value chain in this era of U.S. crude oil exports, LNG exports and the shale revolution than it has ever been before," said Gabriel Procaccini, partner at Akin Gump Strauss Hauer & Feld LLP.

Procaccini's practice focuses on the midstream sector, and he advises companies to "be hyper-focused on finding practical solutions and reasonable compromises to mitigate the risks which have emerged as a result of this crisis," adding, "Now is not the time to necessarily stand firm and risk upsetting long-term relationships."

Additionally, with force majeure, or the claim of a counterparty seeking temporary excuse from performance, on everyone's mind, it is also important to know the precise legal language of your agreements, Procaccini said.

He explained that an onslaught of midstream contract renegotiations is imminent. It will require management teams to "have a deep understanding of the classes of midstream contracts at their companies and the potential exposure under each," he said.

"Midstream companies don't want to be left in a position of trying to find a home for their customers' crude oil that may not exist or may not exist at a price that anyone likes," he explained.

Procaccini's advice applies to the upstream sector as well, since producers face similarly painful realities. That some crude producers, as well as gas producers with liquids exposure, might have to pay buyers to take their product forms only part of the trouble; shut-ins and associated contractual difficulties also loom.

"With respect to [upstream] oil and gas, your main concern is avoiding lease terminations due to having no production, maybe shutting-in, or a lack of production and paying quantity," said partner Michael J. Byrd.

"Usually, low commodity prices alone do not qualify as a force majeure event," he said, but a government shut-in order, for instance, could lead to a dispute.

To this point, Byrd said, "An order that requires all operators to cut production by [a certain percentage] and allows each operator choose where it makes cuts to avoid issues of waste, termination and contracts, can increase the risk of a dispute."

With shut-ins, economic and engineering challenges could arise. The chance is greatest in fields where a sudden shut-in risks damaging the reservoir, Byrd said, citing water-injection operations as an example. Shutting in such fields would "involve decisions that truly require input and collaboration between several departments of a company," he said.

Investors, too, must adapt their capital structures to deal with nonperforming or distressed investments. "The response [to the present environment] varies from investor to investor in addressing credit issues in a portfolio company," partner Thomas J. McCaffrey said.

McCaffrey described a variety of options for investor action, some already undertaken. These actions ranged from waived faults and rescue financing on terms significantly better than the companies could obtain elsewhere to various loan conversion structures, which can be tailored to address the specific needs of the company, he said.

Partner Steve Davis said these options reflect "the growing complexity of capital structures since the last downturn."

Faced with myriad risks and ways to mitigate them, the partners at Akin Gump said that companies must continue to plan, to the extent possible, for the future.

"It's not too late [to plan]," McCaffrey said. "Some companies may find themselves in this difficult business environment, low demand and low commodity prices but are not in any immediate financial distress ... Companies like that should look ahead and be proactive and consider some nonfinancial aspects of their businesses."

He listed filling board vacancies with candidates familiar with distressed environments, ensuring strong retention policies to keep management teams in place and even M&A activity as examples.

Ultimately, companies must be mindful that they may have "more exposure throughout the global value chain in their company profile than otherwise indicated," said Procaccini, and they must collaborate internally and externally to make it through this stormy period.

—Bill Walter

Will OPEC+ members comply with pledged oil cuts?

Barely a few days after OPEC+ announced historic supply cuts, one thing was clear—it wasn't enough to offset destruction to oil demand. Though, the question remains whether members of the alliance will follow through on the promised cuts.

"I don't think we should necessarily believe that the announced cuts over the next two years will be delivered," said Bill Farren-Price, director of RS Energy Group, speaking at a webinar jointly hosted by Enverus and RS Energy Group. "Historically, when prices rise, OPEC+ compliance weakens."

Out of the 9.7 MMbbl/d that OPEC+ agreed to cut starting May 1, Farren-Price expects compliance to be between 6MMbbl/d to 7 MMbbl/d.

He went on to highlight the "unusually short time" it took for OPEC and other producers including Russia, which had been in a price war with Saudi Arabia, to strike a record deal that removes almost 10% of global supply.

"It was extraordinary to see cuts of that size pulled together by parties who were in a price war at such short notice," he said, adding that political pressure by the White House might have helped.

In addition, the alliance agreed to restrain production for two years, which he noted is rare.

"It's worth emphasizing that because it means [OPEC+ countries] are trying to give a clear message that they are planning to underpin the prices and trying to help rebalance the market through supply management," he said.

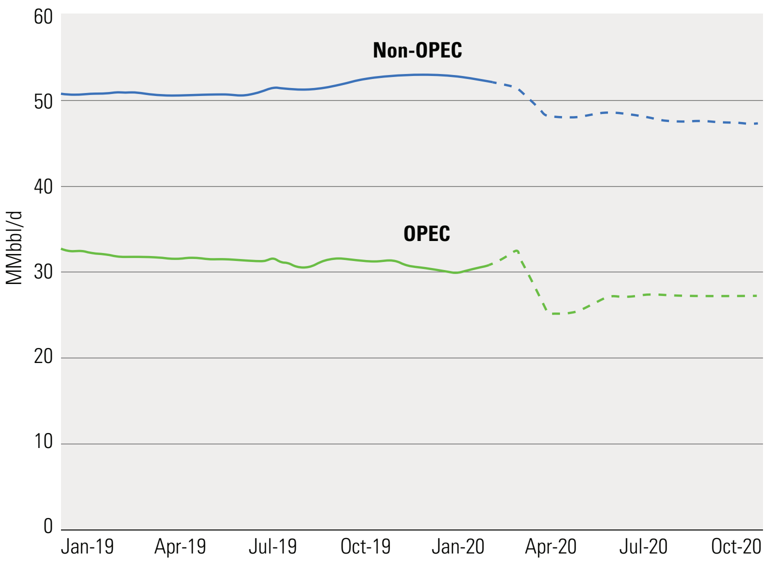
Middle East. Although strong compliance is expected from top oil exporter and de facto OPEC leader Saudi Arabia, backed by its Gulf Cooperation Council counterparts, there are doubts regarding supply cuts from other important and large producers including Iraq, which holds a patchy record, according to Farren-Price.

Compliance from Iraq is difficult due to the country's constant political crisis because of which the country has only managed to deliver cuts from state-controlled oil fields in the past, he said.

The recently pledged cuts of over 1 MMbbl/d will require the country to ratchet back production from the major joint ventures of Iraqi oil companies with international oil companies (IOCs). According to the contracts, national oil companies will need to financially compensate IOCs, making it more difficult for Iraq to cut oil supply.

However, given the unprecedented times, Farren-Price anticipates the countries could begin

OPEC And Non-OPEC Crude And Condensate Production



(Source: Enverus)

making some, if not total progress in May—the first official month of the announced cuts.

Regardless of past records, most countries will be forced to scale back oil production due to global shortage of storage space as the oil sector is set to see demand destruction continue, he said.

Some countries like Kuwait have begun early cuts.

The fourth-biggest member of OPEC, Kuwait "felt responsibility to respond to market conditions" and acted on its own, Oil Minister Khaled Al-Fadhel said, according to the official Kuwait News Agency. He didn't specify if the country has scaled back production by the full amount it pledged to cut, or only part of it.

Saudi Arabia is also considering a proposal to begin cuts immediately, if it aligns with the country's legal obligations and agreed upon deliveries, according to The Wall Street Journal.

Russia. Full compliance from Russia is not expected initially since the country has a tendency to comply toward the end of the cuts agreement period, Farren-Price said.

Russia has made minimal production cuts in the past, scaling back production by 200,000 bbl/d at most. In contrast, the current supply cuts of 2.5 MMbbl/d pledged by Russia are "really significant," he said.

Another matter of concern is that Russian oil producers have maintained flat output in April ahead of OPEC+ cuts.

The country's crude and condensate production averaged 11.28 MMbbl/d from April 1-23—a week before the agreed cuts are expected to begin. The figures, which were reported by Bloomberg citing data from the Russian energy ministry, show the country may not be able to reach its target for production cuts of 2.5 MMbbl/d since it takes time to slow down production at complex fields in cold weather and complex geology.

—Faiza Rizvi

Harold Hamm asks Feds to investigate WTI price meltdown

Continental Resources Inc. wants a federal regulator to investigate the Chicago Mercantile Exchange (CME) for possible market manipulation or other systemic failures related to a staggering fall in May prompt month WTI prices that left oil prices in negative territory for the first time ever.

In an April 21 letter, Harold Hamm, chairman and founder of the U.S. shale pioneer Continental Resources, asked the Commodity Futures Trading Commission (CFTC) to investigate into the potential manipulation, failed systems or computer programming failures at the CME and the circumstances that allowed the unusual negative crude prices. Much of Hamm's letter focuses on what he sees as either peculiarities or failures on CME's part as oil prices plunged in the last 22 minutes of trading on April 20.

"The sanctity and trust in the oil and all commodity futures markets are at issue as the system failed miserably and an immediate investigation is requested and, we submit, is required," Hamm wrote.

"In addition to a review of practices at the CME, we strongly urge the market to change to a daily weighted average price to reflect the trading value experienced throughout the trade month."

Hamm has also lodged a complaint with the CME. He points to the CME's announcement near the end of trading on April 20, which preceded the run on prices.

CME Group Inc. said that Continental's allegations were factually inaccurate.

"CME Group markets worked as designed. We monitor our markets at all times and fully prosecute behavior that violates our rules," CME said in a written statement. "Our futures prices reflect fundamentals in the physical crude oil market driven by the unprecedented global impacts of the coronavirus, including decreased demand for crude, global oversupply and high levels of U.S. storage utilization."

CME said that after providing advance notice to its regulator and the marketplace in early April, "CME Group accommodated negative futures prices on WTI on April 20 so that clients could manage their risk amid dramatic price moves while also ensuring the convergence of futures and cash prices."

The price of oil dropped $40 in the final 22 minutes of trading on April 20—including a three-minute span before closing in which prices sank by $25/bbl, Hamm's letter said.

"Not only did WTI crude futures trade negative, they settled at a bizarre minus $37.63" per barrel, Hamm said in the letter.

On April 20, CME declared that WTI futures could trade negative, which Hamm said sent the May contract price plummeting to about $4 per barrel.

"Notably the CME chose to announce on April 8, 2020, that it had been testing plans to support the possibility of negative options such that if any month, WTI oil futures settle at a price between $8 and $11 a barrel that it could switch to a different pricing model that would allow for negative pricing," Hamm wrote.

CME's announcement said, in part, that, "CME Clearing may switch its pricing and margining options models from the existing models to the Bachelier model, currently utilized in numerous spread options products where negative underlying prices and strike levels are a regular occurrence. If any WTI crude oil futures prices settle, in any month, to a level below $8/bbl, CME Clearing will move to the Bachelier model for all WTI crude oil options contracts as well as all related crude oil options contracts effective the following trade date."

The announcement added: "CME Clearing will send out an advisory notice with one day notice before any implementation occurs with all appropriate details."

Hamm's letter said that the WTI prompt month May contract price settled at $18.27/bbl on April 17. Three days later, the WTI prompt month May crude oil contracts had lost $55.90 in value—a stunning 306% drop—to minus $37.63/bbl.

In his letter, Hamm also noted that WTI trading volume was low before the CME announcement but picked up activity afterward.

"Prior to the CME's announcement regarding negative settlements, the contract was trading positive," Hamm said. "The WTI futures price for the May contract remained positive until approximately 1:08 p.m. CDT when it began dropping precipitously."

Low prices from weakened demand amid a pandemic have already caused E&Ps to recalibrate their plans. Rystad Energy said April 22 that fracking operations will likely decline 60% during May.

—Darren Barbee

ESG more critical than ever for US shale recovery, experts say

Even though demand destruction and oversupply have threatened bankruptcies for many U.S. oil and gas companies, increased focus on environmental, social and governance (ESG) activities could offer some relief to energy companies in the upcoming months.

Several ESG-focused factors, including the safety of workforce, supply-chain diversity and community impact have been key to the survival of companies during the market downturn, said corporate partners at law firm Winston & Strawn LLP Eric Johnson and Michael J. Blankenship in a recent article in Lexology.

"Certainly, there is going to be pain in the short term because the balance sheets are not where they need to be," Johnson told Hart Energy, adding companies will need to recalibrate their financial structure by reducing debt and improving asset bases, both in size and quality.

Longer-term, though, ESG's influence on capital access is here to stay, he said, elevating the importance to embrace ESG principles to ensure future access for oil and gas companies to sufficient and cost-effective capital.

Moving forward, companies that survive the downturn will need, at least to some degree, ESG-focused investors to meet their capital requirements. The biggest issue for the industry, though, is finding a common ESG framework and consistency in reporting, Johnson said.

"We're strongly encouraging companies to get involved with trade associations that are proactively developing ESG resources for their member institutions and providing networks for sharing information and ideas," he said.

Investors have been pushing for standardization of sustainability reporting and other ESG-related disclosures for several years, according to Johnson.

Cross-vertical organizations, such as the newly formed Energy ESG Council, are creating forums for companies in the upstream, midstream, downstream, renewable and service sectors to work together on industry-wide ESG objectives. These include reporting frameworks in order to help the industry communicate a cohesive and positive ESG message.

Johnson also pointed out a strong need for the board of directors to clearly communicate to the corporate stakeholders their commitment to ESG principles. Those involved in strategic planning must focus strategies on developing new technologies that can improve the environmental impact of existing businesses, restructuring organizations to maximize the health and safety of workforce and defining ideal supply-chain configuration.

Johnson also highlighted a need for the industry to adjust its compensation programs and policies to incentivize and drive ESG success. ESG metrics must become a key performance indicator and a significant component of incentive programs, together with strategic, financial, operational and other traditional performance metrics, he said.

The lawyers agreed that the corporate strategy developed by the board must follow through with incentives that will motivate and encourage the desired ESG-related behaviors. Failure to do so will permit competing incentives to potentially derail or postpone ESG success and unnecessarily divert needed capital.

As for the energy transition, Blankenship noted a need by the oil and gas industry to adopt new technologies. This will include continuing to invest significant capital into technological innovation, such as ones that help the transition to a low-carbon future.

"Oil and gas is not going away, but we need to be safer and adopt better practices to attract investment," he said.

This period of market depression, however, presents a chance for the industry players to forge a better and more sustainable path to global energy leadership, he said. New technologies will also attract capital, which will sustain existing oil and gas operations as the transition continues.

—Faiza Rizvi

IS GAS THE GOOD NEWS WE NEED?

With the prospect of associated gas from the Permian and Eagle Ford diminishing, many producers view the future of dry gas plays in the Appalachian Basin more positively. Those well-positioned and well-capitalized companies are staring at an unexpected opportunity.

Appalachian operators grapple with the upside that comes from less associated produced gas from declining oil drilling but risk of less global and domestic demand for natural gas as well.

ARTICLE BY
LEN VERMILLION

PHOTOGRAPHY BY
STEVE TOON

The crisis facing the industry is tragic, but it may "save certain natural gas producers that were heading for bankruptcy," said Trevor-Rees Jones with Chief Oil & Gas.

It goes without saying that silver linings are hard to find these days. Just when you think you have found one, there is a caveat, and convincing others of an optimistic worldview has become an art form. Considering what COVID-19 has wrought upon the world in general, and how it and the oil price crash have hamstrung the industry in particular like never before, it is understandable that many currently view silver linings as far-flung dreams.

But someday these nightmares will fade, and today's silver linings will become tomorrow's realities. For those who look deep enough and prepare accordingly, they will become tomorrow's opportunities.

That is what many of the producers and analysts that spoke with Hart Energy said about the U.S. natural gas market, ranging from the Haynesville Shale to the Barnett Shale, with a particular focus on the Marcellus and its abundance of dry gas and economics capable of handling sub-$3 natural gas prices.

"With lower oil production, they'll probably shut in 2 million to 5 million barrels of oil per day. … So you should see support for gas prices assuming the economy gets better," said Dan Pickering, founder and chief investment officer of Pickering Energy Partners, in a video interview with Hart Energy *(See the full interview at HartEnergy.com/videos)*

"We're exporting a lot of LNG. That is economically dependent. We need factories running and burning natural gas. So demand has to get better as well as associated gas supply coming down. All things being equal, natural gas should be advantaged by what's happening with oil," Pickering said.

Natural gas producers also have noticed the possible opportunity ahead of them.

"While you certainly hate to see what has come about in our world with the coronavirus and the collapse of oil, it does appear that taking an amount of associated gas off the market is going to help balance the natural gas market a lot sooner than was otherwise anticipated," said Trevor Rees-Jones, founder and CEO of Chief Oil & Gas LLC, which has achieved more than 2 Tcf of gas production in the Marcellus and holds close to 100,000 acres of net leasehold in Northeast Pennsylvania (NEPA).

"In all my years in the oil and gas business, I've never seen as dramatic a change in what people expected in pricing occur. In just a span of 60 or 90 days, there's talk about prices being projected for next year [that] nobody would have thought about," Rees-Jones said in an interview with Hart Energy. "It's tragic how it happened, but it may serve to save certain natural gas producers that were heading for bankruptcy."

However, Rees-Jones' bullish outlook also comes with a warning.

"Traditionally, on the natural gas side with the oil price crash, you're going to see a lot less capital allocated to oil drilling. And as oil drilling spins off a large volume of associated gas, you're going to see reduced associated

No one anticipates a pendulum swing that sees $8 gas like what launched the Marcellus Shale, but a sustained price above $2.50 might be more realistic—and welcomed.

"In all my years in the oil and gas business, I've never seen as dramatic a change in what people expected in pricing occur."

—Trevor Rees-Jones,
Chief Oil & Gas

gas, which is then going to put upward pressure on or increase natural gas prices," added Andy Levine, Chief's senior vice president of marketing. "Of course, that benefit only perpetuates as long as oil prices stay low. Once that drilling comes back, that benefit then goes away."

Nonetheless, many operators appear to be positioning themselves to seize the potential natural gas opportunity. In Texas, drilling permit filings are down with the record-low crude oil prices, but the percentage of natural gas wells is entering double-digit territory amid the oil price crash, according to a report by The Houston Chronicle.

On the surface, those moves stand to reason.

"A lot of the bears around natural gas had two primary arguments: We have an unlimited supply of natural gas, and we're persistently oversupplied. Our pricing will never recover," said Chris Kalnin, CEO of Kalnin Ventures LLC, which has committed $1 billion over the last five years in its Barnett Shale acquisition from Devon Energy. "We have this competition from associated gas, which was costless, effectively, and will swamp the market with additional oversupply. What you're seeing today is that those bearish excuses are being taken away."

While Kalnin remains steadfastly bullish on the longer-term value of U.S. natural gas in the Barnett, Kalnin Ventures also is well positioned in the Appalachia region through several acquisitions in the Marcellus.

"There is no basin that is cheaper from a dry gas perspective than the Marcellus," Kalnin said. "In terms of low-cost supply and market where you're running out of associated gas, you want to in the Marcellus because it is still the premier basin in terms of scale but also in terms of economics in bringing on dry gas."

So, while the dark clouds that hovered over natural gas prices before the onset of COVID-19-induced demand/storage issues and the oil price crash provoked by Russia and Saudi Arabia may be thinning for now, even long-time Marcellus drillers warn that things are different this time around.

In addition to a bounce back in the economy, taking advantage of this unexpected opportunity also takes a well-capitalized, well-positioned company with a strong balance sheet, because a natural gas pricing boom still means about $3 prices, not the $8 prices that ushered in the rise of the Marcellus, Haynesville and other plays.

"I don't foresee a time when gas gets back to where we were previously, certainly when


RESIDUAL
WASTE

One fallout from the oil price crash could be fewer service providers surviving, even in Appalachia.

"While you see the gas market strengthening, you have very few companies within Appalachia that can really take part of that strength. The reason is that you still have companies with a tremendous amount of debt."

—Chris Doyle, Olympus Energy

this basin started. What really spurred this basin was $8 gas," said Chris Doyle, CEO of Olympus Energy, in an interview with Hart Energy. Olympus has remained active in the southwestern Pennsylvania Marcellus, having endured the low natural gas prices of previous years when many pulled out of the basin.

"I don't see a tremendous bull run. But what I do see is sustained gas prices above $2.50, and I think we have enough resource available that we can keep gas price in a fairly tight [band]," Doyle said.

To keep things in perspective, a decade ago that price environment would have sent many producers off a cliff.

Seizing the unexpected moment

Doyle, who heads a private operator backed by Blackstone, said Olympus is in a stronger position to take advantage of the uptick in natural gas prices than other companies. In fact, he said his stance on drilling in the Marcellus hasn't changed since he addressed Hart Energy's DUG East Conference & Exhibition in Pittsburgh in June 2019.

"What it takes to win in a commodity business is you have to have a number of things. You need to have core assets and quality assets, and to me that means high margins and great well returns," he said. "You have to be well-capitalized. You have to be nimble as an organization. You have to be a learning organization."

Olympus, which holds a 100,000 net acre position mostly in Westmoreland County, wrapping around the eastern suburbs of Pittsburgh and into Washington County to the south, has continued to drill, but Doyle said the company will pause after finishing its current pad. However, he added that the company will remain active in the near future because it can check off all of the aforementioned boxes.

While the strategy for drilling remains in place, Olympus plans to react to "what the market shows." Right now, that's an unexpected short-term future brought upon by COVID-19 and the expected rebalancing of the market due to the loss of associated gas from Texas oil fields.

Doyle said the company is well positioned to make a quick reaction to the market's changes.

"You need to be able to react to what the market's showing you. I think this is where many companies in Appalachia have really struggled," he said. "In many instances, long-term commitments cloud the right capital allocation decisions for companies. Those complexities take away from a very real decision of whether they should be allocating capital today or not."

Of course, private operator Olympus has access to capital via Blackstone.

"Part of [our ability to be nimble] is because we're private. We're very well-capitalized by Blackstone. [We have a] clean balance sheet and great assets," Doyle said. "But we're also not beholden to a production target or a quarterly mandate by the market, and that helps as it allows us to balance short-term decisions with long-term value."

When asked if he was concerned about whether renewed interest in natural gas as prices inched up would create an even greater oversupply situation in Appalachian Basin gas, Doyle didn't hesitate. He said that many companies are not positioned to enter the market or to obtain a core position in a now mature basin.

"From an industry perspective, when you're looking for high-return opportunities, there's not a whole lot out there currently that works at, call it, $20 oil and $2.50 gas," he said. "The market sees the demand around the corner and knows that if you can deliver high margins and returns there will be a tremendous opportunity.

"We own our own midstream and have some of the highest margins in the basin, so we're excited about what we have going at Olympus," Doyle continued.

"We also know that the next few months will continue to present challenges and will require navigating through uncertainty. We'll be looking to find balance between long-term value and short-term risk mitigation, which means making difficult decisions at the right time in order to optimize opportunity for Olympus," he said, adding that Olympus requires fewer strategic changes to maneuver through the short term than companies without free cash flow and access to capital. Therein lies his confidence.

Managing the short term

Olympus' pause was preplanned, not based on COVID-19 or the dramatic drop in oil prices in late April. However, Doyle admitted it's a strategy that translates well into the uncertain 2020 and expected 2021 environment.

"What we've done over the past couple of years is the reason our balance sheet is in the position it is. We've been in the mode of drilling a handful of wells, bringing those wells online, cash flowing those wells and then drilling the next set," he said. "Because of the uncertainty of the next few months, that strategy plays very well into that environment."

Olympus is drilling on a four-well pad and will demobilize the rig after that. "We'll complete the wells likely later this year into what we think is going to be a very strong and strengthening gas market," Doyle said.

"We've positioned the company to go headlong into development of a continuous rig program, but we know that the right decision

Chief Oil & Gas' Andy Levine said he expects to see "a more aligned reaction [to price signals] because of the lending arena and difficulty of getting access to capital when pricing doesn't justify it."

Chris Kalnin with Kalnin Ventures said the coming natural gas renaissance will also involve consolidation in the Appalachian Basin over the next several years.

Nimble operations are key to success in the new normal for natural gas producers.

now is to pause and confirm that what we are predicting is accurate," he said. "This is an exercise we work on continuously and one that helped frame the way we are thinking about the market. Once we have more clarity, we hope to allocate resources to continue Marcellus development and test our Utica assets."

Doyle said once you get past the next few months, there will be more clarity. He believes the industry is "on the porch of a really strong or at least strengthening gas market." It will take a low-cost approach to succeed in a $3 or less pricing environment, but Doyle also believes the Appalachia region is the ideal place to meet margins at that price versus other basins.

"We've been extremely successful at bringing on supply at very low cost, and that's driven down that cost of marginal supply within Appalachia," he said.

The health of the OFS sector is a primary concern for Marcia Simpson with Chief Oil & Gas, but she said Chief is capable of enduring lost suppliers.

Making the most of experience

Across the state in NEPA, Chief is rolling along with its drilling programs with a similar eye on the positive-looking price signals and the differences in this price environment compared to those in the past.

"What we have experienced historically is we've tended to see activity lag price signals. That can be caused by producer hedging or longer-term service contracts. Sometimes it's just a drill and hope attitude," said Chief's Levine.

"In this last downturn, things started to change somewhat, particularly in the lending arena. Banks were being more conservative on their lending practices, insisting on free cash flow," he said. "I guess what I would say is [compared to] the phenomenon you saw in the past where you didn't see the reaction to the price signal, we think in the future you're going to see a more aligned reaction just because of the lending arena and difficulty of getting access to capital when pricing doesn't justify it."

Marcia Simpson, Chief's senior vice president of engineering and operations, agreed that remaining disciplined over the past years set up Chief for an existing strategy tailor-made for the upcoming price hike.

"I think the larger companies and even the private-equity-backed [companies] have learned a very valuable lesson on growth strategy at all costs," Simpson said. "We've been very disciplined in our company for the last four-plus years on [being] free-cash-flow positive. But our goal was not to grow production. It was to keep production flat and meet our commitments and make margins."

That's left Chief in "a pretty good position" and with an opportunity if there is some consolidation of businesses to possibly pick up some additional production, according to Simpson.

"We've been in this boat for years, so we are very prepared and have a great hedging strategy," she said. "We're very predictable. We have a two-year target to meet, and we're meeting it."

The OFS factor

A caveat to this optimism is the toll the oil price crash will take on the oilfield services (OFS) sector. Simpson, who oversees Chief's well operations, is concerned with the sector's health but also confident Chief is positioned to deal with the loss of suppliers.

"One of the significant exposures is the health of the service companies, and we've seen an impact [in the sector] because of their businesses relying on activity all over the world. We definitely have a concern of seeing those companies go out of business. That is a major potential downside of the oil price crash," she said.

She said Chief has requested proposals with several vendors, and it relies on larger companies for major products. The impact will most likely land on companies that have a smaller footprint. "It's harder [for them] to weather the storm," she said.

The market ahead

"Long term, I think we have line of sight on a gas price that makes our business work really, really well," Olympus' Doyle said.

But that doesn't mean there aren't significant speed bumps along the road ahead for Appalachian Basin dry gas producers. Just like the economy in general as it reopens, the natural gas market ahead is sure to be full of ups and downs—and unfortunately, winners and losers.

"I do believe there is going to be additional volatility given the macro impacts of shut-ins in the Permian," Doyle said.

Kalnin added that while the industry is staring at a renaissance of sorts for the natural gas market, it will come at a time of consolidation for the Appalachian Basin over the next couple of years.

"Companies need to work out their balance sheets and build up their cash," he said. "The marginal gas supply for the country will need to come primarily from the Marcellus to supply what is going to be lost if oil prices continue to be the way they are."

And that's what he and others are betting on as they continue to drill and invest in the Marcellus dry gas fields.

"While you see the gas market strengthening, you have very few companies within Appalachia that can really take part of that strength," Doyle said. "The reason is that you still have companies with a tremendous amount of debt. The spillover from what's going on with oil is very real to the credit markets."

That is where capitalization becomes extremely important, he explained.

"If you look at many of our neighbors and their balance sheets, they still need to be in the mode of paying off or restructuring debt, cleaning up their balance sheet. While the gut reaction from some of these companies will be 'let's get back to drilling'… I don't know that they'll have access to capital to do that," he said. "That's the interesting nuance in my mind where Olympus may yet further be advantaged. We actually do have access to capital. We have great rock to go drill and actually return capital to our stakeholders."

"The other part is the core positions are very much known and they are held," he added. "We're now a mature basin, and if companies want to come in, they'll have to acquire a core position that comes with a tight balance sheet or look for others."

Doyle also said that Olympus' proximity to markets and the Dominion South hub prime it for success for the lower cost structure needed in the natural gas market of 2021 and beyond.

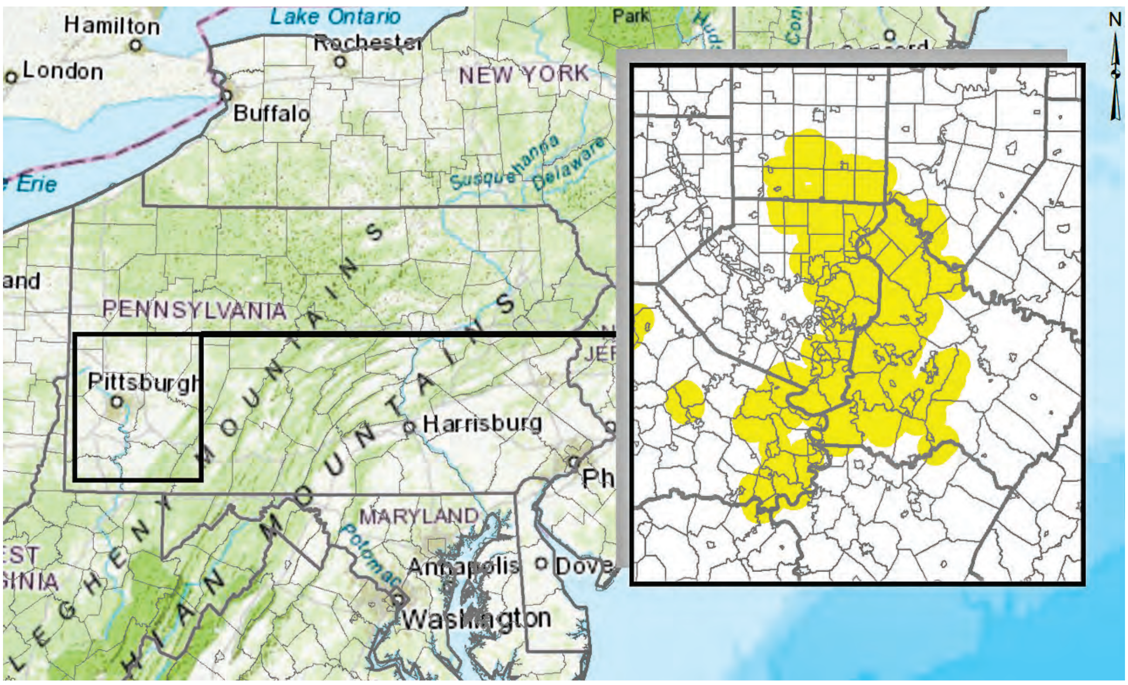
"It's been a real advantage for us because we are very close to one of the most liquid gas hubs in North America," he said. "The differential to Nymex has typically been 40 to 50 cents. We've seen it tighten a little recently."

Taking advantage of that proximity to the hub has been a key component of Olympus' strategy in the past and will grow in importance in the future. Olympus owns its own midstream because its gathering needs to Dominion South are short. Doyle said he is not necessarily looking to manage the market over a long haul.

"We have considered the path many companies have chosen which is, 'I want to lock in gas all the way to the Gulf Coast.' We think, ultimately, economics will work that out," he said. "Rather than sign up for long-haul, long-term commitments, we can actually capture that margin by delivering so close to Dom South as we are."

The next few months will be difficult, but the industry is "on the porch of a really strong or at least strengthening gas market," said Olympus Energy's Chris Doyle.

Olympus Energy Acreage Position



Olympus Energy's position near the Dominion South hub in southwestern Pennsylvania allows it to own its own gathering system.

(Source: Olympus Energy)

Proximity to markets and hubs makes Appalachia more suitable to operating in a lower price environment than other natural gas basins.

While the pipeline buildout in NEPA is not as thorough as the buildout in the southwest corner of the Marcellus, Chief's executives expressed similar confidence in their proximity to large demand markets.

"The northeast doesn't have as robust an infrastructure as the southwest. This owes to the fact that it's farther down the pipe so there's not as much legacy pipeline. Also, it's closer to major metropolitan centers, which makes it more difficult to build," Levine said.

"In NEPA, right now things seem to be unconstrained. For the very near term, they appear to be that way based upon what we see with drilling activity," he continued. "Of course, with higher prices there could be an increase in activity, and there are scenarios where it could be constrained in the next year or two if activity increased."

If NEPA becomes constrained again, Levine said it would be very difficult for Chief to sign up for an expansion because "They've gotten so costly and unpredictable that we would probably tend to operate within our existing asset."

"You have to be well-capitalized. You have to be nimble as an organization. You have to be a learning organization."

—Chris Doyle,
Olympus Energy

"We feel like we have a pretty good situation laid out, and we're happy and productive in staying level and not increasing," he said.

Like Levine, Doyle is balancing his optimism with a bit of caution. "We're feeling very confident, but we acknowledge the need to balance the issues we face as an industry and as an economy right now," he said. "We're immune to some of those challenges, but we will certainly need to remain nimble in order to adapt and overcome others.

"As our industry fuels the economy, we're only as strong as the market environment," Doyle said. "We have to be prudent, and again, that means weighing short-term risk mitigation with driving long-term value." □

CHAPTER 2020

Energy banking in a pandemic that has diminished global oil and gas demand by at least 25%? A 38-year energy finance attorney and author of a history of oil and gas finance describes what the space looks like today.

INTERVIEW BY
NISSA DARBONNE

Book chapters are numbered. In Buddy Clark's book—a history of oil and gas finance that kicks off with how mineral ownership was handled in the Iron Age—were the 1980s going to end up falling under Chapter 7?

Would 2015 fall to Chapter 11?

Without artifice, it happened that the former landed under Chapter 6; the latter, Chapter 10.

That left Chapter 11 available for the next oil and gas event. And here's 2020.

Investor *visited with Clark, a nearly 40-year energy finance attorney with Haynes and Boone LLP, in late April for his thoughts on the current state of capital flow or gridlock.*

If he were to add a chapter to "Oil Capital: The History of American Oil, Wildcatters, Independents and Their Bankers" (2016) one day, would 2020 be worthy? It would, he said.

The 1980s downturn and 2015 were geopolitical and supply-driven. "You still took the oil out of the ground, it went to the refinery and people were buying it. The problem now is that you don't have people at the other end buying it," he said.

Among recent events, Reuters reported—citing three confidential sources—that a few of the major oil and gas lenders were working to create "companies to own oil and gas assets" and "to hire executives with relevant expertise to manage them."

Spoiler alert: Clark said that isn't likely. Banks have usually been reluctant to "take the keys" to oil and gas assets. And they still are, he said. Operating them isn't a bank's expertise, and the risks don't really fit within the Federal Deposit Insurance Corp.-regulated realm.

