Oil and Gas Investor

AUGUST 2020

Good rock, low costs and ample transportation keep Haynesville Shale operators drilling ahead.

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Some horses are not
meant to be tamed

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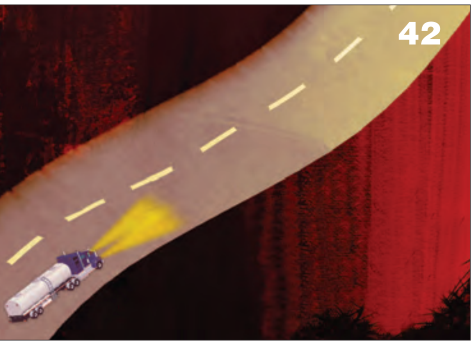
Oil and Gas Investor

AUGUST 2020/VOLUME 40/NUMBER 8



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Although Pickering Energy Partners' Dan Pickering believes the industry is in for a couple of tough years ahead, he also believes the survivors are due for a bounty: Assets will be available for prices not seen in 30 years.

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The remainder of the year's deals will likely involve gas assets (while prices are good) and could come to include the low cost supply areas in the Texas and Louisiana Haynesville. Barring a miraculous rally, oil looks likely to remain the New Coke of commodities.

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Chevron Corp. agreed on July 20 to a buyout of Houston-based independent E&P company Noble Energy Inc. in an all-stock transaction valued at $5 billion. The total enterprise value, including debt, of the transaction is $13 billion, according to Chevron.

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In the International Energy Agency's latest "Oil Market Report," global oil demand for 2020 is expected to fall by 8.1 MMbbl/d, the biggest one-year drop in history. The report also says there will be a rebound in demand of 5.7 MMbbl/d in 2021.

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LATEST CONTENT

US Fracking Set for First Monthly Rise This Year; Permian Leads Recovery
According to a July 23 Rystad Energy analysis, new operations are now set to rise to above 400 wells in July, and recovery will be especially evident in the Permian Basin, where activity has nearly tripled.

California Resources Enters Bankruptcy to 'Finally' Resolve Occidental-inherited Debt
California Resources said it entered a restructuring support agreement with "key creditors" that will eliminate over $5 billion of debt and mezzanine equity interest.

Midyear Oil Market Outlook: Keys to Staying Competitive Amid Uncertainty
In the next three months, a lower cost structure by oil and gas companies may be needed but without hindering the ability to scale production later, Deloitte said.

ConocoPhillips Extends Montney Shale Position with $375 Million Acquisition
ConocoPhillips agreed to pay Kelt Exploration roughly $375 million in cash for 140,000 net acres directly adjacent to the company's existing position in Canada's Montney Shale.

API, Environmental Partnership Report Oil Industry's Emissions Reduction Progress
Reducing emissions remains a goal of oil and gas companies despite current challenges, industry groups say.

ONLINE EXCLUSIVES

Is Energy Transition Ready to Kick Shale to the Curb?

Probably not, but backers believe cleaner fuels are primed, post-COVID-19, to make strides.

Oil Market Uncertainty Remains, Price 'Painful But Not Terminal' for Most

Questions linger around OPEC's oil production cut compliance and a potential ramp-up in U.S. shale plays.

Oil Analysts See More Challenges Ahead for Growing Bankruptcies

About $140 billion worth of debt is due to mature between 2020 and 2022 in the U.S. oil and gas market, analyst says.

Videos

RelaDyne Exec Talks Maintenance, Tech as Oil Industry Resets
RelaDyne Reliability Services vice president Scott Hill discusses how this unprecedented time will change sectors within the oil and gas industry and how what that will look like is yet to come.

HartEnergy.com/videos

Videos

Evercore's James West on Chevron-Noble Energy Deal, Shale Outlook
"M&A has started to pick up. You saw a deal announced with Chevron buying Noble. We would expect to see more of those," James West, senior managing director with Evercore ISI, says.

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Videos

ConocoPhillips CTO on New Technologies Amid Industry Downturn
Greg Leveille, CTO at ConocoPhillips, explains why now is the best time for oil and gas companies to ramp up new technology efforts.

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A BOUNTY AWAITS THE STRONG


STEVE TOON,
EDITOR-IN-CHIEF

Dan Pickering, the featured speaker on a video conference with the ADAM Houston group in July, noted the preeminent downside of virtual industry presentations: "I don't get a free lunch out of this."

I think all the attendees were lamenting the absence of a fine meal at Brennan's restaurant on a summer Friday gathering as many are still working from home amid continued COVID-related stay-at-home directives. I know I'm not contributing much to the global demand number yet as I mostly hunker down in the home office, aside from an occasional foray into the actual office, where we must RSVP to come to work and stay within a maximum attendance. Fifty miles roundtrip a day not back online.

Pickering, the founder and namesake of Pickering Energy Partners and the president and co-namesake of Tudor, Pickering, Holt & Co., proffered his insight on how this all might play out.

First, Pickering's view is that we're in a protracted downturn that began in November 2014 and the COVID-OPEC double black swan scenario earlier this year is a cut-to-the-chase event. Before March, the E&P sector was already dealing with bloated balance sheets, capital flight and attempting to reformat objectives from production growth to returns focused. The events of 2020 just accelerate that: do it now or die.

"We're six years into a downturn. This is our generation's 1986," he said. "Stress, distress and bankruptcy are upon us. A lot of companies have three bullet holes in them and are in the process of bleeding out. That's a brutal way to say it, but it's happening."

Despite the Energy Information Administration and International Energy Agency forecasts for global crude demand to return to 98 MMbbl/d to 99 MMbbl/d in 2021, Pickering is skeptical. "Frankly, that seems way too optimistic," he said. His reasoning: transportation. COVID is still keeping employees at home, many will continue to work from home when the virus passes, and masses remain unemployed and won't return to work soon or won't take vacations.

"My guess is we're going to find equilibrium somewhere around 95 million barrels a day, and it's going to take us all of next year to get there," he said.

Add in some 10 MMbbl/d of OPEC production now offline and the storage overhang, "I'm looking at 2022 as the time period where we get back closer toward equilibrium. My view is we don't see prices in the fifties for the next 18 months. Plan for a couple of tough years. We've got a slog in front of us," he said.

The silver lining is these conditions will make the industry leaner and stronger.

"As we move through the next five years, we're going to have fewer companies," he said, "but they'll be stronger by definition. What created casualties was not enough hedging and balance sheets that were too stretched. So we will have less debt and more hedges as the industry moves forward. That will dampen volatility. It may take some of the upside oomph out of profit and loss statements, but it's going to take some of the risk out as well."

Even this phase of capital famine—by both public and private investors, and reserve-based lenders too—is painfully positive, he said.

"We spent too much in the past. We're going to see more discipline from the business. This capital starvation means less money is going into the ground, which means less production is going to come out of the ground, and that will fix the macro."

Maybe the most positive outcome of this drought will be asset opportunities, Pickering said. "I think this is the best opportunity to deploy capital that we've seen in the past 30 years." But it requires patience. "Things do get cheaper," he said.

Assets first must be squeezed through the restructuring process, which doesn't take three months, rather nine to 16 months. Inherently, banks and bondholders don't want to hold oil and gas equity, he noted. And when bondholders go from 100 cents on the dollar basis to a 20 cent basis following restructuring, "selling a 20 cent bond for 30 cents, that's a win.

"So we think that there'll be sellers at pretty cheap valuations after we get this asset transition over with," he said.

And Pickering, with capital to spend on Permian proved developed producing assets, sees fewer buyers and smaller checkbooks. Not only will the number of E&Ps be slashed through bankruptcies or consolidation, but private-equity capital—and firms—will be slashed by half as well, he predicts.

"Ironically, I think the supply of deals is going to go up, and the demand for deals is going down. The process is going to take time, but it's putting assets in the hands of natural owners," he said.

"There are going to be great opportunities."

Speaking of virtual conferences, Hart Energy's DUG Midcontinent Virtual Conference will be held all online this year. All the same great content and speakers as usual. Register at hartenergyconferences.com/dug-midcontinent.


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DEALDRUMS

DARREN BARBEE,
SENIOR EDITOR

M&A remains overripe, with deals turning to rot on inventory shelves and oil companies forced to wait even longer for their Kool & The Gang's Deal-a-bration to come.

The COVID-19 pandemic remains firmly in command, leaving E&Ps to watch helplessly as the virus parties in Florida, rides tall in Texas and dreams in California. Much work remains to rein in the virus (or extremely lethal hoax). The national strategy for COVID-19 testing remains, "Testing is highly contagious."

Still, if there is hope for an end to the pandemic and some return to normal oil demand, OPEC+ has arrived just in time to annihilate any E&P optimism. Recall in May when OPEC and countries such as Russia agreed to cut production by 9.7 MMbbl/d following mass oversupplies created by OPEC+ (and then the pandemic).

That rollback, naturally, never really hit 9.7 MMbbl/d.

OPEC said it intends to increase production by 2 MMbbl/d, keeping 7.7 MMbbl/d of production off the table.

If this plan sounds bad, worrisome, ineffective, lacking in foresight or kindergarten-ish, stop thinking negatively. The way OPEC figures it, compliance with the May cuts through July was 89% (or 8.6 MMbbl/d).

OPEC+ has declared that their member-cheaters will "make up" for their naughtiness by really, really cutting back this time, pinky swear. So in reality, the 7.7 MMbbl/d cut would actually be 8.1 MMbbl/d to 8.3 MMbbl/d, as OPEC sees it.

Options to describe this plan include 1) foolproof, 2) unworkable or 3) oilmagedon.

With prospects for deals in flux through the rest of the year, dealmaking continues to be a game of pin the tail on a fast moving 18-wheeler.

The bracing postmortem on second-quarter 2020 shows just $2.6 billion in upstream M&A transactions, according to Enverus. That compares with $770 million in dealmaking during the first quarter. While the second quarter haul represented a 200% increase over the first, hold off on your A&D parade float. The second-quarter deal total is the third lowest transaction haul in a quarter since 2009.

Oil, perhaps unsurprisingly, took a backseat to natural gas deals in the second quarter.

Three Appalachia deals totaled more than $1 billion in transaction value. However, top deal honors went to HighPeak Energy's combination with blank-check company Pure Acquisition Corp. at $845 million. Yet, the Permian Basin centered merger proceeded after a renegotiation of terms and a third player, Grenadier Energy Partners II, dropped out of the deal.

Overall, gas increased its share of M&A to 30% year to date from 5% in 2019, Enverus said.

"With the uncertainty around oil, the limited buyers largely targeted low-cost natural gas assets during Q2," said Andrew Dittmar, senior M&A analyst with Enverus. "Broadly, the market for new deals remains highly challenged, particularly in oil plays."

Enverus also cited contingency payments, largely linked to commodity prices, as a byproduct of market uncertainty. Though such payments have been a mainstay in deals for some time, they appear to be closing the bid-ask spread on the rare occasion that a deal is close enough.

In the thin broth of the second quarter, M&A did pick up some seasoning from royalty deals, which accounted for about 20% of deal value in the second quarter, Enverus said.

Institutional capital bought the main royalty deals in the quarter, including Sixth Street Partners and a $100 million acquisition by EnCap-sponsored Pegasus Resources in the Permian.

"Royalty and mineral interests remain a popular way to gain exposure to oil and gas upside while limiting the financial risks inherent with participating in working interests in a volatile market," said John Spears, director of Market Research with Enverus.

For now, about $5 billion worth of assets are available for purchasing, including bankruptcy sales processes in the Permian, Eagle Ford Shale and other regions.

But the remainder of the year's deals will likely involve gas assets (while prices are good) and could come to include the low cost supply areas in the Texas and Louisiana Haynesville. Barring a miraculous rally, oil looks likely to remain the New Coke of commodities.

Going further into the future, Goldman Sachs analysts said in a July report not to expect serious consolidation and "balance sheet healing" until around the first half of 2021 for most E&Ps.

Kool will keep. Put them on your playlist. By next year, hopefully we'll be singing, "Bring your good times and your laughter too. We gonna celebrate your commodity with you."


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EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
KIOGA Annual Convention & Expo	Canceled			kioga.org
World Oilman's Mineral & Royalty Conference	Aug. 10		Virtual	mineralconference.com
Enercom The Oil & Gas Conference	Aug. 17-19		Virtual	theoilandgasconference.com
The Energy Summit	Aug. 17-19		Virtual	coga.org/theenergysummit.html
DUG Midcontinent	**Aug. 18-19**		**Virtual**	**dugmidcontinent.com**
IADC Drilling Onshore Conference & Exhibition	Aug. 19		Virtual	iadc.org
Summer NAPE	Aug. 11-27		Virtual	napeexpo.com/summer
PIOGA Fall Conference	Sept. 22-24	Seven Springs, Pa.	Seven Springs Mountain Resort	pioga.org
TIPRO Summer Conference	Sept. 23-24	San Antonio	Hyatt Hill Country Resort; Virtual	tipro.org
DUG Haynesville	**Oct. 13-14**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
Oil & Gas Council North America Assembly	Oct. 21-22	Houston	The Whitehall	oilandgascouncil.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	Postponed to 2021			energygamechange.com
SPE Sustainability Innovation & Technology Convention	Dec. 10-12	TBD	TBD	spegcs.org/events/5739
2021				
IPAA Private Capital Conference	Jan. 23	Houston	JW Marriot Houston	ipaa.org
Energy ESG Conference	**February**	**Houston**	**Omni Galleria**	**energyesgconference.com**
NAPE Summit	Feb. 8-12	Houston	George R. Brown Conv. Center	napeexpo.com
Innovation & Entrepreneurship Summit	Feb. 24-25	Houston	Norris Conference Center, CityCentre	spegcs.org/events/4637
DUG Bakken and Rockies	**Mar. 25-26**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
CERAWeek by IHS Markit	Mar. 1-5	Houston	Hilton Americas-Houston	ceraweek.com
Williston Basin Petroleum Conference	May 11-13	Bismarck, N.D.	Bismarck Event Center	ndoil.org
Veterans In Energy Luncheon	**November**	**Houston**	**The Westin Memorial City**	**impactfulveteransinenergy.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wed., even mos.	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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

NewsWell

BP report: global energy consumption rises, growth rate slips

Global demand for liquid fuels in 2019 topped 100 MMbbl/d for the first time, but the COVID-19 pandemic will likely reshape economic, political and social trends in unforeseen ways, BP Plc said June 17 in its annual Statistical Review of World Energy.

"It feels like the world is at a pivotal moment: it needs to address these short-term concerns but in a way that builds back better," Bernard Looney, the energy giant's CEO, wrote in the report's introduction.

All fuels, except nuclear, grew at a slower rate than their 10-year averages, the report said. Total energy consumption grew at 1.3% in 2019, less than half the rate of 2018. Oil consumption was up 900,000 bbl/d, led by China with an increase of 680,000 bbl/d. Industrialized economies reduced their consumption by a total of 290,000 bbl/d.

The U.S. led growth in demand for natural gas, increasing usage by 27 billion cubic meters (Bcm), while demand worldwide rose by 78 Bcm, or about 2%. That fell far short of 2018's 5.3%, but it boosted the share of gas in primary energy use to 24.2%.

The U.S. also generated two-thirds of the growth in global gas production, or 85 Bcm of the world's 132 Bcm increase. Australia produced 23 Bcm more in 2019 over 2018, and China added 16 Bcm.

LNG supply jumped by 54 Bcm, a record increase. The U.S. led the way, followed by Russia, with Europe expanding its LNG imports by 49 Bcm, or two-thirds over 2018.

Much of the increase in global gas consumption came at the expense of coal, which decreased by 0.6% for its fourth decline in six years. Coal's share of the world's energy fell to 27%, its lowest level in 16 years.

In its assessment of the BP report, Simmons Energy listed primary risks for the energy business as:

- Weak global economic activity resulting in depressed demand for oil and natural gas;
- Increased supply of oil and natural gas; and
- Weak capital markets (especially given the capital-intensive nature of the energy business).

In his introduction, Looney expressed concern about the trend of carbon emissions. He noted emissions grew only 0.5% in 2019, but that followed a growth of 2.1% in 2018, and the annual increase in the two years surpassed the average for the last 10 years.

"As the world emerges from the COVID-19 crisis, it needs to make decisive changes to move to a more sustainable path," he wrote.

For the third straight year, U.S. oil production increased more than any other country at 1.7 MMbbl/d. That figure was less than 2018's 2.2 MMbbl/d increase. Brazil (200,000 bbl/d) and Canada (150,000 bbl/d) also counted among the leaders in growth, but Canadian output did not expand as much as it did in 2017 and 2018.

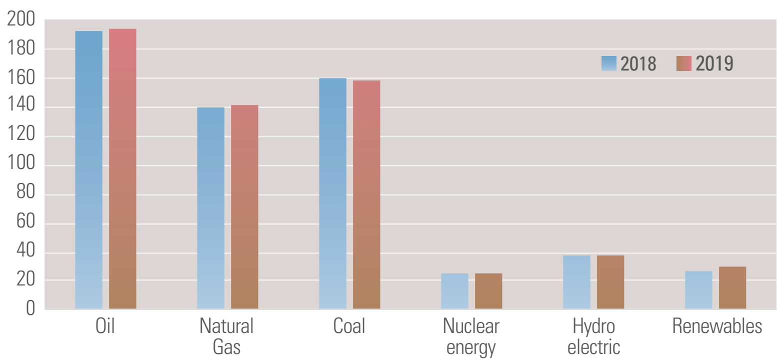
OPEC production took a 2 MMbbl/d-hit in 2019, its most dramatic decline since 2009. The report attributed much of that decrease to U.S.-led sanctions against Iran, which saw its output drop by 1.3 MMbbl/d. Political and economic troubles contributed to Venezuela suffering a 560,000 bbl/d reduction in output, and Saudi Arabia's production dropped by 430,000 bbl/d. Other OPEC members were able to grow production, including Iraq (150,000 bbl/d) and Nigeria (100,000 bbl/d).

Crude oil trade suffered its first decline since the 2009 financial crisis, dipping 0.3% or 230,000 bbl/d. Sanctions against Iran cut Middle East exports by 1.4 MMbbl/d. U.S. exports of 900,000 bbl/d were not enough to offset that total. The U.S. also decreased its imports of crude oil by 1 MMbbl/d.

NGL production growth continued its strong long-term trend with a 520,000 bbl/d increase, or 4.5%. Much of that (440,000 bbl/d) came from the U.S., which the report noted doubled its annual production to 4.8 MMbbl/d between 2012 and 2019.

—Joseph Markman

Global Primary Energy Consumption by Fuel (Exajoules, 2018-2019)



Source: BP Statistical Review of World Energy

No reservoir damage for production from shut-in shale wells

As oil and gas operators move toward bringing previously shut-in wells online, if such moves haven't been done already, industry experts seem to agree there will be no significant impact on unconventional shale reservoirs for the most part.

W.D. Von Gonten & Co., a Houston-based petroleum engineering, geological services and petrophysical modeling firm, has conducted several tests on shut-in wells and bringing them back on different rates.

"We've seen no reservoir damage to speak of that would affect the production data," Bill Von

Gonten, the company's president, said recently during a Tudor, Pickering, Holt & Co. conference session on reservoirs.

"Actually, what we've started to see is positive. The pressures are built up. In some wells rates have doubled from what they were shut in at, and then the water has gone down. In another month we probably won't be talking about the damage. It'll be what happened; how can we explain the production that we saw from the wells."

Companies shut in uneconomic wells as oil prices cratered due to falling demand resulting from the global coronavirus pandemic and a short-lived price war between Saudi Arabia and Russia. The situation remains in flux as eased stay-at-home restrictions give way to more COVID-19 cases.

Unwilling to sell resources at low prices, U.S. producers were expected to curtail about 1.75 MMbbl/d of existing production by early June amid operating cash losses, inadequate storage capacity and demand loss, according to IHS Markit. Most of the curtailed volumes were anticipated to return in the summer and fall 2020 if market conditions improved with WTI above $30/bbl and storage available.

