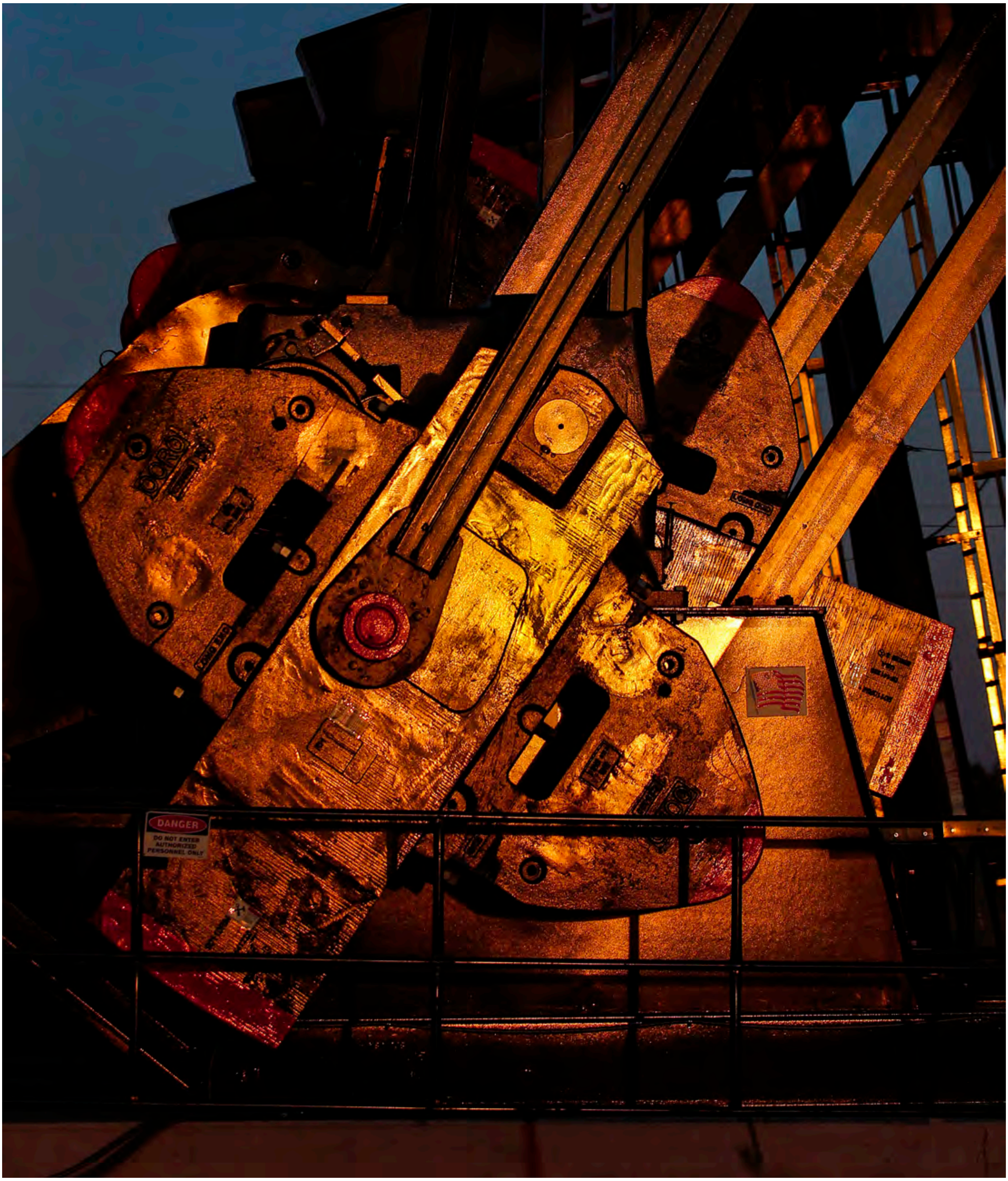
Oil and Gas Investor

JULY 2020



Private operators ponder best time to restart shut-in production and resume activity.

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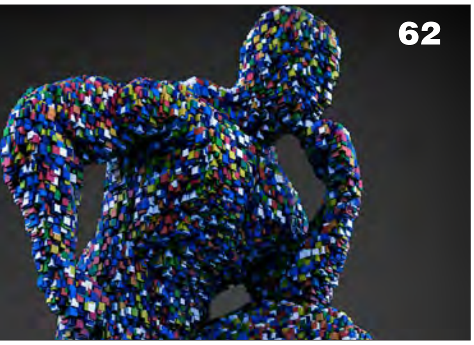

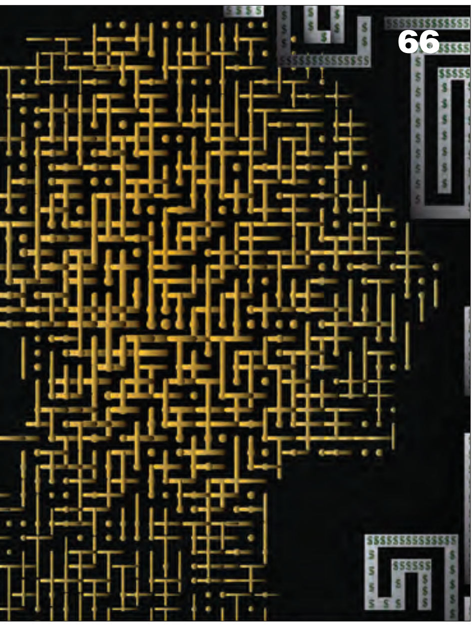

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ABOUT THE COVER: Most private operators shut in some—or all—production for a time in the second quarter, and are in the process of bringing that back online. Photo by Tom Fox

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LATEST CONTENT

W&T Offshore CEO: Expect More Acquisitions in Future
Uncertainty, however, lingers for the oil and gas industry surrounding oil demand recovery and prices.

BP Report: Global Energy Consumption Rises, But Growth Rate Slips
BP CEO expresses concerns about the impact of COVID-19 in a 'pivotal moment' for the world.

Permian Basin Flaring Puts Value of Natural Gas in Spotlight
A recent report sheds light on best practices of Permian operators that include Chevron Corp.

Experts: No Reservoir Damage for Production from Shut-in Shale Wells
Panelists agreed there are, however, exceptions. And costs could run from thousands to millions of dollars depending on services needed to restart production.

Moody's Revises Outlook for Midstream Sector to Negative for First Time
The rapid pace and magnitude of production declines by oil producers has finally spilled into the midstream sector, compromising its aggregate credit quality, according to a new report by Moody's Investors Service.

ConocoPhillips CEO Sees 'Bumpy' Months Ahead for Oil Sector
Eyes are focused on demand, refinery utilization, storage and the pace of bringing wells back online, according to ConocoPhillips CEO Ryan Lance.

ONLINE EXCLUSIVES

Oil and Gas Private Equity: Post-pandemic Road Map to Recovery

A panel of oil and gas capital experts discussed the steps private-equity professionals need to take to recover from the severe downturn.

Coalition Gives Texas Oil Regulators Blueprint to Reducing Flaring

A flaring matrix, seen as a key component of the proposed plan, gives oil and gas operators several options based on their situations.

ConocoPhillips Narrows Digital Strategy on Low-cost Supply Resources

The U.S. independent producer's laser focus on low cost of supply resources has had a significant impact on its technology road map, CTO Greg Leveille says.

Videos

ConocoPhillips Chief Economist Weighs in on Demand Recovery
"We aren't out of the woods yet, but things have moved in the right direction," Helen Currie, chief economist with ConocoPhillips, says of the COVID-19 demand shock to the oil market.

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Videos

Solaris Water Midstream CEO on Handling Shut-ins, Midstream Opportunities
"This was a massive shock to the system and to the country. I think this is one of the times where the oil industry may not have actually been hit worse," Solaris Water Midstream CEO Bill Zartler told Hart Energy.

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Videos

NexTier Oilfield Solutions CEO Talks Recovery, US Shale's Global Role
NexTier Oilfield Solutions CEO Robert Drummond joins Hart Energy editors for a conversation centered on his outlook for the oilfield services sector's recovery on the other side of this downturn.

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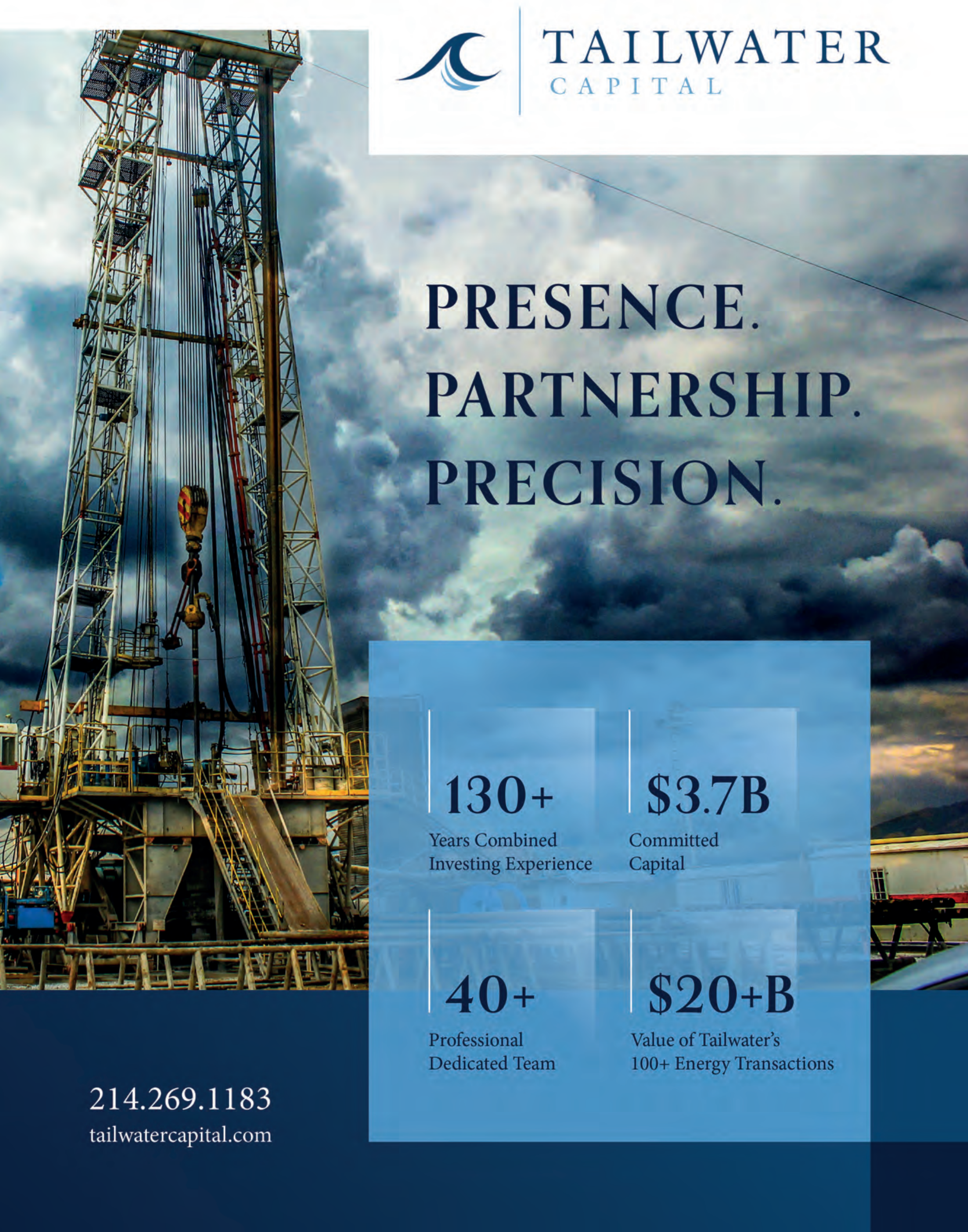
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THE GREAT AWAKENING

STEVE TOON,
EDITOR-IN-CHIEF

I bear good news: We've made it to the third quarter.

The second quarter was one for weeping and gnashing of teeth. In the second quarter, WTI fell into the teens as demand plummeted and supply surged. Producers battened down the hatches as the two collided in a perfect storm. Inventories were built. Nations, cartels and independents were shut in. Oilfield services were put on ice. The second quarter was a massive hurricane of epic proportions only to be survived.

Not all did, as we saw the likes of Whiting Petroleum, Extraction Oil & Gas, Ultra Petroleum and Unit Corp. fall to the winds of bankruptcy during that period. Some $10.5 billion in E&P debt year-to-date as of May 31 has succumbed to the courts, according to law firm Haynes & Boone. The oilfield services sector has fared worse: $14 billion in bad debt year-to-date. More is sure to come.

But the winds are noticeably subsiding, and the oil and gas sector is cautiously emerging from the ruins to check out the damage. WTI rebounded from the depths of temporary negatives to upper $30s by the end of the quarter and, although not the good ol' days of early January when oil was in the $60s, it's survivable. Debris litters the streets, but most companies are intact and reactivating.

Shut-in production is beginning to flow again. An estimated 2 MMboe/d was shut in during the second quarter, per Stifel analysis, but the taps have slowly began opening again. In early June, Parsley Energy reported it would bring most of its shut-in 26,000 boe/d—or 20% of its volumes—back online in June. EOG Resources topped out curtailing 125,000 bbl/d in May, but it eased off that in June and is tapering back over several months.

"Likewise, WPX, which shut in 20% of its oil volumes during May, also noted … that it has begun bringing wells back online with the recent oil price recovery," said Stifel analyst Michael Scialla in a June 4 report. "We look for a similar response from some other E&P companies with low cash costs. In particular, we believe PDCE [PDC Energy], which has the lowest cash cost in our midcap group, and XEC [Cimarex Energy Co.], which has the lowest cash cost in our bellwether group, are well positioned to restore curtailed volumes."

While the return of curtailed volumes could put pressure on pricing—and likely already has as WTI stalled in its upward momentum shy of $40—it is only Phase 1 of the oilfield recovery. The next phases involve completing drilled but uncompleted wells (DUCs) and adding back rigs. That will begin in the third quarter but will take longer. Maybe much longer.

In March, when the bottom fell out of oil, most companies sent completion crews packing right away but kept drill bits turning for a while longer, building DUC inventory. In the third quarter, rig adds will defer to DUCs.

SunTrust Robinson Humphrey analyst Neal Dingmann sees a bifurcation in how big and small companies will ramp up.

"While $37/bbl certainly beats low teens (and even for a brief moment, negative) prices, we continue to believe while our larger operators could likely boost activity in a high $30s/low $40s price environment, smaller operators will continue to be more cautious, particularly as the global demand picture remains uncertain and if the credit market for them remains challenging."

Of 29 covered E&Ps, he said in a June 3 note, approximately 45% were running zero horizontal rigs at the time of the note versus all running at least one to begin the year.

"As many of our companies spent early 2020, and in particular much of March, building up DUC inventories, we believe a rig count recovery of magnitude isn't likely to be seen until at least early next year, as we anticipate companies will first turn to DUCs to boost production," he said.

As of mid-June, the rig count had fallen to 298, per Enverus, an all-time low.

The good news is most analysts predict pricing to recover through year-end as pandemic-closed economies come back online, bringing sunnier days for all.

"Assuming demand recovers, then inventories should peak in 3Q20 and fall rapidly in 4Q20, which will allow a rapid recovery in oil price. We see the market moving back into balance in 3Q20 as demand recovers but supply continues to fall," said Bernstein analyst Neil Beveridge in a June 16 report.

And looking ahead to the fourth quarter, "We believe that the market is facing a serious undersupply, which should support a recovery in prices back to $50/bbl and above. The key risk is a second wave of COVID-19, which derails a demand recovery."

Except for that caveat, the future looks bright. Hopefully, this third quarter is not just the eye of the storm.

GONE VIRAL

DARREN BARBEE, SENIOR EDITOR

Don't look to the supermajors to be M&A's fire and rescue crew as the COVID-19 pandemic continues to burn down vast sectors of the economy.

Companies such as Chevron Corp., Royal Dutch Shell (RDS), Total SA, BP Plc and Exxon Mobil are unlikely to pursue corporate M&A and will be selective in asset-level deals, according to a June 18 report by Cowen Equity Research.

Cowen analyst Jason Gabelman notes that equities haven't benefitted from large M&A activity since the 2014 downturn.

"One could argue M&A is part of the reason RDS cut its dividend and BP faces peer-high gearing. Occidental stock has suffered since its Anadarko acquisition," the report said. "We believe it is unlikely supermajors will pursue wide-scale corporate M&A with independent E&Ps. The industry is in a corrective underinvestment mode, making acquiring and accelerating likely moot while coming at the expense of leverage."

Heightened uncertainty around oil demand recovery after COVID-19 remains a blight on the industry. Low oil prices continue to pressure oil and gas companies. A Moody's Investors Service June 10 report noted that in the previous downturn, shale production fell by about 600,000 bbl between second-quarter 2015 and third-quarter 2016. The recovery, such as it was, came after 28 months.

The pandemic now looks to cut volumes by more than 2 MMbbl/d, and Moody's said it will take longer this time.

For the largest and most efficient shale producers, sustained prices above $40/bbl allow companies to earn adequate returns on investment. Stronger companies are also likely to engage in M&A.

"Corporate mergers and large acreage acquisitions abounded during the 2017-19 price recovery, consolidating assets among the financially stronger and more efficient E&P companies," Moody's said. "The pattern will repeat during the next recovery, although with less robust support from capital markets."

Moody's also predicts widespread bankruptcies are likely, with access to capital "prohibitively expensive" for high-cost operators since 2018. "Investors are likely to remain highly selective in allocating future capital to this sector, given its repeated underperformance," Moody's said.

With size and scale, supermajors appear to be the most natural asset aggregators, but price volatility makes asset-level transactions more likely, Cowen's report said.

"We do not necessarily think M&A is imminent," Cowen researchers said. "Chevron could be [the] most likely to acquire in the downturn given a peer-leading balance sheet and investor concerns around longer-dated backlog."

Chevron has noted that a slowdown in its Permian Basin production extends its production horizon. The company also has said it prefers corporate-level M&A rather than assets because it is easier to find synergies.

Additionally, Cowen research found that, since the prior downturn, large-scale M&A has generally "produced suboptimal returns" that could make companies think twice about moving forward with deals. Deals cost majors an average $55,000 per flowing barrel of oil equivalent (boe).

E&Ps appear unlikely to sell at the bottom of the cycle unless they are under financial distress. Cowen said E&Ps in its coverage universe are capable of generating free cash flow with prices in the upper $30/bbl range in 2021.

Other companies are likely to be besieged. Restructuring specialists have reported being swamped by clients seeking help with their finances. Many experts expect a massive change in finances for the companies, including likely bankruptcies. On June 14, Denver-based Extraction Oil & Gas Inc. became one of the latest companies to file for Chapter 11 bankruptcy protection.

"Widespread bankruptcies will likely also facilitate more sustainable long-term volume growth among better-capitalized producers," Moody's said.

Moody's puts the timetable for recovery in the mid-2020s. The credit rating service said oil prices could recovery significantly by 2022, with financially stronger companies further consolidating shale assets.

"A shale recovery will still need higher prices and take several years," the report said.

And public equity continues to suffer. Bernstein Energy research, published June 8, suggested that at current prices, oil companies' reserves are currently valued on an enterprise value per boe basis at $10/boe, with more inexpensive companies trading at $5/boe.

Bernstein said reserve replacement costs last year were about $17/boe, "implying that it is again cheaper to drill in [the] stock market than in the ground."

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
Unconventional Resources Tech. Con.	July 20-22		Online	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. 11-27		Online	napeexpo.com/summer
EnerCom The Oil & Gas Conference	Aug. 17-19	Denver; Dallas; Houston; Calgary	Host city venues; Online	theoilandgasconference.com
The Energy Summit	Aug. 18-19		Online	coga.org
DUG Permian/DUG Eagle Ford	**Sept. 8-10**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugpermian.com**
DUG Midcontinent	**Aug. 18-19**		**Online**	**dugmidcontinent.com**
TIPRO Summer Conference	Sept. 23-24	San Antonio	Hyatt Hill Country Resort	tipro.org
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. 21	Houston	JW Marriot Houston	ipaa.org
Energy ESG Conference	February	Houston	Omni Galleria	energyesgconference.com
NAPE Summit	Feb. 8-12	Houston	George R. Brown Conv. Center	napeexpo.com/summit
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 Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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

NewsWell

'Bumpy' months ahead for oil sector, says ConocoPhillips CEO

Oil prices have rebounded more quickly than expected from a "double black swan" scenario that saw WTI futures sink into negative territory less than two months ago amid a global pandemic, but ConocoPhillips CEO Ryan Lance is concerned about what else could happen in the near term for the industry.

"There's a lot of mixed signals going on," Lance said. "I think it will be a bumpy few months ahead."

Speaking with financial analyst Jordan Horoschak of CIBC Capital Markets during a June 10 Independent Petroleum Association of America webinar, the head of one of the world's largest independent E&Ps said moves by U.S. oil and gas players to reduce production have helped balance the market along with that of OPEC+ participants, given demand was off by at least 25 MMbbl/d.

Looking at storage builds, evidence that some operators are already coming back online given Brent trading at about \$40/bbl and WTI at nearly \$38/bbl, Lance said questions now are: how quickly will curtailed production return to the market, and will there be sufficient demand?

"We're concerned a little bit about a double trough … as more production comes back on and if demand isn't proceeding or coming back fast enough to absorb all that supply," he said, before turning to the refining side of the business.

"Utilization rates and the running of big machines that chew up all of this oil are still down at around 71% to 72%, and that's concerning. Are they going to come back fast enough to absorb some of this crude? And they're not because the product inventory has been rising most on the distillate and gasoline."

Oil prices have fallen by more than 35% since January. The global COVID-19 pandemic has zapped demand due to widespread travel restrictions. In response, oil and gas companies have drastically cut spending and production.

Demand, however, is slowly recovering as eased stay-at-home orders give hope for the return of normalcy. Plus, some governments are taking steps to help matters.

Government-mandated production cuts, such as the one considered by the Texas Railroad Commission, aimed to ease the pain, however, are not supported by ConocoPhillips. Lance noted struggles on the government's part associated with how to bring production back and how the market works.

"If the U.S. industry comes back too quickly and the demand's not there to absorb the extra supply then the prices are going to go back down; there's going to be another price signal for suppliers to start thinking about," he said. "So, the market is pretty efficient, and we just think it's going to send the right signals to producers on the supply side as demand fluctuates."

There are steps that governments can take to help improve conditions.

In Norway, politicians increased tax incentives for the industry, allowing companies to temporarily shield part of their income from taxes. The move encouraged Aker BP ASAS and Equinor ASA to proceed with several offshore projects, saving jobs and boosting the economy.

Lance called the step by Norway positive. But places like Alaska are "going in the wrong direction and talking about increasing taxes at a time when cash flows are very subdued."

Although ConocoPhillips has the ability to shift capital, depending on fiscal stability and other risks in operating areas, he said "if the tax initiative passes in Alaska [in November], we will decrease capital."

Such decisions determine where companies make long-term investments as they work to meet energy demand in the short-term amid continued volatility and uncertainty.

"Hopefully it [the oil price] stays north of \$30 a barrel, because I think that's going to allow for more production to come back," Lance said. "If we see the demand keep rising, the market will stay relatively balanced."

Weak prices led ConocoPhillips to voluntarily curtail oil production from its Lower 48, Canadian Surmont oil sands and Alaskan operations. About a third of its production—around 400,000 bbl/d—is shut-in for June. It's a mix of conventional and unconventional resources.

"We feel very comfortable that we'll see that flush production coming back," Lance said.

Forgoing cash flow, opting to produce later when prices are higher, makes sense, he said. It requires a strong balance sheet, though.

With \$8 billion in cash on its balance sheet and about a \$6 billion revolver, the company entered the downturn in a "relatively strong position" with plenty of liquidity, he said.

ConocoPhillips cut its planned 2020 capex by about 35% and planned operating costs by about 10%. Its share repurchase program was suspended along with original 2020 guidance.

"We've not made some of the personnel reduction actions that many of our peers have had to make because we tried to keep the productive capacity of the company intact," Lance said.

If pricing recovery continues, the company hopes to slowly bring curtailed volumes back into the market. "We've reduced rigs. We've cut capital like most everybody has to manage through this downturn. So, we're anxious to see some of that recovery in price and then get back to work," he said.

—Velda Addison

EIG: Capital access problem 'serious' for banks, small companies

EIG Global Energy Partners recently announced the successful final close of its Global Project Fund V (GPF V), with total commitments of \$1.1 billion—nearly 50% higher than EIG's \$750 million target. EIG also raised an additional $1.5 billion of commitments in the form of separately managed accounts that will invest alongside GPF V.

GPF V is a continuation of EIG's platform for energy and infrastructure direct lending. It invests across the full energy spectrum: upstream, midstream, power, renewable energy and related infrastructure on a global basis.

"We invest across these sectors with, on average, about one-third allocation in upstream, one-third midstream and one-third in the others—including power, renewables and infrastructure—but we have a lot of flexibility," Rob Johnson, managing director at EIG and its global head of direct lending, said.

"This is not investing in distressed debt; our primary investment is in high quality companies that have financing needs," he added. "The capital access problem in the industry is real, and it is serious. I think we are still at the front end of the commercial banks' problems and, for smaller, private companies especially, capital access is going to remain difficult."

He noted bank replacement, development funding, acquisition financing and junior secured debt as key areas for private capital, as well as E&P companies that cannot access the high-yield market or successfully complete an exchange offer to address debt maturities.

"As you can imagine, there was a lot of investor focus and concern in the market," during the time of the capital raise. Market conditions have been very challenging since fundraising started in May 2019, yet these fundraising results have demonstrated that EIG's investors have confidence it can withstand these downturns, he said.

Johnson said the firm generally looks for deals in the $50 million to $300 million range, with an ability to make much larger commitments with co-investment from its limited partners. Typical hold periods are three to eight years, depending on a company's asset quality, balance sheet and other factors. If development drilling becomes more economic or the A&D market comes back, EIG can increase its capital commitment, he said.

"Our capital allows a company to focus and get through this period of time," he said. "At the moment, there is opportunity in first-lien private debt that they can use to refinance their bank credit. Later the company can refinance our facility."

"Pricing varies, but interest rate is usually in the high single digits for first-lien structures and second-lien structures in the low double-digit range," he explained.

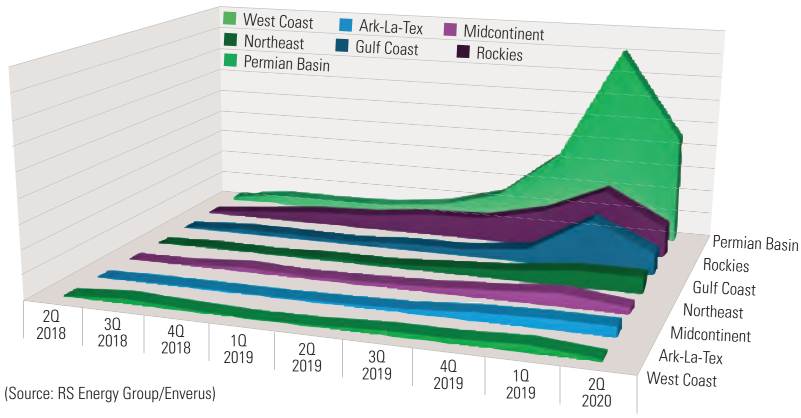
Johnson cited a recently realized investment in a private independent, Felix Energy, with both upstream and midstream assets in the Permian Basin as a good case study.

Felix Energy wanted to add rigs and expand its midstream system in the Delaware Basin, but commercial banks couldn't advance sufficient capital at the time, and the company didn't want to draw further capital from its private-equity sponsor.

EIG came in to provide junior debt behind the banks to fund the E&P's intermediate-term growth capital needs, first for $200 million and, later, for an additional $100 million. Ultimately, the investment helped to accelerate the company's growth and to position it for a successful sale to WPX Energy Inc. in March.

—Leslie Haines

DUC Builds And Trends



(Source: RS Energy Group/Enverus)

Analysts highlight strategy for OFS sector survival

Streamlining operations, pushing technology and using data to drive decisions are among the steps the oilfield services (OFS) community could take to weather current market volatility, energy experts say.

Consolidation among OFS players, however, seems inevitable as the oil and gas industry faces continued headwinds amid weak yet strengthening oil prices. Expectations are for the sector to shrink over the next one to three years, something seen a bit during the 2014 to 2016 trough, according to Mark Chapman, vice president of Enverus' intelligence team.

The drive toward efficiency and lower costs also picked up during the previous downturn, making marginal plays profitable for E&Ps, Chapman added. The gains did not translate to much benefit in terms of profitability for the OFS sector as E&Ps successfully sought discounts.

This time, without much margin built compared to six years ago, some service companies may not be able to lower prices.

"We're going have to stick to our guns a little bit and not push equipment to work until it can actually be at a price that's going to be profitable and generate free cash flow," Chapman said during a recent webinar.

"Most areas just aren't going to make sense, in general, to do activity in," he added, noting a 25% discount is not going to solve today's problem. "We're going to have to be a healthier industry."

Companies that emerge the healthiest from the latest downturn could be those able to reduce the cost of goods sold the most and those able to gain market share.

Certain parts of the service sector will suffer more than others, added Akash Sharma, senior petroleum engineering analyst and consultant for Enverus. He pointed out different sensitivities of land drillers, pressure pumpers and tool manufacturers, which each have varying cost and contract structures, to changes in selling, general and administrative expenses.

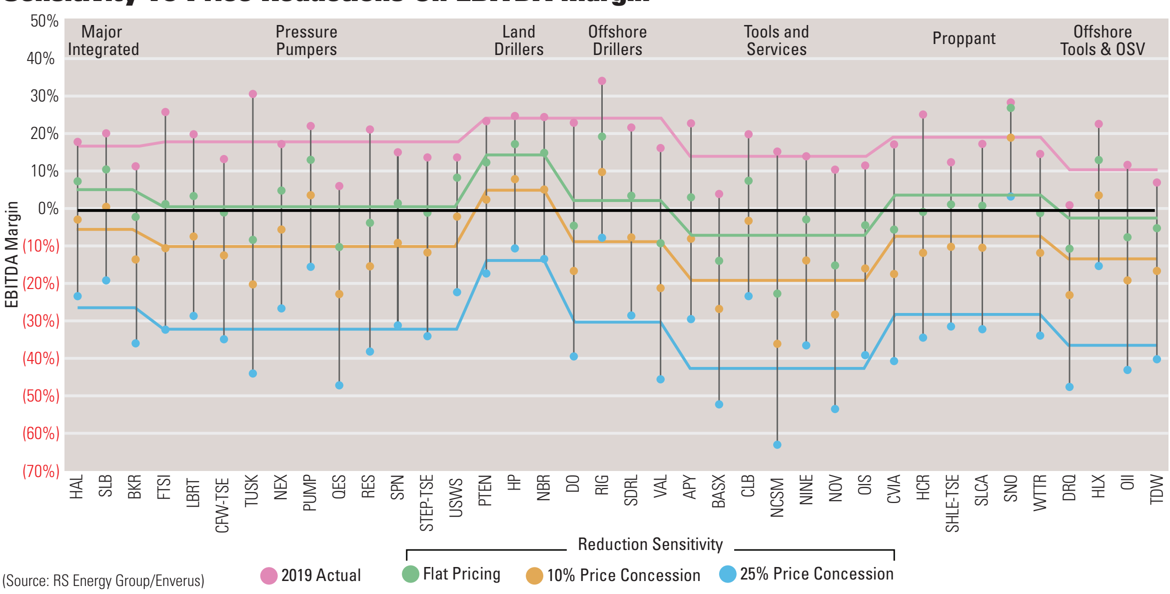
"I think the biggest driver of that is land drillers are fairly consolidated and have had pricing power," Chapman said.

"The challenge we've had in [a segment] like pressure pumping is it's very segmented still," and there are major players plus many smaller companies not far off in scale, he added. "We've been somewhat oversupplied with pressure pumping. That doesn't help that pricing power either."

Consolidation within the sector is needed, Chapman said. However, it won't be easy given the oversupply and unattractive balance sheets.

"Some Chapter 11 might have to happen before some of these

Sensitivity To Price Reductions On EBITDA Margin



(Source: RS Energy Group/Enverus)

mergers look palatable to really consolidate that down and increase the pricing power," he said.

Technology is one of the levers OFS players can pull to help it through volatile times, according to the analysts.

Automate field level activities when possible to lower costs and increase efficiency, Chapman said. Another move is to streamline operations, focusing on the most profitable parts of the business.

"If you do 10 things and you know you do three things really well, it's important to focus on those three things right now," Sharma added.

Let external data drive decisions to help determine risk, Chapman said. As situations turn around, consider who is returning to work and where.

"So, using data to make those decisions to understand where your target should be and then go after them is going to be hugely important," he said. "In a world where we can't go out and shake everybody's hand right now, you have to approach things from a little bit different angle, and I really think that data can tremendously help to drive up that."

As U.S. shale players move to recover from weak oil prices, with some already bringing wells previously shut in back online, a drawdown in their inventory of drilled but uncompleted wells (DUCs) could follow along with recompletions and workovers. These levers make the most economic sense to pull, according to Jonathan Godwin, senior associate for Enverus.

"The lifting cost is going to be relatively small to turn a shut-in around. The next thing that's going to make sense is probably to start burning down your DUC inventory," Godwin said. "If a lot of these DUCs push into next year, you're really looking at drilling costs as a sunk cost, and you're coming into next year almost on a quarter cycle basis."

That's very economic, Chapman added.

"We also have some wells that were part of that natural inventory drilled in the fourth quarter of 2019 that are already sunk costs for this year. They should have been completed already. But they're not, and they're part of that growing wedge of true DUCs," he said.

Analysts see this as an opportunity to bring some frac fleets back sooner.

However, the longer the recovery takes, the harder it will be to get employees back to get equipment running.

The downturn has resulted in salary reductions, deep budget cuts and widespread layoffs. Some yards have been shut or consolidated with others. The moves have helped, Chapman said. "The question is does it carry over for a little longer term as this correction comes around."

Will employees return, if asked, or move onto different industries that are less cyclical, closer to home or have better hours.

Enverus data show the rig count has dropped by 60% to 65% since the beginning of the year, while frac fleets have plummeted by more than 85%.

"In a balanced market you generally have about two rigs for every frac fleet, and that ratio today looks like it's about six to one," Godwin said, adding this leads to a large build in DUCs. "We believe that that DUC build will continue through the end of the third quarter this year. At that point in time, we think that we're going to turn things around a little bit and maybe even begin to burn some DUCs."

—Velda Addison

Shut-ins abound, but which wells first? It's complicated

As a result of a nearly 12% drop in global oil demand compared to last year, North American shale producers have been forced to cut production and new wells. According to Rystad Energy, U.S. oil production will fall to 10.7 MMbbl/d in June, a two-year low. U.S. producers have significantly cut back on drilling new wells and shut in producing wells to slash expenses and level off the massive oil glut that has depressed prices.

However, shutting in wells presents operators with a new set of challenges, with key decisions looming over which wells to shut in, how long can they be shut in without significantly impacting their long-term production and how taking wells offline affects the reservoir.

A panel of industry experts discussed these issues during an SPE-sponsored webinar on May 21 that addressed unconventional well shut-ins and their long-term implications.

Eric Gagen, president of EPG Solutions Co., explained that although operators might initially be inclined to shut in their poorer-producing wells, it could be more beneficial in the long-term to choke off higher-performing wells.

"In an ideal world, with no financial pressures, you'd probably want to choke back or close in your very best wells first," Gagen said. "That may sound counterintuitive, but it actually makes a lot of sense when you realize those wells are the best wells because they have lots of hydrocarbon saturation, they've got lots of pressure and they're very difficult wells to damage. When you turn them off, they turn back on."

Gagen acknowledged, however, that a company's financial obligations might not allow it to close off its best performers.

"Everybody has financial obligations," he said. "As an operator, you've got to have cash flow coming in to pay those financial obligations. So, there is going to be tremendous pressure to close in the worst wells and keep the best wells on."

The problem with closing in lesser-performing wells first is the varying dynamics of the well—its potentially poor rock quality, its poor hydrocarbon saturation or insufficient bottomhole pressure—are likely to make those wells more difficult to bring back onto production, Gagen said.

"There are also two other factors—one is leaseholder obligations. By closing in wells you may have financial penalties that could be worse than the consequences of leaving the well producing at a small loss," he said.

"The final one is flowlines and tank batteries. If you can close in a whole area that flows into a certain area, then you can idle that particular infrastructure. It sounds like a huge cost savings, but if you're in an area like North Dakota where crude lines can gel up or even freeze up in the wintertime, it might be something you try to avoid."

Another key consideration that panelists addressed regarding shutting in wells and bringing them back online is water management. Shut-in wells, whether they are high performers or low-performing wells, are likely to bring back higher volumes of water, perhaps nearly as much as during the initial frac job, and those dynamics and costs should be accounted for when considering a shut-in program.

Buddy Woodroof, technical manager at ProTechnics/Core Laboratories, said some cash-poor independent operators might be inclined to shut down high-volume wells to avoid water disposal costs. However, he said other factors that impact the reservoir should also be considered.

"Let's think about how much water these wells are producing," Woodroof said. "If they are high water producers, there may be a problem with water block issues when you start to bring the well back on. But some have said it's not just the water volume that is produced, you should also consider the oil-water ratio. That could be a critical determinant as to what's a good candidate (to shut in) and what's not."

Gagen explained that as shut-in wells pressure up, once put back online they could produce more water than a wellsite's infrastructure is designed to handle.

"All of these wells are going to pressure up to some degree," he said. "And some of them are going to produce a lot of water initially. And while the flowback facilities and tank batteries for these wells may be properly sized for their expected flowing rates for oil and gas, they may not be properly sized for really large batches of load water. So, you may see a situation where you've actually got to get the flowback crew back out there to start getting the load water out of these wells. It probably won't be as much (water) as an initial frac job, but it could be a considerable amount."

Woodroof added that wells with undulated wellbores might not serve as good candidates for shut-ins nor would those utilizing electric submersible pumps (ESP).

"Those are not good candidates, because those ESP pumps are pretty touchy," he said. "So, I would look for rod pump wells as leading candidates."

While some panelists advocated for shutting in newer wells, Lyle Lehman, principal consultant for Frac Diagnostics LLC, suggested it might be more prudent to consider older inventory for shut-ins because of the differences in completion designs and proppant pumped downhole during the frac stages.

"I would choose an older well perhaps with the reservoir pressure reduced low to depletion over a newer well with lower quality proppants for shut-ins merely for the reason that I can clean up a moderately conductive fracture more inexpensively and effectively than a case where the proppant has potentially crushed on the initial production flowback or actually becomes part of the reservoir due to crushing or damage from crossflow," he said.

Most analysts are predicting that any kind of large-scale oil recovery will not likely occur until 2021 at the earliest, as the world struggles to emerge from the COVID-19 pandemic and energy-intensive industries like transportation take small steps toward their previous consumption demands.

But if oil prices remain in the $30/bbl range, some, like Rystad, believe production could climb to about 11 MMbbl/d.