Meanwhile, an E&P drew $90 million—the remaining capacity—under its revolver one Thursday. In some credit agreements, that's called hoarding.

That evening, the syndicate wrote that it had decided to reduce the borrowing base to $175 million, effective the next day. That's called "using the wild card."

The E&P would need to return $75 million. Cash on hand, including the $90 million drawn, was about $110 million. Its derivatives had a mark-to-market value of about $47.4 million.

Clark's take on 2020 includes an examination of "the least desirable of all bad options."

"The magnitude of what's going on right now is bigger than what happened in the 1980s. The demand loss is what has hammered things."

Investor Without knowing right now where 2020 is going, will some banks take the keys to oil and gas assets after all?

Clark It would be the exception and not the rule—because it would be so complicated, especially with syndicate banks taking over operation. They wouldn't enter it lightly, but it is an option they have.

I have asked other bankers about the Reuters article and they said, 'No, we're not doing that.' It is possible that whoever planted that story is trying to generate business for themselves. I've gotten a lot of calls from people saying, "We're really good contract operators. If you know of anything, keep us in mind."

Bankers generally don't call me for recommendations on contract operators, but the number of unsolicited emails shows you there is a lot of appetite for it on the contract-operating side.

I just don't know what appetite there is on the lender side.

Investor A syndicate bank would have to get the other, say, 11 banks to agree to join the takeover, or it would have to buy the other banks out.

Clark Yes. And, if they do, at what price? Do the others hold out for 100 cents on the dollar even though the loan is probably at some discount?

Even getting it up and running seems problematic. And once you bought it, you own it. They could be owning it for a while. Who knows when the market is going to turn around?

Investor Banks absolutely won't take over the assets then?

Clark It would be the last option they would want to choose. But even before that—even if they didn't like the management team or had lost confidence in them—they would try to keep the management or bring in new management and just keep their liens in place.

Banks aren't looking to take inventory in, wait for the market to turn around and make a killing. That's not their business. Once the loan is in default, they are just looking to recover as much as they can of their principal outstanding.

It is not like a private-equity shop that will put a couple of broken portfolio companies together and just wait this out. It's a different mentality for banks.

But I have heard the concept that banks may find private equity willing to put a little money in a deal, take over the equity and, if banks are the first out, they may give that company or those assets a little longer rope.

That way the banks aren't speculating in the oil and gas market, which they're prohibited from doing. But they are maybe keeping the operation going a little longer and waiting for the market to turn around.

That seems more plausible to me than a bank taking direct ownership.

Investor In the 1980s, there were concerns among banks about assuming environmental risks if taking the keys to oil and gas properties. It's been mostly resolved but not completely resolved?

Clark Well, it depends. If it's with a foreclosure, there is a provision in Superfund [the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980] that gives creditors an exception to the liability for preexisting conditions. That can only last for so long, though.

In the 1970s and early '80s, environmental risks were much more of an unknown and therefore more important to banks. These days, banks have become pretty comfortable with the environmental exposure.

There's really no way to avoid the potential of being sued by somebody under some kind of law—even a nuisance law. But the risk has become more acceptable to all parties in the industry.

I don't think environmental risks stop the banks as much as just the sheer magnitude of operating.

Investor What's that math look like?

Clark We're not talking about one lease and one well and one bank. We're talking about potentially hundreds of leases and thousands of wells and multiple banks in the syndicate with varied agendas and ownership percentages. A lot of the wells right now may be uneconomic and need to be shut in, plugged and abandoned.

And think about the outlay. You're asking your bank's board of directors, "We need another couple of million to plug these wells that we're never going to get back." Think about trying to sell that: "Give me some more money to put in a hole that you'll never see again."

I don't think there is any banker out there that would want to make that ask to its credit committee or board of directors. That's why I see that concept as being the least desirable of all bad options.

Investor What happens to the operators receiving "going concern" statements from auditors?

Clark That breaches the financial reporting standards under almost every RBL [reserve-based loan]. Those guys may theoretically be right side up today, but the "going concern" says that within the next year they may get upside down.

Such a default gives the banks the right to commence remedies and take over, but I really can't imagine why they would want to. That would force a company into bankruptcy.

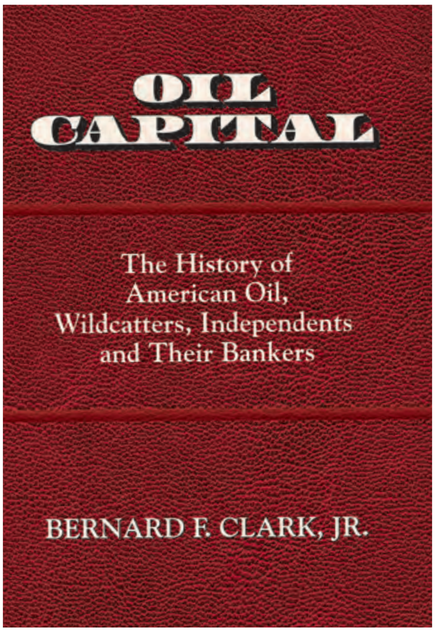
Why would a bank or bank group want to put out a company that is currently operating and isn't wasting money? They're basically working for free because they're not going to get any equity out of it.

Why would you ever foreclose on a company like that? If the banks take that action, they're totally stuck. The operator likely would run to the bankruptcy court. Then they're in a free-fall bankruptcy without an exit plan, and that's a mess.

Foreclosure typically could take up to 90 days once the decision is made to start the process. There's plenty of time to do the work involved to file for bankruptcy. So unless people are walking away from their assets, I don't see a foreclosure ever getting to the red-letter date where you sell the properties at the courthouse steps. A lot of things could happen between now and then.

Investor After the spring of 2016, when your book was published, not much changed. Is 2020 worthy if you added a chapter now?

Buddy Clark's "Oil Capital" analyzes oil and gas finance from its historical beginnings.



Clark Yes, I really do think this is. The magnitude of what's going on right now is bigger than what happened in the 1980s. The demand loss is what has hammered things. In the '80s and again in 2014 and maybe in 1999, OPEC tried to flex its muscle to regain market share.

While it was bad news for U.S. producers, the energy markets continued to function. You still took the oil out of the ground, it went to the refinery and people were buying it.

The problem now is that you don't have people at the other end buying it. This one is fundamentally different.

Demand has to come back, but it's going to be a while before it does. And it won't be switching a light on where it just comes back overnight.

Investor Will the way banks underwrite loans against oil and gas properties change in some way—and permanently?

Clark They're already trying to tighten it up right now, but we saw that in the 2009 to 2010 cycle, and within months they started relaxing them again. The pricing is getting a little higher right now, and covenants are getting a little tighter. Anti-hoarding provisions were introduced in 2015 and disappeared in 2017. Those are coming back. But the structure stayed the same: secured loans with a semiannual borrowing base redetermination. I think that stays.

Investor What again was the anti-hoarding provision?

Clark It's when companies look like they are about to enter into bankruptcy and draw down their facilities to the maximum borrowing base. The borrowers call it a "defensive draw"; the bankers see it differently.

The bank usually has that day to fund a draw request, so there is usually very little time to get together with their lawyers [to decide] if they have to fund it and what kind of restriction they could put on it. The banks ended up funding them.

There were at least a handful of instances where both sides—the banks and the operators—put their guns down and worked through a period of forbearance and restructure, which is always better—both sides doing it in a more rational fashion.

But the defensive draws gave rise to the anti-hoarding provisions. Yet managing that was difficult. The anti-hoarding provisions restrict the daily maximum amount of cash that a borrower can keep on hand; anything above the maximum is swept that night to pay down the loan.

Operators could only have so much cash on hand, but they get paid once a month on their production; meanwhile, they have payroll all month long. The banks finally kind of dropped it in 2017.

Today, as banks get more nervous, we're seeing it, and we're seeing borrowers push back again like they did before.

Investor What's something tried in the past that no one should even think about trying today?

Clark When you have two broken companies, call it "a merger of equals" and think you will make it a healthy company, it has always been a mistake to put these two companies together.

The only thing it does is reduce the G&A [general and administrative costs]. But if the properties are bad, you don't improve them underground by just merging two companies.

Another lesson was in the 1980s when the energy banks were being punished because the stock market didn't like oil and gas anymore, so they doubled down on real estate lending. I would say, "Don't get out of this just because you think there is a better place to make investments. That's not necessarily guaranteed."

You can look at what happened to all of our Texas banks in the '80s. Maybe the watchword is "Don't chase bubbles."

Investor Technology?

Clark That's hot.

Investor A lot of technology remains unbankable, though.

Clark Right.

Investor The bankers—the individuals themselves—how are they doing?

Clark I think they are soldiering through. A lot of people in the industry see it as their job to minimize the damage and prepare for when the markets do turn around. At least the bankers have an option to move from one area of the bank to another.

These oil and gas guys would have to find a new industry to get into. That's a tougher road.

There will be half as many people in the industry. It's a fundamental change. And I don't know if it will recover fully. I have concerns that we are facing a new normal.

Investor Any banks quitting oil and gas?

Clark Some European banks have said they aren't going to make any energy loans.

This happened in the 1980s too. If you want to talk about mistakes, a lot of foreign banks got out of the business of making loans to U.S. producers and then they would come back.

BNP Paribas is an example—in and out, in and out, and they're out again. I don't know if they will ever come back. I think the French banks have a political bias against hydrocarbons.

Also some U.S. banks that have been late entrants, now their investors are saying, "Why did we ever get in this business?"

Banks that might be deemphasizing RBLs might be the foreign banks first [and] then the small regional banks, particularly outside the Gulf Coast region.

It would take something for the medium-sized banks and certainly for the bulge-bracket-sized banks—I hope—because the industry needs that capital to survive.

WTI has to be above $40 for the banks to be comfortable with making loans.

Investor Will it be a generation before the generalist investors forget, like they forgot the 1980s?

Clark If you measure generations in terms of months, yes. In 2015 there was [the attitude], "This is the worst ever, and we will never recover." Then in 2016 they issued all the junk bonds again. In 2017 WTI was $65, and it was great. It got rid of the anti-hoarding provisions.

I don't think it takes a generation at all. This will probably last longer, but it's probably not a 30-year event.

The market sentiment is measured by the prices for hydrocarbons. Once those start going up to a level that is worth investing in, everyone's going to jump in, invest and think "It's different this time" and "We're a lot smarter" and protect themselves against all the bad things that happened.

But—I don't know who said it—you always prepare for the last war and not the current war. So who knows what's ultimately going to happen?

But I don't think people will stay away from the industry unless Elon Musk invents a new source of energy that can be stored as easily and has as much energy density as hydrocarbons. Until that happens, you're still going to see investment in oil and gas.

Investor Do RBLs still have provisions for if the Texas Railroad Commission imposes prorationing?

Clark Yes. There are some vestiges in oil and gas loan agreements from the '70s that nobody took out, so they're still there. In my entire career, I always said, "We ought to strike that because they will never happen again."

And I don't think it will happen again because the market is self-correcting and the Texas RRC doesn't have the market power to change oil prices even if it wanted to. So those are two strikes against it reimposing prorationing. *[Editor's Note: On May 5, the Texas Railroad Commission dismissed the prorationing motion put forth by some Texas producers.]*

Investor Every cycle seems to bring more provisions to RBLs. Will more be added? Or is this just covered by "force majeure" or "pandemic"?

Clark You really don't have force majeure in a credit agreement. The borrowers' obligation is to repay money. Under a credit agreement, this pandemic will not excuse the obligation to repay the loan.

"There will be half as many people in the industry. I think it's a fundamental change. "

I do think you'll see other provisions being included in credit agreements—not the least, anti-hoarding provisions.

You may also see banks wanting to have the ability to pull the wild card instantaneously. A lot of bankers are asking us, "What are our notice requirements? How long do we have to wait?"

And a lot of times, the procedures are old-fashioned because they contemplate the borrower asking for a wild card to increase their borrowing base. Well, these banks are saying they don't want to wait for the spring redetermination.

If they can reduce the borrowing base down to current loans outstanding, then there's no availability, and the borrower doesn't have the availability to make a defensive draw.

If the banks call a wild card, under most agreements they have to wait even 24 hours. If the borrower is going to pull a defensive draw, they will do it in that 24-hour period.

For the banks' protection, they want to be able to do it instantaneously and just notify the borrower that "Your new borrowing base is your current outstanding, so don't ask for more money."

I think you'll see banks trying to impose protections like that.

There are some already out there where the bank can just come up with a new borrowing base. They don't have to tell the borrower they're even talking about it; they notify the borrower, and that's it.

Investor What else should we know?

Clark It's the last week of April right now. By June 1 when this is published, everything we're talking about could be incredibly stale and 100% wrong.

I don't think anyone truly knows if today is now the reset and this is the new normal going forward.

It's such a dynamic industry that you just have to constantly be on your feet. And anybody—i.e., me—could easily say the opposite next week, depending on what occurs in the interim.

It's really difficult to make any prognostications, and it may be difficult to make any reflections on what's happening.

It's hard to have perfect knowledge until a number of years after an event.

I'm not writing any new chapters anytime soon. It will all have to percolate through the system first.

Investor We're looking forward to 2024—whatever it takes to get out of 2020.

Clark Yes. You would have a lot of company at that party.

Hopefully, everybody can get together again then too. □

ON THE BRINK

As oil and gas companies face a hard-scrabble commodity price environment, E&Ps and participants in other industry sectors are already rushing to restructuring advisers in hopes of staving off cash flow calamities, unpaid debts and bankruptcies.

ARTICLE BY
DARREN BARBEE

As the financial picture for the oil and gas industry has become increasingly jigsawed, E&Ps are scrambling to fill in the gaps with smaller and smaller puzzle pieces.

Amid the U.S. health and economic crisis, oil and gas asset valuations have been thrown into ruin. Production has turned, in a brief but literal sense, worthless. And cash, like a true monarch, not only reigns supreme but is rarely seen.

The chaos in the broader markets and in the oil and the oil sector has resulted in robust demand for advice. E&Ps have rushed to restructuring advisers, retaining their services as a result of the tumult.

Restructuring advisers say the carnage in the oil markets—with WTI prompt month prices falling to negative $37 on April 20—has driven many companies to seek immediate aid while others are working to keep restructuring and bankruptcy at bay.

"It's the entire spectrum. We are seeing distress in all corners of the energy complex right now," said Scott Cockerham, a director in the turnaround and restructuring practice of AlixPartners in Houston.

Once COVID-19 hit the U.S., it became apparent that demand for hydrocarbons would drop precipitously and storage would immediately become a critical issue, "which we are witnessing immediately," Scott Cockerham, a director in the turnaround and restructuring practice of AlixPartners LLP in Houston, said.

The collapse in oil demand has not only been felt by already burdened E&Ps; other parts of the sector are in disarray, too.

"It's the entire spectrum. We are seeing distress in all corners of the energy complex right now," Cockerham said. "When you get to the point where midstream operators are saying, 'Look, I want to make sure you have a buyer on the other end before you transport through my line because I don't want it to be a proxy for storage,' that's extraordinary," he added.

The pandemic has pushed forward the timetable for companies already on a troubled path and sent restructuring practices, including AlixPartners, into overdrive, he said.

Prior the downturn and price war, some companies were in for a challenging year with oil prices even at about $50/bbl.

"No one saw this coming, but what we knew was looming was nearly a $100 billion in debt coming due this year for U.S. companies focused in the energy space," Cockerham said.

Companies now face the dilemma of continuing to meet monthly debt service obligations while also funding essential expenses such as payroll.

Finding capital in the weeks and months ahead will become even more vital, as will be negotiating with lenders.

Haynes and Boone LLP partner Jeff Nichols, co-chair of the firm's energy practice group, said that companies financially healthy before the crisis should have an easier time with a few adjustments, such as refinancing debt at a higher rate.

"Where you are in this process depends on where you started back in February," he said.

Liquidity drought

Merely existing as an E&P in June 2020 implies a certain level of pain. Companies are first and foremost struggling with liquidity, said Charlie Beckham, a partner at Haynes and Boone LLP who advises companies on bankruptcies, M&A, debt restructuring and insolvency.

"The biggest crisis or struggle that any of these companies are facing right now is liquidity," Beckham said, adding that, "Companies that are not hedged right now are facing a liquidity cliff in the near short term."

However, at current prices Beckham said that he would be surprised if any E&P company is operating profitably in the short term.

"It is almost impossible to maintain profitability unless they have no costs associated with that production," he said. "The companies that we will first see tumble into Chapter 11 or worse will be companies that are facing this liquidity cliff. They can't afford to operate at current levels."

Haynes and Boone's Nichols added that companies' hedged production is now one of their most valuable assets since they could have a large amount of money payable to them.

To survive, those companies may want to monetize their hedges, start shutting in wells, and, with enough liquidity, bridge the gap between now and when WTI increases. "That's what a lot of them are doing right now," Nichols said.

As companies implement various survival strategies, firms are working diligently alongside them.

David Cunningham, a managing director and head of U.S. oil and gas at Moelis & Co., said that the firm is quite busy, particularly in oil and gas but also more broadly in businesses that support other major sectors of the economy.

In the past four years, Moelis has participated in 50 oil and gas companies' restructurings. Like other such firms, it's been thrown into a tumultuous environment that seems unlikely to normalize anytime soon.

Along with liability management and M&A projects, Moelis is also working to identify sources of capital for oil and gas companies, which remain difficult to come by for most of the industry, particularly after the catastrophic value-loss the sector has endured in the past couple of years.

While traditional access to capital from public-equity issuances and banking is closed, Moelis has been successful in finding alternative sources of liquidity.

"Some alternative financing sources, like credit funds, hedge funds and pension funds, are saying that they have capital to deploy. However, it's expensive on a relative basis from where it was even six or nine months ago in the oil and gas space," Cunningham said.

The company has also found success raising capital from international entities, which are generally more stable than some of their U.S. oil and gas counterparts.

Lenders and private-equity owners also appear willing to continue working with companies to find solutions or give companies more time.

"We do see where they are willing to really try to work hand in glove with the companies in order to find a solution," Cunningham said. "Because if they don't find a solution, there is growing concern that the end result could be a bad outcome for all parties."

Terms of indenture

Lenders are in their own scramble as all industries suffer from the pandemic. AlixPartners has surveyed the lending landscape, including reserve-based lending providers, "and their portfolios are universally distressed," Cockerham said.

Developing an executable plan will give companies an edge in dealing with lenders. Unlike during the most recent downcycle, other E&Ps' troubles don't serve as examples for others needing relief.

"Where we are now is unprecedented," Cockerham said. "There's no impact in telling a lender, 'We need relief just like other companies need it.' That doesn't work."

But he said that an E&P management team doesn't want to be the 10th company in line asking a lender for help.

"You need to have a proactive plan that starts with a bridge to profitability, details measures that you're going to implement and shows that the plan is actionable," he said.

Haynes and Boone's Beckham agrees that lenders are "disturbed" by the economic crisis. He said it's important to have clear communication with customers and employees, especially lenders.

"Lenders are afraid that their borrowers are not doing the things that they need to do," Beckham said. "So communicate with [your lenders] that adjustments are being made and that cost savings are being applied to manage the crisis."

Nevertheless, many companies may falter, should management teams' expertise at building E&P companies fail to translate fluently into managing a crisis.

Debt service, while governed by schedules that companies plan for, may also push some companies into insolvency, Cockerham said.

"You might see some overnight bankruptcies filed by companies that genuinely come up against immediate liquidity constraints coupled with mounting debt service. Management teams with a little bit of foresight can proactively plan," he said.

"The bottom line is that if you think that you're not going to be a solvent entity, [then] the moment you realize that, you should be talking to advisers to prepare your company because of the enormous shift that occurs in how you operate and whom you ultimately serve in a crisis," he explained.

However, some lenders may agitate for transactions, even preferring to take the stock of another company and reduce their ownership stake if that means owning a more viable business.

Companies may be engaging earlier because lenders, which will eventually be equity owners in a reorganization, "may actually be supporting and encouraging M&A … because they want to be part of a better organization going forward," Cunningham said.

Transactional limbo

Inevitably, some companies will end up in bankruptcy and liquidation, particularly for those backed by lenders no longer willing to wait for recovery. And certain buyers are waiting for bankruptcies before engaging in transactions.

Nichols said many companies that had marketed assets have pulled them back because prices weren't what sellers needed to pay off debt or for other purposes. "Unfortunately, the market rest right now is really sales through bankruptcy," he said.

Those sales may be forthcoming, Nichols' colleague Beckham added, as some capital providers have run out of patience and are willing to "force the issue and complete an orderly liquidation of sales of assets."

Because of oil's devaluation, the value of assets has similarly collapsed. That's likely to spell chaos, at least initially, for asset deals.

"Where you are in this process depends on where you started back in February," said Jeff Nichols, a partner at Haynes and Boone LLP.

"The biggest crisis or struggle that any of these companies are facing right now is liquidity … Companies that are not hedged right now are facing a liquidity cliff in the near short term," said Haynes and Boone partner Charlie Beckham.

"Consolidation offers tremendous benefits in a world that appears to have fundamentally changed," said David Cunningham, a managing director and head of U.S. oil & gas with Moelis & Co.

TAKING PAINS

As the E&P situation worsens, companies will need to shift how they view their responsibilities—not merely to shareholders and the company itself—but to all stakeholders, including lenders, trade counterparties and other unsecured creditors.

"There are steps that can be taken to shorten the time to manage cash flows on a daily basis because … it's extremely difficult to make that shift overnight," Scott Cockerham, managing director at AlixPartners in Houston, said.

One tool employed by AlixPartners involves a detailed examination of cash management at the "granular level … where operators scrutinize receipts, disbursements and develop specific plans to ensure that they can show transparency as well as a path to improvement to all stakeholders," he said.

Scrutiny of expenditures at a minute level can reveal waste and challenges that allow performing areas to stand out and point the way toward targeted belt-tightening as well as the magnitude of problems, he said. Such methods can sometimes produce enough cash flow to potentially avoid missing a bond payment.

"Then, it's possible to make structural changes and even consider alternative sources of capital to pursue if needed. But it all starts with the ability to see what you have on a finely sliced and examined basis," he said.

The alternative is a more haphazard cutting of expenses that may be too little.

"The first point of focus is identifying what's needed to bridge the profitability gap [fiscally] and what the potential downside is," he said.

As E&Ps' capex guidance has fallen by roughly 30% and forward strip prices head for a year-end sub-$30/bbl, the idea is to quantify how badly an upstream company will get hit and how long it needs to implement stopgap measures.

"Once you understand the impact, then you can realistically start looking to constrain your capex," he said.

Companies are also grappling with general and administrative (G&A) expenses and might assume the need to reduce, say, 30% of overhead expenses.

But the potential damage to the company, as well as compliance with federal regulations, may warrant a more finessed approach.

"Slashing production and withdrawing from an area that's been part of a company's identity can limit its eventual return, and getting that back may be extremely difficult, especially with mineral rights holders," he said.

Rather than artificially reducing G&A, companies should be more surgical in how they cut.

"Instead of saying … I need to cut 15% of G&A wholesale, it's far more productive to be sensitive and conscientious in how you do it," he said.

"From the lender's standpoint, [they don't] want to own the assets," Beckham said. "They just want their borrowers to sell their assets, but they want to sell the assets for more than the market will allow."

However, Beckham said prolonged, low prices will open the door to opportunistic buyers.

"As long as they have cash or adequate access to capital, there are going to be folks that see this as an opportunity to come in and acquire good assets with a long-term future," he said.

Moelis' Cunningham said most potential buyers don't appear able to pay cash for any assets, commenting, "We're not expecting to see the A&D market … coming back with any velocity anytime soon."

M&A amid chaos

Still, in a market focused on preservation of liquidity, M&A can flourish.

Consolidation, particularly in merger-of-equals transactions, was already gaining momentum toward the end of 2019. In a down market, companies with equal footing may see benefits and even survival in joining their organizations together.

"We could envision that continuing to happen," Cunningham said. "If your strategy is consolidation, taking costs out … high-grading portfolio, high-grading capex matters …We want to do those M&A transactions.

"In today's world, the majority of M&A transactions are going to be stock, and the majority of stock transactions are going to be between parties with similar types of capital structure," he said.

After all, the industry doesn't need the number of companies operating in many regions and subsectors as it once did.

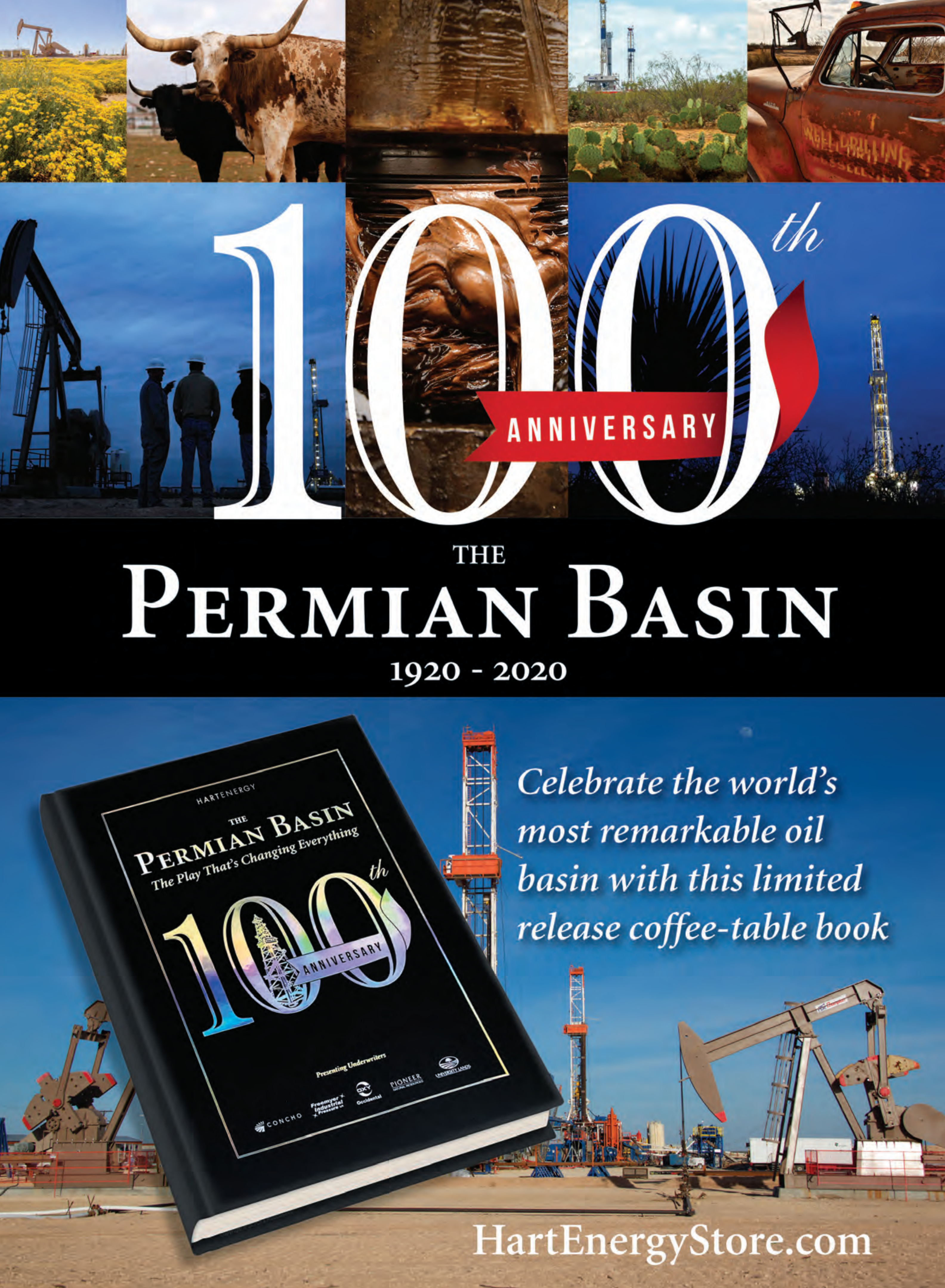
Consolidation offers benefits "in a world that appears to have fundamentally changed, at least over the last four years and even more meaningfully over the last four weeks," Cunningham said.

Still, he said the industry's pain will likely be prolonged, even as people return to work, because it appears the supply/demand imbalance will persist.

"It would not be surprising if we undergo 18 to 36 months of prolonged stress for the entire industry across all three streams," he said. "The supply fundamentals don't seem to portend a V-shaped recovery."

April oil demand is estimated to be 29 MMbbl/d lower than this time last year, down to levels last seen in 1995, according the International Energy Agency. Overall, demand in the second quarter is expected to trail 2019 by 23.1 MMbbl/d.

"The last downturn really showed us the resilience of different markets when A&D activity dries up and new capital enters the space to bridge the gap for challenged operators," Cockerham said. However, he added, "It's tough to look at what's happening right now and think, 'If our economy started going back to work immediately, we'll be at $65 oil in six months.'" □



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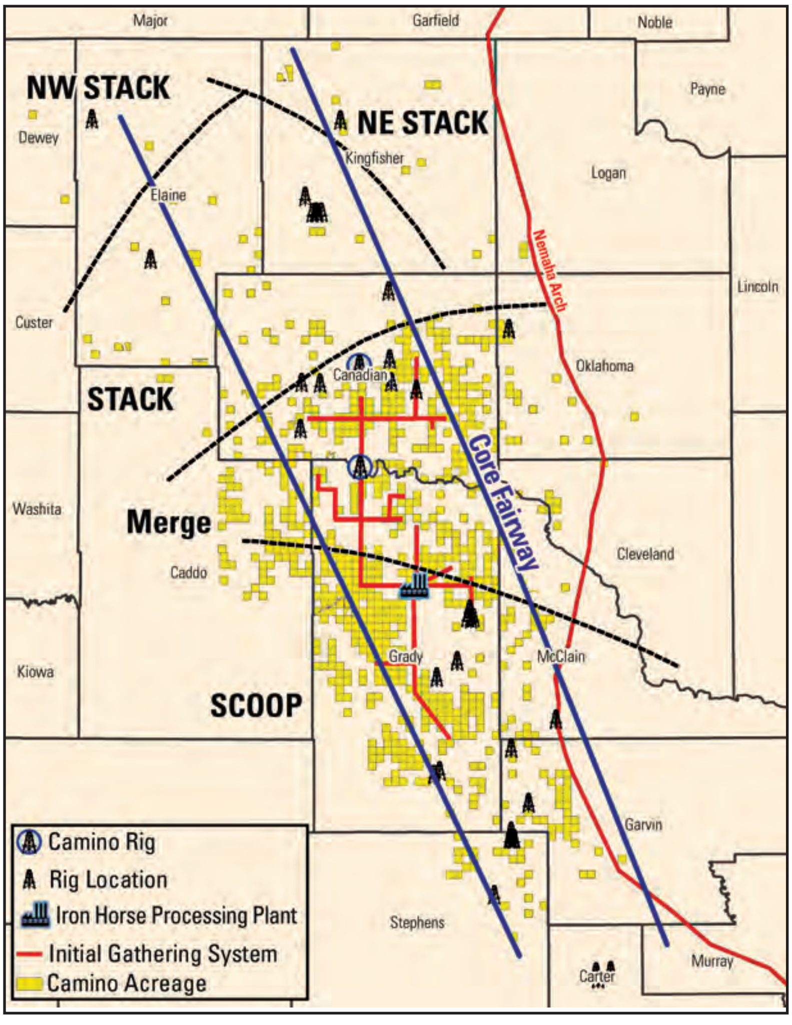
SIZE MATTERS

Camino Natural Resources embraced scale, an out-of-favor shale play and a robust hedging strategy as a beacon through the darkness.

ARTICLE BY
BLAKE WRIGHT

Ward Polzin was in Dallas when an email ticked into his inbox the morning of January 17, 2013. He was there on assignment with Pioneer Natural Resources Co. while working as a managing director for investment bank Tudor, Pickering, Holt & Co. The email was from an old friend, David Hayes, a partner at the private-equity firm NGP Energy Capital Management LLC. Hayes had a proposition: He wanted Polzin to run an MLP the firm would set up in Denver. Intrigued, Polzin agreed, but he needed a few months to tie up his affairs with the investment bank.

Camino's Portfolio



Through multiple transactions, Camino has scaled its acreage in an effort to become a large private operator in the SCOOP/STACK.

(Source: Camino Natural Resources LLC)

The MLP never happened.

In the interim, an NGP-backed producer in the Delaware Basin needed management willing to take the company public. NGP asked Polzin if he would shift his priorities and build a team that could execute in the Delaware and get the producer on an IPO track. By April 2014, Polzin was in charge of the newly-renamed Centennial Resource Development Inc. He and his team navigated Centennial through the ebb and flow of 2014 and 2015, successfully driving costs down and productivity up, and began positioning the company to go public.

The IPO never happened.

Instead, former EOG Resources Inc. CEO Mark Papa and his Silver Run special purpose acquisition company came calling in mid-2016, eager for an entry into the Delaware. Centennial was sold to Silver Run later that year.

The same year, a Marcellus producer, Vantage Energy Inc., was purchased by Rice Energy Inc. for $2.7 billion. The deals left a pair of veteran leadership teams without a home. NGP had conversations with Vantage vice president Seth Urruty about possibly moving forward with a new NGP-backed venture, but then a light bulb went off. NGP partner Chris Carter introduced Urruty to Polzin, and the pair hit it off.

"So we had these two groups that had done these large, private-equity-backed things on the cusp of going public, sold at roughly the same time," Polzin said. "These teams spun out around the same time to figure out what was next career-wise. There was a lot of common DNA [such as] running multiple rigs in a big shale play and having quality [rock and people] and financially [being capable of going] public. So we said let's try it again. We merged the teams together in late 2016."

The result was Denver-based Camino Natural Resources LLC.

Camino's Oklahoma growth spurt

The new NGP-backed venture's first order of business was targeting assets for A&D. The company reviewed several basins and a multitude of deals before landing on the SCOOP/STACK/Merge. But how does a company headquartered in the Rockies and filled with veterans of the Permian and Marcellus shales end up with an appetite for acreage in western Oklahoma?

CAMINO NATURAL RESOURCES LLC

A rig is on location at Camino's Cora Mae 10-15-1WH well in Grady County, Okla.

Ward Polzin took over as CEO of Camino Natural Resources in late 2016.

"Rock-wise, [the SCOOP/STACK/Merge] had a lot of productivity," Polzin, now CEO of Camino, explained. "There were a lot of private-equity-backed companies there, but they were [generally] small. We didn't see that one company trying to become a large private company in that space. We thought it had a lot of running room, and we wanted to go big again.

"I'm a strong believer in what you learn in one shale play is 100% applicable to other shale plays. Ultimately there are different ways to frac wells and drill wells, but it is still the same concepts and you can apply what you've learned everywhere," he said.

The company made its first acquisition in the middle of 2017.