Industrywide, everything seems to work from a price perspective in the U.S., according to Dave Pursell, executive vice president of development planning, reserves and fundamentals for Apache Corp.

Houston-based Apache operates about 12,000 wellbores in the Permian Basin, mostly in the Wolfcamp and Bone Spring formations. The rest are legacy vertical assets in the Central Basin Platform.

"At $40, our DUCs [drilled but uncompleted wells] will compete in our portfolio again, though they might be economic at a lower price," Pursell said. "They can compete with our international alternatives at $40 and then a full-on drilling program in the Permian starts to compete at $50. That doesn't mean at $40 we'll initially complete the DUCs or at $50 we'll bring a program on. But we can start having that conversation."

The company shut in about 2,500 wells in the basin and elected not to fix some wells with mechanical problems because of low commodity prices. Apache's workover count dropped from 60 rigs to 12, including two doing standard plug and abandonment work.

Shutting in wells is nothing new. Operators have taken such steps for various reasons before and brought production back online.

However, a sliver of production might be permanently lost from shut-ins, panelists agreed. These include wells with high water cuts, bringing corrosion potential, Pursell said.

"We tried to get the wells shut in in a proper state so that we minimize any return to production issues," he said.

He compared the scenario to not cranking up a vehicle.

"If you leave it in the driveway for a week, you're OK," he said. "You leave it in the driveway for three months, you're likely going to have a hard time getting started."

Industry wells likely to lose production are expected to be older ones already near the end of their life, according to Pursell. He noted the number of wells in this category might be large, but their total production is not significant.

Some wells might encounter artificial lift issues, with electric submersible pumps (ESPs) damaged by corrosion and paraffin the longer a well sits idle.

The extent of potential problems when bringing a well back online comes down to how the well was preserved at the beginning of the shut in and geology, added Gary Olliff, executive chairman of Brigade Energy Services LLC.

"There's always some risk that the well may not return to normal production levels," he said.

Returning production also carries a price tag.

Removing fluid from the wellbore and running tubing could start around $15,000, while tasks such as replacing pumps and tubing due to paraffin buildup could cost at least $25,000. Costs move further up when ESPs need fixing. Such repairs run between $150,000 and $175,000, Olliff said, noting replacing one is upwards of $300,000.

Gas lifts may have fewer problems, compared to rod pumps and ESPs, considering most of their complicated parts are at the surface, Pursell added, making way for regular maintenance with the well shut in.

"What we're starting to see and have been doing for some time are the clean out jobs, going into these horizontal wellbores and going all the way to the toe and cleaning them out," Olliff said. "Those can be upwards of $150,000 all in, depending on if there's any treatments done. Water treatments with diversion agents [are] anywhere from probably $35,000 to $50,000. Worst case scenario is refrac, and those things can cost upwards of $2 million to $3 million."

Also, of concern are wells with high H_2S and CO_2.

"Those kind of well reactivations, depending on how long it's been shut down, can easily result in some parted tubing rods and things like that," Olliff said. "Again, it goes back to the geology and if they were preserved properly."

The latest downturn also presents another learning opportunity for shale players, particularly when it comes to collecting data. Under this price environment, the industry is not going to get the core and physical logs it always seeks, Von Gonten said. Performance data during production has been obtained. Now is the time to collect shut-in data, matching drawdowns, rates of pressure and build-up data.

Panelists also discussed the learning curve associated with cube developments in the Permian Basin as well as relative permeability and low recovery rate concerns among other topics.

"There's something else down there that we're missing," Von Gonten added, pointing to relative perm problems and water challenges. "I think there's going to be a lot of lessons learned from the build-up data after the wells have been shut in."

—Velda Addison

Oil and gas private equity: post-pandemic road map to recovery

As the oil and gas industry continues to face significant challenges, private-equity professionals have


Exceptional People
Innovative Technology
Great Rock

their hands full. Valuations that were once reliable are now fraught with new complexities due the extreme volatility in commodity prices. Lawyers from Winston & Strawn LLP recently spoke to Hart Energy about the challenges for private equity in the oil sector and their path to recovery.

Private-equity partners need to effectively work with their portfolio companies to ensure survival and plan for future success, according to Mike Blankenship, corporate partner at Winston & Strawn.

"Survival requires ensuring the financial strength of the individual portfolio company, which includes checking balance sheets, analyzing credit facilities and other debt arrangements, watching for supply chain disruptions, counterparty and bankruptcy risks. In some cases, consolidating portfolio companies within a fund may help create the desired economies of scale and reduce unwanted G&A [general and administrative] costs. This is especially true in basins or regions where it is clear there is only room for a few companies to succeed," he explained.

"There is certainly a tough environment for private equity in the energy industry," said Eric Johnson, corporate partner at Winston & Strawn.

"Sourcing new deals and putting money to work is difficult when everyone chases the same assets," Johnson continued. "Raising new money for non-distressed assets may be difficult when potential investors have negative views of the oil and gas industry. In a similar vein, limited partners [LPs] may want to see more ESG [environmental, social and governance]-focused solutions going forward, which some professionals may not have as much experience with. Also, exits or liquidity events are being delayed until the bid-ask spread returns to normal."

Regarding dealmaking, sponsors can enhance their diligence processes across the upstream, midstream and oilfield service sectors to deliver better investment results, said Brad Ratliff, associate at Winston & Strawn's corporate department.

"To unlock value from the diligence process, sponsors will need to accomplish more with fewer resources available to them," Ratliff explained. "Firms should embrace technology to help them drill down on the common areas of interest with more efficiency.

"For upstream and midstream targets, these areas will focus on land and title, engineering and geology," he continued. "For service company targets, attention should lean more towards intellectual property, human resources and operational matters. Understanding how the pandemic has changed customer and supplier relationships will also be key to determining a target's future financial performance"

Even though most diligence processes will need to take place virtually due to lockdown, it will be important for sponsors to identify any areas that still require physical in-person diligence. These could include environmental, land and mineral title and inventory counts, which could potentially cause a delay in timing of the transaction.

Successful general partners will chart parallel paths, learning to grow their diligence capabilities online while crafting safe and effective plans for resuming in-person diligence once applicable restrictions have been lifted, Ratliff said.

Once the immediate fund-level and portfolio concerns have been addressed, the focus will shift toward new investments, Ratliff said, adding that right from the outset, fund professionals should understand their mandates to know whether they are allowed to seek out alternative investments from the normal course, such as Section 363 of the U.S. Bankruptcy Code.

As Blankenship pointed out, this is the time to "get creative" in putting deals together.

"We are seeing some private-equity firms looking at more public company investment opportunities such as private investment in public equity, or PIPEs, and high-yield debt, which they have not typically invested in," he said.

In addition, LPs may want to see sponsors increase their commitments to more sustainable or ESG-related investments to the extent which their funds mandates allow them.

"As more distressed assets come to market, sponsors should roll up their sleeves to understand how such assets became impaired and whether there is any potential for future growth," Blankenship said.

—Faiza Rizvi

'Worst is over' for oil and gas, OPEC's Barkindo says

As countries across the globe continue easing lockdown restrictions related to the COVID-19 pandemic, OPEC Secretary-General Mohammad Barkindo expressed hope that recovery of the energy industry will be in full swing later this year.

"We are cautiously optimistic that the worst is over, even though the fragilities and the uncertainties with regards to recovery, whether it is a U-shaped, V-shaped or inverted hockey stick, are still uncertain," Barkindo said during a recent energy dialogue organized by Abu Dhabi International Petroleum Exhibition and Conference.

"Nevertheless, I am hopeful by the end of this year we will begin to see some further semblance of stability restored to oil markets," he continued. "Then we will be in a position to move into the next phase of sustaining that stability."

Underlining the importance of the two-year agreement signed by OPEC and non-OPEC countries in April, which was revalidated earlier this month, Barkindo is confident that more stability would return to oil markets in the second half of the year. However, he noted additional work will be required to draw down existing oil inventories and help rebalance markets.

Barkindo applauded the response from oil producers globally and the historic supply cuts by OPEC members, following the meltdown of the oil and gas industry.

The unprecedented oil market imbalance that struck the industry in the wake of COVID-19 pandemic required an unparalleled response from producers. OPEC rose to the challenge, Barkindo said.

"The collaboration and cooperation was at the highest momentum," he said.

Almost 20 MMbbl/d of production was cut by both OPEC and non-OPEC producers in response to the "unprecedented demand destruction," he added, marking the largest single supply adjustment of oil output in history.

Additionally, Barkindo stressed the importance of restoring oil market stability to attract new long-term investments, citing projections of a nearly 20% contraction, or $1.5 trillion, in energy investments as a result of the volatility and uncertainty around markets

"It is important we restore stability and sustainability to oil markets, not only for producing countries but also for consuming countries," he said. "Both parties know that a lack of investment in energy today will sow the seeds of another energy crisis in the medium to long term. That would not be in the interests of the global economy."

Highlighting the issue of sustainability and energy transition, Barkindo said that addressing carbon emissions would remain a central challenge for the oil and gas industry post-COVID-19. He urged the global community to address the twin challenge of climate change and energy poverty, but added he believes all energy sources would be needed to meet global demand for energy in the medium- to long-term.

—Faiza Rizvi

Eyeing recovery: oil sector trends indicate improvement

North American operators have cut capex by 42% to $58.6 billion, the rig count has plummeted to less than 300, wells have been shut-in and production has slowed as OPEC+ and others removed millions of barrels of oil from the market amid the continuing global pandemic.

WTI fell from more than $61/bbl in January to -$37.63 in late April, rising to about $40/bbl in June.

"While this felt like a lot of chaos, it actually was the market functioning very well," Bernadette Johnson, vice president of market intelligence for Enverus, said during a June 24 webinar hosted by the Independent Petroleum Association of America.

Signs of a recovery are evident.

Traffic has picked up in China, even exceeding pre-COVID 19 levels in some instances, she said, noting the same is being seen in Europe.

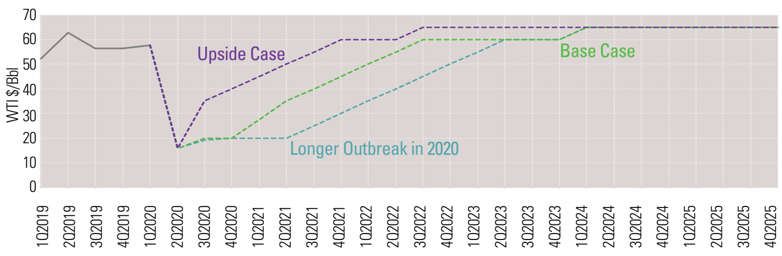
That bodes well for gasoline demand and barrels of oil that yield the transportation fuel.

However, the news is not good on all fronts.

Air travel and the need for jet fuel have not recovered as airlines feel the impact of consumers opting not to travel due to the coronavirus. Johnson compared the situation to the Sept. 11, 2001, terrorist attacks in the U.S. and people being hesitant to fly on planes. It took three years for the airline industry to recover back then. It could happen again.

Petrochemicals, specifically the chemicals needed to make plastics and rubber, have taken a hit, too, given unemployment levels and

WTI Price Outlook Scenarios



Source: Enverus

Under the Enverus base case for global petroleum demand, recovery in late 2020 is the single greatest factor driving its supportive outlook for crude oil prices in 2021 to 2024.

dire macroeconomic conditions impacting consumer spending. This slows the need for product transport and related fuels.

"Essentially, demand's not going to bounce back immediately," Johnson said. "The need to manage supply and some of the decisions that OPEC makes become that much more important."

OPEC+'s decision to extend the initial 9.7 MMbbl/d cut through July plus additional cuts by Saudi Arabia and other Gulf states, shut-ins in the U.S. and natural declines have put the market on a fast-track recovery, she said.

However, "You can't necessarily fast track [demand]," she said, which relies on individual behavior.

Demand, which dropped due to the coronavirus and related COVID-19 mitigation efforts, is still a work in progress. Plus, the oil market remains oversupplied.

Enverus put the supply-demand imbalance at nearly 15 MMbbl/d for second-quarter.

Demand is expected to start outpacing supply in the third quarter with global storage levels falling dramatically, according to Johnson, who noted a recovery also depends on what OPEC+ does next among other factors.

Look to refinery runs for recovery signs.

Utilization rates dipped to 66% about a month ago but have since risen to about 75%, Johnson said. Refiners are seeking crude, giving operators buyers as gasoline demand returns, making those barrels desired. "So, the unconventionals' need for that supply is coming back."

However, middle distillates are another story, given jet fuel demand remains low.

"This is the dynamic that pulls U.S. shut-ins out of shut in," Johnson said, later pointing out oil price is not the only factor in determining when to bring back shut-in wells or complete drilled but uncompleted wells (DUCs).

Buyers showing up in the field to purchase barrels are also at play. "That brings these wells back online. So, these are things to watch for. We're starting to see it," she said. "It's also important to note that you buy crude typically 30 to 45 days in advance. But today there's a lot of activity out there that's actually looking to buy for July delivery."

However, if refiners "overshoot" what's needed, they may pull back, she added. "So, it's not necessarily smooth sailing, and I would expect some volatility."

She suggested industry players watch the distillate level storage numbers because they're tied to the underlying economy.

Of course, another outbreak—triggering more restrictions—would prolong the recovery.

"Generally, I would tell you, we're trending in a better way, certainly, than we were two months ago," Johnson said. "A lot of it is through this very, very careful balancing of supply relative to how quickly that demand is coming back."

But don't expect $50/bbl oil prices this year. It'll likely stay in the $30s, according to Enverus.

"If you see prices recover too fast, then you see shut-in production come back too fast. You might see OPEC not extend their cuts," Johnson said. "You might see supply come back a little too fast for demand. And then you don't see that quick withdrawal from storage. You just prolong the price recovery."

Enverus forecasts many of the U.S. rigs will return when the oil price is between $45/bbl and $50/bbl. The recovery could take hold in mid-2021 with production rebounding, following a DUC drawdown starting by late third-quarter or early fourth-quarter 2020 from a cumulative count of nearly 3,600.

However, getting back to the 12.8 MMbbl/d production mark in the U.S. may not come until 2023 at the earliest based on Enverus data that includes type curves, go forward lateral lengths, completion technologies and spacing dynamics across U.S. plays.

"We do get there again, and it's not at a $100 oil price," Johnson said.

—Velda Addison

Research points to hidden opportunities in Permian Basin

With expectations that service cost concessions will disappear as oil and gas companies work to survive, the search may be on for hidden opportunities with low breakevens.

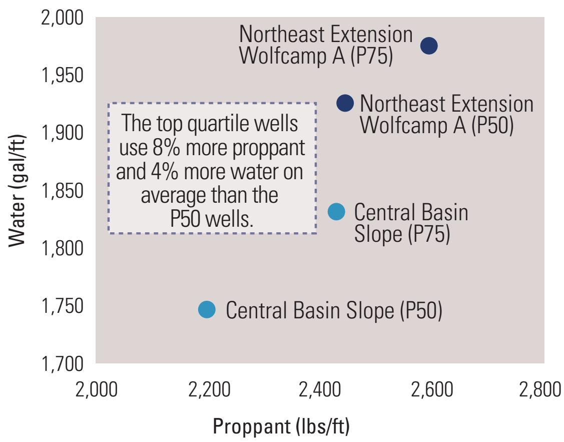
Analysts at energy research firm Wood Mackenzie pinpointed what they say is left standing in basins across in the U.S., including in the best zip codes of the Permian Basin. These areas, they say, can still make money—even at today's low oil prices. Players not already in the game still have a shot to get off the bench because some cash-strapped companies are looking to get out.

Brandon Myers, a geoscientist and senior analyst with Wood Mackenzie's Lower 48 research team, turned attention to ultra-core areas of the 2nd Bone Spring Sand and Wolfcamp A Northeast Extension in the Delaware subbasin during a webinar this week.

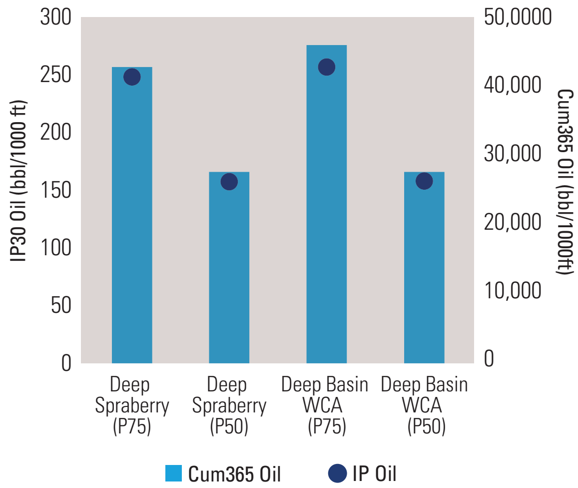
Some wells in the basin can clear a "10% half-cycle hurdle rate even with WTI below US$30/bbl," according to Wood Mackenzie.

Looking at petrophysical properties, geological attributes and other research using its integrated data analytics platform, Myers said companies want to be "hugging that border between the black oil and volatile oil," which runs through the area of New Mexico's Lea and Eddy

Average Proppant And Water Loading



Normalized Average IP30 and Cum365 Oil



Source: Wood Mackenzie

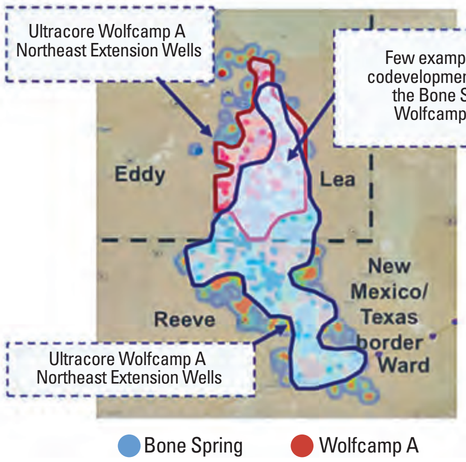
counties and Reeves County, Texas. Too far west, he said, there's lower quality product while heading into the condensate window. Too far east in the Wolfcamp, one could run into the hydrogen sulfide corridor or mass wasted carbonates off the Central Basin Platform.

Areas considered ultracore, producing the most with high oil cuts, are typically the deepest, highest pressure and lowest gas-oil ratio parts of the basin.

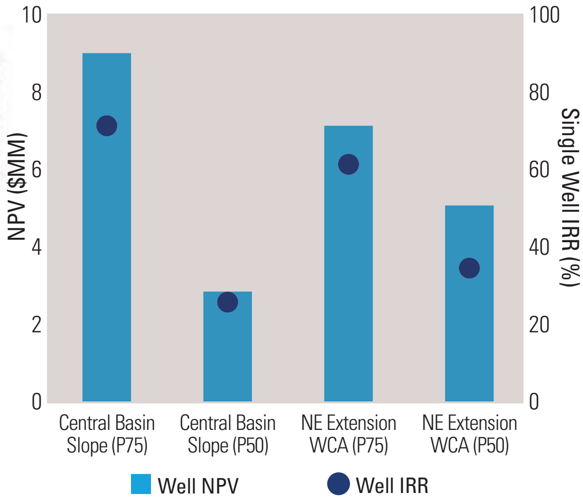
The firm also incorporated completion and engineering designs, noting more intense completions resulted in more production per foot, in these ultracore areas. Research showed the top-quartile wells used on average 8% more proppant and 4% more water than P50 wells, according to Myers' data.

In the Delaware, especially the Bone Spring, "There is a huge spread between your median operator in the best subplay and your top quartile operator in the best subplay," compared to other plays, Myers said. This reinforces the concept that being in the best rock is not good enough

P50 Wells (Heat Map) Vs. P75 Wells (Circles)



Normalized Average IP30 and Cum365 Oil



Source: Wood Mackenzie

in today's price environment, he added.