—Brian Walzel

Energy transition to remain priority for oil industry leaders

Despite reeling from the economic challenges and disruption brought on by a global pandemic, oil and gas leaders are expected to remain committed to decarbonization goals, according to new report from Deloitte.

Environmentalists have questioned the industry's commitment to the energy transition as the collapse in oil prices has caused many companies to slash their budgets for the year. However, the Deloitte report shows 92% of the surveyed oil and gas executives reaffirmed their companies either already have a plan to reduce reliance on fossil fuels in place or one under development.

The Deloitte report, which surveyed 600 C-suite executives and other senior corporate leaders in the oil and gas industry globally, stated that most company leaders are making energy transition a strategic priority.

For instance, a group of CEOs at oil majors, including Exxon Mobil Corp., BP Plc and Saudi Aramco, pledged to maintain a strategic focus on helping to mitigate climate change despite the impact of the coronavirus pandemic on oil and gas prices.

"Decarbonization priorities have become deeply embedded into business strategies and created a momentum for action that will not easily be compromised by present circumstances," Stanley Porter, vice chairman of Deloitte and U.S. energy, resources and industrials leader, and co-author of the report, said in a press release.

More than half of surveyed CEOs indicated that the key component of their decarbonization strategy was a focus on low-carbon fuels, including natural gas, citing consumer support and regulatory mandates like policy incentives as the top drivers for the energy transition.

In addition, oil and gas executives reported developing low-carbon products such as "green" gas and replacing hydrocarbons with cleaner fuels or renewables in operational processes.

A large number of executives reported that meeting decarbonization reduction targets are tied to board and executive compensation. Though, 60% of surveyed CEOs agreed that the key benefit achieved from their plans for a lower-carbon future was to improve the environment, Kate

Hardin, executive director for the Deloitte Research Center for Energy and Industrials and co-author of the report, told Hart Energy.

While environmental benefits will likely be deemphasized as companies regain their footing through the economic crisis, reducing costs and maintaining a competitive position are expected to remain important even in the downturn, the report stated.

Survey respondents overwhelmingly cited technology as a key enabler of progress in the energy transition.

"While a near-term pause in spending on new technologies is expected, they are unlikely to be canceled completely as these investments help increase operational efficiency, reduce carbon emissions, and benefit companies in the long run," according to the Deloitte report.

Digital technologies that improve energy efficiency were ranked as the top priority with carbon-capture, utilization and storage and other carbon-reducing technologies identified as a key component to emission reduction by oil and gas leaders.

Another enabler of the energy transition, according the report, which has been important in the current downturn, is increased collaboration with parties outside a company's core business.

Survey respondents highlighted collaboration with niche technology firms and academia, as well as developing partnerships and joint ventures, as important efforts in their low-carbon strategies. Moreover, as companies move to asset-light portfolios and diversify their activities, mergers and acquisitions are also expected to be important.

—Faiza Rizvi

Oil, gas explorers face murky future after oil price crash

Oil and gas explorers were off to a good start this year making discoveries until market conditions forced activity cutbacks. The future could hold more uncertainty as factors such as emissions targets come into play, analysts say.

"In an ideal world, the future should look rosy for explorers and developers around the world; however, the world is not quite that simple," Graeme Bagley, head of exploration and appraisal for Westwood Global Energy Group, said on a recent webinar. "We're seeing a number of different factors coming into play now."

He turned back to pre-COVID-19 headlines focusing on emissions targets factoring into investment decisions, societal pressure on climate change and a halt by some countries—namely New Zealand, France and Ireland—in frontier exploration rounds. Assuming the current oil price crash and global pandemic is a short-term crisis, he expects such concerns will be resurrected.

"What we can see is that long-cycle oil is now less fashionable," Bagley said.

Other reasons come to mind as well.

While some frontier play discoveries can move to first oil within three to four years like the Exxon Mobil Corp.-operated Liza offshore Guyana and the Kosmos Energy-BP Plc's Tortue offshore Mauritania and Senegal, it takes most frontier discoveries about 8½ years on average to make that journey, according to the firm's data. In some instances, it has been longer.

"We've seen companies such as Kosmos making very public statements and recently Woodside as well saying they will no longer invest in long cycle frontier exploration," Bagley said, noting companies are thinking about the "implications of the growing climate change agenda."

Kosmos, which is known for its frontier exploration work, in February said it aims to make its operations carbon neutral by 2030. The company also plans to increase the weight of natural gas in its portfolio.

The environmental, social and governance movement also means strategies will shift, Bagley said.

The transition to gas, considered a clean fuel that is popular with investors, has gained momentum in recent years. There is, however, already a lot of it.

"We estimate about 25 billion barrels of gas has been discovered since 2008 that remains stranded," Bagley said. "It's a great thing to explore for. But is the market going to be there? Is the infrastructure going to be there onshore?"

What does still make sense are short cycle, high-return oil developments, Bagley said.

Companies pursuing exploration have taken the infrastructure-led exploration (ILX) approach, searching for hydrocarbons in mature basins. Some are even pursuing ILX in super basins, a basin that has either produced at least 5 Bboe or has at least that much in recoverable reserves.

There are still opportunities within reach for some, despite today's market conditions.

Counter-cyclic investment for certain companies with deep pockets, he added, could allow for expanding exploration footprint, particularly for NOCs as smaller companies pull back.

"Companies that don't rebuild their portfolios in the time of distress such as today may find it hard to get back into business as usual," Bagley said.

Although no one is certain how the future will change the exploration sector, the analyst said one thing that likely won't change are the "molecules, the rocks, the hydrocarbons, the oil and the gas in the ground."

For the most part, oil and gas explorers started the year with success.

"We got off to quite a good start to the year. There were 37 high impact wells drilled in the first four months, and that was the highest recorded since 2014," said Jamie Collard, senior analyst for Westwood. "Commercial success rates reached again a high of about 35%, and there was a good amount of oil discovered."

High-impact discoveries have been reported in Suriname-Guyana with Apache Corp. and Total's Sapakara West-1 and Maka Central-1 and the Gulf of Mexico with Equinor's Monument along with others in the Campeche Salt and Colville basins, he said.

Activity, however, is slowing down as operators defer or cancel plans to drill wells following the latest oil price crash and pandemic. Already about seven of the original 22 key wells to watch globally this year in proven and frontier plays have been deferred or canceled. These include Tullow

Oil's Goliathberg North, Svenska's Atum, Petronas' Jove, Eni's Milma, Aker BP's Stangnestind, Total's Mailu and Equinor's Stromlo, according to Collard.

"There's already been 37 wells completed. Our estimate now for the rest of 2020 is that we're expecting somewhere along the lines of maybe 60 to 65 high impact wells to complete," Collard said. That is down to levels seen in 2016.

Supermajors have been driving high-impact drilling this year, led by Total followed by Royal Dutch Shell, Exxon Mobil and BP. Equinor, Petronas and Qatar Petroleum have also been among the more active companies, he said.

The strong start to 2020 followed continued improvement seen in 2019, which Collard said was driven by a large number of natural gas discoveries. Most of the discoveries were in deep water, clastic reservoirs and emerging plays. The largest finds—those over 1 Bboe—were gas. The operators were nearly all NOCs, supermajors or large majors.

There were 28 high-impact discoveries recorded in 2019.

Westwood studied exploration trends from 2015 to 2019. Among the firm's other notable themes were that exploration success has been highly concentrated geologically. The top 10 of 342 plays tested delivered 64% of the discovered resources. The top three were the MSGBC, Suriname-Guyana and Nile Delta—all Upper Cretaceous plays.

Research also showed that stratigraphic traps are becoming more important, leading to most of the discoveries. Stratigraphic trap targets doubled from 2019 to 2015, rising to about 30%, according to Collard.

Analysts also found that the fast-follower strategy is not working for emerging plays. As Keith Myers, president of research for Westwood, pointed out, 90% of the 57 Bboe of resources in plays opened since 2010 was found in frontier acreage.

High-impact exploration increased nearly 40% in 2019, compared to the past five years, with 93 high-impact wells completing, Collard said.

"This is being driven by maturing and mature plays and mainly in shallow water," he added, noting it's mainly related to activity in the North Sea. "There was a slight increase in the number of emerging play wells drilled about going from 25 to 26, and frontier wells actually increased to 35," the highest since 2014.

However, 51%—or 74 Bboe—of high-impact discoveries found since 2008 remains undeveloped, Collard said.

"I think it's fair to say that this is probably one of the most difficult times to be reviewing exploration performance. The period we're covering 2015 to 2019 was the five years after the last oil price crash," said Myers. "We were entering 2020 with a degree of optimism, with increasing activity. Now we're all sitting in lockdown, demand has fallen through the floor and companies are busy cutting back exploration expenditure again. So, it's a difficult time."

—Velda Addison

Will debt-laden MLPs be the next takeover targets?

Despite the relative health of MLPs during this market-crushing downcycle, several notable partnerships in distress could be primed for private-equity takeovers in the near future, an oil and gas investing executive believes.

The sector itself could be in worse—a lot worse—shape. EBITDA estimates for the Alerian MLP Infrastructure Index slumped to -5.9% for 2020 and -10% for 2021, making the index the envy of the oil and gas investing universe.

The figures reported by Alerian show the percentage change in 2020 and 2021 EBITDA estimates from Jan. 31 through May 11. The MLP index was outperformed by two other Alerian indexes but escaped the devastation wrought upon those listed on the S&P Oil & Gas Exploration & Production Select Industry Index and the S&P Energy Select Sector Index.

The MLP sector, dominated by midstream partnerships, benefits from its companies' fee-based business models, Stacey Morris, Alerian's director of research, said during a recent webinar.

"MLPs are less directly impacted by oil prices, but they're not totally immune to some of the concerns that arise from lower oil prices like counterparty concerns," she said.

Some groups that remain confident in the long-term fortunes of the oil and gas space may be painting targets on certain MLPs.

"I think you're going to see a lot of these publicly traded partnerships be taken private by private-equity funds," Michael Underhill, founder and chief investment officer of Wisconsin-based Capital Innovations LLC, told Hart Energy. "They look at a publicly traded MLP. It's got asset valuation, full transparency, audit and financials—all the things that you want. You have to go out and spend money on it, but the company's already publicly traded so they already spent all the money on corporate governance and everything else."

They're not cheap, Underhill said, but at the moment can be had for a steep 50% to 60% discount to fair market value. The struggling entities, just like their counterparts in the upstream space, have piled on a lot of debt but retain valued assets.

Potential targets include but are not limited to:

Western Midstream: Western Midstream Operating was one of six energy "fallen angels," including Occidental Petroleum Corp., that Fitch Ratings dropped from investment grade to high-yield grade in the first quarter. Western Midstream Partners LP reported a $251.4 million loss in the first quarter. Long-term debt is about $8.8 billion.

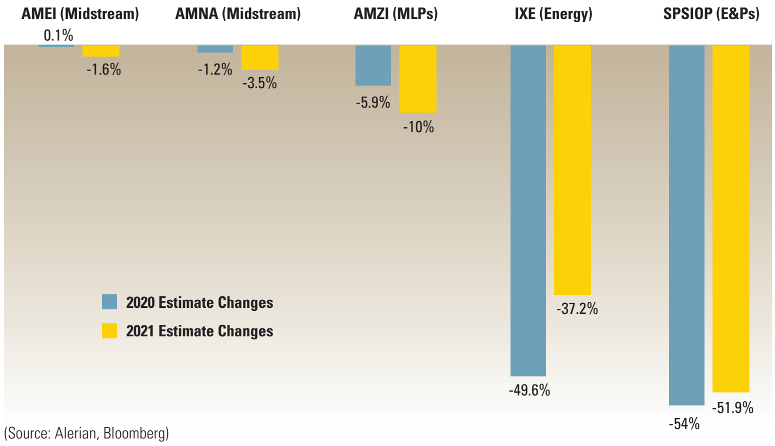
USA Compression Partners LP: First-quarter loss totaled $602.5 million with long-term debt of $1.9 billion.

Summit Midstream Partners: First-quarter net income was $5.3 million; stock price has mostly remained below $1/unit since the stock market crash in early March. Long-term debt was about $1.5 billion.

Shell Midstream Partners LP: First-quarter net income of $138 million and debt of $2.7 billion were reported.

Oasis Midstream Partners: It reported first-quarter loss of $69 million and debt of almost $500 million.

Midstream And MLP Forward EBITDA Estimates



(Source: Alerian, Bloomberg)

"I think it's the slow dance of the elephants," Underhill said. "It's beginning. And you're starting to see a little bit more response, at least from some of these [large private-equity] groups coming in. It's asset aggregation."

Underhill is not optimistic about the future of the MLP as a financial structure, believing the structure could become a casualty of the downcycle by the end of the year.

"If you're asking me today, is this the death knell? I would say yes," he said. "In another week, maybe not. But I think so. We don't invest in MLPs anymore. We just invest in C-corporations. We love the infrastructure. We love the ability to own cash flowing assets, but I think the MLP structure itself has outlived its usefulness."

Not everyone agrees. Seth Finkel, managing director of Neuberger Berman investment firm, likes MLPs because, as Morris said, they are typically transporters and less exposed to oil market volatility. Still, he notes they are not for everyone.

"For several reasons, any investor in MLPs should not be faint of heart and should be prepared for a rocky road," Finkel told Barron's. "Fundamentally, there should not be a strong correlation between oil prices and MLP performance, but that has been the case for the past couple of years. MLPs are not typically oil producers but energy transporters. And in many cases, they are more connected to the natural gas producers than oil producers as customers."

David Harrison, an attorney in Los Angeles, noted in his blog the expectation by Standard & Poors that a number of MLPs appeared primed to be downgraded to junk bond status. But that doesn't mean any proposed investments in the space should be rejected out of hand.

"The question from my standpoint is … should a customer ever have an MLP in his portfolio?" he told Hart Energy. "It is kind of hard to say, no, you shouldn't, because it gives a higher amount of yield."

Harrison does not dispense investment advice. He represents clients in malpractice cases against financial advisers. Many of his clients, he said, are seniors who invest in MLPs because they are attracted to the distributions. When downcycles strike, as they did in 2015, his clients have been startled to receive margin calls.

"Because MLPs by definition have to distribute most of their earnings to investors, that leaves companies highly leveraged without monetary reserves to sustain themselves during difficult periods," he said. "In addition, many MLPs—specifically shale related—require oil not to fall below a certain price to survive."

But the MLP structure will remain viable, he said.

"I think it will be," Harrison said. "MLPs were created from a tax perspective to pay out the majority of their earnings to investors. So I don't think in the long run [the downcycle marks] the death of MLPs by any means. Even in 2015, you had many investors who were still very profitable because the yield was so great for over the years."

—Joseph Markman

Frac horsepower utilization falls along with sand demand

Satellite imagery and photos of stacked frac fleets across major oil- and gas-producing shale plays in the U.S. show the pain oilfield service providers are experiencing. Likewise, sand mines are at risk as more than a dozen such facilities in the Permian Basin alone have a status of intermittent or nonproducing.

This, according to analysts at Westwood Global Energy Group, comes as U.S. oil and gas companies cut spending in response to low commodity prices, driven down by a supply-demand imbalance due in part to the OPEC+ fallout and a global pandemic that slowed travel.

The firm's data show 43 E&Ps have lowered capex by $51 billion. The reductions came amid fear of global oil storage reaching capacity as WTI prices fell into negative territory last month.

But there are signs of a recovery: oil prices are inching higher, and COVID-19 shelter-in-place orders are being lifted—though some health experts warn of the potential for new outbreaks.

Market research suggests balance will be achieved by third quarter this year, said James Jang, lead analyst at Westwood.

"The speed of U.S. and Canadian supply reduction really surprised many of the OPEC+ nations," Jang said on a recent webinar. "North Dakota's Williston Basin output has dropped by nearly one-third, or about 400,000 barrels per day, since March. In Texas, the output is expected to drop by about 20%, or about 1 million barrels per day, by the end of May."

Some of the biggest planned production cuts are from ConocoPhillips Co., Exxon Mobil Corp. and Chevron Corp.

"It's estimated that April was the inflection point with a mindboggling 30 million barrels per day of demand drop," Jang said. "Significant supply cuts are being made by most producing countries," including Saudi Arabia, Russia and the U.S.

Small E&Ps have cut their spending in the U.S. by 42% (accounting for 2% of the total reduction), compared to 37% spending cut by independents and 22% by supermajors, he said.

The cuts, however, have dealt frac companies a blow.

Horsepower utilization for six companies providing services in the U.S. onshore has dropped to an average of about 25%, Westwood analyst Luke Smith said.

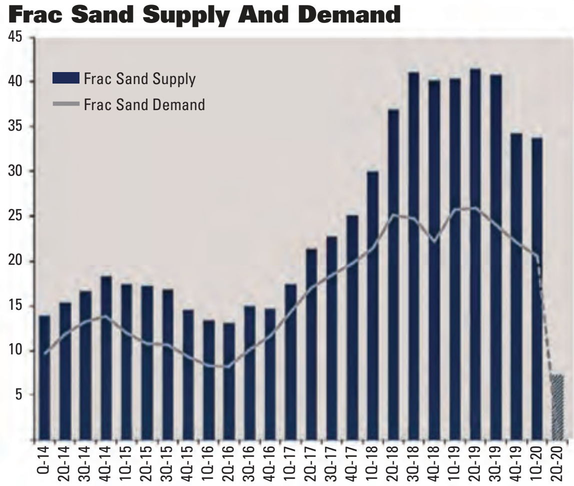
"FTSI (FTS International Inc.) had quite a significant drop off going from about 70% [in third-quarter 2019] down to about 20% for [the second quarter]," Smith said, later showing SatScout imagery of stacked fleets in West Texas and Oklahoma. "Halliburton, the largest U.S. onshore pressure pumper, had essentially about 61 active frac crews at the end of 2019 … and that number has been significantly diminished, especially in the Permian."

The story was similar for others such as Liberty Oilfield Services Inc., NextTier Oilfield Solutions Inc., Patterson-UTI Energy Inc. and Schlumberger Ltd.

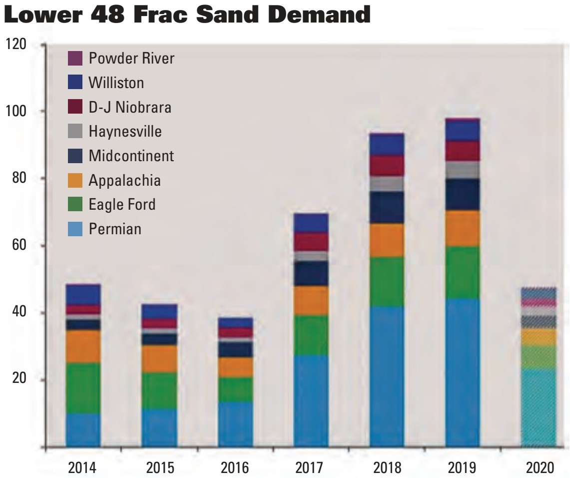
HHP utilization varied by basin.

"When we take a look at Appalachia we see that it already had a lower utilization than [the] Eagle Ford and the Permian," Smith said. "That's largely due to prices and storage in the natural gas market. The [second-quarter] drop off in

Frac Sand Supply And Demand

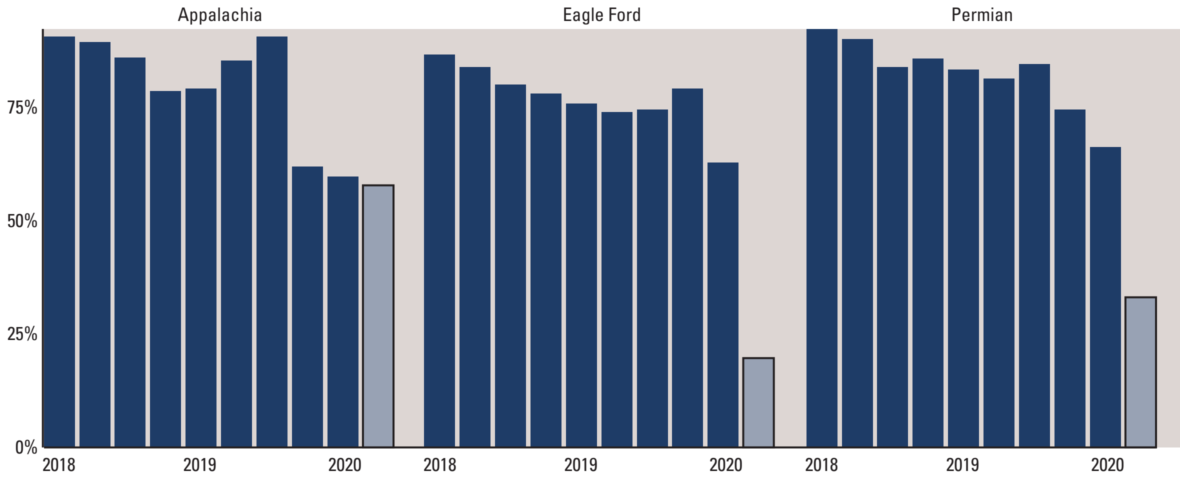


Lower 48 Frac Sand Demand



(Source: Westwood, Horsepower Outlook)

US Onshore HHP Utilization



(Source: Westwood, Horsepower Outlook)

Appalachia isn't quite as severe as what you see in the Eagle Ford and the Permian," where he added companies like Parsley Energy Inc., Diamondback Energy Inc. and EOG Resources Inc. essentially took off the month of April.

Lingering in the background of market turmoil, Smith said, is how efficiency gains—such as improving the amount of time crews can frack wells—impact utilization. "These frac crews can pump more stages per quarter. They're essentially putting in more proppant, and they're kind of diminishing their demand," he said, noting big efficiency gains in Appalachia and Eagle Ford.

Westwood's data show stages per crew in Appalachia jumped from 200 in 2018 to nearly 400 this year. Stages per crew jumped to just over 500 from 300 in the Eagle Ford during the same period.

A sharp drop in frac sand supply and demand is also playing out, according to data from Jonathon Clark, the firm's lead analyst for frac sand.

"In [the second quarter] we are expecting to see both supply and demand reach a historic low on a quarterly basis, and in terms of overall demand, we are estimating the Lower 48 total demand to decline by roughly 51% this year compared to 2019," Clark said.

The firm tracks about 180 mines, of which roughly two-thirds are in the Midwest and Permian, that account for about 280 MMtons of annual nameplate supply. Reduced activity in shale plays has put mines at risk.

In the Permian, average mine utilization is expected to drop to about 40% in second-quarter 2020, down from more than 70% in the first quarter, Westwood data show.

Clark said the firm is tracking 14 operations in the Permian Basin with mine status as intermittent or nonproducing.

Mines are also at risk in the Eagle Ford, where average mine utilization is forecast to drop to around 60% in second-quarter 2020, down from 100% in the first quarter. Here, Westwood is tracking five operations with mine status as intermittent or nonproducing.

—Velda Addison

In memoriam: Oil industry legend David L. Bole

Throughout his 50-year career in the oil and gas industry, Bole was best known as a tireless networker and business builder. He passed away peacefully with family by his side, according to an obituary in the Houston Chronicle.

Bole is an Oklahoma native born and raised in Bartlesville, where his chemical engineer father arrived in the 1920s' oil boom to join Cities Service Oil Co. Young Bole started in the oil patch at age 17 working on cable tool rigs in the summer.

After graduating from the University of Oklahoma in 1961 with a BBA in Petroleum Land Management, he joined Humble Oil, an Exxon Mobil predecessor company, in Oklahoma City as a field landman. He took a leave of absence to serve in the U.S. Army. Following his return to Humble, he worked in Ardmore, Oklahoma City, New Orleans and Houston.

He left Humble in 1968 to join Merrill Lynch, where he became national product manager for oil and gas investments in New York. Returning to Oklahoma City, he was co-founder and president of Edwards & Leach Oil Co., then CFO for Alexander Energy. Later, he went to Pittsburgh to work for Equitable Resources Energy Co. as vice president of corporate development.

Back in Houston by 1996, he became a managing director of A&D advisory firm Randall & Dewey, now a part of Jefferies & Co. In 2007, Bole joined private-equity firm Quantum Energy Partners in Houston, where he served as managing director until his retirement. Prior to joining Quantum, he was president of SouthView Energy, a Quantum and Jefferies portfolio company.

Bole was also active in many industry associations including the American Association of Professional Landmen, Texas Alliance of Energy Producers, Texas Independent Producers & Royalty Owners Association and Independent Petroleum Association of America (IPAA). He received the IPAA Leadership Award in 2004.

At OU, Bole was on the Sarkeys Energy Center board of directors and served on the advisory board for the Energy Management Program in the Price College of Business. In 2011, he received the Price College Distinguished Alumni Award.

—Hart Energy staff

PRIVATE RESERVES

Zero- and lightly levered private operators throughout U.S. oil basins are on the lookout to buy—and not just where they operate currently. These five producers—in Wyoming, Oklahoma, Colorado and South Texas—share their plans.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LD LMT 209400 LB 94950 KG
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2 INCH HF COMP SHOES

STEVE TOON

ARTICLE BY
NISSA DARBONNE

The challenge of the next year is clear: "If you cannot survive with what you have today—and without being able to access new capital until the end of '21—then you better be thinking of what your options are," said Joe Mills, Samson Resources II LLC.

Overleaf, tankers pause at an oil-tanker loading facility in the Powder River Basin. Facing page, a worker clears a deck in the Eagle Ford.

In the Powder River Basin, Joe Mills was expecting to sell Samson Resources II LLC this year. "Samson is doing very well, thank goodness," Mills, president and CEO, said in early May.

"We've made a lot of good decisions along the way with Samson—outside of the one disappointment: I really thought we would be exiting right about now."

The rig count in Wyoming had fallen to two by mid-May from 25 the first week of January when WTI was $63, according to the Baker Hughes Co. count. "I don't know if we'll go to one or to zero," Mills said. "It's just a matter of how long this thing will go."

Tulsa, Okla.-based Samson itself has about $10 million in debt. Its spring bank-facility review "was redetermined down, but not as bad as everybody else," he said.

The borrowing base was lowered from $100 million to $80 million, "giving us approximately $70 million of liquidity and a very strong hedge book."

Mills joined the company in 2017 after the former Samson Resources Corp. exited Chapter 11 restructuring. Privately held, its roughly 80 investors are primarily former second-lien debtholders.

Cost-cutting and paring Samson's portfolio to only the Powder during the past three years Mills has led the company "made us leaner and meaner and more profitable," he said, "which obviously is going to carry the day through this epic mess."

With shut-ins, production was down to 300 bbl/d in May from 8,000 bbl/d in March. "We're evaluating our production shut-ins month by month," Mills said. "I expect we will remain fairly shut-in through June and hopefully start to bring wells back on in July or August as prices start to improve."

WTI closed on March 9 at $31. Mills was already on the phone, arranging a board meeting.

"I said, 'This is what we're going to do: We're going to shut down rig activity and live off our hedges. And we have to extend our runway to the end of 2021.'"

About 90% of Samson's shut-in 8,000 bbl/d are hedged at $60 this year; in 2021, 63% is hedged at $55.

Shut-in-while-hedged may become complicated. Most credit facilities prohibit being more than 100% hedged. With production shut-in, though, producers may be over-hedged.

"Right now, we're living off our hedges," Mills said. "Our hedge book is close to $50 million mark to market."

If over-hedged more than two consecutive months, bank agreements usually require the excess contracts be sold. "[The agreement] doesn't allow us to just keep doing it forever. But [selling the hedges means] you're just bringing in the cash. You're just accelerating it."

The income can't be treated as EBITDA under the credit facility, though. "There are some nuances to it, and everyone is having to deal with these."

Samson initiated a conversation with its bankers when it saw the situation. "They said, 'Yeah, this is really unusual.'"

It was worked out. "Everyone is working well together—so long as you're not in receivership and you're not in the middle of restructuring. Then, obviously, the banks have a different tenor," Mills said.

'Year of the Powder'

The Powder itself is demonstrating potential, after a sluggish start during the past decade. Major operators are Occidental Petroleum Corp., EOG Resources Inc., Devon Energy Corp. and Chesapeake Energy Corp.

Samson's roughly 132,000 net acres are primarily in southern Campbell and northern Converse counties where most of the basin activity is concentrated. It had two rigs drilling in February, both in northern Converse.

"For the Powder, this downturn is such a shame," Mills said. "I thought 2020 was going to be the Year of the Powder. The work Devon, EOG, Occidental, Chesapeake and all the smaller independents are doing to drive down the overall drilling-cost structure has just been amazing."

And the cost-decline wasn't from "gouging the rig companies and other service providers. We're starting to see quantum leaps in our ability to drill these wells faster than ever. Our penetration rates are up substantially."

Devon reported first-quarter new Powder wells cost $6.4 million. In Niobrara B, its Tillard 36-4X averaged a 90-day rate of 1,200 boe/d, 85% oil.

EOG reported its Powder Niobrara wells cost $663 per lateral foot; Mowry, $737. A new completion design in the former is delivering 45% more oil; in the latter, 70%, it added.

Samson's targets are Turner and Niobrara. Mills said both "are clearly the two front-runners in the basin."

Niobrara wells were getting to sub-$7 million, drilled and completed; entering 2019, costs had been $12 million or more.

"It's a game changer in economics. At $37 oil, you'll see the Turner and Niobrara rig activity pick back up. At $37 oil, you can generate a decent return."

EUR was reaching between 800,000 MMboe and 1.2 MMboe from Turner wells, underlying the Niobrara. From the Niobrara, EUR was between 600,000 boe and 1.3 MMboe.

In southern Johnson County, where Chesapeake is, the Niobrara tends to be gassier. Where Samson operates, it's oilier. "But the GOR can vary across the basin—as low as 60% oil to as high as 85% oil, depending on where you are," Mills said.

While "Everyone looks for at least 900,000 boe to 1 million boe that is at least 75% oil, if at $7-million-or-lower D&C costs, 700,000 boe becomes very economic."

For Samson, "At $40-plus, we're back to drilling," he expects.

Zombie watch

While plans were to sell Samson this year, might it become a buyer instead? "We are be-


TOM FOX

TOM FOX

ing opportunistic," Mills said. "There is no doubt some balance sheets are not as strong as ours. We've had calls from people talking to us about buying them out."

Samson won't borrow to do that, though. "We have an excellent portfolio and balance sheet. I'm not interested in scaling Samson up just to tread water," Mills said.

A one-plus-one deal would have to equal three—making the company more attractive and extending its runway. Otherwise, "We're happy to stand where we are," he said.

But he does expect some consolidation in the Powder, if not by Samson itself. "It kind of needs to happen."

Samson will likely consolidate some smaller players. "Scale matters today more than ever. Being small is not a strength today. To capital providers—I don't care if it's private equity or hedge funds—scale matters," Mills said.

And big buyers want big deals. "They're going to want to eat larger fish than small ones because of the time and money required. I think you will see us be opportunistic in this downturn," he added.

Devon and EOG are in good shape to bolt on in the basin, for example, he said. In April, EOG raised $750 million in a 4.375% senior-note sale due 2030 and $750 million from 4.95% notes due 2050.

It had used cash on hand on April 1 to pay $500 million of 2.45% notes due that day. Its $2 billion senior unsecured credit facility was undrawn.

Devon in early May had $1.7 billion of cash and an undrawn facility of $3 billion. Its $4.3 billion of senior notes' first maturities begin in late 2025.

While some operators have powder, those and others that are shut-in "means everyone's inventory has been extended that much further out," Mills said. "The big guys don't have to make acquisitions; they aren't burning through their inventory right now."

Absent of restructuring-driven asset offerings, "I'm not optimistic about M&A returning any time soon," he said. And operators that enter reorganization in this cycle might not get just fresh paint and put back in the field.

"I don't think you'll see that this time," Mills said. "I think you'll see more and more get broken up and sold off.

"The banks don't want to run these companies. We have too many walking zombies out there. We need to deal with the walking zombies."

Operators should be ready to make it through the end of 2021, he estimates. "If you cannot survive with what you have today—and without being able to access new capital until the end of '21—then you better be thinking of what your options are.

"And I mean $35 oil to the end of 2021," he said.

Time might show that fundamental oil-demand mechanics have been altered irreparably, he added. "We might never see—or certainly not in the next five or six years—another 100 MMbbl/d demand cycle again."

'Have to shrink'

Also in the Powder, Gene Shepherd and the team at ATX Energy Partners LLC have been looking at deals since entering the basin in 2017. The co-founder and CEO was CFO for Brigham Exploration Co. as it made an early entry to the Bakken in 2005, selling its 376,000 net acres for $4.4 billion to Equinor ASA in 2011.

He then co-founded and led Brigham Resources LLC as its CEO, selling a similarly grassroots-grown, 77,000-net-acre Delaware Basin portfolio for $2.6 billion to Diamondback Energy Inc. in 2017.

"My view is it could take 18 months or longer for the global economy to get back to where it was," Shepherd said. Meanwhile, "Our industry will go through a period of consolidation and rationalization. We're going to have to shrink."

How much? "I don't really know; maybe 50% is a guess. A lot of it will depend on the timeline for the global economy to recover," he said.

Shepherd sees larger independents high-grading their inventory and focusing capital there, "which leaves a lot of acreage and opportunity that, depending on oil prices, is not going to compete for capital.

"So what does an operator do with acreage that's not competing for capital? Unless they have a bullish view on a recovery, it's hard to imagine that they keep it in inventory."

If putting it on the market, though, from where do the buyers get the capital? "The world has been turned upside down," Shepherd said. "I think there is going to be a lot of opportunity and a lot less capital, whereas last year we had the inverse."

He expects "a number of" private-equity sources that had been focused on energy "will leave the space. Some of the traditional providers don't have any capital, and those that do are being very careful as to how they put it to work."

"So who takes advantage of the very unique opportunity that we expect to see later this year?" In the standstill that was the second quarter, Shepherd said, "the A&D markets were locked down.

"But, in [this] half, as this rationalization gets kicked off and attractive opportunities start to surface, how will operators source capital and what will be the underwriting criteria and return expectations for this capital?"

Looking at the aftermath of the 1980s, the robust return of capital was slow to come. "I think we will go through a period where there is just too much uncertainty over the global economy reengaging and getting back to 100 MMbbl/d.

"It's a timing question that I don't think anyone can answer right now," he said.

Some investors with past experience with energy but that haven't played it in a while may come back. "Initially, maybe some deep-value-oriented investors," Shepherd said. "We have recently talked to several that are looking."

Assessing the current environment, Gene Shepherd with ATX Energy Partners LLC said, "The world has been turned upside down. I think there is going to be a lot of opportunity and a lot less capital, whereas last year we had the inverse."

Left page, pumpjacks are lined up in the Eagle Ford.

Of his company, Bison Oil & Gas Energy Partners II LLC, David Gonzales said, "We're kind of contrarians. We raise capital to grow in a down market."

How serious are they? "I don't know. It feels like we need to see oil prices continue to recover and serve as a catalyst to trigger new sources of capital to flow to the industry."

ATX spent most of 2019 attempting to add to its portfolio, targeting opportunities with developmental risk to complement ATX's exploratory foothold in the Powder in Johnson County, Wyo.

"Last year, the A&D bid/ask spread was too wide, and we didn't get a transaction done. In hindsight, that worked to our benefit."

Maybe the Permian could become affordable? "There will be some outstanding opportunities to look at that," he said. "Before the downturn, we didn't think we would have a chance to compete. We are very excited."

Science-ing

Austin, Texas-based ATX picked up 121,000 net acres, mostly contiguous, in Johnson County, beginning in 2017 with an initial 35,000 net from Black Hills Exploration & Production.

Before this past March, coring had been done, and four science wells had been drilled. "We were planning to take what we had learned, make some significant adjustments to our drilling and completion formula and apply those learnings in our next group of wells," Shepherd said.

Plans were for three more wells this past spring. "Obviously, those efforts were shelved."

ATX shut in its four wells in April as the differential in the basin blew out to more than $15 a barrel. But it put them back online in mid-May as the basis improved.

The Powder was picked by ATX for its resource potential, while the Johnson County entry was exploratory in nature. Delineation and exploitation of the Powder was slowed in the past decade by the presence of conventional targets "productive enough" to distract from going after the source rock.

The Powder is "way behind other basins in terms of prosecuting its shale potential," Shepherd said. "But—with its tremendous, oily resource potential—it's just a matter of time and probably higher oil prices for this to change."

Of ATX's initial four wells, three were landed in different benches of the Niobrara, and one was landed in Mowry.

The Powder is complicated. "The geology is very different," Shepherd said. "You have widespread lineaments that conduct heat flow, creating thermal anomalies necessary for source-rock maturity from basement rock."

If right on top of some of the larger anomalies, there is a greater gas component in the GOR. ATX thinks it's found a spot in Johnson County in the oily window.

Shepherd expects it will take another dozen wells for ATX to delineate the shale potential on its leasehold. "We have more work to do on the Powder but won't get back to work until we see higher oil prices."

Hit the brakes

David Gonzales spoke at Hart Energy's DUG Bakken & Rockies conference in Denver in mid-February. In May, February had seemed like an eternity ago.

"It's been quite the drastic change since then," he said.

STEVE TOON

Denver-based Bison Oil & Gas Energy Partners II LLC was formed in 2017 after a sale of the first Bison's portfolio in the Denver-Julesburg Basin (D-J) to Extraction Oil & Gas Inc. The second Bison acquired leases in the D-J's northeastern extension and in the San Juan Basin; the latter property was sold in 2019.

This past fall, the group formed Bison III; for it, the team is looking at a platform entry "throughout" in "the general Rockies area" with a heavy focus on North Dakota. All three of the Bisons are backed by Carnelian Energy Capital Management LP.

In the D-J, Bison II has drilled 22 wells on roughly 50,000 net acres entirely in rural northeastern Weld County, Colo., clear of urban opposition to drilling.

Mid-reach laterals currently cost it about $4.9 million—drilled, completed, online. Gonzales expects that to fall to between $4.6 million and $4.8 million if it were drilling now. Its wells to date had averaged 30-day peak production of 125 boe/d per 1,000 lateral feet, approximately 80% oil, with a flat decline.

It had a large program lined up for May and "hit the brakes on that," Gonzales said. It has no drilled-but-uncompleted wells. It shut in all of its pads in April, except for one—an eight-well pad it had just drilled.

"It's our first full-density unit in Baja, which is our core area. So we wanted to make sure we got good data on what an eight-well pad looked like in our prospective region."

Keeping it online, Bison should have "the data we need to fully drill out the remainder of our acreage and make any adjustments between now and when we start drilling again," Gonzales said. "That's what our thought was.

"This just positions us to come out of this downturn with a lot more momentum and allows us to play a little more offense," he said.

'Ready to go'

Differentials haven't been overwhelming in the D-J to date. "I haven't seen a ton of movement this year," Gonzales said, "mainly because many companies signed term contracts—for one or five or 10 years."

For Bison, the differential has actually improved for its barrels, "Niobarrels," outside the core of Wattenberg Field. The sub-42-API oil is needed in blending refinery feedstock. Shut-ins by other producers had resulted in a shortage.

"The higher-API oil couldn't flow because they needed our barrel," Gonzales said. "Bison's barrels were able to flow through the system continuously."