Camino purchased the SCOOP and Hoxbar oil trend assets of Ward Energy Partners LLC, a subsidiary of Ward Petroleum Corp. Around the same time, NGP-backed companies Rebellion Energy LLC and 89 Energy Holdings LLC contributed assets in the SCOOP and Merge for Camino equity. By the end of January 2018, Camino closed its fourth acquisition—the purchase of Chesapeake Energy Corp.'s Merge position. The culmination of these deals brought Camino's holding to roughly 100,000 acres split evenly between the SCOOP and the Merge.

"Through those acquisitions, 89 and Rebellion each had a rig running, so we stepped into some activity," said Camino COO Seth Urruty. "We were able to almost immediately apply some of our completion beliefs and do some testing with slightly larger water and sand concentrations, but [we focused] mainly [on] optimization around the types of sand and the types of fluids that we believed were appropriate."

The first well the company drilled 100% as Camino was the ABEL 25-36-1XH—an early lower Mississippian/Sycamore target in Grady County. The probe was an offset to a Ward-operated well that was drilled a year before the acquisition. It was challenging drilling for the new operator right out of the gate and resulted in a series of tool failures and lessons learned, but ultimately it became one of the SCOOP's better wells. IP from the ABEL well was 18 MMcf/d of natural gas and 450 bbl/d of oil with a high NGL cut.

"Based upon that IP30 rate, it is still one of the top three wells ever drilled in the SCOOP," Polzin said.

Today, Camino holds about 118,000 net acres in the STACK/SCOOP/Merge and is producing about 40,000 boe/d.

As the company grew, the importance of scale continued to drive its narrative. From its earliest days, Camino was organized and run like a public company; scale was going to be important as the headwinds facing the industry stiffened. Even though there were three dozen private-equity-backed companies in the SCOOP/STACK/Merge, none of them appeared prepared to take on the role of being a singular, large entity. They simply were not capitalized to do so. It was an opportunity for the Camino team and its investors that wouldn't arise somewhere like the Permian Basin, where many billion-plus dollar private-equity-backed operators reside.

"The bigger you are, historically it's either a 'go public' or a 'smaller buyer' universe,"

CAMINO NATURAL RESOURCES LLC

Camino's Cora Mae 10-15-1WH well is located in Grady County, Okla. Camino has drilled some of the SCOOP's top wells.

Camino CFO Ryley Hegarty said. "If you want to do the scalable concept, then you have to think through longer time horizons than the normal three-year to five-year private-equity model. It was that common DNA across Vantage and Centennial.

"With Centennial, the whole plan was to go public. You need to be prepared to run that thing for the long term. At Vantage, that was a 10-year run for those guys. Seth brought a lot of good practices when thinking about running this for 10 years. It's serendipitous now with where the market is, but that was how we started."

Scale is seen as part of the longer model for private equity in the oil and gas space. The industry has emerged from the days of the three-year flip to those of a lower-for-longer and living within cash flow approach. Camino has not only gotten bigger via acreage deals; they have also integrated, taking on a midstream partnership with Cardinal Midstream and its Iron Horse System and a minerals partnership with Land Run Minerals.

"We had a track record with our previous companies of improving EURs and production rates, reducing costs and getting full cycle returns out of that," Polzin said. "We're applying that here, too. We can work marketing better now that we're bigger and optimizing our infrastructure, whether it's water handling or selling gas and moving NGL downstream with pipes.

"Equally important to all of that is financial [structure]. To last longer, you need to be financially conservative, frankly, and create optionality. We've done that by having the large equity support from NGP. By having scale we have a large lending capacity with our senior lenders. I think capacity is important, both equity and debt."

A hedging imperative

One area where Camino has proved ahead of the game has been with its robust hedging strategy. Most public companies hedge portions of their production for the span of the current calendar year if they hedge at all. Sometimes a portion will also be pushed into the following year. In contrast, Camino has hedged a lot.

"It's imperative that we have consistent and robust hedges," Hayes explained. "I think public companies reposition the optics of their hedge book depending on the direction of commodities prices, but generally speaking they hedge about half of their next year's production. Whereas with most of our companies, we have not only hedged their projected PDP [proved developed producing] but a significant amount of the projected increase in production [as well]. Now today, nobody's drilling."

He added, "We don't really get into business with anybody who is not willing to hedge."

During 2018 and 2019, the company locked in pricing for its 2020 and 2021 production. Today, basically 100% of the company's PDP wedge is hedged for the balance of 2020. Its oil production is 100% hedged for 2021. Placing the hedges early locked in a per barrel crude price in the mid-$50 range.

"If we are going to be here a long time, we're not going to roll the dice, so to speak, and be unhedged," Polzin said. "That could be a good place to be if oil goes to $80, but a bad place when it goes to $20. We were certainly giving up upside but reducing our downside."

Flexibility in a complex shale

During the time Camino was growing its position in western Oklahoma, the play was slipping out of favor with many. Touted early on as "Permian Jr.," the play was deemed an expensive underachiever by pundits. The per barrel cost to develop in the region swelled to the upper-$40 range by some estimates. Operators were pushing the boundaries of the core, while the issue of parent/child well interference began to rear its ugly head.

Camino knew the area was complex. Even as it reviewed deals, it studied what made each play tick—the natural drivers.

"I think the capital markets' narrative that the Midcontinent will never recover is a false narrative—it's fake news," Hayes said. "You had this land rush to grab lots of acreage across the basin, but it is not all created equal. There is a trend with some primo rock. It got drilled too tightly, and there were really high expectations. There is no 500-foot spacing; it's 1,200-plus foot spacing. You have multiple zones. During the land rush, people paid up for it while there was still a lot of learning going on across the industry. The capital markets felt like they got burned and threw the baby out with the bath water."

The underlying Woodford Shale in western Oklahoma is shallow in the east and deep in the west. When the original SCOOP area started around 2012, it was right atop of the very thick Woodford. The Woodford is thick in northwest Canadian County where the Cana Field resides. The Woodford is also thick in the middle of the basin.

"Our basin gets gassier to the west and oilier to the east, but quite frankly, we've found when you are looking for returns, it is not the oilier eastern part that has the highest returns," Polzin said. "It is somewhere in the middle. You lose pressure when you move to the east. You gain pressure to the west, but you lose oil. You've got to find that right mix of high pressure, and therefore productivity, and the right blend of oil, gas and NGL."

"[We found] the sweet spot runs southeast to northwest in our basin. Continental [Resources Inc.'s] Springboard [SCOOP] is right in the middle of that, the Lone Rock area for Cimarex [Energy Co.], the Cana Field—all of those go right down the spine of the basin. We've tried to focus in those areas as well, whether it's STACK, SCOOP or Merge. It still has those same characteristics," he said.

When the play overheated in 2017, operators pulled away from the core, trying to find

Camino COO Seth Urruty said the company was cautious with well spacing once it became apparent that aggressive downspacing wasn't working in the play.

Camino CFO Ryley Hegarty was part of the Centennial team that transitioned to the new producer.

productive extensions to widen the footprint. Pushing the STACK northwest and northeast did not yield the same results. In addition, fracture-driven well interaction issues arose once operators pushed aggressive well spacings during development.

"[With] every well we drill, we're learning, and we're trying to improve and advance, but you have to be cautious that you haven't drilled too many wells at a well density or a landing before you have technical certainty on the EURs and well productivity," Urruty said. "That's been a negative for our play. Interwell spacing was way too tight over the last couple of years, and people are now having to up-space and come back, but also the combined targeting of the formations. Certain folks had views that they were independent petroleum systems and you could stack wells, or drill Woodford wells and then come on top and drill lower Mississippian, and not have interference.

"Our view has been that those are going to communicate to some degree, certainly aided with the fracturing and the structural complexity that we see in the formations. You have to be thoughtful, and on a DSU [drilling spacing unit] by DSU basis, come up with a plan to develop those reservoirs together. We'll step into it more conservatively on an absolute spacing basis," he said.

Camino has drilled about 10 wells to date that offset either another operator's well across the lease line or one of its own. Most drilling has been done with one year to three years between completions, and the company has encountered infill—or child—well degradation. The company employs different strategies for managing the primary well to help optimize the fracture complexity in the child.

"The child wells are right in line on average with our type curve expectations," Urruty said. "There absolutely are issues with parent wells, and that's a big piece of wanting to understand how to protect the parent, how [to] produce that parent and help it get the frac fluid off early.

CAMINO NATURAL RESOURCES LLC

A blowout preventer at Camino's Cora Mae 10-15-1H well, which is located in Grady County, Okla. Parent/child interactions pose challenges in the areas where Camino operates.

CAMINO NATURAL RESOURCES LLC

A hydraulic fracturing spread is on location at a Camino well site in Grady County, Okla.

"It's a different answer for every well depending on where you are at in the basin and whether you've got more gas or more pressure to work with versus oily and lower pressure. We will do additional testing with some artificial lift mechanisms to try to get that frac fluid back and return those [wells] to previously forecasted rates," he said.

Intentions to consolidate

In late 2019, Camino was running three rigs on its western Oklahoma acreage. When it became apparent that oil prices were heading for $50, the company moved down to a two-rig program to stay within cash flow. By February 2020, the company was operating a single rig. Today, they are at zero.

"We were already decelerating before the big move," Polzin said. "We were anticipating a tough market. We certainly weren't anticipating this tough of one, but thank goodness we were already making moves to do better in a tougher market. Now, the new world order is like the old world order on steroids. It's lower prices for a longer time frame, and deeper cuts [are] required. It's more of that U-shaped recovery. We think this is going to be a rough environment through 2021. I hope we're out of it in 2022, but it's a minimum of 18 months."

Camino hopes it can bring a rig back if prices inch up, but for now all drilling activity has paused. The company reduced its capex by 70% over last year's spend. It is also fortunate to be able to continue paying down debt. The plan is to lower its debt from 2x EBITDA to closer to 1x by year-end. Additional hedges are also being examined as far out as 2023.

"The last thing we're worried about is production growth," Polzin said. "It's an output, not an input. It will probably run about flat this year, but we're really not aiming to be flat. We're not aiming to grow. It just is what it is. I want to be a survivor, and we will be. There is no question about that."

Survival is on a lot of minds in the oil patch today. The oil markets are flooded with product, and the COVID-19 pandemic has smothered demand. Bankruptcies in the space have already begun, and many more are expected. Camino intends to be a consolidator when the time comes, adding more of the critical scale it covets.

"For the same reasons [that] the publics want to get bigger, we believe that privates need to get bigger," Polzin said. "There will always be room for the small, entrepreneurial, focused company, but we think we need to position ourselves to be a larger private. I expect we will be bigger, and that's the goal. Merge with some other companies, maybe. Buy some other companies, maybe, but the goal is to be bigger because it is just a better economic, stable position for everybody involved. We hope to do some deals."

Hayes added, "They are very well hedged. Lightly levered. They stand out among smaller industry players in that geography as a team that is a likely consolidator based on the strength of their balance sheet and strength of performance." □

NGP partner David Hayes believes the Polzin-led Camino Natural Resources will be a consolidator in this low-price environment.

WHY ESG MATTERS IN A CRISIS

The oil price implosion and strategies for survival have replaced climate change and diversity as the top issues for energy industry boards, but employee health and safety, executive succession and compensation, and industry perceptions are ESG issues that will need attention, legal experts say.

ARTICLE BY
JOSEPH MARKMAN

ILLUSTRATION BY
ROBERT D. AVILA

If it's 2020, then climate change, board diversity, worker protections and data privacy are supposed to be driving corporate discussions. Obviously, priorities shift during a crisis.

"We're not spending any time talking about ESG in the boardrooms right now," said Hillary Holmes, partner in the Houston office of Gibson, Dunn & Crutcher LLP, whose job entails advising oil and gas company boards of directors on a range of strategies including—particularly at this moment—survival.

But don't push those issues aside for too long.

"It's really important to note that COVID-19 is an ESG crisis," stressed Sarah Fortt, counsel in M&A and capital markets at Vinson & Elkins LLP, during a recent webinar. "It's not the scenario that everyone was necessarily looking at. A global pandemic, without a doubt, is an ESG scenario. It's a nonfinancial risk. I think one of the things that's going to be interesting going forward is to see how investors respond to other areas of nonfinancial risks."

More immediately, ESG touches on succession for board members and senior executives who tend to be in the vulnerable age range for the virus. The crisis has also revealed the strengths of companies that addressed ESG seriously prior to the downcycle.

"At this moment, the value-add of diverse perspectives in the boardroom and strength in the leadership team—however that's defined at a particular company—is becoming … more important than ever," Holmes said. "I think that will highlight for companies what they already knew: having a diverse board, diverse perspectives, experience, background, race and gender and other things, is what a company needs, particularly in a time of crisis."

That realization will have ripple effects as the crisis abates and ESG returns to the conversation, she said. But even in the near term, companies will still need to grapple with a host of unexpected ESG issues.

Hillary Holmes at Gibson, Dunn & Crutcher said that diversity in board member makeup and perspective is critical during this crisis.

Honey, I'm home. And at work.

"We are in the middle of the largest telework experiment ever conducted on the planet," said Thomas Wilson, Houston-based partner with Vinson & Elkins, during a recent webinar. "We need to learn from this. This is not just the question of technology. It's about, how does work actually get done?"

Companies need to develop mechanisms for studying productivity during this period, he said, and determine the good and bad of telework. Will this iteration of the modern workplace show itself to be an improvement, or will it illustrate why the traditional office setting has always been in favor?

"The families of your employees are now, in effect, in your workplace," Wilson said. "Their pets are even there."

The oil and gas industry is no stranger to the concept of the remote work policies, with employees operating in far-flung onshore and offshore locales around the world, wherever hydrocarbons may be. But those outposts are purposeful. The newly at-home workforce in this crisis was forced into this situation hurriedly, with little preparation.

"When it comes to employees, there's the legal considerations and then there are also the human considerations," Fortt said. "That has to do with employee wellness with respect to their health but also mental and emotional wellness at this time of additional stress and

"A global pandemic, without a doubt, is an ESG scenario. It's a nonfinancial risk," according to Sarah Fortt at Vinson & Elkins.

unexpected moments of not knowing what's coming next."

To get a handle on employee isolation, Wilson recommends companies establish teams to examine these issues. Keeping in contact with workers will help establish how the workplace will function in the future because, as interminable as it may seem to be at times, the ongoing lockdown will end.

"We need to prepare our employees for the fact that this will be a slow process back to normal," he said. "We will also need to prepare for that new normal that we should be working on, and we should be working on that new normal now. How companies communicate with those who are watching is more important than ever."

It can happen to you

As the United Kingdom learned, Wilson said, even a head of state like Prime Minister Boris Johnson can be exposed to the coronavirus and contract COVID-19. Many inhabitants of oil and gas corporate C-suites are in at-risk categories for the illness.

"To operate a company in these times takes, obviously, strong leadership in today's situation," he said. "Success in succession planning takes on a whole new meaning. It is often difficult for leaders to consider the need to have a clear plan should the worst happen to them."

It's a tough discussion, Wilson said, but criteria are necessary ahead of time in the event that an officer or board member becomes ill, even if the plan is only in effect for a temporary period while the individual recovers.

When the company is in flux, people will be moved into new positions with new duties, meaning that compensation must be addressed. It could involve review of employment contracts or other kinds of agreements. For example, he said, do those agreements define disability? Any amendments to those agreements need to be addressed quickly in a crisis.

"Again, planning this ahead of time may make this process slightly less painful," Wilson said.

Of course, it's not just those at the top who can get sick. What happens when a worker with access to important data contracts the virus? First thing is to be careful. This is not one of those times a company wants everyone on the same page.

"I just want to remind people [that] the principles of data minimization from the data privacy perspective, meaning you don't collect more than you need, still do apply with respect to COVID-19," said Devika Kornbacher, partner in technology transactions and intellectual property at Vinson & Elkins, during the webinar.

Kornbacher recommended that companies keep the team made aware of the health information very small, only including people in a position to make a decision about whether that worker can continue to work onsite. The company at large does not need to know.

"So, yes, COVID-19 has absolutely changed how much data employers are feeling like they need from employees," she said, "but it hasn't changed the basic principles of keeping that information confidential."

If the company is publicly owned, then disclosure must be addressed.

"This is a real-world example of when emergency bylaws may need to be used," Fortt said. "So if you don't have emergency bylaws in place and it's permitted under the applicable state law where your company is incorporated, I think it's definitely timely to consider adding that so that the board can act with less than a traditional quorum if necessary."

And keeping investors in the loop is critical as well.

"That's what COVID-19 is really telling us going forward," Kornbacher said. "There's going to be enhanced disclosure expectation for how nonfinancial risks really do fit into enterprise risk management."

Companies may be accustomed to dealing with crises, but dealing with disclosures during one—especially one like COVID-19—is likely uncharted territory for most. It's not just about remote work policies but overall governance, climate change and cybersecurity risks come into play.

How do we look?

"At no time has there been an opportunity to show strong corporate culture as we have today," Wilson said. "Certainly your employees are watching how this all goes. We also have to understand that others are watching. If you think social media discussion about your company was important before all of this happened, with almost everyone using social media to maintain their connections to others, a negative report about your company's treatment of employees will catch fire and spread quickly."

It's not too early for companies to start thinking about how they want to be perceived following this crisis, Fortt said. The best-case scenario is to be seen as a company that took a balanced approach and communicated well and thoughtfully. Worst-case scenario: to be judged tone deaf to the situation.

"In a presidential election, which will no doubt ramp up the heat of the rhetoric, we need to start this process now," Wilson said. "We cannot have that tone deafness as to what we are doing now, and in the coming weeks and months [have that perception] by our workers, our shareholders and all types of activists."

Each decision on compensation, employment, safety and the like will be magnified in importance for some time, he said.

"If we don't have a relative revolution on the streets and in social media, we will need something of a revolution in corporate culture," Wilson said. "We cannot forget the lessons we are learning right now."

Among those lessons are paying attention to executive compensation and CEO pay ratio; safety in the workplace; and treatment of the workforce. Those could include flexible work arrangements in the future and studying whether remote work helps or hurts companies and employees.

To prepare for the industry's future as it operates during this crisis, "We could use ESG to do better and to improve our imagination," said Thomas Wilson at Vinson & Elkins.

They also include the well-being of employees sent around the world to work. The protection of those employees can be a difficult issue to address in the energy business, in which staff is regularly shipped to sites overseas.

"A lot of thought in the future needs to be given to the need to operate in some areas," he said. "And if the conclusion is that operations in these areas are imperative, we need to really think thoroughly through the issue of how we protect our employees who are there and how we bring them home in case we need to do so very quickly."

Few, if any, anticipated the convergence of a global pandemic with an oil price collapse, but Wilson views ESG as a useful tool in prompting companies to stretch their imaginations to prepare for the next crisis.

"Rather than just being concerned about what the rating companies are doing, what your scores are, we could use ESG to do better and to improve our imagination," he said. "This may not be something we can do just company by company. Maybe we need to create a new industry group, the 'Black Swans Association,' if you want to call it that, to consider what the future could bring and prepare for it." □

Companies must be mindful of what information they disclose during the COVID-19 pandemic, said Devika Kornbacher at Vinson & Elkins.

ON THE OFS FRONT

Several oilfield service shops have cash and no or little debt. They plan to expand.

ARTICLE BY
NISSA DARBONNE

Check in on oilfield service firms' (OFS) outlooks in mid-April, they said. It'll be fine, they said.

And it was, when talking to an OFS executive who once drank the frac fluid, one who handles produced water and one who delivers sand.

A bonus: some virtual birding as each was working from home. In Denver and on the Texas coast, springtime courtship serenades were well underway.

April frac starts in the U.S. were some 300—"the largest monthly [percent] drop in fracking activity ever recorded in the U.S.," reported research firm Rystad Energy near month-end. The February count was 807, falling in March to 550.

Of the April jobs, two-thirds were in the Permian and the other 100 were split between the Bakken and Eagle Ford. The U.S. land rig count was 512, according to Baker Hughes Co., with more than half of those drilling in the Permian.

"Offshore is deteriorating faster than it has in previous cycles …," wrote CapitalOne Securities Inc. analysts.

The Louisiana Oil & Gas Association's weekly activity report on YouTube was brief: One rig in federal waters, one on the Gulf Coast and 24 drilling for Haynesville gas.

The CapitalOne team said current OFS budget cuts "likely won't be the only one." Calling it "Fracpocalypse," they were nostalgic for the "times in the oil field when the biggest issues were impacts to the lesser prairie chicken."

J.P. Morgan analyst Sean Meakim titled his summary "We're Going Down The Big Slide This Time." Bernstein Research analyst Nicholas Green concluded, "Grab that kitchen sink and throw it. Take the initial commentary to the market and double it."

Barclays Capital Inc. analyst David Anderson forecasts the other side of the cycle will see that "digital is propelled, de-manned operations are accelerated and E&Ps will consolidate their surviving service providers."

Balance sheet

Apple stores have a Genius Bar for diagnostics. The oil and gas industry has them too. One of them is Chris Wright, CEO and chairman of Liberty Oilfield Services Inc.

"All the guys and gals on our locations have a long-term mentality … And in several months, they'll be back at it. It will be months away, but they will be there," said Chris Wright, CEO of Liberty Oilfield Services Inc.

SOLARIS OILFIELD INFRASTRUCTURE INC.

Solaris Oilfield Infrastructure Inc. silos of proppant at a multilwell pad in the Permian Basin.

Besides playing a role in the birth of the shale revolution, Wright once made a serving of frac fluid and drank it in a YouTube demonstration of its benign ingredients.

One evening in early April, he had to write to Liberty's approximately 2,500 current and newly former employees. Half had been laid off during the day. He described the company's plan going forward. More than a dozen who had been laid off that day wrote back immediately.

"They were hoping I was okay," Wright said. "They were pulling for Liberty and couldn't wait to come back some day. They had just lost their job—and at the worst possible time—and they're emailing me, hoping I'm okay."

Founded in 2011, Liberty entered the 2015 to 2016 downcycle with 600 employees and exited with 600.

"I had never laid off anyone in my life," Wright said. "But this one is really different. The incredible pace of the collapse for our products—oil and gas—it's just a very different time."

He expects Liberty to grow through this cycle, though. "It's not only our goal; it's our mission as this thing rebounds to grow the business back up and bring everyone back," he said.

Liberty's balance sheet at year-end was $113 million of cash on hand—about $1 per share—and total debt of $106 million in term loans maturing in the second half of 2022. Its credit facility—$283 million at the time—was undrawn. That wasn't by chance.

"This industry is crazy," Wright said. "You don't get a long warning before a downturn. You have to have a strong balance sheet. The next few quarters are going to be dreadful, but we're going to get through this."

For how long should it be prepared? Six quarters? Three years? "I definitely think a good while. We've never seen demand destruction like this. The financial crisis [of 2008 to 2009] was not even close. Even the Great Depression was not even close," Wright said.

The estimated demand destruction is 25%, which is about 25 MMbbl. "That's a big hole to dig out of," he said. "It's going to create so many things we can't predict."

Among these, governments funded by oil exports are going to collapse, Wright expects. "There will be a lot of supply disruption. I think it's 18 to 24 months before we feel fully on the other side," he said.

The other side will look remarkably different from the oil industry of the past, he added. "When the dust settles, a large number of companies on both the E&P side and service side will be gone.

"Sadly, there will be a huge number of bankruptcies. There will be a huge number of mergers," he said.

The pressure pumping business will be smaller. CapitalOne Securities estimates that the remaining providers will be Halliburton Co., Nextier Oilfield Solutions Inc., ProFrac Services LLC, ProPetro Holding Corp. and Liberty "as cash can't keep being injected into the business," the analysts said.

Revolutionary change

Wright was part of the early shale fracturing industry. His frac diagnostics business, Pinnacle Technologies Inc., was on the Union Pacific Resources job in 1995 when it determined that just using slick water when fracturing tight rock—at the time, the Cotton Valley in East Texas—worked better than gel.

Wells were more productive, and they were less expensive.

Pinnacle Technologies was also involved when George Mitchell first tried it on the Barnett Shale. The shale gas revolution was born. Recipes developed in its ongoing trials were adopted in trials of fractured horizontals in the Bakken in eastern Montana and in North Dakota, spurring the tight oil revolution.

Wright would do it all again, of course. "I'm incredibly proud of what the shale industry has done for this country and for all the citizens of the world—particularly low-income citizens.

"We save over $1 trillion per year for consumers. For low-income people, energy is a huge cost. We've helped lift literally tens of millions of people out of poverty, and we've grown life opportunities. So, yeah, I'm thrilled it happened," he said.

Sure, free markets naturally seek the outer limits of demand. "Like any revolutionary change, it causes big disruption, and this did too. Lots of capital was destroyed. Everybody rushed to put money in, started companies, too many poor businesses.

"That made the business very challenged. Our industry has had a bad decade of return on capital, and investors are tired of us," Wright said.

Liberty's stock price was $3.34 in late April, after the May contract for WTI delivered to Cushing fell to negative $40 on paper as it was being settled. It had IPOed in January 2018 at $17. Its all-time high was $23. Its dividend had been a nickel per share, quarterly; it was suspended in April.

Tudor, Pickering, Holt & Co. (TPH) analysts wrote after the Liberty cost-cutting news that it was "better positioned than most pumpers." The analyst said the cuts "struck us as some of the more laudable cuts across the OFS space" although "painful and unfortunate."

Manned crews fell from 24 to 12. They expected Liberty would "toe the line on" free cash flow.

"Couple that with their net cash position, top-notch management team and undeniable execution prowess, and we believe Liberty's equity will survive this squall," the analysts said.

CapitalOne Securities' Luke Lemoine wrote that Liberty was "directionally positive." In addition to layoffs, it reduced officer compensation by 66%, including cutting salaries 30% and board member retainers 30%. Net, "We're still modeling Liberty generating $20 million to $30 million of annual free cash flow in this environment," Lemoine added.

"We really view our field guys as our front line. They are the key to customer relations and make sure everything works for our customers," said Bill Zartler, founder, chairman and CEO of Solaris Oilfield Infrastructure Inc.

MORE OFS

In addition to the Big Three—Schlumberger Ltd., Halliburton Co. and Baker Hughes Co.—here are a few more of the several OFS names getting love.

Cactus Inc. (WHD): Raymond James & Associates Inc. analyst Praveen Narra wrote that, despite the downturn, Cactus "should be a free-cash-flow generator over the next two years, further bolstering its net cash position." He reiterated his Strong Buy and raised the target from $15 to $22. Its net cash position was $200 million with zero debt, and Narra expected it to exit 2020 with $300 million and zero debt.

"In our opinion, Cactus is one of the most defensive names on the small-cap side for U.S. oilfield services," Narra said. With the stock undervalued, "We view the name as a take-private candidate," he said.

Cactus IPOed in February 2018.

Helmerich & Payne Inc. (HP): The land rig operator has $355 million of cash and net debt of $124 million. "There's also an undrawn $750-million credit facility that matures in 2024," wrote CapitalOne Securities Inc. analyst Luke Lemoine. Its outstanding bonds—about $480 million—are due 2025.

H&P cut its second-quarter dividend from 71 cents (about $300 million per year) to 25 cents (about $100 million per year). That "would allow HP to keep building cash in a tough operating environment," Lemoine said.

Tudor, Pickering, Holt & Co. (TPH) analysts wrote that the remaining dividend is both attractive and sustainable at "roughly 6% current annual dividend yield, but more importantly [it] ensures that its balance sheet will remain in strong position even as contract coverage wanes in coming years."

They added, "We have zero survivability concerns here."

Patterson-UTI Energy Inc. (PTEN): Exiting 2019, Patterson-UTI had $174 million of cash, an undrawn $600-million bank facility with a 2024 maturity, $525 million of 2028 notes and $350 million of 2029 notes, Lemoine said.

"In today's stressed scenario, we're modeling normalized free cash flow of some $130 million, which would be sufficient to meet all debt maturities through 2029," he said.

Trican Well Service Ltd. (TOLWF; TCW.TO): "Despite a menacing outlook, we've no survivability concerns here," TPH reported. Cost cuts and a 2020 capital budget for only maintenance means "Trican is following the right playbook."

Fourth-quarter 2019 net debt to capitalization was about 5%, offering "more than enough flexibility to ride out the forthcoming storm," TPH said.

Growing market share

Liberty's success has derived from the company being "the preferred provider for our customers," Wright said.

"In the past two years, we have been growing our market share with the largest E&Ps," he continued. "The pie is shrinking now, but we're growing our piece of that pie because I think we do a better job than our competitors."

Liberty also has been selective of its customers. "I think they will be consolidators. They are going to do much better than the average E&Ps in this downturn," he said.

Wright also points to the Liberty team as a source of strength. "They're strong, resonant folks. They love their jobs and that's everything," he added.

Later in April, Wright hosted a town hall teleconference. Among employees joining were crew members at a frac site on pause between stages. (They were off duty at the time.) The customer had announced that morning that it was shutting down completions across North America.

"And these members of the crew were on the call." Wright asked them spontaneously from the more than 300 individuals on the video call, unaware which crew they were on. The crew said, 'We know we're going to be furloughed, but it's not impacting our love of Liberty. We are Liberty Strong, and we'll be ready to go back to work.'"

Wright said, "People view Liberty as a career and not a job." Some 96% of employees participate in the company's 401k program.

"All the guys and gals on our locations have a long-term mentality," he said. "And in several months, they'll be back at it. It will be months away, but they will be there. That's a huge asset. They saw how Liberty handled the last downturn."

Meanwhile, Wright said, "The next nine months for the frac industry are really going to be awful."

"We're very sad to make cuts we need to make on the operating side, but we are making investments for what this looks like in a turnaround in a brighter future," said Kyle Ramachandran, president and CFO of Solaris Oilfield Infrastructure Inc.

All cash, no debt

Over at Solaris Oilfield Infrastructure Inc., the team was holding up well. "We haven't heard anyone break a window during a video conference, so I think everyone is as sane as could be right now," said Bill Zartler, founder, chairman and CEO.

Cowen & Co. LLC analyst Marc Bianchi had proppant-delivery firm Solaris on its short list of favored small-cap OFS stocks. TPH analysts expected "completions activity to fall off a cliff, but Solaris will survive the fall." The balance sheet has $46 million in net cash and, they added, it is a preferred last-mile offering and has limited capex needs.

TPH reported, "They're one of the best-positioned U.S. onshore completions-oriented OFS equities in our space, and we expect them to leverage all the arrows in their quiver to survive this brutal oil market blitzkrieg."

Zartler said, "We've set our balance sheet up really conservatively. We have cash on the balance sheet north of $1 per share, no debt, a very scalable model, pretty low corporate overhead for a public company and … we really view our field guys as our front line. They are the key to customer relations and make sure everything works for our customers."

The layoffs there have been difficult as well. "It's tough to see them go as the market

Liberty Oilfield Services Inc. crew members monitor a hydraulic fracturing job underway. The frac firm reduced its fleet count from 24 to 12 in April but plans to exit the current cycle with a greater overall market share.

has fallen," he said. "It's a pretty dramatic reduction in completion activity."

Kyle Ramachandran, Solaris president and CFO, said, besides a strong balance sheet, "our team is pretty diverse." This includes a sizable software team, an R&D team and a team that leads business development, capital-raising and investor relations. "It's unique for a company our size. We kind of see this as an opportunity," he said.

He and Zartler noted this isn't Solaris' first downturn. It was founded in 2014 and IPOed in May 2017. Ramachandran said, "Starting in 2014, leading into 2015, was not a great time. But we were slow and methodical, focused on building the business."

In this one—again with a strong balance sheet—Solaris is on the offensive. Ramachandran said, "We're very sad to make cuts we need to make on the operating side, but we are making investments for what this looks like in a turnaround in a brighter future."

Fleet optimization

Solaris entered 2020 with about one-third of the market for its core business—storing, managing and delivering proppant to the frac site. "We think there is opportunity to grow that share as well as consolidate other offerings during the downturn," Ramachandran said.

It is also upgrading its fleet. "We view this as an opportunity to really evaluate our system," Zartler said.

Much of its fleet has been in the field nonstop. Bringing some back into the yard, Solaris is giving them an Oz treatment, making them shiny again but optimizing them as well "to make them better when they go back out," Ramachandran said. That will be during the next six to 18 months. A "more normalized version" of the industry will begin to emerge six months after onset, he estimates.

"I don't think it's going to happen much sooner than that. But, as it happens, we want to be prepared with the same kind of service and quality reputation," he said.

Meanwhile, Solaris continues to work in earnest on R&D. "We launched [Solaris] when it was a bad time to start an oilfield service company," Zartler said. "But we were spending a lot of time, making sure the offering, the people and the product were ready to take on the challenge."

At the time, other firms were focused on mending their balance sheets. "We have a strong balance sheet and are focused on offense and making sure our offerings are state of the art," Zartler said.

These include more automation at the well site. "All of the focus is on making our customer more efficient—things that help them do better," he said.

The supply chain upstream of Solaris' offering is the proppant, which the company is delivering and blending. "We're not in the business of making proppant, selling it or mining it," Zartler said. "There will be temporary challenges, but the core industry has shown a pretty rapid response now in proppant availability."

The downturn is not a permanent problem, he emphasized. "It's a cycle," he said. Of course, he also noted, "This one is like one that no one has ever seen."

At Solaris, Zartler said they are "making sure we learn our lessons and get more efficient—that we create something new and don't lose that edge coming out of this cycle."

"I think we all have been awakened to the idea of black-swan events if we hadn't already ... Anyone planning on fewer than 12 months is probably kidding themselves," said Justin Love, CEO of Blackbuck Resources LLC.

Ramachandran noted that several of the Solaris team members started a water infrastructure firm during the last downcycle. To borrow a quote, he said, "Don't ever let a good downturn go to waste."

The rest of former White House chief of staff Rahm Emanuel's comment, referring to dealing with the 2008 to 2009 financial crisis: "It's an opportunity to do things that you think you could not do before."

M&A opportunities

Over at Justin Love's work-from-home office in the midst of homeschooling, his daughter complained that her business partner—her 6-year-old brother—wanted to sell the lemonade for $4 per serving. Love talked his son down to 50 cents. "You have to price it to your market," he said.

Love's plan for water infrastructure firm Blackbuck Resources LLC is to expand. Demand for freshwater and recycled produced water is declining as frac jobs decline. But volume for disposal will grow in the near term.

Formed in 2018 with equity backing of Dallas-based Cresta Fund Management, Blackbuck has no debt. "We feel really good about the market for companies like ours," Love said. "We are really disciplined in our approach. We contracted with great parties with contract structures that support our continued growth. We see a world of opportunity."

Love expects Blackbuck's expansion to be via M&A. "We're ready to grow. We've seen many E&P companies divesting their water assets, and the current market conditions will only accelerate that. Servicing debt will be a top priority for many E&Ps," he said.

The firm's commercial development team is "the most sophisticated development team in the business," he added.

"In fact, we evaluate acreage and upstream modeling with the same depth as E&Ps," Love said. "We look at it like we're the oil company and try to find the really good, economic rock. We try to justify the business case for the actual rock."

Love expects that will result in Blackbuck enduring the cycle. "I think these factors will be a big differentiator for us to grow, and we have the ability to stop and hunker down if we need to versus having to service debt.

"If you're not servicing debt right now, you're trying to restructure it, and that's huge time resources spent," he said.