To determine the top quartile within the top two core subplays, the top 25% of well results using the P75 case were ranked by cumulative 180-day oil per foot, the firm said.

Location within the zip code matters.

"It's usually two to three companies making up 40% to 60% of those top quartile wells," Myers said.

With geologic and petrophysical cutoffs mapped along with completion designs, analysis pointed to an area that could probabilistically create a distribution around that P75 case, Myers said.

"There are about 8,400 two-mile locations left in what we consider that defensive strategy ultracore," compared to about 300 locations in the Bakken, he said.

He added that, "There is not a defensive fortress in every basin where operators will retreat to and keep production up. It just doesn't exist anymore. We've drilled through it. But it does exist here" in the Permian.

Outside from small sections of the Meramec, for example, he doesn't believe there are any ultracore areas left in the SCOOP/STACK, where the rig count has plummeted to the single digits from more than 130.

The rig count has dropped dramatically in the Permian Basin as well; however, there are still some rigs operating in this ultracore area, Myers noted.

He called it no surprise that companies like Devon Energy Corp. had opted to drop rigs in the SCOOP/STACK and high-grade capital into the Permian.

"It makes sense for them to do that because they can actually still generate returns through this year," he said.

For those not already in the ultracore areas, the best way to gain access is to become a working interest partner, according to Robert Clarke, vice president of upstream research for Wood Mackenzie. Budget constraints are causing some existing partners to back out, so "With the right network, I think there's a good chance you can get into some of these wells nonop."

Wood Mackenzie's data show Devon, EOG Resources Inc. and Concho Resources Inc. have drilled more than half of the P75 wells in the ultracore areas of the Bone Spring Central Basin Slope and Wolfcamp A Northeast Extension.

Such wells produce 85% more oil than P50 wells, translating to a $6.14 million increase in NPV10 and 175% jump in IRR, the firm's data showed for the Bone Spring.

However, it may not be in an operator's best interest to bring ultracore wells online now.

"If you're not starved for cash flow today [and] you can afford to wait, there is a little bit of asset preservation that you can achieve by waiting," Myers said.

Waiting until 2021 could improve the payback period by 21%, according to Wood Mackenzie.

There are, however, exceptions.

"If you drill a top quartile well in the Bakken ultracore in 2021 instead of Q1 2020, ...you'd actually break even on that 2021 well before your 2020 well paid out," Myers said. "And we did not have an aggressive price deck when we walked through that."

—Velda Addison

Chevron's Burger: Tech startup ecosystem 'vibrant'

Downturns tend to make the financial environment for innovation difficult. When it's partnered with a global pandemic, the road gets even tougher for new technologies and the startup community. However, investors that develop and support technologies that can address multiple problems will succeed in the current market conditions, according to Chevron Technology Ventures (CTV) President Barbara Burger.

"I think the startup ecosystem is vibrant, and it's needed," Burger said. "But each startup company has to assess its own situation, employees and operations, and really understand the impact of COVID and the market conditions on their business plan. Then, do some self-help, look to their investors for whether or not they're going to support them through that, and then make the changes that they need to."

During a recent Society of Petroleum Engineers webinar, Burger discussed how the venture capitalist (VC) firm is directing its investments toward technologies that can lower cost, increase cycle time and lower emissions. In addition, Burger provided guidance on how investors and startups should position themselves during this time.

For CTV, one of the industry's oldest venture groups, Burger said the focus is still on its current portfolio, but "We also have dry powder for new investments, and there's a lot of opportunities." She said the company's primary interest when seeking new areas to invest boils down to whether it gives Chevron a competitive edge.

Chevron is looking to invest in "cheaper and reliable" solutions for the subsurface that provide more information about the reservoir, drilling operations and better data, Burger said. On the surface, the company is focused on asset integrity technology.

Though the company has been investing in the energy transition for a while, Burger said Chevron is placing a huge emphasis on companies that play in that space.

"In 2018 we launched our Future Energy Fund to really concentrate in this area; investing in energy efficiency technologies, capturing and storing CO_2—and possibly using it—reducing and detecting methane emissions and mitigating it," she said.

So far, Chevron has used the Future Energy Fund's initial commitment of $100 million to make nine investments toward a low carbon footprint.

"We know that the energy mix is going to be more diverse as we go forward, and by 2040 most estimates are that 50% of total primary energy demand is going to be oil and gas and so 50% will not. The system is going to be an integration of all of that so we're also placing bets in nonoil and gas," she said.

Rather than just storing it in the ground, Burger said Chevron is exploring the avenues for utilization of CO_2 for purposes of a "circular economy." Additionally, she said the company has focused on mobility since "transportation and oil are so much tied together" but lacks any real improvement, lowering the emissions from hydrogen and making it cheaper, and a power value chain that sees Chevron get more decentralized and adopt different energy sources.

"We're investing in all, and some have a direct linkage currently into Chevron's operations and some have no linkage, but we see them as important in the energy system of the future, and we want to make sure we understand what it takes to be successful and make sure Chevron is positioned to be able to capitalize on them," Burger said.

"Hopefully, all of us are not thinking back to when it is going to get back to normal, but rather we're envisioning the new normal," she said.

Despite the impact current challenges have had on startups, Burger said the time has created opportunities for investors and startups.

"Some valuations went down, and that's always good as an investor, particularly a new investor," Burger said.

"Most investors are staying the course, but there are some that have flown so that gives us opportunities," she added.

From the vantage point of a VC, Burger said investing is necessary but not sufficient in connecting what happens at a company's headquarters to the wellhead.

"We learned that we had to take things through what we call 'use,'" she said.

"We needed to collaborate with our business units and our functions to really ask the questions like 'Does it work, and will it add value to Chevron?'

"It could work but not really add any value because it doesn't either take costs away or produce more, so we've worked on that over time, and we've had a fair amount of success. It's not a slam dunk, but you have to do that."

When this is achieved, she said investors should be cognizant of the results to provide startups with adequate feedback.

"Sure, they want investment dollars and revenue, but they also want to know 'Does it work?' before they go and scale it up," Burger said.

Burger said Chevron's sweet spot for investments is typically in the A and B seed round where the company feels it has the most influence and where startups need support.

However, she warns startups against thinking unilaterally about the solution.

"First of all, don't fall in love with the solution; fall in love with the problem," she said.

"We try to guard against that even upfront. If you bring me a solution, I'm going to see what's around it, what's the landscape, who are the competitors and all that type of stuff."

Chevron hosts "bake-offs" to combat this where it trials one company's technology against its incumbent "because we want to pick the winner."

"People think innovation is all about technology, but it is about people, your willingness to try new things, collaboration and credibility," Burger said.

It is a good time for big companies that are trying to embrace external technologies to better the relationship with small companies by giving them the financial runway and practical experience to grow in a risk-averse business, according to Burger.

"Houston has been able to distinguish itself relative to the startup ecosystem from the connection with the corporates," she said.

"There is a very high concentration of corporates here, and corporates bring experience in understanding the problems, scale, and ultimately they bring their supplier dollars.

If you can get the little guys and the big guys to work together, I think that really is a good recipe for success."

—*Mary Holcomb*

HAYNESVILLE 2020

Kicked out of the club in 2012, the Haynesville was resurrected beginning in 2017 to take on the mighty Marcellus in metrics, aided by a proximity-to-market kicker. Now, it's taking on oil basins at the IRR weigh-in.

ARTICLE BY
NISSA DARBONNE

In early 2020, LNG tanker-spotting at Gulf Coast ports had become common—online and in person.

A day trip to Surfside Beach, Texas, for example, usually netted a bonus view of one or two docked at the Freeport LNG Development LP terminal across from the town's boat launch.

Then there were none.

Not there. Not at Corpus Christi, Texas. Not at Sabine Pass, La. Not at nearby Hackberry. In early July, a quick online scan of the Gulf of Mexico spotted none underway either.

But they're coming, according to Welles Fitzpatrick, managing director of E&P research with SunTrust Robinson Humphrey.

While U.S. LNG exports were down 6 Bcf/d from the pre-downturn 9.6 Bcf/d, demand should improve in October, he reported. The indicator is seen in the Asia-versus-Henry-Hub (JKM-HH) autumn spread. It was more than $1/Mcf in June, "implying send-out could double into year-end."

U.S. resumption of just the April level of 8.3 Bcf/d of liquefaction "alone would shift us into an immediate and significant undersupply" in November, he added.

While some gas from turning shut-in oil wells back into sales is coming, there are too few rigs drilling to make up for the overall loss, he wrote.

His forecast is that a Henry Hub price of between $3 and $3.50 "is likely in 2021."

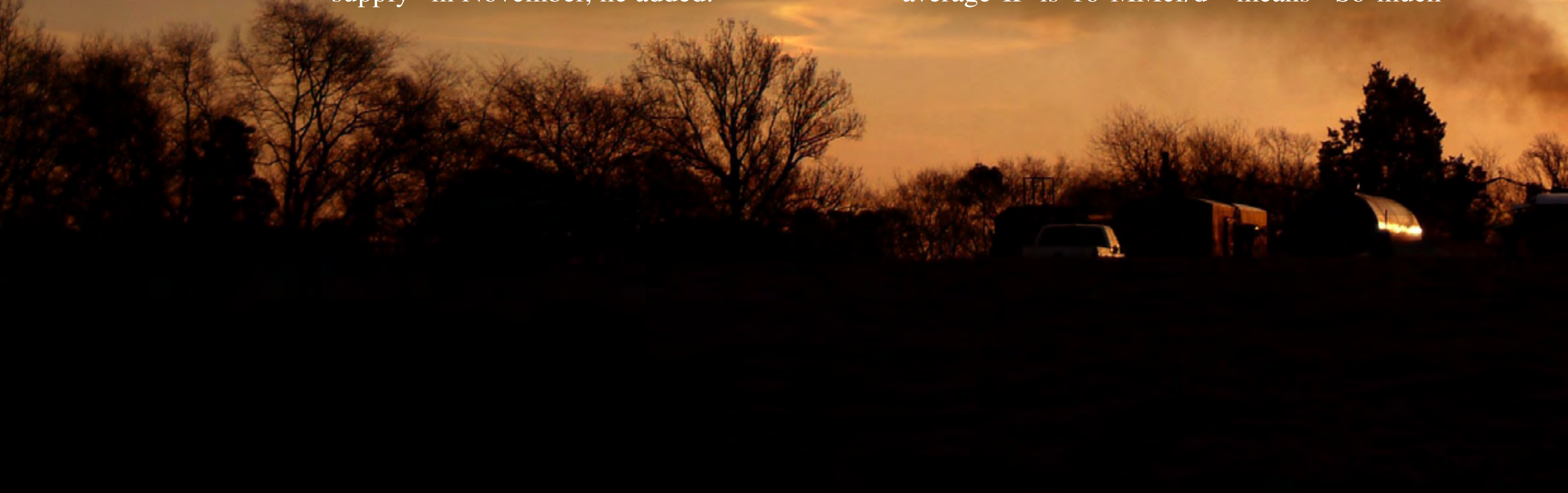
And the Haynesville is ready. J.P. Morgan Securities LLC's Arun Jayaram, an E&P analyst, wrote in mid-June that there are more than 150 drilled but uncompleted wells (DUCs) in the play.

Leo Mariani, managing director and equity analyst with KeyBanc Capital Markets Inc., reported in early July that, for winter and full-year 2021 futures prices, "Almost every gas-focused E&P is planning to ramp up production during this time."

At 12 Bcf/d currently, Haynesville production could grow another 2 Bcf as takeaway is expanded, wrote Jean Ann Salisbury, senior natural gas analyst with AB Bernstein.

As it pushed past 12 Bcf last year, the local differential blew out. Two expansions—CJ Express and Acadian—should make the basin grow to 14 Bcf/d next year, she wrote.

Powerful IPs from Haynesville wells—the average IP is 16 MMcf/d—means "So much



Good rock, low costs and ample transportation have made the Haynesville a strong play for Comstock Resources, said CEO Jay Allison.

money is made in the first year that hedging 24 months of production guarantees payback at the current forward curve," she added, "and an estimated 40% unlevered IRR by the end of Year 3 even with no terminal value."

Balance sheet

The rig count, including both Louisiana and Texas, was 32 entering July with 21 of those in Louisiana. Four of them were drilling for Comstock Resources Inc., which is now the largest Haynesville operator, producing 1.4 Bcfe/d and marketing 2 Bcfe/d.

As a conventional-formation producer in the region beginning in 1987, Comstock went horizontal in the Haynesville in 2008 in the play's early days. Already having leases, it stayed clear of the land rush that pushed an acre to as much as $30,000. Instead, Comstock began buying out others in just the past two years.

The company's Haynesville-prospective portfolio is now 307,000 net acres with proved reserves of 5.4 Tcfe, 98% gas.

In mid-June, Comstock paid down its bank debt—to 62% of the $1.4-billion revolver that had been decreased in April from $1.5 billion—with $441 million of net proceeds from a $500-million 9.75% senior notes placement due 2026, priced at 90% of par and increased from an initially anticipated appetite of $400 million.

The 9.75% notes join its $619 million of 7.5% notes due 2025 that had been paid down by $5.6 million this spring with equity.

In mid-May, it redeemed its $210 million of Series A convertible preferred with $190.4 million of net proceeds from a 40-million-share offering at $5 each. The preferred was held by Covey Park Energy LLC investors, who received them in the $2.2-billion Covey-Comstock merger last summer.

Overleaf, a rig drills for Goodrich Petroleum Corp. before this summer, making DUCs for the operator to complete and bring online at the winter natgas price.

Comstock's remaining preferred shares outstanding had a face value in June of $175 million, all owned by Dallas Cowboys owner Jerry Jones, who holds 84% of Comstock common.

After the notes offering, Fitch Ratings revised its outlook on Comstock from Negative to Positive, giving the operator a B issuer-default rating.

Among reasons, it cited Comstock's position as the largest Haynesville producer, low operating and drilling costs, ability to generate free cash flow at strip, low differentials, inventory of nearly 2,000 net well locations, which are 91% operated, and its "significant equity commitment from" Jones.

A unicorn

Investor buy-in of E&P debt and equity offerings had become rare before 2020; uptake in the midst of global-pandemic-inspired soft oil and gas demand is a neutrino-capture type of event.

But natgas investment ideas appear to have some takers.

"There is just such a chasm now between haves and have-nots," said Jay Allison, Comstock chairman and CEO.

Allison formed Frisco, Texas-based Comstock 33 years ago, building portfolios of both commodities. He transitioned the company fully to gas beginning in 2015 and exclusively in the Haynesville in northeastern Texas and northwestern Louisiana.

Each commodity has had its ups and downs.

"I have seen it from both sides," Allison said. "It's hard for the have-nots, and you have to see what kind of resolve you have, what kind of asset base you have and if you can bounce back."

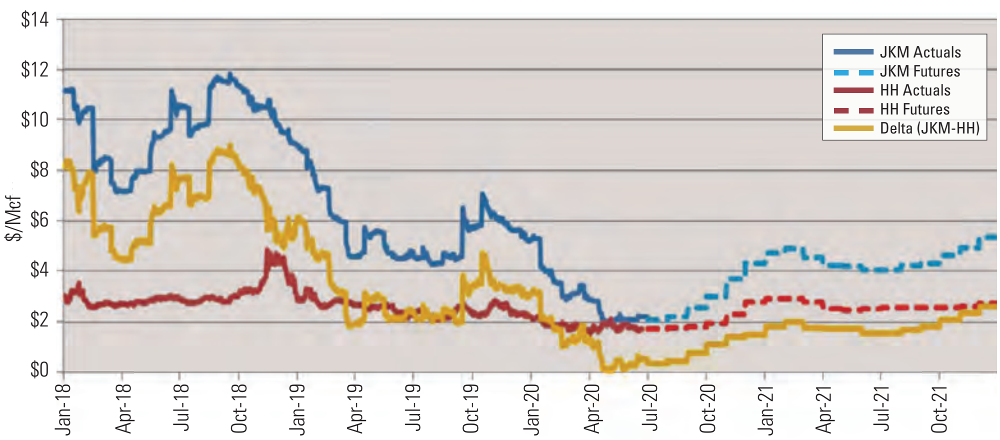
At Comstock over the years, the focus has been on increasing well productivity and decreasing costs. In 2010, when gas was $5 or more, "We would get about a 30% IRR," he said.

Early Haynesville wells, at a depth of more than 10,000 ft, cost as much as $12 million, drilled and completed (D&C), for about 5,000 ft of lateral.

Today, "With $2.50 natural gas, we get a 55% IRR," he said. "You used to think that you have to have a $4 gas price to have that type of return."

Comstock's capex budget this year and its outlook for 2021 expect a 55% IRR from its new wells. That includes having hedged 64% of its 2021 production at $2.51. For 2020, 48% is hedged at an average of $2.64.

Autumn Asia Vs. Henry Hub Spread



Source: Bloomberg, Factset

The Asian and Henry Hub prices for natgas converged this spring, but futures indicate the Asian market will pay more again beginning later this year.

That there were buyers of its debt and equity offerings demonstrates it has checked all the boxes, he added.

Completion costs have declined further this year as pressure pumpers are looking for where they can deploy equipment and crews.

"Our frac costs really are impacted by the activity in the Permian," Allison said. "They are not impacted by how busy the Appalachian producers are."

Peak Permian hydraulic fracturing spreads at work totaled 170; there were 17 in mid-June. Compared with peak Permian, Comstock's completion costs per frac stage have declined 70%.

Just as recently as first-half 2019, D&C wells of 6,000 ft or more of lateral cost about $1,400 per lateral foot. As 2020 began, it was $1,100. The 2020 target is $950.

Currently, "We're a little less than $1,000 [per ft]," Allison said. "We've come down $400 per foot just to drill and complete these wells."

Building DUCs

Comstock had nine rigs drilling for it in the fourth quarter. It began 2020 with six and was at four in June, working across its leasehold—not for HBPing leases; its leasehold is virtually 100% HBP.

Rather, Comstock maps targets based on not overwhelming takeaway capacity or disrupting its offset wells.

"So our marketing, geological and operations groups can tell you where every well should be drilled between now and 2022," Allison said.

Meanwhile, as Haynesville operators are in a long-running collaboration consortium, "We share information with each other, which helps us know where offset operators are planning to drill," he said. "So we try to coordinate with each other and not interfere with each other's operations as much as possible."

Comstock was not completing wells in June—it had more than 20 DUCs—but it had not planned to. Completions will resume in this quarter, putting the new wells online during winter-gas pricing.

When resuming, Allison expects frac costs to decline a further 15% from the 2019 level.

Plans are to produce at least $200 million of free cash flow in 2021 and use that to further pay down its bank debt.

Extended laterals in the bag are 237 to date—the most among Haynesville operators. General and administrative (G&A) expenses declined from 14 cents per Mcfe pre-Covey merger to 6 cents this year. Unit operating costs have fallen from 68 cents per Mcfe to 50 cents.

The 20 wells that were completed in the first quarter had IPs averaging 23 MMcf/d—and from four corners of the play rather than in one hot spot.

Rigs drill Aethon Energy Management LP's 16-well "Megalodon" pad, which has eight wells landing in Haynesville and eight in Bossier. The pad is expected to fill a new gas plant immediately upon in-service.


AETHON ENERGY

Goodrich Petroleum should appeal to investors that like the future of gas and want a conservative balance sheet and good rates of return, president and COO Rob Turnham said.

Versus Appalachia

Comstock's differentials to Henry Hub are between 20 and 25 cents per Mcf. Its gathering and transportation costs are about 23 cents per Mcf, and the Appalachian was at $1.03 in the first quarter.

Comstock's EBITDA-margin-to-finding-cost ratio was 3.6 in 2019; the Appalachian Basin's average was 3.1.

"The advantage is primarily driven by the higher IRR of Haynesville wells," Allison said.