The first Bison was formed during the downturn in 2015; the third one, in 2020. "We're kind of contrarians. We raise capital to grow in a down market," Gonzales said. "This is the market where we thrive. We have fresh capital and no liabilities."

Bison III is fully capitalized and "ready to go," he added. "We're extremely busy right now, combing through acquisitions."

Some offers had already been made by early May.

The team finds parts of North Dakota "interesting in terms of being economically justifiable." Still, "They're just hard to get into" as well.

"In North Dakota, there is a lot of data, so it's much less exploratory," Gonzales said.

Wind-power turbines stand amid a rig targeting oil on the Oklahoma prairie.

Drew Deaton with Red Wolf Natural Resources LLC favors a "managed recovery" and said U.S. oil and gas producers are "ingenious, sometimes to our detriment. Our efficiencies have, at times, hurt us overall as an industry."

"We're good at prospecting, and we're a good operating team. But we want to go to areas where we have controllable data points and we leverage the information available and quantify the variables controllable by us.

"If we can change those or enhance those, then we can underwrite the investment," he said.

Capital ready

In a $155-million term-loan facility signed with Varde Partners Inc. in 2019, Bison II had a drilling program lined up in which it could draw on the financing as it went. "We didn't have to take down the entire capital.

"Obviously it doesn't make sense to produce those reserves at this price, so that capital is still sitting there for us to grow," Gonzales said.

Can it draw from it for acquisitions? Is it exclusive to Bison II or can it be used by Bison III? "It is exclusive for Bison II, but we can use portions of it for acquisitions," Gonzales said.

"It's structured in how much we can use for that. It wasn't necessarily intended for acquisitions; it's intended for development. But there are buckets we can pull from for acquisitions."

It's fortunate, he added, that Bison II is in the D-J in a low finding and development (F&D) area. Looking at property elsewhere, he said "What we have found—and we love—is that our assets in the D-J are some of the most efficient assets in the country and some of the most economic."

With that, a strong balance sheet and a strong hedge position, it has "allowed us to weather the storm pretty well. We are ready and able to ramp up development quickly in a modest price-recovery environment," he said.

Many areas require $50 oil to be both economic and profitable. At Bison, "Our position in the D-J has extremely low F&D, so we start to get excited above $40, which puts us in a really good position to grow quickly in a recovery environment," Gonzales said.

Oklahoma gas

Formed in first-quarter 2019, Red Wolf Natural Resources LLC is in the SCOOP/STACK—about 65% SCOOP. It picked up the 56,000 net acres—including some 500 legacy conventional wells that have the leasehold HBPed—from Apache Corp. in second-quarter 2019.

"We were very fortunate as we were getting our company formed," said Drew Deaton, co-founder and CEO. The Edmond, Okla.-based E&P's operated and nonoperated positions are in Stephens, Garvin, McClain, Pontotoc, Lincoln and Logan counties.

"It felt like a perfect starter asset. There is a lot of legacy. It's HBP. It covers a lot of ground we like," he said.

Some of its nonop wells, particularly newer ones, have been shut in, said Jeff Dahlberg, co-founder and COO. But none of its operated wells are shut in; about two-thirds of Red Wolf's production is gas, including NGLs.

"So it doesn't really help us to shut in our wells," Dahlberg said. "It would affect us in a

A rig is being relocated in South Texas.

negative way because of the gas revenue we would lose.

"Combining residue gas and NGL revenues, net of the associated midstream costs, gives us acceptable prices. Not 'great,' but acceptable."

Good gas winter

U.S. associated-gas production has declined while oil wells are taken offline. By late May, producers had shut in 1.6 MMbbl/d of the 13.1 MMbbl flowing before March.

"Gas prices should be strong the rest of the year," Dahlberg said. "Predictions are for gas prices of $3.50 and $4 into the winter months, so that would be good for us."

Deaton doesn't expect it to last, though. "It's easy for me to see a reaction—almost whipsaw—at some stage as supply and demand are trying to rebalance," he said.

New-well decline curves were pretty steep in shale plays. Near suspension of new drilling and completions across the Lower 48 in oil basins will appear pretty quickly in diminished supply, Deaton said, resulting in a "burn off in the overhang of oil in storage."

"It's not too difficult to see a healthy recovery once those items come into balance," he added.

Bloomberg reported in May that Diamondback would turn some wells back on at $30 oil. Others, it reported, said $30 is a critical price point.

Deaton said, "I would guess $30 works in certain areas, but I wouldn't paint it across the breadth of where the [Permian] was active, say, maybe 12 months ago."

Deaton favors a "managed recovery." U.S. oil and gas producers are "ingenious, sometimes to our detriment. Our efficiencies have, at times, hurt us overall as an industry. We innovate, become real efficient, flood the market and hurt ourselves."

Postponed

Red Wolf hadn't had layoffs, although it was continuing in May to evaluate the possibility. Deaton said, "We run a pretty lean shop as it is."

Most of Red Wolf management came out of Ward Energy Partners LLC, and the entire team has "very specific knowledge of the Anadarko Basin," Deaton said. With its platform asset, it's ready to grow.

"The best way to take on challenges such as this is to look for opportunities," Deaton said. "It's a cyclical business, and we can't be totally shocked, although this one is quite a doozy.

"But we're looking to grow and come out of this stronger."

Backed by Pearl Energy Investments LP, the operator was looking at assets it could add to the portfolio. Deaton said, "One way we look at a downturn like this is certainly opportunistically. We're looking to turn over stones to grow the future."

He expects there will be fewer E&Ps on the other side of this era, "but those that are still standing should be stronger and in a better position, and that's where we look to be."

Whether adding property or not, it has plans for its existing acreage. "We had a couple projects in SCOOP that we were excited about that could extend the window a bit," Deaton said. And it had been looking at oilier potential.

While the plan has been on hold, "It doesn't take away the luster or excitement. It's just postponed it."

Dahlberg added, "We are fortunate that our acreage is HBP. We can be selective about when to develop our remaining acreage position. It will be there when the time comes to develop it."

STEVE TOON

Workers engage in an Eagle Ford well completion.

South Texas natgas

Beginning his oil and gas career in 1978, Glenn Hart was also a founder of two professional ice hockey teams—the Houston Aeros and the Laredo (Texas) Bucks. What would it be like to be in professional sports in 2020?

"That would be tough," he said.

At his newest venture, Rio Grande Exploration & Production LLC, Hart also isn't dealing with oil prices. The leasehold is in the dry-gas window of the Eagle Ford.

"It's on the comeback trail," Hart, president and CEO, said of the U.S. gas story. "In the dry-gas area of the eagle Ford, we are only 100 miles from one of the largest manufacturing areas in North America, being Monterrey, Mexico, with plenty of pipelines and pipeline capacity to deliver the gas."

Additionally, LNG users are nearby as well as the Houston Ship Channel. "The result is that gas prices in our region are typically Houston Ship Channel-plus with very low transportation rates.

"The net effect of this means that our region will consistently continue to have the best netback price in North America," Hart said.

His preference is to get the gas to Mexico. "But you have to be in the right place, the right pipe.

"We were one of the very first ones [at a predecessor company] that sold gas to Mexico when the energy laws there were changed. It's a big part of our strategy," he said.

Red Wolf Natural Resources LLC can afford to be patient because "our acreage is HBP … It will be there when the time comes to develop it," said Jeff Dahlberg.

Glenn Hart with Rio Grande Exploration & Production LLC sees a new outlook forming among those that remain in oil and gas: "You might as well go for the big bucks, if there is as much risk of losing your job whatever the company is. I think that evolution has taken place."

Houston-based Rio Grande's property is some 70,000 net acres in Webb, Zapata, Jim Hogg, Duval, Live Oak and McMullen counties. The $20-million platform acquisition in 2018 of Columbus Energy LLC, an Amplify Energy Corp. subsidiary, came with some 68 Bcfe of PDP, producing 16 MMcfe/d.

"Timing is everything," Hart said. "We got into our assets about two years ago. We're in great shape."

Rio Grande didn't have a rig at work in the spring. Hart said, "We're gearing up to start back up early [this] quarter. We didn't get our program started until December."

The asset has some 500 vertical wells a few miles apart from Rio Grande's unconventional targets. Having acreage that has both types of opportunity gives it flexibility, Hart said.

"In the vertical, traditional world, we have dozens, if not hundreds, of little projects that we can deploy our capital to until gas prices get high enough to drill the big, sophisticated $6- and $7 million wells."

There is a place in E&P companies today for both types of production, he added: conventional and unconventional. "We are not going to be beholden to drill horizontal exclusively, and we're not going to be beholden to conventional drilling. That makes us a little different.

"I think that also gives us some patience in a downturn. The drilling economics in the last several months have been just horrible.

"No one should have been drilling wells in that situation. We didn't," he said.

'Rumor time'

South Texas is also an area Hart and most of the team have worked in for more than 30 years. "So we have all kinds of relationships and knowledge," Hart said.

The weekly staff meeting starts with "rumor time. We go around the table and talk about rumors." It's key to operating in the area, particularly as most of the land is held by huge ranches.

There's an intersection in South Texas where digital aggregation of data just doesn't do the job. "There's not enough public data," he said.

"For example, some of the most critical information—like pressure and choke size—never sees the light of public eyes, and that may be the most important information of all."

Like the horse, "You can lead [artificial intelligence] to water, but you still can't make it drink. AI is helpful, but humans are making the judgment.

"Only a human can understand what it means and put it into practice," Hart said.

Several neighbors are under financial stress, despite an improving natgas price, as they were early entrants to the dry-gas window while it took some time to make the rock in the area pay, he said.

"It was literally so long that the private-equity guys hit their plateau where they could no longer reinvest the proceeds of their fund, and that left a bunch of operators stranded on the island out there without access to more capital," Hart said.

Mezzanine capital appeared, "and that's expensive capital that makes the hill even harder

TOM FOX

Workers perform drilling operations in South Texas.

to climb. It's just eating those guys' lunch, and that's where the M&A market is coming in."

Meanwhile, many neighbors are operating with leases that have continuous-drilling requirements. Would the Texas RRC suspend that? Oklahoma has ordered that producers there could shut-in wells without losing their leases, for example.

Hart said that isn't likely to work in South Texas. "The land owners here are too big and too powerful. We're in the region of these gigantic ranches; in Oklahoma, it's very fragmented."

'The big bucks'

Rio Grande has capital and little encumbrance, "so we're looking for new opportunities in our space," Hart said.

Its private-equity sponsor is Intrepid Investment Management LLC. In addition to Hart, Rio Grande was co-founded in 2017 by GS Gas LLC, whose principals include former Florida Gov. Jeb Bush and son Jeb Bush Jr.

The company hasn't downsized in the downturn. "We just got here," Hart said. "But I have the best team I've had in my entire career. It boggles my mind how good these guys are."

About half were part of the team at South Texas-focused Laredo Energy, which was Hart's most recent venture; the other half, formerly with SilverBow Resources Inc.

While there is a "shocking amount" of professionals leaving oil and gas, Hart said, "the ones staying are the cream of the crop." And, he added, "They want to go to a better reward system."

That would be more participation in the upside to soften the blow of another downturn, he said. These are professionals who didn't join a PE-backed E&P early on, seeing it as job insecurity, and went "to big companies, and that's not safe either.

"So you might as well go for the big bucks, if there is as much risk of losing your job whatever the company is," Hart said. "I think that evolution has taken place."

Getting services

After deep price cuts in 2015 to 2016, can operators wring much more of service providers? ATX's Shepherd said, "There is some potential, but not to the degree we experienced back in 2014.

"Outcomes for service providers may range from eking out some level of positive margin to being marginally free-cash-flow positive. I've heard that some of the bigger operators in the Permian are asking for price reductions of 10% to 15%."

But the industry overall doesn't "have the opportunity to do today what we accomplished back in 2014," he said.

In the Powder, ATX has seen the challenge of getting top-shelf services to the play—in the shadow of activity in other basins. "It has been a struggle and, with the deteriorating outlook for the service industry today, it's a real concern," Shepherd said.

"After 2015, service providers had shrunk and were trying to regrow their staff. There was a period where you had inexperienced crews and that impacts your ability to get wells drilled and completed efficiently.

"It was then and will be a huge issue," he said.

If this cycle persists, some oilfield-service staff might not return to the industry this time. "When it's time to go back to work, we will pay a price for that," Shepherd said.

"This downturn is unlike any we've experienced in the past."

In Oklahoma, Red Wolf's Deaton said, "Costs are probably getting close to the bleeding out point for those [service] guys. We're always pushing for the best deal we can, but I think our basin has become pretty efficient, and we're down to the best guys.

"There aren't any 'B Team' guys left."

Samson's Mills began his career in 1982. "I was there in '86 and, obviously, this is worse than any time before this."

The oil and gas industry remains manpower-intensive. "A lot of guys aren't going to come back," he said.

"In this downturn, there aren't a lot of jobs for people to go to; I think companies are hoping they will still be able to hire them back."

TOM FOX

A pumpjack works outside the La Salle County Courthouse in Cotulla, Texas, in the Eagle Ford.

But the best of the best might not be won over. "Good people always have options," Mills said. "I don't care how bad things get."

'We will survive'

In addition to running Samson, Mills was called in as executive chairman of Midcontinent operator Roan Resources Inc., which was sold last year to Citizen Energy Operating LLC for $1 billion.

In January, Mills joined the board of Riviera Resources Inc. He said of U.S. oil and gas producers overall, "We will survive. We've been here before. Our industry is resilient. We are innovative. We will adapt."

For Samson, in particular, "At some point we will sell the company, but today is not the day. We're going to fight the good fight and get to the other side."

ATX's Shepherd said, "There will be opportunities. But the nature of these has changed.

"In the past, we've focused on resource capture by entering new basins, developing a detailed geologic model and modifying our geologic view as we did the early-stage delineation drilling."

Having the best map isn't in short supply now, he said. "After the industry's almost two decades of horizontal shale-focused drilling, the boundaries of the high-quality rock in the major resource basins have been established," he said.

"In [this phase], it's now about being an efficient operator and getting wells drilled and completed effectively and efficiently."

ATX is anxious to add a second project to its portfolio. "Ideally, we would like to do so in an area where we have had prior experience—until the next technological breakthrough opens the next door." □

Cattle graze in the Eagle Ford.

TOM FOX

PUTTING TOGETHER THE PIECES

Management consultant CEO Alan Carnrite was an active player in the flurry of mergers in the oil and gas industry 20 years past. He thinks the industry once again is ripe for a house cleaning.

INTERVIEW AND PHOTOGRAPHY BY STEVE TOON

Price shocks should come as no surprise to the oil and gas industry, according to Alan Carnrite, founder and CEO of The Carnrite Group, a Houston- and London-based boutique management consulting firm. They show up like clockwork every few years. The only thing shocking to Carnrite is how many companies are perpetually unprepared for the inevitable downturn in commodities when they do happen—like now.

The Carnrite Group is in the business of transforming companies. In the current environment, oil and gas clients faced with strategic, operational and financial challenges, as well as oversized cost structures and underperforming portfolios, look to Carnrite to help them navigate this unprecedented environment. Formed in the early 1990s during the recovery period following the legendary bust of the 1980s, Carnrite has seen its share of downturns—and has guided numerous companies through them.

"Change management" is one of the company's driving forces. "No matter what we do, if the changes don't get implemented and ingrained into the organization, then the company doesn't get the benefit of it. We spend a lot of time thinking through how we make it part of the DNA and culture of a company," he said.

Born and raised in Canada, Carnrite found his foothold in the energy industry with Pacific Petroleum, at the time the major Canadian affiliate of Phillips Petroleum. Pacific Petroleum was subsequently bought by Petro-Canada, where Carnrite spent two years as the upstream lead of a project team tasked with taking the company public, at that time Canada's largest initial public offering.

As fate would have it, he tapped a Houston firm named Sterling Consulting Group to help with the IPO, which later wooed him to move to Houston with his family. He later acquired Sterling Consulting Group in a leveraged buyout, and he ultimately formed The Carnrite Group in 1992.

"I love the freedom to explore opportunities with every company because the cultures are so different," he said of his choice to become a consultant. "People in the industries with which we work are great—they're second to none—so when I had the opportunity to be a consultant to a diverse group of companies, I jumped at it."

Carnrite Group played an active role in many of the corporate consolidations, as well as the predecessor companies that ultimately consolidated, that took place in the late 1990s, including Chevron/Texaco, Exxon/Mobil, and Conoco/Phillips. In that period, companies were being restructured to survive in an extended period of low oil prices. Today, he said, "A lot of the new management teams have never been through an extended period of low commodity prices. We haven't truly had one for 20 years, and now we're faced with the possibility that we've come full circle."

Investor *visited with Carnrite in his Houston office for his perspective on how companies can best manage the current downturn.*

Investor: Is this downturn fundamentally different than those that came before, or is it just another turn on the boom and bust cycle?

Carnrite: This is dramatically different. Over the years we've had events such as the dot-com bubble and the financial crisis that destroyed oil and gas demand temporarily, but those were relatively short cycles. The current crisis is the first time we've had massive demand destruction driven by the pandemic as well as a supply issue. To think that 20 or 25 million barrels a day of oil demand has fallen away in a short period of time—that's a major issue for our industry. Now the question is, is it a V-shaped recovery? Is it U-shaped recovery? What will it really look like?

Honestly, I don't think it really matters.

We're not going to have a pandemic every few years, but we're in a commodity business, which means we need to be able to function and make money in a low-price environment. We need to get used to the fact this is the business we're in.

It would be naïve to think we're not going to have some level of structural, long-term demand destruction coming out of this. More people will work from home. People will continue to shop online. People aren't going to

"We're not going to have a pandemic every few years, but we're in a commodity business, which means we need to be able to function and make money in a low-price environment," said Al Carnrite, founder and CEO of The Carnrite Group.

travel like they did previously. The beauty of services such as Zoom is everybody has figured out we don't need to be together in one place to have a meeting. The days of flying to London and Amsterdam for a meeting, I think, are gone, which will impact jet fuel demand in the long-term.

We're working with our clients to plan for lower for longer for at least a three- to five-year period. If higher oil prices come back before then, hallelujah, but the industry can't afford to plan for it to happen. We've never had two black swan events—the Saudi-Russia push for market share and COVID-19—at the same time.

Investor: So do you see this as a short-lived downturn or one that's more extended?

Carnrite: I think it's more extended. The reason I say that is even if you believe demand will rebound quickly, the first 15 million barrels coming back online are barrels currently shut-in, largely in Saudi Arabia and Russia. The market is really not balanced until we get back to somewhere close to 100 million barrels a day on demand, which is going to take at least two or three years. I think we're in a lower-for-longer environment. Certainly lower than $50 a barrel. That's the way I'd be running my company if I were the CEO of an oil company.

Investor: What's the health of the U.S. oil and gas industry at present?

Carnrite: It's severely stressed. Whether you're a producer or an oilfield services company, capital is fleeing our industry in this environment—as it should be, because the vast majority of companies can't make money at today's prices. Unfortunately, there are many more restructurings and much more consolidation that needs to occur.

Part of the problem is that the cost structure in our industry is still just too high. We have too many companies, too many management teams, too much of everything. If there's ever a point where we're going to see a major restructuring of our industry, it needs to be now.

The last time the industry went through major restructuring was in the late 1990s and early 2000s, when major consolidation took place. That's where costs really fell out of the system and portfolios improved substantially. Since then, we've had a lot of new entrants into the industry, which has resulted in some benefits but also driven up the cost structure. Personally, I think we need to go through a similar restructuring like we did back then, but this time, it's going to be more complicated because there are a lot more players today.

Investor: What differentiates companies that were prepared for the price shock and those that weren't?

Carnrite: We've been reminded again that leverage matters, particularly in a commodity business where companies are price-takers. Companies with too much leverage in this

price environment, especially if they aren't well hedged, are in a world of hurt. Absent a large increase in commodity prices, it will be really challenging to overcome a lot of debt. We seem to get reminded of that every few years.

The other thing is the cost structure is simply too high in many companies. High cost structures can manifest themselves in a number of ways—too many offices, the way they do their business in the field, an organization structure built for growth and even excessive compensation. The cost structure of the industry must continue to come down for many companies to have a chance at surviving a long-term price shock like we're in currently.

Investor: What do management teams in the fray need to understand and adapt to while navigating this low-price period?

Carnrite: Our advice to them is to assume we're going to be in a low-price environment forever. In other words, forget about your hedges—hedges are just an asset sitting on the balance sheet. How do you not only survive but generate reasonable returns in a $30, $35, or $40 environment? That's the type of approach we're recommending to all of our clients. Operate as if this is the new normal. If we see some uplift in price, we'll take it, but don't plan on it.

Investor: How long is forever?

Carnrite: At least five years.

Investor: What's the framework when you go into a company to evaluate what needs to change within the company?

Carnrite: The first thing we do is compare the company's cost structure to what we consider best-in-class. We know what best-in-class looks like thanks to years of experience throughout all segments of the industry. We typically attack costs first before looking at other opportunities, because cost is usually the quickest way to move the needle and improve cash flow.

Beyond cost, portfolio is the next critical step. Using E&P companies as an example, we work together to get a handle on economics at the well level. Well-level economics allow management to focus on what the portfolio looks like today versus where we need to take it tomorrow. We're big believers in running a business for today's economic reality.

We always build a value proposition and ask, "How are we going to capture the opportunity quickly and efficiently?" Everybody is busy. It's not as if we walk into a company and see people sitting around doing nothing. There are good, talented, hard-working people in these organizations. We just bring a level of objectivity and experience from across a variety of companies to assess costs, performance and the way work gets done.

Investor: You mentioned a lot of companies are headed toward bankruptcy. When should a company be proactive in seeking restructuring? Are there any signs that they should be aware of?

Carnrite: Most of them know the warning signs but sometimes tend to ignore them. There is enough data out there to know whether a company's costs are best-in-class or not. Companies can either ignore the data or acknowledge they have to do something differently.

> "We're working with our clients to plan for lower for longer for at least a three- to five-year period. If higher oil prices come back before then, hallelujah, but the industry can't afford to plan for it to happen."

Same thing for portfolios. There are enough data points to measure whether a portfolio is performing and generating returns. There are typically a lot of internal warning signs that go off that tend to get ignored—because tomorrow's going to be a better day than yesterday. That eternal optimism has always been the mentality of our industry.

Investor: Why haven't we seen more consolidation?

Carnrite: I think the Occidental/Anadarko acquisition may have sparked a wave of consolidation among companies of that size. Unfortunately, commodity prices collapsed shortly thereafter, and balance sheet strength suddenly became really important. We're not seeing consolidation because of the distressed balance sheets in our industry.

You are starting to see private-equity companies coming together. As an example, if a private-equity firm has three E&P portfolio companies in the Eagle Ford, combining the companies is a natural thing to consider. It's starting to happen. One reason we haven't seen even more of this type of consolidation is you have to pick a management team. You have to pick a winner. Doing so can be emotional and is never easy. But we're starting to see major consolidation in that space.

Investor: Do overlevered companies need to go through a bankruptcy or restructuring to eliminate debt before we'll see consolidation?

Carnrite: If you've got two weak balance sheets, it's hard to put them together and make the combined company better. Sometimes the asset fit is so good it can make sense, if you're able to capture certain cash flow improvements and synergies. But, again, if the balance sheets are too stressed, then you're not going to be able to make the math work in most cases. Some of the best companies to acquire are the ones that are coming out of Chapter 11.

There are a few important questions to ask when considering consolidation. Can the combined assets generate reasonable returns? Is there a natural owner of those assets? If there is, does that potential owner have a balance sheet that allows them to stretch to buy that company?

In past cycles we would have seen the midsized companies be the consolidators. However, many of those companies are limited by both their own balance sheets and those of the companies they may otherwise acquire.

"Part of the problem is the cost structure in our industry is still just too high. We have too many companies, too many management teams, too much of everything. If there's ever a point where we're going to see a major restructuring of our industry, it needs to be now."

The only companies that definitely have the balance sheets to consolidate are the integrated majors.

Investor: Do they have any desire?

Carnrite: No. In general, they're happy with their current portfolios, so I don't think you're going to see them acquire in a large way. Anadarko was a great fit for Chevron because of the international and Gulf of Mexico assets.

Is there another "Anadarko" that a major would consider? I personally don't think so. You could say, "Why not buy a company like Occidental?" It all comes back to the balance sheet. Companies don't want to take on the debt, even if you're a major.

When Mobil merged with Exxon, Mobil was convinced we were going to be in a low-price environment forever and scale was going to be critical. It wasn't forever, but we were in a low-price environment for a number of years, and scale was critical. A lot of CEOs believe scale is important now, and it is a matter of making sure you are the best and natural owner of those assets and have a combined balance sheet positioned for a low-price environment. I expect the consolidation we do see will be equity transactions.

Investor: You compare today with the late '90s when a lot of consolidation happened and suggested it needed to happen among the independents today. Is that even realistic?

Carnrite: I think it's happening now among the private companies. It just doesn't make the headlines. But among the public ones that are of any scale, we don't have that many left. You count them, and the list is pretty short. Will they consolidate with each other? It's not an obvious asset fit in the majority of potential transactions. I think most of the consolidation is going to take place amongst private companies over the next couple of years.

Most companies, even small private companies, have about $25 million or more of overhead. If you have 50 small companies with $25 million of overhead each, at some point you only need five of them. That's the consolidation that needs to take place.

Investor: Is now a good time to buy assets for those that can?

Carnrite: Yes. We've been waiting for the bid-ask spread to close for a long time. Now the ask has come down, and there's no bid. I would think if there's a bid for a particular set of assets, there's going to be a receptive audience where there was not before. I'd advise clients to look at assets if you have the liquidity to do it.

The best companies get better in environments like this one at the expense of weaker companies. Frankly, that's the way it should be. The best companies bring a better cost structure, better processes, better capability, better technology. The best companies should be using this environment to acquire, assuming it doesn't compromise the health of their balance sheet. I'd much rather buy in a $30 environment than a $100 environment.

Investor: Private equity tends to be an expert in knowing when they can get a good deal. It looks like now would be the time for private equity to jump in. Are you seeing that trend at all?

Carnrite: No. Private-equity money going forward is likely going to be focused on investments where they can earn a distribution on invested capital. It will be much longer-term capital instead of the "build and flip" model of past cycles. It will be interesting to see if the funds allow longer-term capital, which may require 10- or 15-year time horizons. There are a couple of private-equity funds that were built for that, but I don't see a lot of new capital coming into the space right now from private equity.

Investor: Why not if the opportunity is ripe?

Carnrite: We didn't do well in the last round; we have a lot of history to get over in the private-equity world. A lot of people that made past investment decisions are leaving the private-equity space because many of the investments did not pan out and the industry destroyed a lot of value.

Additionally, you have the ESG movement. Investors of all kinds are looking at that saying, "Okay, now what does that mean for us? Do we really want to be a bigger player in oil?" I think the verdict is still out, but it's going to be a while before you see private equity invest substantially again.

Investor: Do you think E&Ps need to diversify away from shale only, or can shale compete economically in the global market?

Carnrite: There's no doubt shale can compete, but shale can't compete on a global scale if you're in the shale business with a highly leveraged balance sheet. In shale, there is a velocity of capital required to continue to invest because of the steep decline rates. It's massive. If you don't manage your business well, all of a sudden, you're out over your skis and only need a short downturn in commodity price to really put yourself in a box.

But can shale compete? Absolutely. Shale competes.

Investor: Are you concerned about a talent exit from the industry?

Carnrite: It really scares me, actually. Every time I go on LinkedIn I see people leaving jobs after 15 or 20 years at the company or in the industry. We don't have a plethora of new people coming in behind them to fill the void.

We did this in the '80s, and we lost a whole generation of engineers. Nobody wanted to be in the industry. People went away, and they never came back. We're going through the same thing right now, and they're likely not going to come back to the industry.

There's a technical component to it for sure, but it's also the experience of having lived through a down cycle. The level of experience we're losing is frightening. In many cases, when the horse leaves the barn, it doesn't come back.

Investor: So what does this mean for the future?

Carnrite: We may see companies get a lot more aggressive bringing retirees out of retirement. A lot of these people left the industry at 50 and 55. I think they're going to wake up a year from now and say, "Now what am I going to do in retirement? It's not what it's cracked up to be." I think a lot of people recognize they want the flexibility but don't want to be home all the time.

I do think you're going to see a variable workforce that's going to put new stresses on how the company operates. You're used to having somebody at your beck and call as a full-time employee. You will no longer have that. It will add a layer of complexity to managing your workforce.

Investor: What are your thoughts on natural gas and the prospect forward for those companies?

Carnrite: We think we're oversupplied natural gas until about 2023 globally. We overbuilt LNG, in essence, so it's going to take until 2023 for demand to catch up with the supply we currently have in operation and under construction.

And yet we're still sanctioning new LNG projects, especially internationally. On the Gulf Coast, I think you'll see them get shelved for a period of time, but a lot of the international ones are still getting built, which says the industry will likely be oversupplied a little bit longer than we think. Gas is going to be in a low-price environment for a number of years.

For U.S. domestic gas, we've got to continue to curtail wells and drill less. We have so much natural gas. We have to continue to exercise the same discipline we're seeing right now on the oil front, because there's just so much of it [gas].

Investor: What best advice would you give to management teams today to prepare for the future?

Carnrite: Plan for the reality of today. This industry has a great history of optimism. Frankly, you wouldn't be in this industry if you didn't have some level of optimism. You're dealing with a commodity thousands of feet below the ground. You've got to find it and produce it, despite all the unknowns and variables. So, if you're not an optimist, you likely shouldn't be in the industry.

But we have to be disciplined and screen that same optimism through our plans. The reality is we could be in the world we're in today for a number of years, so how do you become the best company today?

> "The best companies get better in environments like this one at the expense of weaker companies. Frankly, that's the way it should be. The best companies bring a better cost structure, better processes, better capability, better technology. The best companies should be using this environment to acquire."

If you can be the best company in this environment, you're going to be gangbusters in a better environment. And being the best company in this environment, you're going to attract capital, making you the natural consolidator when opportunities present themselves. That's our advice to our clients.

Investor: What do you think the industry will look like on the other side of this?

Carnrite: Smaller. Fewer companies. Much more capital discipline because the capital won't be there, which I think is a good thing in the long run. A lot more focused on returns. I don't think anybody will be focused on just volume. We're not going back to that.

If I'm right, it will feel like a totally restructured—and different—industry. The restructuring will include the companies that are going through bankruptcy today. That's a lot of debt leaving the industry. My hope for them and whoever owns them post-bankruptcy is they continue to drive that discipline. The fact they have minimal, if any, debt doesn't mean they should have debt and go back to out-spending cash flow. I hope they don't layer it back on by doing the same stupid things we did before.

Recognize that we're in a commodity environment. 2008, 2014, 2020. Three times in the last 18 years; every six years we had some kind of shock. Be prepared.

Investor: What's the mission of your Carnrite Cares initiative?

Carnrite: Thank you for asking. Carnrite Cares is near and dear to our hearts. We support various programs and charities—generally in the communities in which we work. Our efforts are currently focused mainly in Houston because that's where many of us live. The organizations we support are the ones that are important to our staff. We've always given back to the community as individuals, so naturally, we want to give back to the community as an organization as well.

Once we start supporting a specific organization, we generally stay with them for years, but we also try to layer on new charitable causes every year. It's about supporting our employees and the causes that are important to them and their families. Even in our worst year, our first dollar of profit will always go to support our charitable giving program. That is how important it is to us. □

PLANS, SCHEMES AND BROKEN DREAMS

After years of hoping for oil prices to return to better days, the magical thinking by optimistic E&Ps is out, and private-equity firms are poised to pounce.

ARTICLE BY
DARREN BARBEE

Billy Quinn with Pearl Energy Investments is skeptical of strong industry predictions about COVID-19. "We're all learning this as we go along," he said.

Any meeting involving money is a significant business, perhaps more so for a private-equity firm and its backers. In April, as the COVID-19 pandemic continued to weaken oil demand and shutter the United States, Billy J. Quinn, managing director at Pearl Energy Investment, met with the private-equity firm's limited partners.

Quinn began his assessment of his portfolio companies and the world of oil and gas by deliberately bypassing the pandemic. Quinn's aim was for Pearl's investors to see what he'd been seeing, starting from where the firm had left off in 2019. It wasn't, Quinn said, "a banner year for the oil and gas business."

Untangling the COVID-19 mess will take time, Quinn said. First, he wanted to drive home a point. "I wanted to have the right frame of reference," he said. "And 2019 stunk. It didn't feel like this was a great business. And we averaged $57 oil. But that allowed most of our companies to be prepared for what happened in March."

If there's a unifying point of view in the private-equity world, it's that pragmatism gets results, and hope is the equivalent of hemlock. For too long, as private-equity players see it, a group of fragile E&Ps have been struggling to survive as they waited—or hoped—for oil prices to rise.

The pandemic has effectively snuffed out magical thinking.

Jordan Marye, who leads Denham Capital's oil and gas segment, said that asset owners will ultimately have to face an emotional but practical question: "What do we own? How broken is it?"

"Because everything is some version of broken below $40 oil," Marye said. "The key decision then becomes what do you dispose of—via bankruptcy or restructuring—and what things do you hang onto?"

Private-equity players from Pearl, Quantum Energy Partners, Denham Capital, EnCap Investments LP and Warburg Pincus largely agree along these lines: The industry was wobbly before the pandemic. With some hard and difficult work, it can stand again.

The firms also recognize they're part of a pool of potential buyers—among the few—with billions of dollars at their disposal.

Though M&A is on the menu, the wait times could be murder. Some private-equity firms are already kicking the tires of potential deals, but they largely see the industry's recovery from the pandemic crash in terms of months or even years. They'll be opportunistic, but only for the right assets—proved developed producing (PDP), cash flow and quality. Most see no upside in undeveloped acreage, except as an afterthought.

The pandemic didn't so much interrupt the plans of those companies as further erode already shaky ground. As the bottom falls out

> "This asset class, oil and gas for the past 15-plus years, has been money chasing deals. For the first time in my career, it's deals chasing money."
>
> —Jordan Marye, Denham Capital

from underneath E&Ps, private-equity funds will be ready to take advantage of upstream and midstream assets with little foreseeable competition.

While private-equity has its own kinks to work out, it's also planning to move aggressively but responsibly as distressed E&Ps begin to capsize.

David S. Habachy, a managing director and member of the Warburg Pincus energy team, said he sees this as a time for potential opportunities in the market.

"We're actually looking to do business and invest in attractive opportunities that arise in this environment," he said.

The companies have proven resilient in the face of the COVID-19 outbreak, in part because they're well-hedged and carry modest leverage, he said.

Habachy said he expects some private-equity firms to wind down and consolidate companies that were challenged prior to the pandemic and have "no visible runway or meaningful option value."

Like other oil and gas companies, private portfolio companies have not been spared from the pain of cratering oil and gas demand declines that set the industry on edge in March.

"Our near-term focus has been on liquidity and survival, and I think that'd be true among the public and private universe," said Brad A. Thielemann, a partner at EnCap Investments LP. "We had 18 rigs running in our portfolio in January, and we're down to zero now."

Roughly 80% to 85% of EnCap's rig activity was tied to oil-weighted projects, and more than half of its rigs were running in the Permian Basin.

"The first thing we did from a defensive standpoint was to halt activity where we didn't think it made economic sense," he said. "You're starting to clearly see a lot of shut-ins over the last month with prices moving down significantly, particularly on a regional basis."

Across the industry, Thielemann said companies have been forced to shrink from a cost cutting and an activity standpoint. And that's still an ongoing process.

And industry leverage has clearly been magnified at current pricing.

"You're seeing some restructurings that were maybe headed that way anyway being accelerated, and there is quite a bit more to come," he said. "In the near term, there's no quick way out."

Pearl, for instance, said its portfolio is in solid shape. The bulk of its investments are in high quality assets with great teams, low to no leverage and lots of hedges, Quinn said.

Still, Pearl had some immediate cleaning up to do within its own portfolio.

"We're not unscathed," he said. "Nobody is. We've had a few headaches to deal with. But we've been fortunate that they've been smaller dollar issues. We're doing our best to fix them and that they can survive another 24 months."

Still, in a worse-case scenario, some of those companies may not survive and get merged with other Pearl portfolio companies.

"That's just a function of the market we are in today."

Given the curent deal market, Jordan Mayre with Denham Capital said, "We came into this year underinvested, which ended up being fortunate."

Wake-up time

Over the past several years, Quantum Energy Partners has taken a far more cautious approach to the energy market than its peers.

It's why the company will be looking more closely at opportunities now that sellers may have no other choice than to part with assets to survive.

Quantum's approach was born out of a realistic view of the world's supply and demand dynamics, said Quantum president Dheeraj "D" Verma.

For Verma, the current state of distress started in 2014, when OPEC first decided to flood the market with oil, and it didn't really end. The industry's bumpy ride since has been partly due to "flashes of optimism" that don't square with reality.

"If you step back and think about it, people were constantly projecting the V-shape recovery. I'm talking mostly about the capital market. These debt and equity investors … have bailed out the industry so many times."

Quantum continued to be selective, cautious and careful.

Now, with the pandemic acting as a kind of cataclysm for oil and gas, E&P company investors hold stock or debt worth a fraction of what it was issued at.

"A lot of companies issued and refinanced a lot of debt in the capital markets. Again, most of which is trading at fractions of what it was issued at," he said. "And then a lot of companies are buying back their shares. So you can see just from 2014, the industry continues to suffer from this optimism despite the facts."

Quantum hasn't been willing to make transactions on what it considered ill-priced assets.

"In the last 18 months, we haven't bought much of anything," he said. "We have not been able to transact on anything because we would bid up some asset or business, and we would have a cautious commodity outlook on it."

Yet there were always other buyers willing to bid more while projecting crude oil to be $60, $70 or $80 per barrel.

"I think people just want to believe in the upside," he said.

Prioritizing predictability amid uncertainty, David S. Habachy with Warburg Pincus said the firm "will be more focused on what we refer to as brownfield, so more mature assets that still have upside."

The pandemic may have finally cured that.

"The demand destruction is so deep. It's so dramatic that it's a wake-up call. You begin to see things shaken up and wake up to the fact that as a business we all need to be more deliberate and cautious on how we deploy capital," he said.

Production is already being shut in, and companies are rationalizing staff; many appear to be struggling.

"That's what the industry has needed since 2012. And we've not had the kind of endogenous [catalyst] to force that outcome," he said.

Curtis Flood, a managing director at Evercore, said companies are trying to manage high debt levels and reduced cash flows by employing either out-of-court liability management transactions to amend bank covenants, defer debt maturities and opportunistically capture some debt discount. Or they're turning to in-court restructurings to equitize their balance sheets.

Selling off assets piecemeal into a depressed A&D market to pay back creditors at cents on the dollar is seen as only a last resort.

Evercore has been involved in the surge of oil and gas restructurings since the pandemic stifled oil demand and OPEC+ initiated a price war. The firm is currently advising on about 20 energy restructurings totaling more than $60 billion in debt. A combination of liabilities and steep declines in oil and gas demand have already resulted in Whiting Petroleum Co., Diamond Offshore Drilling Inc., and Ultra Petroleum Corp. seeking bankruptcy protection for a collective $9.7 billion in debt.