In addition, Love said Blackbuck can operate E&P assets if needed: "We're just extremely creative right now. We want to help E&Ps improve operating expenses and capital efficiency," he said.

He expects the downturn will last at least 12 months. Blackbuck is wholly focused on the Permian where Love said "It's going to be tough. We're prepared for 24 months. But who knows when recovery will start?"

Love added, "I think we all have been awakened to the idea of black-swan events if we hadn't already. There's always the potential for conflicts globally or [the virus could] come back in the winter. Anyone planning on fewer than 12 months is probably kidding themselves."

Reenlisting the workforce

In under two years, Blackbuck carefully built its team—an "A team" that Love calls Blackbuck's "most valuable resource."

After 2014, E&Ps and service firms pared to their first string; the current round of layoffs is of many all-stars. How many will return to the industry on the other side of this cycle?

Solaris' Ramachandran said the human capital side of the business is at risk. But this cycle might be different from 2015 to 2016. In that downturn, there were other jobs workers could go to.

Currently, as the broad U.S. and global economies are in self-imposed park, maybe "It could mean people stay in the oil and gas sector," Ramachandran said. Still, he added, a human capital challenge in the upstream industry will remain.

Ramachandran joined the industry in this century. Use and development of technology in the business will continue to drive excitement about getting into it. "So there is opportunity to pick up talent," Ramachandran commented.

But the field personnel—the laborers—might not be keen. "They are looking at the need for a steady income. In some ways, the shale revolution has increased the frequency but shortened the duration of volatility."

The ups and downs aren't for everyone. "This business has had more short-term cycles," he said. "But the massive demand-driven challenge has raised hairs on the necks of even the most experienced folks."

At Liberty, Wright expects many workers won't return to the industry. There will also be fewer jobs. "One of the great things—but one of the tough things—about this shale revolution is the incredible change in efficiency," he said.

In 2008, before U.S. gas supply overwhelmed what demand existed at the time, there were 1,600 gas-directed rigs at work.

"We were the largest natural gas importer in the world, and we had 1,600 rigs drilling for gas. Today we have fewer than 100, and we're the third largest LNG exporter in the world. That's awesome for price and efficiency, but it means fewer employees," Wright said, explaining that the 2015 to 2016 downturn was "another step toward a leaner industry. Maybe this is another one."

With Liberty's plan to increase market share, it expects to be back at 2,500 employees two years from now. Wright said, "We will do far more work, far more stages, more sand than fourth-quarter 2019, and we probably have a much larger market share."

However, he added, "Market share isn't the goal unto itself. We want to be the best provider, and that results in a growing demand for what we do." □


Wright & Company, Inc.
Petroleum Consultants

LITIGATION BOOMS AS SHALE TRIES NOT TO BUST

The sudden price collapse, global recession and enduring pandemic set this downcycle apart from previous troubles, but the steps leading to bankruptcy filings remain the same. Oil and gas litigators explain how they are guiding their clients.

ARTICLE BY
JOSEPH MARKMAN

In some ways, the "new normal" oil and gas downcycle resembles the old normal.

"We are seeing expected trends in unprecedented times," Reagan Marble, who specializes in complex energy litigation and transactions in Jackson Walker's San Antonio office, said. So, whether it is a global pandemic/recession/price war or a garden-variety glut, the legal fallout follows a pattern.

Three trends of litigation have emerged since the March 9 crash, Marble said, that apply to oil and gas companies, as well as landowners:

- Lease termination disputes;
- Post-production cost disputes; and
- Bankruptcy.

"The mood generally is that those people that barely survived 2015 won't survive this [downturn]," said Reagan Marble at Jackson Walker.

Leases

As WTI plunged on March 9, Jackson Walker's phones were ringing and inboxes were filling with calls about the perpetuation of oil and gas leases.

"Remember that we haven't been in an increased price environment for an extended period of time," Marble said. "We have actually been in a depressed price environment for a while now. It was already teetering on the edge."

In Texas, an oil and gas lease is in effect as long as there are production and paying quantities, or that revenues exceed expenses. A price collapse from \$60/bbl at the start of the year to \$20/bbl by mid-March can easily allow expenses to exceed revenues.

As a result, Marble said, landowners need to ensure that expenses are not exceeding the revenue from an oil and gas well. Operators also need to make sure expenses are in line with the market. This is probably a good time, he said, to renegotiate contracts with service companies.

Where it can get complicated is when there's an issue about whether a well is producing in paying quantities, Michael P. Darden, partner-in-charge of Gibson Dunn's Houston office and chair of the firm's oil and gas practice group, said.

"The test for producing paying quantities is a very difficult one to apply," Darden said. "You can have a well that doesn't produce for two years, and it could still be considered to be producing in paying quantity. You look at a real long period of time to make that determination and a lot of factors."

Some leases allow shut-in wells for certain specific reasons over specific lengths of time, he said. If the lease doesn't allow shut-ins, then it's a matter to test whether the well is producing in paying quantities.

"So in either event, over some period of time there will be arguments by landowners that the wells on their leases are no longer producing in paying quantities and that the oil companies will have to release that acreage," Darden said. Of course, in this time frame, that situation is entirely theoretical.

"It would not be a great environment right now for the lessor—the landowner—to do that," he said. "It's not like somebody else is going to lease it from them and drill it and pay them more for it."

Post-production

The second trend originates, to some extent, in rumors, as executives ask, "Who will survive this downcycle? Is my partner in this project one of those that will not? And what do we do about it?"

"The mood generally is that those people that barely survived 2015 won't survive this one," Marble said. "We have had multiple calls about what they can do if they have a claim or if they're behind on collecting some monies owed from those parties to make sure they preserve their rights in the event something forces that company to go into bankruptcy."

"You'd like to hope people [come up with a win-win], but with a lot of insolvency looming, it's hard to say how that will play out."

–Cliff Vrielink,
Sidley Austin LLP

Jackson Walker represents both landowners and operators; while the attorneys understand both perspectives, they also know when it's time to have a candid conversation. The landowner's claim that the operator has failed to live up to the terms of a lease might be a good one, Marble said, but terminating the contract right now is probably not a great idea. The question is, would anyone else want to drill in this market environment?

Or a landowner could sit until the market bounces back with land unleased until the market improves and bonuses return, perhaps with a negotiated higher royalty.

"Sometimes your landowner response is, 'No, I don't want the lease terminated at the moment; I just want to negotiate better provisions of my lease,'" he said. "And this is a good time to use that leverage to fix some things that you want to have a second bite at the apple for."

One of his landowner clients had a lease with a Fortune 500 oil and gas company that had drilled four more wells but not completed them. The contract included a continuous drilling clause that required the company to drill and complete these wells to perpetuate the lease.

But the landowner didn't want to terminate the lease. He was calling Marble because he didn't want to be paid royalties on $20 oil.

"Sometimes it behooves the landowner to cooperate with the operator and it almost always behooves the operator to cooperate with a landowner," he said.

A number of the more recent and more sophisticated leases, particularly in the Permian Basin, also have continuous development or continuous drilling requirements, Peter Hosey, partner in Jackson Walker's San Antonio office, said.

"The conundrum is there's an obligation to drill but the resulting economics aren't there to do so, yet the operator wishes to maintain his lease in whole," Hosey said. "These are extraordinary circumstances, quite unforeseen. They would have a difficult time in doing that, especially if it's one of the myriad companies that may be, at this point, capital strapped."

The value of a claim is dependent on the counterparty, Cliff Vrielink, co-managing partner of Sidley Austin LLP's Houston office, said. "If your counterparty is insolvent, then it may not do you a lot of good to go to court."

Bankruptcy

To contrast this downcycle with 2015, remember the closing price of WTI at Cushing, Okla., was $95.55/bbl on Sept. 26, 2014. One month later, the price had declined to $81.26/bbl. Then in November, the price closed at $73.70/bbl the day before Thanksgiving; it closed at $65.94 the day following the OPEC summit.

By the end of first-quarter 2015, the price was in the $50s; by the end of the third quarter, in the $40s; by the end of 2015, in the $30s. Certainly not the best of times, but because it was drawn out, the phases of litigation were drawn out as well.

"We at least saw some runway [in 2015]," Marble said. "I mean, we saw massive wipeouts of portions of the market over the last two weeks in March [2020,] and we saw an industry that was already teetering on the edge and an industry where capital markets had dried up all of a sudden have 66% of its value wiped out essentially overnight."

Hence, the recent scramble. As companies try to increase revenue any way they can, they sometimes attempt to renegotiate contracts with their service companies, he said. That often means deducting costs from the royalties of the landowner that are expressly prohibited by a lease agreement. Those are known as post-production costs, and sophisticated landowners put audit rights into their oil and gas leases.

"In the last two weeks, I've kicked off two audits on the basis that the landowners already anticipate because they saw this trend, and a few months before this hit, [on the basis] that the lessee will continue to deduct post-production costs that are prohibited under the oil and gas lease," Marble said. "And that's another trend that you see in a market downturn. You see lease termination disputes. You see post-production cost disputes, and then you see all of the stuff priming you for bankruptcy and then the bankruptcy itself."

The attorneys all agreed that court battles were not inevitable. Vrielink noted that there was a great deal of litigation following the Sabine Chapter 11 case, in which the E&P was able to reject contracts with midstream service providers.

"What we instead saw was a lot of people sitting down at the table and saying, 'Let's reconsider our structure, and let's come up with something that ends up being a win-win,'" he said. "So you'd like to hope people do the same thing here, but with a lot of insolvency looming, it's hard to say how that will play out."

Clearly, that would benefit the upstream company in such a dispute, but Darden said that a rational midstream company would also agree to renegotiate a contract, realizing that if it doesn't, an insolvent producer will pay nothing.

"That would incentivize or motivate midstream companies to renegotiate their contracts," he said. "Sometimes it takes a lot of pain before somebody realizes that." □

Terminating a lease is not necessarily in landowners' best interests, said Michael Darden at Gibson Dunn. He added, "It's not like somebody else is going to lease it from them and drill it and pay them more for it."

Operators in continuous drilling agreements face an unprecedented conundrum, Peter Hosey at Jackson Walker said, since they are obligated to drill but lack the economics to sustainably do so.

LOOKING FOR GAIN, NOT PAIN

A year from now, which E&P stocks will investors wish they'd bought in 2020's summer doldrums?

ARTICLE BY
LESLIE HAINES

ILLUSTRATION BY
ROBERT D. AVILA

Low oil prices might be the cure for low oil prices by year-end, but for now, "There ain't no cure for the summertime blues," as the song covered by the likes of The Who and Alan Jackson said.

Oil and gas equities were under siege well before the OPEC+ price war erupted in early March and COVID-19 simultaneously swept the globe to stop economies in their tracks, killing oil demand. Storage tanks began to fill. Then came April 20; let's call it Black Monday. The near-month contract for WTI briefly plunged below zero, dragging energy stocks along for a hairy ride. Both recovered somewhat over the next few weeks, but uncertainty left investors mulling their options.

It has been difficult for analysts to make any Buy calls for the near term, much less for longer, when E&P companies under coverage are in flux and suspending their production guidance and markets are gyrating. Many analysts have suspended price targets or earnings estimates until the second half of this year comes into focus, much less 2021.

John White, managing director at ROTH Capital Markets, said he suspended all coverage of the E&P and service sectors and that all his ratings became Neutral until companies revise their guidance. He's emphasizing free cash flow, a good credit position and hedge strength. Later, however, he issued a Buy on Earthstone Energy Inc. because it is 80% hedged for the year at a blended rate of $58.90/bbl. Later, he upgraded Talos Energy Inc. to a Buy, citing its low leverage, hedges and a low decline rate.

"Visibility is virtually nonexistent. Take all of this [our report] with a grain—no, a fist—of salt," said the E&P analysts at Simmons Energy Co. in one of their reports in mid-April.

At press time, WTI for June delivery was hovering between $13/bbl and a whopping $17/bbl, with the 12-month strip a woeful $25/bbl. In a research note, Simmons highlighted the problem E&P companies face: They need $15/bbl to cover production costs, $20 to cover all cash costs and $50 to hold production flat within cash flow in 2020 (not counting any hedging gains they may be lucky enough to book).

As oil fell to $20 and below, Bakken and Eagle Ford producers were starting to shut in some wells. First-quarter conference calls indicated many companies intended to stop drilling, hoping to keep production flat at best. Announced production cuts totaled about 600,000 bbl/d, and analysts estimated U.S. oil output could fall by as much as 1MMbbl/d or 2 MMbbl/d by year-end.

The U.S. oil-directed rig count was down by about 50% from 2019 levels to the lowest count since July 2016, dropping below 500 in the week ending April 24, according to Baker Hughes Co. The Permian count fell below 250.

In such an unprecedented environment, can any long-term Buy signals be found? Surely this is a great time to hunt for bargains. At this point, analysts said, it is really about identifying which companies will lose the least this year.

"I don't think valuations matter much in the near future," Leo Mariani, analyst at KeyBanc Capital Markets, told Investor. "It's more about financial liquidity, not having any bonds due soon, hedging and which companies will have less damage and can come out the other side."

He said he hoped for a U-shaped recovery, which is his base case.

"I don't think valuations matter much in the near future. It's more about which companies will have less damage and can come out the other side," said Leo Mariani with KeyBanc Capital Markets.

Looking for multiples

Multiples of EBITDA won't expand in 2020 because most companies will report lower production and lower cash flow through year-end. However, analysts think these metrics will improve in 2021 as cash flows rise, and even if their production is held flat, oil prices should recover enough to be above $30/bbl, therefore improving cash flows.

"Today, there is no discussion about which company has a multiple of X or Y; it's more about survivability," Mariani said. "Stocks are trading down to the point that investors are assuming no recovery or that we stay at or below $40/bbl, but no one knows how this will play out."

Multiples were trending lower compared to historical numbers before the dual oil price/virus crisis hit, he said. Traditionally, E&Ps have traded at five to 10 times earnings over the past 10 years, but lately they were trading at multiples of only three to six times, he said.

Mariani covers 29 names, from small caps under duress such as Gulfport Energy Co. to much larger and more solid players like EOG Resources Inc., so he has plenty to chew on. He's bullish for 2021, thinking WTI will get back into the $50s as the economy recovers—indeed, his official forecast is $55/bbl for oil and $2.30 for natural gas next year.

In addition, he said he is optimistic because many companies on his coverage list are well hedged and many have less debt than they did in the last big downcycles seen in the '90s or in 2008 to 2009.

Others are not as optimistic, with bankruptcy tracker Haynes and Boone LLP telling Reuters that the law firm expects that up to half of the top 60 independent producers will need to restructure their balance sheets.

Safety in hedge books

In these trying times replete with dire forecasts, analysts and investors will have to rely on highly selective core holdings rather than going out on a limb. That means stocks of companies with the strongest balance sheet, best assets, scale and lower costs can survive.

"Buying E&P stocks during an oil freefall doesn't typically work out, so our message is to sit tight and remain patient," John Freeman of Raymond James said in a written note. "However, now is the time to get your shopping list ready."

In late March Freeman said a buying opportunity would open up in the second quarter, with some names approaching low valuations never seen before. Despite the crash in oil prices, he cited Permian pure-plays such as Diamondback Energy Inc. and Parsley Energy Co., noting both can generate free cash flow even at these low oil prices. He said Concho Resources Inc., Devon Energy Corp. and WPX Energy Inc. also screened well, with "Concho in particular looking safest given its robust 2020-2021 hedge book."

In such an environment, it's no surprise that analysts recommend taking a defensive posture. They favor companies with a good hedge position and geographically diverse operations. Mariani's stock picks in April reflected this philosophy.

"Anyone who buys EOG now will have really good upside; it could be almost a double," he said. "The pure-play Permian names should do well. A SMID [small and midcap] I like a lot is WPX; it's trading at $4 and could double. SM Energy Co. has been absolutely clobbered but could go up a multiple of the current price. It's 90% hedged.

"And I like Concho a lot. It's done well on the downside compared to some other names. Parsley could potentially double," he said.

Mariani cited SM Energy as an outlier of sorts, although its stock price at the time certainly indicated it is viewed with a lot of concern by most observers. He also cited Gulf of Mexico explorer Talos Energy Inc., which is well hedged.

He said he favors some of the well-hedged small cap E&Ps because they have been beaten down so much that their upside looks good, mentioning Magnolia Oil & Gas Corp., Brigham Minerals Inc., Diamondback Energy and WPX.

"The companies that will survive and do well are pretty obvious," another analyst told Investor off the record. "But at the end of 2019, no one on the buy-side cared about the oil and gas sector, and now they care even less. I've been told that the buy-side in all sectors is not looking at valuations right now anyway. They are looking at what's going to happen to a business during this crisis and what it will look like after the crisis.

"I think this situation is going to change everything forever. It's going to change how investors look at equities and how banks look at lending—and that's true for every industry, not just oil and gas," the analyst said.

For Morgan Stanley's E&P team, the core holdings meant a lineup of the usual favorites often touted by many other sell-siders: Chevron Corp., ConocoPhillips Co., Noble Energy Inc., Hess Corp., Pioneer Natural Resources Co., Concho, EOG, Parsley and Cimarex Energy Co.

The team at Simmons Energy developed a list based on where things stood on April 24, placing the E&Ps under coverage into three main buckets:

- Bottom fishing: stocks that are in long-term decline but starting to make a multi-month rounding bottom;
- Positive developing: a much longer list, where stocks have reversed their woeful decline or have crossed back above their 50- to 200-day moving average; and
- Positive trending: stocks that are trending positive to make a new series of higher highs or higher lows and are above their 50- to 200-day moving average.

Only two stocks were on the latter list, and unsurprisingly they were gas-oriented: Range Resources Co. and Cabot Oil & Gas Corp., both heavy-duty Marcellus producers.

The bottom fishing list included disparate core holdings such as global giants BP Plc, Royal Dutch Shell Plc and Total SA as well as U.S. independents Callon Petroleum Co., Chesapeake Energy Inc., EOG and Viper Energy Partners.

At Siebert Williams Shank & Co. LLC, analyst Gabriele Sorbara listed Diamondback Energy, Concho, Parsley and Pioneer, all Permian oil-weighted names, as top picks. His Buy ratings were Devon Energy, PDC Energy Inc., WPX and Cimarex.

Jeff Grampp of Northland Capital Markets listed Earthstone Energy Inc., Rattler Midstream LP, Ring Energy Inc., Diamondback, Parsley and Callon as his favorites.

"We continue to prefer 'resilient' companies including Overweights Chevron, Conoco, Noble Energy and Hess…," wrote Devin McDermott at Morgan Stanley & Co. "While Pioneer and Cimarex also screen well against peers, Texas regulatory interventions into free markets could become a risk … this is also a risk for much of our midstream coverage."

Like most observers, McDermott thought OPEC production cuts and additional cuts by U.S. companies would be unlikely to match the decline in global demand this year, estimated to be anywhere from 25% to 35% off the norm. He predicted that well shut-ins in the U.S. are a given.

If oil ends up soaring later this year, Bernstein's Bob Brackett said his Buys would include what he called "lower-tier" stocks such as Devon and Apache Corp. In mid-March he analyzed the near-term note obligations of 80 E&P names and noted that if oil was $30/bbl, then the following would generate enough cash to pay off debt but might also have to refinance or cut dividends to do so: Canadian Natural Resources Ltd., Chesapeake Energy Corp., QEP Resources Inc., Apache and EQT Corp.

Until the direction of health trends becomes clear and the pace of the world's economic recovery is known, the price of commodities is in doubt, so estimating the stock performance of most E&P companies over the next 12 months is not going to be a rewarding game. Laggards could linger, or a V-shaped recovery could reward investors with huge upside off these terrible lows.

"The hot potato clearly has a name, and it is called [oil] storage," said Rystad Energy in a report as April drew to a close. □

JOE FOSTER, 1934-2020

Remembering the wildcatter who formed Newfield Exploration Co. and was a leader of the American oil and gas industry for more than 60 years.

TRIBUTE BY
ART SMITH

Upon the death of Joe Bill Foster on May 9, the oil and gas industry lost a giant leader of remarkable accomplishment—and a down-to-earth good guy. The tall, Lincoln-esque Foster was always a gentleman in business and in life, intensely loyal, friendly and outgoing. His 31-year career with Tenneco Oil Co. followed by founding Newfield Exploration Co. resulted in relationships with thousands of associates and friends.

I had the good fortune to spend many hours working with Joe on the biography "Something from Nothing: Joe B. Foster and the People Who Built Newfield Exploration Company" (2011).

Foster, 85, passed away at his home in Houston; his death was not COVID-19-related. He is survived by his wife, Harriet, six children, five grandchildren and four great-grandchildren. He was preceded in death by his first wife, Mary Alice.

Fitting to his future career in petroleum, Joe was born in an oilfield camp in Arp, Texas, on July 25, 1934, during the heat of activity on the giant East Texas deposit. At Texas A&M University, he excelled in the Corps of Cadets (Battalion Commander) while pocketing a Bachelor of Science degree in petroleum engineering and a Bachelor of Business Administration degree in general business in 1957.

Tenneco recruited Foster at A&M after an unscheduled campus interview. The result: a remarkable 31-year path of success that began in Oklahoma and blossomed when he was assigned to Lafayette, La., and hitched a ride on the booming activity in the Gulf of Mexico.

"There is no greater joy in life than starting with nothing and winding up with something."

—Joe Foster, Newfield Exploration Co.

At Tenneco, he last served as chairman of both Tenneco Oil and Tennessee Gas Transmission Co. Betty Smith, Foster's longtime executive assistant, recalled, "I thought something was wrong with the oil business if Joe didn't get promoted every 18 to 24 months."

In 1988, as parent Tenneco Inc. was looking to exit the oil and gas business, Foster argued for continuing it. But the board disagreed, and the oil and gas assets were auctioned off by Morgan Stanley.

Foster bid for select assets. But outbid, he found himself at 54 unemployed but not destitute. He could pocket his severance, collect

dividends on the Tenneco shares he owned and head to the golf course. But he had too much fire in his belly and another surprise venture yet up his sleeve: Newfield.

Operating on the ragged edge

In 1989 Foster and other former Tenneco employees founded the wildcat E&P with $9 million in employee and outside investments, growing the company to 2 Tcfe of proved reserves upon his retirement in 2005.

Newfield was built on the bedrock of Foster's founding business principles: talented employees, focus, a balance of exploration and acquisitions, an emphasis on technology and teamwork, the mindset of an independent, control of operations and employee ownership.

"When oil prices were in the pits in the late 1980s," Foster said, "I never hesitated to start a new oil company. I didn't know whether we would make it or not, but I was very sure that the opportunity would be there for us to do well."

One of his many business philosophies was to "operate on the ragged edge."

"To be a success in any business, you must operate 90% of the time at the ragged edge between chaos and order, between too little and too much, between comfort and anxiety, if not outright fear," he said.

Foster lived on the ragged edge during the startup years at Newfield as the company drilled successive dry holes, experienced a capsized rig and was perpetually and precariously short of capital. But the investors and founders did not despair; they had the confidence of teamwork, a solid plan and Foster's leadership.

Looking back on his years at Newfield, Foster described his pride in the accomplishment: "There is no greater joy in life than starting with nothing and winding up with something. That's what parents do when they have children," he said. "That's what poets and artists do when they create something new and different. And that's what we did when we created and built Newfield."

Lifelong contributions to leadership

Foster was always a leader, and this reputation led to his appointment as interim CEO at Baker Hughes Co. in 2000. At the time, the oil and gas sector was mired in yet another painful downturn, and the board at Baker Hughes demanded new leadership.

A Baker Hughes board member since 1992, Foster was set to retire as CEO from Newfield while remaining chairman. He agreed to assume the temporary position but only when he was assured that he had the authority "to do those things that need to be done now."

Foster helped to right the ship at Baker Hughes. The stock climbed from $17 in January 2000 to $40 by that September.

Foster also made lifelong contributions to leadership on the IPAA and the National Petroleum Council. He was also active on the boards of McDermott International Inc., New Jersey Resources Co. and Targa Resources Co., and he was chairman and senior adviser of private-equity fund TPH Partners LLC.

Howard Newman, a managing director in 1989 of Warburg Pincus that was a second-round investor in Newfield and later co-founded Pine Brook Road Partners, said the investment "was a bet on a very effective and proven CEO, on an experienced and competent management team and on a solid business plan.

"Moreover, all of the founding employees had made a significant investment, and all our interests were aligned."

Former Newfield board member Dale Zand said, "There's 'Joe time,' and there's ordinary time. Joe can see and understand a problem 100 times faster than anyone else."

Foster's philosophy referenced Rudyard Kipling's "If—" poem when he said, "If you can meet with Triumph and Disaster and treat those two impostors just the same … Yours is the Earth and everything that's in it."

From its start, Newfield's days were ascetic. For example, office furniture consisted of what founding employees, who were all owners, could put together. Thus, meetings were held at folding card tables complemented with an assortment of lawn chairs.

Spartan use of money was evident in a Wall Street Journal article in the early 1990s in which a Newfield platform in the Gulf was noted for its "kaleidoscope of colors." The platform was made from spare parts of other platforms; the pieces were blue, red, yellow or gray.

Six-foot Foster and all Newfield employees flew coach class—even to Australia, a 26-hour flight. Investor relations chief Steve Campbell, a 6-foot-4 man, joined Foster in coach on a flight to New York just two days after joining Newfield from Anadarko Petroleum Corp., which had a corporate jet.

Upon landing at LaGuardia at almost midnight—Foster liked to fly after business hours because it allowed you to get in a full day of work in the office—Foster told Campbell, "You know what I like about flying coach? It's so damn uncomfortable you can get a lot of work done!"

And employees found cabs, not limos. During the company's 1993 IPO road show, which involved meetings in Boston, New York, Chicago and on the West Coast, Foster said, "There sure is a lot more road than there is show in a road show."

Bobby Tudor, a Goldman Sachs managing director at the time and later co-founder of Tudor, Pickering, Holt & Co. (TPH) Securities Inc., was a co-manager of the IPO.

The second week, Tudor said, "Look, Joe. We're going to get limos, and Goldman Sachs will pay for them. It's not coming out of Newfield's pocket." Tudor's rationale was that arranging the logistics for all of them was just hell on the secretaries.

And, about that IPO, Foster said he thought it might be too soon for Newfield, which had some 100 Bcfe of proved reserves at the time. Newman emphasized that the IPO window was open right then, and it was unknown when it would be open again.

He told Foster, "Joe, you take the cookies when the tray is passed—not just when you're hungry."

Foster carried a yellow legal pad to any meeting and made copious notes. Smith, the longtime assistant and a founding Newfield employee, said, "We never ran out of them. That was one of my key jobs: to keep a good supply of yellow tablets."

In early 1989 while forming Newfield, Foster listed what he would tell the team: Startup pains are normal; Newfield will be data-driven; networking and exposure are essential, but take care that it isn't taking more time than it is giving back; and we must be prepared to live with failure.

He concluded his list with this: Finally, when we achieve success, we must not let it go to our heads. □

Art Smith is the author of Something from Nothing (2011), founder of Triple Double Advisors LLC and led oil and gas research firm John S. Herald Inc. from 1984 through its sale to IHS Markit in 2007.

Nigeria

A special report by Global Business Reports

Cover photo courtesy of Equinor.

The Troubled Giant of Africa

The development of Nigeria's oil and gas industry, currently the largest in Africa, has not adequately engendered the social and economical development of its population, which is also the continent's largest. Such is Nigeria's predominance in the region, that what happens in Nigeria matters elsewhere. The opportunity for the riches derived from extraction industries to be deployed to foster a healthy and equitable society may not last for much longer.

This report was prepared by Lina Jafari and Germaine Aboud of Global Business Reports.

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Nigeria's prominence at the epicentre of the African stage is credited to its giant population and its international role in the energy market. Nigeria's swelling population, expected to reach 500 million by 2050 according to the UN, is the root of its socioeconomic challenges, experiencing acute inequality, poverty and increasing youth unemployment. Coupled with the fraud and corruption that are so often associated with the controversial curse of the black gold, the Nigerian government has struggled to foster a just and sustainable development.

Prior to independence, agriculture was the mainstay of the Nigerian economy and, between 1962 and 1968, it was the leading global exporter of palm oil. The discovery of oil in 1956 by Shell D'Arcy (later known as Shell-BP) at Oloibiri in the Niger Delta changed everything. From contributing an insignificant 0.1% to the Nigerian economy in 1959, the petroleum industry today represents over 60% of the country's annual budgetary income, in addition to employing over 250,000 Nigerians due to the sector's dependence on local service providers.

In an attempt to control oil resources, in 1970 the Federal Government of Nigeria (FGN) established the Department of Petroleum Resources (DPR) to supervise and regulate the industry. Today, the industry is characterized by its numerous institutions and governing bodies led by the Nigerian National Petroleum Corporation (NNPC) formed in 1977, which undertakes a commercial and regulatory role. The long-awaited Petroleum Industry Bill (PIB) should address and evaluate the role of each institution and bring about more certainty, improving the industry by boosting investor confidence.

In addition to addressing the overlaps in the petroleum industry's institutions, the PIB will recognize the rights of host communities in the Niger Delta, who have a fraught relationship with oil companies due to their interests being neglected, as well as update bidding processes and the fiscal framework. With royalties and petroleum profit taxes as the largest contributors to the State's oil revenues, it is unclear whether these will be altered under the PIB.

The PIB's delay is also keeping the nation from exploiting its huge gas resources. Home to an estimated at 200.79 trillion cubic feet of natural gas, Nigeria has the capacity to power Africa, yet currently, gas production stands at only 8.5 billion standard cubic feet per day (bscfd). The fiscal and regulatory infrastructure to support the industry is lacking. H.E. Chief Timipre Sylva, Minister of Petroleum Resources, announced 2020 as the 'year of gas' in Nigeria: "Natural gas has the capacity to transform an economy. Qatar has the world's highest GDP per capita – its growth anchored on natural gas," he stated.

To this end, Nigeria has launched the Gas Master-Plan Policy initiative, launching the Nigerian Gas Flare Commercialization Program (NGFCP) in 2016 and setting a target to eliminate flaring by 2020. Approximately 40% of gas from crude oil production is flared according to the NNPC, across 178 flaring sites in the Niger Delta. The DPR states that the flared gas could produce 600,000 metric tonnes (mt) of liquefied petroleum gas (LPG), create 300,000 jobs and attract at least US$3.5 billion in investments.

Nigeria's interest in gas will not, however, steal the spotlight away from its core focus on producing its high value, low sulphur, light crude oil, but it will struggle to meet its 2020 production target of 2.18 mbod with the current oil price plunge and global pandemic and if there is no major rehabilitation of existing domestic refineries. Crude oil production averaged 1.92 mbod in the fourth quarter of 2019, and reached its maximum in March 2019, averaging 2.02 mbod. Production increased relative to 2018 and is expected to experience a more notable increase by 2023, when 11 new pipelines will come on stream. The general managing director of the NNPC, Mele Kyari, is hopeful that local oil companies will be supplying 50% of national oil production in two to three years, which is feasible according to Ebiaho Emafo, managing director/CEO of Eroton E&P, operators of the OML18 block: "Indigenous producers have contributed significantly towards oil exploration and production in Nigeria over the past few years. Today, indigenous companies produce approximately 25-35% of the country's crude oil and are consistently growing production."

Exploration, on the other hand, has decreased. Bank-Anthony Okoroafor, president of the Petroleum Technology Association of Nigeria (PETAN) suggested: "The uncertainty fueled by the PIB, which has been up in the air for the last two decades, is deterring exploration."

Lekan Akinyanmi, CEO of Lekoil, a Nigerian E&P company operating four assets, suggested a remedy to promote exploration: "The challenge is that when our fiscal terms are priced based on existing production, it is not attractive enough for exploration. There also has to be sanctity of contracts to make exploration more attractive."

Over recent years, Nigeria has become less competitive in attracting foreign direct investment (FDI) compared to its West African neighbours, especially Ghana. Even though FDI in Africa rose by 11% last year, it shrunk by 43% in Nigeria, according to the United Nations Conference on Trade and Development (UNCTAD), mainly due to the protectionist policies of the current administration.

The continued failure to utilise its resources domestically hinders Nigeria's economic growth. "Nigeria's gas to power journey is another example of failure to optimally utilize its

resources whereby the country continues to rely on generators even though it has over 200 trillion cubic feet of gas reserves," said Abiola Ajayi, managing director of Energy and Mineral Resources Limited, an indigenous oil service company.

Local refining capacity is insufficient to meet domestic demand, leaving 80 million Nigerians without access to power and forcing the largest oil producer in Africa to import US$8.1 billion worth of petroleum products annually, as well as increasing the cost of power for local businesses as explained by Chief Davies Ikanya, managing director of Hopeup Integrated Industries, an indigenous gas and barite producer: "high cost of Power as a result of inadequate public power supply which has made the companies rely on the use of diesel Generators lowers profit margins. Lack of interest of financial institutions in financing for example barite businesses and absence of roads also hinder business."

Ekimini Thompson Amos, director of projects and technical services at Thompson and Grace Investments, a local mechanical manufacturing service company, agreed, identifying corruption as the reason behind Nigeria's addiction to generators as opposed to finding other

"There is the potential for Nigeria to grow, but the speed at which the country can grow is a limitation on its own. Looking at the estimated volume of fabrication which is expected to happen in the next three years, Nigeria does not yet have the capacity."

– Ese Avanoma, CEO, Brade Group

"The high cost of power as a result of inadequate public power supply has made companies rely on diesel generators, which lowers profit margins. The reluctance of local banks towards lending to certain industries and the absence of roads also hinder business."
– Chief Dr. Davies Ikanya, Managing Director, Hopeup Integrated Industries

solutions such as renewable energy. The privately-owned Dangote refinery, set to be the largest in Africa and the largest single train petroleum refinery in the world when completed in 2020, could be the answer to local supply issues if the state chooses to subsidize Dangote to sell at a lower price to ensure that production is not exported at the international price.

2020 carries with it high expectations with the increasing presence of private refineries, the rehabilitation of state-owned refineries, as well as the renewed hope that the Petroleum Industry Bill will pass and 2020 'year of gas' spurs the rise of Nigeria as a gas nation. "There is the potential for Nigeria to grow, but the speed at which the country can grow is a limitation on its own," explained Ese Avanoma, CEO of Brade Group. "Looking at the estimated volume of fabrication which is expected to happen in the next three years, Nigeria does not yet have the capacity."

2020: The 'Year of Natural Gas'?

The Minister of State for Petroleum Resources H.E. Chief Timipre Sylva declared 2020 as 'the year of gas for the nation,' an announcement that set the theme for the year and chronologically coincided with the FID on the Train 7 project by the NLNG (Nigeria Liquefied Natural Gas Ltd). "Nigeria has enormous potential to diversify the economy away from crude oil, which has overshadowed the gas in Nigeria's oil and gas industry. The country is struggling to exploit its natural gas resources which rank among the 10 largest worldwide," stated Gbite Falade, managing director and chief operating officer of Oilserv, a leading Nigerian EPC company.