Comstock's wells typically pay out in 1.5 years, and the Appalachia plays out in about 2.5 years, extended by higher transportation costs.

"So we get our money back faster. The wells cost more, but we'll get our money back quicker," he said. "The midstream costs are less here."

Comstock doesn't have minimum volume commitments (MVCs) to shippers.

Altogether, "That's the difference in where we are and why we're there," Allison said.

Frac science

That Haynesville consortium has resulted in intel sharing toward perfecting best practices in the play, particularly in completion design. Operators share results, including findings from individual science projects.

Earlier this year, Comstock was evaluating pumping smaller fracs—less proppant—on some wells.

"We think we can achieve a similar well performance for less cost, resulting in better economics," Allison said.

Meanwhile, Comstock is staggering intrapad landings in Haynesville and overlying Bossier. And over the past several years, it's been reducing the length between frac stages and the spacing between clusters, "which delivers better capital efficiency," he said.

Chokes are being managed to tailor drawdown, maximizing recovery.

"We've been doing that for several years, and it seems to be working. The results are pretty impressive."

How the wells are drilled hasn't changed much, but "We're always changing up completions," Allison said. The recipe is "probably 90% settled out."

Comstock is also looking at using diverters more often; a neighbor in East Texas is doing this.

"I do think they're probably going to improve the effectiveness of the fracs.".

Goodrich DUCs

Goodrich Petroleum Corp. is also seeing lower service costs.

"When you're spending $11.5 million to $12 million per well and, all of a sudden, you're

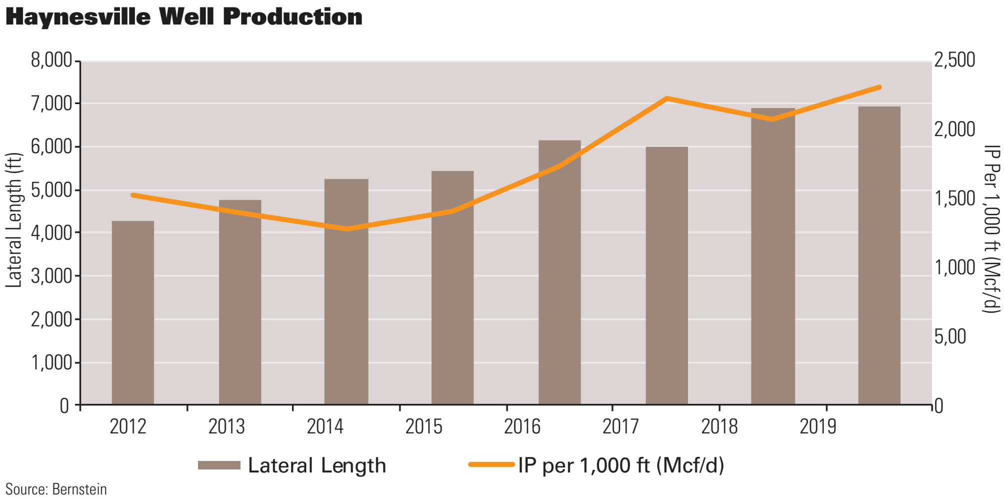
COMSTOCK RESOURCES

An operator uses AI-assisted drilling in the Haynesville for Comstock Resources Corp.

seeing a 15% to 20% reduction, that's pretty dramatic," said Rob Turnham, Goodrich president and COO. "You're looking at $1.5 million to $2 million per well, if not $2.5 million in cost savings."

As well productivity remains strong—12.6 Bcf on average for a 4,600-ft lateral—adding in the D&C savings is "a big improvement in the economics," he said.

The Houston-based operator holds 22,300 net Haynesville acres. Proved reserves are 510 Bcfe. Production is 137 MMcfe/d.



Haynesville IPs per lateral foot grew in 2019 from an average of the same amount of lateral.

While service firms are open to long-term contracts, Goodrich would also have to be willing to commit to a level of activity for an extended period. The newly discounted bids are spot rates.

"We can get a two-, three-, four-well package at that rate," Turnham said. "But they won't go 12 months out or [longer]. Unless you're willing to commit to a full-calendar-year program, they're not willing to lock those prices up."

Meanwhile, Goodrich's rig count in June was zero. It had two at work earlier this year and left the wells uncompleted for now, managing for commodity price when it brings them online rather than turning them to sales at the sub-$2 prompt-month price this summer.

"So we have some DUCs that are set to be completed later this year. We built an inventory that would give us that flexibility, once prices recover," Turnham said. "Thankfully we did it that way because service costs, particularly on the frac side, just continue to fall."

Otherwise, its $40 million to $50 million of capex this year is to keep its production flat, "with the ability to accelerate in the back half of the year, if prices do materialize," he said.

At the full-year 2020 strip as of June, Goodrich's budget generates free cash flow of between $10 million and $20 million. At $2.50 gas and current service costs, it can generate a more than 100% rate of return.

"We've never seen that type of return in the basin," Turnham said. "And, you know, it's a margin business based on how productive your wells are, how much revenue you generate, what your lifting costs are and what service costs you factor into the capex."

Roughly 50% of Goodrich's gas is hedged at $2.60.

"So even though, prompt month, we're below $2 physically in the market, the numbers work very well when you blend it with our hedges," he said.

In early July, the lowest 2021 price on Nymex was $2.48; the 12-month strip, beginning this month, was $2.42.

Rubble-ize

Goodrich is also a member of the Haynesville consortium.

"As a group, I think we are very comfortable that we've designed the optimal completion recipe, which is tighter frac intervals and proppant concentration of approximately 4,000 pounds per foot," Turnham said.

Earlier Haynesville wells' intervals were some 200 ft apart on average; the formula has settled on between 100 ft and 125 ft—"tighter frac intervals, which get you better near-wellbore stimulation.

"You spread the same amount of perforations or holes over a tighter interval. You're going to rubble-ize the near-wellbore and recover a higher percentage of gas in place," he said.

In trials with Chesapeake Energy Corp. in 2016, Goodrich pumped as much as 5,000 lb/ft of sand in what were dubbed the "Proppant-geddon" wells. Since then, Goodrich has settled on 4,000 lb/ft, which is still higher than the 1,000-lb formula that was the standard pre-5K trials and the 500 lb in the play's earliest days. The 5K-loading was resulting in 3 Bcf per thousand feet or more.

"We just didn't see a big enough incremental difference for the added costs; the rate of return was lower," Turnham said. "The 5,000 pounds per foot would get you more gas over the long haul. But we just don't think it gets you the best rate of return on your capital."

The combination of tighter spacing and the 4K-sand concentration—no matter if a 4,600-ft or 7,500-ft lateral—is booking reserves of between 2.7 Bcf and 2.8 Bcf per foot.

"And that's compared to our initial hopes of a type curve of 2.5 Bcf per thousand. So we're getting flatter curves and more reserves per well," he said. "And because of the service cost reductions, our finding costs have dropped dramatically and rates of return have risen dramatically."

Closely held

Like Comstock, Goodrich was already an operator in what became the horizontal Haynesville play in 2008.

Aethon Energy co-president Gordon Huddleston said managing for optimal natgas prices is the core of its business model as the Haynesville has shifted to development mode.

COMSTOCK RESOURCES

"We were spending probably 30% more to drill and complete our wells. And we were getting less than half the reserves from each well," Turnham said.

That was when it was pumping some 1,000 lb/ft and getting 1.1 Bcf per thousand feet.

"We're now pumping four times the proppant, spending 70% of the capital and making 2.5 to 3 times the well result," he said. "It is phenomenal, really."

Among all Lower 48 producers, Goodrich is getting the third highest return on capital employed—"and that includes all the Permian guys," he added.

Its debt is about 1.3 times EBITDA, "so very low from a leverage perspective," he said. And returns on capital deployed? "We're probably Top Five, no matter how you calculate it or what your peer group looks like."

The stock was trading in June at less than 2.5 times enterprise value to EBITDA. Usually that low of a premium suggests a company's "balance sheet is upside down or they don't have a place to spend money that makes any money," he said.

But in Goodrich's case, the low multiple is likely due to thin trading. Some 56% of shares are held by six individuals and funds; daily volume averages are fewer than 54,000 shares.

Aethon Energy COO Paul Sander said the 16-well Megalodon pad should fill the new Bland Lake gas plant from the outset.

"Everyone sees where we're going, and therefore they don't want to unload shares, so it doesn't trade as much," he continued.

Short-horizon investors aren't playing the ticker.

But "if you like where gas is going, if you want a conservative balance sheet, if you want good rates of return and you have a time frame that would allow us to let that materialize," he said, "then it's a good place to look to make an investment."

Aethon, 6,000 lb/ft

Private operators produce roughly half of the Haynesville's 12 Bcf/d, according to Bernstein's Salisbury. Of the 33 rigs drilling in the Haynesville in early July, according to the Baker Hughes Co. count, about 80% were drilling for privately held operators.

Among those, eight rigs were working for Dallas-based Aethon Energy Management LLC.

Aethon's Haynesville portfolio has been built through roughly a dozen acquisitions and is virtually 100% HBP. Last year it picked up QEP Resources Inc.'s position, adding 49,700 net acres, 607 operated wells and gathering infrastructure for $735 million.

In May it made a well commitment on Black Stone Minerals LP minerals in the Shelby Trough Haynesville and Bossier in Angelina County, Texas, in exchange for a reduced royalty rate. The operator on the property had been BPX Energy, the Lower 48 onshore upstream unit of BP Plc that has been paring its work to focus on the Haynesville core.

Aethon's Haynesville and Cotton Valley net acreage totals 340,000 to date, producing net 1 Bcfe/d.

The company has several field trials underway in the play.

"Our business has really turned more into manufacturing with highly predictable results," said Gordon Huddleston, Aethon co-president. "But there are always a few tests and modifications we're doing to continuously get better."

In one, the company is working with a BJ Services Co. natgas-powered frac fleet.

"We've done some initial testing, and it was successful," Aethon COO Paul Sander said. "Fewer pumps on location, fewer people and using a cheaper fuel."

Sander expects it "could be somewhat transformational for the fracking industry."

In addition, Aethon is using Precision Drilling Corp.'s latest-generation rig that allows automated drilling.

"That's really helping us speed up connection times," he said. "And we're also using managed pressure drilling that has reduced the amount of time required to run casing, primarily, so some benefits are associated with that."

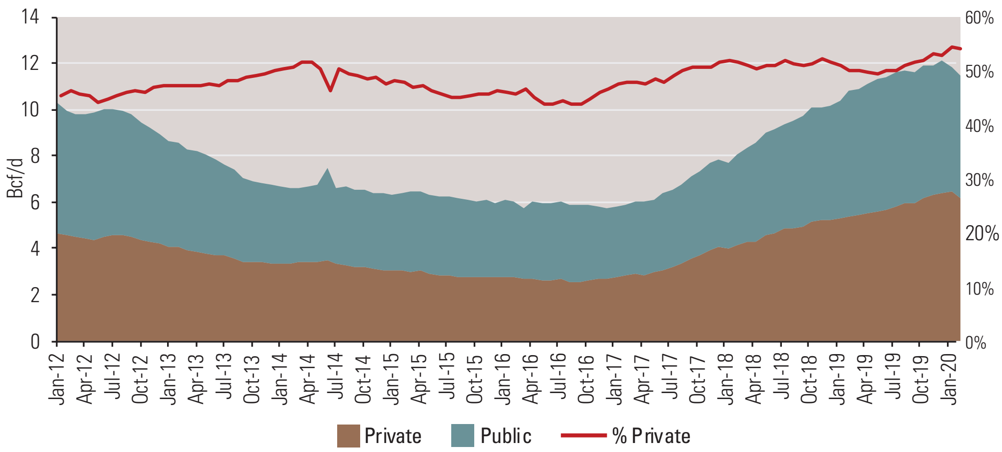
In East Texas in mid-June, the company was developing a 16-well pad, Megalodon, to test both capital efficiency and spacing. Eight of the wells are landed in Haynesville and eight are in the upper Bossier.

Laterals in each are about 7,500 ft. Half of the Haynesville and Bossier wells travel north and the other half travel south.

Half of the wells were expected to be brought online in July and the other half in November.

The to-sales timing is while Aethon is building out its midstream business in East Texas. The staggered time line is in tandem with the startup of its main gathering system as well as its new gas plant at Bland Lake in northern San Augustine County.

Haynesville Production Public Vs. Private



Source: Enverus, Bernstein

More than half of Haynesville production is by privately held operators.

"So as opposed to developing one well at a time [from small-pad developments] with production slowly ramping up, you are bringing on a set of wells to fill the plant at the outset," Huddleston said. "These midstream infrastructure projects have a much better return when they can be closer to capacity."

Sander said the midstream business was the primary driver for the Megalodon project.

"It's doubtful that we'll do another 16-well pad," he said, "but we may entertain four- and six-well pads instead of two- or three-well pads based on what we learn here."

The operator also has trials underway with eight-well pads, adding a couple of wells per section to determine whether two more affects overall recoveries.

It was also testing pumping the same amount of sand but with less water. Its frac jobs are usually slick water; the design being tested requires a gel system.

Meanwhile, it is testing as much as 6,000 lb/ft of sand in wells.

"We tend to be a bit more aggressive in terms of how much sand we pump," Sander said.

And the company was investigating results from far-field diverters to see if that improves the overall frac efficiency and complexity, thus better well performance—"and perhaps also minimizing damage to wells while we frac," he said.

The slowdown in the oil side of the industry has brought new oilfield technology attention to the Haynesville, he added.

"A lot of R&D efforts have been focused on the Permian, and that's really not the same animal as the Haynesville. We have a lot higher pressure and a lot higher temperature," Sander said.

The Haynesville's depth is between 11,000 ft and 13,000 ft in Louisiana and between 13,000 ft and 14,000 ft in Texas, while Permian targets are between 4,000 and 12,000 feet. "So we just have different equipment needs and different reliability issues," he said.

EURs, rigs

Across its well portfolio, Aethon is booking 2.5 Bcf per thousand feet of lateral in Louisiana, on average, and 2.2 Bcf per thousand in Texas, depending on vintage and geology, Sander said.

Outside of field trials underway, the company's completion recipe varies little.

"I think that, for the most part, we've standardized our operation," Sander said. The trials are "usually multiyear-type efforts. And if they work, they become part of the new standards. But we believe we're between 90% and 95% there."

Aethon started 2020 with 10 rigs; in June, it had eight in the field.

"That's kind of where we expect to remain," Huddleston said. "It's really more about just managing capital and whether our working interest partners are going to participate in future development. That has the biggest impact on our rig count right now."

The company is hedged. It keeps the details private. But, Huddleston said, "We have more than 90% of expected volumes hedged for both 2020 and 2021 and then it trails off from there.

"We really view how we manage commodity price volatility as the core of our business model. It really is the critical component, especially because things have shifted into a more predictable type development mode."

Sander added, "We try to lock in and ensure our cash flow. And we are also trying to own as much of the pot [as possible]. We're not only an E&P player; we are a significant midstream owner/operator."

Oilfield service costs are declining, resulting in a roughly 10% lower cost structure to Aethon. "Just like we lock in our cash flows with hedges, we also tend to do long-term arrangements with our major service providers," he added.

Huddleston said, "Our main focus from a corporate standpoint is on risk management. And I think that's why we're able to continue developing through these downturns, whereas some of our peers may be in a more difficult or challenging position."

Rockcliff Energy president and CEO Alan Smith disagrees with analysts' outlooks on the Haynesville's margins. "They say that the best parts of the Haynesville need $2.50 at a minimum. But that is just not true. We're living it," he said.

> "We think natgas is a cleaner fuel and will bridge us to the future."
>
> —Doug Krenek,
> Sabine Oil & Gas Corp.

Drilling through it

Also privately held, Houston-based Rockcliff Energy II LLC had four rigs drilling for it in East Texas in June. After picking up its 276,000 net acres—of which 150,000 include the Haynesville—in two acquisitions, including from Samson Resources II LLC in 2017, it has had four at work continuously.

Plans are to continue with four through 2020. It is running DUC-less, and it is completing new wells as they're done. Net production is just under 700 MMcfe/d.

In the early days of targeting Haynesville in East Texas in Rockcliff's area, "A lot of people were thinking 'East Texas isn't going to work. It's going to have too much clay, or it's just not going to be as good as Louisiana,'" said Alan Smith, Rockcliff president and CEO. But "It's just performing really well."

Smith's oil and gas career began in East Texas in 1986. Beginning in 2003, East Texas assets have been a part of five of his startups' portfolios.

Current declines in service costs are a boon. "You name it. Across the board, it's all come down," he said.

Rockcliff's rig contracts tend to be six months, rolling, plus or minus. On completions, it contracts with one pressure pumper for a year.

"And then we have another frac player that kind of plays our second spot, which is pretty much full time, and we're locked in with those guys for the year," Smith said. There are "outs in the contract on both sides, but it's a commitment to move forward with them and vice versa."

Rockcliff has 80% of its 2020 production hedged at about $2.60, about 80% of 2021 at $2.56, and, for now, between 50% and 60% of 2022 at $2.48.

"We focus on locking in our underwriting on commodity prices, which, in this environment, has helped us increase the margins and make our economics even better," Smith said. "A lot of people ask 'Why are you running four rigs?'"

Natgas in June was sub-$2.

"The answer is 'Because it's economic.' We just plan to drill through the cycle," he said. "We've taken a lot of the price-risk out. We've got flow assurance with transportation and are pretty well locked in on basis. So we feel good about it."

Even without the hedges, though, "It's highly economic," he added. Rockcliff's IRRs at the June strip were some 50% on most of its wells. "That's a very good return," he said.

It is a sharp contrast to the oil-weighted business today. While oil producers were struggling to find returns, natgas producers have clarity.

"I tell the guys [here] every day, 'stay humble,'" he said. "We've got a great asset and, while most everyone else's borrowing base is staying flat or getting cut, our borrowing base just went up."

It was increased from $700 million to $750 million—and on organic growth in asset value rather than acquisition.

"So that's a huge testimony to the quality of our assets," Smith said. "We're putting new wells online that further enhance the value of the company, and we were rewarded by the banks. When you have 13 banks doing their due diligence and all agreeing that you should get an increase, that's a big stamp of approval."

Rockcliff's leverage is less than 2 times EBITDA, which is "roughly two times asset coverage," Smith said. "So that's a very strong position to be in.

"That's why we hedged such significant amounts—because we're not worried about what we're leaving on the table. We're more worried about protecting our capital."

Denser spacing

To combat costs, Rockcliff began developing its leasehold in 2018 with pad drilling exclusively. "So nearly every well we drill has been anywhere from a two-well to a four-well pad. There are a lot of efficiencies in that," Smith said.

Also it is wine-racking, landing in both the upper and lower Haynesville in most of its pads.

"Here in East Texas, we're getting more thickness in a large part of our acreage than they have in Louisiana, which translates to more gas in place," he said.

Well spacing is 800 ft and stage spacing is 100 ft. Proppant is 3,500 lb/ft, delivered with between 85 and 100 bbl of water per foot, up from recipes of between 30 and 50 bbl per foot in the Haynesville's early days.

"I think that's what cracked the code over here on the East Texas side," Smith said. "You're trying to maximize stimulated rock volume.

"And by going to denser stage spacing on the fracs and pumping more fluid, we're able to get a significant amount of stimulated rock volume."

The 800-ft spacing is possible "because you are able to stagger your locations," he added.

As for EURs, these are complicated by that, prior to Rockcliff's entry to the area, the Haynesville had been completed with less sand and water than today. Rockcliff's application of modern-intensity completions has resulted in enough wells to predict EUR across its acreage.

"In the initial wells we drilled, most of our results were semibounded in a lot of ways," Smith said. "And when it's semibounded, you get higher EURs.

"Then, as you begin to drill in a development pattern, you end up with bounded and semibounded wells and some parent/child situations."