"We're seeing a restructuring wave now that will likely continue for at least the next 12 to 24 months," Flood said. "And on the back end of that, those companies that have gone through Chapter 11 and equitized their balance sheets will be controlled by a new group of equity owners who are going to be interested in consolidation—getting to scale, driving efficiencies, realizing synergies and de-risking the business model in order to survive in a very volatile market."

Prelude to M&A

The market and the environment for opportunities is of natural appeal to Pearl. The company is well stocked with dry powder, with about 70% of its $1.2 billion fund uncommitted.

Yet the mood is still muted.

"Even though we're opportunistic, and we're trying to look at the bright side," he said, "it's still really hard to feel good at times. This is one of those odd times that, because we're all navigating uncharted waters, it's really hard to feel aggressive."

> "The demand destruction is so deep. You begin to see things shaken up and wake up to the fact that as a business we all need to be more deliberate and cautious on how we deploy capital."
>
> —Dheeraj "D" Verma, Quantum Energy Partners

M&A may be on private-equity leaders' minds, but it's not necessarily what they expect to race toward.

While some deals will present themselves, the M&A market has nearly gone dark. In the next 18 to 24 months, many private-equity sponsors expect distress, bankruptcy and deals, as well as companies that are well positioned to survive.

Within a year, a large portion of the oil and gas market "won't exist in the form that it existed prior to … the COVID-19 crisis," Quinn said.

Thielemann said that as EnCap surveys the situation, they see an overall lack of capital that presents challenges and, eventually, opportunities.

"We can't tell you exactly when, but our view is that well-capitalized survivors or private companies that have access to capital really should be in a great position to thrive on the other side" of the pandemic.

The timing for deals, however, is difficult to predict.

"I don't think there are any quick, sustainable fixes to the supply and demand issues in the near term," he said. "So we're probably in a slower, longer recovery. But hopefully with a continued focus on profitability over growth, we will come out the other side with an energy industry, in particular in the E&P space, that's healthier and has an ability to generate returns."

Quinn divides E&Ps into two basic camps: the "haves" and "have-nots."

The have-not producers share some common traits: poor hedging, some or abundant debt and a relentless struggle to stay afloat over the next several months.

"Many of them won't survive," Quinn said. "They'll get restructured, recapitalized, bought, merged. A whole number of things can happen to these companies, but they won't survive in their current form."

In the opposite camp are a "handful" of public and private companies that have great hedges in place this year and in 2021.These companies have no or low debt and can watch the market opportunistically.

"Hopefully with a continued focus on profitability over growth, we will come out the other side with an energy industry, in particular in the E&P space, that's healthier and has an ability to generate returns."

—Billy Quinn,
Pearl Energy Investments

"And look to try to grow through acquisitions—pick off assets at distressed price levels. They can clearly be the winners of what's gone on in the past two to three months," he said.

Eventually, those businesses will get cleaned up over the next couple of years, Quinn said.

"You'll have winners, and you'll have losers from this cleanup," he said. "But it's going to take a few years. I think it's going to take some time for demand to come back to where it was."

Deals chasing money

In Denham Capital's view, the market has turned on its head.

The firm exited 2019 with the least amount of money it had invested in the ground during the past 10 years. The company had also sold a "fair amount" of its existing portfolio, Marye said.

"We had an opportunity to sell more things than buy, and we had a really hard time finding great values in the past two to three years," he said. "So, we came into this year underinvested, which ended up being fortunate."

Since the commodity price crash, Marye said he's seen an abrupt reversal in buyer-seller dynamics.

"This asset class, oil and gas for the past 15-plus years, has been money chasing deals," he said. "For the first time in my career, it's deals chasing money. We just have to be patient and let the physics of the market work themselves out."

The task now is for Denham's teams to set the table for what they want to own, how they want to own it and to stay patient. However, the waiting period may be months.

Denham, which raised $900 million in commitments in 2017, plans to invest its remaining capital evenly between E&P and midstream.

In the meantime, Denham has focused on finding opportunities to invest its callable capital.

"What we've been on for the past eight weeks is essentially a shopping spree," albeit one that largely involves window shopping so far.

Marye says asset owners are not at the point of action today. But looking ahead, it's clear there will be "a fairly significant wave of asset restructuring in the third and fourth quarter of this year and all of 2021."

The future timing for those deals is a matter of debate for many private-equity sponsors, including Denham. Pandemic or not, Denham is still eyeing oil and gas assets from the simple business point of view: Does it make money when revenue is accurately predicted and after all expenses are taken into account?

Other private-equity firms similarly stressed a willingness to buy—but only for more mature, brownfield development that's scalable and has cash flowing assets.

Verma said the natural inclination in times of distress leads to "trying to buy low and sell high. That's kind of the age-old concept that a lot of private investors are seeking."

He takes a broader view of the topic. While the price matters, he's most interested in buying tier-one acreage. Companies, he said, are still trying to sell some of their tier-two and tier-three assets.

"We're not interested in a cheap price for a tier-three asset or a tier-two asset," he said. "We'd rather pay a fair price, but we need to get a tier-one asset that we can do something with."

Quantum is careful not to predicate its purchasing strategy on prices, and Verma noted that oil could be low-priced for the next three years.

"We are very eager to buy today, and frankly we have a lot of capital available to us while many other firms may have less of that available," he said.

While Quantum hasn't engaged in any large deals over the past couple of months, the firm has engaged in four or five partnerships with public companies to jointly develop their assets. Quantum was preparing two new deals in May, including another partnership with a public company and a $60 million acquisition of core, tier-one assets from a company that intends to use the proceeds for debt reduction.

"I think for us the key thing is that we don't want to change our stripes. A lot of people get tempted to change their stripes when there's volatility," Verma said.

Verma, for instance, said Quantum stayed back from special purpose acquisition corporations and other "flavor of the month" vehicles.

"The key word is discipline," he said. "That's what we find: fight that temptation and focus on our business."

While oil prices have recovered somewhat, they're still too low to resolve the problems

EnCap Investments' "near-term focus has been on liquidity and survival," said Brad A. Thielemann. "We had 18 rigs running in our portfolio in January, and we're down to zero now."

Many companies are tempted to "change their stripes" amid volatility, said Quantum Energy Partners' Dheeraj Verma, but Quantum remains committed to its cautious, selective strategy.

After the ongoing restructuring wave, "those companies that have gone through Chapter 11 … will be controlled by a new group of equity owners that are going to be interested in consolidation," said Curtis Flood with Evercore.

many highly leveraged oil and gas companies face—particularly those companies that were already strained in a $45 or $50 WTI world.

Habachy said the "bar will be high" for Warburg Pincus when it comes to pursuing opportunities.

"My sense is you're really going to see things play out in the back half of this year or even in 2021, when prices stabilize and the dust settles," he said.

Warburg Pincus considers entry price and risk profiles associated with an asset and whether they can eventually achieve a growing and scalable business that generates cash flow. Beyond that, the type of commodity and asset is largely immaterial, with a good balance of oil and gas assets already in the portfolio.

"We really prioritize efforts that are predictable and that could be underwritten with a high degree of certainty and confidence," he said.

What the firm doesn't intend to pursue is raw acreage. The right deal will have a combination of optionality with wellbores and potential reduced operating costs. Potential targets will have to be established cash flow generators.

"We will be more focused on what we refer to as brownfield, so more mature assets that still have upside and will come with a lot of predictability," he said.

The prudent

Pearl is already engaged in looking at some deals, and Quinn said the firm is bidding on things cautiously because of the extreme volatility.

Pricing assets appears to be equally difficult for buyers and sellers. Sellers want what they consider fair value. Buyers are trying to quantify what an asset, potentially with shut-in wells, could produce in revenue, all under the light of a badly disturbed commodity market.

To some extent, the uncertainty of pandemics and fiscal devastation have made sellers and buyers gunshy.

"If you're bidding on an asset that was PDP heavy, you never modeled in or even really thought there was a risk that your PDP volumes for the next three months could go to zero because you've got to shut in production," Quinn said. "There are a lot of unique things you have to think about in this market, even when buying something as simple as long-lived production."

Thielemann said higher and more sustained price levels would start to move the market, but for now EnCap, like all interested parties, said looking at the front month price of oil isn't useful.

"There's not necessarily a magic number where everything is going to turn back on. I think you're going to want to see sustained oil prices in the $40 to $50 range and a forward curve that you want to hedge into before we move into a development mode," he said. "You definitely would want to see a less volatile price environment."

EnCap, with about $6 billion in its more recent funds available to be put to work, is also looking at deals and brushing aside the urge to move fast rather than prudently.

"We spend a lot of time talking about being patient and disciplined and opportunist," he said.

However, Thielemann said it's difficult to know when and how oil demand will recover.

"We focus on high quality assets, and we want to capitalize the opportunity properly, which means a low amount of debt and certainly less than was traditionally acceptable," he said. "There also has to be a low cost structure and a management team that can execute and be nimble."

In some ways, it's the same type of combinations that EnCap always looks for, though ensuring the pieces fit together appears to be more important. Also, the firm isn't searching for opportunities that only pay off in dramatically improved price environments.

"You want to make sure you have liquidity and an asset that will endure through the cycle yet still have option value on the other side," he said.

Expanding beyond traditional asset opportunities, EnCap has also been looking at opportunities to help troubled companies with quality assets repair their balance sheets.

Quantum, likewise, has been in talks with a creditor group to help bring in new money to help restructure the business.

However, Verma said most distressed companies appear to have tier-two or tier-three assets that aren't of interest to Quantum.

"There are a few distressed companies that have really good assets," he said. "Those are the ones that we're spending time on."

Pearl's investments are split between conventional and unconventional assets.

Quinn said Pearl will look for PDP heavy acquisitions, and creative corporate deals, though those can sometimes become complicated.

"Today, we're looking at assets or companies going into bankruptcy. And for us, E&P and midstream are our focus areas," he said.

Quinn said purchases will be skewed toward returns on cash that are based on production.

"The upside return on the asset has to look good enough to justify as we navigate these murky waters," he said.

Unconventional shale production brings its own set of challenges because further outbreaks of COVID-19 are possible and may alter broader demand needs, he added.

Predicting how to operate short-lived assets and how oil markets move month to month over the next 12 to 24 months seems thornier.

Given the steep decline rates of some shale wells, "How do you underwrite it? Because the economic decision you're making is completely contingent on what happens in the next 12 to 24 months, which is a very hard way to build a business," Quinn said, adding "Every time I hear somebody who has a strong opinion about what's going to happen based on COVID-19, I kind of laugh because nobody knows. We're all learning this as we go along." □


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REBUILDING PEDEVCO

In a time of industry stress and uncertain recovery, it may be hard to find a few good stories, but restructuring to emerge as a roll-up vehicle is one way forward.

ARTICLE BY
LESLIE HAINES

Rest assured that the smart, quiet money is on the hunt now during a time of duress and recovery. From the muddy scrum of restructurings and recapitalizations underway, some golden opportunities will surface, but it takes capital and contacts to score the right deal.

A few small-cap E&P companies, even though they may be microcap stocks these days, are fortunate to have no debt and to have cash on the balance sheet. More important, they may have some big-ticket investors backstopping them as well. Since undergoing a restructuring effort and getting a capital infusion a few years ago, Houston independent Pedevco Corp. is one.

Today it defines itself as an acquisition vehicle with the long-term goal of consolidating assets in its favored target, the San Andres play on the Northwest Shelf of the Permian Basin. There, just west of the Texas-New Mexico line, it holds 38,000 net acres in New Mexico. Relationships between and among its principals and some of its present target companies show how the oil industry continually reinvents itself by turning over assets from one management team to another.

"There are a lot of good companies out there that are just financed incorrectly," said Pedevco president J. Douglas Schick, who has an undergraduate degree and MBA in finance.

Schick spent the first half of his career in finance and planning at Royal Dutch Shell Plc, ConocoPhillips Co., The Houston Exploration Co. and Mariner Energy Inc. "For people with

Pedevco's main asset is the Chaveroo Field in New Mexico, with some 150 locations yet to drill.

a five- to 10-year horizon, I can tell you oil prices have to come up," he said. "You can't sustain the industry at these low prices. So this could be a monumental buyers' market."

That thinking led the Pedevco board and management team to be "keenly interested in and actively pursuing growth opportunities during these troubled times," Pedevco CEO Dr. Simon Kukes told Investor.

Through his family office, SK Energy LLC, Kukes more or less rescued Pedevco in June 2018 right before it was delisted from the NYSE American Exchange, acquiring a majority shareholding position and buying its debt for 10 cents on the dollar, thereby obtaining a majority equity and debt stake in the company. To date, SK Energy has infused over $82 million of cash into the company; its assets in Colorado and on the Northwest Shelf of the Permian constitute a platform that the company aims to grow.

"We believe, now more than ever, that Pedevco can become a serious player in the U.S. oil and gas industry through managing our costs and capitalizing on M&A opportunities—both lessons I have learned from over 40 years in the industry," he said. The plan is to roll up companies and assets and merge them into Pedevco.

In addition to seeking growth through transactions, before the disruption caused by the coronavirus and oil price war, the company was producing about 1,000 bbl/d from its San Andres assets straddling Chaves and Roosevelt counties, New Mexico, and its Denver-Julesburg (D-J) Basin assets in Weld County, Colorado. The company also had several horizontal San Andres wells that were shut-in waiting on completion of a saltwater disposal well. In April the company temporarily shut in most of its production to reduce operating costs and weather the storm.

"We are uniquely positioned," said Schick. "We're public but have zero debt, so therefore no risk of default. And we have one shareholder who owns about 75% of the company. That certainly has made it easier to work through this recent downturn," he said. "Our original plan was to have a $15-million budget this year ... now it's just $5 million."

Schick and Kukes view Pedevco as an aggregator, especially in the San Andres play where approximately 70% of the company's production is located. For the management team, the Colorado properties that came with Pedevco weren't the prize; they have more experience in the Permian and less in the D-J, where the team is happy to partner with other companies as a nonop.

It may be early in the cycle, but Pedevco Corp. hopes to consolidate San Andres players, said president J. Douglas Schick.

Background connections

The pair had worked together before—when Schick was looking for private capital as the CEO of American Resources Inc., which he still helms.

Formerly head of planning for Mariner Energy Inc. under CEO Scott Josey, Schick started American Resources Inc. in 2012 after Mariner merged with Apache Corp., with the goal of buying distressed oil and gas assets. In 2013 he bought the Fort Stockton Field, cleaned it up, did a water flood study and sold it in 2015 for a generous profit.

PEDEVCO CORP.

RUSSIA'S REBALANCING ROLE

At press time, world oil demand was creeping up as most economies began to open up for business again, and producer shut-ins were helping to drive the price of oil up from the historic lows seen in April and May. There was much speculation among commentators about how long those trends would continue and to what degree OPEC+, which includes Russia, would adhere to its promised production cutbacks.

"Based on my current discussions with former colleagues and current executives at major Russian oil companies, I see a strong commitment by Russian majors to comply with the announced 20% production cuts," Dr. Simon Kukes said. "I also believe smaller U.S. producers will continue to reduce production significantly more than the market has seen to date, if oil continues to trade at current levels [as of mid-May, around $34/bbl]."

"I am convinced … production will be difficult to restore to prior levels. The real question in my mind is when consumption will return to prior levels as that is difficult to predict and is a major variable," he said.

Rystad Energy said in May that the 16 MMbbl/d oversupply seen in April could be reversed in June, with OPEC+, the U.S. and Canada effectively reducing their respective oil output. It cautioned, however, that a drawdown of the nearly 1 Bbbl of oil in storage also needs to be considered in any supply-demand analysis. The EIA has forecast that U.S. production would fall to a two-year low this summer.

Dr. Simon Kukes, Pedevco Corp. CEO, said, "We believe, now more than ever, that Pedevco can become a serious player in the U.S. oil and gas industry through managing our costs and capitalizing on M&A opportunities."

Looking around for the next idea, he found the San Andres to be intriguing.

His partner in American Resources is Ivar Siem, who has a distinguished career of rolling up and restructuring energy and oilfield service companies in the U.S. and whose family owns a large stake in Subsea 7 and other Norwegian holdings. Together, Schick and Siem evaluated some 70 deals, and the Chaveroo Field rose to the top. They went looking for big private investors, private-equity funding or family offices to stake a deal (estimating need for $50 million for the buy and subsequent drilling), and added SK Energy to their list.

Kukes, a longtime friend of Siem, and Schick met in July 2017 when Schick approached Kukes for funding for a bid to purchase assets in the Permian from ConocoPhillips. American Resources made a bid but did not win it.

Later, Kukes came back to Schick with a small Colorado operator: Pedevco. Initially, Schick turned down that deal because it was in the Wattenberg extension and not the core, but Kukes returned a few months later, asking for them to reconsider it.

The decision was made to buy Pedevco. Even though it was in financial distress, it was a public vehicle that could be used as a stepping stone to other, potentially bigger things—like buying and expanding the San Andres assets. So, Kukes bought the debt and all of the preferred stock, which then converted into a controlling interest in the company. Bingo: done deal in June 2018.

That August, Pedevco acquired the Chaveroo and Milnesand fields in New Mexico. Development started in December 2018. (Eight wells have since been drilled.) Pedevco promptly began to pursue additional Permian asset acquisitions that Schick and his team had previously evaluated, successfully acquiring the Chaveroo Northeast Field in February 2019. (There, one well has since been drilled.) Now the San Andres assets outrank the Colorado assets in the company's portfolio.

"I was intrigued with Pedevco as a public vehicle because it was a fully compliant and reporting, NYSE-American Exchange-listed company that had high-quality D-J Basin assets that were out of favor at the time because of their geographic location," Kukes explained.

"I like the San Andres because it has conventional long-lived production with a low cost of entry. When we were previously looking at acquisitions in the Permian and other basins in 2017 and 2018, the costs were sky-high. But the San Andres had much lower entry costs on a per-acre basis, and much more of the play was held by production; therefore you can control your pace of development."

Kukes said he decided to get more involved with Schick and his team because they had built a good working relationship over the past few years. "They brought good deals; they did good evaluation work; and they were an honest, hardworking and straightforward group," Kukes said, "and Doug possesses outstanding knowledge and skill in M&A."

Schick gained some of that skill by working under Josey's leadership at Mariner Energy as well as earlier in his career when he helped defend The Houston Exploration Co. against JANA Partners.

Kukes, a Russian native, is no stranger to deal-making. He is a chemical engineer and former post-doctoral fellow at Rice University who holds more than 130 patents. He is very well known in international oil circles. In 1999, he was voted one of the top 10 Central European executives in a poll conducted for The Wall Street Journal Europe edition, and in 2003 he was named by the Financial Times and PriceWaterhouseCoopers as one of the 64 most respected business leaders in the world.

He started his career at Phillips Petroleum in 1978. "Since that time I have successfully weathered four major downturns that impacted both the U.S. and the Russian oil industries alike. These experiences have taught me this: the strongest companies will survive, and in order to survive—and ideally, thrive—in such challenging times, companies must cut costs and capitalize on M&A opportunities."

After many years in the U.S., Kukes returned to Russia when it started to open up in the late

1980s and beckoned people with technical expertise from the West to help speed up the modernization of the Russian oil industry. He served as CEO of Tyumen Oil Co., known as TNK, which had partnered with BP from 1998 to 2003, and he also served as the chairman of Yukos. He later became CEO of Samara-Nafta, a Russian company that partnered with Hess Corp. from 2005 through April 2013.

After success at Samara-Nafta and its partner Hess, Kukes returned to Houston in 2013. Today he is controlling shareholder, CEO and board member of Pedevco, and he is the largest individual shareholder of Ring Energy Inc.—Pedevco's only other publicly traded peer and close neighbor in the Northwest Shelf of the Permian Basin.

Coping

As it searches for deals, Pedevco has taken familiar steps to get through this challenging time. It reduced general and administrative expenses about 22% before enacting salary cuts of 20% for each of its 14 officers and employees, and most contractors were let go, Schick said. Lease operating expenses are down by over a third. Some of that comes from electrical costs saved by shutting in wells in the company's four oil fields. He also deferred completion of a Permian Basin disposal well that was held over from 2019, until the environment improves.

Like Kukes, Schick has been through downturns before. He worked at Shell Oil Co. and ConocoPhillips early in his career and then, after receiving an MBA from Tulane, worked for The Houston Exploration Co. until it was acquired by Forest Oil, at which point he joined Mariner Energy, which had just gone public through a reverse merger with an entity spun off from Forest Oil. Later, after a six-year run of explosive growth, Mariner merged with Apache Corp.

A common thread in this story is oilman Craig Clark, who was CEO at Forest Oil at the time and later of privately funded Wishbone Energy LLC, which once owned Ring Energy's current San Andres assets on the Northwest Shelf. These are the assets Pedevco now hopes to acquire.

Ring paid $300 million for Wishbone and is burdened with debt as it attempts to cope with the current downturn. It stopped drilling in the San Andres in mid-March, but until that point, its average IP on six new wells completed there in the first quarter was about 558 bbl/d, according to a report from Roth Capital's energy analyst, John White.

Now, Kukes and American Resources have Ring in their sights. In a February letter addressed to Ring's board of directors, they contended Ring is undervalued. Kukes and Schick pointed out what they see as deficiencies in Ring's business strategy, management and corporate governance. Ring's common stock has fallen from the mid-$15 per share in January 2018 to a low of nearly $0.53 more recently, a fall nearly double that of the XOP (small-cap E&P index).

"To survive—and thrive—in these challenging times, companies need to manage costs and pursue M&A opportunities."

—Dr. Simon Kukes, Pedevco Corp.

Much of that decline can be blamed on the oil industry's shocking market conditions, but the letter from American Resources and SK Energy also claims part of the erosion in value "falls squarely on the board's and management's shoulders. It must be obvious … that certain corrective actions should have been taken some time ago!" the letter said.

Ring has high debt and a working capital deficit. Schick and Kukes have called for at least two new directors to be placed on the board.

But clearly, it is Ring's assets on the Northwest Shelf, adjacent to Pedevco's acreage at Chaveroo, that interest them. Ring also has assets on the Central Basin Platform, mostly in Andrews and northern Gaines counties, and has recently divested other assets it owned in the Delaware Basin.

While Pedevco has neither publicly announced nor would it comment in this article regarding any intentions, discussions or potential transactions with Ring, Kukes said, "As previously stated, Pedevco is certainly interested in evaluating potential transactions with Ring Energy and other San Andres-focused parties—public and private—who are interested in working with us to consolidate the San Andres play."

Pedevco is currently evaluating opportunities in the Permian involving distressed companies that own assets that could be synergistic with those of its current footprint. The field of ideas is wide open, as many good companies in this current environment have good assets but are struggling under what Kukes called "crushing debt" and declining production.

In May, Ring filed with the SEC to replace its shelf registration for equity and debt securities and warrants that had recently expired, but the company also said it has no immediate plans to issue any such securities. The shelf enables offerings of up to $313 million.

Schick said he thinks all the E&Ps with good assets in the horizontal San Andres play should merge into one entity. Were that to happen, the new company would end up with production of roughly 50,000 bbl/d. He admits it is probably early in the cycle, but he aims to have Pedevco roll up some of these companies and not necessarily throw out the management teams.

He wants to create a company with scale: "Since Pedevco is public, it needs a bigger transaction base than what we've done in the past. This is not a buy and flip situation. At American Resources, we'd buy something for $2 million and sell it later for $4 million.

"This is not an enjoyable time, but I do hope it presents opportunities," he said. "I wish the market was better—this was a much better story at $50 oil." □

THE DIGITAL FRONTIER

Capital investment in digital technologies is helping evolve the energy industry.

ARTICLE BY
MARY HOLCOMB

Private-equity-backed tech startups are fostering change in the oil and gas space with innovative, disruptive technology. Many investors have turned to transformative technologies to enable digitalization and improve returns. Given the current price environment, harnessing digital technologies has proven to be a critical part of survival.

As many oil and gas companies look for solutions to help cut costs, Investor profiled three forward-thinking digital technology startups that are moving through the energy industry and helping streamline operations, boost efficiencies and maximize production.

Data Gumbo

Data Gumbo, a Houston-based industrial blockchain company, has developed a trusted transactional network, GumboNet, to automate smart contracts for the energy industry.

Established in 2015, Data Gumbo was originally an Internet of Things platform used for aggregating and cleaning data for oil and gas companies that struggled to get a clean view of data across multiple sources.

However, after identifying a multimillion-dollar cost-saving opportunity to eliminate a sizable inefficiency between an oil supermajor and one of its suppliers, CEO An-

DATA GUMBO

With blockchain, companies can forge win:win situations for buyers and sellers.

drew Bruce developed GumboNet, an industrial blockchain network that provides a single transactional record.

The underlying issue in the transactional ecosystem, he said, is that data are interpreted differently between operators, E&P companies and service providers. This discourse complicates data coordination and ramps up expenses.

Data Gumbo acts as a neutral infrastructure that uses field data to confirm the execution of pre-agreed contracts to prevent disputes and automate contract execution. This enables parties on both sides of the transaction to significantly reduce their operating expenses.

"Blockchain provides a direct measure of the value you want to gain from a contract," Bruce said.

By using field data to verify contract terms, the network eliminates interpretation differences and facilitates automated calculation, reconciliation and payment of invoice line items with total transparency. GumboNet cuts 5% to 10% on average out of contract costs and, in some cases, up to 25%, according to Bruce.

"E&Ps can save millions of dollars from automating transactions because it eliminates contract leakage, reconciliation expenses, and they can negotiate discounts and do daily accruals … if you add all of that up, then you will see double digit million-dollar savings on your opex," he said.

The startup is financially backed by Saudi Aramco's venture arm, Saudi Aramco Energy Ventures, and Equinor Technology Ventures, the venture subsidiary of Equinor. In May 2019, the company completed a $6 million equity funding round co-led by the venture firms. The round brought Data Gumbo's total funding to $9.3 million.

Operators in the Permian and Bakken oil fields have adopted GumboNet. Last year, Austin-based Antelope Water Management LLC tapped GumboNet to provide real-time transparency and contract automation across its water infrastructure, treatment, sourcing and disposal services. This marked the first use of a blockchain platform for water management services in U.S. shale plays.

Data Gumbo provides third-party oversight to Antelope's water quality and water volumes, an important capability that prompted the company to enter the deal, according to Antelope CEO Dustin Brownlow. Cost savings from this project are about $4 million annually, Bruce said.

In the Bakken, the OOC Oil & Gas Blockchain Consortium piloted the technology for water haulage services in a bid to lower administrative costs while reducing payment disputes and chances for fraud. The consortium includes oil and gas majors Chevron Corp., ConocoPhillips Co., Exxon Mobil Corp., Equinor ASA and Royal Dutch Shell Plc, among others.

GumboNet will replace a manual transaction system with automated payments, which could generate $3.7 billion annually in cost savings for the water business, according to Bruce.

In the Gulf of Mexico, the company is working with a large oil company to track drilling equipment, personnel on board and drilling fluids using blockchain.

In March 2020, Data Gumbo entered the global market when specialized drilling and project management services provider Air Drilling Associates (ADA) installed the application on a project in Southeast Asia. GumboNet will automate execution and invoice payments for ADA's integrated project management contracts, including personnel, consumables and drilling tools.

This project is the first use of blockchain in geothermal energy drilling, adding to the company's list of successful endeavors.

"This is the prime time for this technology in the market when everyone is doing everything they can to remove all of their opex. At this point, companies desperately need technologies like GumboNet to drive down the costs from their operations," Bruce said. "Data Gumbo's network enables companies to gain access to that hidden value within their organization."

GumboNet utilizes a subscription-based model, which alleviates pressure on companies to build and sustain an in-house blockchain model from scratch. Bruce notes that the integration of technology poses little to no risk because there is the option to unsubscribe; it does not involve cryptocurrency and mining like other blockchain platforms; and there are no upfront costs.

"Users have the ability to pick up profits that go straight to their bottom line by cutting expenses from their existing operations using an industrial blockchain that is subscription-based, so you don't have to spend a bunch of time and money trying to figure out how it works or how to implement it," he said.

Data Gumbo intends to drive the adoption of blockchain and help establish its legitimacy as a linchpin technology in industrial business relationships.

"Blockchain will have a major impact on the oil and gas industry—and all global industries—and we will lead the charge in its broad adoption for sweeping operational improvements," Bruce said.

"E&Ps can save millions of dollars from automating transactions because it eliminates contract leakage, reconciliation expenses, and they can negotiate discounts and do daily accruals," said Data Gumbo's Andrew Bruce.

Novi Labs Inc.

Formed in 2014, Austin-based software company Novi Labs Inc. emerged on the scene with capital from Bill Wood Ventures and, later, equity investment firm Cottonwood Venture Partners.

Novi's cloud-based technology leverages large-scale datasets and machine learning algorithms to predict and analyze economic outcomes for oil and gas investments. Novi's mission is to help operators design and drill wells that are more profitable by solving the challenges of well planning, and Jon Ludwig, president and co-founder of Novi, has led the company's efforts to do that on a global scale.

To date, Novi's technology has been deployed in every major shale basin, including

NOVI LABS INC.

Novi team and a customer in front of a horizontal drilling rig located in the Appalachian Basin.

"Most of the workflows and tools in the pre-drill decision-making process are fairly archaic, manual and tedious. The pace of decision-making in unconventional plays drives it beyond the breaking point and leads to suboptimal decisions," said Jon Ludwig with Novi Labs Inc.

the Delaware and Midland basins, the Williston Basin, the Appalachian Basin, the Denver-Julesberg Basin, Oklahoma's SCOOP/STACK, the Montney Formation, the Duvernay Shale, Eagle Ford Shale and Argentina's Vaca Muerta Formation.

In May 2019, the startup closed a $7 million series A funding round with Cottonwood and Bill Wood Ventures. Novi deployed the funds toward scaling its team and software platform to meet the demands of shale producers and investors.

In Novi's beginning stages, the company developed a partnership with Hess Corp. that resulted in the field trial and implementation of Novi's software on Hess' Williston Basin asset during Ludwig's tenure with the corporation. The full-scale project gave Ludwig firsthand experience with applying machine learning algorithms and large-scale datasets to the problem of unconventional development optimization. It also provided him with insight into the economic disparities that operators experience from well development.

Witnessing the pressure of running 10 to 20 drilling rigs at once and a massive ramp up in capital, Ludwig saw how the pace of shale development put significant strain on planning workflows and software tools for operators and their decision-making apparatus overall. There was simply not enough automation and efficiency to keep up with the pace of development.

"Most of the workflows and tools in the pre-drill decision-making process are fairly archaic, manual and tedious. The pace of decision-making in unconventional plays drives it beyond the breaking point and leads to suboptimal decisions," he said.

Novi developed its well planning software to address this issue. The technology targets three use cases: fully automated producing well forecast, A&D evaluation and, at the core, return on capital optimization.

Novi's solution combines machine learning driven predictive analytics with multiple well design inputs, capital costs and commodity price assumptions to model the financial performance of a well over time, enabling shale producers to optimally allocate capital and mitigate risks for development projects.

Given the present supply and demand shocks, Ludwig anticipates that A&D evaluation will be the most important use case for Novi's software, as it adds scale and efficiency to the evaluation workflows for potential acquisitions.

"The A&D market is frozen now, but it will be robust after spring redeterminations," he said. "Companies with strong balance sheets are going to see opportunities and private-equity sponsors are going to sponsor companies to go out and acquire assets."

In January, Novi and Paramount Resources Ltd. formed a strategic partnership focused on increasing net asset values by enabling Paramount's engineering teams to rapidly analyze all possible development scenarios to produce the most capital-efficient drilling plan.

The integration of Novi's well planning suite into the workflows of the liquids-focused Canadian energy company will help quantify and predict changes to development scenarios resulting in improved capital allocation.

Traditionally, the industry's approach to workflows utilizes spreadsheet driven type curves that provide a general prediction, assuming the completion design for all the wells in an area. This averaging methodology results in less accurate and biased results, according to Ludwig.

However, Novi's software makes individual well forecasts and captures nonlinear and nonparametric data relationships. This shortens the processing timeline for capital allocation scenarios from a couple of months to a few hours.

"Most of our customers are looking to replace traditional manual, Excel-driven workflows with our software. So the efficiency difference is [over] 50%," Ludwig said.

Additionally, the level of quality of the output is greatly improved with precise forecasts and a better understanding of performance drivers in a given basin. Novi's workflows represent a much more accurate and efficient replacement to what operators—in most cases—manually use now, according to Ludwig.

In March, the company released Novi Prediction Engine version 2.0. The new software provides critical economic data to E&P workflows such as well planning or A&D. Users can run a wide range of large-scale scenarios in minutes and get immediate feedback on the economic feasibility of each plan.

Novi Prediction Engine was built to add efficiency and scale by simplifying the creation of "what if" scenarios that are key to reducing risks associated with maximizing return on capital and net asset value. It uses machine learning to automate resource intensive capital allocation based on a wide variety of inputs and enables parallel testing of spacing, stacking and stimulation intensity scenarios.

Novi plans to make the platform completely self-service in the future, allowing users to create datasets, run predictive models, propose large scale development or A&D valuation scenarios and evaluate the results—all in near real time.

"We want to unlock every possible scenario for companies in the industry, so more time is spent on evaluating the answers and determining the best scenario for the organization," Ludwig said.

ResFrac Corp.

Driven by a commitment to "work hard and maximize return on investment" for its customers, Palo-Alto, Calif.-based ResFrac Corp.'s unique software has catapulted the company in the E&P sector in just two short years.

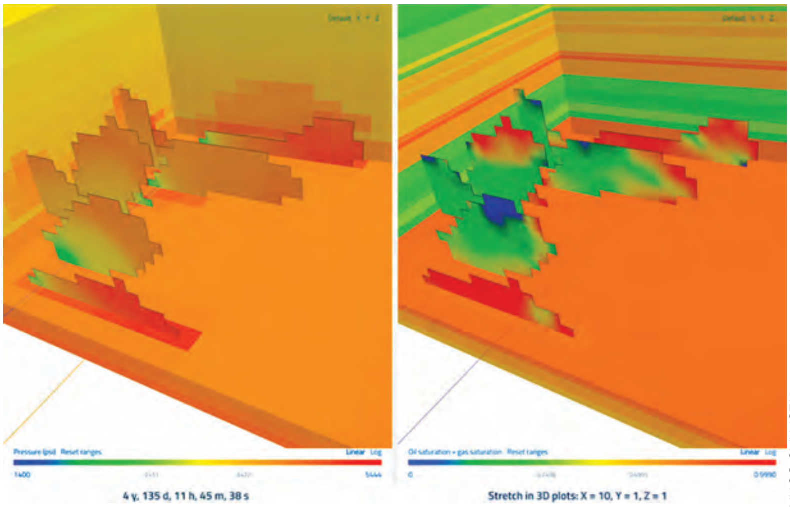
CEO Mark McClure quit his job as an assistant professor at the University of Texas at Austin and established the software startup company in 2015, going commercial in 2018, after observing a need in the marketplace for an integrated fracture and reservoir simulator.

"In shale you create the reservoir, and the fractures are the fundamental aspect of pro-

"At a time when companies are struggling to survive and maintain profitability, or at least minimize loss, it's more important than ever to maximize their rate of return, and that has to be done as smartly as possible," according to ResFrac Corp.'s Mark McClure.

RESFRAC CORP.

CEO Mark McClure leads a ResFrac simulation course held in early 2020, hosted at NextTier's corporate training facility in Houston.



RESFRAC CORP.

ResFrac simulates the full 3D multiphase flow problem in the fractures and in the formation.

duction. Having to separate them into different categories of software makes for a very awkward, incomplete workflow that could lead to the wrong answer," McClure said.

With backing from venture capital firm Altira Group LLC, the company has successfully developed a fully integrated 3D, cloud-based hydraulic fracture and reservoir simulator. Through a single simulation, the technology helps shale operators model and solve conventional design problems surrounding frac hits, parent-child interactions and refracs before completing wells.

In traditional projects, the fracture simulation defines frac geometry and proppant placement, while the reservoir simulation would describe the multiphase flow and fluid production from the shale. By combining these capabilities, operators can capture the life-cycle of an unconventional well and directly compare frac designs on the basis of predicted production. Ultimately, this improvement helps preserve capital for operators by shortening the trial and error of unconventional development.

"The deliverable from a ResFrac project is a prediction of net present value for different decisions," McClure said. "For example, once we've built a model and history-matched it, we'll run scenarios to see what the impact would be on NPV [net present value] if the spacing is changed. We literally plot NPV versus well spacing."

In the current price environment, he said leveraging the ResFrac tool is critical for companies still drilling and fracturing because the optimal frac design changes based on the price of oil.

"At a time when companies are struggling to survive and maintain profitability, or at least minimize loss, it's more important than ever to maximize their rate of return and that has to be done as smartly as possible," he said. "Frac designs need to be revisited and reconsidered to adjust for the new price environment."

Resfrac's software serves roughly 25 E&P companies and has been applied across most major American shale plays including the Permian, Bakken, Eagle Ford, Marcellus, Duvernay and Vaca Muerte. The company has also completed case studies with Hess, QEP Resources Inc., Range Resources Corp., ConocoPhillips and Shell International Exploration and Production Inc.

But McClure said the study with Hess revealed the most significant issue that the company has seen in its entire lifecycle.

"We found that specifically in gas shales there is a tendency for a conventional DFIT [diagnostic fracture injection test] interpretation to come in with a permeability estimate that's too high—very, very high," he said. "Our follow-up paper with Hess, on their now-sold Utica asset, showed how the permeability estimate makes a huge impact on the optimization of the well spacing, so essentially we showed how a very common and widespread error is made in the DFIT interpretation in gas shales."

These inaccurate permeability analyses lead to economically suboptimal well and cluster spacing designs, which result in a 30% to 40% difference in NPV, according to McClure.

Additionally, ResFrac performed an integrated parent-child study with Hess in the Bakken. The software successfully captured a complex series of production, reinjection, DFIT, a frac hit from and offset well and subsequent production uplift. With the results, the company was able to model parameters such as fracture toughness, permeability and proppant conductivity, which Hess leveraged to address other completion design scenarios.

"Parent-child interaction is one of the biggest issues that operators report as impacting their production, and we're the only tool that can describe the physics of parent-child interactions in a complete way," he said.

On top of these efficiencies, the modeling process requires geologists, reservoir engineers and completions engineers to all work together. "I think a lot of companies see the value in that as well," McClure added.

In May, ResFrac closed a preferred share financing with Altira Group and debuted a new user interface that streamlines use and provides results that are more detailed. The company also reported a 250% growth in revenue last year as its customers doubled.

In the next year, the company intends to enhance the software with an advanced automation to the workflow. The idea is to create an algorithm that automatically runs ResFrac simulations for operators and returns a recommended optimum design or automatically matches a model to data.

"Our strategy is twofold: continue to invest and work hard on the product and, of course, try to continuously grow our market share and penetration … we want to be the No. 1 solution in this market segment, period." □


WARBURG PINCUS
A LEADING
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for
over 30 years

A PARTNER FOR PANTHEON

Analysis of recently completed geophysical work points to an estimated 1.8 Bbbl of oil in place at Pantheon's Talitha project on Alaska's North Slope. But in the midst of an oil price collapse, will anyone join them to dance?