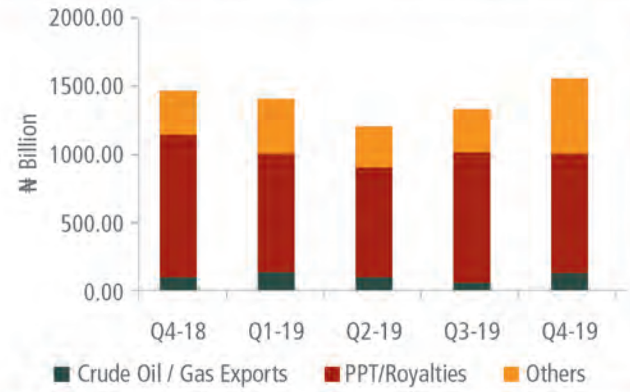
According to the DPR in April of 2019, of the 1.2 billion cubic feet per day (cf/d) of gas produced locally, approximately 41% was exported, only 48% used domestically, the rest was flared.

Underlining the move towards gas is the Nigerian Gas Flare Commercialisation Program (NGFCP), which aims to reduce waste as well as promote the monetization of natural gas. Between September 2018 and September 2019, more than 276.04 billion cubic feet (bcf) of natural gas was flared, which exceeded 275.31 bcf supplied to local power generation, which remains intermittent despite successive governments' focus on deepening domestic gas penetration. Flared gas in Nigeria is enough to generate 2.5 gigawatts (Gw) of power, which would rid the country from its reliance on diesel generators. In 2018, the government increased the fine for flaring to US$2 per 1,000 standard cubic feet (scf). Nonetheless, the opportunity cost companies bear for the penalty of flaring remains low, therefore financial incentive is lacking to utilise the gas as opposed to flare it. "One of the challenges with gas in Nigeria is the lack of infrastructure. The government is addressing this issue and gas is being channelled for power and other derivatives," explained Prof Anthony Adegbulugbe, chairman of Green Energy International Limited, operators of the OML30 block. "The second is the issue of pricing. Gas has not been priced very well for the past few years. There has also been a problem with tariff collection and companies are forced to sell power to the national grid. I believe that we are now at a stage where these issues are being addressed"

The lack of investment in power and gas distribution infrastructures hampers gas distribution to householders and industrial plants more than flaring. The government recognises this infrastructural deficit and is responding with projects to stimulate Nigeria's gas economy. "One of the key components of the Gas Master Plan is the development of strategic pipelines to deepen the availability of gas as a source of power for the country which include OB3 (Obiafu-Obrikom-Oben) and AKK (Ajaokuta-Kaduna-Kano). OB3 is a 48-inch gas transmission system with an associated gas treatment plant which is able to handle up to 2 billion cf/d," highlighted Falade.

Meanwhile the 614 km natural gas AKK pipeline project is expected to commence operation in 2020, costing US$2.8 billion. Another one of the seven critical gas projects announced is the Assa North-Ohaji South (ANOH), one of the largest greenfield gas condensate development projects being undertaken in Nigeria under the joint venture of Seplat and the Nigerian Gas Compa-

Gross Oil Revenue and Its Components



Source: Federal Ministry of Finance, Nigeria

ny (NGC). It is expected to contain reserves of 4.3 trillion cubic feet (Tcf) of gas in addition to 215 million barrels of condensate.

"The catalyst to upstream gas supply is the LNG Train 7 project, which is at the helm of Nigeria's natural gas that reached a FID in Q4 of 2019," highlighted Tony Osuagwu, managing director at Calaya Engineering, a local oilfield service provider.

The Train 7 project is led by the NLNG, which supplies 40% of annual domestic Liquefied Petroleum Gas (LPG) and is comprised of the NNPC as a majority shareholder (holding 49% of shares), followed by Shell (25.6%), Total (15%) and Eni (10.4%). The Train 7 project is expected to add up to 8 million mt/y of LNG capacity to the existing 22 million mt/y supplied by the existing six LNG trains. After a delay of 12 years, mainly attributed to a lack of consensus among shareholders and an uncertain investing environment, the project finally reached a FID on the 19th December 2019, after seven consecutive meetings held by the shareholders. The project will generate US$20 billion in revenue for the government and create 10,000 direct jobs and 40,000 indirect jobs for Nigerians, according to Mele Kyari, the NNPC's group managing director. With a value amounting to US$12 billion, the project will increase domestic supply of LNG and pave the way for Train 12, aligning with President Muhammadu Buhari's vision.

Other ambitious projects, including the Nigeria-to-Morocco gas pipeline, which was pledged to be delivered in record time, lack funding. The first phase of its FID was signed in 2018, making headlines as it aims to supply power to 15 West African countries. On the other hand, Shell's US$9.7 billion Bonga South-West/Aparo project, expected to reach 270 million cf/d at peak production by 2022, hass yet to reach a FID, delayed due to the uncertainties surrounding the legal and fiscal framework. Meanwhile, 45% of the population remains without access to electricity. "Nigeria requires more action as opposed to catchy phrases such as 'the year of gas'. The country could have established two more LNG plants (Brass and Olokonla) but failed to do so, again because of politics," commented Olufemi Abegunde, partner and leader of the energy and resources industry at Deloitte Nigeria.

"The Gas Master Plan Policy was another catchy phrase initiative announced in 2008, highlighting major gas infrastructure expansion and integration to initiate gas monetization as well as gas supply development," explained Godwin Izomor, the group managing director of MG Vowgas, an indigenous oil service company offering EPCI services.

Nonetheless, Nigeria has not been able to satisfy domestic energy requirements, nor has it positioned itself competitively in natural gas exporting markets.

The Jinx of the Petroleum Industry Bill (PIB)

Nigeria's journey to a comprehensive petroleum industry legislative framework has been a long and bumpy ride as two decades have passed without updating the industry's regulation. "The uncertainty is harming the development of the industry. If the bill had already passed it would have radically changed the fiscal outcomes of the industry and helped the government get a better share of profits. Since it has not passed, the oil companies negotiate lower taxation rates with uncertainty in the country on their side, which the government accommodates to," elaborated Chiagozie Hilary-Nwokonko, partner at Streamsowers & Köhn, a leading Nigerian law firm.

What tops H.E. Hon. Timipre Sylva, Nigeria's Minister of State for Petroleum Resources' agenda for 2020 is the passage of the PIB. Its delay is costing the economy an approximated US$200

Photo courtesy of Green Energy Limited Nigeria.

billion annually, according to the Nigeria Extractive Industries Transparency Initiative (NEITI), in addition to US$15 billion lost due to decreased investments, especially in exploration since no licensing round has occurred since 2007. However, 42 oil block licenses held by IOCs and NOCs were renewed in 2019 by the government, 35 of which are oil mining licenses (OML) in addition to 7 oil processing licenses (OPL). Civil groups criticised the government's decision to renew these licenses, claiming that it is a setback for Nigeria since it allowed oil and gas companies to negotiate a lower tax rate due to the regulatory uncertainty in which they are forced to operate. "Oil and gas investments are long term and therefore investors want to have as much certainty as possible. Your counterpart, i.e. the host country, can do a lot to alleviate your uncertainty by showing consistency. Certainty, trust and consistency very often go hand in hand. This is the same wherever we operate in the world. Countries that can provide a consistent policy package with good engagement with the stakeholders generally attract more capital at lower rates of return than countries that cannot provide consistency," clarified Heine Melkevik, vice president and managing director of Equinor Nigeria, a Norwegian upstream company and the world's largest offshore operator.

Projects such as Shell's Bonga South/West Aparo, expected to add 143,274 bopd and to be the largest deep-water project since Total's Egina, have yet to reach an FID, in addition to ExxonMobil's Bosi project and Chevron's Nsiko, estimated to boost production by 126,784 bopd and 95,685 bopd respectively. At the fourth Sub Saharan Africa International Petroleum Exhibition and Conference (SAIPEC) in February 2020, Mike Sangster, managing director of Total Nigeria, identified the PIB as a catalyst that will drive investment in Nigeria's oil and gas industry and increase Total's investments in Nigeria, which currently represents only 16% of the US$160 billion Total invested in deep water projects in Africa the last decade.

The federal government of Nigeria (FGN) is aware of the urgency in passing the PIB, notwithstanding it remains a work in progress due to the lack of harmony over the last two decades between the legislative and executive arms of the government. According to Sylva, there is now accord between the two; hence the aggressive promotion of the bill tops his agenda for this year. The legal framework for the industry has not been updated since the Petroleum Act of 1969 was enacted, and the sector has undergone a huge transformation since then. "In 2000, the Nigerian government established the Oil and Gas Implementation Committee (OGIC), which had the mandate to identify how to privatize the industry. I had the privilege of being on that committee and, over the course of the committee's deliberations, the mandate of the OGIC evolved. The OGIC ended up reviewing the legal and regulatory framework for the entire industry and produced a draft of a new law which later became the PIB," stated Sola Adepetun, senior partner at ACAS-Law, a leading law firm in Lagos.

The OGIC published a report that later resulted in the PIB being drafted in 2008. After undergoing several redrafts, including a wholesale amendment, it still failed to pass the sixth National Assembly. The PIB was thus split into three parts for easier passage. "The former Minister came from a legal and petroleum background, so he tackled the issue of the bill aggressively by breaking the PIB into different pieces of legislation guiding specific aspects of the industry: the petroleum industry governance bill (PIGB), the Petroleum Industry Fiscal Bill (PIFB) and the Host Community Bill," commented Abiodun Adesanya, chief executive officer of Degeconek - a geoscience and engineering consulting company. "The PIGB passed the National Assembly in 2016, however, it was refused ascent by the President, his reasons being that his powers i.e. those of the Minister of Petroleum, have been reduced. The industry's leadership lies with the Minister of Petroleum, who is also the President, and the Minister of State for Petroleum Resources, who oversees day-to-day activities. When the bill intertwines with politics it is difficult to reach a decision."

The politicization of the PIGB prevented its passage and quelled the industry's renewed optimism after almost two decades of deadlock. This first series of the PIB, the PIGB, seeks to establish a framework for the creation and alteration of commercially and profit driven petroleum entities, and alter the current framework of the petro-state's institutionalization. In an effort to enhance transparency and efficiency, the industry's powerful behemoth, the NNPC, will be divided into smaller entities and will be replaced by the NPC, which will oversee the nation's joint venture assets and refineries. The NRPC will act as a single regulatory and supervisory body for the industry funded by the FGN's annual budget, replacing the DPR and the Petroleum Products Pricing Regulatory Agency (PPPRA).

What concerns investors most is the PIFB, which will alter the existing fiscal terms of production sharing contracts (PSCs), joint ventures, royalties and taxes. Even though the PIFB is yet to pass, the Deep Offshore and Inland Basin PSC Act (DOIBP-

Crude Oil Production in Nigeria 2010 – 2019 (million barrels per day)

Source: Federal Ministry of Finance, Nigeria

SCA) was amended in the fourth quarter of 2019. Dayo Okusami, partner at Templars, one of the leading full-service law firms in Nigeria, explained: "With regards to the PSC Amendment Act, the Original Act came out in 1993 and provided for periodic reviews of the PSCs, taxes and royalties that are supposed to apply to these upstream assets. In spite of these provisions, no review has been done since the act was passed, which has resulted in the government's recent amendment of the act. In the short term, the amendments significantly increase the government's share from the increase in royalty rates. However, this will have a detrimental effect on operating companies as they have invested in their projects based on certain economics which have now changed."

The Amendment Act introduces a new royalty regime, highlighting a baseline royalty of 10% for condensates and crude oil produced in deep offshore, and 7.5% of the frontier and inland basin. An additional royalty will be applied if the crude oil price exceeds US$20 per barrel.

Changes in the DOIBPSCA in 2019, coupled with further amendments under the PIB if it passes at the end of 2020, create confusion. Meanwhile, disagreements between stakeholders on the regulatory frameworks such as the power of the Minister, ownership and control of the resources, as well as host community benefits are the main reasons behind the current setback and delay. However, regardless of these disagreements and the certainty the PIB will bring, the bill remains inherently vague to some extent, lacking major clarifications. The power it grants to the NRPC, for example, remains broad and not well defined. It also fails to acknowledge the conflict of interest that arises when the NRPC is granted the authorization to charge fees for 'services rendered' to players. The bill also lacks provisions to ensure stable tenures for executive directors that insulates them from the political dynamics. Even though the broader aim of the PIB is to introduce deregulation, one of the NRPC's functions is to compute a fair market value for petroleum products and tariffs for gas transport and processing. This somewhat increased regulation could reduce incentives for private oil and gas companies to develop power plants and distribution networks as the price could be fixed at an economically unviable level. Finally, further uncertainty is introduced with the new entity, NAPLMC, due to the lack of clarity regarding which liabilities of the NNPC it will receive.

The PIB should modernise the industry and provide more certainty for IOCs and NOCs to explore, develop the nation's refining capacity and ignite its gas revolution with a new regulatory and fiscal framework that replaces the industry's out-dated regulation with a more comprehensive industry law that aligns with global standards. To that extent, 2020 brings renewed hope and, even if a cloud of scepticism hovers about, the majority of industry professionals that we met with were optimistic that the ninth National Assembly will likely break the jinx this time around.

Offshore operations. Photo courtesy of Point Engineering.

Nigeria's security challenges

Given Nigeria's economic, cultural and demographic hegemony, its elusive quest for stability has inextricable consequences across the African continent. Unfortunately, Nigeria has become an incubation centre for violence fuelled by poverty, incompetent institutions and rampant corruption as a result of decreased political accountability. The nation's great oil wealth is associated with great risk that negatively impacts investment due to the unpredictable nature of its multifaceted security problems, from Boko Haram to piracy and militancy in the Niger delta.

The constant clashes between the government and Boko Haram, a jihadi terrorist group in existence since 2010 in the north of the country, has detrimental effects on the petroleum industry. In July 2017, the government had to halt exploration in the north after Boko Haram terrorists attacked and killed dozens of NNPC oil contractors in an ambush. President Buhari is leading an aggressive campaign to bring an end to the national suffering they cause.

Nonetheless, the pain inflicted by Boko Haram on the nation's petroleum industry is less severe than that caused by the militants in the oil-rich Niger Delta. "In the Niger Delta, also known as the south-south, the government has made a choice to turn a blind eye to oil theft," said Tunde Aleye, senior partner at SBM Intelligence, a local geopolitical macroeconomic research firm operating in Lagos.

Black gold carries with it influence and profit, attracting the attention of thieves and kidnappers in the region. Militancy in the Niger Delta developed as a result of grievances arising due to the exploitation of the region. Despite its oil wealth, the people of the Niger Delta remain deeply impoverished. "Resource allocation in Nigeria has been unfair to the host communities who should come under the local content initiative. The increased violence in the Nigeria Delta since 2005 can be traced back to these communities trying to draw government attention to their plight," explained Atamuno Atamuno, managing director of Midis Energy, an indigenous oil and gas service company.

The violence began in 2005, when a group known as the Movement for the Emancipation of the Niger Delta (MEND) attacked key oil installations and conducted high profile kidnappings. MEND isthe most organised militant group in the Niger delta, however other acts of violence are committed by a loose network of individuals and smaller groups of host communities in the Delta region. For example, in April 2019, two foreign oil workers were kidnapped from an offshore oil rig only two weeks after two Shell workers were also abducted and their police escorts killed.

In addition to kidnappings, acts of vandalism and theft also prevail. According to the NNPC, a total of 2,146 vandalised points in pipelines have been recorded between September 2018 and September 2019. Blessing Ayamhere, managing director of Umugini, a local pipeline infrastructure service company, described the unfortunate consequences faced in the midstream sector due to pipeline vandalism: "It leads to the intermittent shutdown of our pipelines, loss of revenue to crude oil producers who depend heavily on the evacuation of their product through the use of the pipelines and effectively reduces government revenue, as well as increased security, surveillance and maintenance costs. Pipeline vandalism pollutes and degrades the environment where these activities take place, which in turn becomes hazardous to the people that live in the affected communities."

However, the upstream sector faces more adverse costs relative to the midstream. As the IOCs moved offshore, they handed over the burden of addressing host communities' violence, and especially oil theft, to the National Oil Companies (NOCs) that bought their oil mining licenses (OML) "The theft is significantly impacting on our cash flow as we are losing approximately 20 - 30% of our production. We are working on improving community engagement to prevent illegal bunkering," confirmed Dr Ladi Bada, managing director of Shoreline Natural Resources, holder of the OML30.

According to Reuters, oil theft cost Nigerian oil companies US$1.39 billion in lost revenue in the first of six months of 2019 alone. Oil theft begins with hot tapping, then connecting a secondary pipe to an illegal refinery where the crude oil is refined and smuggled out of the country. Asharami Energy, a Nigerian E&P subsidiary company of Sahara Group with operations across West Africa, recognises the root of oil theft as being unemployment. "When trust exists between operating companies and host communities, it significantly decreases security risks. At Asharami Energy, we have a very cordial relationship with our host community, a development that makes our operations seamless. We have also laid electric poles from our station to the community to supply them power," elaborated Olajumoke Ajayi, managing director of the company.

The IOC's, meanwhile, face the new challenges of piracy in open Nigerian waters. According to the International Maritime Bureau, Nigeria witnessed 48 piracy attacks in 2018, a twofold increase since 2017. Services offered by maritime security companies such as Aquashield Oil and Marine Services have become essential to reduce the risk by escorting vessels to and from terminals or through patrols to secure the deep-water wells. Ahmad Ojeh, executive technical director at Aquashield, gave an insight into the dangers of Nigerian waters: "Militants in Nigerian waters are well equipped. Their goal is not theft but instead the kidnapping of the highest-ranking officer or engineer on board for a ransom, then they take them to secluded areas such as mangroves and jungles where they cannot be found. A vessel coming into Nigerian waters without security is exposed to high risk, however the militants do not approach a vessel when it is escorted by security, especially when the Nigerian navy is present on board."

The Nigerian navy is battling the piracy crisis in the Gulf of Guinea, that saw a 50% increase in maritime kidnappings in 2019 compared to 2018, according to the International Chamber of Shipping. Greg Ogbeifun, the chairman of Starzs limited, operators of the oldest indigenous ship repair yard in Nigeria, suggested a less aggressive manner to address piracy issues that threaten Nigeria's maritime economy: "It is necessary to conduct a study to understand why piracy occurs. The ecosystem of the people has been destroyed and degraded and the people in the region have not been carried along in the development of the oil and gas industry and the country. Developing human capital and integrating communities into operations and the industry will significantly alleviate the piracy issue"

Acetylene gas plant, photo courtesy of Hopeup Integrated Industries.

Unemployment, which is expected to reach 33.5% by the end 2020 according to the federal government, breeds poverty which leads to theft when complemented with vengeance and corruption. As long as a market for stolen crude oil exists, theft will persist if sanctions and surveillance remain weak and inadequate.

The downstream sector is also exposed to risk, as highlighted Abayomi Awobokun, chief executive officer of Enyo Retail, a technology-driven fuel retail company: "Enyo operates out of 19 states and there are security risks both for the trucks in transit and at the operations. We have put a lot of thinking into how we can keep our staff and sites protected. We keep very little cash on the forecourt, if at all, and are deeply invested in cashless sales. We are also working with technology partners to ensure cybersecurity."

Due to the financial burden of pipeline vandalism and theft on all sectors of the industry, the federal government under president Olusegun Obasanjo set up a committee to address the issue. In 2009, the government launched a military strike against operational bases of MEND. Chief Sylva has prioritized addressing security challenges around oil and gas installations on his agenda for 2020. Companies are resorting to the use of technologically advanced leak detection mechanisms and must invest in training and hiring unemployed youths from host communities.

"A more permanent solution, however, is needed to untangle the complex roots of the Niger Delta involving the three tiers of government, the petroleum industry and Niger Delta communities who must communicate and collaborate to reduce tensions" highlighted Chinedu Maduakoh, managing director of Topline limited, a Nigerian process engineering company specialising in pipeline construction.

"The specter of corruption, violence, insecurity and sabotage are the most important hindrances to the industry's and the country's social and economic development. The security issues in some part of the country have stalled gas development in the country."
– Tunde Ajala, Founding Executive Director, Dovewell Oilfield Services

The Petroleum Host and Impacted Communities Development Bill attempts to do just that, with an objective to foster sustainable, shared prosperity amongst the oil and gas companies and host communities. It stipulates that an annual contribution of 2.5% of the actual operating expenditure (OPEX) of the E&P company will be placed into a fund. 70% of the fund will be allocated to a Board of Trustees for projects in each host community, meanwhile 10% will be used to support the impacted communities. If the PIB passes in 2020, it will contribute to lowering the oil theft rates if host communities are satisfied.

Bracing for 2020

Concerted government coordination and action is needed to develop nation-wide physical, legal and fiscal infrastructure to utilize Nigeria's resources efficiently for the nation's prosperity. More importantly, persistent neglect of the importance of integrating the petroleum industry into the mainstream economy through local refineries is preventing Nigeria from realising its potential, coupled with increasing security threats and corruption. "The spectra of corruption, violence, insecurity and sabotage are the most important hindrances to the industry's and the country's social and economic development. The security issues in some part of the country have stalled gas development in the country," maintained Tunde Ajala, founding executive director of Dovewell Oilfield Services, a Nigerian-owned oil and gas service company.

2020 brings a new set of challenges to the Nigerian petroleum industry, as oil producing countries embark on a horrific year amid the coronavirus crisis bringing businesses to a standstill, and the ongoing price war between Saudi Arabia and Russia. OPEC and IEA warned in March 2020 that developing countries might lose up to 85% of oil and gas income this year, if current market conditions persist. Nigeria is therefore rethinking its 2020 budget that estimated crude oil price of US$57. "Nigeria is blessed in a way, even if it drops to US$30 per barrel, the majority will continue producing due to the low cost of operation compared to elsewhere," highlighted Wale Adelaja, managing director/CEO of Ashbard Energy, an indigenous engineering services provider operating in the energy sector.

The cost of producing one barrel of oil in Nigeria is US$15-17. As of the 27th of March 2020, the price of Nigeria's Bonny Light has dropped to US$24.83, 56.4% below the US$57 per barrel benchmark that the government anchored its budget on.

According to Kyari, Nigeria has about 50 and 12 stranded cargoes of crude oil and LNG, respectively, that have not found landing due the low demand in March 2020. As it struggles to find buyers, Nigeria is facing a crisis as revenues from oil production represents 31% of the 2020 budget and accounts for 90% of foreign exchange. The downturn does, however, offer some opportunities, suggested Kayode Thomas, managing director at Substrata Oil and Gas, a local oilfield service company: "The industry is aware of the volatility and constant downturns which it should use to its advantage by conducting exploration activities which should be undertaken in the downturn phase of the cycle, as it is cheaper due to lower cost of services."

Nigeria's over-reliance on petroleum hurt the economy in 2014, and will likely do so again in 2020. "The strength of an economy lies in diversification. Nigeria could become one of the technology hubs of Africa," stated Huub Stokman, CEO of OVH Energy, an Africa-focused downstream company. "One needs to diversify one's economy when there is money and time are there to do so. I hope that Nigeria uses the time while the oil and gas prices are reasonable, to invest in those areas."

Gbolahan Elias, partner at G. Elias & Co, a leading indigenous law firm, believes that Nigeria is already diversifying, "the ICT sector is greater than the oil and gas sector, representing 13% of GDP as opposed to oil and gas, which represents 9-10%. Oil is the second largest source of foreign currency, after remittances. The economy is being diversified and I believe that this trend will continue in the future."

The extent to which the economy diversifies will increase its immunity against the volatility of the petroleum industry, however, it is unlikely to shield it against the ongoing pandemic that is already taking its toll on nation-wide industries.

A&D Watch

EDITED BY
DARREN BARBEE

Shell Divests Appalachia Position For $541 Million

JNIX/SHUTTERSTOCK.COM

ROYAL DUTCH SHELL Plc agreed to sell its entire Appalachia shale position to New York-based integrated energy company **National Fuel Gas Co.** for about $541 million, the two companies said in separate releases on May 4.

The transaction is part of Shell's strategy to focus on the development of higher-margin, light tight oil assets, according to Shell upstream director Wael Sawan.

"Divesting our Appalachia position is consistent with our desire to focus our shales portfolio," Sawan said in a statement. "While we maximize cash in the current environment, our drive for a competitive position in shales continues. It is a core part of our upstream portfolio along with the deepwater and conventional oil and gas businesses."

The transaction includes roughly 450,000 net leasehold acres across Pennsylvania, with about 350 producing Marcellus and Utica wells located in Tioga County and associated facilities. The current net production is about 250 MMcf/d. Shell will also transfer its owned and operated midstream infrastructure as part of the agreement.

Payment for the transaction will be made in cash, but National Fuel has the option to provide up to $150 million of NFG common stock as consideration. According to a release by the company, National Fuel has taken appropriate steps to ensure ample liquidity and protections as it pursues permanent financing for the acquisition, though the transaction is not contingent on financing conditions.

In its release, Shell said it remains committed to Pennsylvania as it still plans to build the Pennsylvania Petrochemicals Complex. The project, which began construction in November 2017, will consist of an ethylene cracker with a polyethylene derivatives unit near Pittsburgh.

In the release, the company affirmed that it continues to see attractive opportunities in U.S. shale as it seeks increased efficiency in all its business areas.

The sale is subject to regulatory approvals and is expected to close by the end of July this year. The transaction will have an effective date of Jan. 1.

J.P. Morgan Securities LLC and **Goldman Sachs & Co. LLC** are financial advisers to National Fuel. **Kirkland & Ellis LLP** and **Jones Day** are the company's legal advisers.

—Emily Patsy

DGO Wins $110 Million Deal Following Long Courtship

TWO YEARS AFTER Diversified Gas & Oil Plc's (DGO) on-again, off-again pursuit of **Carbon Energy Corp.**'s Appalachian Basin gas assets, the companies inked a deal in April for about $110 million.

Birmingham, Ala.,-based DGO also agreed to contingency payments of up to $15 million based on natural gas prices and scheduled proved developed producing (PDP) quantities, according to regulatory filings. DGO has 45 days to conduct due diligence prior to executing the purchase agreement.

The assets fit with DGO's existing portfolio of conventional, low-decline gas production and include acreage in West Virginia, Kentucky and Tennessee. Production in 2019 averaged 59,400 Mcfe/d, of which 97% was natural gas. The agreement would add an additional 6,500 wells to DGO's arsenal of wells.

The deal additionally includes about 4,700 miles of intrastate gathering pipelines in West Virginia, which currently transports most of the production from Carbon's Appalachia wells and provides additional third-party transportation revenue. The system interconnects to higher-priced interstate pipelines.

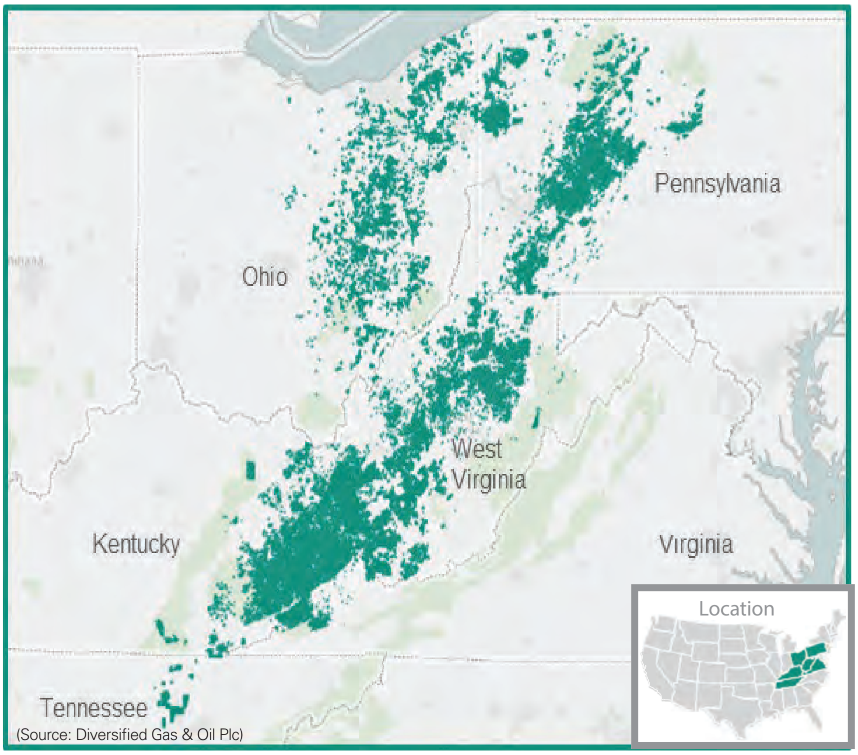
Carbon also would sell two active natural gas storage fields, which DGO said gives it greater optionality while generating third-party storage revenue. The deal includes interests held by Carbon affiliate **Nytis LLC**.

Carbon reported that, as of year-end 2019, it owned working and royalty interests in Illinois, Indiana, Kentucky, Ohio, Tennessee, Virginia and West Virginia in its Appalachian and Illinois basins. The company said its Appalachian and Illinois basin leasehold consists of 304,700 net developed acres as well as 1.25 million net undeveloped acres. Carbon also owns assets in the Ventura Basin in California.

In first-quarter 2018, DGO first broached a potential acquisition with Carbon with an offer for up to $165 million. At the time, the Nymex natural gas futures price for March 2018 was $2.698/MMBtu. Carbon declined the offer, believing its assets should command a "materially higher valuation," according to Securities and Exchange Commission documents.

During 2018 and 2019, three other parties approached Carbon concerning a possible acquisition of its Appalachia assets, including DGO in March 2019. Carbon ended up declining DGO's proposed purchase price of $135 million and broke off discussions. At the time, the Nymex natural gas futures price was $2.859/MMBtu.

Then, in October 2019, DGO again approached Carbon to renew discussions regarding a possible deal. Negotiations continued throughout the new year, with Nymex natural gas prices at $2.122/MMBtu. The parties continued to hammer out the deal, including contingency payments, between February and April.



Rusty Hutson Jr.

DGO said the deal includes a hedge portfolio with an average Nymex downside protection of about $2.60/MMBtu for an 18-month period from the effective date. The hedges represent roughly 75% of the assets' 2019 produced volumes.

"DGO is uniquely positioned to capitalize on compelling opportunities in the current market and moved quickly to secure exclusivity on this value accretive package," said DGO CEO Rusty Hutson Jr. "We can comfortably fund the acquisition without dilution to our loyal shareholders using our existing credit facility."

Hutson said the assets are strategically located in the company's existing area of operations and will allow it to leverage field personnel and technology across the additional assets.

"Expanded scale combined with our focus on a variety of identified opportunities to further improve the assets' free cash flow, enhance operating margins and provide additional insulation and resilience in this low commodity price environment," he said.

DGO, which trades on the London-based AIM stock exchange, said the transaction falls within its criteria of paying less than four times EBITDA. The deal would have an effective date of Jan. 1.

—Darren Barbee

Alta Mesa Goes Lower In Sale

ALTA MESA RESOURCES/SHUTTERSTOCK.COM

TURMOIL IN THE oil and gas markets shaved $100 million off the closing price for bankrupt Oklahoma E&P **Alta Mesa Resources LLC**, after the COVID-19 pandemic and an oil price war threatened to derail the deal, buyers said in an April 16 release.

A U.S. bankruptcy court approved on April 8 the sale of Alta Mesa and its midstream subsidiary to a partnership involving Tom L. Ward-led **Mach Resources LLC** for $220 million—a price nearly one-third less than what creditors had negotiated earlier this year before the oil price crash.

In a statement on April 16, Ward said his goal has been to be a patient buyer of choice for both undercapitalized and distressed sellers in the Midcontinent region.

"We believe this strategy will reap large rewards in the future as this market corrects itself through a lack of capital invested in future drilling," he said.

An industry veteran, Ward has formed and led several oil and gas companies throughout his career including shale pioneer **Chesapeake Energy Corp.**, which he co-founded in 1989 alongside Aubrey K. McClendon. He also went on to start **SandRidge Energy Inc.** in 2006 and **Tapstone Energy LLC** in 2013.

Through his latest venture, Ward partnered with **Bayou City Energy Management LLC (BCE)**, a Houston-based private-equity firm founded by Will McMullen, who said in a statement that he views the partnership with Mach Resources as being a consolidator in the Midcontinent. Since forming the partnership in 2018, the pair have made seven acquisitions, which include the purchases of Alta Mesa and its **Kingfisher Midstream LLC** affiliate.

Despite betting big on Oklahoma's STACK shale play through a three-way combination that involved a special purpose acquisition company led by industry veteran Jim Hackett, Houston-based Alta Mesa Resource succumbed to bankruptcy in 2019 after struggling with debt.

In May 2019, Alta Mesa reported debt of about $1.1 billion and $144 million of total liquidity. Roughly $868 million of the reported debt was allocated toward Alta Mesa's upstream operations.

In his statement, Ward commented that he has seen the need for caution with regard to further investment in the upstream space for several years.

"Stretched reserve valuations and cash being spent in excess were creating a situation that was untenable for the industry," he added. "Although we did not know at the time we developed the thesis that a global pandemic would further exacerbate the already dire situation, we did understand that the situation was unsustainable."

The renegotiated price for the Alta Mesa transaction adjusts by $1.75 million for every $1/bbl change from a $23/bbl baseline price. The reference price is set two days before closing, which occurred on April 9.

With the addition of the Alta Mesa assets, the BCE-Mach partnerships will now have net production of about 58,000 boe/d, interests in more than 5,700 wells and roughly 500,000 net acres across the Midcontinent.

The strategy for the Alta Mesa position primarily located in Oklahoma's Kingfisher County, according to McMullen, is to "conservatively develop the assets with an unwavering focus on maximizing free cash flow."

"By applying to these assets, the same prudent operatorship that the BCE-Mach partnerships have employed with assets previously acquired in the Mississippi Lime and Western Anadarko Basin, we believe the additional scale of these assets will bolster strong returns for our investors," McMullen said.

—Emily Patsy

Chevron Closes $1.6 Billion Deepwater Sale

CHEVRON CORP. completed the sale of a deepwater asset offshore Azerbaijan in a multibillion-dollar deal, the U.S. oil major said April 16.

MOL Plc, a Hungarian multinational oil and gas company, agreed to buy the asset, which consisted of Chevron's nonoperating interests in the Azeri-Chirag-Deepwater Gunashli (ACG)—the largest oil field in the Azerbaijan sector of the Caspian Basin, for $1.57 billion.

ACG had a net production of 20,000 boe/d in 2019, according to the Chevron press release.

Through its affiliate, **Chevron Global Ventures Ltd.**, the San Ramon, Calif.-based company held a 9.57% interest in the ACG oil fields. The sale also included interests in the Western Export Route Pipeline and an 8.9% interest the Baku-Tbilisi-Ceyhan oil pipeline located in Azerbaijan.