Nevertheless, Rockcliff's EUR is looking like between 2.2 Bcf and 2.7 Bcf per thousand feet of lateral in the bulk of its acreage, averaging about 2.5 Bcf.

Sometimes it has to use four strings to drill and complete a well.

"But our three-string wells were originally $13.5 million. Now those wells cost $11.4 million. So we've taken $2 million of the capital costs per well out of the equation," Smith said. "And the results are just as good or better on the EUR side. That's why you're getting such really strong returns—even in this environment."

'Living it'

Rockcliff picked the Haynesville when forming in 2017 for a couple of reasons, Smith said. It saw the rock being productive over a large area.

"Secondly, it is located in one of the best places in North America to own natural gas because it is the closest to the Henry Hub," he said. "Haynesville gas is in front of just about any gas that's produced in the country in going to the markets."

And the rock performance "has been even better than expected," he added.

The neighborhood is friendly, and there is plenty of takeaway capacity.

"So when you put all those ingredients together, it's really some of the best economics in the country right now," Smith said.

Rockcliff's all-in cash costs are under $1/Mcfe. For most Marcellus operators, it is more than $1.50. For one of them, it is nearly $2.50.

Gathering/transportation/compression is 25 cents per Mcfe for Rockcliff. For most Marcellus operators, it is 75 cents or more.

"No one's questioning whether they have great rock," he said. Rather, "They agreed to these MVCs in a much higher gas-price world. Some are 10-year. Some are 15-year. Depending on the company, they still have multiple years of MVCs on their books."

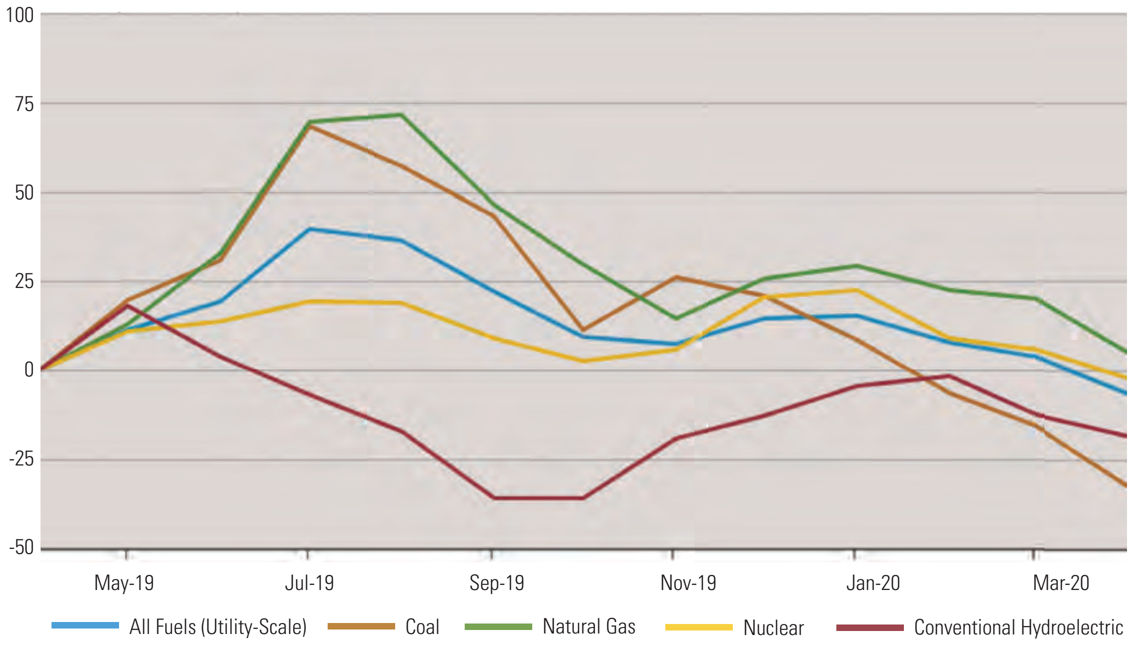
Rockcliff's breakeven cost with a 20% return is between $1.90 and $2.15 flat, depending on where it is in its leasehold.

"I do not understand why the research analysts have such a hard time grasping the Haynesville," Smith said. "If you look at the stuff they put out, they say that the best parts

COMSTOCK RESOURCES

A multiwell pad drills for Comstock Resources.

Percent Change in Fuel Share in U.S. Powergen



Source: Enverus, Bernstein

While overall U.S. powergen demand has declined in 2020, natgas' share of total consumption has grown 5% from the more than the year-ago level. Demand for all other fuel types has declined, including a 32% decline in coal use.

of the Haynesville need $2.50 at a minimum.

"But that is just not true. We're living it."

Osaka's Sabine

Doug Krenek has long been familiar with the East Texas subsurface. The president and CEO of Sabine Oil & Gas Corp. had worked with Rockcliff's Smith at Chalker Energy Partners II LLC.

Smith's first iteration, Chalker I, was sold to Forest Oil Corp. in 2006; Chalker II was sold to Nabors First Reserve (NFR Energy LLC) in 2008. Smith and Krenek moved on to forming other startups.

Meanwhile, NFR Energy was renamed Sabine Oil & Gas Corp., and it merged with Forest in 2014. So Sabine's portfolio includes "legacy Chalker I and legacy Chalker II," Krenek said.

Sabine exited Chapter 11 reorganization in 2016. Krenek was hired in 2017 to run the company.

This past November, it was purchased by Japan-based, publicly held, Osaka Gas Co. Ltd. subsidiary Osaka Gas USA Corp., which also holds an equity interest in Freeport LNG and several U.S. gas-fired power plants.

Sabine's 175,000 net acres and Rockcliff's acreage "touch in a lot of places, and we've done deals together with trades, joint wells and water disposal," Krenek said. "We communicate and work together a lot."

Sabine has three rigs running—two drilling Haynesville and one in Cotton Valley—up from two in the fourth quarter of 2019. The Cotton Valley drilling is in Rusk and Upshur counties, which are adjacent to the west to Panola and Harrison counties where Sabine is drilling for Haynesville.

As the operator went through reorganization, its MVCs were rejected in what is cited as a precedent ruling in U.S. Bankruptcy Court.

Finding and development expenses are between 70 and 80 cents; facilities development and operations all-in costs, including G&A, are about $1.60. Production is about 300 MMcfe/d, which includes some oil from the Cotton Valley. More than 80% of its gas is hedged. Its well count is approximately 1,200.

Currently, science-ing right now is on parent/child wells, Krenek said.

"We haven't drilled many parent/child wells yet," he said. "But understanding how they're going to perform will be important to us because, as we go further into development, we'll be doing more of these kinds of wells."

In eastern Harrison County, the company's acreage is prospective for both Haynesville and Cotton Valley.

"We're looking at some areas where we could develop potentially 10 wells from a pad," Krenek said. "You'd have three Haynesville wells to the north, three to the south, two Cotton Valley to the north and two to the south.

"We've done individual wells confirming productivity, but we haven't done the pads yet."

Meanwhile, its completion recipe is fairly settled on.

"We're doing little tweaks on number of clusters and testing increased proppant loading. But, for the most part, we feel pretty comfortable with where we're at," he said.

EURs for its Haynesville are more than 2 Bcfe per thousand feet of lateral; for the Cotton Valley, it is about 1.5 Bcfe per thousand.

Sabine's acreage is primarily HBP except for its newly acquired leasehold.

"We try to replenish our inventory every year through grassroots leasing and bolt-on acquisitions and farm-outs," he said. "All our drilling is HBPing in that new acreage we have picked up."

Long-term view

Osaka had been evaluating ownership of U.S. natgas reserves since 2015. It picked up 35% working interest in the Haynesville half of Sabine's portfolio in 2018, before buying Sabine as its platform U.S. upstream entry as an operator last year.

Ownership by an international conglomerate with an interest in gas reserves has meant that Sabine now has a long-term view when developing its assets, Krenek said.

When working for private-equity investors in the Chalker series and with the original Sabine owners, "We knew we were going to have an exit," he said.

"But now, with a long-term view [at Osaka], we think and plan everything long term. We can make long-term investments in infrastructure. We can work with our service providers on a more long-term basis.

"We want them to be around for the long term with us. So we're trying to get win-win solutions with all our providers, whether it's the gatherers, the frac companies, the drilling companies, everyone."

That includes land and minerals owners.

"When people have land open and are trying to lease, a lot of times they're calling us because over the past three years we've demonstrated that we do what we say," he said. "They're confident that, if they partner with us, they're going to be successful."

Is Osaka looking to buy more Lower 48 gas reserves?

"Right now, we're kind of in the 'prove we did a good deal stage.' So they're not willing to take that leap yet until we can get this first year under our belt and they're comfortable that their investment is doing what they wanted it to," he said.

He believes Sabine will stick to natgas.

"I think we see that we're not going to be a player chasing oil. I think they're on board with that, because we think natgas is a cleaner fuel and will bridge us to the future," Krenek concluded. □

A rig drills for Comstock Resources, making DUCs for turning into sales at the winter price.

COMSTOCK RESOURCES

ROCKIN' WHILE OTHERS ROLL

Unfazed by challenging market conditions, Appalachia-focused Diversified Gas & Oil Plc is actively pursuing A&D following recent successful fund raises. With a model focused on amassing mature production and little to no drilling, is it the perfect vehicle to weather a perfect storm?

INTERVIEW BY
STEVE TOON

PHOTOS COURTESY OF DIVERSIFIED GAS & OIL PLC

Rusty Hutson Jr.'s father and grandfather both worked for the same small West Virginia oil and gas company while he was growing up, so the business was in his blood. But it wasn't what he aspired to do in his early career.

"My dad would put me to work in the summers. The majority of what I did was a lot of pipelining, which back then was a lot of manual labor for sure," Hutson, the CEO of Diversified Gas & Oil Plc, said. "You didn't have as much equipment, and I did a lot of hand digging and pipe fusing. When I graduated from college, the last thing on God's earth that I wanted to do was work in the oil and gas industry."

And he didn't. With a degree in accounting from Fairmont State College in West Virginia, Hutson worked in banking for 13 years. But along the way he bought a package of producing wells in West Virginia from an individual that largely owner-financed the deal. He funded the cash portion from a home-equity loan. "My wife was none too happy taking out a home equity loan for what she stated was a piece of pipe sticking up out of the ground." That deal led to others, which he financed with loans, until he finally left banking in 2005 to tend to his small but growing gas and oil portfolio.

In 2014, with total production of just 6.5 MMcfe/d at the time, Hutson recognized an opportunity. The larger Appalachian shale players were intensely focused on drilling and were neglecting their conventional portfolios. He just needed the capital to make offers.

Banks were tight following the 2014 oil price collapse, and he didn't like the idea of giving up control to private equity, but an arranged meeting with a London attorney introduced him to the London market. Too small to list, Diversified raised $13 million for an unsecured bond on the ISDX exchange, which it used to buy conventional assets from Seneca Resources and Eclipse Resources. With the additional scale and size, Diversified was able to IPO on the London AIM for $50 million in 2017. In May this year, it moved to the main board of the London Stock Exchange.

What began as a family business 20 years ago, Diversified Gas & Oil Plc has grown into a formidable aggregator of mature Appalachian assets led by its founder Rusty Hutson Jr.—with solid cash flows even while prices remain depressed.

DGO, commonly known by its acronym, based in Birmingham, Ala., most recently completed acquisitions with EQT Corp. and Carbon Energy Corp. in May for $125 million and $110 million, respectively. Just prior, in April, the company completed its second asset-backed securitization (ABS) debt financing for $200 million as a follow-on to its first ABS fundraising of $200 million in November. DGO is only the second E&P to use the financing structure.

Since going public, Diversified has acquired some $1.7 billion in deals involving 710 MMboe proved developed producing (PDP) reserves. Current total production is 112,000 barrels of oil equivalent per day (90% natural gas), with more than 600 million a day of gas. It now employs more than 1,000 individuals—with Hutson's father being one.

"A lot of people get confused about how you can have an E&P company that's not drilling. Our drilling is acquisition. Rather than acquiring undeveloped resource, we focus exclusively on buying producing assets, which changes our risk profile meaningfully versus others."

Hutson spoke with Investor *from his base in Birmingham.*

Investor Why does Diversified seem to be playing offense when so many other E&Ps are on the defense currently?

Hutson Our model is different. It has been successful because we're acquiring assets at compelling multiples from others needing or otherwise motivated to sell. We've also been focused on reducing our costs. The commodity price cycle has been extremely low—I mean, it's been terrible, really, if you're not a low-cost operator. If you are having to put your cash flow back into the ground, the returns are low right now because the flush production from the new wells is likely flowing back unhedged and at prices that really don't work.

The industry is highly levered and has been out over its skis for too long. It would rather not be drilling, but for a variety of reasons it can't seem to stop. The result is drilling what I would deem to be uneconomic or low rate-of-return wells, but ones needed to maintain production and cash flow to cover debt service.

We love low commodity price environments. That's when we can buy assets at very attractive multiples. When companies are stressed or bankrupt and looking to sell assets to raise cash often to lower debt and repair the balance sheet, it's a perfect opportunity to step in and be on the offense.

Our balance sheet is strong. We keep our leverage low, and we operate at a flat production profile. We're at about a two times leverage ratio, net debt to EBITDA. That puts us in a strong position. And we have access to the equity markets, which few have at this point and for the last few years.

Investor How would you describe DGO? What's your business strategy?

Hutson What makes us different is we're not a drill-and-build company. We're more acquire-and-optimize. We like to acquire producing properties, get more production out of them and operate more efficiently than the previous owners, which are generally more focused on managing costly development programs and deploying cash into the ground.

A lot of people get confused about how you can have an E&P company that's not drilling. Our drilling is acquisition. Rather than acquiring undeveloped resource, we focus exclusively on buying producing assets, which changes our risk profile meaningfully versus others. I've evaluated it in every way, shape and form, and in all the times that I was drilling wells, the risk-adjusted internal rate of returns on new drilling were not as high as those from acquiring PDP properties. We're buying the assets based on the current strip price and hedging them, so we're getting good internal rate of returns on our acquisitions.

Our model is just different. What I really love about it is that it results in significant cash flows—cash flows that are not having to be returned to the drill bit, but that can be returned to equity and debt investors.

Investor So do you have a drilling program at all?

Hutson We do not. We have a substantial land bank—10 million acres in Appalachia of undrilled, largely held-by-production acreage. Most of it is conventional only, though we have some unconventional opportunities in the Marcellus and Utica. We could drill. We have a lot of prospects that we could drill, both gas and oil, but as long as opportunities exist on the acquisition side, we will not turn to the drill bit.

When you're drilling wells, you're focused on drilling, and that's it, because drilling programs take a lot of time and attention and a lot of resources. You get distracted from your producing operations.

We buy existing production and put time and attention into it, to optimize the production to get as much efficiency from an operational standpoint as we can. We have a substantial ground game in Appalachia, and every time we acquire another asset there, we become more efficient.

Investor What about infill or development drilling?

Hutson It's an option for us if gas prices should pop back up at some point in the future. And prices will move higher. The gas price that we have right now is not sustainable. If we see prices start to rebound, and sellers want more for their assets than we are willing to pay, we have the ability to switch to a drillbit growth strategy.

Another benefit of having low decline rate assets is that we can also afford to be patient through market cycles by waiting to buy until valuations are right. If we ever add organic growth to our mix, we would do so moderately. We would not jump into drilling like some in the industry have and, in my opinion, undermine shareholder value by drilling at any costs.

Investor At what price would you do that?

Hutson We have very compelling returns in the $3 range. We have a lot of acreage down in Southern Appalachia in some of the shallow shale plays. We have a lot of opportunities but, for us, it's all about returns. It's always about the highest rate of return that we can put our capital to.

Investor Would you consider your model similar to a modern-day MLP?

Hutson There are some similarities but there are major differences. At their core, MLPs made a lot of sense. However, a major difference relates to what we're willing to pay for an asset. The MLPs did things that they shouldn't have. They started paying high multiples for assets. I know because we used to compete against them quite a bit. We'd come out of a bidding war and ask, 'How did they spend that much for that asset?' We couldn't come up with those kinds of valuations. Well, come to find out, they probably shouldn't have either.

Also, they used more leverage than they should, and their distribution policies were too aggressive. Next, add that they started getting into some of these shale plays with higher decline rate assets. Those were recipes for disaster for companies that once were steady-as-you-go, cash-flow generative structures.

We share some similarities in terms of cash flow distributions to shareholders, but we stay away from high leverage. We keep our balance sheet in check, and we don't overpay. I tell our institutional investors and our employees, 'We will not risk the balance sheet for the sake of growth.' We won't do it. And we also stick with what works for us, which are long-life, mature, producing assets with manageable, shallow decline rates.

Investor How do your economics work with natural gas below $2?

Hutson We've got approximately 80% of our gas production hedged this year and next year at $2.65 to $2.70 per Mcf. So, if I'm talking to anybody about how current natural gas prices are affecting us, I'm not doing my job. We want to always be talking about natural gas two years out or further. We should be covering the commodity price risk well in advance. So, we're constantly evaluating natural gas prices further out.

It's all about visibility of cash flows. We've driven our total operating per unit, including G&A costs and operating more than 12,000 miles of midstream, to just under $1.20/Mcfe. We've built the business to not only survive but to do well even in low commodity price environments. We use hedging to provide line-of-sight to those stable returns.

Investor The word on the street is that the deal market is dead, but you've completed several significant deals recently. Why is Diversified able to get deals done now when others aren't?

Hutson It's a result of having capital availability. The markets have been dead because there are not a lot of people that have any capital. I think people would like to sell, and I think people would like to buy, but there's some disconnect between expectations and reality.

We haven't had that problem. Once you are known to have the ability to execute on a transaction, you typically can get deals done. In May, we raised $250 million between equity and debt, and when people know that you can do that, they're more willing to take a reasonable price if they know they can get it executed. And we're seeing a pretty heavy flow of deals, so I would expect that we're going to be doing more as we move throughout the year.

Investor So how are you getting the deals financed?

Hutson We've done it multiple ways. We've done some through the RBL [reserve-based loan] with the support of a 17-bank syndicate led by KeyBank, and just last month we did a $160 million, 10-year term note with a fixed coupon and principal amortization with MunichRe. For some, the idea of principal amortization trips them up. Many don't want to do a principal and interest note, but I've always thought it best to pay back your debt.

We've also completed two ABS structures, which have helped us create liquidity for deals and reduce our reliance on RBL financing that's exposed to redetermination. We've all seen the challenges it creates to have your borrowing capacity pulled away from you when you need it most. The ABS structures are also on interest and principal amortization.

Investor Aren't you paying half equity, half debt for these deals?

Hutson Yes, cumulatively. That's how we're able to keep our leverage profile in check with our self-imposed leverage limits.

Investor But you mentioned that the equity markets aren't open, though.

Hutson While they're not open to others, they've been open to us, which speaks to the appeal of our business model to equity inves-

Yoder #22 pumps for Diversified Gas & Oil in Fayette County, Pa.

"We are one of the few E&P companies that actually have a significant amount of income funds in their investor base. These investors may not know much about oil and gas, but they do know about dividends."

tors. Since February 2017, which is when we did the IPO, we've raised over $800 million of equity in London via our LSE listing, including our most recent raise of $86 million that settled directly on the main market following our uplist to the premium board.

Investor So is that an advantage to being in London versus the U.S. exchanges?

Hutson There is some truth to that, for sure, but I think more than anything it's just the business model. It is cash-flow generative, paying a dividend and low risk because we're not putting it in the ground with a drill bit. Certain institutions see that as a very attractive investment.

When I founded the company in 2001, it was about cash flow for my family. Today, it's about free cash flow for my equity and debt investors who are looking for yield in a yield-starved market. And we've been able to tap into that. We are one of the few E&P companies that actually have a significant amount of income funds in their investor base.