ARTICLE BY
VELDA ADDISON

Unlike some oil and gas companies deciding whether to shut in wells as prices remain at historic lows, Pantheon Resources Plc is facing a different task: finding a partner to develop its Alaskan North Slope assets amid a global pandemic.

"It's a difficult dance," said Bob Rosenthal, chief technical director for Pantheon.

Travel restrictions have prevented some potential partners from going to Alaska, forcing the London-headquartered company—like the rest of the world—to communicate more virtually with everyone working from home. But conversations are picking up after a lull late last year, driven by recent news of a discovery that added resources at Pantheon's Talitha project located south of Prudhoe Bay, which executives believe made the company more "visible on the world stage."

Analysis of recently completed geophysical work by eSeis Inc. indicates the shallowest of four zones at Talitha—the Shelf Margin Deltaic—is estimated to contain 1.8 Bbbl of oil in place.

The work was undertaken as Pantheon aims to high-grade its inventory, reprocessing and merging 3D seismic data covering multiple zones at Talitha along with the Theta/Theta West projects to the west, Leonis to the north and Greater Alkaid to the northeast.

Pantheon believes Talitha could produce about 500 MMbbl of hydrocarbons. It's near the company's Greater Alkaid, part of the 250,000 leased acres acquired during Pantheon's acquisition of Great Bear Petroleum in 2019.

"We're through the idea stage. We're through the exploration stage. We're ready to come onstream to work with somebody that wants

PANTHEON RESOURCES PLC

The Alkaid-1 well is located on the Alaskan North Slope.

to reposition their portfolio to a low-cost onshore, huge, impactful reserve position, with big production," Pantheon CEO Jay Cheatham said. "Just out of two reservoirs we could be averaging 100,000 barrels a day easily and then add on from there. We're pretty excited about our position."

Pantheon's continued appraisal work and search for a farm-in partner comes as the oil and gas industry faces one of its worst downturns in history. While other companies, including those in Alaska, are holding back production and slowing development, Pantheon is looking to drill but can't proceed alone. Like everyone else, the company—which has only six full-time employees and a handful of contractors—has reduced its budget, cutting personnel expenses by 20%.

Despite the headwinds, Cheatham sees a chance to strengthen the company and considers it fortunate not to be a producer at the moment.

"We are uniquely positioned in the world today, and we see that as an opportunity," he said.

Resources

Alaska's North Slope has been the site of some large conventional discoveries in recent years, adding several billion barrels of recoverable resources. Notable finds in the Brookian Sequence have included Caelus Energy's Smith Bay discovery, ConocoPhillips Co.'s Willow and Narwhal discoveries and the Horseshoe discovery made by Armstrong Energy LLC and Repsol SA (now operated by Oil Search Ltd.). Both are in the Nanushuk Formation.

Oil Search Ltd. added to its production potential from the Nanushuk Formation, reporting in late March the discovery of oil from a well west of the Horseshoe discovery and hydrocarbon pay from a sidetrack.

Pantheon's major discoveries at Talitha, farther southwest, have been in the Brookian and Kapurak formations. The latest petrophysical work at Talitha points to about 1.8 Bbbl of oil in place in the Brookian-age reservoir. Previous estimates for three zones combined were about 2.6 Bbbl oil in place, the company said in late March.

Results of an old exploration well, the Pipeline State #1 well, along with full core and log data, helped the company see the scale of its Alaskan assets, according to Rosenthal, who noted the well has a more than 2,000-ft oil column. "Our next steps are to finish all our work on all the zones. As each individual job is done, we'll put out a resource evaluation."

Analysis includes two other zones at Talitha—the Slope Fan System (Brookian) and Kapurak Formation.

The site is near Pantheon's Greater Alkaid project, where the field development plan calls for 44 long-reach, 8,000- to 10,000-ft horizontal wells with multistage fracs.

"Each well, we anticipate, will have ultimate recoveries of over 2 million barrels," Cheatham said. "We think it'll generate about 30,000 barrels a day peak rate for an extended period of time and then decline over time."

Having picked up additional acreage during a lease sale in December, Pantheon is also evaluating a zone in the Pipeline State #1 well where analog oil pay was identified in the Brookian Formation. The Theta West project is just west of Talitha.

Economics

The North Slope can be an expensive place to develop oil and gas assets, particularly for areas that lack sufficient infrastructure, are remote and are slowed by icy conditions.

Today's market conditions are making matters more challenging.

ConocoPhillips in March said it planned to lower its 2020 capital spending plans in Alaska by about $200 million, laying down a couple of rigs in its Alpine and Kuparuk fields, according to an Associated Press report. Oil Search made similar moves, revising Alaska spend to about $160 million from $230 million this year, slowing down work at its Pikka Unit.

Pantheon isn't drilling but wants to, executives said.

"That all depends on bringing in a partner. Other than bringing in a partner we're just spending our overhead to work on what we have," Cheatham said.

The company also has assets in East Texas, but activity there has halted due to low crude oil and natural gas prices. However, development plans continue in Alaska.

"We are planning to submit to the state next month a plan for two units—a unit at Greater Alkaid of 23,000 acres and a unit at Greater Talitha of 97,000 acres," he added.

Being near existing infrastructure helps to keep costs down, Cheatham said. Pantheon's assets are bisected by the Dalton Highway and Trans Alaska Pipeline System.

Searching for a partner now has its downsides, but there are interesting upsides, Rosenthal added.

"I think people are reevaluating their own internal portfolios," he said. "Do you want to develop a $2 billion-barrel oil field in deepwater Gulf of Mexico and have a 10-year outlook, or do you want to get into a big project that is probably much higher in terms of NPVs onshore in Alaska?"

Pantheon's virtual data room has been busy, the executives said, and one meeting with a potential partner—a national oil company—stretched well beyond its originally scheduled two-hour limit.

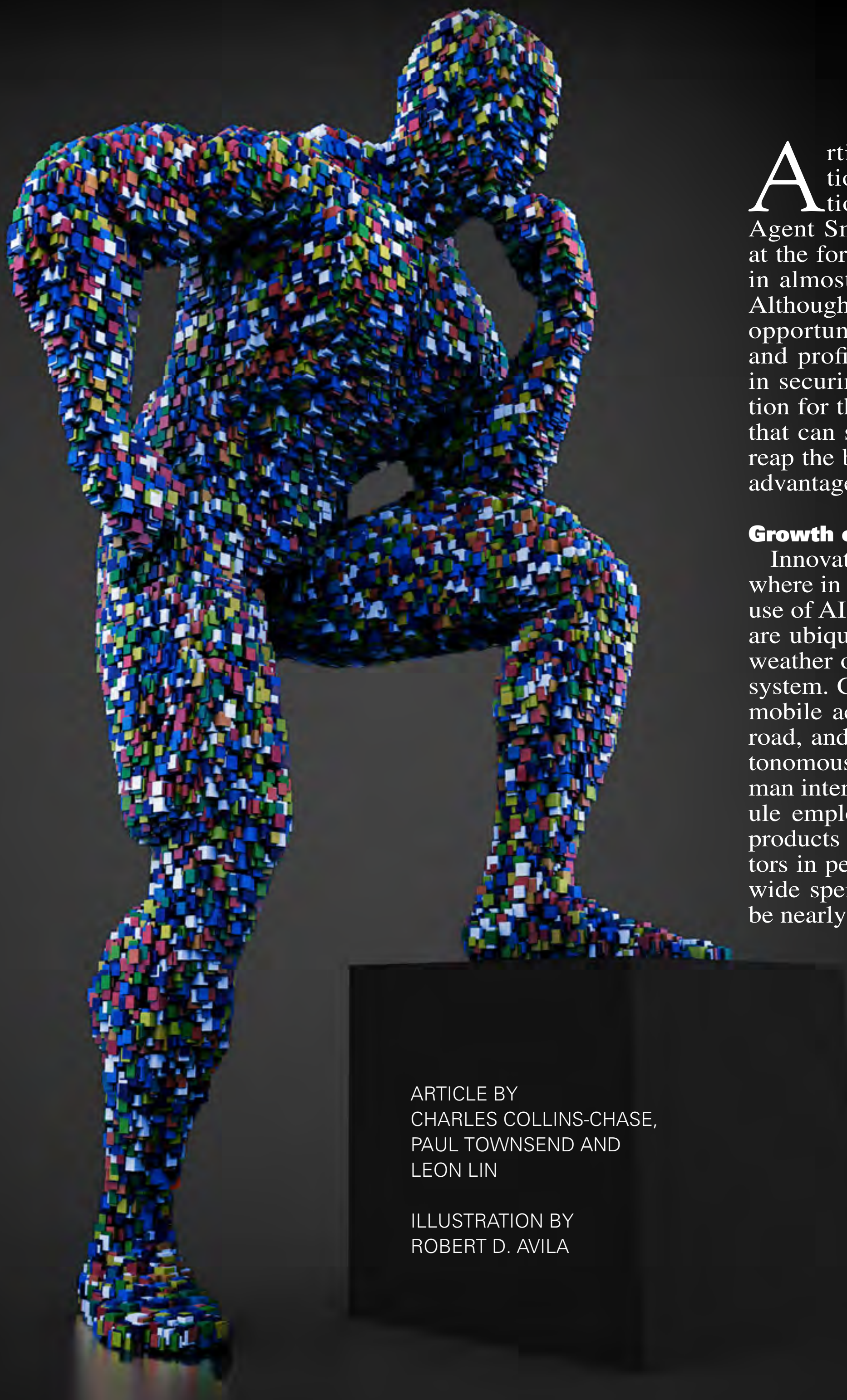
"We know the industry is going through huge upheaval, but I think our assets are going to shine in this environment," Cheatham said.

Market conditions may force high-cost producers out of business, he added. "We won't be producing any significant quantities of crude for two, three, four years and at that point and time, crude oil prices should be—all other things being equal—higher than they would have been otherwise." □

"We're ready to come onstream to work with somebody that wants to reposition their portfolio to a low cost onshore huge impactful reserve position, with big production," said Jay Cheatham, Pantheon Resources Plc.

BIG DATA, BIG OPPORTUNITY

As innovations in artificial intelligence become increasingly essential to the success of oil and gas companies, the need for companies to protect their inventions grows.



Artificial intelligence (AI) has traditionally been the stuff of science fiction—Hal 9000, Skynet, R2-D2 and Agent Smith come to mind. But today AI is at the forefront of technological advancement in almost every field, including oil and gas. Although these innovations offer tremendous opportunities to increase efficiency, safety and profits, companies may face challenges in securing intellectual property (IP) protection for their AI-based inventions. Companies that can successfully navigate IP pitfalls can reap the benefits of AI and gain a competitive advantage over competitors.

Growth of AI

Innovations incorporating AI are everywhere in modern industry and society, and the use of AI is growing rapidly. Digital assistants are ubiquitous—we can ask Siri to tell us the weather or have Alexa arm our home security system. Computer vision helps us avoid automobile accidents and stay in our lane on the road, and it will soon usher in a world of autonomous cars that operate with little or no human intervention. Companies use AI to schedule employee shifts, predict the shelf life of products and power robots that can assist doctors in performing surgeries. By 2023, worldwide spending on AI systems is estimated to be nearly $98 billion.

ARTICLE BY
CHARLES COLLINS-CHASE,
PAUL TOWNSEND AND
LEON LIN

ILLUSTRATION BY
ROBERT D. AVILA

In oil and gas, AI and data analytics are already being used in a range of applications, from operating in dangerous environments that could endanger human workers to efficiently analyzing data to enhance exploration and drilling. This can allow companies to drill challenging wells more easily and reduce emissions in the process. AI also can assist with certain menial or repetitive tasks, automating them with little to no human involvement to achieve significantly higher efficiency. In the future, AI-enabled drilling systems may even steer drill bits with limited human oversight, and AI-powered robots may be used to autonomously map the ocean floor or inspect equipment for damage or defects.

Oil majors have already begun implementing these technologies. Royal Dutch Shell Plc, for example, uses AI to help guide drills as they move through the subsurface. The system applies algorithms derived from historical drilling data and simulated exploration including subsurface data from seismic surveys and mechanical information from the drill bit. Shell also relies on AI to improve safety for some dangerous tasks, such as using an automated pipehandler on its 120,000-ton Olympus platform to avoid needing human workers to handle 300-lb sections of drillpipe. Shell also leverages AI's data processing and predictive capabilities in customer-facing applications, such as monitoring and predicting the demand for charging terminals for electric vehicles.

However, most of AI's benefits have not yet been realized in oil and gas. Data analytics alone is an enormous area for growth as companies work to manage the explosion of data from offshore seismic studies and drilling tools that transmit drilling data to the surface in real time. Some reports estimate that petroleum engineers and geoscientists already spend over half their time searching and assembling data, a task that AI can perform more quickly and on larger datasets. AI also can perform analysis that humans cannot, such as detecting patterns in sensory data that humans may not perceive. As retirement in the industry increases, AI will be particularly crucial to fill the gaps in knowledge and expertise.

AI patenting

The rise of AI innovation has led to a corresponding rise in patent applications for AI inventions. A 2019 report on AI by the World Intellectual Property Organization showed the rate of patent filings on AI-based inventions is beginning to catch up with the rate of scientific publications on AI technology.

Of the nearly 340,000 patent applications for AI technologies that have been filed since 1960, more than half have been filed since 2013. The pace of AI-based patent filings is growing quickly in certain subareas. Machine learning, which is the dominant technique disclosed in AI patents, saw average annual growth in patent filings of 28% from 2013 to 2016. Within machine learning, neural network filings increased by an average of 46% over the same period, while deep learning saw an enormous average annual growth in patent filings of 175%. Filings for robotics and control methods saw 55% average annual growth. Patenting rates for AI-based inventions are growing far faster than for other technologies.

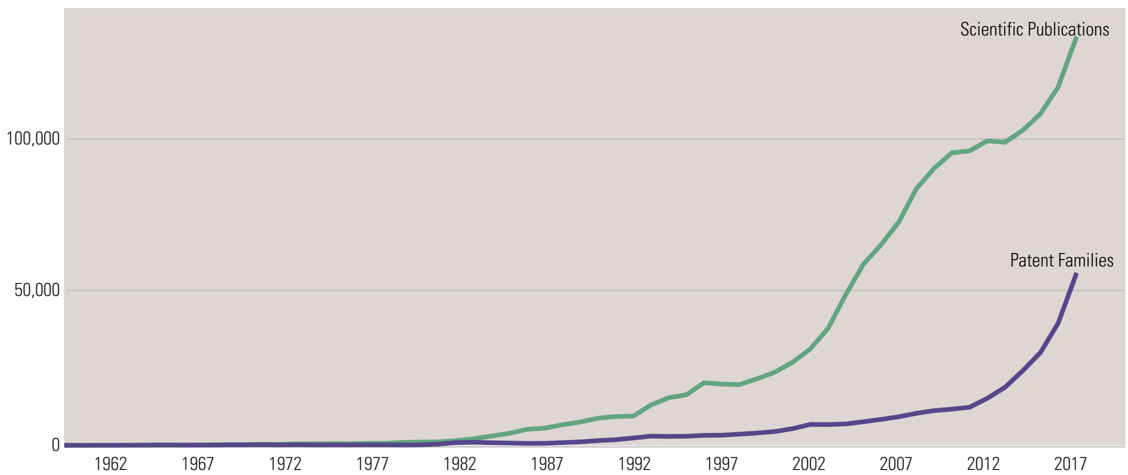
Despite the potential value of AI technologies in the oil and gas sector, other industries have been faster to capitalize on them by filing patent applications. In particular, transportation, telecommunications, personal devices, medical devices and security fields account for a great number of recent AI-based patent applications.

Challenges to patenting AI-based inventions

As with any technology, it is vital for companies to protect their investments in AI-based innovation through IP. Yet inventors may face serious hurdles both in obtaining AI-based patents from the U.S. Patent and Trademark Office (USPTO) and in defending such patents from legal challenges by competitors.

Recent case law addressing subject matter eligibility for patents poses a particular problem,

Artificial Intelligence Patent Family Growth



(Source: World Intellectual Property Organization)

AI patent families grew by an average of 28% and scientific publications grew by 5.6% annually between 2012 and 2017.

with both the USPTO and courts frequently ruling that computer-based inventions involving manipulation of data are not eligible for patenting. Companies that are aware of these challenges to patenting and have strategies to overcome them will be best positioned to reap the benefits of AI innovations.

Section 101 of the Patent Act states that "[w]hoever invents or discovers any new and useful process, machine, manufacture or composition of matter, or any new and useful improvement thereof, may obtain a patent therefore, subject to the conditions and requirements of this title."

Despite this broad language, the U.S. Supreme Court has interpreted this language to include several categories of subject matter that are ineligible for patenting—abstract ideas, laws of nature and natural phenomenon.

The Supreme Court explained in its opinion in *Alice Corp. Pty. Ltd. v. CLS Bank Int'l* that an invention directed to an abstract idea can only be eligible for patenting if it adds "something more," sufficient to transform the underlying abstract idea.

What's more, the Supreme Court has held that implementing an invention on a general purpose computer is insufficient to transform an abstract idea into a patent-eligible invention.

Recent cases applying Section 101 show it has become increasingly difficult to obtain or defend patents on AI-based inventions, which typically rely on a computer to gather and analyze data.

In *TDE Petroleum Data Solutions v. AKM Enterprises*, the U.S. Court of Appeals for the Federal Circuit held patent claims ineligible under Section 101 that recited "various processes for determining the state of an oil well drill."

The claimed invention was a method of receiving data from oil well sensors (e.g., the rpm of the drillstring or the pressure of drilling fluid in the standpipe); removing any erroneous data; and determining the state of the oil well drill (e.g., drilling, sliding or borehole conditioning).

The court held that the method involved "the sort of data gathering and processing claim that is directed to an abstract idea."

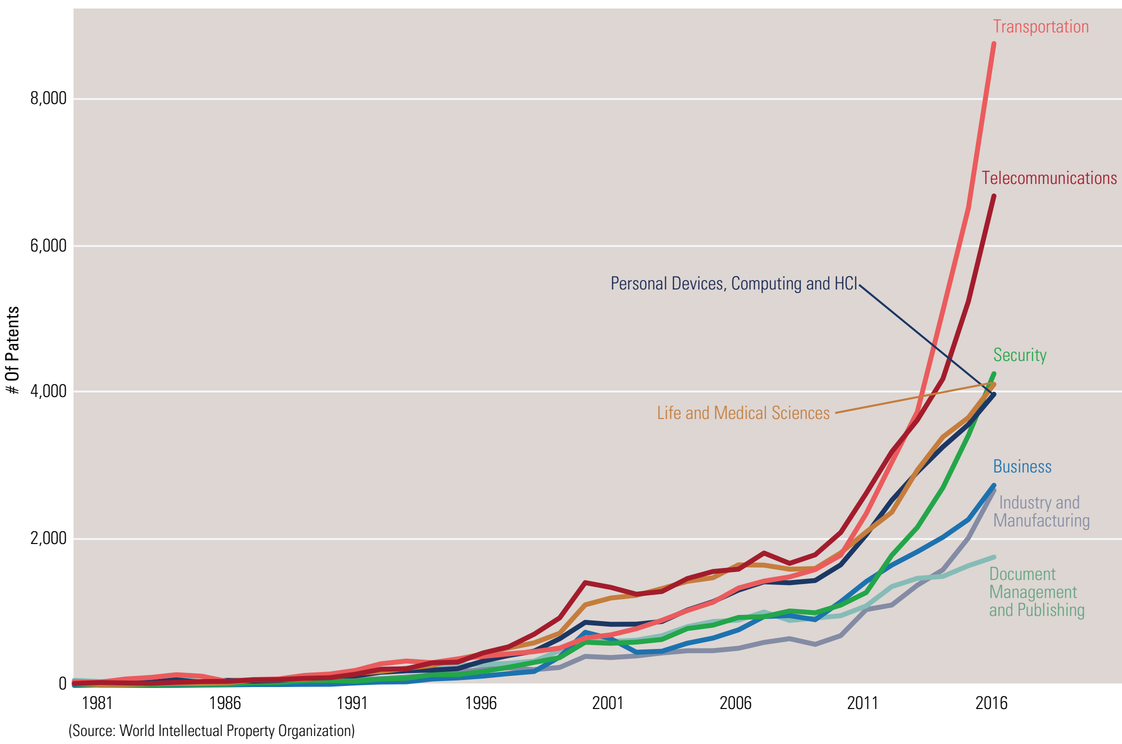
The court also held that the patent claims did not include "something more" that could transform the underlying abstract idea into a patent-eligible invention. Instead, the claims simply recite "generic computer functions that amount to nothing more than the goal of determining the state of an oil well operation."

The court noted that, although the patent described certain embodiments of the invention in which the system automatically selected one of the states of the oil well based on its analysis of the data, that aspect was not recited in the claims. The court thus held the challenged patent claims invalid under Section 101.

The Federal Circuit similarly held patent claims invalid under Section 101 in *Electric Power Group LLC v. Alstom S.A.* The patent claims recited systems and methods for monitoring the performance of an electric power grid in real time by collecting data from multiple sources, analyzing the data and displaying the results.

The court explained that "information as such is intangible" and "analyzing information by steps people go through in their minds or

Patent Families For Top Application Fields



Patent families related to AI application fields emerged in the 1980s, with transportation and telecommunications overtaking all other fields.

by mathematical algorithms" fall within the abstract idea category.

The court also concluded that the patent claims did not transform the underlying abstract idea because they used "off-the-shelf, conventional computer, network and display technology" to perform the invention. Even though the invention may have been a valuable improvement in power grid monitoring, claims covering conventional computer technology to gather and analyze data made the patent ripe for a (successful) Section 101 challenge.

In *Kaavo Inc. v. Amazon.com Inc.*, the U.S. District Court for the District of Delaware held patent claims invalid under Section 101 that related to managing a cloud-computing environment. Certain claims in the patent recited methods of analyzing data and using it to forecast an optimal cloud-computing environment.

The court held that even those claims did not contain any inventive concept sufficient to transform the underlying abstract idea of setting up and managing a cloud-computing environment. That court explained that, even though the forecasting claims may be performed using techniques such as neural networks, the claims "do not specify how the forecasting is performed, what monitoring data are used or how [the data] are used; any generic algorithm, neural network or regression analysis could be used."

These cases and others show that AI-based inventions, which invariably use computers and usually involve data gathering and analysis, face challenges when it comes to patenting.

Strategies to protect AI inventions

Although the patent landscape is certainly treacherous for AI-based technologies, a strategic approach to patent drafting can help inventors maximize the chances of obtaining patents that can survive a Section 101 challenge.

Companies should draft patent claims to recite a practical application of any underlying abstract idea to avoid a court concluding that the claims cover the abstract idea itself. To do so, companies should tie any underlying concept or data-gathering steps to the physical activity or equipment from which data are being gathered.

The outcome in *TDE Petroleum Data Solutions v. AKM Enterprises* might have been different if the patent claims had required the system to not only gather and analyze data but use those data to control oil well operation. Companies must remember, however, that tying an invention to conventional computer components or specifying a particular field of application (e.g., oil well drilling) is not enough to transform any underlying idea.

It was such a practical application that led a court to uphold patent claims under Section 101 in *Canrig Drilling Technology v. Trinidad Drilling*. The patent claimed systems and methods that allowed directional drilling by rotating a drillstring to a predetermined angle and reduced friction by oscillating the drillstring between predetermined angles.

"A strategic approach to patent drafting can help inventors maximize the chances of obtaining patents that can survive a Section 101 challenge."

Even though the patent claims recited some of the same generic computer implementation as in the TDE Petroleum case, such as receiving rotational information from a sensor and analyzing that information, the court found that patent claims were not an attempt to patent the underlying abstract concept of rotation because they also involved controlling the drillstring.

The court thus held that the claims were more narrowly drawn to physical apparatuses and processes and addressed "specific challenges in directional drilling through a concrete process for controlling the rotation of the long drillstrings to and between predetermined angles."

Although the claims involved the abstract concept of rotation, they were eligible under Section 101 because they reflected a practical application of that concept to position and oscillate the drillstring.

Companies should draft their patents to include sufficient detail about the inventive aspects of their invention to show the patent claims "transform" any underlying abstract idea. This detail should include both the ways in which the invention improves on prior art systems or methods and how the inventive aspects of the invention operate.

In *Kaavo Inc. v. Amazon.com Inc.*, the patent failed to include this disclosure. Although the court seemed to recognize that using neural networks to forecast an optimal cloud-computing environment might be inventive, the patent lacked detail about how a neural network would accomplish this.

Companies can avoid this outcome by providing additional disclosure in their patent specification about how to implement the inventive aspects of their invention.

Finally, where possible, companies should include detail in their patents about how their invention improves the underlying technology. Although patent claims that recite generic computer limitations are unlikely to survive Section 101, claims that describe an improvement in how computers operate have been more successful.

In the context of AI, companies should include in their patents a description of how their invention improves AI itself or the computer systems on which the AI-based invention is implemented. Courts are more likely to view an improvement in the underlying computer operation as sufficiently transformative to add "something more" to any underlying abstract idea, and thus patents that describe this type of improvement are more likely to survive a Section 101 challenge. □

JOINED AT THE PIPE

Producers and midstream operators must work together to survive, and contract renegotiations could be part of that effort. Here are some key considerations for when companies have to come to the table.

ARTICLE BY STEVE REESE

ILLUSTRATION BY ROBERT D. AVILA

Willingness to renegotiate now will go a long way for both parties, producers and midstream operators to survive and even thrive once again, according to Steve Reese of Reese Energy Consulting Inc. and Reese Energy Training Inc.

Because recent events have decreased demand for crude oil, forced shut-ins of oil producing wells and reduced drilling activity, the energy industry's focus has turned back to natural gas. As oil wells are being shut in, volumes of rich associated gas are declining as well. Moreover, a decrease in drilling activity means normal decline is not being replaced with new volumes of rich gas, thus creating dilemmas for producers and midstream operators.

Producers are now focused on finding every available revenue stream, including scrutinizing their existing midstream commercial contracts. Relief with lower fee levels for gathering, processing, compression and other midstream services is being sought out. As lower oil prices appear to be in the cards for at least the near term, any increases in gas revenue ease producer pain.

Midstream operators also face a major hurdle: declining volume throughput. With the transition over the last 20 years from legacy allocated percentage of proceeds (POP) contracts to fixed fuel and recovery fee-based contracts, gathering and processing inlet volume levels have become the largest variable for most midstream operators' bottom lines. Moving away from commodity price exposure has flattened the risk curve for operators and afforded them other means of achieving slices of margin.

Under pro forma fixed fuel and recovery fee-based contracts, several items can affect margin levels:

- Fees for gathering, treating, compression, marketing and processing;
- Fee levels based on volume levels;
- Fees for low-volume receipt points;
- The delta between actual NGL plant recoveries and the "fixed" contractual levels;
- The delta between actual field fuel and "fixed" contractual fuel charges;
- The delta between actual plant/recompression fuel and "fixed" fuel charges;
- The delta between actual lost and unaccounted for gas (L&U) and "fixed" L&U;
- The delta between actual residue gas pricing and "fixed" contractual price;
- The delta between actual NGL transportation and fractionation (T&F) rates and "fixed" contractual T&F rates;
- Any fees or capital recovery under volume throughput commitments (VTCs);
- Any fees for various levels of service for gathering or processing capacity (firm versus interruptible); and
- Plant tailgate imbalance fees for producers taking their products in-kind for marketing.

Volume throughput language

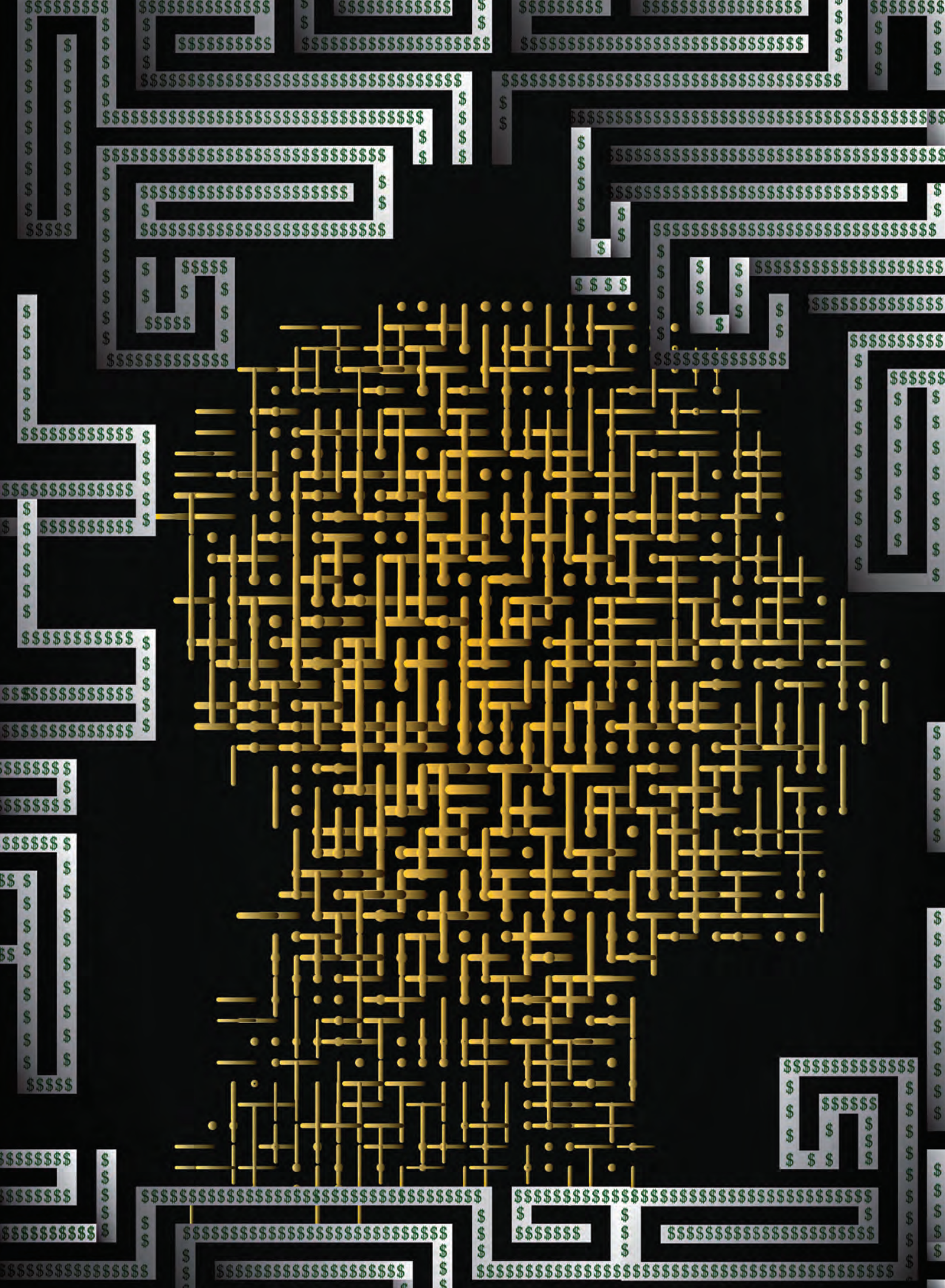
In this environment, producers' risks do not only lie in decreasing gas revenue due to lower volumes; those companies that are subject to contractual VTCs could face additional challenges.

Some midstream commercial contracts contain VTCs whereby producers agree to deliver guaranteed volumes over a period of time, and producers that fail to meet the VTC are subject to penalties in the form of increased fee rates or cash payments to the midstream entity based on the level of volume shortfall.

VTC language has been prevalent in recent times when midstream operators have outlaid capital for greenfield or extended gathering and/or processing assets upfront in newly developed areas.

As the shale revolution unfolded, producers realized they needed a connection ready to go for their flush gas production. Without that, the larger flush volumes could be wasted, and their frac time could be delayed. VTC language ensured a return on capital employed for the midstream operator in exchange for the installation and commissioning of new facilities in a timely manner (many times before wells were completed) for the benefit of the producer.

Now, producers with VTC contracts are beginning to stare down the possibility of further deterioration of their gas revenue stream if faced with increased midstream service fees and/or a cash payment due to volume shortfalls in the VTC contract language.



Midstream companies, on the other hand, have some hard decisions to make on the VTC issue:

- Do they persist on the higher fees or cash payments if due now?
- If so, could this accelerate some producers into bankruptcy?
- If inflexible, could this affect dealings in the future with this producer?
- Is there a possibility of a producer claiming force majeure?
- Could there be potential litigation or arbitration involved?
- Could a regulatory body step in?
- If the producer goes into bankruptcy, is there a risk the court throws out the contract?
- If the producer is given an extension or the terms are renegotiated, what does that do to the return on the capital that has been deployed by the midstream company?

Legacy production and contracts

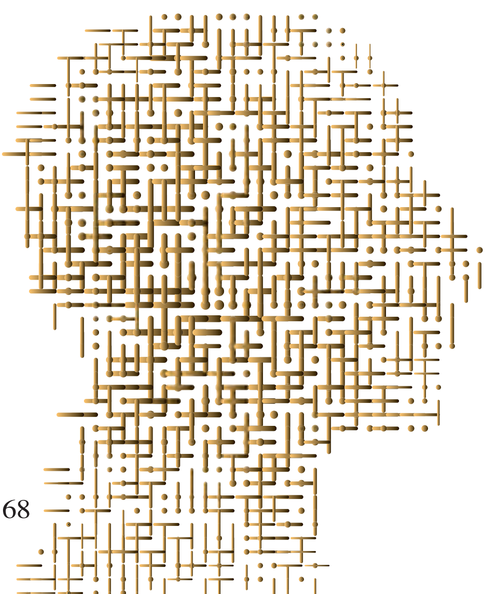
Producers with older vertical wells and legacy contracts face different hurdles. With the decline in gas and NGL prices since 2015, both POP contracts and fee-based contracts have deteriorated net wellhead gas prices. Since POP contracts are based on producers receiving only a percentage of value for their attributable residue gas and NGL products' value, the net effect has been much lower netback pricing.

In addition, as the overall value chain is lower, net back pricing is further diminished by ancillary fees for items such as low volume meter charges. In some fee-based contracts in certain basins, these fees have actually resulted in some gas having a negative value at the wellhead. As gathering systems age and legacy wells require lower system pressures to produce, compression fuel and system loss tend to increase, exacerbating the issue of gas not getting to market.

Renegotiations: possibilities and conclusions

Since both sides of the table have hurdles in this environment, what do they have to gain or lose to come together for renegotiation?

Producers are after price relief. They also want to continue to benefit from the same level of gathering and processing service regardless of whether they are producing significant volumes from horizontal wells or lower, steady amounts of gas from legacy verticals.



Midstream operators want to continue generating margins that afford them cover for their operating expenses while making a return on their capital. During "normal" times, these parties work in harmony as new wells are drilled, decline curves are flattened and more private and public money is invested into drilling activity and midstream infrastructure buildouts.

Despite the hurdles each side faces, potential reasons exist to come to the table through contract renegotiations, with each party holding different advantages.

Producers have two major advantages: term and dedication. Midstream companies are built on revenue streams and on the security of their gas supplies. Long-term gas supply contracts enable a midstream operator to focus on operational efficiencies, business development and technological innovation. Also, larger acreage dedications under midstream contracts bring future value, and while the original producer under contract may not develop all its acreage, there is an excellent chance that successors will.

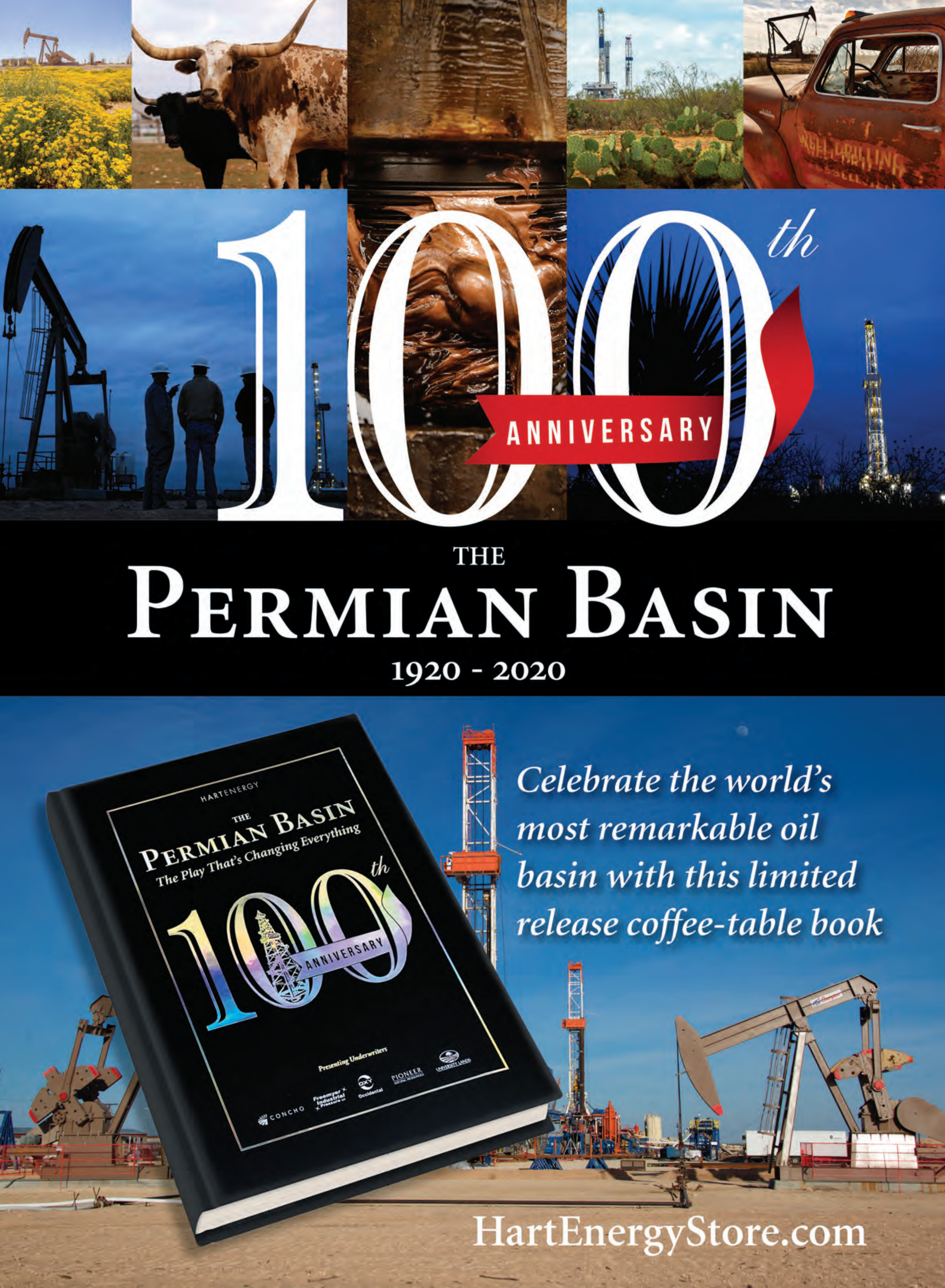
For producers offering term extension and expanded acreage dedications, midstream operators could offer:

- VTC time extension and/or lowering VTC shortfall fees/capital payback;
- Fee tables based on volumes for incentives;
- Waived or renegotiated low volume meter fees to keep legacy gas moving;
- A transition to actual fuel on fixed fuel contracts for a period of time;
- Options for actual or fixed product recoveries; and
- Expanded producer rights for take-in-kind gas and NGL.