Remaining interest holders in ACG are **BP Exploration (Caspian Sea) Ltd.** (operator, 30.37%), **SOCAR** (25%), **Inpex Southwest Caspian Sea Ltd.** (9.31%), **Equinor Apsheron AS** (7.27%), **Exxon Azerbaijan Ltd.** (6.79%), **Turkiye Petrolleri A.O.** (5.73%), **Itochu Oil Exploration (Azerbaijan) Inc.** (3.65%) and **ONGC Videsh Ltd.** (2.31%).

Jay Johnson, executive vice president of upstream with Chevron, said the sale of its Azerbaijan assets plays "an important part" in the company's divestment program.

Chevron is targeting before-tax proceeds of $5 billion to $10 billion through asset sales between 2018 and 2020. The company also recently sold its U.K. North Sea assets for $2 billion to Israel's **Delek Group Ltd**.

"Chevron regularly reviews its global portfolio to assess whether assets are strategic and competitive for capital," Johnson said in a statement.

Investment bank **Jefferies** advised Chevron on the deal, according to a Reuters report from November 2019.

HighPeak Plans New Merger After Scuttled Permian Deal

HIGHPEAK ENERGY AND blank-check company **Pure Acquisition Corp.** agreed to a new business combination on May 4 following a scuttled three-way merger agreement with private-equity-backed **Grenadier Energy Partners II**.

Previously, the duo, which share board members and are both led by industry veteran Jack D. Hightower, had agreed to acquire Grenadier, backed by **EnCap Investments LP** and **Kayne Anderson Capital Advisors**. The combination was expected to form the largest pure-play northern Midland Basin E&P with a 73,000-net-acre position.

The crash in oil prices, however, forced a renegotiation of terms and, citing "current market uncertainty," the companies agreed on April 24 to terminate the combination, according to a filing with the U.S. Securities and Exchange Commission.

The new business combination agreement between only HighPeak and Pure is expected to close in the third quarter.

The combined company, set to trade as HighPeak Energy Inc., will hold a 51,000-net-acre position in the northern Midland Basin, which HighPeak Chairman and CEO Hightower described in a statement as "providing the best onshore domestic U.S. opportunities."

Located primarily in Howard County, the contiguous position will be greater than 90% operated and is expected to provide scale and a depth of inventory to maximize capital and operating efficiencies. Anticipated net production is about 12,000 boe/d—comprising more than 80% oil—upon completion of HighPeak Energy's inventory of drilled but uncompleted wells.

HighPeak's Anticipated Assets

Metric	Total
Net Acres	51,000
Gross / Net Operated Locations	495 / ~400
Net Production (90% Oil)	3,000 boe/d
EBITDA (NTM at Closing)	$166 million
EBITDA (2021E)	$285 million

(Source: HighPeak Energy)

Additionally, about 495 gross (400 net) drilling locations have been identified in either the Wolfcamp A and/or Lower Spraberry formations that are planned to be developed with mostly 2-mile laterals. Planned pad development assuming three operated rigs is set to begin after close of the business combination, the company release said.

Hightower, who previously led Titan Exploration and Bluestem Energy Partners, said the HighPeak management team is confident in achieving its development program after reviewing its "drilling success" over the end of 2019 and beginning of 2020.

"With the decline of energy prices over the last few months, several energy companies are struggling," Hightower said. "However, due to our low drilling and completion costs and our low operating costs, our breakeven prices are much lower than our competitors, which enables us to operate profitably at lower price levels."

HighPeak's development costs prior to the pandemic including drilling, completion, equipping and facilities averaged less than $525/ft for 10,000-ft or longer laterals, according to President Michael L. Hollis, who added the company has worked to lower costs further over the the beginning of 2020.

"The combination of our high oil cut and low operating costs enables us to earn among the highest margins in the Permian Basin," Hollis said in a statement.

Jefferies LLC acted as financial adviser with respect to the business combination agreement. **Hunton Andrews Kurth LLP** provided legal counsel to the special committee of the board of directors of Pure. **Latham & Watkins** acted as legal counsel to Jefferies. **Vinson & Elkins LLLP** was legal counsel to the HighPeak Funds. **EarlyBirdCapital Inc.** acted as adviser for Pure.

—Emily Patsy

Devon Renegotiates Barnett Exit

DEVON ENERGY CORP. could receive up to $60 million more for its Barnett Shale assets as part of newly amended deal terms, the company said in an April 14 release.

OIO JU SONG/SHUTTERSTOCK.COM

The Oklahoma City-based shale producer previously said it would sell its Barnett Shale assets for $770 million in an agreement announced in December. The sale, which would mark Devon's exit from the Barnett, would complete the company's transformation to concentrate on high-return oil assets.

As part of the amended terms, **Kalnin Ventures LLC**, a gas-focused investment company backed by Thailand's **Banpu Pcl**, agreed to pay up to $830 million for Devon's Barnett assets. Payment now comprises a $570 million cash at closing plus contingent payments of up to $260 million based on future commodity prices.

Originally expected to be completed during the second quarter, the scheduled closing date for the transaction also has been extended to Dec. 31 from April 15.

The contingent payment period commences on Jan. 1, 2021, and has a term of four years. Contingent payments are earned and paid on an annual basis with upside participation beginning at either a $2.75 Henry Hub natural gas price or a $50 WTI oil price, according to the company release.

Devon initially entered the Barnett Shale through the 2002 acquisition of **Mitchell Energy & Development Corp.** for $3.5 billion in cash and stock, which also included the assumption of $400 million in debt. The original deal included 2.5 Tcfe of proved reserves plus midstream assets valued at $800 million to $1 billion.

—Emily Patsy

Deal Dispute Lands Continental Resources In Court

CASILLAS PETROLEUM Resource Partners LLC has sued **Continental Resources Inc.** in district court, alleging the Oklahoma shale producer backed out of a $200 million oil and gas deal in March as prices crashed.

U.S. crude futures prices have tumbled, with coronavirus-related lockdowns and travel restrictions souring demand as OPEC and other producers waged a price war, sending oil to $13/bbl in April from $61/bbl at the start of the year.

On March 6, the day that a supply pact by OPEC and allies collapsed, Continental agreed to buy oil and gas properties from Tulsa, Okla.-based Casillas. The deal was set to close roughly three weeks later, according to a lawsuit filed in Tulsa County District Court in Oklahoma.

But Continental got cold feet and proposed to postpone the closing due to "changes in the oil and gas markets" and then terminated the agreement on March 24 citing title and other problems, the lawsuit alleged.

Continental Resources did not respond to a request for comment.

Casillas could not immediately be reached for comment on the suit, filed on April 15, which asks the court to order Continental to complete the purchase and pay Casillas attorneys' fees and other associated costs.

Harold Hamm

Crashing oil prices have upset several deals in the process of closing. On April 27, **BP Plc** agreed to restructure a $5.6 billion sale of Alaska oil properties to **Hilcorp Energy**. Shale producers **Alta Mesa Resources** and **Devon Energy Corp.** accepted lower prices for pending asset deals.

Continental slammed the brakes on spending and oil production as prices nosedived. On March 19, it disclosed a 55% reduction in 2020 spending. Three weeks later, it suspended its dividend and reduced output by 30% for April and May.

Founder Harold Hamm, an early supporter of U.S. President Donald Trump, has urged Washington to impose tariffs on foreign oil imports and pushed for federal support of the oil industry.

In late April, he called for futures market regulators to investigate potential market manipulation after oil futures turned negative for the first time. His firm recently declared force majeure on certain sales contracts.

The case is *Casillas Petroleum Resource Partners v. Continental Resources*, Tulsa County, Okla. district court, No. CJ-2020-1346.

Tallgrass Shareholders Greenlight Buyout

TALLGRASS ENERGY share holders on April 16 backed a buyout by a group led by **Blackstone Infrastructure Partners** that valued the U.S. oil pipeline operator at $6.3 billion, a rare case of a premarket crash deal going ahead without a price cut.

Terms were struck ahead of this year's collapse in energy prices that has U.S. oil producers cutting output and pipeline operators reducing their fees to hold onto dwindling business. About 30% of global fuel demand has been lost from business shutdowns to combat the coronavirus pandemic, hitting high cost U.S. shale producers the hardest.

Tallgrass shares would have dropped to $8 apiece had Blackstone walked away from the deal, estimated Ethan Bellamy, a senior equity analyst at **Robert W. Baird & Co.** The stock traded on April 16 morning at $22.35.

The pipeline's former owners "are getting a better deal than they otherwise would in this turmoil, but it doesn't mean Blackstone investors will suffer," Bellamy said. The new owners likely view the turmoil as transitory and may use Tallgrass to build a larger business through acquisition, he said.

The Blackstone group previously acquired a 44% stake in Tallgrass, and in August it offered $19.50 apiece for the remaining shares. Four months later, it sweetened the bid to $22.45 per share after big holders criticized the original offer.

Sticking with the pre-crash price spared Blackstone from having to write down the value of existing holdings, said Simon Lack, managing director of investment firm **SL Advisors**, which focuses on pipeline and other energy infrastructure deals.

It continued with the deal even after other precrash deals were renegotiated. **Banpu Kalnin Ventures** (BKV), a Thailand-based investment group, shaved 25% off its $770 million deal for Devon Energy Corp. Barnett Shale assets on April 16. Private-equity firm **Bayou City Energy Management LLC** and **Mach Resources LLC** earlier cut a third off a $320 million deal for Alta Mesa Resources Inc. BKV delayed closing its deal to 2021 but offered contingency payments if oil prices hit $50/bbl before 2025.

Oklahoma pipeline operator **Glass Mountain LLC** sued shale gas pioneer **Chesapeake Energy Corp.** April 13 for allegedly defaulting on an oil transportation contract it had only weeks earlier renegotiated.

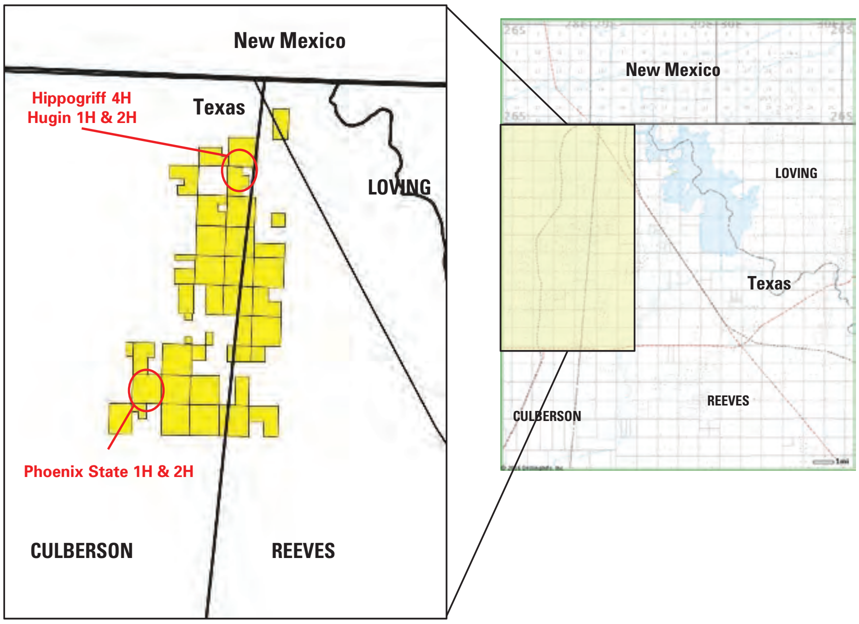
Tallgrass pipelines carry oil from fields in Wyoming, Colorado and Kansas to the top U.S. storage hub in Oklahoma and has proposed a line to U.S. Gulf Coast export markets. Co-investors in the buyout include Spain's **Enagas SA** and **Jasmine Ventures**, an affiliate of Singapore's GIC sovereign wealth fund.

Ring Energy Sells Delaware Assets

RING ENERGY INC. managed to pull a rabbit from its hat in mid-April, agreeing to sell its Delaware Basin assets despite historic oversupply due to a global pandemic and the aftershocks of an oil price war.

In the first announced Permian deal since Valentine's Day, Ring's sale of nearly 20,000 acres in Culberson and Reeves counties, Texas, comes as the oil market continues to plummet. The deal, by an undisclosed buyer, is expected to bring in cash for Ring, which, like all operators, will need capital to survive the coming months.

Richard Tullis, an analyst at **Capital One Securities**, estimated that Ring Energy's sale—for about $31.5 million—would improve year-end liquidity for the company to $110 million from $62 million.



(Source: Ring Energy)

Capital One had valued the Delaware Basin assets at $48 million, suggesting Ring received about two-thirds of the value in the deal. Tullis added, "Investors will likely be more focused on cash infusion." The company agreed to sell the assets for about $1,575 per acre.

Ring Energy, based in Midland, Texas, said April 14 it received a $500,000 nonrefundable deposit and expects the transaction to close within 60 days.

The transaction does not stand to substantially impact Ring's production and represents about 8% of the company's pre-deal enterprise value. The Delaware Basin assets contributed about 980 boe/d in the fourth quarter (56% oil).

Ring Energy entered the basin in July 2015 through the purchase of 14,000 net acres held by **Finley Resources Inc.** for $75 million. At the time of the deal, production in Culberson and Reeves was about 1,300 boe/d (80% oil).

Ring's assets at the time of the April agreement included 112 producing vertical wells, five horizontal wells and six saltwater disposal wells.

The company also owns and operates 39 miles of water gathering pipeline and 23 miles of gas gathering pipeline.

Ring Energy CEO Kelly Hoffman said that since formally announcing it was marketing its Delaware assets in November 2019, the company has worked to find a fair and equitable transaction.

"As we have stated in the past, the proceeds from this transaction will be used to reduce the current balance on the company's senior credit facility," Hoffman said in a news release.

"The current environment mandates a cautious, conservative approach going forward, and strengthening our balance sheet is a step in the right direction."

At year-end 2019, the assets held 3.48 MMbbl of oil and 10,055 MMcf of natural gas with a total PV-10 value of about $43 million, according to estimates by **Cawley, Gillespie and Associates**. The estimates were based on $52.41/bbl oil and $1.47/Mcf gas.

Ring Energy continues to hold positions in the Permian Basin in the Central Basin Platform and the Northwest Shelf.

—Darren Barbee

Lufkin Resurrected Through Baker Hughes Sale

BAKER HUGHES CO. has agreed to sell the rod lift solutions business it inherited from the fallout of its **General Electric Co. (GE)** merger, reaching a deal intended to relaunch **Lufkin Industries Inc.** as a freestanding company.

GE purchased the 118-year-old Lufkin business for $3.3 billion in 2013—four years before merging its oilfield equipment and services arm with Baker Hughes. Despite selling a majority stake in 2019, GE still owns 36.6% of Baker Hughes.

Per a May 1 release from buyer **KPS Capital Partners LP**, Baker Hughes will part with the Lufkin rod lift business, based in Missouri City, Texas, for an undisclosed amount. KPS, a New York-based private-equity firm, solicited about $7 billion in investments in October 2019.

Lufkin, which operates globally, will be led by an independent team. KPS and Lufkin will acquire additional complementary technologies and products as Lufkin serves the upstream oil and gas sector.

Baker Hughes, like other oilfield service sector businesses, has been buffeted by the COVID-19 pandemic, which caused a glut in oil supply and resulted in a sharp drop in operations. Since January, the U.S. Lower 48 rig count has fallen about 49% to 388 rigs in the first week of May, according to Baker Hughes rig count data.

Baker Hughes wrote off $14.8 billion in value in April through a goodwill impairment charge and announced it would take cost-savings measures, including cutting its capex by about 20% compared to 2019. At the end of March, the company had about $3 billion in cash and equivalents on hand, largely overseas.

Analysts at **Tudor, Pickering, Holt & Co. (TPH)** have noted that, while no company will escape what it called the frac activity "bloodbath," Baker Hughes' international presence will leave it less drenched than some of its rivals. TPH estimates Baker Hughes has about "70% international exposure and about 40% exposure to industrial-type end markets."

KPS said Lufkin manufactures surface pumping units, downhole sucker rod pumps and automation systems in six manufacturing and assembly facilities worldwide. It operates globally in "every critical rod lift market in the world," the firm said.

Lufkin's power transmission business will remain part of the Baker Hughes portfolio and is not included in the transaction with KPS.

KPS expects to close the transaction by mid-2020, subject to customary closing conditions and approvals.

"KPS will build a successful energy platform on the foundation of Lufkin's legendary brand name, unparalleled reputation for reliability, superior technology and global footprint. The historic dislocation in current global and domestic energy markets has created an extraordinary investment opportunity for an investor like KPS," said Michael Psaros, co-founder and co-managing partner of KPS.

Andy Cordova, rod lift solutions general manager with Baker Hughes, said KPS is an ideal partner for Lufkin's return as an independent business.

"KPS' global platform, commitment to manufacturing excellence and significant financial resources will enable Lufkin to accelerate its growth and invest in technology and process improvements for our customers while enhancing our established reputation for industry-leading technology, quality and customer service," he said.

FILE PHOTO

Simmons Energy, a division of **Piper Sandler & Co.**, acted as adviser and **Paul, Weiss, Rifkind, Wharton & Garrison LLP** served as legal counsel to KPS and its affiliates. **Citi** and TPH were financial advisers and **King & Spalding International LLP** served as legal counsel to Baker Hughes.

—Darren Barbee

TRANSACTION HIGHLIGHTS

ALASKA

■ **BP Plc** said April 27 the sale of its Alaska business remained on track to close as planned—and with the same multibillion-dollar price tag—despite the recent plunge in oil prices.

Privately held **Hilcorp Energy Co.** agreed in 2019 to buy BP's Alaska business, including the British oil major's entire upstream and midstream assets in the state, for $5.6 billion. However, oil prices have fallen more than 75% since the agreement was struck in August 2019.

On April 27, BP said to better reflect the "recent significant market volatility and oil price falls," it had renegotiated the financial terms of the deal with Hilcorp.

The new agreement will retain the original sale price and mid-2020 close date, but it includes a revised structure and phasing of payments.

The original agreement provided for Hilcorp to pay $4 billion near-term and $1.6 billion through an earn-out thereafter. Hilcorp paid a $500 million deposit on signing of the transaction in 2019, according to the BP press release.

Though details on timing of the payouts or amounts were not disclosed, the company said the revised structure will feature lower completion payments in 2020, new cash flow sharing arrangements over the near term, interest bearing vendor financing and a potential increase in the proportion of the consideration subject to earn-out agreements.

Analysts with **Tudor, Pickering, Holt & Co.** (TPH) potentially view the restructured deal as positive for BP given the company's more than $20 billion in cash at year-end 2019 and undrawn $8 billion revolving credit facility. However, the analysts question Hilcorp's ability to fund its side of the deal.

"Hilcorp's ability to finance any significant near-term payment is likely to continue to draw questions as the company originally wished to fund the deal entirely with debt, which seems challenging in a seized up junk market and the company's publicly traded debt trading at ~52-57c," the TPH analysts wrote in an April 27 research note.

Upon completion of the deal, analysts expect Houston-based Hilcorp will become the second largest E&P in Alaska. Meanwhile, the sale represents BP's exit from the state, where the British oil major had been active since 1959.

The transaction remains subject to state and federal regulatory approval and is expected to close in June.

"We are confident that completion of this sale is the right thing for both parties, for the business and for Alaska," William Lin, COO of upstream regions for BP, said in a statement.

NORTH AMERICA

■ **Gyrodata Inc.** agreed to sell its directional drilling business to **Intrepid Directional Drilling Specialists Ltd.**, doubling Intrepid's directional drilling capabilities in North America, the privately held companies said in a joint release on April 30.

The transaction includes effectively all of Houston-based Gyrodata's directional drilling personnel as well as its high-performance drilling motors and MWD tools. Financial terms and conditions of the transaction were not disclosed.

"We strongly believe that expanding our business at this time will allow us to better meet our customers' needs as the market continues to evolve in the coming years," Intrepid President Clint Leazer said in a statement.

Founded in 2001, Intrepid has drilled more than 5,000 directional and horizontal wells in every major basin in the U.S. The Midland, Texas-based company said it also expects the Gyrodata acquisition to expand its presence into certain Latin American countries.

ALGERIA

■ Energy major **Total SA** has been told by **Occidental Petroleum Corp.** that it cannot acquire oil and gas assets in Algeria that were part of an $8.8 billion deal reached by the companies on Anadarko Petroleum's assets in Africa.

"Occidental officially told us that we cannot acquire the Algeria assets," the French company's CEO Patrick Pouyanne told analysts during a conference call after its first-quarter 2020 results.

"It releases part of the acquisition budget," Pouyanne said.

As part of its cash-raising to fund its purchase of Anadarko, Occidental agreed that Total would take over some of Anadarko's assets in a $8.8 billion deal.

The Anadarko assets in are in Algeria, Ghana, Mozambique and South Africa. The deal in Mozambique, which includes a giant LNG project has been concluded.

Algerian authorities had moved to block Total's acquisition of the assets.

Pouyanne told analysts the decision was based on the objection of Algiers, and Occidental will remain as operator unless it can find a way to sell it to Total.

On the assets in Ghana, Pouyanne said things were moving on with the deal, but declined to comment further.

LOWER 48

■ **Occidental Petroleum Corp.** shareholders next month will get their first say on the oil company's troubled acquisition of **Anadarko Petroleum Corp.** when they vote on issuing shares and warrants to **Berkshire Hathaway Inc.** for helping finance the $38 billion deal.

The Anadarko acquisition closed in August, months before an oil price crash sapped the cash flow Occidental needed to pay the debt taken with the purchase. Critics, including activist shareholder Carl Icahn, have said the financing deal with Berkshire Hathaway's Warren Buffett was too generous.

Occidental and Berkshire Hathaway declined to comment.

Berkshire Hathaway's $10 billion investment provided it with warrants for 80 million common shares in addition to an 8% dividend on preferred shares received for its support for the Anadarko acquisition.

Shareholders, who did not get to vote on the 2019 Anadarko deal, were to vote at Occidental's May 29 annual meeting to authorize the warrants and to issue 400 million new shares, some of which could pay the Berkshire dividend.

Cash-strapped Occidental recently paid Berkshire its first-quarter dividend with about 17.3 million shares, which are trading at one-fifth of what they fetched in 2019. When paid in shares, the dividend increases to nearly 9%.

Berkshire's warrants are nearly worthless, because their $62.50 strike price was well above Occidental's $13.63 closing price on April 17. But they give Berkshire more than a decade to exercise the option, and dividends paid in shares could make it a major holder in short order.

EASTERN US

1 A Marion County, Ill., discovery was announced by T D Energy Inc. The #2 ***T D Energy*** was tested flowing 50 bbl of oil per day from Clear Creek. The Centralia Field well is in Section 19-1n-1e and was drilled to 2,955 ft. It is producing from perforations between 2,948 and 2,955 ft. TD Energy's headquarters are in Ponchatoula, La.

2 An Edgar County, Ill., exploratory test has been planned by ***Pioneer Oil Co.*** The #1-35 Keske has a planned depth of 800 ft and will be drilled in Section 35-15n-14w. The Illinois Basin venture is targeting oil pays in Clear Creek. About one-half mile to the northwest, the company drilled #1 Bosch Farms in 2018 in Section 2-14n-14w to an unreported depth. The proposed total depth was 1,800 ft with a Trenton objective. Details of #1 Bosch Farms are being held as confidential by Illinois regulators until late 2020. Pennsylvanian oil production in Warrenton-Borton Field is approximately 3.5 miles south-southeast of Lawrenceville, Ill.-based Pioneer's scheduled drillsite. First production from the reservoir was reported in the 1900s.

3 A Knox County, Ind., Aux Vases completion was announced by ***Siskiyou Energy LLC***. The #1 Small Roger Etal produced 45 bbl of oil and 1 bbl of water per day. The Monroe City Consolidated Field well was drilled to 2,350 ft and is in Section 35-2n-9w. It was tested after acidizing and is producing from perforations at 1,537-1,541 ft. Siskiyou's headquarters are in San Antonio.

4 A Harrisville Consolidated Field-Utica Shale completion in Belmont County, Ohio, was announced ***Ascent Resources***. Located in irregular Section 6-8n-5w, #2H Bannock UNN BL produced 25.925 MMcf of gas and 98 bbl of water daily. The 21,834-ft completion has a true vertical depth of 21,834 ft, and the true vertical depth is 9,122 ft. Production is from perforations between 9,182 and 21,711 ft. Ascent Resources is based in Oklahoma City.

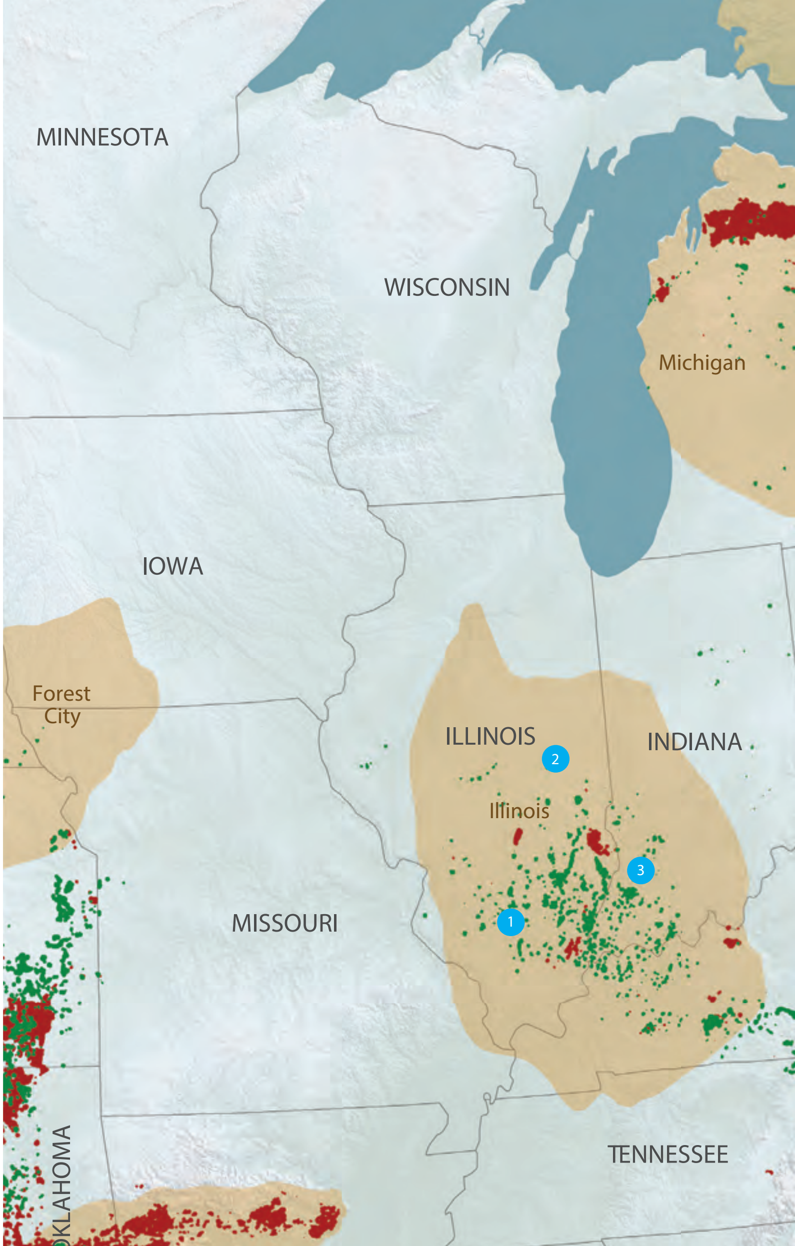
5 A Utica Shale discovery in Jefferson County, Ohio, initially flowed 42 MMcf of gas and 219 bbl of water per day. ***Ascent Resources***' #3H Darrow E MTP JF is in irregular Section 23-7n-3w in Harrisville Consolidated Field. The well was drilled to 27,775 ft, and the true vertical depth is 9,366 ft. It was tested after acidizing and fracturing with production from perforations between 10,019 ft and 25,626 ft.

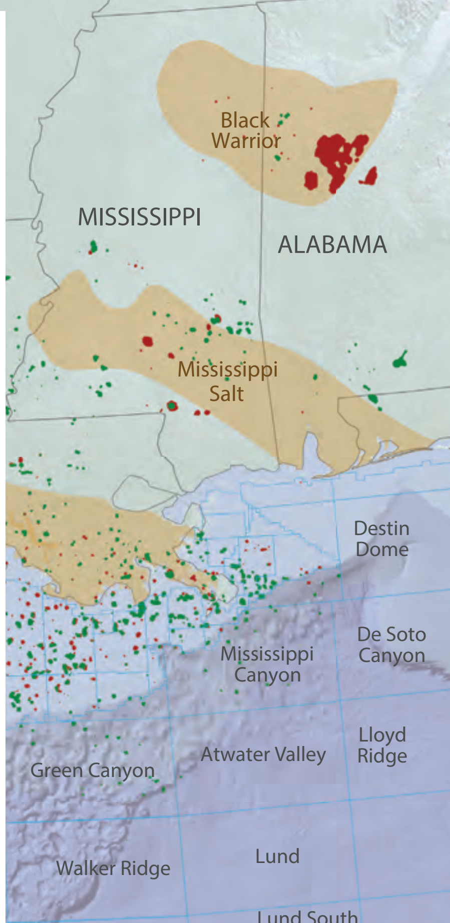
6 A Woodruff Field well was completed in Pennsylvania's Greene County by ***EQT Production Co***. The #590613 Carpenter was drilled in Section 7, Rogersville 7.5 Quad, Center Township and was tested flowing 38.97 MMcf of gas per day. It was drilled to 26,856 ft, and the true vertical depth is 7,836 ft. Production is from perforations between 8,305 and 26,726 ft with a shut-in casing pressure of 3,450 psi. EQT's headquarters are in Pittsburgh.

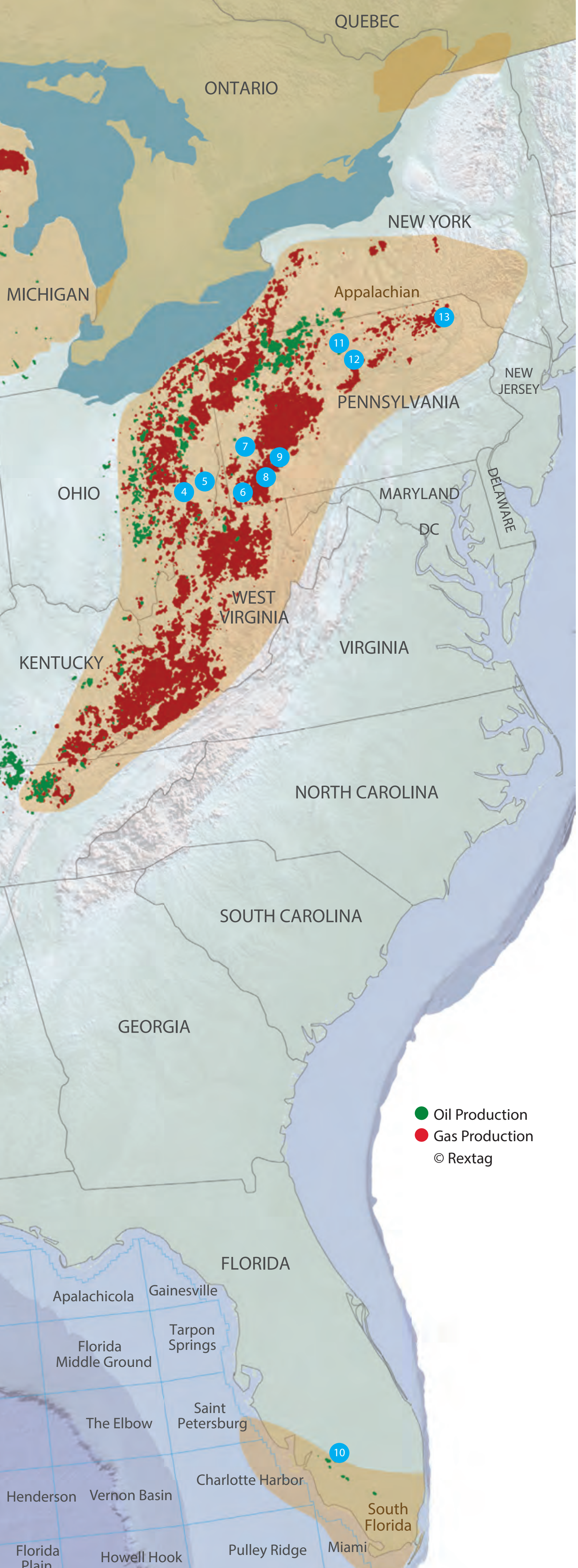
7 In Allegheny County, Pa. ***Range Resources*** completed a Marcellus Shale well that was tested flowing 10.66 MMcf of gas per day. The Cork Field discovery, #2H Ziolkowski Ray 11771, was drilled in Section 2, Clinton 7.5 Quad, Findlay Township to 16,193 ft (5,807 ft true vertical). It was tested after 50-stage fracturing, and production is from perforations between 6,447 and 16,148 ft. Range's headquarters are in Canonsburg, Pa.

8 ***EQT Production Co.*** announced results from a Marcellus well in Greene County, Pa. The #203MATH26 River is in Highhouse Field. It was drilled to 21,110 ft with a true vertical depth of 7,517 ft. It was tested flowing 26.53 MMcf of gas per day with no reported water from perforations at 8,197-20,950 ft. The shut-in casing pressure was 2,900 psi.

9 An Allegheny County, Pa. Marcellus completion was announced by ***EQT Production Co***. The #21H12 Mon Prentice is in Forward Field and was drilled to 17,825 ft, 7,781 ft true vertical. It was tested flowing 12.934 MMcf of gas per day with a shut-in casing pressure of 3,300 psi. It was acidized and fractured. It is producing from perforations between 8,101 and 17,705 ft and is located in Section 2 Monongahela 7.5 Quad, Forward Township.

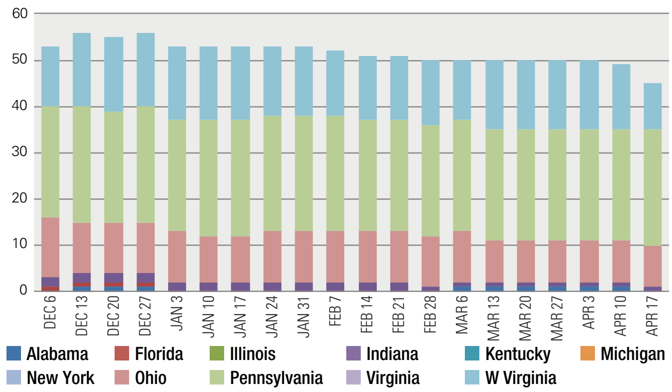






Eastern US Rig Count

Dec. 6, 2019-Apr. 17, 2020



Source: Baker Hughes Co.