These investors may not know much about oil and gas, but they do know about dividends. They like the income stream and the fact that we're able to generate a lot of free cash flow. In this industry, paying a dividend is difficult to find. Our dividend has been very generous from the perspective of the E&P sector. We're trading at about 11% dividend yield right now.

Investor What do you look for in an acquisition?

Hutson It has to fit our profile: long life, low decline assets. We're generally not interested in new wells that have just been drilled that have a significant decline rate associated with them. We target a two-to-four times cash-flow multiple. We're looking at anywhere from a PV12 to PV18 for PDP and complementary midstream assets or around PV20 on PDP-only transactions. If it will fit in those molds, then we'll do the deal.

We're not going to overpay, and in this market—there's no reason to do so. You don't have to pay for undeveloped acreage. You don't have to pay PV8 or PV10 for producing properties because nobody can or will, particularly when the financing is not there for people to do it. Further insulating us is that the equity markets haven't been available to others. Our ability to raise some capital affords us the ability to determine valuations. And if sellers won't come off of it, then we just don't do the deal.

Investor Do you pay for unproved upside?

Hutson We do not. In this market, there's no reason to. There are very few plays in the U.S. where somebody can sell their asset and value for undeveloped. Maybe the Permian, but that's about it.

Investor What about the asset opportunity? Are you finding there are more mature, producing assets on the market?

Hutson What we're seeing mostly is large companies looking to raise cash to both improve their debt profiles or to reposition their business around a more defined core asset base. Maybe it's a nonstrategic asset for them. EQT, for example, sold us unconventional assets that were out of their core area where they're going to be developing. And so I think a lot of the companies are going through those kinds of reviews, saying, 'What cash is available to us now?' for assets that are noncore to get their balance sheets back in check. We're seeing a lot of those.

Investor What inspired you to launch a securitized financing?

Hutson Our assets are very conducive to that type of structure. An ABS needs visibility into production and cash flows, which our assets provide as they don't have steep declines and are well suited for long-term hedging. We were able to carve out a working interest percentage off the whole portfolio so that there is no real concentration of assets in the security.

What was really attractive to us is that when we set that working interest into an SPV [special-purpose vehicle], we achieve an advance rate higher than it is on our RBL. That creates liquidity, which for us is particularly important in this market where we're focused on transacting on other deals.

Investor Is this a new structure?

Hutson Obviously, it's been well known in other industries like mortgages and other types of loans that banks do, but for the E&P sector, it is a new product.

Investor What do you see as the advantages to the ABS structure versus more traditional capital vehicles?

Hutson For us, it was the additional liquidity and alignment of our cash flows with the financing to avoid bullet maturities in markets that may not be open to refinancing. We're not big on high-yield bonds. We see high yield as a kick-the-can-down-the-road type structure. They never seem to be repaid but refinanced over and over and over again.

And we've hit a period of time here where, guess what?—no refinancing opportunities. Now you've got all these high yield notes that are coming due and they have been difficult to refinance. That's what's gotten people in big trouble.

I liked the ABS structure because it puts us in a position to repay principal before maturity through excess cash flows. And, at maturity, the assets simply roll back to the balance sheet unencumbered. That's a major benefit to having an ABS.

Investor Does the ebb and flow of natural gas prices affect your ABS structure?

Hutson We've got approximately 85% of the production hedged, which more than covers the principal and interest in the coverage ratios that are necessary to pay back the loan. They are 10-year hedges, so the only variable is the production. And because we've built our portfolio with long-lived, low-decline assets, we are very comfortable with the amortization structure of ABS. The pricing risk is off the table.

And because the structure has no recourse back to the parent company, even if we hit some volatility due to something unforeseen, the rest of our asset base would be unaffected.

Investor Would you do any more of these ABS structures? Do you have the capacity?

Jackson Farms #19 in Fayette County, Pa., is reflective of a good majority of company wells—simple, single wells, often in rural areas.

Hutson We could later. It's not something we're presently considering.

Investor What is your outlook for natural gas?

Hutson The natural gas market right now is suffering heavily from LNG exports being depressed. Nobody's back to work except the U.S. for the most part, and so all the markets where this LNG goes has been pretty dismal. As we get closer to the fall and things start to recalibrate, we'll see some improvement as the economies in the world start to recover and use natural gas again.

I'm a firm believer of $2.50 to $3.50 gas range bound. The United States has a lot of resource, and the industry can turn on-and-off very quickly. I do see natural gas with a long-term future as the cleaner fossil fuel. I think oil will continue to decline in use, and natural gas will continue to fill that void.

But I think there are going to be fewer and fewer natural gas producing companies. You're going to continue to see some consolidation there, which will be good for the industry and for prices.

Investor What about oil?

Hutson The industry has long needed a disciplined approach. U.S. operators have been relying on repeated OPEC production cuts to essentially prop up prices to promote continued drilling and therefore putting capital in the ground that they probably shouldn't have been. Now, OPEC appears to have had enough, and when coupled with the impacts of COVID, it demonstrates the need for a change in how the industry thinks about drilling and growth in the future.

It's going to be interesting to see where the oil price goes from here. I have a sneaky suspicion that it may drop back off before it gets much better. But I do see the new dynamics in oil being supportive for higher, more stable natural gas prices.

Investor Do you think yours is a new model for what oil and gas or gas companies should be?

Hutson If you look at some of the announcements that were made within the industry in the last few months, some companies are articulating a move away from growth and toward maintenance mode over the next five years. We've also seen preferred, convertible type structures to pay down debt in the near term to lower the debt loads, which means—guess what?—free cash flow. So I think that some companies are trying to move to that model, which is a good thing.

It's difficult if you've been running the drill bit for a long period of time to make the switch from developer to operator. You have to get your debt levels down because, if you don't, your covenants may trigger as you slow down the drilling. So I do think that ours is a model that only the ones that are really capable and healthy will move to. The rest, in my opinion, will be a consolidation target.

Investor Where do you expect DGO to be in the next five years or so?

Hutson We have significant opportunity in front of us. We'll continue to see these acquisitions materialize. I think there is going to be a lot more stress and distress that we'll be able to take advantage of. I truly believe we can double the size of the company in the next 12 to 18 months without a doubt, production wise. Especially in Appalachia, we're going to be able to work with the large shale guys to be their monetization outlet. That's where we're headed. □

"We have a lot of prospects that we could drill, both gas and oil, but as long as opportunities exist on the acquisition side, we will not turn to the drill bit."

SHRINK TO FIT

Dismayed E&Ps are feeling the pinch as their banks shrink RBL credit lines. What are the remedies, and what about this fall?

ARTICLE BY
LESLIE HAINES

ILLUSTRATION BY
ROBERT D. AVILA

In these days of duress and distress, a CEO or CFO asking the bank(s) for more money resembles an antsy teenager asking for some cash and the car keys. Father replies, "Not until you clean up your room and bring your grades up."

As one source said, "Even banks with good clients are not advancing higher borrowing bases. They're saying in effect, 'Do not ask us for more money.'"

This year Job 1 for E&Ps has been to clean up their balance sheets, renegotiate their public debt obligations and navigate the loan redetermination season with their commercial bankers.

It hasn't been easy for many. For the 36 public E&P companies that it tracks, Reuters found the average cut to their borrowing base this spring was 10% to 20%, or an aggregate $7.5 billion.

S&P Global Ratings said the majority of the E&Ps it has rated as speculative grade reported "material" cuts to their reserve-based loans (RBLs) this past spring.

"For 80% of these companies, the elected commitments now equal the borrowing base amounts (up from 40% pre-redetermination), which could be troublesome in the fall," according to the S&P Global Ratings report. "This redetermination cycle has been more prolonged and less forgiving than previous cycles."

For example, Oasis Petroleum's base was reduced to $625 million, and it had drawn $522 million of that as of March 31.

Long-time observers have seen these ups and downs many times. Earthstone Energy Co. executive chairman Frank Lodzinski has seen this play out before, having been in the oil business for 48 years.

"It's a bit ironic that I am ending up my career in this industry in a collapse like we had in 1986, which was near my start. But as far as Earthstone goes, we never went broke before, and we're not starting now," he said.

Lower oil and gas prices—and commercial bankers' desire to lower their risk exposure to energy—were the understandable reasons for the tough redetermination season just past. Falling commodity prices and fewer drilling rigs at work meant less proved reserve value to be used as collateral.

"Banks look at everything in a company. They rip it apart and then come back with their redetermination," said Rob Sabo, director of interest rate trading at Aegis Energy in Houston. "As the industry faces all these issues, the banks are cutting the amount producers can borrow, and they are also increasing the credit spread [the points above Libor]."

Despite rising credit spreads, companies still have options amid redeterminations, said Rob Sabo with Aegis Energy. "You do have control over the base rate because you can put on hedges," he said.

The spread, or bank's margin, is calculated based on a borrower's risk profile, the quality of its assets, cash flow ratios, other metrics and the outlook for that particular business—all part of the underwriting process.

"The point is [that] you, the borrower, may have no control over the rising credit spreads we are now seeing, but you do have control over the base rate because you can put on hedges. You can lock in a variable or floating interest rate or put on an interest rate swap," he said.

Sabo said a company can do such a swap on a monthly basis or longer term. "Credit spreads for shale producers are expanding, but at least you can lock in the floating rate side of it," he said.

Aegis' advisory service on interest rates began in March to enhance its long-time business in commodity price hedging.

Regardless of whether a borrower can hedge the commodity price or the cost of money, by most accounts this fall's loan redetermination season will be just as tough as it was this spring, people said. The outcome hinges on the price deck banks are able to use at the time.

"Banks are less forgiving now than they were in 2015 to 2016," said Rob Johnson of EIG, a firm that makes first lien and other types of investments as an alternative to commercial bank loans. In May the firm closed on nearly $3 billion of new capital to be used as secured debt for companies in need of capital.

"Then, the banks were more optimistic about a rebound in oil prices, and they were more patient. To some degree, they engineered a soft landing. But the companies that saw a soft landing then are some of the ones having greater losses now. In today's market it's very hard to sell assets, whereas in 2015 and 2016 you still had some kind of A&D market," he said.

Feeling the pinch

As 2020 unfolds, signs of distress throughout the industry have not abated: fewer well

Banks are wary of being fooled again, having engineered a soft landing for oil and gas companies in the 2015 to 2016 downturn that "are some of the ones having greater losses now," EIG's Rob Johnson said.

Trevor Wommack with Latham & Watkins LLP emphasized the value of hedge books. "If you're in a deficiency situation, you can sell your hedge position … and put that cash on your balance sheet," he said.

completions, impaired loans, huge reserve write-downs, bankruptcies and credit downgrades by the rating agencies like S&P Global Ratings and Moody's. E&Ps were certainly feeling the pinch.

Too many dire predictions color the scene. S&P listed 17 energy companies in default near the end of June; about half of those had already filed for Chapter 11 proceedings to restructure their debt through the courts. Some had trouble completing distressed exchange offers.

You have seen the data: Moody's Investors Service said in January that North American oil and gas companies have more than $200 billion in debt maturing over the next four years, with about $40 billion due this year alone. In the last downturn, Moody's said companies issued $250 billion of new debt from January 2015 through September 2018. Could they do so again?

Rystad Energy warned that if oil remains low, about $30/bbl, 73 companies might be at risk of having to declare bankruptcy this year to restructure their debt. Even though the price is above that figure, Rystad said many companies are still threatened.

A recent Deloitte study said 30% of all shale E&Ps are technically insolvent, even at $40/bbl. It predicted reserve write-downs for the second quarter could top an astounding $300 billion, with consolidations, forced or otherwise, to follow. That is a big hole to dig out of.

In the interim companies strapped for cash have been drawing more from their bank line, sometimes 100%, leading their bankers to call for an end to so-called "cash hoarding." Wells Fargo said earlier this year that private shale operators have drawn down 70% of their bank lines, and more than a third of energy high-yield bonds were trading at distressed prices, per Bloomberg data.

Having a bank line fully drawn down chokes off any further liquidity, so if a company's wallet still comes up short, it has to sell assets, issue equity in an unforgiving market or try to add additional banks to its list of backers. Banks cannot provide 100% financing on development because the upside is capped, but the downside risk is not. And because of regulatory changes in 2016, they cannot fund an acquisition where the bank's debt portion would be more than 50% of the total deal.

Cowen & Co. analysts said in a late May report that these credit concerns may be overblown, at least for the companies it covers. It conceded the E&P sector has serious debt issues to handle, with average leverage in 2021 estimated at 3.6 times. It cited Pioneer Natural Resources Co., Diamondback Energy Inc. and EQT Corp., among others, that have issued five- or six-year notes to pay down near-term debt maturities. It also said the industry as a whole is about 19% drawn on its revolving credit facilities.

Remedies and options

Options companies can pursue include "kicking the can down the road" by extending the date of the spring redetermination to later in the fall or reducing the credit line on an interim basis until the fall. Those companies that can have issued new public debt. In one week in June alone, 25 companies accessed $18 billion in public debt.

"With spending cut to the bone, operators likely exploring debt exchanges or relying on borrowing bases that are still generally supportive, it does not appear that a wholesale capital structure disruption is set to take place," according to the Cowen report.

This might ultimately put a ceiling on the group's equity rally that occurred from the April lows.

To cope, companies have slashed spending dramatically in favor of servicing debt, maintaining dividends or other financial considerations. Some 14 of the 27 E&Ps Cowen covers were running a mere two rigs or less in late May, about a 60% decline from fourth-quarter 2019 activity.

Although E&P executives have reacted fast to the troubles caused by the coronavirus and the Saudi-Russian price war debacle, they need headroom to make it to January 2021. They need to buy time, use exchange offers to pay down their revolvers, hold tight to liquidity and survive to drill another day.

"For the most part, banks were tightening liquidity and borrowing base capacity, not enough to put companies in real jeopardy but rather to give them enough time to get through 2020," said George Ward, in the Houston office of PJ Solomon's energy advisory practice. He said, "Just give them enough to pay down the revolver some and get through the rest of this year."

To help its energy clients cope, Solomon has been facilitating conversations on one restructuring, some public mergers of equals and advising strategic or financial players that are bidding on so-called "363 deals" (acquisition of assets out of a bankruptcy).

Ward said he thinks new money will come into the space from the financial community, including options such as direct lending and secured offerings, which will inject new equity and debt into E&Ps that sorely need it.

The industry "may see some consolidations [occur] after a restructuring, since many of these companies have too much debt to combine and you can't refinance the consolidated entity," said Opportune's David Baggett during a webcast. Dire circumstance may force their hand.

Certainly consolidation among E&Ps is an option that would create companies with larger balance sheets that spread general and administrative expenses over a wider set of assets under one umbrella. But with so little visibility, it is hard to assign a meaningful value to a company or an asset package.

Finding value

Rumors circulated this past spring after a Reuters article claimed commercial banks were facing several customer defaults and bankruptcies that would force them to take over assets, but Ward does not see it that way. If banks tighten up too much and a borrower has to file for bankruptcy or try to sell oil and gas assets, there is not enough value in the market right now. It's a losing game.

"It's a very fluid situation, but I think banks are working with companies to get them at least to the fall redetermination," Ward said. "I'm more focused on what the price of oil will be in June 2021 and December 2021, and whether companies need to hedge or put more rigs to work."

Companies might try to add some more assets to the reserve report or amortize a loan deficiency over several months.

"The deficiency amortization is the choice everyone is going to elect," said Trevor Wommack, partner with Latham & Watkins LLP, speaking on a webcast the law firm held in June to explore options for borrowers.

Adding reserves could be difficult, as there is little visibility for acquisitions right now, he added.

The average drop in the banks' price deck this past spring was 15%, but some faced a 20% drop, resulting in a corresponding borrowing base decrease.

"This magnitude of drop in the borrowing base is difficult to cure," said Catherine Ozdogan, another partner with Latham & Watkins LLP. "A downward redetermination is meant to bring all the parties to the negotiating table. It's customary that 100% of the banks [in a loan syndicate] must approve an increase in the base but only 50% to 60% 65% a decrease."

At that point, the other options include forbearance of debt payments due or other changes to a company's capital structure and bank covenants. When an E&P elects not to make an interest payment, that starts a 30-day clock of forbearance, and presumably at that point the company is already in discussions with creditors anyway.

If it cannot make a borrowing base deficiency payment, then it has to set up milestones to prepare for bankruptcy, appoint a restructuring adviser, execute a PSA for potential asset sales and so on.

Forbearance can last up to 120 days, thus giving the borrower time to refinance the RBL or close a transaction to pay it off.

"Lenders don't call the shots; they don't tell the company what to do," Wommack said. "If banks dictate what approach a company takes to address liquidity, that gets into too much liability [for the bank]."

Pick your poison

Though no bank yet admits to taking over oil and gas assets, and none of them claims a desire to do so, even if they did, banks would preferably only hold assets until the M&A market recovers and they can unload, but the time line on that is still uncertain. Also, do they replace the existing E&P management team or let it stay during the process? After all, someone has to operate the fields, pay the royalty checks and manage the accounting. Do they consolidate the assets of more than one distressed company into one chunk and place that under one management team?

> It's a very fluid situation, but I think banks are working with companies to get them at least to the fall redetermination.
>
> —George Ward, PJ Solomon

"You have to pick your poison," Wommack said. "If it's a fire sale (or Chapter 7 liquidation), then or banks do end up owning assets at the end of a very time-consuming process. And each bank in a syndicate of many banks ends up being an equity owner in a special purpose vehicle. The time and effort it takes for banks to manage owning E&P assets is too much … so they try to kick the can to an M&A market opening back up."

For companies that were not doing well before this spring's twin tragedies of the virus and the oil price war, the spring redetermination cycle was basically "used as a hammer" after the price crash, Ozdogan said.

Wommack said he has seen instances where a company's hedge book value is 150% of the company's borrowing base.

"Just let that sink in for a minute," he said. "If you're in a deficiency situation, you can sell your hedge position … and put that cash on your balance sheet."

Milestones can always be extended as long as the parties negotiating a company's financial position see that some progress is being made, Ozdogan said. Given the many options that companies and bankers can pursue, and amid extreme price volatility and economic uncertainty, the road ahead looks about as straight as the auto climb up Pike's Peak. □

A reckoning had been in order for oil and gas, and so the spring redetermination cycle was basically "used as a hammer" after the price crash, according to Catherine Ozdogan with Latham & Watkins LLP.

STRATEGIC WITHDRAWAL

With historic drops in oil price, mass layoffs and the likelihood of prolonged recovery, some wonder how the industry will regroup as demand recovers.

ARTICLE BY
DARREN BARBEE

After months of falling back, the oil and gas industry has settled for a stalemate with the COVID-19 pandemic. But the losses have mounted.

In the U.S., wells have been shut in, rigs idled and oil filled storage faster than it drained out. The pandemic and OPEC+ price war, like a nationwide blackout, have knocked offline nearly 2 MMbbl/d of U.S. oil production.

In the estimation of the International Energy Agency (IEA), the global energy system is facing its greatest shock since World War II with a resulting drop in energy demand that will dwarf the 2008 financial crisis. Globally, world demand is expected to fall 6%, "the equivalent of losing the entire demand of India," the world's third largest energy consumer, David M. Turk, acting deputy executive director with the IEA, told Congress in July.

In the U.S., WTI spent most of June and early July struggling in the mid $40s following an abrupt plunge of oil prices that forced the industry to choke back activity and cut tens of thousands of jobs.

PwC's Reid Morrison said the industry is having to respond to forces that it cannot change when reducing its workforce.