Willingness to renegotiate now will go a long way for both parties, producers and midstream operators, to survive and even thrive once again. This reality will not change between the two parties: Producers need their midstream services as much as midstream operators need the gas supply and the security that it will be there long term. □

Steve Reese is celebrating his 40th year in the energy business. He is the founder and CEO of Reese Energy Consulting Inc., Reese Energy Training Inc. and the publisher of the Reese Midstream Report with offices in Edmond, Tulsa and Houston. The Reese family of companies specialize in energy commercial contracts, midstream engineering and operations, energy contract and midstream field auditing, due diligence, and energy research and project planning. He can be reached at sreese@coxinet.net.

"Despite the hurdles each side faces, potential reasons exist to come to the table through contract renegotiations, with each party holding different advantages."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EDITED BY
DARREN BARBEE

Project Teabury Confirmed: Diversified Gas & Oil Knocks Out Two Appalachian Deals

DIVERSIFIED GAS & OIL PLC (DGO), with its love of transaction code names, disclosed in May what it had dubbed "Project Teaberry"—deals with **Carbon Energy Corp.** and **EQT Corp.** totaling at least $235 million.

Diversified, which previously has used "Project 007" and other code names to internally discuss its acquisitions, agreed to purchase upstream and midstream Appalachia assets from EQT for initial consideration of $125 million. The deal includes contingency payments of up to $20 million to EQT.

In April, Diversified said it had reached an agreement with Carbon Energy to buy Appalachian assets for $110 million, not including potential contingency payments of $15 million.

Much of the Carbon Energy assets overlap geographically, primarily in West Virginia and Pennsylvania. Diversified also added that the Carbon

Diversified Gas & Oil Transactions

	Carbon	EQT
Gross Purchase Price ($MM)	$110	$125
Maximum Contingent Payment ($MM):	$15	$20

(Source: Diversified Gas & Oil)

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Energy assets are in proximity to its existing footprint and can be managed by the company's existing personnel without need for additional general and administrative expenses.

The EQT deal, which closed on May 26, adds about 8,500 net acres and includes an estimated 48 MMboe reserves with a PV-10 value of $185 million.

The sale also relieves EQT of about $47 million in asset retirement obligations and other liabilities associated with the assets.

Proceeds from the sale have been used to pay down EQT's term loan due 2021, which CEO Toby Rice said demonstrates the company's commitment to improving the balance sheet and reducing debt.

DGO, primarily a conventional asset operator, also noted about 10% of the wells included in the EQT deal are unconventional and prospective for the Marcellus and Utica shales.

Overall, the two deals will also add about 7,000 net operated wells and an average 18,100 boe/d in production for the company.

Additionally, the deals are set to expand Diversified's midstream network with the acquisition of 4,900 miles of midstream infrastructure from Carbon plus EQT and its affiliate **Nytis LLC**.

Gathering and pipeline services along the Cranberry Pipeline, included in the Carbon transaction, generate about $12 million of third-party revenue. Diversified will also add two operational gas storage fields in West Virginia with 3.5 Bcf of capacity.

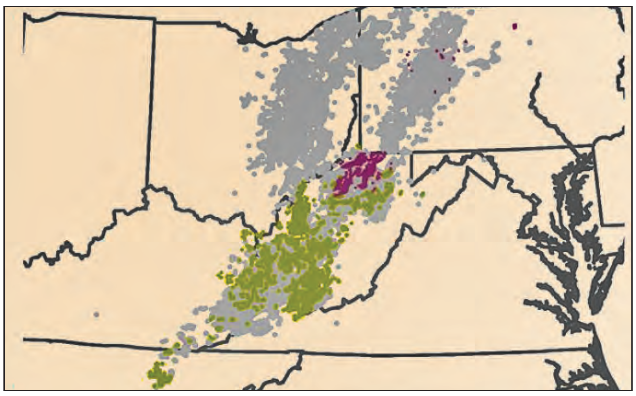
Diversified, which trades on the London stock exchange, plans to pay for the two deals with an $85.8 million equity issuance and $162.5 million in debt. The company added that excess cash proceeds from its debt and equity issuances would either fund future acquisitions or be used to reduce debt.

Diversified said the transactions pay about 3.4x of adjusted EBIDTA, within its criteria of paying less than 4x EBITDA. One such past acquisition includes a deal with EQT in 2018 where Diversified purchased about 2.5 million net acres for $575 million.

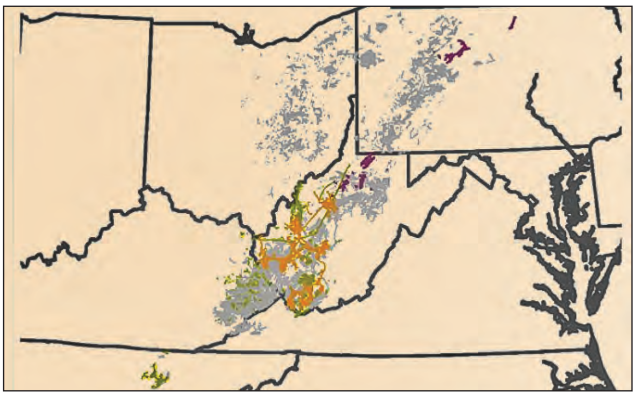
The EQT and Carbon deals would have an effective date of Jan. 1.

—Darren Barbee

Upstream Asset Map



Midstream Asset Map



Existing DGO Assets   Carbon Assets   EQT Assets   Cranberry Pipeline

(Source: Diversified Gas & Oil)

Black Stone Minerals Trims Permian Position

ASDF_MEDIA/SHUTTERSTOCK.COM

BLACK STONE MINERALS LP said June 4 it had entered agreements for the sale of Permian Basin assets with combined proceeds of $155 million earmarked to pay down debt and possibly boost distributions.

In a company release, Black Stone Minerals said it entered into two separate agreements to sell certain mineral and royalty properties from its Permian position for gross proceeds totaling approximately $155 million. The larger of the two agreements—worth about $100 million—involves **Pegasus Resources LLC**, a portfolio company of **EnCap Investments LP**.

Black Stone Minerals added that proceeds from the asset sales will be used to reduce the balance outstanding on the company's revolving credit facility, accelerating the Houston-based company's debt reduction goals. As a result, the company said management and the board of directors of its general partner intend to evaluate increasing distribution levels after closing the transactions, expected in July.

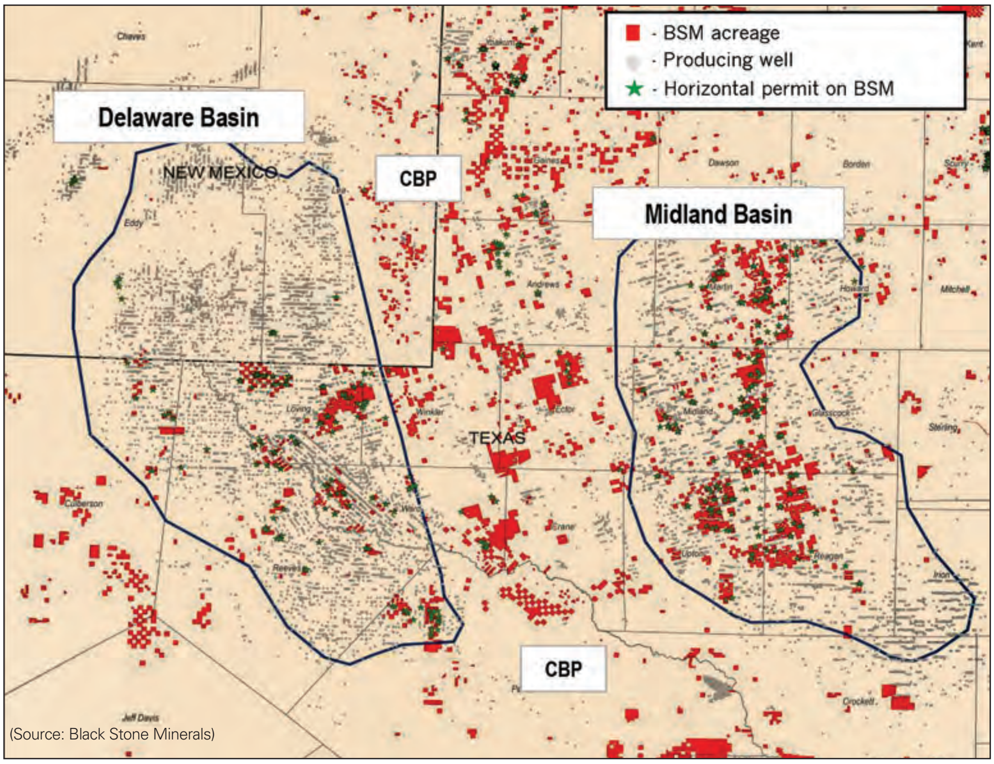
Driven by a reliance on E&Ps to generate revenue, a majority of publicly traded mineral companies, Black Stone included, recently slashed dividends and pulled guidances for the year as shut-ins and curtailed activity announced by U.S. shale producers created near-term uncertainty for the business.

One of the largest mineral owners in the U.S., Black Stone Minerals has a portfolio of mineral and royalty interests across 41 states with concentrated positions in the Permian Basin, Haynesville and Bakken shale plays. The company said on April 22 that the reduction to its distributions were the result of its board's decision to increase the amount of retained free cash flow for debt reduction and balance sheet protection.

"To the extent that we can get greater clarity around our producers' plans for the year, we are happy to revisit those guidance measures, but for now, there is just simply too much uncertainty in the market and our crystal ball is frankly a little cloudier than usual," Jeff Wood, Black Stone's president and CFO, said during the company's first-quarter earnings call on May 5.

Following closing of the two transactions announced on June 4, Black Stone expects its total debt levels to be under $200 million.

Black Stone Minerals Acreage



(Source: Black Stone Minerals)

One of the transactions involves the sale of Black Stone's mineral and royalty interests in specific tracts in Midland County, Texas, to a private buyer for gross proceeds of about $55 million. The effective date of the agreement is May 1.

The other agreement involves the sale of a 57% undivided interest across parts of the company's Delaware Basin position and a 32% undivided interest across parts of the company's Midland Basin position to Pegasus Resources for gross proceeds of $100 million. The effective date of the transaction is July 1.

Production associated with the properties to be sold, in total, is estimated to be approximately 1,800 boe/d, according to the company release.

—Emily Patsy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Deal, Legal Hurdles Test Occidental

TOTAL SA has called off plans to acquire **Occidental Petroleum Corp.**'s assets in Ghana, which was conditional on the completion of the acquisition of Occidental's other assets in Algeria, the French energy company said May 18.

The deal was part of an $8.8 billion agreement reached between Total and Occidental to help foot the bill for Occidental's merger with **Anadarko Petroleum Corp**. The assets are located in Mozambique, Ghana, Algeria and South Africa.

While a deal over the assets in Mozambique has been reached, Total said that an agreement over the assets in Ghana fell through after authorities in Algiers blocked Total's acquisition efforts.

The acquisition of assets in Ghana was conditional upon the completion of the Algeria asset sale, Total said, adding that an understanding between Occidental and Algerian authorities is preventing Occidental from selling the interests.

"Given the extraordinary market environment and the lack of visibility that the group faces … Total has decided not to pursue the completion of the purchase of the Ghana assets," Total said in a news release.

Occidental is also facing continued challenges, first taken up by activist investors, to its $35.7 billion acquisition of Anadarko in 2019.

On May 26, investors filed suit, accusing the company of hiding its ability to weather plunging oil prices.

The proposed securities class action, filed on May 26 in a New York state court in Manhattan, seeks remedies on behalf of former Anadarko shareholders who swapped their stock for Occidental shares and investors who acquired $24.5 billion of Occidental bonds that helped fund the August 2019 merger.

Investors said Occidental should have disclosed in its stock and bond registration statements how quadrupling its debt load to $40 billion would leave it "precariously exposed" to falling oil prices and undermine its ability to boost shale oil production and its common stock dividend.

The investors also said Houston-based Occidental's issuance of $10 billion of preferred stock to Warren Buffett's **Berkshire Hathaway Inc**. compounded the overleveraging.

As of May 26, Occidental's market value had dropped to $13 billion from about $44 billion when the merger closed. Some of Occidental's new bonds traded at between 60 and 90.5 cents on the dollar.

Vicki Hollub, Occidental Petroleum Corp. CEO

"Investors have suffered severe losses," the complaint said.

Occidental spokeswoman Melissa Schoeb declined to comment on the suit.

—Reuters

Apergy Completes $4.4 Billion ChampionX Merger

APERGY CORP. completed its multibillion-dollar merger with the upstream business of **Ecolab Inc.** on June 3, resulting in the launch of **ChampionX Corp**.

Sivasankaran "Soma" Somasundaram, president and CEO of ChampionX, said the company will be "an essential player and long-term winner in the oil and gas industry."

"Our combined company will be a strong and resilient organization with a broad geographic footprint, high quality customer base and significant recurring revenue," he said in a news release.

The merger combined Apergy with Ecolab's **Nalco Champion** business, which was renamed ChampionX Holding. The combined product lines include artificial lift, production chemicals and digital technology.

In association with the transaction, Apergy changed its name to ChampionX Corp. Its shares began trading on the New York Stock Exchange under the symbol "CHX" on June 4.

Sivasankaran "Soma" Somasundaram

Apergy and Ecolab announced the transaction, which includes the assumption of valued at $4.4 billion, in a joint release last December. The companies expected the combined company to generate pro forma revenue of about $3.5 billion with annual run-rate cost synergies of $75 million.

The transaction resulted in existing ChampionX Holding equity holders owning approximately 62% of ChampionX on a fully diluted basis, with Apergy equity holders prior to the merger owning approximately 38% of ChampionX on a fully diluted basis.

Analysts with **Tudor, Pickering, Holt & Co.** (TPH) described the merger as "alluring" in a June 4 research note.

"We continue to believe that CHX's earnings stream will outperform most (all) other public OFS companies through the cycle and their free cash flow profile will prove resilient," TPH analysts wrote. "We also fancy the industry structure surrounding drilling technologies and ChampionX's production chemicals business."

In addition to the seven directors which formed the board of directors of Apergy prior to the completion of the transaction, ChampionX also appointed on June 3 Heidi Alderman, former **BASF Corp.** executive, and **Denham Capital** founder Stuart Porter to its board.

—Emily Patsy

Blackstone Sues Caprock Over Troubled Midstream Deal

SERGEY NIVENS/P.V.R. MURTY/SHUTTERSTOCK.COM

PRIVATE-EQUITY BACKED EagleClaw Midstream is suing the former owners of **Caprock Midstream**, alleging they failed to disclose tens of millions of dollars of liabilities during acquisition talks.

EagleClaw in 2018 acquired natural gas pipeline operator **Caprock Midstream Holdings** from Energy Spectrum Capital and Caprock Midstream Management for $950 million. After the deal closed, EagleClaw discovered "numerous issues and claims for liabilities" with the pipeline assets, according to a lawsuit filed in a Texas court in Houston.

The largest amount was a $22 million bill presented after the close by **Cimarex Energy Co.** from an audit of a gas gathering, water handling and electrical services agreements, the suit claimed. EagleClaw is owned by private-equity firms **Blackstone Capital Partners** and **I Squared Capital**.

EagleClaw would not have completed the deal without obligating Caprock to defend those claims had it been aware of the audit, according to the lawsuit.

EagleClaw's suit seeks undisclosed damages for breach of contract and access to $4.75 million held in an escrow account.

The company said it also expects to incur $4 million in costs to fix "severe corrosion" in a gas pipeline it claimed had defective joints and $600,000 to repair a natural gas processing plant in Texas that suffered shutdowns.

The case is *Eagleclaw Midstream Ventures v. Caprock Midstream, Harris County District Court, 2020-31025.*

Centennial Terminates $225 Million Water Infrastructure Transaction

FREEDARST/SHUTTERSTOCK.COM

CENTENNIAL RESOURCE Development Inc. terminated the sale of Permian Basin water infrastructure on May 15 citing failure of the buyer to close the multimillion-dollar transaction.

The transaction included saltwater disposal wells and associated produced water infrastructure located primarily in Reeves County, Texas, where Centennial's Delaware operations are focused. Houston-based **WaterBridge Resources LLC** agreed in late February to acquire the assets in a $225 million transaction, which was expected to close at the end of the first quarter.

"Centennial provided written notice of termination relating to the divestiture after WaterBridge failed to close the transaction … on May 15" Denver-based Centennial said in a company release.

Centennial also expects to receive the $10 million purchase price deposit, which is held in escrow.

In a February release, Centennial described WaterBridge as a long-standing partner, adding that the company historically disposed of nearly half of Centennial's produced water volumes in Reeves County.

WaterBridge is backed by **Five Point Energy LLC**, which sold a 20% minority equity stake in the company to affiliates of Singapore's sovereign wealth fund **GIC** in May 2019.

Analysts with **Tudor, Pickering, Holt & Co.** (TPH) said they continue to see a "tough road ahead" for Centennial absent a material rally in crude, with the company suffering from elevated leverage, high PDP declines and tightening liquidity constraints.

"While we see the official announcement as a negative event, we had already removed proceeds from our model in anticipation of a low probability of closure given the plunge in crude prices and significant decline in [Centennial's] production," the TPH analysts wrote in a May 18 research note.

TPH's model for Centennial currently calls for roughly $255 million of spend this year driving exit-to-exit oil declines of 25%. The firm's analysts estimate the company's 2021 budget will be $145 million, continuing to roll production by an additional 17% exit-to-exit as Centennial "attempts to protect liquidity."

—Emily Patsy

TRANSACTION HIGHLIGHTS

MIDSTREAM

■ Pipeline operator **TC Energy Corp.** said May 25 it had completed the sale of a 65% stake in its Coastal GasLink pipeline, which will move gas from northeast British Columbia to the Pacific Coast.

Private-equity firm **KKR & Co. Inc.** said in December that it and **Alberta Investment Management Corp.** would jointly buy a 65% Coastal GasLink stake.

The company said the partnership also includes a credit agreement with a syndicate of banks to fund the majority of the construction costs. Together, these transactions have resulted in the company realizing immediate proceeds of approximately C$2.1 billion, TC Energy said in a company release.

The C$6.6 billion pipeline, to be operated by TC Energy, had earlier faced opposition from an indigenous group, saying the project interfered with hunting and trapping rights.

SURINAME

■ Malaysia's national oil firm **Petroliam Nasional Bhd** on May 19 said it had completed a 50% farm-down of its participating interest in an offshore block in Suriname to a subsidiary of **Exxon Mobil Corp**.

The deal was made between **Petronas Suriname Exploration & Production B.V.** and **ExxonMobil Exploration and Production Suriname B.V.** for Block 52, which covers over 4,700 sq km (1,800 sq miles), in the Suriname-Guyana Basin.

With the completion of the farm-down, Petronas will focus on drilling a well in the third quarter of this year and acquiring new 3D seismic data of the entire block, the company said in a statement.

FEDERAL LEASES

■ The Trump administration shelved all but one of the oil and gas lease sales it had scheduled for June as the coronavirus pandemic has caused energy prices to crash and left U.S. drillers in crisis.

According to a government website on June 3, sales in Utah and Colorado were officially postponed, adding to the recent delay of June auctions in Nevada and Mississippi.

The U.S. Bureau of Land Management (BLM), which oversees the federal government's oil and gas leasing program, did not give a reason for the delays.

Drilling on federal lands is a crucial part of President Donald Trump's "energy dominance" agenda to maximize domestic production of fossil fuels.

In Colorado, the BLM had been expected to offer 15 parcels covering 4,851 acres. The Utah sale would have been for four parcels on 4,376 acres.

The bureau began putting off lease sales when it abruptly postponed a May auction in New Mexico. It had previously proceeded with a slew of auctions on public lands earlier this year as the novel coronavirus began spreading rapidly in the U.S., prompting a historic drop in oil prices.

A sale by the bureau of 135 leases covering 169,750 acres in Wyoming is still scheduled for June 23 and 24.

NIGERIA

■ Nigeria has launched its first licensing round for marginal oil fields in nearly 20 years, the Department of Petroleum Resources (DPR) said on June 1, despite court rulings last week that barred some of the fields from being auctioned.

Marginal fields are smaller oil blocks that are typically developed by indigenous companies. The new licensing round is the first marginal field round since 2002, which the country hopes will boost oil output and bring in much-needed revenues from fees associated with the licenses.

"A total of 57 fields located on land, swamp and shallow offshore terrains are on offer," the DPR said in a statement posted on its Twitter feed.

Nigeria revoked the existing licenses on the fields so that they could be put into the new licensing round.

The licensing round was announced even though judges in Lagos have blocked Nigeria's efforts to revoke two existing oilfield licenses, court documents seen by Reuters showed.

AUSTRALIA

■ **ConocoPhillips Co.** said May 27 it had completed the sale of its northern Australian business to partner **Santos Ltd.**, which included a restructuring of the originally agreed upon upfront cash payment.

The pair had previously announced the deal in October 2019 with Santos agreeing to pay $1.39 billion in cash for ConocoPhillips' subsidiaries that hold its Australia-West assets and operations. The sale includes interest in the Athena, Bayu-Undan, Bayu-Undan and Poseidon fields, Barossa project and Darwin LNG facility.

On May 27, ConocoPhillips said that while the total consideration for the sale remains unchanged upon closing, it had reached an agreement with Santos so that $125 million of the original upfront cash payment would be timed for a future final investment decision (FID) of the proposed Barossa development project. As a result, the total due to ConocoPhillips upon an FID of the Barossa project increased to $200 million from $75 million.

Based on an effective date of Jan. 1, customary closing adjustments and the increased allocation to the final investment decision payment, ConocoPhillips net cash proceeds total about $765 million in the current quarter. Proceeds from the transaction are expected to be used by the Houston-based independent for general corporate purposes.

MIDDLE EAST

■ **Occidental Petroleum Corp.** is reviewing options for its Middle Eastern assets in a bid to ease its debt load, Bloomberg News reported on June 8, citing people familiar with the matter.

Occidental is considering reducing its stakes in oil and natural gas fields in Oman, where its assets could be valued at more than $1 billion, the report said.

The Houston-based company is also open to divesting other assets in the Middle East, though it is not formally soliciting interest, Bloomberg said. Outside of Oman, Occidental operates in the United Arab Emirates and Qatar.

Occidental has been trying to sell assets to reduce the $40 billion in debt it took on since its $38 billion purchase of Permian rival Anadarko Petroleum last year, an ill-timed bet on rising oil prices.

Occidental's shares have plunged this year amid the worst oil and gas industry downturn in 40 years, and the company has cut staff and reduced expenses to deal with its massive debt levels.

EASTERN US

1 ***DAC Energy & Drilling*** has scheduled three wildcats in Illinois' nonproducing Menard County. According to IHS Markit, DAC's new exploratory tests are each scheduled to be drilled to 1,400 ft and will be targeting oil pays in Spechts Ferry (Lower Decorah). The #3-1 Dart will be drilled in Section 10-19n-7w, and #6-1 Dart will be in nearby Section 10. The company's #4-1 Dart will be drilled in Section 3. Only about 30 tests have been drilled in the county with the last activity in late 2017 to the east of DAC's planned program—#1 Dart Oil in Section 3-19n-7w. It was permitted to 1,400 ft, and the wildcat was junked and abandoned at 180 ft. About 2 miles southeast of DAC's new locations is an 1,845-ft test drilled in 1959 at #1 C. Schmidt in Section 23-19n-7w. Production in this part of Illinois comes from Morgan County's Prentice Field, about 20 miles to the southwest. Opened in 1953, reservoir recovery comes from Pennsylvanian. Within 7 miles to the southwest is shallow production in Jacksonville Field. DAC Energy is based in Alma, W. Va.

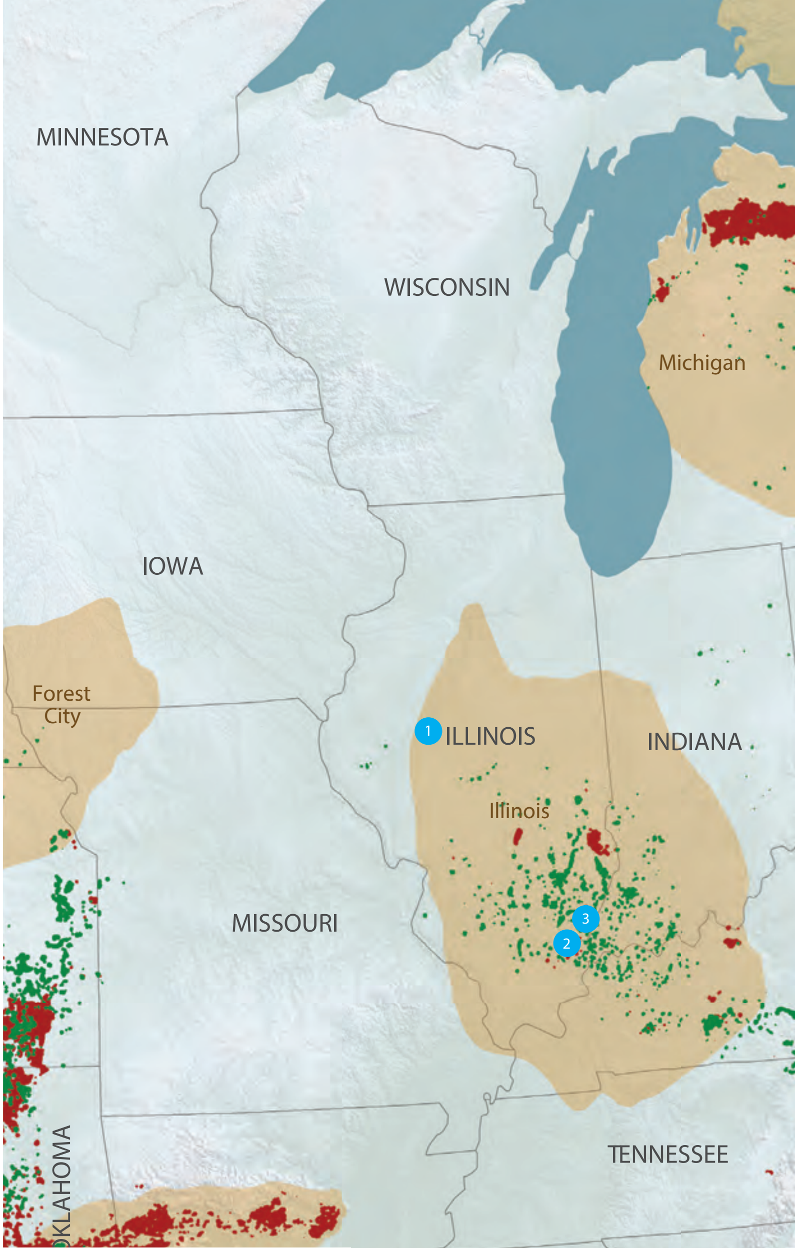
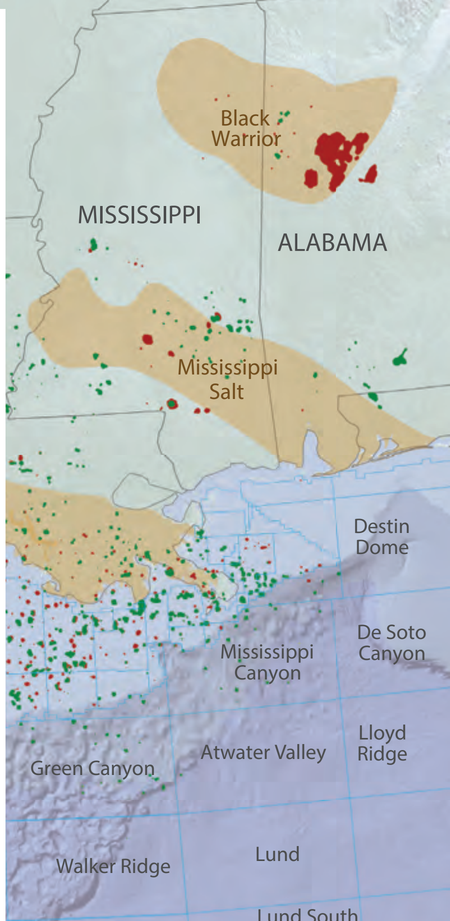
2 IHS Markit reported that Omaha-based ***Patrick Webb Oil LLC*** plans to reenter and deepen an oil well in Section 17-7s-8e White County, Ill. The #1 F. Douglas will be deepened to 4,795 ft and is targeting oil in Fort Payne. The original hole was drilled and completed in an open-hole zone in Aux Vases at 2,924-34 ft flowing 250 bbl of crude per day. It was drilled to 2,934 ft and is in Roland Consolidated Field. The Illinois Basin reservoir produces from Pennsylvanian and Mississippian pays, with the deepest wells in the field yielding crude from Ullin (Mississippian) at 4,050 ft. ***Pioneer Oil Co.*** also has a deeper pool wildcat drilling program in the county about 10 miles to the northeast—a 2010 completion at #1-36 Ackerman Trust in Section 36-5s-8e was drilled in mid-2019 to 4,550 ft. Pioneer has permitted several additional 4,550-ft tests in the area, with oil objectives in Chouteau Lime (Lower Mississippian).

3 ***Herman L. Loeb LLC***, based in Lawrenceville, Ill., announced results from two New Harmony Consolidated Field wells in White County, Ill. The #1-21 Ford is in Section 21-4s-14w and was drilled to 3,980 ft. It produced 10 bbl of oil and 120 bbl of water per day from commingled St. Louis, 3,226-3,302 ft, Salem Limestone, 3,430-3,594 ft, and Warsaw, 3,893-3,902 ft. Within 1 mile to the southeast, #1-21 Donald Mary was drilled to 3,974 ft. It was tested flowing 6 bbl of oil and 124 bbl of water per day. It is producing from commingled perforations from St. Louis at 3,243-86 ft, Salem Limestone at 3,457-3,465 ft and Warsaw at 3,844-74 ft.

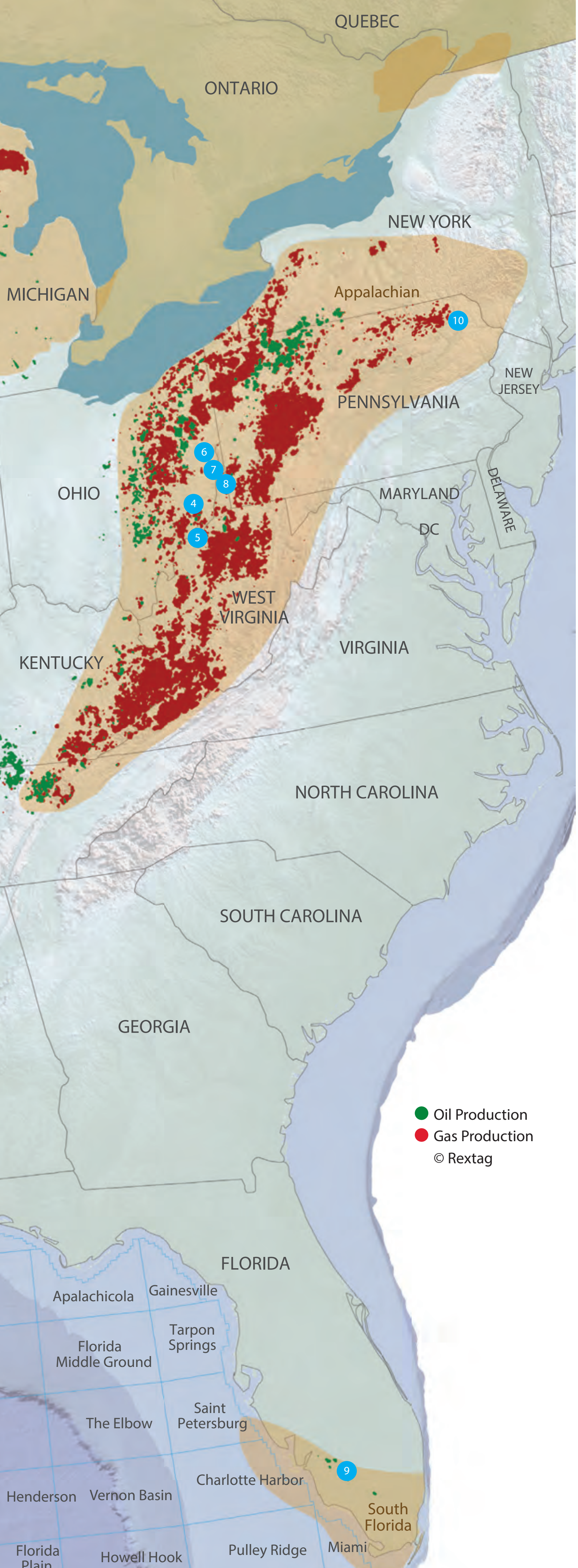
4 Canonsburg, Pa.,-based ***Rice Drilling*** completed a Utica Shale well, #5H Razin Kane, which flowed 32.24 MMcf of gas, with 2.059 Mbbl of water daily. The Belmont County, Ohio, discovery is in Section 16-7n-5w. It was drilled in Morristown Consolidated Field to 27,229 ft, and the true vertical depth is 8,836 ft. Production is from acidized and fractured perforations between 9,289 and 27,143 ft.

5 Two Ritchie County, W. Va., Marcellus Shale wells were completed at an Ellenboro Field pad by Denver-based ***Antero Resources Corp.*** The pad is in Clay Dist., Ellenboro 7.5 Quad. The #1H Hayhurst Unit was drilled to 15,544 ft, 6,290 ft true vertical. It initially flowed 86 bbl of oil, with 6.267 MMcf of gas and 1 bbl of water per day from perforations between 6,695 and 15,368 ft. The #2H Hayhurst Unit was drilled to 16,519 ft, 6,299 ft true vertical. It was tested flowing 96 bbl of oil, 8.1 MMcf of gas and 7 bbl of water per day with production from perforations at 6,514-16,393 ft.

6 ***EAP Ohio LLC*** announced results from a Jefferson County, Ohio, completion. The #10H Bruner Land Co 20-11-3 is in Section 11n-3w and initially flowed 29.746 MMcf of gas and 2.111 Mbbl of water per day from Utica Shale. The Fairfield Field well was drilled to the northeast to 23,981 ft, and the true vertical depth is 9,001 ft. Production is from perforations at 9,250-23,801 ft. EAP Ohio's headquarters are in Houston.

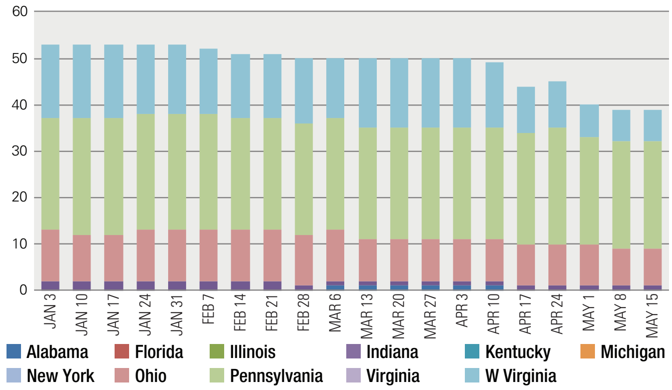



7 In Jefferson County, Ohio, ***Ascent Resources*** completed a Utica Shale well in Section 1-8n-3w. The Oklahoma City-based operator's #7H Buddy SMF JF is in Bloomingdale Field and initially flowed 40.92 MMcf of gas and 295 bbl of water per day. It was drilled to 23,014 ft with a true vertical depth of 9,350 ft and bottomed in to the northwest in Section 14. Production is from perforations between 10,067 and 22,892 ft.



Eastern US Rig Count

Jan. 3, 2020-May 5, 2020



Source: Baker Hughes Co.

8 Two Brooke County, W. Va., Marcellus discoveries were announced by ***Southwestern Energy Co.*** The wells were drilled from a pad in Buffalo Dist., Bethany 7.5 Quad. The #10H Corbin Margaret Brk was drilled to the south to 15,830 ft, 6,193 ft true vertical. It was tested flowing 564 bbl of oil, with 6.648 MMcf of gas and 413 bbl of water per day. Production is from perforations between 6,288 and 15,785 ft. The offsetting #3H Margaret Corbin Brk was drilled to 18,044 ft, and the true vertical depth is 6,079 ft. It initially produced 547 bbl of oil, 4.221 MMcf of gas and 206 bbl of water per day. Production is from perforations at 6,291-17,997 ft. Southwestern's headquarters are in Spring, Texas.

9 A short-lateral horizontal test in Florida's Sunoco Felda Field was spud by ***MKJ Exploration***, marking the first new drilling in the reservoir in 40 years. MKJ began drilling the vertical part of the well, #29-4BH Red Cattle. It is in Section 29-45s-29e of Hendry County. The proposed total depth at the Sunniland Lime oil venture is 12,194 ft, and the planned true vertical depth is 11,475 ft. Straddling the Hendry/Collier county line, Sunoco Felda Field last reported oil production in 1992. The field was opened in 1964, and cumulative field recovery is 5.2 MMbbl of crude, 418 MMcf of gas and 32 MMbbl of water. Production is from perforations in Sunniland Lime at 11,400-11,500 ft. To the west of Sunoco Felda Field is another Sunniland Lime reservoir, Mid-Felda Field, which was opened in 1977. Reservoir production has been sporadic in recent years, with 2019 output totaling 485 bbl of crude from one active well. A directional sidetrack was permitted in Mid-Felda Field in late 2019 at #27-4C Red Cattle in Section 27-45s-28e. It has a planned depth of 11,582 ft (11,436 ft true vertical). MJK is based in Metairie, La.

10 ***Chesapeake Operating Inc.*** completed three Marcellus Shale wells from a pad in Pennsylvania's Susquehanna County. The Jessup Field pad is in Section 5, Auburn Center 7.5 Quad, Auburn Township. The #101H Masso was drilled to 14,069 ft (7,013 ft true vertical) and flowed 44.44 MMcf of gas with no reported water per day. Production is from perforations at 7,618-14,040 ft with a shut-in casing pressure of 2,800 psi. To the southeast, #6 Masso was drilled to 14,458 ft (7,489 ft true vertical) and produced 45.56 MMcf of gas and no reported water per day with a shut-in casing pressure of 3,200 psi. Production is from perforations at 7,569-14,434 ft. The #106H Masso was drilled to 15,100 ft, 7,424 ft true vertical, and produced 37.998 MMcf of gas with production from 7,552-15,075 ft, but additional information is not currently available.