10 IHS Markit reported that ***MKJ Exploration*** has scheduled a short-lateral horizontal test in South Florida's Sunoco Felda Field, an abandoned Sunniland Lime oil reservoir straddling the Hendry/Collier county line. The well, #29-4BH Red Cattle, will be drilled in Section 29-45s-29e in Hendry County. The proposed total depth is 12,194 ft (11,475 ft true vertical). Before drilling the horizontal portion of the test, Metairie, La.-based MKJ intends to drill an 11,600-ft vertical pilot hole. If drilled, MKJ's venture would mark the first new drilling in Sunoco Felda Filed since 1980. The last oil production from the field was reported in 1992. Opened in 1964, cumulative field recovery totaled 5.2 MMbbl of crude, 418 MMcf of gas and 32 MMbbl of water. Wells in the field yielded crude through a narrow range of perforations in Sunniland Lime at 11,400-11,500 ft. To the west of Sunoco Felda Field is Mid-Felda Field, another Sunniland Lime reservoir that was opened in 1977. Reservoir production has been sporadic in recent years, with 2019 output totaling 485 bbl of crude from one active well. Nearby activity is at a directional sidetrack permitted in Mid-Felda Field at #27-4C Red Cattle in Section 27-45s-28e and about 20 miles to the northwest at #33-4 Indigo in Section 33-43s-32e.

11 In Bradford county Pa., ***Chesapeake Operating Inc.*** completed a Marcellus Shale well in Section 7, Towanda 7.5 Quad, Towanda Township. The #1HC Rose is in Asylum Field and was drilled to 17,169 ft, and the true vertical depth is 6,126 ft. It flowed 26.36 MMcf of gas from perforations at 5,798-17,141 ft. The shut-in casing pressure was 1,681 psi. Chesapeake is based in Oklahoma City.

12 Two Marcellus Shale wells were drilled from a pad in Bradford County, Pa., by ***Chesapeake Operating Inc***. The Mehoopany Field drillpad is in Section 4, Jenningsville 7.5 Quad, Wilmot Township. The #4HC Roland was drilled to 19,244 ft (8,506 ft true vertical). It flowed 35.88 MMcf of gas per day from perforations at 8,335-19,196 ft. The shut-in casing pressure was 3,250 psi. The offsetting #5HC Roland was drilled to 19,924 ft with a true vertical depth of 8,506 ft. It produced 41.54 MMcf of gas daily with a shut-in casing pressure of 3,900 psi. The discovery produces from perforations at 8,234-19,858 ft.

13 Two Susquehanna County, Pa., Marcellus Shale wells were completed by ***Southwestern Production Co***. The Page Lake Field ventures were drilled from a pad in Section 6, Harford 7.5 Quad, Jackson Township. The #7H Blue Beck Ltd was drilled to 14,016 ft with a true vertical depth of 6,954 ft, and it produced 16.865 MMcf of gas per day with a shut-in casing pressure of 2,793 psi. Production is from a perforated zone at 6,946-13,972 ft after 47-stage fracturing. The #8H Blue Beck Ltd was drilled to 14,688 ft, 6,936 ft true vertical, and flowed 16.28 MMcf of gas per day from perforations at 6,740-14,644 ft after 53-stage fracturing. The shut-in casing pressure was 2,125 psi. Southwestern's headquarters are in Spring, Texas.

GULF COAST

1 Three Dimmit County (RRC Dist. 1), Texas, Eagle Ford Shale wells were completed by ***Chesapeake Operating Inc***. The wells were drilled from a Briscoe Ranch pad in Section 22, Block 7 I&GN RR CO Survey, A-1174. The #3H Faith-Sandy D Unit S was drilled to 16,668 ft (6,466 ft true vertical) and produced 1.026 Mbbl of condensate, 3.588 MMcf of gas and 443 bbl of water per day. It was tested on a 33/64-in. choke with a flowing tubing pressure of 761 psi and a shut-in casing pressure of 2,963 psi. Production is from perforations at 6,659-16,561 ft. The #4H Faith-Sandy D Unit S was drilled to 15,498 ft, 6,420 ft true vertical, and flowed 836 bbl of condensate, 3.264 MMcf of gas and 275 bbl of water daily. It was tested on a 36/64-in. choke with a flowing tubing pressure of 648 psi and a shut-in tubing pressure of 1,574 psi. Production is from perforations at 6,528-15,388 ft. Chesapeake's headquarters are in Oklahoma City.

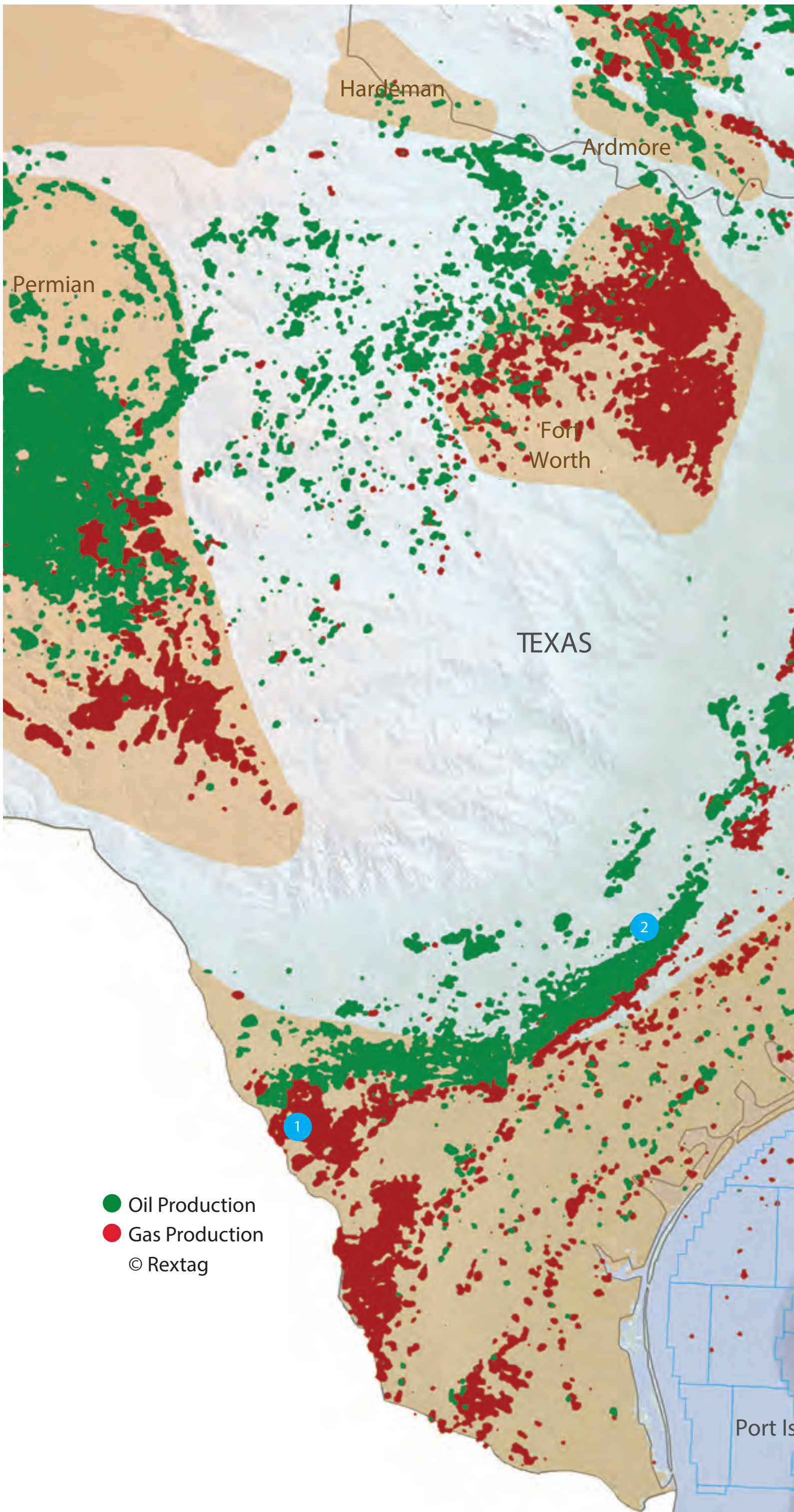
2 In Gonzales County, Texas (RRC Dist. 1), ***EOG Resources Inc.*** completed an Eagle Ford Shale well. The #2H Arctic B is in Eagleville Field, and it was tested flowing 1.148 Mbbl of oil with 531 Mcf of gas and 2.328 Mbbl of water per day. It was drilled in Section 14, B D Mclure Survey, A-41. The venture was drilled to 17,289 ft, and the true vertical depth is 10,676 ft. The well was tested on a 36/64-in. choke after fracturing. Production is from perforations between 10,356 and 17,223 ft.

3 Results from three San Miguel Creek Field-Haynesville discoveries were reported by ***Indigo Minerals***. The Sabine Parish, La., ventures were drilled from a pad in Section 1-9n-11w, and the parallel wells all bottomed to the south in Section 12. The #3-Alt Tristar 1&12-9-11HC initially flowed 28.72 MMcf of gas and 264 bbl of water from an acid- and fracture-treated zone at 14,576-20,780 ft. The flowing tubing pressure was 10,613 psi when tested on a 25/64-in. choke. The well was drilled to 20,934 ft (14,020 ft true vertical). The #1 Tristar 1&12-9-11H and #2 Tristar 1&12-9-11H were recently completed from an offsetting surface location. The #1 Tristar 1&12-9-11H flowed 25.3 MMcf of gas and 360 bbl of water per day through perforations at 14,546-21,542 ft. It was drilled to 21,700 ft (14,019 ft true vertical). The #2 Tristar 1&12-9-11H was tested at a daily rate of 28.8 MMcf of gas and 192 bbl of water from perforations at 14,063-20,341 ft. The total depth is 20,500 ft, and the true vertical depth is 13,387 ft. Indigo's headquarters are in Houston.

4 ***Indigo Minerals*** completed two Haynesville Shale wells in Natchitoches Parish, La. The King Field discoveries were drilled from a pad in Section 11-10n-10w. The #1 Russ 12&13-10-10HC flowed 29.01 MMcf of gas and 151 bbl of water per day from an acid- and fracture-treated zone at 13,427-19,304 ft. The 19,432-ft horizontal sidetrack well has a true vertical depth of 13,263 ft and bottomed to the south in Section 11-10n-10w. Gauged on a 25/64-in. choke, the flowing casing pressure was 10,265 psi. The offsetting #1 Russ 11&14-10-10HC produced 25.98 MMcf of gas and 647 bbl of water per day from perforations at 14,130-20,374 ft. It was drilled to 20,503 ft (13,873 ft true vertical), and it bottomed to the south in Section 14.

5 Two Haynesville Shale wells in the southern Red River Parish portion of Redoak Lake Field were reported by ***Brix Operating***. The #1 Coats 30-19H was tested with a daily flow rate of 19.715 MMcf of gas with no liquids through acid- and fracture-treated perforations at 13,767-20,683 ft. It was drilled in Section 30-11n-9w and bottomed within 2 miles to the north in Section 19. The well was drilled to 20,688 ft with a true vertical depth of 13,497 ft. The offsetting #1-Alt Coats 30-31HC produced 17.202 MMcf of gas per day from perforations at 13,868-18,450 ft. The 19,460-ft well has a true vertical depth of 13,795 ft, and it bottomed about 1 mile to the south in Section 31. Brix is based in Plano, Texas.

6 An oil discovery was reported at the Monument exploration prospect by ***Equinor*** and partners ***Progress Resources USA Ltd***. and ***Repsol***. According to the Stavanger-based company, #1 OCS G35081 encountered approximately 200 ft of net oil pay with good reservoir characteristics in Paleogene-aged sandstone. The well was drilled to 33,348 ft and is in Walker Ridge Block 316 (OCS G36084). It bottomed to the north beneath Block 272. Area water depth is 6,300 ft. The Monument discovery is operated by Equinor (50%) with partners Progress Resources (30%) and



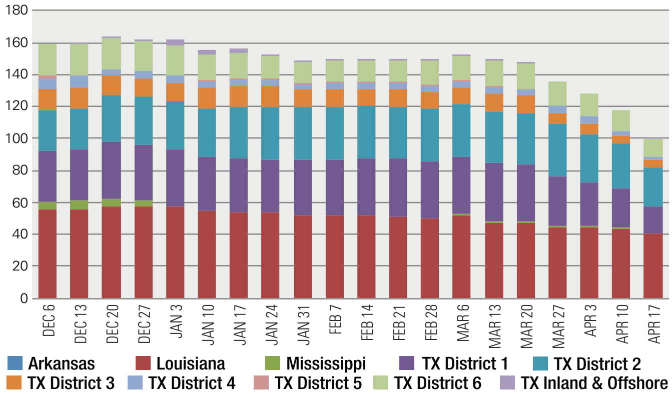
Repsol (20%). Walker Ridge Block 271 (OCS G35080) is also part of the Monument project.

7 ***EnVen Energy*** plans to sidetrack a Pliocene oil well in the company's Lobster Field. According to IHS Markit, #10-A (ST) OCS G12136 will be drilled from the existing A platform on Ewing Bank Block 873. According to the permit, the original hole will be sidetracked at 8,000 ft. Water depth is 773 ft. Lobster Field (Ewing Bank Block 873) was discovered by ***Marathon Oil***, with first production reported in 1994. Field ownership has changed hands several times since the reservoir's discovery. The #10-A (ST) OCS G12136 was drilled in 1995 to 11,934 ft. Through late 2019, well production totaled 8.3 MMbbl of crude and 5.3 Bcf of gas from Pliocene at 11,486-11,736 ft. EnVen is based in Houston.

8 IHS Markit reported that Houston-based ***Walter Oil & Gas*** plans to bypass a deepwater exploratory on the company's Mississippi Canyon Block 881/882 prospect. The #1 (BP) OCS G35988 will be in the western portion of the block and has a planned bottomhole to the west beneath Block 881. According to the permit, the original hole will be bypassed at 5,331 ft. Water depth in the area is 2,200 ft. ***Exxon Mobil*** drilled an exploratory test has been drilled on Block 881 in 1990. The well was abandoned at 10,189 ft in Pleistocene.

Gulf Coast Rig Count

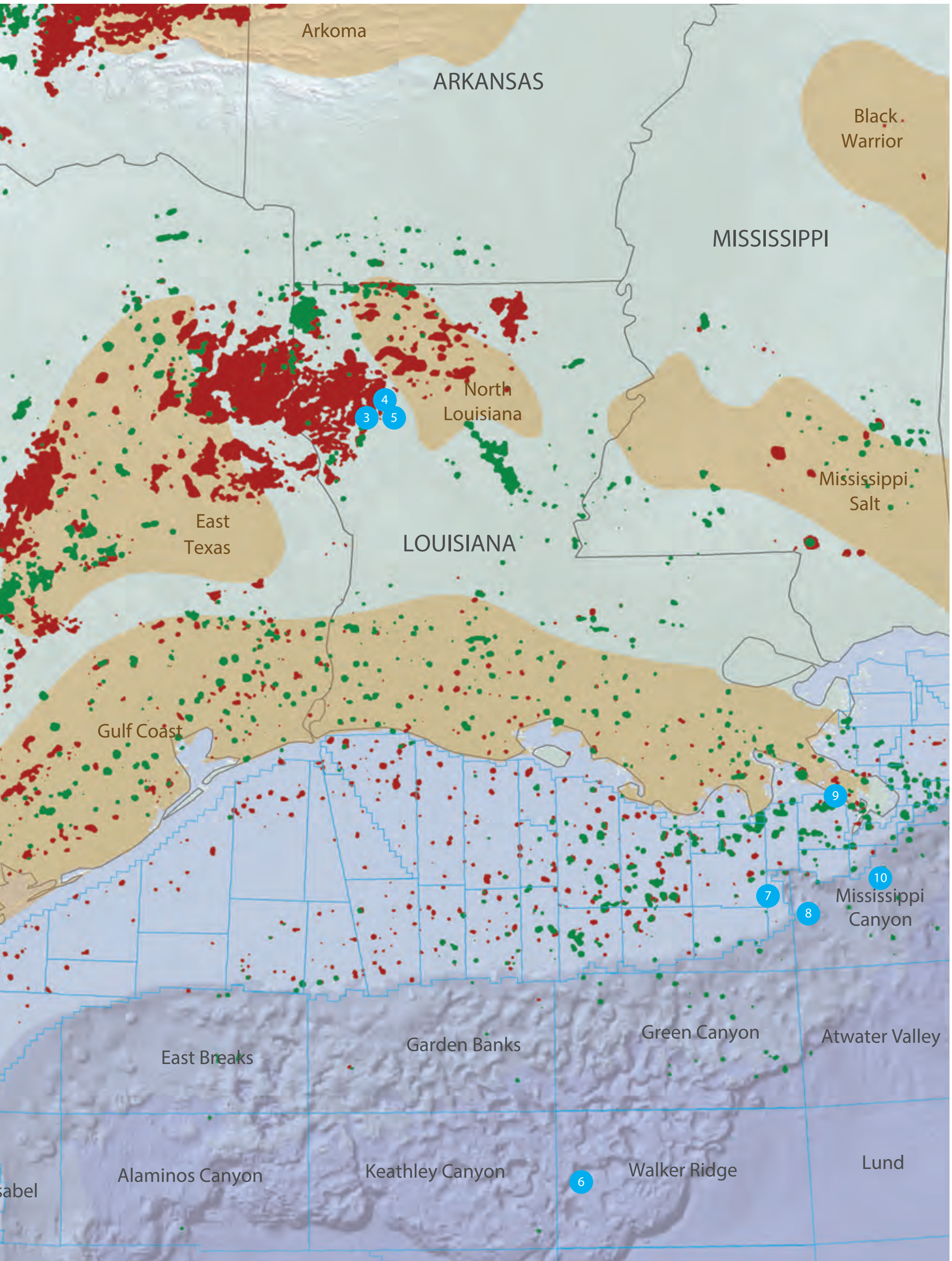
Dec. 6, 2019-Apr. 17, 2020



Source: Baker Hughes Co.

9 Results from a Miocene recompletion in Louisiana's Lake Washington Field were reported by ***Badger Energy***. In Plaquemines Parish's Barataria Bay, #1 State Lease 20984 was tested flowing 164 bbl of 41.8-degree-gravity crude and 1.073 MMcf of gas per day from perforations at 12,279-12,326 ft. Gauged on an 11/64-in. choke, the flowing tubing pressure was 3,050 psi. The well was initially completed as a gas well in 2014. The directional well produced 3.041 MMcf of gas and 304 bbl of condensate daily from a deeper Miocene zone at 12,410-34 ft. Well production during one month online was 74 MMcf of gas and 8.981 Mbbl of condensate before apparently being shut in. It was drilled to 14,682 ft in Section 32-19n-26e, and the true vertical depth is 13,420 ft. Badger's headquarters are in Lafayette, La.

10 A drillship is being moved to drill a new development test, #6 OCS G27277 in ***LLOG Exploration***'s producing Who Dat Field in the southeastern portion of Mississippi Canyon Block 503. Water depth in the area is 3,100 ft. The drillship is being moved from the company's Green Canyon Block 157 prospect, #1SS (ST3) OCS G12210. Who Dat Field (Block 546) is made up of Blocks 502, 503, 546 and 547. Wells in the reservoir yield oil and gas from the Pliocene at around 12,000-16,000 ft and Miocene at 16,000-20,000 ft. LLOG has filed several exploration plans in the area, most recently submitting a plan in early 2020 for Mississippi Canyon Block 634 (OCS G34904). Two exploratory tests are planned for the undrilled tract. LLOG is based in Covington, La.



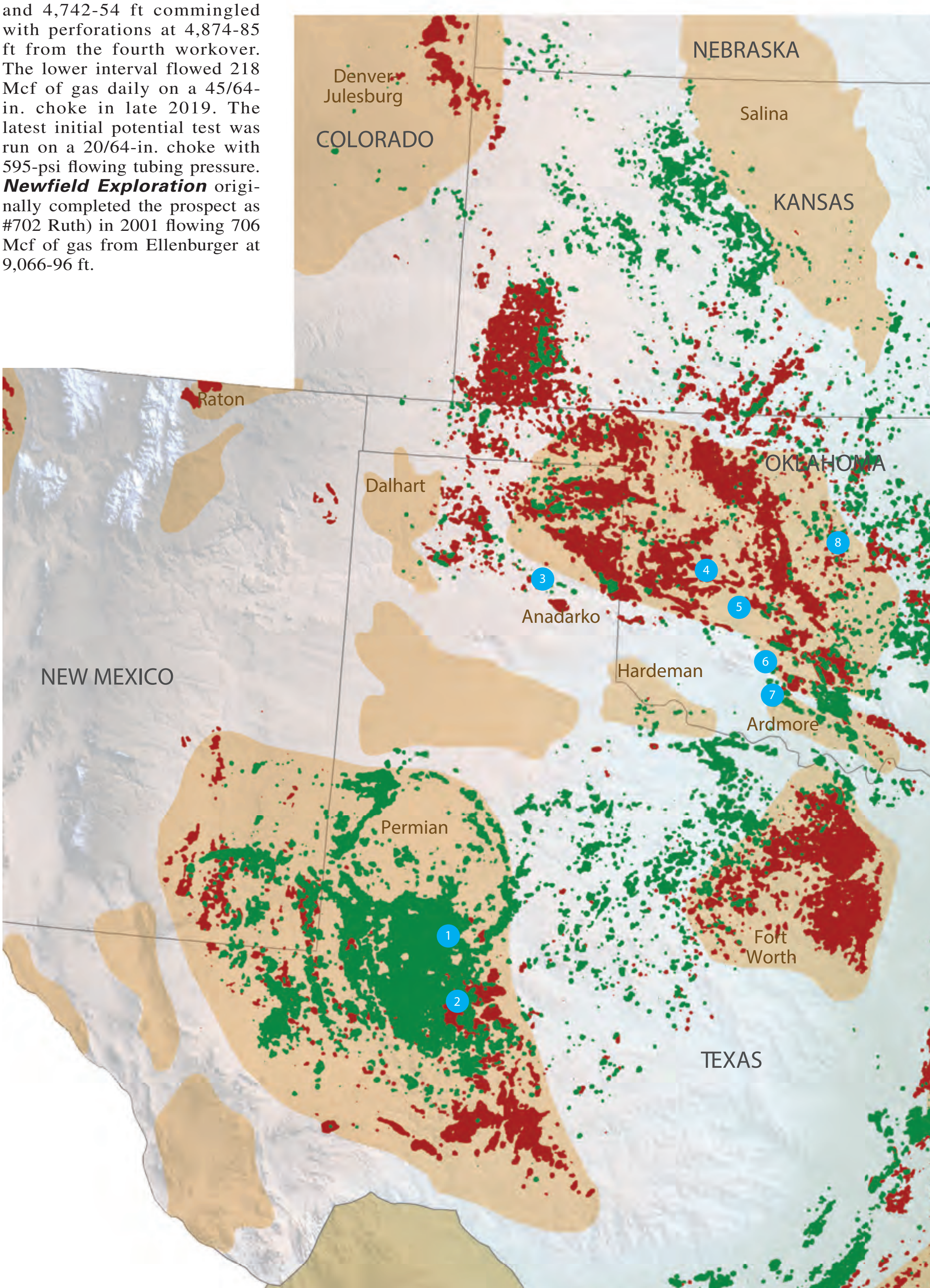
MIDCONTINENT & PERMIAN BASIN

1 In T&P RR CO Survey, A-1338 in Howard County (RRC Dist. 8), Texas, ***Crownquest Operating*** competed a Wolfcamp producer. The #2HB WR Vitex was drilled to 19,157 ft (8,488 ft true vertical) and is in Spraberry Field. It was tested flowing 1.475 Mbbl of 39-degree-gravity oil, with 1.43 MMcf of gas and 2.076 Mbbl of water per day. Production is from a perforated zone at 8,789-18,999 ft.

2 Three extended-lateral horizontal Wolfcamp wells have been completed at a pad in Reagan County (RRC Dist. 7C), Texas, by Houston-based ***Hibernia Resources III LLC***. The Spraberry Trend wells are on a 273.39-acre Midland Basin lease in Section 22, Block K D&DS RR Co Survey, A-4. The #1H Sheriff Justice A was drilled to 22,164 ft,(8,587 ft true vertical) and bottomed about 2.5 miles to the south-southeast in Section 1, SAD CO Survey, A-410. It was tested on gas lift for an initial daily potential of 1.588 Mbbl of 41.3-degree-gravity oil, 1.79 MMcf of gas and 4.699 Mbbl of water from acid- and fracture-treated perforations at 8,300-22,439 ft. The offsetting #2H Sheriff Justice B was perforated at 8,250-18,784 ft and flowed 1.639 Mbbl of oil, 2.01 MMcf of gas and 4.573 Mbbl of water per day. It was drilled to 18,853 ft (8,560 ft true vertical). The fracture-treated lateral bottomed 2 miles to the south-southeast. The #3H Sheriff Justice C was completed in a sidetracked hole producing 1.044 Mbbl of oil, 1.176 MMcf of gas and 2.987 Mbbl of water per day from treated perforations at 8,325-19,073 ft. The parallel 2-mile leg bottomed at 19,228 ft (8,656 ft true vertical).

3 Tulsa-based ***Seek Energy LLC*** completed a Hoover Northeast Field workover in Section 2, Block 3, I&GN Survey, A-315 in Gray County (RRC Dist. 10), Texas, the well, #702 Ruth 23, was tested flowing 853 Mcf of gas and 276 bbl of 50-degree-gravity condensate per day, with no water. According to IHS Markit, the reentry is the fifth for the well. It is producing from untreated, newly perforated intervals of Virgil Lime at 4,718-32 ft and 4,742-54 ft commingled with perforations at 4,874-85 ft from the fourth workover. The lower interval flowed 218 Mcf of gas daily on a 45/64-in. choke in late 2019. The latest initial potential test was run on a 20/64-in. choke with 595-psi flowing tubing pressure. ***Newfield Exploration*** originally completed the prospect as #702 Ruth) in 2001 flowing 706 Mcf of gas from Ellenburger at 9,066-96 ft.

4 ***Devon Energy Corp.*** has reported the completion of three Stack play horizontal Meramec wells from a common pad in Section 32-16n-10w in Blaine County, Okla. According to IHS Markit, #5HXX Fleenor 5_8_17_15N-10W, was tested on a 16/64-in. choke flowing 1.171 Mbbl of 45-degree-gravity oil, 2.95 MMcf of gas and 1.286 Mbbl of water per day from a treated interval at 10,740-24,613 ft. The Watonga-Chickasha Trend prospect was drilled south across Sections 5 and 8 and bottomed in Section 17-15n-10w. The respective measured and true vertical depths are 25,045 ft and 10,809 ft. About 30 ft west on the pad, #4HXX Fleenor 5_8_17_15N-10W flowed 1.153 Mbbl of oil, 2.26 MMcf of gas and 1.17 Mbbl of water per day. It was drilled to 24,515 ft (10,780 ft true vertical) and was tested on a 16/64-in. choke producing from perforations in a parallel, treated lateral between 10,800 ft and 24,255 ft. The #3HXX Fleenor 5_8_17_15N-10W was perforated and fracture-stimulated at 10,732-24,240 ft, and it had a daily flow rate of 971 bbl of oil, 2.36 MMcf of gas and 1.655 Mbbl of water. It was tested on a 16/64-in. choke and



was drilled to 24,483 ft, 10,794 ft true vertical. Devon is based in Oklahoma City.

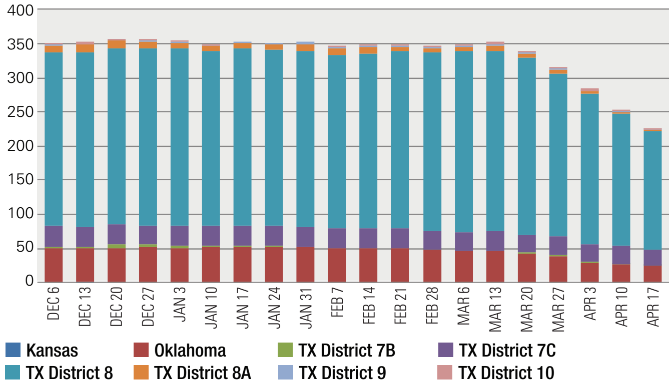
5 ***Camino Natural Resources LLC***, based in Denver, has completed an extended-lateral Anadarko Basin oil well in Oklahoma's Canadian County. The #1WXH Mount Scott 1207 4-9 flowed 182 bbl of 35-degree-gravity oil, 1.345 MMcf of gas and 2.911 Mbbl of water per day. Production is from acid- and fracture-treated Woodford perforations at 9,950-19,725 ft. It was tested on a 40/64-in. choke, and the flowing tubing pressure was 783 psi.

The horizontal El Reno Field well was drilled to 19,776 ft in Section 3-12n-7w and bottomed 2 miles to the south in Section 9-12n-7w with a true vertical depth of 9,734 ft.

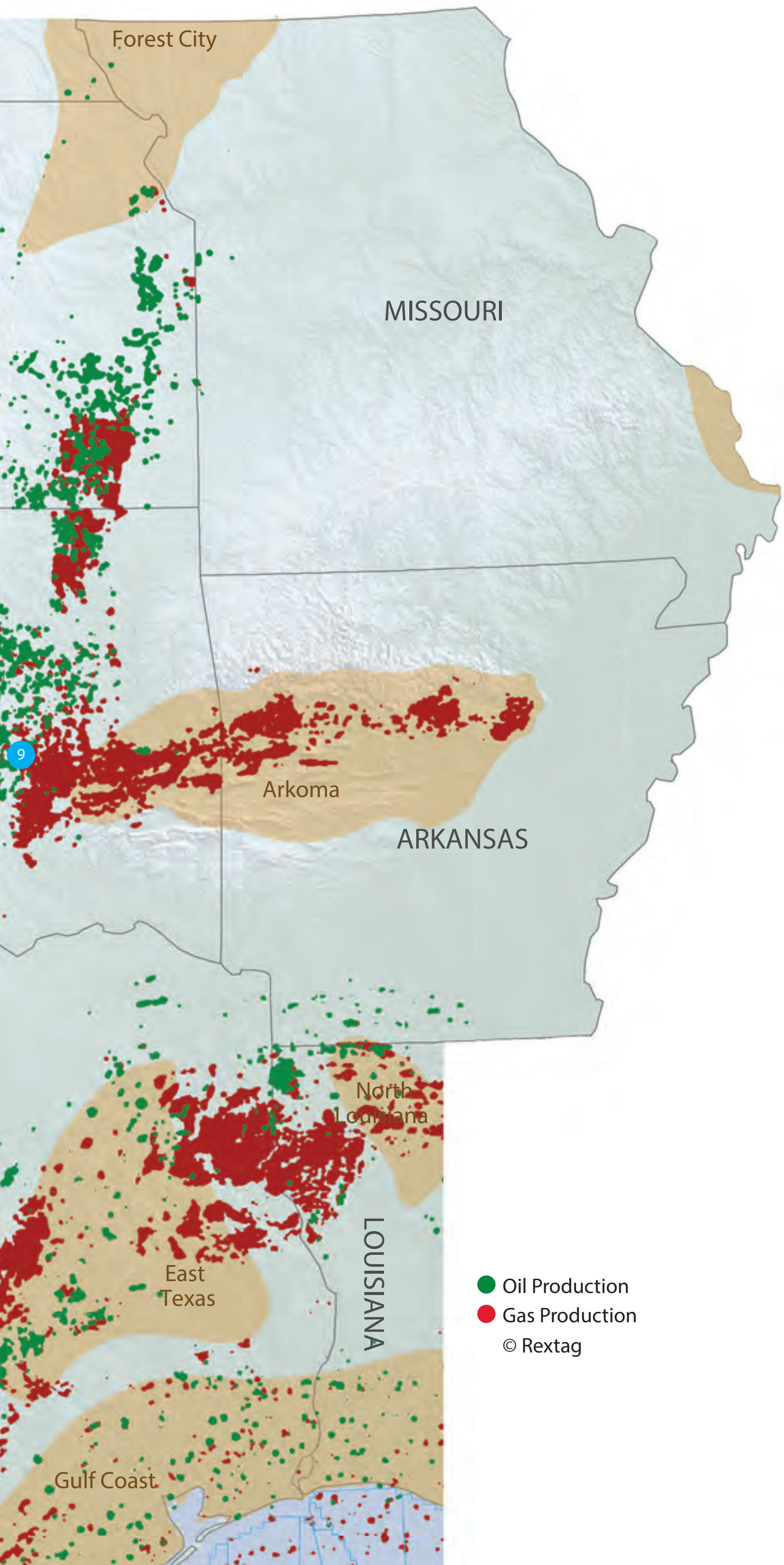
6 In Garvin County, Okla., ***Marathon Oil Co.*** completed a Springer Shale well in Section 5-3n-4w. The #1-5-32SXH Yoshi 0304 is in Golden Trend Field. It initially flowed 1.547 Mbbl of 40-degree-gravity oil, with 1.38 MMcf of gas and 1.164 Mbbl of water per day. The venture was drilled to 20,358 ft, 11,303 ft true vertical and tested on a 96/64-in. choke.

Midcontinent & Permian Basin Rig Count

Dec. 6, 2019-Apr. 17, 2020



Source: Baker Hughes Co.



Production is from perforations at 12,827-20,208 ft. Marathon's headquarters are in Houston.

7 An extended-reach Ardmore Basin horizontal well by ***Continental Resources Inc.*** in Stevens County, Okla., is producing from Mississippian/Sycamore. The #1-23-14 XHM Leon is in Section 26-1n-4w. It was tested in an acidized and fractured interval between 9,433 and 17,438 ft flowing 630 bbl of 37-degree-gravity oil, 981 Mcf of gas and 3.01 Mbbl of water per day. Gauged on a 40/64-in. choke, the shut-in tubing pressure was 1,010 psi, and the flowing tubing pressure was 744 psi. It is on the northern edge of the former Sholom Alechem Field, now incorporated into Sho-Vel-Tum Field. The well was drilled 2 miles north across Section 23 to a depth of 17,650 ft (9,369 ft true vertical) with a bottomhole location in Section 14-1n-4w.

8 A horizontal Mississippian producer in Lincoln County, Okla., was tested flowing 175 bbl of 40-degree-gravity crude with 270 Mcf of gas and 1.12 Mbbl of water per day on-pump. The ***Roberson Oil Co.*** discovery, #1-12MH Potter, is in Section 1-16n-3e. It was drilled about 1 mile south across Section 12-16n-3e to 8,648 ft (4,439 ft true vertical), and was perforated, acidized and fractured at 4,830-8,500 ft. Roberson's headquarters are in Ada, Okla.