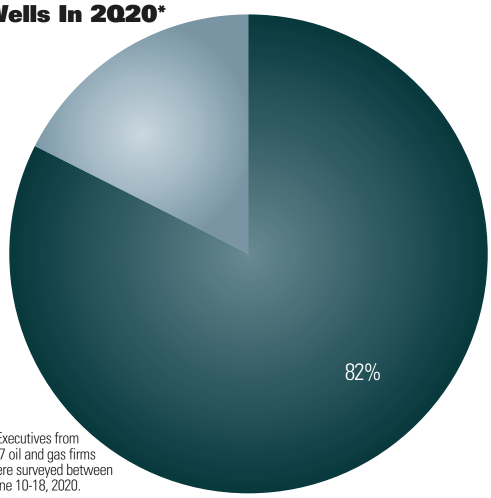
Reid Morrison, PwC's leader of the Global Energy and U.S. Energy & Chemicals Advisory practices, said the industry, designed for growth, is now expected to generate free cash flow and dividends, which means shifting resources and capabilities, including staff.

"What you're seeing is a submission of the industry to two forces that they can't change," he said. "One is investors want returns, and growth is a secondary focus. … And there's a level of activities that are smaller than what has happened historically. Therefore, you need fewer resources, and just doing the math, it means fewer and fewer people are needed.

"And that's the unfortunate side of where we are right now."

Most industry executives expect to be solvent next year—though not all. A Dallas Fed survey of oil and gas executives shows little optimism for a quick turnaround to pre-pandemic activity levels. The survey, conducted in June, found that 41% of respondents expected drilling and completion activity to return in 2021, with nearly as many expecting drilling to reset by 2022 or later. But one out of six executives don't foresee a return to previous activity levels, ever.

% Of E&Ps That Slowed Production, Shut Wells In 2020*



* Executives from 147 oil and gas firms were surveyed between June 10-18, 2020.

Source: Federal Reserve Bank of Dallas survey of E&P executives

That's if prices return to normal. As one executive told the Dallas Fed, without a recovery in commodity prices, "All bets are off."

In candid responses, executives largely see 2020 as a lost summer stretching into a forgettable fall. Of the survey's respondents, most were confident in their ability to remain viable, with just 5% saying they expect to be insolvent next year.

One E&P executive gave a desultory timetable for recovery beginning with the "dismal" lockdown, a "miserable" transition from June through December and a "somber" new normal in 2021.

"The oil industry went into a deep hole in first-quarter 2020," the executive told the Dallas Fed. "We reached the bottom, and now we are trying to climb up. It will be quite a while (2022+) to get back up the hole to the pre-COVID-19 level of activity and service pricing."

In just two months—March and April—all sectors of the energy industry slashed 1.3 million jobs, or 13% of the workforce, erasing five years of job growth, former U.S. Energy Secretary Ernest J. Moniz told Congress in June.

Moniz said the oil and gas industry faces a period of uncertainty as oil demand recalibrates.

"We don't know the recovery from COVID. We don't know how the secular change in the energy industry is going to affect demand," he said.

Through June, oilfield service (OFS) and equipment employment is down by 116,000 compared to June 2019, bringing employment to its lowest point since March 2017, according to a report by the Petroleum Equipment and Services Association (PESA).

The job losses already surpass $11.4 billion in lost annual wages, and more are expected in coming months, said Tim Tarpley, PESA's vice president of government affairs.

After withstanding the initial blast of the pandemic, companies will need the expertise they're currently shedding as oil prices keep wells shut in and new wells undrilled.

"Our biggest fear is that when you start seeing a lot of these employees that have 20 and 30 years of experience leaving the industry, they may go work in another sector," Tarpley said.

'We may lose them'

NexTier Oilfield Solutions Inc.—the company created by the 2019 combination of C&J Energy Services and Keane Group—is well positioned to survive the downturn, said president and CEO Robert Drummond. The company has established liquidity through various synergies associated with its merger.

NexTier has positions in all U.S. basins, with the largest in the Permian. The company has 45 hydraulic fracturing fleets, which Drummond said is likely the second largest in the U.S.

Still, with oil inventories brimming over and gas prices similarly depressed, NexTier and other service companies have had to make painful decisions to remain financially viable.

"Unfortunately, like everyone in this sector, we've had to shrink our organization in response to these activity declines," he said. "As a result, we've got a workforce with more talent, concentrated expertise, drive [and] motivation. I have no doubt we can rebuild around a team of people like that."

Drummond is not concerned about a brain drain among his ranks. NexTier has protected its talent as much as possible through measures such as warm stacking equipment and keeping on supervisors in low-run positions until a full restart is called for.

"Being a very versatile workforce, for example, you have supervisors in the field who take temporary demotions to become an equipment operator to allow us to concentrate the skill set," Drummond said. "Then when activity returns, you re-dilute it and put the guys in the jobs they had before."

As of July, activity remains slow in most basins, including the Permian, Tarpley said. Texas, which is home to a large portion of the Permian as well as the Eagle Ford Shale, has lost 57,000 jobs since 2020—more than the next six states combined, according to PESA. Many OFS companies have 25% to 50% of their workforce on furlough.

With oil prices in the low $40s, Tarpley said prices are close to breakeven only in the most profitable areas within basins, causing activity to sputter. There are also concerns that furloughs may ultimately lead to more layoffs.

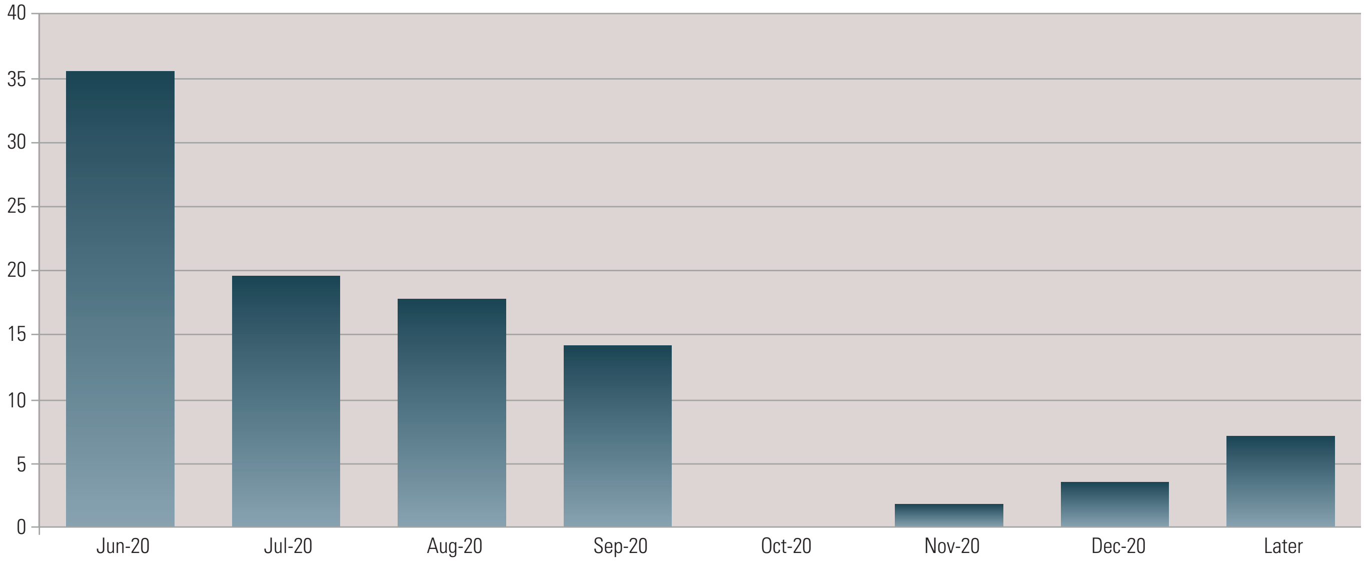
"It's been very slow and, quite frankly, from a service perspective they're going to need some significant activity really to start" again, he said.

PESA also is thinking about the future in terms of workforce members lured away by jobs in other industries.

"We may lose them," Tarpley said. "Our principal desire, in all of our companies, is to try to keep as many of those folks in the industry as we can."

Carbon capture technology, for instance, will likely be in demand as a recovery gets underway.

Month Executives Expect To Resume Most Of Their Production



Source: Federal Reserve Bank Of Dallas survey of E&P executives

"So a big concern is that we see significant institutional knowledge basically leave not only the sector but the area perhaps where a lot of hardware companies are operating," he said.

Upstream E&P companies are similarly concerned about the marketplace for workers. One executive surveyed by the Dallas Fed said COVID-19 will only exacerbate the "Great Crew Change" retirement of baby boomers.

"The industry is depopulating itself of knowledgeable and experienced personnel," the executive said. "That collective knowledge drain is not being effectively replaced by 'newbies.' The newer, younger employees don't know much, and while they can stare at computers and run applications, they are making critical land, legal, financial and business errors at an astonishing rate."

Morrison said the oil and gas industry will face increased competition for workers after the pandemic.

"I think the overall sentiment of the industry is not attractive to the younger generation," he said. "I think there is actually sufficient talent that's out there, and it's not going to be where the problem is. The biggest concern that I personally have is attracting the next generation that may look at this industry as something that either has too much volatility or just a reputation of the industry they don't want to be part of."

The industry should tell its story in a way that emphasizes it is on the leading edge of science and technology.

"For those STEM students that really want to cut their teeth on leading-edge technology and innovation, the industry is the vanguard, but they've let the headlines be written by others, not around the real science and innovation that happens."

Drummond said the industry has always been able to bounce back.

"Should the industry be concerned? I think yes. But I also know that we will collectively respond," he said. "We've done it so many times before. After all, who doesn't want to be involved in a winning system? I think we can handle it."

The industry should be concerned about lost talent, but it has recovered many times before from similar shortages, said Robert Drummond, president and CEO of NexTier Oilfield Solutions Inc.

A long convalescence

The picture for industry recovery remains murky, largely because it is dependent on the broader economic recovery globally. In the U.S., which is leading in reported cases of COVID-19, fears of a prolonged pandemic appear to justify outlook of E&P executives.

Asked when global oil consumption will return to levels seen before the pandemic, roughly 55% of executives said they expected oil to recover in 2021, while more than one-third expected a full recovery in 2022 or beyond.

The IEA projected that global oil demand this year will fall by 8.1 MMbbl/d compared with 2019, the largest drop in history, according to the June IEA Oil Market Report. IEA said containment measures in 187 countries and territories had "almost brought global mobility to a halt."

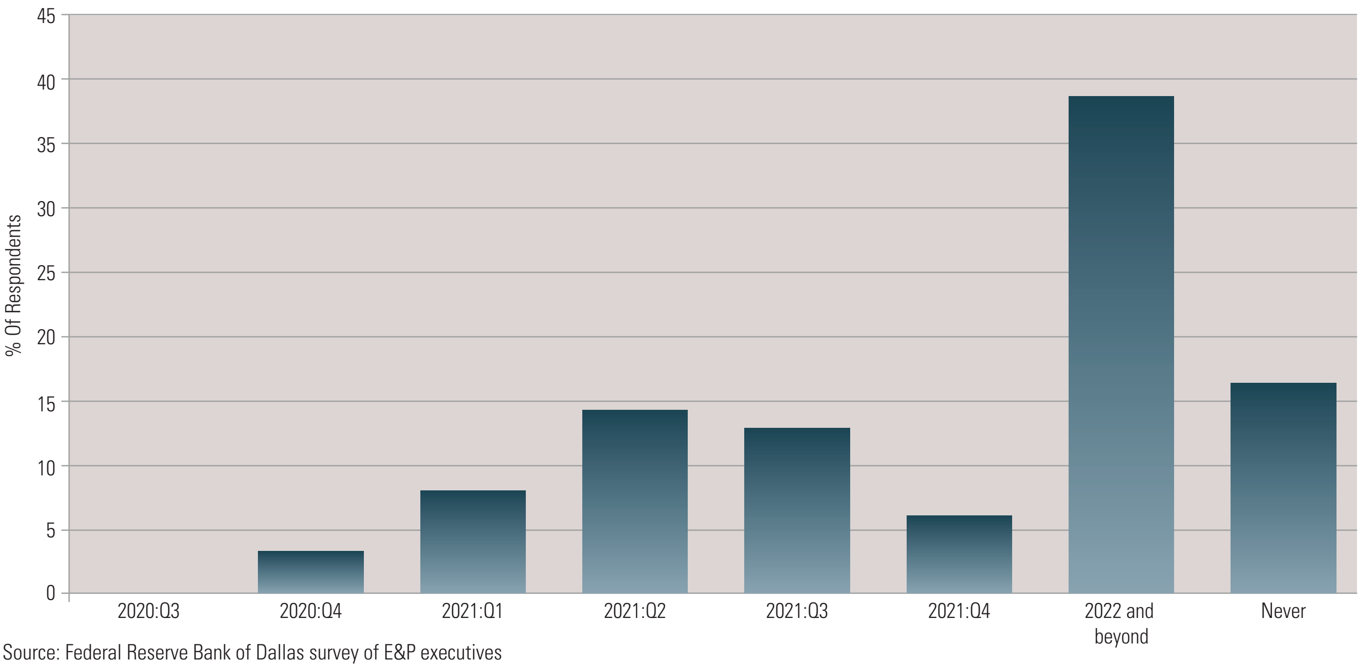
Improvement in WTI prices close to $40/bbl is not enough to allow a significant increase in U.S. output, "which in June is estimated to have fallen to 10.5 MMbbl/d, down by 2.4 MMbbl/d from a record high seen in November," IEA reported.

At a U.S. Senate hearing in July, Turk told Congress the IEA expected advanced economies to see the largest demand declines, including 9% in the U.S. and 11% in the EU.

The COVID-19 crisis is affecting all major fuels and technologies. Turk said demand for oil would fall by about 9% and natural gas by 4%.

Investment, already chilly for shale oil and gas companies, is icing over due to the pandemic. To begin 2020, global energy investment was set to grow by 2%, the largest

Timeframe For Return To Pre-COVID Activity Levels



Source: Federal Reserve Bank of Dallas survey of E&P executives increase in six years, according to the IEA. Instead, investment is now likely to fall by nearly $400 billion, a year-over-year retreat of 20%.

Underscoring the industry pain is an outsized loss of investment globally and specifically in shale projects. Investment in shale is anticipated to fall by 50% in 2020, Turk said.

"We truly have a historic shock to the global energy system," he added.

Morrison said PwC's outlook shows demand recovering to about 100 MMbbl/d in three years.

"The silver lining we're telling clients is that demand is probably going to start to increase steadily for the next five to change to 10 (from seven) to read next five to 10 years," Morrison said, adding the peak demand could be as high as 105 MMbbl/d by 2030.

As the development of reserves is put on hold, inventory will drain off while "Current production will have had its natural decline rate, and nobody will be replacing the barrels," he said.

"You'll then start to see a supply shortage as the new theme, and that's going to drive higher prices and activity activity, which drives higher employment," he added.

However, demand is likely to shift as people emerge from a massive quarantine and work differently.

"You're not going to have as much commuting and air travel," Morrison said. "But the fact that we're having to move goods from warehouses to the doorstep is a driver of transportation. And then the movement of goods is going to be a big driver."

At the macro level, PwC sees the next three years "fighting our way out of a recession." At the same time, economic stimulus will have taken hold.

"Then you kind of pivot from deep recession to recovery to then some growth that's going to start having some green shoots in 2023, 2024, and then that's going to be a driver of the petrochemical demand," Morrison said.

No handouts

In what's become a typical scene at senate hearings, Frank J. Macchiarola, senior vice president of policy, economics and regulatory affairs with API, testified via internet chat. Asked what Congress can do for the oil and gas industry, Macchiarola's response was succinct.

"In terms of asks going forward, our major request would be, essentially, do no harm," he said.

Macchiarola said Congress could help most by getting the economy up and running in a safe and swift fashion, which will restore demand. He added that punitive trade measures, tariffs or production quotas are "the wrong direction to go."

Tarpley said PESA wants the sector and the oil and gas industry as a whole to be treated just like everyone else.

"We don't expect an oil and gas bailout bill to become law," he said.

But Tarpley would like to see more fairness applied to the Paycheck Protection Program, which some industry companies have had trouble accessing.

"If they are a private company and have investors, sometimes the way that that's structured counts against them," he said. "The argument is that they would have access to other funding through those private investors. The truth is they're really maxed out on their ability to access that capital."

As oil prices stabilize but are unable to make a strong rally, it appears that operators are in a lockdown.

Tarpley said, "We do certainly have hope that they can catch up a little bit and they start seeing some activity back in the Permian," where $40 prices are close to breakeven for some companies.

Morgan Stanley research said in a July report that activity appears to be stabilizing as crude oil prices "grind higher," but recovery remains uncertain.

"Our updated base case calls for a marginal uptick in activity in select markets through year-end," analyst Connor Lynagh said.

Hammond said OFS recoveries are typically intense and rapid. Since 2015, he sees more available supply than needed for services in the sector, even before COVID-19. That's slowed overall growth of investment into the sector and put more focus on sustaining and strategic investments, he said.

"We also believe the service providers are going to have to adapt their cost structures to the current low activity levels while also maintaining resources to respond to the future opportunities once everyone goes back to work," he said.

A clear trend for the sector is toward lower capacity and more efficiencies—and partnerships.

"It's apparent to us that the operators … have been moving in the direction of selecting service companies as partners that are adapting to this trend of doing things more efficiently and sustainable," he said. "I think this trend is going to accelerate because it helps the E&Ps improve their returns, often measured in dollars per barrel."

Others are more fatalistic. An oil and gas executive for a support services company told the Dallas Fed, "Times like these are purely about survival, and many of our competitors and customers will not survive without a material change in the energy space, which I don't expect for several quarters." □

"The biggest concern that I personally have is attracting the next generation that may look at this industry as something that either has too much volatility or just a reputation of the industry they don't want to be part of."

—Reid Morrison, PwC

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COLLIDING WITH MIDSTREAM

As E&P bankruptcies trend upward, the opportunity to reject midstream "running with the land" covenants is once again in the limelight, and the resolutions could get hairy.

ARTICLE BY
JOSEPH MARKMAN

Many distressed E&Ps and their midstream partners could be flying blind into a litigation collision course as the number of expected bankruptcies and reorganizations ramps up in the third and fourth quarters.

That's because recent upstream/midstream disputes have in many cases centered around whether an E&P in Chapter 11 bankruptcy can reject midstream agreements they are unable to meet. In 2016, a court ruled that Sabine Oil and Gas Corp. could reject its agreements because they did not include covenants that "run with the land" as defined by Texas bankruptcy law.

Until that decision, those types of agreements were understood to fall under the province of "covenants that run with the land." So, when it was handed down, the decision was viewed by many to be a game-changer. Turns out, subsequent rulings over contracts like these—particularly cases involving Badlands Energy Inc. and Alta Mesa Resources Inc.—have shown that the game continues to change.

"I think there are some people that had the belief that, since 'Sabine,' 'Badlands' and 'Alta Mesa' came out, that issue is settled," Liz Freeman, partner with Jackson Walker LLP, said. "That's not it at all. What we have are guidelines."

In "Sabine," the U.S. bankruptcy court in the Southern District of New York interpreted Texas law when it ruled that Sabine Oil and Gas Corp. could reject agreements with midstream operators because the agreements did not "touch and concern the land." In "Badlands," a Colorado court ruled, based on Utah law, that the E&P could not reject the agreements because they contained covenants that run with the land. Also, the midstream operator's transportation of dedicated reserves involved real property that satisfied the condition of having to touch and concern the land. The Texas court interpreting Oklahoma law reached a similar conclusion in "Alta Mesa."

So, what does that mean for the next bankruptcy case involving an E&P seeking to reject its midstream agreements based on covenants running with the land? Not a whole lot.

"You don't see the exact same dedication language in every single agreement," Freeman said. "You really have to take a look at each one and do a very fact-intensive analysis as opposed to just knowing that you could have a processing agreement, it has covenants, therefore it's rejectable or it is not. I think there is going to be a lot of litigation over individual agreements."

Mike Blankenship, Houston-based partner with Winston & Strawn LLP, echoed Freeman.