GULF COAST

1 Two McMullen County (RRC Dist. 1), Texas, Eagle Ford wells were completed by Oklahoma City-based ***Chesapeake Operating Inc.*** The Eagleville Field discoveries were drilled from a pad in Section 23, J A Poitevent Survey, A-388, and both bottomed to the northwest in Section 3, Susan Skinner Survey, A-815. The #3HQ McKenzie HC 3 was drilled to 22,454 ft (9,959 ft true vertical). It flowed 1.089 Mbbl of oil, 655 Mcf of gas and 1.213 Mbbl of water daily from perforations at 10,590-22,397 ft. Gauged on a 21/64-in. choke, the flowing tubing pressure was 2,057 psi. The #4HQ McKenzie HC4 was drilled to 22,428 ft (9,953 ft true vertical). It produced 1.642 Mbbl of oil, 941 Mcf of gas and 681 bbl of water per day from perforations at 10,641-22,339 ft. Tested on an 18/64-in. choke, the flowing tubing pressure was 1,946 psi, and the flowing casing pressure was 119 psi.

2 ***Hilcorp Energy Co.*** has completed a Frio well in Matagorda County (RRC Dist. 3), near Tres Palacios Bay. The #2 Green Unit 1 initially flowed 12.94 MMcf of gas, 380 bbl of 47.7-degree-gravity crude and 30 bbl of water per day from Textularia mississippiensis at 14,120-86 ft. Gauged on a 26/64-in. choke, the flowing casing pressure was 8,428 psi. The directional sidetrack was drilled to 15,121 ft, and the true vertical depth is 14,982 ft. The venture is on a 640-acre Upper Texas Coast lease in Section 19, Lewis DeMoss Survey, A-145. The original hole was abandoned at 15,244 ft. Hilcorp is based in Houston.

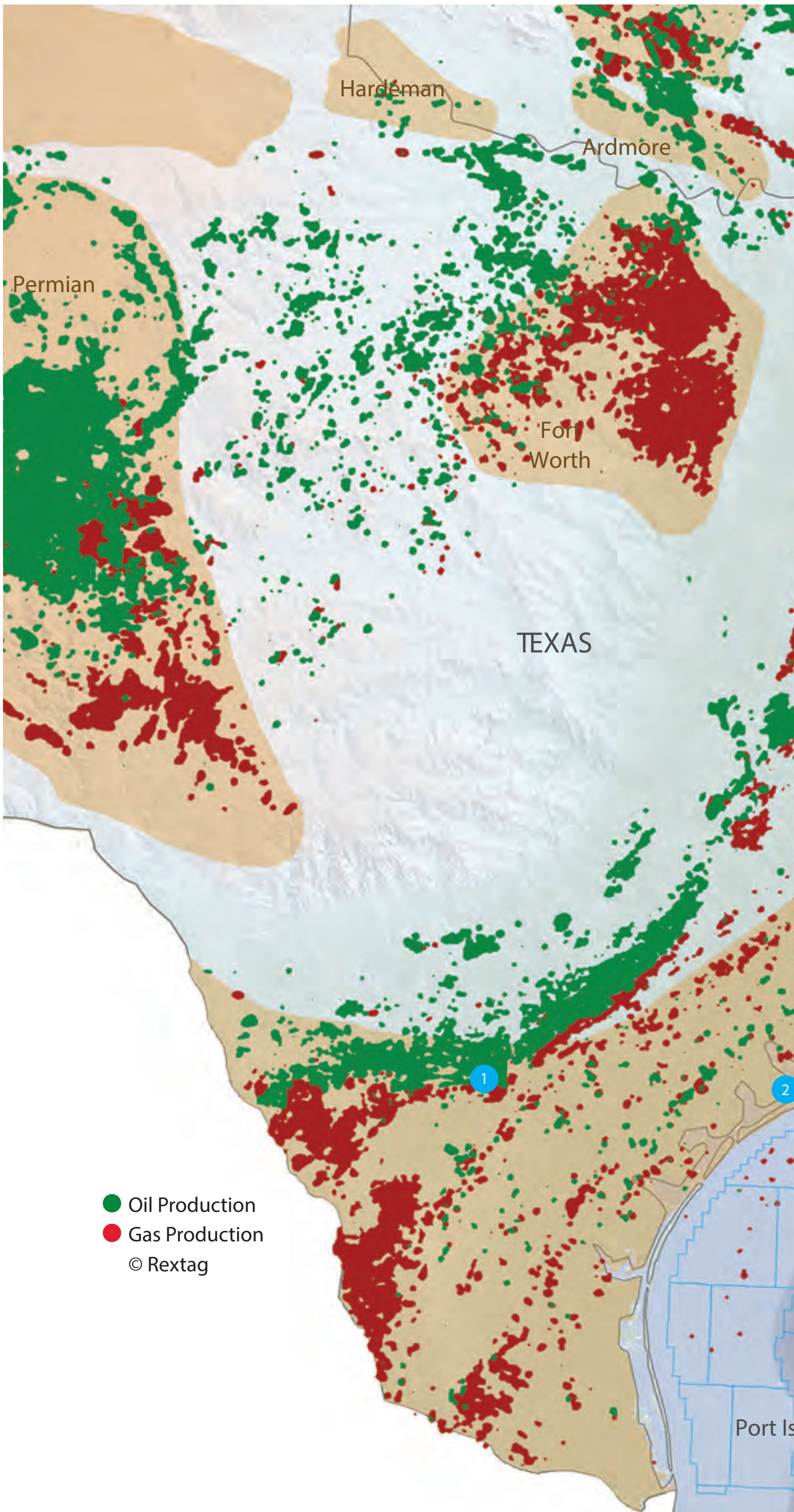
3 Two Frio gas wells were completed by ***Cimarron Energy LLC*** in Brazoria County (RRC Dist. 3), Texas. The wells are a 440-acre Upper Texas Coast lease in Alfred Swingle Survey, A-369. The #1 State Lease 00021 produced 2.799 MMcf of gas and 206 bbl of 49.3-degree-gravity crude from perforations at 12,770-80 ft. Tested on a 10/64-in choke, the flowing casing pressure was 6,878 psi, and the shut-in casing pressure was 8,900 psi. The directional gas well in Pegasus Gulf Coast Field was drilled to 12,994 ft, 11,807 ft true vertical, and bottomed within 1.5 miles to the south-southeast beneath Chocolate Bay. The offsetting #1 Blackstone 156 flowed 726 Mcf of gas and 6 bbl of water per day from perforations at 6,963-70 ft. The Rattlesnake Mound Field well was directionally drilled to 7,537 ft (6,801 ft true vertical), bottoming within one-half mile to the southeast. Cimarron is based in Houston.

4 In San Augustine County (RRC Dist. 6), Texas, ***XTO Energy Inc.*** completed a Haynesville Shale discovery in Carthage Field. The #2 H BSI Seahawks DU was drilled in Section 1, SP RR CO Survey, A-268 to 22,603 ft, 14,330 ft true vertical. It initially flowed 14.99 MMcf of gas and 128 bbl of water per day from perforations at 14,774-22,566 ft. Tested on a 24/64-in. choke, the flowing casing pressure was 5,901 psi, and the shut-in casing pressure was 9,612 psi. Houston-based XTO is a subsidiary of ***Exxon Mobil***.

5 In Panola County (RRC Dist. 6), Texas, ***Rockcliff Energy*** announced results from a Haynesville Shale completion in Alford Bissel Survey, A-89. The #2H Reeves-Curtis HV Unit B is in Carthage Field and was drilled to 22,087 ft, and the true vertical depth is 11,418 ft. It was tested flowing 30.31 MMcf of gas and 569 bbl of water per day. Gauged on a 30/64-in. choke, the flowing casing pressure was 7,025 psi, and the shut-in casing pressure was 7,800 psi. Production is from perforations between 11,691 and 21,889 ft. Rockcliff is based in Houston.

6 In Caddo Parish, La., ***Chesapeake Operating Inc.*** has completed a Haynesville Shale well. According to IHS Markit, #1-Alt AFP 28&21&16-15-16HC was tested flowing 38.312 MMcf of gas and 1.944 Mbbl of water per day through acid- and fracture-treated perforations at 11,684-22,722 ft. Gauged on a 37/64-in. choke, the flowing casing pressure was 6,669 psi. It was drilled to 22,786 ft (11,375 ft true vertical) and is in Section 28-15n-16w. The Bethany Longstreet Field well bottomed about 2 miles to the north in Section 16.

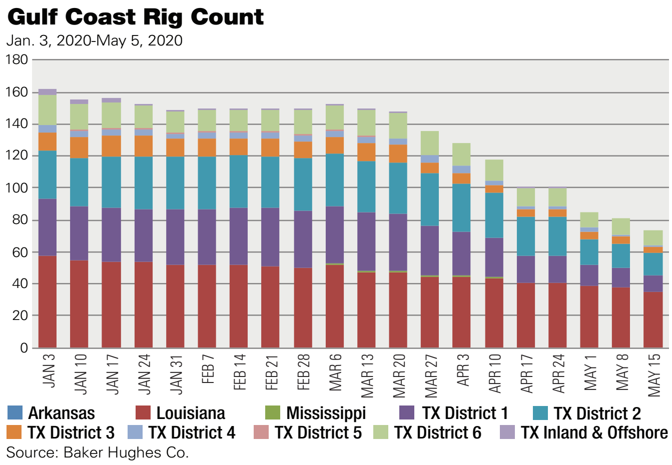
7 Three horizontal Haynesville Shale wells were completed from a pad in DeSoto Parish, La., by ***Comstock Resources***. The Trenton Field wells were drilled from offsetting surface locations in Section 34-12n-13w, with the parallel laterals bottoming about 2 miles to the south in Section 10-11n-13w. The #1-Alt Bedsole 3-10HC was tested flowing 29.596 MMcf of gas per day from an acid- and fracture-treated zone at 12,180-21,741 ft. The flowing tubing pressure was 7,330 psi during testing on a 29/64-in. choke. It was drilled to 22,114 ft (11,894 ft true vertical). The #2-Alt Bedsole 3-10HC produced 23.643 MMcf of gas from perforations 11,620-21,450 ft. It was drilled to 21,543 ft (11,350 ft true vertical). The #3-Alt Bedsole 3-10HC initially flowed 28.33 MMcf of gas per day from

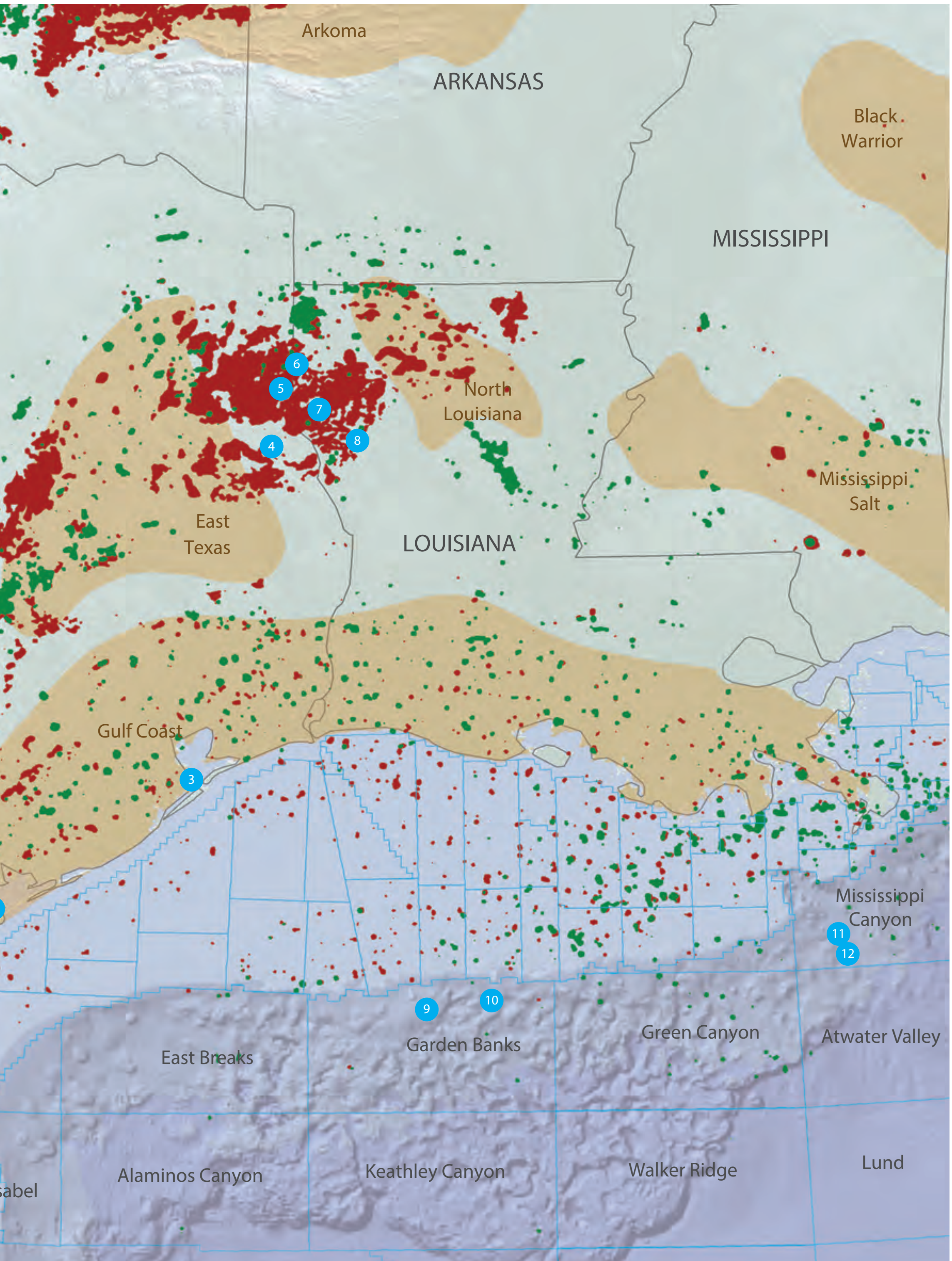


perforations at 12,225-22,069 ft. The total depth is 22,129 ft, and the true vertical depth is 11,883 ft. Comstock's headquarters are in Frisco, Texas.

8 In Section 1-9n-11w in Sabine Parish, La, ***Indigo Minerals*** reported results from a Haynesville Shale discovery. The #3-Alt Tristar 1&12-9-11HC is in San Miguel Creek Field and was drilled to the south to 20,934 ft, 14,020 ft true vertical. It produced 28.716 MMcf of gas and 264 bbl of water daily from perforations at 14,576-20,780 ft and was tested on a 25/64 in. choke, and the flowing tubing pressure was 10,613 psi. Indigo's headquarters are in Houston.

9 ***Total*** has spud an exploratory test in the western half of Garden Banks Block 1003. The #1 OCS G36155 is on the South Platte prospect, and area water depth is 4,500 ft. The Paris-based company intends to drill three exploratory tests on the tract. Block 1003 had previously been designated ***Cobalt International Energy***'s South Platte prospect under OCS G30882, although no drilling occurred before the lease expired. In 2018, Cobalt sold its stake in North Platte to Total and ***Equinor***. The two companies held smaller stakes in North Platte before taking complete control of the project. Cobalt drilled #1 (BP) OCS G30876 on adjacent Block 959 of the North Platted prospect, and it hit more than 550 net ft of oil pay in multiple Lower Tertiary reservoirs. After appraisal and sidetrack drilling, Cobalt reported the estimated total recoverable hydrocarbons is more than 500 MMboe.





10 Houston-based ***EnVen Energy Corp.*** has spud the first exploratory test on the company's two-block Mt. Ouray prospect in the Gulf of Mexico. The #1SS OCS G35409 is in Green Canyon Block 767, and area water depth is 4,600 ft. According to an exploration plan filed in 2019, as many as four tests are planned for various sites on the two blocks. EnVen also operates the adjacent Mt. Shavano prospect and has planned up to four exploratory tests for previously undrilled Green Canyon Block 722 (OCS G36053). Mt. Ouray and Mt. Shavano are both Upper Miocene prospects.

11 ***BP Plc*** announced a Mississippi Canyon Block 430 discovery. The #002S0B0 OCS G35823 ST00BP00 produced 11.335 Mbbl of oil, 13.986 MMcf of gas and 376 bbl of water daily from an Upper Miocene perforations at 13,090-13,424 ft. It was drilled to 13,690 ft, and the true vertical depth is 13,362 ft. Gauged on a 50/64-in. choke, the flowing tubing pressure was 4,750 psi. BP is based in London.

12 A deepwater exploratory test has been scheduled on previously undrilled Mississippi Canyon Block 518 by ***BP Plc***. The company's Galapagos Deep prospect, #1 OCS G35828, is in the southwestern portion of the tract. Water depth in the area is 6,379 ft. According to a recently approved exploration plan, as many as six tests could be drilled on Block 518. Fields adjacent to the Galapagos Deep prospect (Santiago and Isabela) are part of BP's Galapagos development, and production from the fields comes from Miocene at 18,200-20,200 ft.

MIDCONTINENT & PERMIAN BASIN

1 In Eddy County, N.M., a Bone Spring completion was reported by Oklahoma City-based ***Devon Energy Corp***. The #331H Spud Muffin 31-30 Federal Com is in Section 31-23s-29e. It produced 1.357 Mbbl of oil, 2.403 MMcf of gas and 4.34 Mbbl of water per day. The Cedar Canyon Field well was drilled to 19,938 ft, 9,637 ft true vertical, and was fractured in 42 stages with a shut-in casing pressure of 2,555 psi, and production is from perforations between 9,782 and 19,767 ft.

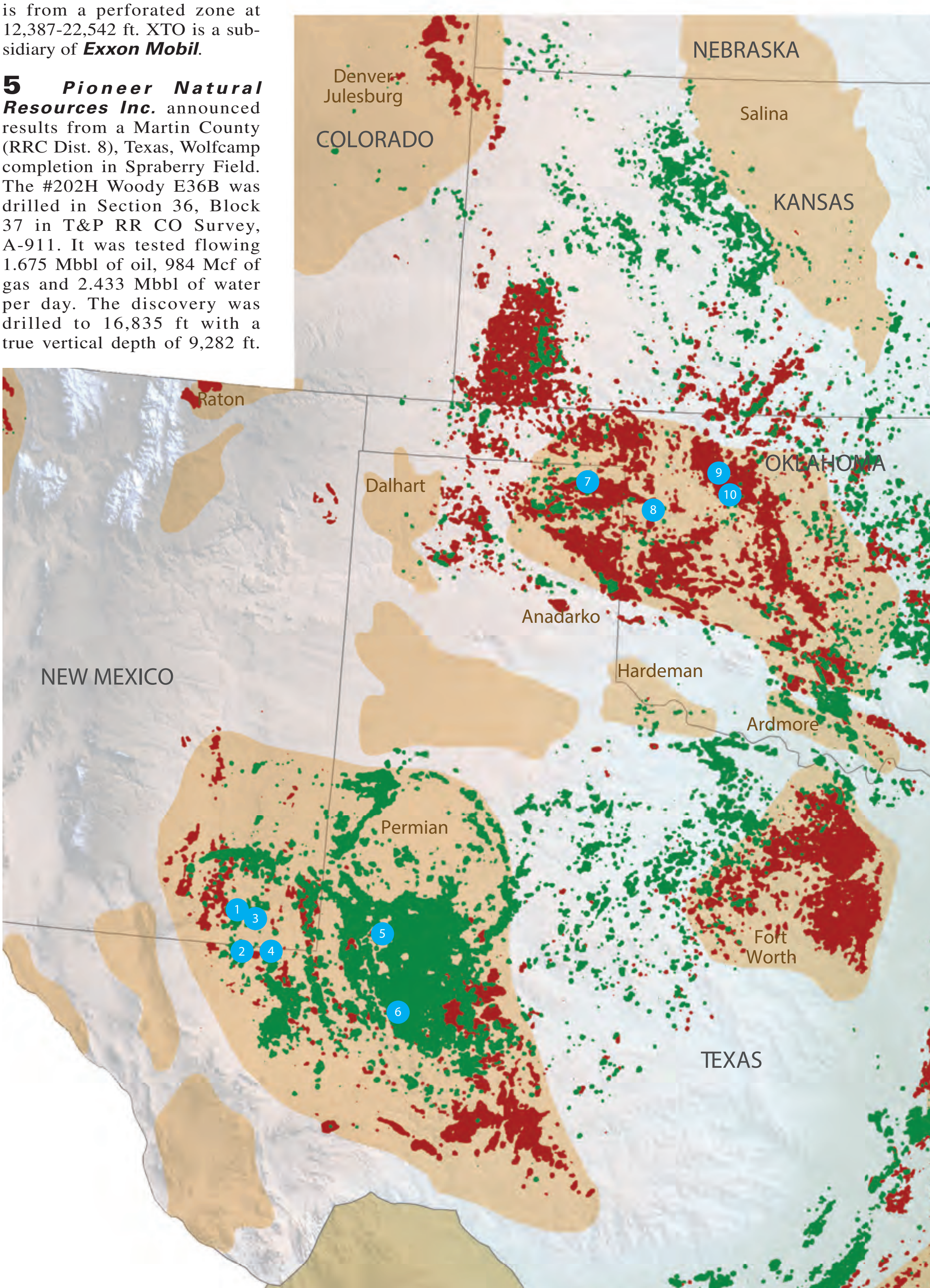
2 According to IHS Markit, ***ConocoPhillips*** has completed the first long-lateral well on a four-well pad in the Delaware Basin in Reeves County (RRC Dist. 8), Texas. The #1H Monarch State flowed 1.456 MMcf of gas, 458 bbl of 50-degree-gravity condensate and 1.546 Mbbl of water per day from Wolfcamp. Production is from fracture-treated perforations at 10,000-20,276 ft. Gauged on a 1-in. choke, the flowing tubing pressure was 2,357 psi, and the shut-in casing pressure was 2,820 psi. The Ford West Field well is on a 1,310-acre West Texas lease in Section 37, Block 58 T1S, T&P RR Co Survey, A-652. The horizontal leg bottomed about 2 miles to the south at 20,451 ft (9,742 ft true vertical) in Section 48. ConocoPhillips is based in Houston.

3 Two Purple Sage Field-Wolfcamp completions were reported in Section 34-23s-31e by ***Oxy USA*** in Eddy County, N.M. The #175H Platinum MDP1 34-3 Federal Com was drilled to 21,690 ft, and the true vertical depth is 11,638 ft. It was tested flowing 3.255 Mbbl of oil with 8.638 MMcf of gas and 7.862 Mbbl of water daily. It was fractured in 41 stages. Production is from perforations at 11,764-21,584 ft. The #176H Platinum MDP1 34-3 Federal Com was drilled to 21,902 ft, 11,808 ft true vertical, and it bottomed in Section 31. It produced 3.646 Mbbl of oil, 9.489 MMcf of gas and 5.894 Mbbl of water per day after 41-stage fracturing. Production is from perforations at 11,935-21,795 ft. Oxy USA's headquarters are in Houston.

4 A Phantom Field discovery by ***XTO Energy Inc***. produced 2.913 Mbbl of oil, 4.571 MMcf of gas and 4.347 Mbbl of water per day. The Wolfcamp producer, #12H Saint Kitts 76 2833, was drilled in Loving County (RRC Dist. 8), Texas, in PSL Survey, A-1237. It was drilled to 22,687 ft with a true vertical depth of 11,886 ft. The flowing tubing pressure was 492 psi, and the flowing casing pressure was 315 psi during testing on a 74/64-in. choke. Production is from a perforated zone at 12,387-22,542 ft. XTO is a subsidiary of ***Exxon Mobil***.

5 ***Pioneer Natural Resources Inc.*** announced results from a Martin County (RRC Dist. 8), Texas, Wolfcamp completion in Spraberry Field. The #202H Woody E36B was drilled in Section 36, Block 37 in T&P RR CO Survey, A-911. It was tested flowing 1.675 Mbbl of oil, 984 Mcf of gas and 2.433 Mbbl of water per day. The discovery was drilled to 16,835 ft with a true vertical depth of 9,282 ft. Pioneer's headquarters are in Irving, Texas.

6 Three horizontal Wolfcamp wells have been completed from a pad by Houston-based Hibernia Resources III LLC in Reagan County (RRC Dist. 7C), Texas. The wells are in Section 17, Block F, C&M RR Co Survey, A-79. According to IHS Markit, #1H Hail Tap Rock was tested flowing 1.004 Mbbl of 41.8-degree-gravity crude, 902 Mcf of gas and 1.503 Mbbl of water per day from acidized and fracture-stimulated perforations at 8,723-13,824 ft. Tested on a 46/64-in. choke, the flowing tubing pressure was 346 psi. The 13,952-ft Spraberry Trend well has a true vertical depth of 8,356 ft, and the lateral bottomed about 1 mile to the northwest in Section 14. The parallel #2H Hail Tap Rock flowed 1.131 Mbbl of oil, 827 Mcf of gas and 1.794 Mbbl of water per day. Treated perforations are at 8,510-13,611 ft, and the flowing tubing pressure was 645 psi when tested on a 34/64-in. choke. The 13,741-ft well has a true vertical depth of 8,220 ft. The #3H Hail Tap Rock was drilled to 14,014 ft (8,342 ft true vertical) and produced 1.007 Mbbl of oil, 907 Mcf of gas and



1.528 Mbbl of water from perforations at 8,783-13,884 ft.

7 An Ochiltree County (RRC Dist. 10), Texas, Cleveland discovery in the western Anadarko Basin was announced by ***Courson Oil & Gas Inc***. The #3H Dickinson 312 was tested on gas lift producing 344 bbl of 42-degree-gravity crude, 336 Mcf of gas and 451 bbl of water per day. The Pan Petro Field well was completed in a fracture-stimulated interval at 7,637-11,834 ft. It was drilled to 11,942 ft, 7,322 ft true vertical, in Section 312, Block 43, H&TC RR Co Survey, A-638. The venture bottomed within 1 mile to the north in the same section. Courson is based in Perryton, Texas.

8 In Ellis County, Okla., ***FourPoint Energy LLC*** has completed three extended-lateral Peek South Field wells in the Anadarko Basin. The Cleveland producers were drilled from a pad in Section 29-17n-23w.The #1S HA Spoonbill 20X17-17-23 was tested flowing 246 Mcf of gas, 203 bbl of 43-degree-gravity oil and 813 bbl of water per day from fracture-treated perforations at 10,165-20,322 ft. The flowing tubing pressure was 300 psi during testing on a 28/64-in. choke. It was drilled to 20,470 ft, 9,667 ft true vertical, and the lateral bottomed about 2 miles to the north in Section 16. About one-half mile to the east, the Oklahoma City-based company drilled two wells from offsetting surface locations. The #2HB Spoonbill 20X17-17-23 flowed 320 Mcf of gas, 182 bbl of oil and 1.253 Mbbl of water daily from perforations at 10,150-19,201 ft. It was drilled to the north to 20,441 ft (9,652 ft true vertical). The #3HC Spoonbill 20X17-17-23 initially flowed 354 Mcf of gas, 160 bbl of oil and 1.137 Mbbl of water per day from perforations at 10,175-20,324 ft. It was drilled to the north to 20,477 ft (9,666 ft true vertical).

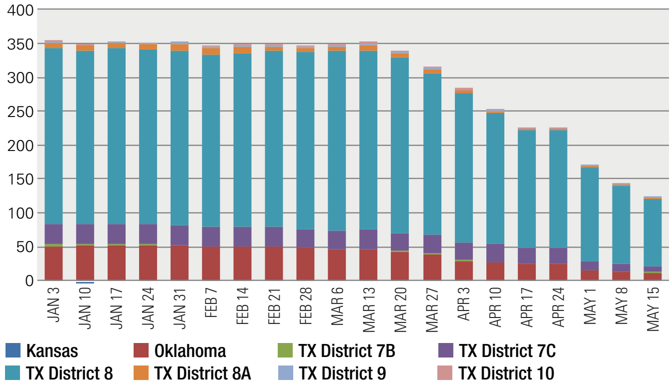
9 ***Red Bluff Resources Operating LLC*** has completed a horizontal Mississippian oil well in Oklahoma's Okeene Northwest Field. The Anadarko Basin well, #7-31MH Wilmott Heritage 2113, is in Section 39-21n-13w in Major County. It was tested on-pump flowing 386 bbl of 33-degree-gravity crude, 687 Mcf of gas and 2.183 Mbbl of water per day. Production is from perforations between 6,166 and 13,489 ft. The well was drilled to 13,647 ft, and the true vertical depth is 8,308 ft. The lateral was expected to bottom more than 1 mile to the south. Red Bluff's headquarters are in Oklahoma City.

10 A Mississippian Solid completion in Blaine County, Okla., was announced by ***Crawley Petroleum Corp***. The Okeene Northwest Field well, #2-1Mhh Hoffman Trust, initially flowed 253 bbl of 42–degree-gravity oil, 2.773 MMcf of gas and 1.393 Mbbl of water per day. It was drilled to 13,555 ft, and the true vertical depth is 8,957 ft. Production is from perforations at 9,185-13,459 ft and is in Section 13-19n-13w. Crawley's headquarters are in Oklahoma City.

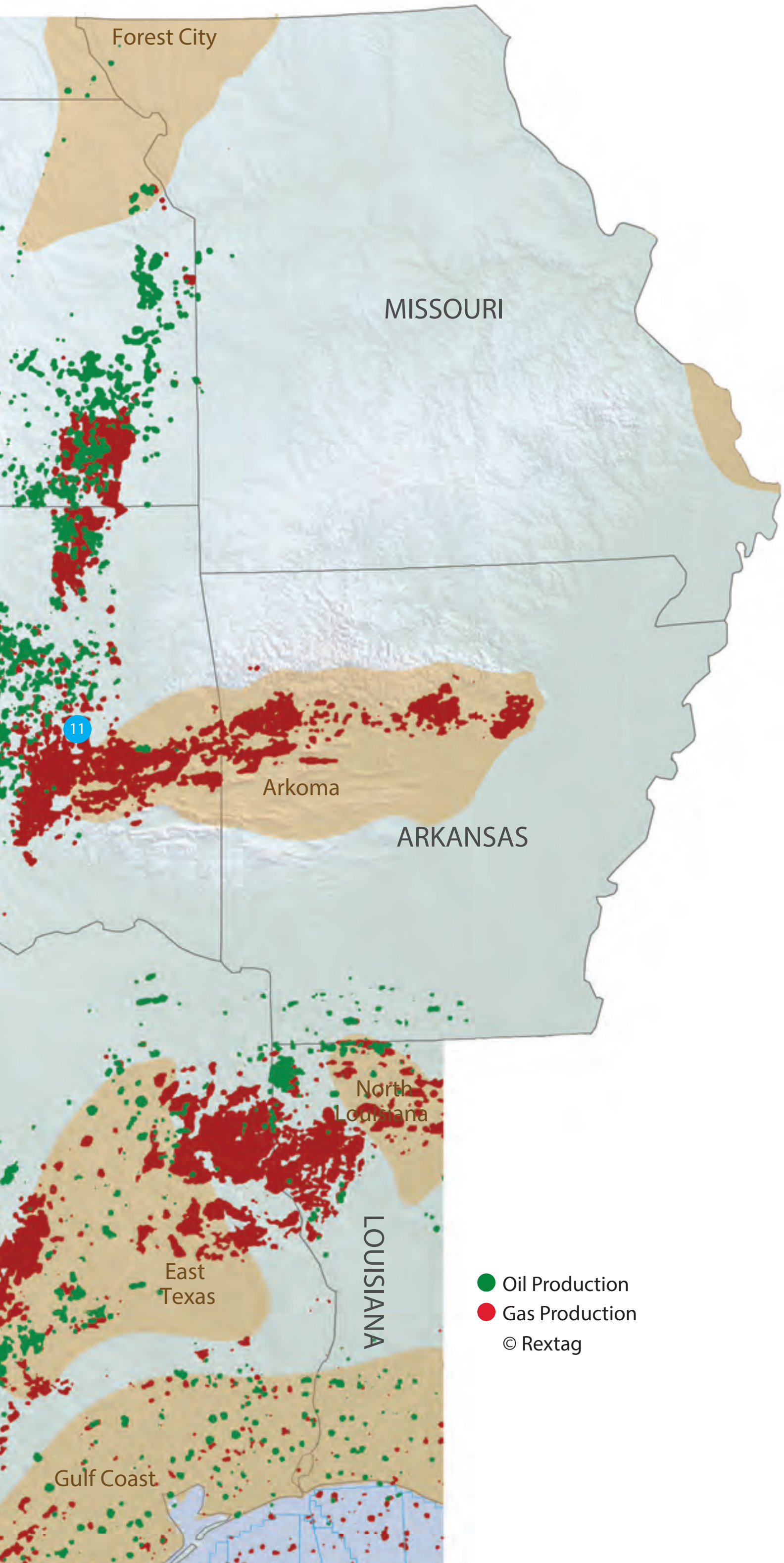
11 ***Trinity Operating Inc.*** completed two Hughes County, Okla., Woodford wells from a Lamar East Field pad in Section 31-8n-12e. The #2-31/30H Glynell was drilled to 15,934 ft (4,484 ft true vertical) and bottomed in Section 30. It produced 8.334 MMcf of gas and 2.59 Mbbl of water per day. It was tested on an unreported choke size with a flowing tubing pressure of 950 psi. Production is from commingled perforations in Woodford (5,534-15,737 ft) and Mayes (13,543-14,673 ft). The #2-6/7H Leann was drilled to 15,970 (4,905 ft true vertical) and bottomed in Section 7-7n-12e. It was tested flowing 65 bbl of 42.5 degree-gravity oil, 6.785 MMcf of gas and 1.488 Mbbl of water per day from Woodford at 5,359-15,919 ft. The flowing tubing pressure was 850 psi. Trinity is based in Houston.

Midcontinent & Permian Basin Rig Count

Jan. 3, 2020-May 5, 2020



Source: Baker Hughes Co.



WESTERN US

1 IHS Markit reported that Las Vegas-based ***Western Oil Exploration Co.*** has permitted three remote wildcats in eastern Nevada's Newark Valley. The #25-1 Scott-Federal will be in Section 25-17n-56e of White Pine County. Within one-half mile to the southwest in Section 35, the company has also staked #35-1 Scott-Federal. The vertical tests are expected to reach 10,000 ft each and apparently will target the Mississippian Chainman Shale and Paleozoic Dolomite. The third location is currently unpermitted but will be located farther to the southwest at #3-1 Scott-Federal in Section 3-16n-56e. No objectives have been identified by the operator. Nearby drilling includes a 7,500-ft wildcat about 5 miles west-southwest of #3-1 Scott at #1-FLT in Section 11-16n-55e, which was drilled in 2011 and had no information released.

2 A Sublette County, Wyo., venture was announced by ***Jonah Energy LLC*** in Jonah Field. The company's #101X-12 Stud Horse Butte is in Section 12-29n-108w. It produced 19 bbl of oil, 3.415 MMcf of gas and 233 bbl of water per day. Production is from commingled perforations at Fort Union/Lance, 9,105-9,821 ft and Lance/Mesaverde at 9,865-13,260 ft. The well was drilled to 13,652 ft with a true vertical depth of 13,575. Gauged on a 48/64-in. choke, the shut-in casing pressure was 756 psi after 10-stage fracturing. Jonah's headquarters are in Denver.

3 In western Colorado's Garfield County, Denver-based ***TEP Rocky Mountain LLC*** completed a Trail Ridge Field well. The #544-22-597 TR Chevron produced 2.01 MMcf of gas per day from commingled zones at Williams Fork/Cameo (6,549-8,428 ft); Cameo (8,448-8,622 ft); Cozzette/Corcoran (8,903-9,127 ft) and Corcoran (9,163-9,379 ft). It is in Section 22-5s-97w and was drilled to 9,510 ft with a true vertical depth of 9,419 ft. The venture was fractured in 12 stages.

4 A Sweetwater County, Wyo., Lewis producer was announced by ***Crowheart Energy LLC***. The #10-22-94 1LH Siberia Ridge initially flowed 245 bbl of 45-degree-gravity oil, 2.214 MMcf of gas and 1.198 Mbbl of water daily. The Siberia Ridge Field well was drilled to 15,946 ft, 10,883 ft true vertical, and is in Section 10-22n-94w. Production is from perforations at 11,532-15,841 ft. Gauged on a 21/64-in. choke, the shut-in tubing pressure was 1,720 psi, and the shut-in casing pressure was 2,180 psi. Crowheart's headquarters are in Denver.

5 In Section 19-33n-69w of Converse County, Wyo., Oklahoma City-based ***Chesapeake Operating Inc.*** completed a Turner Sand venture. The #20H York 19-33-69 USA A TR was drilled to 18,772 with a true vertical depth of 11,086. It was tested producing 608 bbl of 48-degree-gravity oil, with 5.275 MMcf of gas and 1.69 Mbbl of water daily. It was tested on a 32/64-in. choke with a shut-in casing pressure of 2,524 psi and a shut-in tubing pressure of 2,520 psi. Production is from perforations at 11,578-18,544 ft.

6 ***Chesapeake Operating Inc.*** has completed the first horizontal producer from a multiwell pad in Converse County, Wyo. The discovery is on the southwestern flank of Flat Top Field at #1H Cole 27-33-69 USA A NB. It was tested flowing 1.18 Mbbl of 47.2-degree-gravity crude, 2.968 MMcf of gas and 2.205 Mbbl of water per day from Niobrara at 11,109-18,412 ft. The 18,472-ft well is in Section 27-33n-69w with a true vertical depth of 10,590 ft. It bottomed 2 miles to the north-northwest in Section 22 and was tested after 27-stage acidizing and fracturing. Production is from perforations at 11,109-18,412, and it was tested on a 44/64-in. choke with a shut-in casing pressure of 2,466 psi.

7 ***Burlington Resources Co.*** completed four D-J Basin-Niobrara producers from an Adams County, Colo., pad in Section 27-3s-65w. The #3BH Florida 3-65 27-26 flowed 1.087 Mbbl of oil, 1.112 MMcf of gas and 1.5 Mbbl of water per day after 28-stage fracturing. It was drilled to 18,043 ft, 7,802 ft true vertical, and is producing from perforations at 8,400-17,870 ft. Gauged on a 28/64-in. choke, the flowing tubing pressure was 766 psi. The #3AH Florida #3-65 27-26 initially produced 456 bbl of oil, 22.1 Mcf of gas and 883 bbl of water per day. It was drilled to 18,011 ft, 7,729 ft true vertical, and production is from perforations at 8,395-17,829 ft. It was tested after 26-stage fracturing on a 20/64-in. choke with a flowing tubing pressure of 1,230 psi. The #3CH Florida 3-65 27-26 flowed 1.003 Mbbl of oil, 1.386 MMcf of gas and 480 bbl of water per day from perforations at 8,225-17,727 ft. It was drilled to 17,910 ft, 7,730 ft true vertical. Gauged on a 25/64-in. choke, the flowing tubing pressure was 643 psi. The #3DH Florida 3-65 27-26 was drilled to 17,942 ft, 7,799 ft true vertical, and produced 1.123 Mbbl of oil, 564 Mcf of gas and 982 bbl of water per day. It was fractured in 28 stages and tested on a 28/64-in. choke with a flowing tubing pressure of 635 psi and produces from perforations at 8,286-17,766 ft. Burlington Resources is a subsidiary of ***ConocoPhillips***.