9 ***Calyx Energy***, according to IHS Markit, completed three, two-mile horizontal Woodford producers from a pad in Section 1-8n-11e in Hughes County, Okla. The Arkoma Basin wells were all drilled to the north across Section 36-9n-11e to bottomhole locations in Section 25-9n-11e and were tested on open chokes following acid- and fracture-stimulation. The #5-36-25WH Eisenhower initially produced 9.93 MMcf of gas, 7 bbl of 46-degree-gravity oil and 3.625 Mbbl of water per day from perforations at 5,401-15,628 ft with 394-psi flowing tubing pressure. The respective measured and true vertical depths are 15,716 ft and 4,457 ft. About 15 ft west on the pad, #4-36-25WH Eisenhower produced 9.45 MMcf of gas per day, with 3 bbl of oil and 3.217 Mbbl of water. It was drilled to 15,417 ft (4,458 ft true vertical) and tested on an unreported choke size with 611 psi flowing tubing pressure. Production is from perforations at 5,096-15,326 ft. The #3-36-25WH Eisenhower initially flowed 9.14 MMcf of gas, 13 bbl of oil and 3.04 Mbbl of water per day from a perforated zone at 5,192-15,387 ft. It was drilled to 15,512 ft, 4,495 ft true vertical. Tested on an unreported choke size, the flowing tubing pressure was 451 psi. Calyx is based in Tulsa.

WESTERN US

1 Las Vegas-based ***Western Oil Exploration Co.*** is seeking approval to drill its third remote test in Nevada's Newark Valley. No objectives or proposed depth were released. The #3-1 Scott-Federal will be in Section 3-16n-56e of White Pine County. The company has filed permit applications for two 10,000-ft wildcats, #35-1 Scott-Federal and #25-1 Scott-Federal with targets including the Mississippian Chainman Shale and Paleozoic Dolomites in a northeast trend away from the newly proposed site. The project area is approximately 45 miles north of Trap Spring Field in neighboring Nye County's Railroad Valley.

2 IHS Markit announced that ***Jonah Energy LLC*** has completed two horizontal Lance producers from a common drillpad on the Pinedale Anticline in Sublette County, Wyo. The pad is in Section 2-29n-108w. The #313-02-500H SHB Curiosity initially flowed 1.131 MMcf of gas with a flowing casing pressure of 2,870 psi. The well was drilled to the west-southwest across two sections to a proposed depth of 22,267 ft (11,593 ft true vertical), and it bottomed in Section 3-29n-108w. The #312-02-500H SHB Curiosity was drilled to the west across the section to a proposed total depth of 22,049 ft (11,800 ft true vertical), bottoming in Section 3-29n-108w. It flowed 1.624 MMcf of gas per day with a flowing tubing pressure of 3,121 psi. Completion details are not yet available on the new Curiosity wells. Jonah is based in Denver.

3 According to IHS Markit, Denver-based ***Crowheart Energy LLC*** has completed its first two horizontal Lewis discoveries from a common drillpad in Wyoming's Red Desert Basin. The pad is in Section 10-22n-94w of Sweetwater County. The #10-22-94 2LH Siberia Ridge was drilled to the south to a projected depth of 15,947 and a projected true vertical depth of 10,938 ft. It produced approximately 101 bbl of oil, 10.57 MMcf of gas and 17 bbl of water per day. Completion plans included a 42-stage fracturing (plug and perf) between 11,304 and 15,852 ft. The #4LH well produced 171.4 bbl of oil, 1.5 MMcf of gas and 17 bbl of water per day. It was drilled southeastward, and the completion plans included a 42-stage fracturing (plug and perf) between 11,687 and 16,105 ft.

4 Houston-based ***EOG Resources Inc.*** completed a horizontal Niobrara discovery in Campbell County, Wyo., that initially flowed 1.199 Mbbl of oil/condensate, 1.958 MMcf of gas and 3.08 Mbbl of water per day. The discovery, #2833-02H Telluride, is in Section 28-42n-73w. Production is from a lateral drilled to the south-southwest to 20,485 ft (9,778 ft true vertical), and it bottomed in Section 33-42n-73w. It was tested on a 22/64-in. choke following 36-stage fracture stimulation between 10,706 and 20,391 ft.

5 ***Anschutz Oil Co.*** has completed a Niobrara discovery in the Powder River Basin. The well is in Section 33-42n-71w in Campbell County, Wyo. The #4271-33-28-12W NH Zeus-Fee initially flowed 878 bbl of 47.7-degree-gravity oil, 4.251 MMcf of gas and 780 bbl of water per day. Production is from a lateral that was drilled to the north to 11,267 ft with a true vertical depth of 9,572 ft at a bottomhole location in Section 28-42n-71w. It was tested through a 30/64-in. choke after 26-stage fracturing between 9,887 and 16,192 ft. Anschutz is based in Denver.

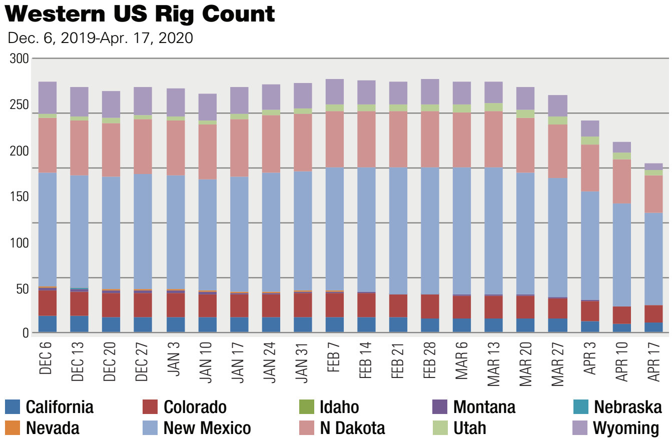
6 Two Niobrara producers by Oklahoma City-based ***Chesapeake Operating Inc.*** were completed from a common drillpad in Section 7-34n-70w of Converse County, Wyo. The #1H Clausen 7-34-70 USA A NB initially flowed 553 bbl of oil per day, with 276 Mcf of gas and 3.332 Mbbl of water per day. Production is from a lateral drilled to the northwest to 18,815 ft (11,398 ft true vertical) with a bottomhole location in Section 1-34n-70w. It was tested on a 26/64-in. choke after 26-stage fracturing between 11,618 and 18,764 ft. The #2H Clausen 7-34-70 USA A produced 478 bbl of oil, 322 Mcf of gas and 1.753 Mbbl of water per day. Production is from a lateral drilled to the southwest to 21,649 ft (11,177 ft true vertical), and the well bottomed in Section 19-34n-70w. It was tested on a 22/64-in. choke after 35-stage fracturing at 11,843-21,570 ft.

7 ***Anadarko Petroleum Corp.*** completed a horizontal Turner venture in Converse County, Wyo., that initially flowed 2.14 Mbbl of oil, 2.608 MMcf of gas and 161 bbl of water per day. The #3570-8-T4XH Dora-Federal was drilled in Section 5-35n-70w, and production is from a lateral drilled to the south to 22,606 ft at a bottomhole location in Section 8. The true vertical depth is 11,252 ft. It was tested after 35-stage fracturing between 11,985 and 22,491 ft. The discovery is in an area of shallower Cretaceous Teapot Sand oil production in

Mikes Draw Field. Anadarko is based in The Woodlands, Texas.

8 Another Turner Sand discovery was drilled from the Galaxy drillpad in Converse County, Wyo., by ***Anadarko Petroleum Corp***. The #3569-31-T4XH EH Fed Galaxy E was drilled to 21,575 ft with a true vertical depth of 10,862 ft. It was tested after 51-stage fracturing flowing 3.368 Mbbl of oil, with 2.915 MMcf of gas and 481 bbl of water per day. Production is from perforations between 11,378 and 21,471 ft.

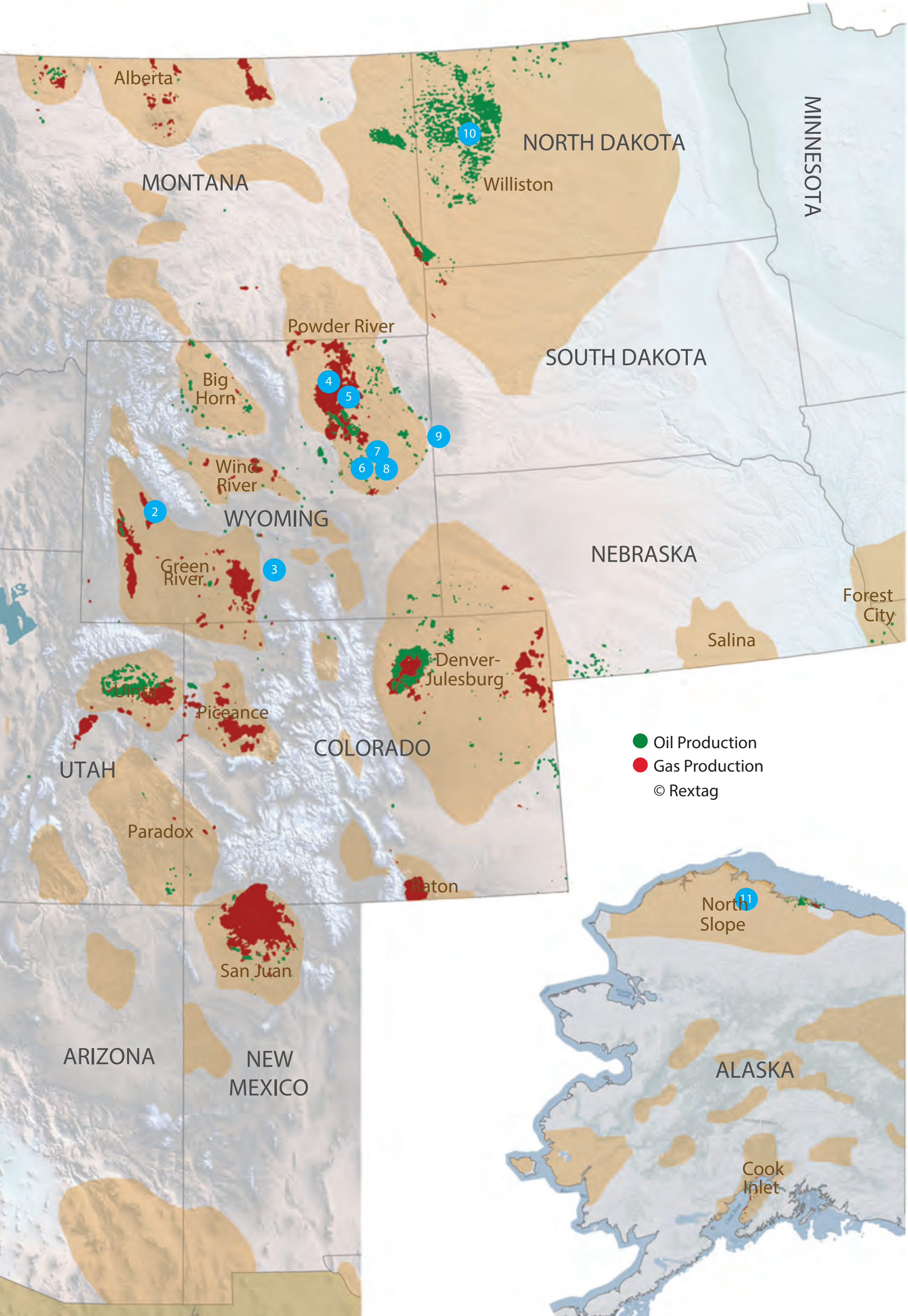
9 A wildcat completion on the Black Hills Uplift was reported by ***Gulf Exploration*** in southwestern South Dakota as a discovery in Pennsylvanian Leo (Minnelusa). The Oklahoma City-based company's #1-10 Fortitude was drilled in Section 10-10s-1e in Fall River County. It initially flowed 74 bbl of 32-degree-gravity oil and 14 bbl of water per day. It was tested on a 12/64-in. choke in Second Leo perforations at 3,440-44 ft and was drilled to 3,680 ft, cased with production pipe to 3,665 ft and plugged back to 3,540 ft. It was tested on a 12/64-in. choke, and the flowing tubing pressure was 300 psi. The drillsite is 3 miles northeast of North Hollingsworth Field, an inactive, four-well Leo pool that produced 584 Mbbl of oil, 292 MMcf of gas and 6.85 MMbbl of water between July 1984 and June 1997.



Source: Baker Hughes Co.

10 ***Newfield Exploration Co.*** completed a Bakken producer and a Three Forks producer from a Siverston Field pad in Section 18-150n-98w of McKenzie County, N.D. The Three Forks completion, #150-98-18-19-10H Hoffmann, was drilled to 21,120 ft, 11,164 ft true vertical, and produced 2.022 Mbbl of oil, 4.006 MMcf of gas and 7.739 Mbbl of water per day. Production is from perforations at 11,515-21,071 ft. The Middle Bakken completion, #150-98-18-19-5H Hoffmann, was drilled to 21,378 ft with a true vertical depth of 11,100 ft. It was tested flowing 2.397 Mbbl of oil, 5,292 MMcf of gas and 3,119 Mbbl of water per day from perforations between 11,754 and 21,242 ft.

11 An ***Oil Search LLC*** completion of the North Slope was tested flowing at a stabilized rate of 3.52 Mbbl of oil. IHS Markit reported that #1 Stirrup was tested in a single stimulated zone. It was drilled to an estimated depth of 4,960 ft and encountered an oil column with net pay of 75 ft in Nanushuk. The wildcat discovery is in Section 8-8n-3e, Umiat Meridian. The well is southwest of the Pikka Unit development area. The well's results could help determine the viability of a standalone processing facility within the Horseshoe Block. Oil Search is based in Sydney.



INTERNATIONAL HIGHLIGHTS

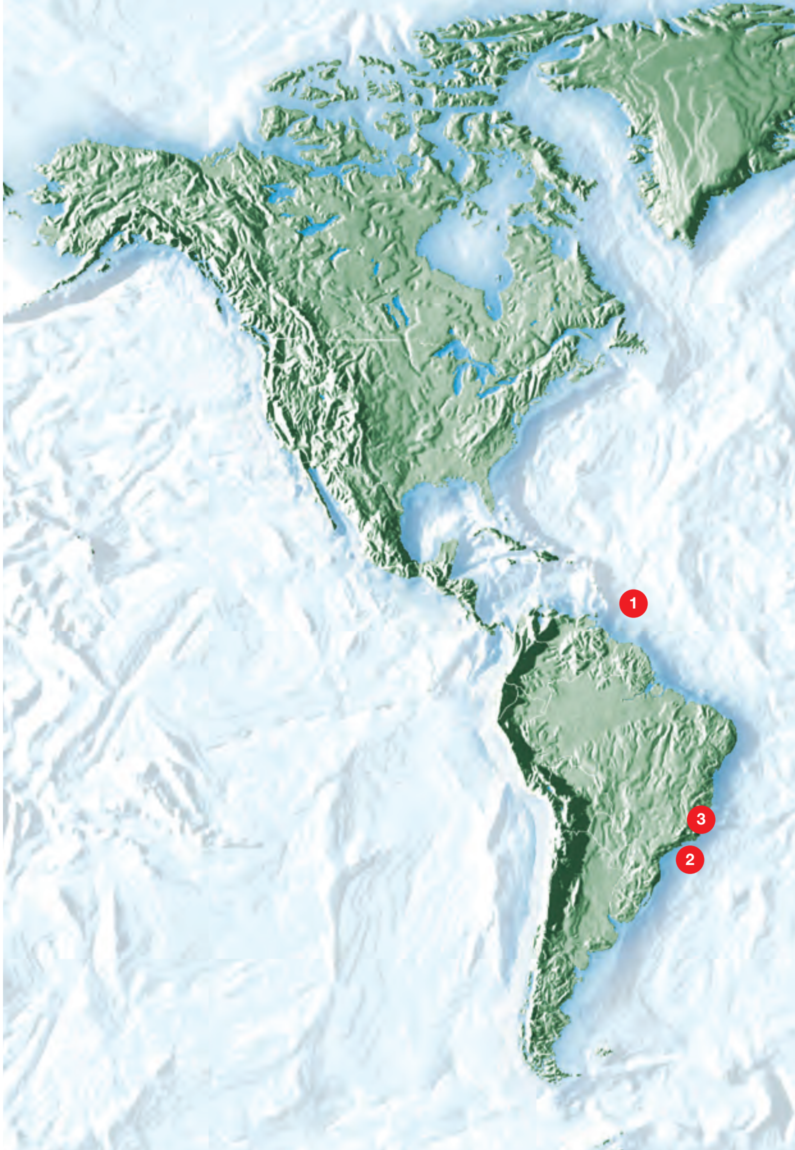
In its latest oil market report, the International Energy Agency (IEA) concluded that global oil demand is poised to fall to levels not seen in 25 years.

The organization's "Oil Market Report," published in April, forecasts that global oil demand is expected to fall by a record 9.3 MMbbl/d in 2020 as the impact of containment measures worldwide has halted fuel demand. Oil demand in April is estimated to be 29 MMbbl/d, a level last seen in 1995.

The recovery during the second half of 2020 will be gradual. In December, the agency estimates that demand will still be down 2.7 MMbbl/d compared to December 2019.

On the oil production side, IEA forecasts global supply falling by a record 12 MMbbl/d after oil-producing countries made a deal to cut production by about 10 MMbbl/d. Additional reductions are set to come from other countries with the U.S. and Canada seeing the largest declines as drilling slows and production falls due to low commodity prices. IEA's predicted output in the U.S. and Canada will fall by around 3.5 MMbbl/d in the coming months due to the impact of lower prices.

—Larry Prado



1 *Suriname*

A significant offshore Suriname oil discovery was reported by Houston-based ***Apache Corp.*** at #1-Sapakara West. The well is in Block 58 and was drilled to 6,300 m. Preliminary fluid samples and test results indicate at least 79 m of net oil and gas condensate pay in two intervals. The shallower Campanian interval contains 13 m of net gas condensate and 30 m of net oil pay (35-40 degree-gravity). The deeper Santonian interval contains a 36-m, net oil-bearing reservoir (40-45 degree-gravity). Block 58 comprises 1.4 million acres and offers potential beyond the discoveries at Sapakara West and Maka Central. Apache has identified at least seven distinct play types and more than 50 prospects within the thermally mature play fairway. Two other wells are currently planned at #1-Kwaskwasi and #1-Keskesi. Both will test oil-prone upper Cretaceous targets in Campanian and Santonian intervals in reservoirs that appear to be independent from #1-Maka and #1-Sapakara discoveries. Apache is the operator and holds a 50% working interest and ***Total***.

2 *Brazil*

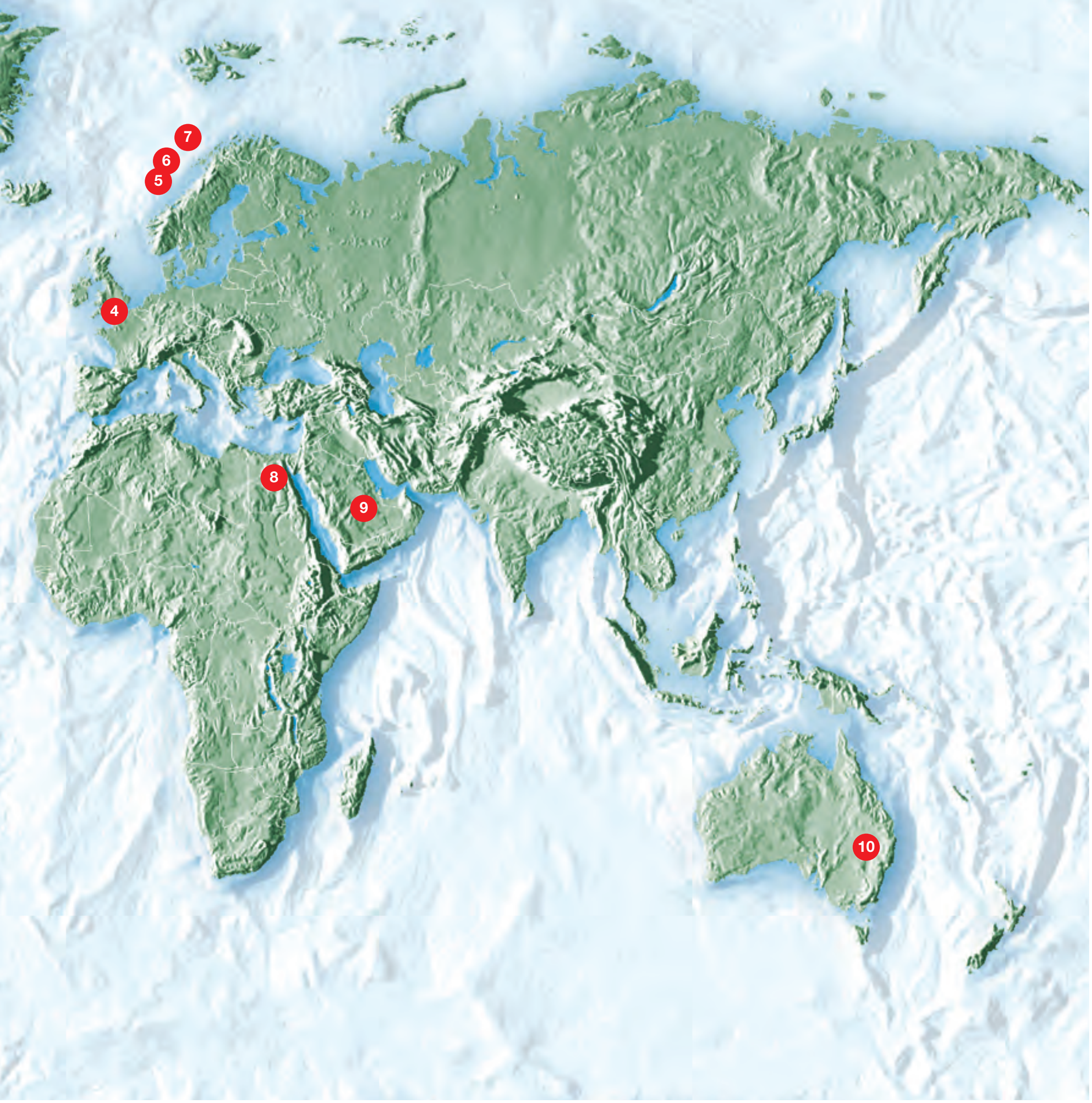
Petrobras found oil in the pioneer well of the Uirapuru Block, located in offshore Brazil's Santos Basin presalt. The well, #1-Uirapuru, is in 1,995 m of water. According to the operator, oil was found in porous reservoirs in the exploratory prospect known informally as Araucária. The well data will be analyzed to better target the exploratory activities in the area and assess the potential of the discovery. Petrobras is the operator of the block and holds a 30% stake, in partnership with ***Exxon Mobil*** (28%), ***Equinor*** (28%) and ***Petrogal*** (14%).

3 *Brazil*

Petro-Victory Energy has announced an oil discovery at exploration well 1#-VID-1-ES (Vida) in Block ES-T-487, Espírito Santo Basin, Brazil. This is the company's first exploration well in Brazil. It was drilled to 1,890 m in the onshore portion of the basin. Evaluation of logging, pressure and fluid data confirms that Vida comprises of high-quality, oil-bearing Cretaceous sandstone reservoirs. The well encountered 49 m of net oil pay. Oil was recovered to surface during fluid sampling from a sandstone reservoir at 1,600 m, and preliminary testing of oil samples indicate similar qualities (24-degree-gravity) to a nearby oil field. Most of the reported oil pay was found 1,560-1,660 m. The well will be suspended, and additional tests, including recoverable oil resource estimates, are planned. Petro-Victory Energy's headquarters are in Fort Worth.

4 *U.K.*

UK Oil & Gas has filed a planning application with the U.K. Isle of Wight Council for exploration drilling and flow testing of the Arreton oil discovery. A deviated borehole test is planned for wells #3-Arreton and #3-A Arreton and a possible horizontal sidetrack off the main borehole at #3z-Arreton or #3-A3 Arreton. The Arreton conventional oil discovery is similar to the company's Horse Hill oil field. It contains three stacked Jurassic oil pools with a calculated, aggregate gross P50 oil in place of 127 MMbbl of oil. The planned wells will duplicate #1-A Arrenton and #2-A Arrenton discovery wells. If short-term flow testing of #3-A Arrenton indicates commercial viability, flow testing could also conducted in the planned horizontal sidetrack wells, including extended well test to assess longer-term flow performance. London-based UK Oil & Gas holds a 95% operated interest in PEDL331, which covers most of the southern half of the Isle of Wight and includes the Arreton discovery.



6 *Norway*

In offshore Norway production license 836 S, ***Wintershall*** completed wildcat well #6406/3-10. The primary target for the well was to prove petroleum in reservoir rocks from Early and Middle Jurassic (Ile and Tilje). The secondary exploration target was to prove petroleum in reservoir rocks from Middle Jurassic Age (Garn). In the primary exploration target, the venture encountered a 35-m, hydrocarbon-bearing sandstone layers in Ile with poor reservoir quality. The well also found a 120 m oil column in Tilje, with sandstone layers totaling about 75 m with poor-to-good reservoir quality. In the secondary exploration target, a 60-m oil zone was encountered in Garn, with poor-to-moderate sandstone reservoir quality. Preliminary estimates place the size of the discovery at between 4 and 15 MMcm of recoverable oil equivalent. The well was drilled to 4,566 m. This is the first exploration well in the license area. Wintershall is based in Kassel, Germany.

7 *Norway*

Aker BP completed wildcat well #6506/5-1 S in PL 1008, the first well in the license. The objective of the Skarv Field well was to prove petroleum in Upper Cretaceous reservoir rocks (Lysing). The wildcat encountered a gas column of about 15 m in Lysing, of which 10 m of sandstones had very good reservoir quality. Deeper in the Lysing Formation, about 25 m of net water-bearing reservoir rocks were encountered with moderate reservoir quality. It was drilled to 3,225 m and terminated in Lange in the Lower Cretaceous. Area water depth is 409 m. Preliminary estimates indicate that the discovery is between 1-2.4 Bcm of recoverable gas. Oslo-based operator Aker and partners will evaluate the discovery with nearby. The well was not formation-tested, but extensive data acquisition and sampling have been carried out. The well has been temporarily plugged and abandoned.

8 *Germany*

Neptune Energy announced an oil discovery in Germany's Rhine Valley at exploration well #1-Schwegenheim. According to the company, two oil-bearing layers of Bunter Sandstone reservoir were found to be oil-bearing. The venture was drilled to 2,600 m. It has been cased and suspended for further testing. The Bunter Sandstone reservoir is an equivalent to the nearby Romerberg structure. During production testing, the well produced 1.5 Mbbl of oil during an unspecified period. Neptune Energy's headquarters are in London.

8 *Egypt*

SDX Energy announced an oil discovery at #12X-SD-12X in the South Disouq Exploration Permit in Egypt's Nile Delta region. It was drilled to 7,245 ft and hit 108 net ft of high-quality gas-bearing sands, with an average porosity of 20% in Kafr El Sheikh (KES). The top of the KES Sand was encountered at 6,506 ft. Current estimates by the company indicate about 24 Bcfe of recoverable gas and condensate resources. Additional testing is planned. London-based SDX is the operator.

9 *Saudi Arabia*

Lukoil plans to drill two deep unconventional gas exploration wells in Saudi Arabia's Rub al-Khali region. Two wells are currently planned, and both will be drilled to about 5,800 m in Mushaib Field, a tight gas play. ***Shell*** and ***Sinopec*** have been exploring the region for conventional gas and oil deposits from about 15 years. ***Aramco*** wants gas to help it cover subsidized domestic power demand so it can save oil for more lucrative exports. Aramco is willing to spend up to $3 billion on shale gas development in the Kingdom, but the company has given no details on the investment. Adequate supply of water for fracturing will be a major issue. Aramco is developing new hydraulic fracturing technologies to increase recovery rates and improve cost efficiency, including a CO_2-based fracturing fluid. Aramco has a plan to produce 200 MMcf/d of unconventional gas to supply a new phosphate project and power plant in the Eastern Province. Moscow-based Lukoil is the operator of the 29,928 sq km Block A in Saudi Arabia's Rub al-Khali.

10 *Australia*

Santos Ltd. has submitted a development plan for the Narrabri Gas Project in New South Wales, Australia. The project will develop a coal seam gas field with as many as 850 gas wells on up to 425 well pads over 20 years. Gas processing and water treatment facilities are also planned. According to the company, the project can potentially supply enough gas to meet 50% of the demand for New South Wales, and it has committed 100% of Narrabri gas production to that market, which will be supplied through the existing Moomba-to-Sydney pipeline. Santos is based in Adelaide.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Camelback Midstream Holdings LLC	N/A	Scottsdale, Ariz.	$400 million	Secured a capital commitment from an **ArcLight Capital Partners LLC** managed fund and management team. Proceeds will be used for acquisition and organic development of midstream infrastructure, including gathering, transportation, storage and marketing. **Vinson & Elkins LLP** provided legal advice.
Percussion Petroleum II LLC	N/A	Houston	N/A	Closed equity commitment from **Carnelian Energy Capital LP**. Proceeds will be used to pursue an acquisition and development strategy in select onshore basins in North America.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Exxon Mobil Corp.	NYSE: XOM	Irving, Texas	$9.5 billion	Entered agreement for the issuance and sale of $2.75 billion notes due 2020; $1.25 billion notes due 2025; $2 billion notes due 2030; $750 million notes due 2040 and $2.75 billion notes due 2051. Proceeds will be used for general corporate purposes. **Deutsche Bank Trust Co. Americas** was trustee. **BofA Securities Inc.**, **Citigroup Global Markets Inc.** and **J.P. Morgan Securities LLC** were joint book-running managers.
EOG Resources Inc.	NYSE: EOG	Houston	$1.5 billion	Closed sale of $750 million of 2030 notes and $750 million of 2050 notes. **Wells Fargo Bank NA** was trustee.
NuStar Energy LP	NYSE: NS	San Antonio	$750 million	Entered unsecured term loan agreement with funds managed by **Oaktree Capital Management LP**. The three-year, 12% facility provides that NuStar will draw $500 million at closing and may elect to draw an additional $250 million under the facility during the first year. Proceeds will be used to pay down its revolving credit agreement and address near-term debt maturities. **Intrepid Partners LLC** was exclusive financial adviser. **Sidley Austin LLP** provided legal advice. **Kirkland and Ellis** was exclusive legal adviser to Oaktree.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
EQT Corp.	NYSE: EQT	Pittsburgh	$500 million	Priced private upsized offering of convertible senior notes due 2026. Includes option for initial purchasers to buy up to an additional $60 million of notes. Notes will be senior unsecured and bear interest at a rate of 1.75% per annum. Portion of proceeds will fund capped call transactions with remaining proceeds used to repay or redeem certain outstanding debt, including those with near-term maturities, and for general corporate purposes.
Centennial Resource Development Inc.	NASDAQ: CDEV	Denver	$450 million	Launched offer to exchange outstanding 2026 and 2027 notes for up to $250 million of newly issued second lien senior secured notes due 2025 and up to $200 million of newly issued third lien senior secured notes due 2027.
CNX Resources Corp.	NYSE: CNX	Pittsburgh	$345 million	Closed private offering of convertible senior notes due 2026. Includes full exercise of $45 million option to purchase additional notes granted to initial purchasers. Portion of proceeds will fund privately negotiated capped call transactions with certain initial purchasers or their respective affiliates and/or other financial institutions with remainder used for general corporate purposes, including repayment or redemption of outstanding debt. Vinson & Elkins was legal adviser to the underwriters.
Tellurian Inc.	NASDAQ: TELL	Houston	$56 million	Sold zero coupon, unsecured notes in exchange for warrants to purchase up to 20 million shares of common stock. Roth Capital Partners acted as sole placement agent for the offering.

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LOOKING FOR THE V SHAPE

LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

No doubt you were getting dizzy following oil, so you thought you needed to sit down. But wait—you have been sitting down for about eight weeks now. From a number below zero to $25/bbl or so, Brent finally got above $30—crude's been on a wild ride. Disneyland may not be open, but the reality show unfolding in the oil patch provides more than enough thrills. However, note that in early May when Disneyland Shanghai reopened, the park sold out in a few minutes.

It's one sign that cities around the world will get back to business, although the economic recovery will be uneven and take time. We have to bet on pent-up demand. The recovery appears to be V-shaped in most markets. We hope to see that in the energy world as well.

"This is an event-driven correction that we're in right now. We expect there will be an economic recovery behind it … and with that, demand for the product we produce," said Marathon Oil Corp. CEO Lee Tillman on the company's first-quarter conference call.

No one can wait until 2023, however, for oil to reach $40 again, as the futures strip indicated at press time. Besides, that's still a terrible price for most plays and a nonstarter for most E&P companies' budgets.

To cope, Marathon suspended its dividend and share buybacks; voluntary curtailments are on the table.

"Our starting point is that our most economic barrels are flowing barrels … those are the ones you want to keep online," Tillman said. "If we see barrels start to become a negative drag on our cash flow, then we would take a different set of options."

IHS Markit said it expects global oil demand in the second quarter to be down 22% from a year ago—that's 22 MMbbl/d of surplus that can't be sold. The firm said, "It is pretty clear where production will be cut. Nearly everywhere."

It expected about 14 MMbbl/d to be cut or shut in during the June quarter.

A Reuters survey found that North American producers alone will have cut up to 1.7 MMbbl/d by the end of this month.

Help is on the way in the form of naturally declining production in most fields. Companies are delaying or canceling final investment decisions for new projects around the globe, so they will not replace those lost barrels when demand creeps back up. The tug of war between supply and demand will thus continue unabated. No one knows when or if global demand will reach 100 MMbbl/d again.

Consumer confidence to drive and fly is unknown, and governments may be encouraged now to go greener even sooner.

Help is not coming from Austin nor is it needed. The Texas Railroad Commission opted to let the free market work, and even those who wanted to see prorationing have reduced production voluntarily.

Cuts have started to accumulate. ConocoPhillips Co. said it will have cut its North American volumes by 460,000 bbl/d by June. EOG Resources Inc. will cut more than E&P peers by 85,000 bbl/d this quarter, 45,000 bbl/d in the third quarter and 20,000 bbl/d in the fourth quarter, primarily in the Williston and Anadarko basins, which are areas most challenged by low oil prices.

"In the current commodity environment, shut-ins are the logical conclusion from a rate of return perspective," said Raymond James' analyst John Freeman in a research note.

Noble Energy said it will cut 30,000 bbl/d to 40,000 bbl/d in June. Earthstone Energy Inc. cut 70% of its operated production in May alone, one of the biggest cuts among its small-cap peers.

Texas crude output might fall by as much as 20% this year, according to Karr Ingham, economist for the Texas Alliance of Energy Producers. Hess has chartered three very large crude carriers to store its Bakken output for May, June and July, effectively removing 6 MMbbl from the market at least temporarily.

Most experts think the U.S. economic recovery will begin in the third and fourth quarters. Lone Star oil production (and that of North Dakota) may well be inching back up by year-end. After all, the Energy Information Administration said there are about 7,500 drilled but uncompleted wells sitting out there, a new form of storage that could be ready if the price is right.

The number of U.S. oil rigs at work was 807 a year ago in May; this year it was 325. Is this decline going to be enough to turn things around?

"Until the impact of reduced drilling and natural decline reduces productive capacity, there will remain barrels readily available to meet any increase in demand," said Ralph E. Davis Associates president Steve Hendrickson, in the firm's weekly update. "We should expect the supply overhang to keep prices depressed until it's resolved."

J.P. Morgan analysts predict demand won't reach pre-COVID-19 levels until November 2021. We'll see if oil prices follow.