8 Three Mountrail County, N.D., wells were announced by New York City-based ***Hess Corp.*** in Robinson Lake Field. The ventures were drilled from a single drillpad in Section 30-154n-93w. The

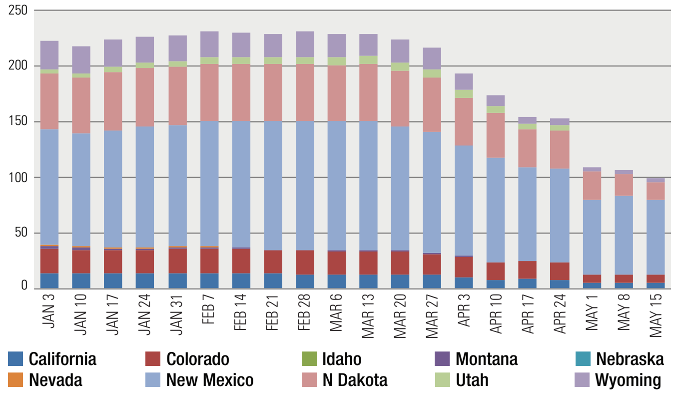
#154-93-3031H-7 EN-Weyrauch B was drilled to 21,575 ft, 10,759 ft true vertical, and bottomed in Section 31. It flowed 3.389 Mbbl of oil, 3.066 MMcf of gas and 2.284 Mbbl of water per day after 30-stage fracturing from perforations at 11,341-21,313 ft in Middle Bakken. Tested on a 44/64-in. choke, the flowing tubing pressure was 1,451 psi. The #154-93-3031H-5 EN-Weyrauch B was drilled to 21,420 ft, 10,779 ft true vertical. It produced 3.949 Mbbl of oil, 4.728 MMcf of gas and 2.252 Mbbl of water per day from Middle Bakken after 30-stage fracturing from perforations at 11,173-20,628 ft. Gauged on a 46/64-in. choke, the flowing tubing pressure was 1,645 psi. The #154-93-3031H-6 EN-Weyrauch B was drilled to 21,378 ft (10,899 ft true vertical). It produced 2.462 Mbbl of oil with 1.863 MMcf of gas and 2.653 Mbbl of water per day from Three Forks perforations at 11,162-20,579 ft after 30-stage fracturing. It was tested on a 44/64-in. choke with a flowing tubing pressure of 1,396 psi.

9 ***ConocoPhillips*** has encountered hydrocarbons at the first wildcat on its Harpoon prospect in the National Petroleum Reserve-Alaska. IHS Markit reported that #2 Harpoon was drilled to 5,611 ft and is in Section 30-7n-3e, Umiat Meridian. It was expected to evaluate Nanushuk oil zones. Determining the viability of Harpoon will likely require additional drilling. Two more tests were originally scheduled, but drilling on the North Slope was shut down due to COVID-19 concerns. The Harpoon prospect still includes three undrilled locations: #1 Harpoon in Section 33-8n-4w, #3 Harpoon in Section 7-6n-4w and #4 Harpoon in Section 29-7n-4w. More than 20 miles northeast of #2 Harpoon is the Houston-based company's Willow Field discovery, #2 Tinmiaq. It was completed in 2016 with a sustained 12-hour test rate of 3.2 Mbbl of oil, 1.263 MMcf of gas and 443 bbl of water per day from Nanushuk at 3,688-3,708 ft.

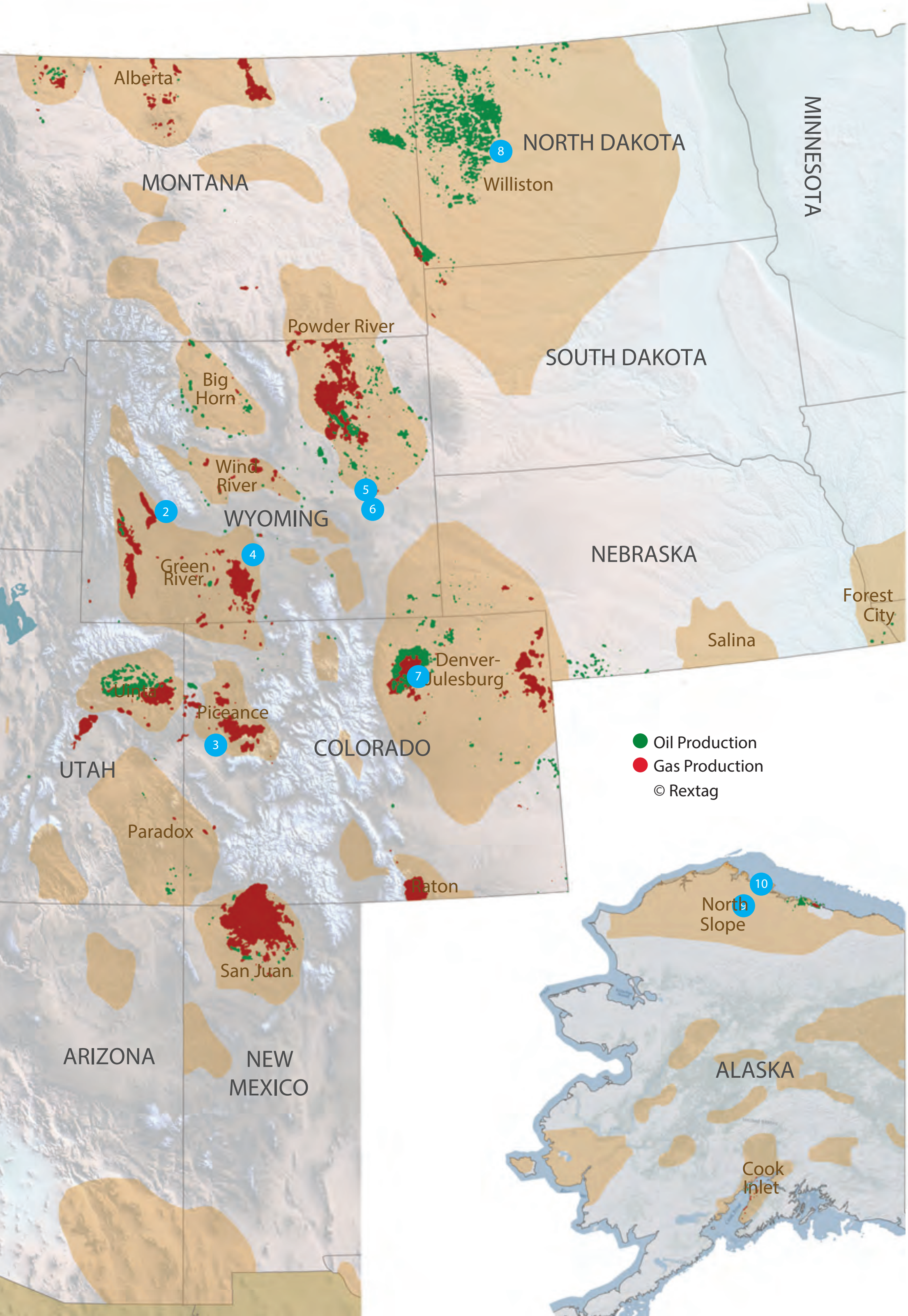
10 Results from a Collville River completion in Section 18-11n-4e in Alaska's Umiat Meridian were announced by ***ConocoPhillips***. The North Slope well, #5CD-26L1 Colville River Unit, was drilled to 17,932 ft, 7.634 ft true vertical. It was tested flowing 1.758 Mbbl of oil, 529 Mcf of gas and 816 bbl of water per day from openhole Alpine. Production is from perforations at 14,369-17,932 ft. Additional completion information has not been released by the Houston-based company.

Western US Rig Count

Jan. 3, 2020-May 5, 2020



Source: Baker Hughes Co.



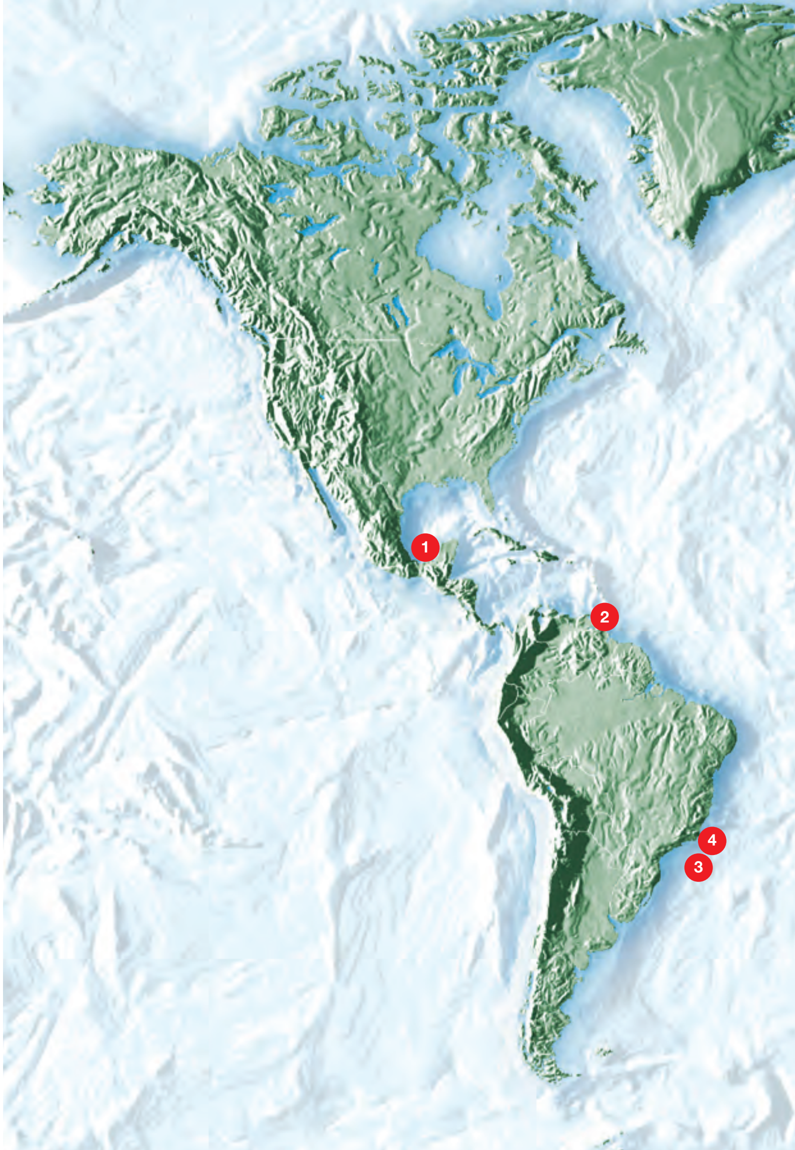
INTERNATIONAL HIGHLIGHTS

According to a Rystad Energy analysis, the current oil glut will diminish when the inevitable rebound of global oil demand occurs, which, along with the present lack of activity and investment, will send crude prices higher to about $68 per barrel and produce a supply deficit of about 5 MMbbl/d by 2025.

With the COVID-19 pandemic, it was expected that supply would exceed demand, but the analysis notes that the curtailment of investment and activity has significantly added to the current situation. However by 2025, global demand for liquids will be about 105 MMbbl/d, and the downcycle in the upstream industry will remove about 6 MMbbl/d from production forecasts for 2025

To fill this gap, Rystad Energy said that some OPEC countries, like Saudi Arabia, Iraq and the UAE, will be able to ramp up production and in total might fill 3 MMbbl/d to 4 MMbbl/d of this gap. The remaining shortfall will most likely be filled with volumes from U.S. tight oil. To achieve this, prices may move above our current base case, which currently stands at an average price of $68 per barrel in 2025.

—Larry Prado



1 Mexico

Repsol announced two significant oil discoveries on the Polok and the Chinwol prospects in offshore Mexico's Block 29. In the Polok prospect at #1-Polok, the venture found oil pay in an early Miocene reservoir of the Salina Basin, which is part of Sureste Basin. The #1-Chinwol encountered oil in the Pliocene pay at the Chinwol prospect. Wireline formation testing performed in both wells has shown good flow capacity in multiple stations in the separate reservoirs. Water depth at both sites is about 600 m. The #1-Polok was drilled to 2,620 m and found more than 200 m of net oil pay in two zones. The #1-Chinwol was drilled to 1,850 m and encountered more than 150 m of net oil pay from three zones in Lower Pliocene. Both reservoirs show excellent petrophysical properties, and 108 m of core samples have been collected. Appraisal testing is being planned. The discoveries are off the coast of the state of Tabasco, about 50 km west-northwest of the Zama discovery, and are approximately 12 km apart. Madrid-based Repsol is the operator of Block 29 and the discovery wells with 30% interest in partnership with ***Petroliam Carigali*** (28.33%), ***Wintershall*** (25%), and ***PTTEP*** (16.67%).

2 Trinidad

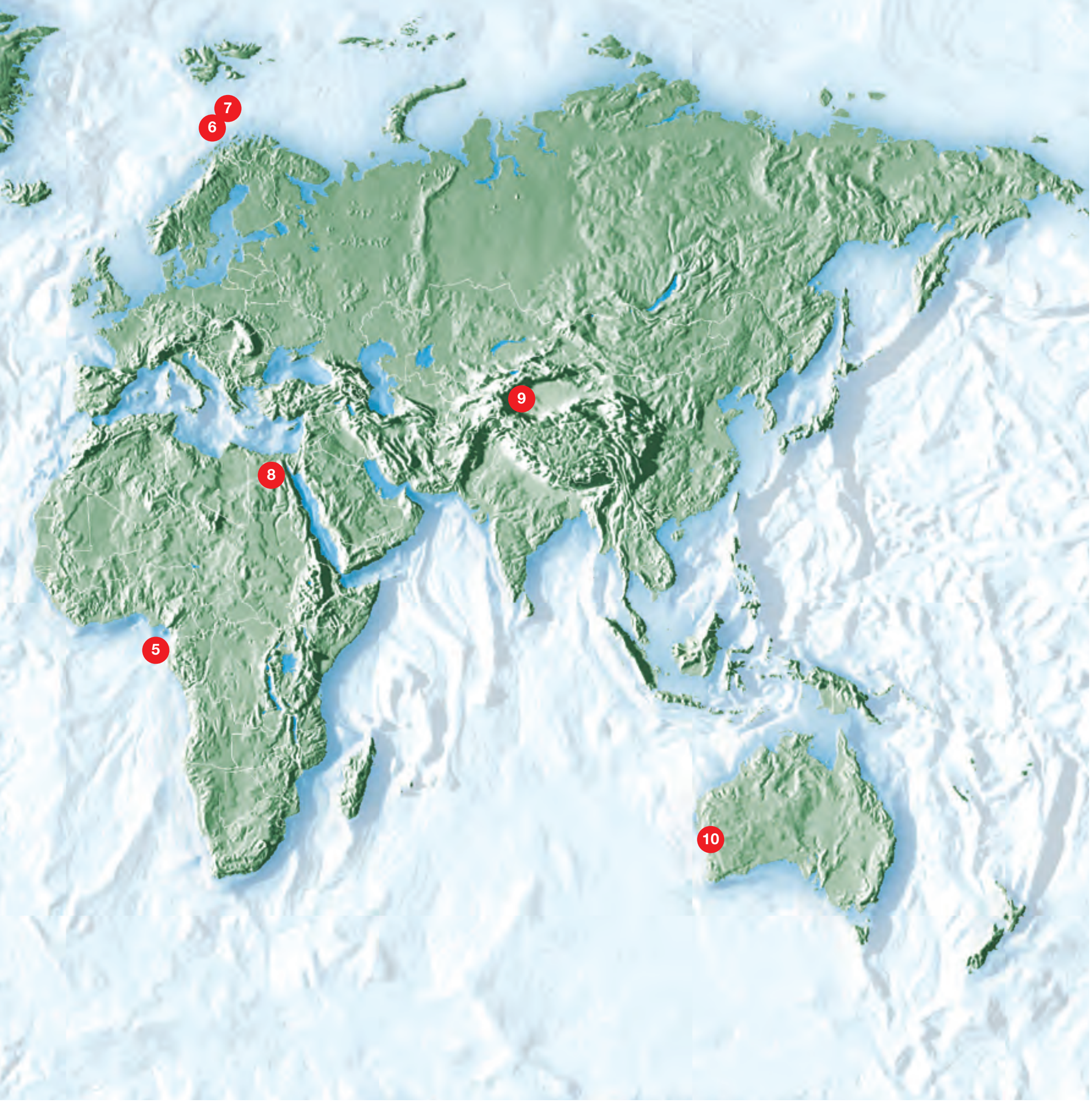
Columbus Energy Resources has reported the discovery of oil at exploration well #1-Saffron in onshore Trinidad's Southwest Peninsula. The 4,634-ft well hit 2,363 ft of gross sands with six reservoir intervals of interest in Lower and Middle Cruse. It is in the Bonasse license area, which includes Bonasse Field. Three of the six intervals have been tested flowing 40-degree-gravity oil from Lower Cruse, which is in line with pre-drill estimates of recoverable oil at 11.5 MMbbl. An appraisal well is also planned during 2020. London-based Columbus Energy is the 100% owner of the Bonasse license area.

3 Brazil

Petrobras has confirmed a presalt oil discovery in the southeastern part of Buzios Field. The #9-9-BUZ-39DA-RJS Poco is in the southeastern part of the field in the Santos Basin presalt region. Area water depth is 2,108 m. It was drilled to 5,400 m, and it hit a 208-m reservoir, with confirmation of the same quality as the oil produced in Buzios Field. Additional completion information is not currently available. Rio de Janeiro-based Petrobras is the operator (90%) of the consortium in the field, in partnership with ***Chinese National Oil Corp.*** which holds 5% and ***China Southern Petroleum Exploration and Development Corp.*** with 5%.

4 Brazil

In offshore Brazil's Albacora Field in the Campos Basin, ***Petrobras*** reported results from a presalt discovery. The #9-AB-135D-RJS POCO is within the Plano de Avaliacao de Descoberta of Forno area. It encountered approximately 214 m of reservoir with light oil. The venture was drilled to 4,630 m, and area water depth is 450 m. Additional testing is planned. Petrobras is the operator (100%) of Albacora Field in the Plano de Avaliacao de Descoberta of Forno.



5 *Gabon*

Vaalco Energy announced results from appraisal drilling at its #4P Southeast Etame well drilled at the Southeast Etame North Tchibala platform in offshore Gabon. Located in the Etame Marin permit area, the venture encountered oil sands in Gamba. It hit approximately 20 ft of good quality sands with similar reservoir quality as previously drilled #2H Southeast Etame. The appraisal well was drilled to 6,311 ft and has estimated gross prospective resources of 1MMbbl to 2 MMbbl of oil in this newly discovered stepout area. No water was encountered in the reservoir. The planned #4H Southeast Etame development test is based on this successful appraisal. Expected initial production rates are 1.2Mbbl/d to 2.5 Mbbl/d. Houston-based Vaalco is the operator of the block and its fields with 30% interest. Other participants in the permit are ***Sinopec*** (31.36%); ***Sasol Petroleum Etame Ltd.*** (27.75%); ***PetroEnergy Resources*** (2.34%) and ***Tullow Oil*** (7.5%).

6 *Norway*

Lundin AB has received a drilling permit for wildcat well #7219/11-1 in production license PL 533 B. The venture will be drilled from the West Bollsta drilling facility. Stockholm-based Lundin is the operator and owns 40% along with partners ***Aker BP*** with 35% and ***Wintershall*** with 25%. The area in this license consists of part of Block 7219/11. The well will be drilled about 35 km northwest of the Alta discovery well, #7220/11-1. This is the first well to be drilled in the license.

7 *Norway*

London-based ***Spirit Energy*** has received a drilling permit for well #7321/8-2 S in the Norwegian North Sea. The wildcat well will be drilled from the Leiv Eiriksson drilling facility. The area in this license consists of parts of blocks 7321/8 and 7321/9. The well will be drilled about 60 km west of the 7324/8-1 (Wisting) discovery. Spirit Energy is the operator with an ownership interest of 50% interest. The other licensees are ***Lukoil*** with 30% and ***Aker BP*** with 20%. This is the first exploration well to be drilled in the license.

8 *Egypt*

SDX Energy provided an update from well testing operations at #12X-SD in the South Disouq Exploration Permit in Egypt. During a drillstem test, the well produced 25 MMcf of gas per day on a 54/64-in. choke. It was followed by a three-hour period flowing at a stable rate of 15 MMcf of gas per day on a 28/64-in. choke and then a four-hour test on a 16/64-in. choke flowing 10 MMcf of gas per day. The well was then shut in for a 12-hour build-up period during which pressure continued to increase back to pretest levels. Additional testing is planned to determine the recoverable volume in the discovery, which is currently estimated to be 24 Bcf of recoverable resource. London-based SDX is the operator and holds a 55% working interest.

9 *China*

PetroChina has reported a major new oil and gas field discovery within the western portion of the Tarim Basin. The Beijing-based company announced that exploration well #1-Mashen penetrated a fractured zone containing reserves of approximately 1.6 Bboe. The discovery initially flowed 3.925 Mbbl of oil and 13 MMcf of gas per day. According to company, the discovery is a regional-level, oil-rich fracture zone and confirms the overall contiguous oil-bearing in Tabei-Tazhong area in Xinjiang.

10 *Australia*

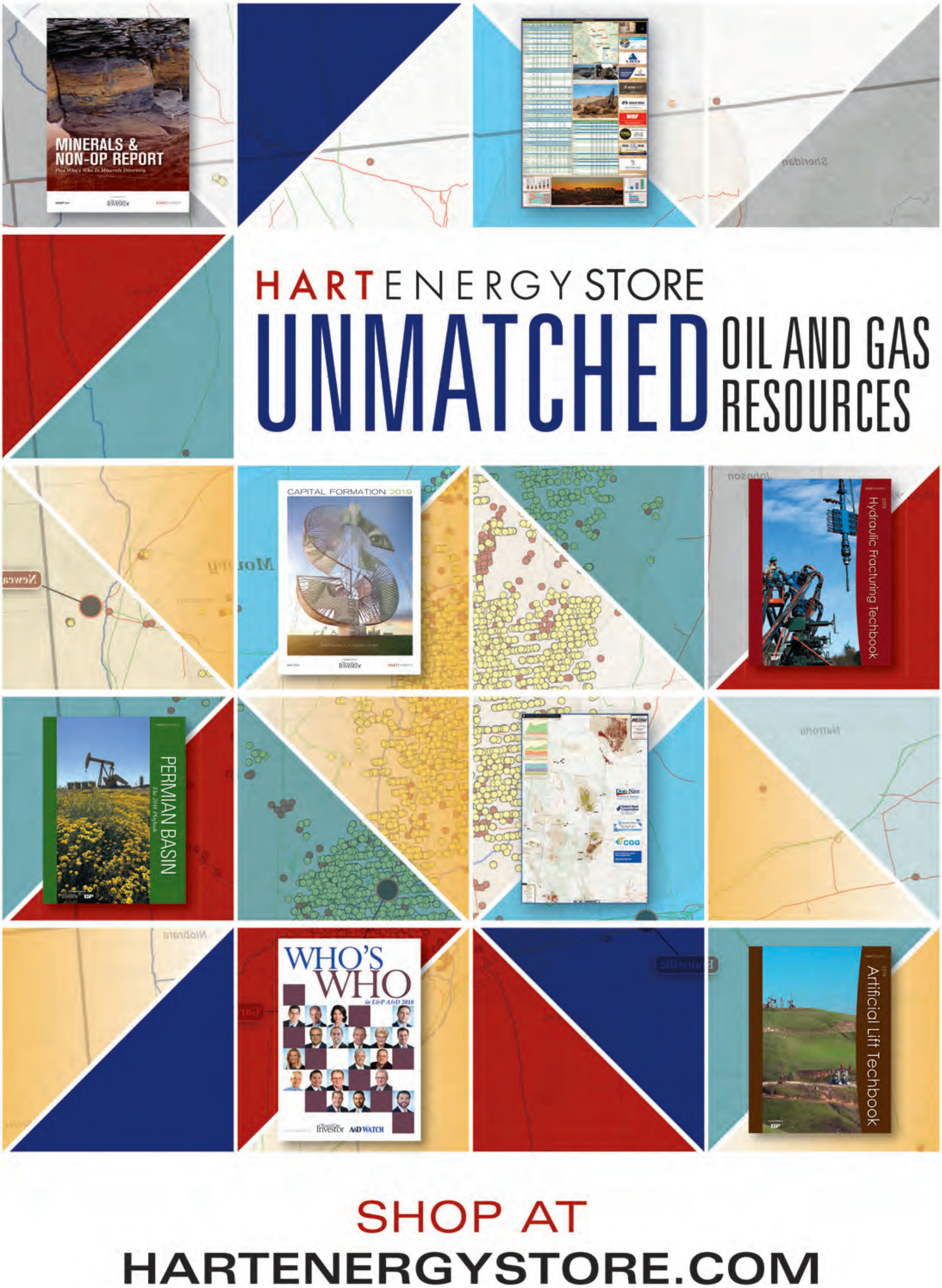
An independent, third-party review by ***RISC Advisory*** for Sydney-based ***Warrengo Energy*** indicates that in the central area of the West Erregulla gas field has a confirmed 2C contingent resources of 513 Bcf. Additional upside of the central area is 966 Bcf. The review also showed that the prospective resource of the northern area of the field is 102 Bcf. The West Erregulla gas field is in EP 469 in Western Australia's Perth Basin. The review confirms that West Erregulla is a significant gas discovery with low-risk exploration upside. The Kingia Sandstone is classified as a high quality, conventional gas reservoir. Additional data and further testing of the High Cliff, Dongara and Wagina reservoirs will be undertaken with the planned wells #3-West Erregulla and #4-West Erregulla to make a more definitive determination. No wells have been drilled in the Northern Area, which has been classified by RISC as a prospective resource and has been given a 65% chance of geological success. The Northern Area would become a contingent resource in the event of a successful well.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Energy Spectrum Capital	N/A	Dallas	$969 million	Closed Energy Spectrum Partners VIII LP, which will be used to invest primarily in midstream assets within the energy industry. Midstream assets include oil and natural gas gathering and transportation systems, processing and treating plants and storage facilities. A diverse mix of 82 limited partners committed to the fund, including private and public pension funds, insurance companies, university endowments, foundations and family offices. Baker Botts LLP served as legal counsel.
ONEOK Inc.	NYSE: OKE	Tulsa, Okla.	$400 million	Launched an underwritten public offering of 26 million shares of its common stock with expectations to grant underwriters a 30-day over-allotment option to purchase up to 3.9 million additional shares. Proceeds are expected to be used for general corporate purposes, which may include the repayment of existing indebtedness and capex funding. Barclays, J.P. Morgan and Citigroup are lead book-running managers. BofA Securities, Credit Suisse and Wells Fargo Securities are also book-running managers.
Comstock Resources Inc.	NYSE: CRK	Frisco, Texas	$200 million	Commenced an underwritten public offering of 40 million shares of common stock priced at $5 per share. Underwriters were also granted a 30-day option to purchase up to 6 million additional shares at the same price. Proceeds will be used to redeem outstanding preferred stock. Citigroup, BMO Capital Markets, Mizuho Securities and Wells Fargo Securities are joint book-running managers. Citigroup representative of the underwriters. Fifth Third Securities, Regions Securities LLC, KeyBanc Capital Markets, Barclays, Capital One Securities, Natixis, Citizens Capital Markets, CIT Capital Securities, Credit Agricole CIB, Goldman Sachs & Co. LLC, Huntington Capital Markets, Johnson Rice & Co. LLC, Societe Generale, Tuohy Brothers, U.S. Capital Advisors and Hancock Whitney Investment Services Inc. are co-managers.
Brigham Minerals Inc.	NYSE: MNRL	Austin, Texas	$90.8 million	Priced an upsized underwritten public offering of 6.6 million shares of its Class A common stock by certain of its stockholders, which are affiliates of Warburg Pincus LLC, Yorktown Partners LLC and Pine Brook Road Advisors LP, at $13.75 per share. Certain selling stockholders granted the underwriter a 30-day option to purchase up to an additional 990,000 shares. Brigham Minerals will not sell any shares and will not receive any proceeds therefrom. Credit Suisse Securities (USA) LLC is sole underwriter.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Cheniere Energy Partners LP	NYSE American: CQP	Houston	$2 billion	Priced offering by Sabine Pass Liquefaction LLC of senior secured notes due 2030 at a price equal to 99.744% of par to yield 4.532%. Proceeds will be used to redeem all of Sabine Pass Liquefaction's outstanding 2021 notes.
Equinor ASA	NYSE: EQNR	Stavanger, Norway	$1.5 billion	Executed debt capital market transactions comprised of the issuance of $750 million 1.75% notes due 2026 and $750 million 2.375% notes due 2030. Proceeds will be used for general corporate purposes, which may include the repayment or purchase of existing debt or other purposes. BofA Securities Inc., Barclays Capital Inc., BNP Paribas Securities Corp., DNB Markets Inc., Goldman Sachs & Co. LLC and J.P. Morgan Securities LLC were joint book-running managers.
Pioneer Natural Resources Co.	NYSE: PXD	Irving, Texas	$1.2 billion	Priced an upsized offering of 0.250% convertible senior notes due 2025 that included an option to purchase, within a 13-day period, up to an additional $172.5 million aggregate principal amount of the notes. Notes will bear interest at a rate of 0.25% per year and will be payable semiannually. Proceeds will be used to fund capped call transactions plus tender offers of up to $500 million of outstanding 2021, 2022 and 2028 notes as well as the repurchase of about $50 million in shares of common stock. Remaining proceeds will be used for general corporate purposes, which may include paying down debt. Vinson & Elkins was legal adviser.
The Williams Cos. Inc.	NYSE: WMB	Tulsa, Okla.	$1.2 billion	Priced a private debt issuance by Transcontinental Gas Pipe Line Co. LLC of $700 million of 3.25% senior notes due 2030 and $500 million of 3.95% senior notes due 2050. Proceeds will be used by Transco for general corporate purposes, including capex funding.
EIG Global Energy Partners	N/A	Washington, D.C.	$1.1 billion	Closed EIG Global Project Fund V (GPF V) with total commitments nearly 50% higher than the $750 million target. Raised an additional $1.5 billion of commitments in the form of separately managed accounts that will invest alongside GPF V. Proceeds will be used for the energy and infrastructure direct lending platform that invests across the full energy, midstream, power, renewable energy and infrastructure complex on a global basis. Credit Suisse was the placement agent. Kirkland & Ellis served as legal counsel.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DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Suncor Energy Inc.	NYSE: SU	Calgary, Alberta	$1 billion	Priced an offering of $450 million in aggregate principal amount of senior unsecured notes due 2023 and $550 million in aggregate principal amount of senior unsecured notes due 2025. Proceeds will be used to repay short-term indebtedness and for general corporate purposes. RBC Capital Markets and J.P. Morgan are joint book-running managers.
The Williams Cos. Inc.	NYSE: WMB	Tulsa, Okla.	$1 billion	Priced a public offering of 3.5% senior notes due 2030 at 99.495% of par. Proceeds will be used to repay 2020 notes and for general corporate purposes. J.P. Morgan Securities LLC, Deutsche Bank Securities Inc., Morgan Stanley & Co. LLC, Scotia Capital (USA) Inc. and Wells Fargo Securities LLC are joint book-running managers.
Plains All American Pipeline LP	NYSE: PAA	Houston	$750 million	Completed an underwritten public offering of 3.8% senior unsecured notes due 2030 at a public offering price of 99.794% with a yield to maturity of 3.825%. Proceeds will be used to partially repay the principal amount of 2021 notes and, pending such repayment, for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capex and additions to working capital. J.P. Morgan Securities LLC, Barclays Capital Inc., BofA Securities Inc. and RBC Capital Markets LLC were joint book-running managers and representatives of the underwriters.
Baker Hughes Co.	NYSE: BKR	Houston	$500 million	Closed an offering of 4.486% senior notes due 2030 that were offered and sold pursuant to an underwriting agreement by and among the issuers and J.P. Morgan Securities LLC and Morgan Stanley & Co. LLC as representatives of the underwriters.
Diamondback Energy Inc.	NASDAQ: FANG	Midland, Texas	$500 million	Priced a public offering of 4.75% senior notes due 2025 at 100% of the principal amount. Proceeds will be used to make an equity contribution to Energen Corp. in order to fund the purchase 2021 notes plus cover fees and expenses of the tender offer, to repay a portion of the outstanding borrowings under the revolving credit facility of Diamondback O&G LLC and for general corporate purposes. J.P. Morgan Securities LLC, Citigroup Global Markets Inc. and Wells Fargo Securities LLC are joint book-running managers.
Magellan Midstream Partners LP	NYSE: MMP	Tulsa, Okla.	$500 million	Priced an offering of 3.25% senior notes due 2030 at 99.88% of par to yield 3.264% to maturity. Proceeds will be used for general partnership purposes, which may include capital projects and repayment of indebtedness, including borrowings under its revolving credit facility and commercial paper program and redemption of its 2021 notes. J.P. Morgan Securities LLC, Mizuho Securities USA LLC, RBC Capital Markets LLC, SMBC Nikko Securities America Inc. and U.S. Bancorp Investments Inc. are joint book-running managers. Barclays Capital Inc., PNC Capital Markets LLC, SunTrust Robinson Humphrey Inc., TD Securities (USA) LLC and Wells Fargo Securities LLC are co-managers.
Pembina Pipeline Corp.	NYSE: PBA	Calgary, Alberta	C$500 million	Closed an offering of senior unsecured medium-term notes conducted in two tranches consisting of $400 million in series 16 notes with a fixed coupon of 4.67% per annum, paid semi-annually, and maturing 2050 and $100 million issued through a reopening of 3.71% medium-term notes, series 7, due 2026. Proceeds will be used to repay indebtedness under its unsecured revolving credit facility due 2024 incurred in connection with the acquisition of the U.S. portion of the Cochin Pipeline system, fund capital program and for general corporate purposes.
WPX Energy Inc.	NYSE: WPX	Tulsa, Okla.	$500 million	Priced a public offering of $500 million of 5.875% senior notes due 2028 at 100% of par. Proceeds will be used to fund previously announced cash tender offers for outstanding 2022, 2023 and 2024 notes. Any excess proceeds will be used for general corporate purposes, which may include the repayment or redemption of outstanding indebtedness. Wells Fargo Securities LLC, BofA Securities Inc. and TD Securities (USA) LLC are lead book-running managers.
NGL Energy Partners LP	NYSE: NGL	Tulsa, Okla.	$250 million	Entered into a new term loan facility with certain funds and accounts managed by affiliates of Apollo Global Management Inc. to refinance an existing $250 million bridge term loan facility established in 2019 with TD Securities (USA) LLC as lead arranger and bookrunner and The Toronto-Dominion Bank, New York Branch as initial lender to finance a portion of the acquisition of Mesquite Disposals Unlimited LLC. TD Securities was debt adviser, and Paul Hastings LLP provided legal counsel to NGL. Vinson & Elkins LLP was legal counsel to Apollo Funds.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

OPEC'S DILEMMA, SHALE'S HOPE

LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

So far this summer, estimates about the timing, magnitude and shape of the recovery in the world economy and, in particular, crude oil demand and price keep fluctuating. They are powered by hopeful signs, only to be dialed back by reality.

Even for the leanest, meanest producer sitting on the best assets in the land, fate hinges on the nature of the recovery. Bernstein Research analyst Bob Brackett has questioned if the emerging E&P business model will look more like Lazarus or like a zombie. If careful spending to keep production flat continues to be the right way to go, what then is the catalyst to invest in any company?

It appears the warning lights are still yellow, but they are interrupted by the occasional flash of green—and then, unfortunately, of red.

At press time, oil was languishing below $40/bbl and the U.S. oil-directed rig count had fallen below a key psychological threshold, 200, down to a mere 199. The typical summer travel bump up in oil demand did not occur (talk about flattening the demand curve), although Chinese vehicular traffic was recovering, and in May its oil imports reached an all-time record high.

Is the glass half full or half empty? If oil demand recovers, but only to 80% of its pre-COVID-19 level, is that good enough? Or must we wait to see the remaining 20%? Our inbox was full of outlooks and answers, as every observer developed a viewpoint.

The International Energy Agency predicted a V-shaped recovery through the second half of 2020 due to global drawdowns of oil inventories. But those inventories stand at more than 1 Bbbl—one reason that OPEC is deciding what to do on a month-by-month basis.

Rystad Energy's latest monthly estimate called for global oil demand to fall by 11.7 MMbbl/d year over year, or to about 87.8 MMbbl/d. On the plus side, OPEC+ is cutting about 10.7 MMbbl/d. But Rystad also cited the Federal Reserve's gloomy economic outlook; an increase in virus cases, especially in South America and certain U.S. cities that surfaced in June; and a report that the U.K.'s GDP had cratered by 20% in April, thus requiring a huge recovery.

"Prompt prices returning to above $50/bbl will likely only occur after the recent inventory builds—more than 1 Bbbl—are drawn down," said a Cowen & Co. report. "It could take until 2022."

This litany of dangerous datapoints lurks behind every analyst's spreadsheet.

"While the worst of the demand shock appears to be over, a smooth recovery is unlikely," cautioned a June report from the Center for Strategic & International Studies (CSIS), a bipartisan, nonprofit think tank in Washington, D.C. The group listed several risks.

"First, there is the risk of extrapolating too much from China," said analysts Ben Cahill and Frank A. Verrastro. When prices were low, the Chinese had an incentive to import more oil and place it in their strategic stockpiles.

Second, according to CSIS, worldwide refining margins are still weak due to lack of demand, and if the price of oil rises, those margins will shrink further. U.S. gasoline inventory is above the five-year average, even though frustrated consumers who have been cooped up for too long have a strong drive to drive.

We are not past this coronavirus yet, and if a spike in cases or hospitalizations occurs in scattered locations, that will tamp down demand again. Finally, even a modest recovery in oil production could lead to bloated inventories, which will again need to be worked off, CSIS said.

Several analysts posit that a supply deficit is in the future. They have warned about the lack of drilling and the plunge in replacement of oil production, which sets us up for an oil shortage at some point, assuming demand recovers to previous levels. Rystad Energy said global upstream investments will end this year at a 15-year low, and this would be a stunning 29% decline from 2019 (shale spending alone to fall by more than 50%).

Bill Herbert with Simmons Energy said in his macro outlook that a supply deficit beginning in the second half of this year will persist through 2022. At first, much of that supply will be increased by restarting shut-in production or completing DUCs.

As for drilling, the debate over the profitability of shale has resurfaced. "The reality of the last few years is that very few companies have actually made a profit from shale oil production," reminded Stephens Inc.'s Jim Wicklund in a recent note. "With increased investor focus on profitability, how strong will the U.S. shale industry recover, and is this the market that oilfield service companies want to gear up to serve?"

One fact remains, CSIS said: OPEC will continue to grapple with the uncertainties of U.S. shale. After all, the oil price most OPEC nations need happens to be high enough to incentivize U.S. shale producers to drill.

That is OPEC's dilemma, but it is shale producers' hope.


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