"While the opposite holdings in 'Badlands' and 'Alta Mesa' do add a certain level of comfort for midstream operators in these regions," he said in an email, "the reality is that these determinations are fact-specific so every new case going forward will have its own singular set of facts and potential challenges in establishing that their agreements are real property covenants."

Complicating the issue is integration. A midstream operator could be providing an array of services to its upstream customer, including processing, marketing and transportation that may be deemed rejectable by an E&P.

Much depends on how the contracts are structured, Freeman said. Are they sufficiently integrated to be all-for-one, one-for-all? Or can an E&P pick and choose among those agreements, deciding which to assume and which to reject?

"We have a framework of analysis, but there's no easy answer in this," she said. "This is going to be really complicated and very hairy."

Rejection of agreements might be a logical courtroom strategy, but an E&P hoping to continue operations has to consider the reality of how that work will get done.

"Often the most important considerations revolve around who has the leverage and whether the producer has realistic alternatives for its midstream needs," Isaac Griesbaum, partner with Winston & Strawn, said. "In particular, the likelihood of a third-party midstream company being able to offer similar or better terms and service based on the contract rates, service level, available capacity, capital flexibility, as-

"These determinations are fact-specific so every new case going forward will have its own singular set of facts and potential challenges in establishing that their agreements are real property covenants."

—Mike Blankenship, Winston & Strawn LLP

"I think there are some people that had the belief that, since 'Sabine,' 'Badlands' and 'Alta Mesa' came out, that issue is settled. That's not it at all. What we have are guidelines."

—Liz Freeman, Jackson Walker LLP

set locations and other key commercial and operational requirements (as well as the timing of being able to provide service at all) are frequently the driving factors."

Handling these issues effectively is particularly critical in a cyclical and relationship-driven business such as oil and gas.

"Operators don't forget service providers that were unwilling to work with them during tough times," said Chris Cottrell, an associate at Winston & Strawn who worked as a landman for an E&P before joining the firm. "Failing to strike a balance now will almost certainly guarantee that volumes find their way into other midstream systems once existing commitments begin to expire."

In prior downcycles, disputes tended to center around royalty interest, environmental liability and plugging and abandonment obligations, Freeman said. Those won't go away in this round, but newer challenges heavily involve midstream. In some ways, that relates to the different economic environment since the last downcycle.

"The difference now is that so many companies that previously built their own gathering systems spun those systems off in an effort to raise capital in the past number of years," she said. "So now you have a situation where you have an E&P company that is entering into contracts with midstream providers."

Frequently, these providers are operating assets that the E&P company had owned and operated. So, in the past, the E&P could control the rates. Not so when dealing with a third party.

"Sometimes the midstream provider is a public entity with an entirely different structure and ownership," Freeman said. "It's a somewhat new challenge that a lot of E&P companies didn't deal with in prior cycles."

Through May, 18 E&Ps had declared bankruptcy, according to the Haynes and Boone LLP Oil Patch Bankruptcy Monitor. That number doesn't include the recent filings of Chesapeake Energy Corp. and Extraction Oil and Gas Inc., and it pales in comparison to the 51 that Haynes and Boone recorded in the first two quarters of 2016. But the year is only half over, and it is likely that some midstream companies will soon find themselves counted among the distressed.

"It seems almost certain that the headwinds faced in the upstream sector will have a domino effect on the rest of the sectors," Blankenship said. "Although U.S. shale production only accounts for about one-tenth of the global supply, it accounts for a large portion of the global drilling activity and almost all of the growth in the U.S. midstream and export-oriented storage and refining sectors."

For midstream operators, a big concern will be the credit-worthiness of their upstream partners, Cottrell said. Griesbaum noted that lenders will seek to limit their exposure to oil and gas companies. While the impact on midstream might be delayed, the sector should have a clear idea of how significant it will be by the end of the third quarter, he said.

"All signs point to stress in the market," Freeman said. "There have been a number of companies that we've worked with that have been able to have an out-of-court restructuring. Whether companies are forced to file bankruptcy cases or whether they're able to restructure their debts outside of court is something to be seen, but we know that there will be a lot of restructuring." □

BLACK DIAMOND GATHERING

Effectively handling disputes over midstream contracts during E&P bankruptcies could prove critical in months to come, especially given the importance of relationships in the industry.

CLOSE TO THE EDGE

Remote connectivity provides the foundation for digital innovation in oil and gas, and Infrastructure Networks offers a unified wireless service to help enable it.

ARTICLE BY BILL WALTER

PHOTOS COURTESY OF INFRASTRUCTURE NETWORKS

Oil and gas operators increasingly recognize that data, the vast, nonphysical resource gathered as part of E&P, are critical to their success. The growing presence of data analytics firms in the sector confirms this. So far, so good, and the digital transformation of oil and gas marches along—assuming that operators can get their field data efficiently, reliably and securely from facilities at the remotest edge of connectivity to an office where an analyst can process it.

To address this need, Infrastructure Networks (INET), a Houston-based technology and telecommunications company, offers the oil and gas industry's first end-to-end, private licensed wireless network, now covering 130,000 square miles of oil field, including the Permian Basin, Eagle Ford, Bakken and SCOOP/STACK. The industry's only provider of private Long Term Evolution (LTE) infrastructure and service, INET can alleviate the strain on capex that companies face when they build their own networks. In any of these areas, oil and gas customers can buy into INET's existing coverage. INET retains ownership of the network, but each customer receives its functionality privately and securely.

Infrastructure Networks helps connect decision makers to their remotest facilities without making them leave their offices, CEO Mark Slaughter said.

INET promises upward of 99% reliability in its service-level agreements and can deploy its network immediately, granting "plug and play" connectivity for applications ranging from geosteering and drilling data collection to SCADA or video monitoring.

"The idea is that you don't have to be at the edge as often or at all," INET CEO Mark Slaughter said. "You can use our technologies both for automation and sensors and actuators, but you can also remotely monitor that from the office to a greater degree as we go forward. Your decision makers, your expertise … can be at the office covering more than one site, and that productivity and lifestyle improvement, we think, will take the industry to a new level."

Telecom free-for-all

INET recently upgraded its network to become 5G-capable, preparing for the industry to adopt the next generation of telecommunications technology. However, INET's network service precedes this latest communications standard, having originated with the emergence and evolution of 4G LTE in early 2010.

After observing the limited network technologies at several remote oil fields in California, INET founder and CTO Stan Hughey saw an opportunity to "leapfrog the state of the art in the [oil and gas] industry" by introducing recent 4G developments to the industry, he said.

At the time, companies were diverting significant capital toward building and maintaining their own private communications networks. Many of these private networks were operated "on an unlicensed or shared spectrum, which means [companies] would go into a geographical space and deploy their own capital, their own networks and compete for a shared, common spectrum resource," Hughey said.

Unlicensed radio spectrum has no protection against interference from other users, and the frequency bands designated by the Federal Communications Commission (FCC) for unlicensed operation—all above 900 MHz—are more difficult to propagate, especially in rural areas, limiting coverage.

The resulting free-for-all over unlicensed spectrum entailed competition for a resource that deteriorated with additional users.

Beyond oil and gas, the FCC granted some organizations rights to licensed spectrum, which includes legal protection and enforcement to prevent interference, "particularly reused television spectrum in the 700-MHz range," Hughey said. "That operates very well in a rural environment; it propagates."

In April 2011, Hughey formed INET to "acquire those [spectrum] licenses over the major shale plays and build a network that we basically had complete control of and built from the ground up to serve the industry," he said.

Since first validating the network technology in the Permian, INET has received significant support from the industry and investors. Altira Group LLC, a Denver-based venture capital firm, made an investment in September 2012, followed by a significant investment by Apollo Global Management Inc. in 2018.

"Apollo's capital was used this past year to really expand and deepen the network," Slaughter said, adding that it also facilitated the network upgrade to 5G capability.

Focusing capital and expertise

Freedom from the need to develop a private network allows oil and gas companies to commit more capital and expertise to their drilling and production programs. The current downturn pulls operators' attention in myriad directions, placing new demands on managerial skill sets and budgets, so it behooves companies, now more than ever, to consider means of attaining greater network capabilities without further dividing their resources.

Building one's own network involves a twofold investment: the initial capital investment to construct it and the ongoing operating costs to maintain and update it. INET, on the other hand, manages its already existing network's maintenance and development on behalf of its oil and gas clients. Customers simply receive an invoice, which provides a 3:1 cost difference in some instances, Hughey said.

"We have actually seen specific cases, since we've been doing this for 10 years now, where over a total cost of ownership 10-year term … every dollar spent with us would require an operator to spend about three dollars to get a similar level of connectivity," he said.

INET's service can facilitate expertise efficiencies too. To build their own networks, Slaughter said companies "are having to develop expertise, having to build out skill sets in the company that are communications related ... and the knowledge to keep those network technologies current."

Given some companies' lean human resources, this risk draws the attention of valuable personnel away from core operation areas.

In contrast, "As a [telecommunications] company completely focused on the oil and gas industry in those basins, we make those investments [of capital and expertise] for companies," he said.

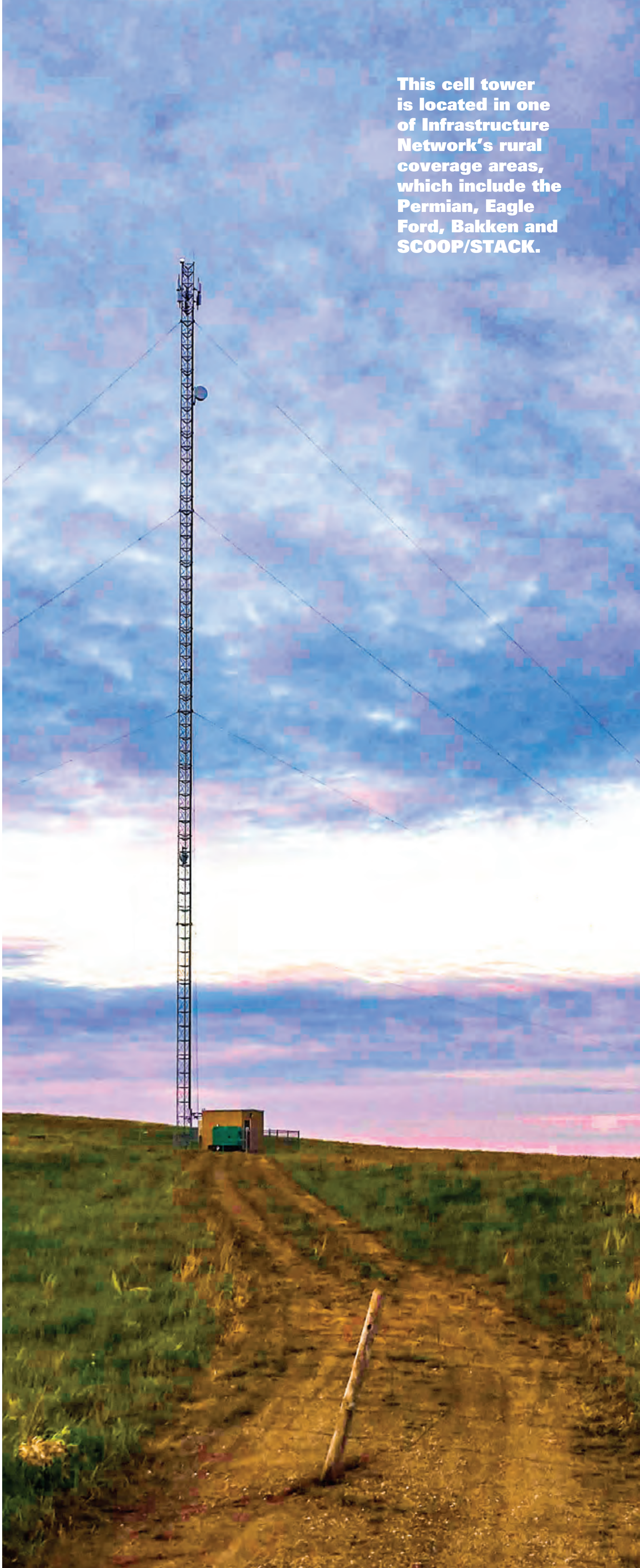
Slaughter added that INET works with companies of varied sizes, ranging "from major operators that are moving more aggressively to progressive independents to small oil and gas operators. They're all going through digital transformations" that require more connectivity.

Proof in the Permian

For example, INET was critical to Noble Energy Inc.'s network transformation in the Permian. After acquiring Clayton Williams Energy Inc. in 2017, Noble needed to establish a reliable network to well sites without standardized network technology. To do this, it partnered with INET. Brandon Wise, business analyst of operations technology with Noble, led the effort to update the new assets' technological capabilities. He said INET offered the most complete service.

Wise highlighted how INET's IP-based network has enhanced Noble's visibility to well conditions.

In terms of automated polling data, he said, "We've moved from the industry average of 15- to 20-minute polling—basically, pinging the device and saying, 'every 15 minutes,



This cell tower is located in one of Infrastructure Network's rural coverage areas, which include the Permian, Eagle Ford, Bakken and SCOOP/STACK.

Technicians service a cell tower for Infrastructure Networks. The company recently doubled its network coverage to 130,000 square miles.

"That's the opportunity we have—to help meet [operators'] critical data transmission needs reliably and robustly."

—Mark Slaughter, Infrastructure Networks

give me a number' to [INET's network] doing one- to two-minute polling.

"The production engineers love it, especially for new wells and electronic submersible pumps. They can get instant feedback on adjustments they make while trying to optimize a well's production."

On older, serial radio networks—the type most commonly used in the oil field today—it takes significant time to send and receive data, and operators risk potential data loss if a missed poll occurs, which can prove especially problematic, even dangerous, in situations where an operator might need to remotely shut in a well.

However, on INET's network, Noble is able to see "if there are any leading indicators that we need to turn off a well" before onsite emergency shut-down equipment kicks in, Wise said. This allows the control room operator to remotely shut in wells when necessary, "which is critical from a safety and environmental perspective," he said.

Noble now uses "INET for every one of our well sites in the field throughout the Permian; we use them for our man camps and one of our offices out there; and our midstream uses them for five or six central gathering facilities and terminals," Wise said.

Noble is one of the aforementioned 3:1 cases, not just in terms of finances.

"From a cost standpoint, it would have cost about three times as much and taken three times longer to build [this network] ourselves," Wise said.

"Also, the flexibility it gives us is invaluable," he added. "If we acquire a new acreage position or wells in a different part of the basin, all we have to do is set up a new LTE radio and have everything online in a matter of days compared to spending several months designing and installing our own infrastructure."

Though not a foreseen benefit of partnering with INET, Noble has found that the flexibility of the company's network has allowed it to continue to integrate new assets during the COVID-19 pandemic. At the onset of the pandemic, many factories had delays up to several months in providing the equipment needed for a company to build out a personal network, Wise said, making INET's already established equipment vital.

Noble is interested in additional INET services, Wise said, specifically remote wellsite monitoring. To get workers off the roads and out of the field, he said, "Our next step with INET is … doing remote wellsite visits" with pan-tilt-zoom cameras.

This would enable technicians "to go through a guy's route, as if they were on site … and just go through [lower risk sites] on their computer," he explained. The time saved by not having to drive to every well site "can be spent optimizing existing wells or focusing on other alarms, preventative maintenance" and other critical tasks.

Of these advancements, they're "just impossible" with non-IP technology, Wise said, adding that a network built "the way networks always have been for the last 30 years won't set us up for future opportunities."

Two paths for 5G

According to INET's Hughey, the proprietary technologies that companies often use to develop their own networks generally, and increasingly, risk obsolescence. They are proving insufficient for "emerging use cases for data science, advanced artificial intelligence and connectivity of the enterprise out to the edge as a way to remove workers from the field," he said.

And this risk will grow as the industry embraces the 5G standard, which promises significant rewards and is significant to INET's growth plans.

"5G standards have hit a fork in the road with a split between low-power, wide-area sensor type connectivity, what you think of as Internet of Things (IoT) applications, and then they've also split into ultrabroadband, which are the gigabit speeds to your LTE radio and connectivity," Hughey said.

Regarding the IoT path, he said, "INET can push out very low-cost connectivity to sensors that can run on batteries for years at a time. They don't need SCADA infrastructure in between them; [customers] can stick a sensor out there, and it can plug directly into our network."

Oil and gas operators' sensor networks continue to grow, potentially including millions of end points, which poses challenges for managing battery life, device health, etc. Through its 5G low-power connectivity, which is already available to clients, "INET is allowing customers to manage that number of devices," Hughey said.

Of course, "There's also the ultrabroadband side, where we can deploy a 5G small cell, the same type you see Verizon or AT&T deploying in a downtown metropolitan area," he continued.

For the companies that utilize them, these cells will enable gigabit speeds directly at and around the well site, hundreds of miles from anything like city traffic and shopping malls.

Yet much like in some urban areas, where consumers and businesses benefit from rapid fiber connections, fiber-optic cables form the intermediate links, or backhaul, between remote facilities and corporate offices.

"We have a lot of operators actively deploying fiber to their major facilities out in the field," Hughey said. "At the end of those fiber connections, we'll be able to put 5G services."

These two paths for 5G converge into "a unified communications solution," Slaughter said, which consists of "gigabit speed at the well pad via 5G; at the other extreme are 5G standards for narrowband industrial internet, which can be across the basin; and then our standard 4G broadband will still be there for general communications at a megabit speed across the basin."

A neutral player

INET aims to streamline collaboration between operators and their subcontractors, such as drillers or frac crews, and with other technological partners. The growth of its network can benefit operators at a basinwide level.

"That's something that gets lost on a lot of oil and gas companies when they build their own private networks—they really are closed networks" that prevent third parties from leveraging their benefits, Hughey said.

He added that operator-specific communications hardware, security concerns and regulations have "really stifled adoption [of new technology] in the past."

Referring to the growing platform of companies offering digital services, including video and chemical monitoring as well as data analytics, he said INET "allows them to take off-the-self, standard hardware, deploy it out there and begin serving their customers immediately."

This is analogous to "what the smartphone has done for app store," Hughey said. "It's given you a platform on which all these applications and service reside. We're not the platform, but we're providing connectivity into [it]."

"We act as a neutral player, in bringing all those parties together," Slaughter said, pointing toward INET's partnerships with advanced analytics providers in particular. "We can help these small [analytics] companies, each of which are helping the industry evolve and innovate ... scale very quickly across our network and across our installed customer base in ways that can be very difficult for them to do alone."

He explained, "We can measure [data usage at the well site], at least for rigs in the Permian. This past year the average rig has really used almost a terabyte of data over the course of an average month." The amount of data used grows rapidly, he added.

Slaughter said research suggests that the data currently transiting to/from rigs for analysis represent only about 1% of all data actually generated at the site.

"As more people figure out what information they need for decision-making, we think the more they'll seek to transmit that to decision makers in the office," he said.

"That's the opportunity we have—to help meet those critical data transmission needs reliably and robustly," he said. "Our partners and advanced analytic providers turn those data into information and insights to drive better decision-making."

Slaughter said, "We play that critical role. If you can't get [data] back to the office, it can't be analyzed." □

According to INET CTO Stan Hughey, oil and gas companies need more sophisticated networks to handle emerging use cases for advanced technologies.

Brandon Wise, business analyst of operations technology with Noble Energy, said Noble uses INET for all of its Permian well sites and several other facilities and offices.

SETTING A NEW BENCHMARK

The Harold-Hamm led American Gulfcoast Select is the first new crude benchmark since 2010, designed to more accurately price U.S. liquids being exported by tanker. Will it provide the value uplift as hoped?

BRIAN NADURAK

ARTICLE BY
LESLIE HAINES

Like all oil producers, when the price of WTI plunged way below zero as the May contract expired on April 20, Harold Hamm watched in dismay and disbelief. Something was seriously not right. Something was broken.

But unlike others, the chairman and founder of U.S. shale producer Continental Resources Inc., which bills itself as America's oil champion, sprang into action. "I'm a very positive person and I look for solutions, so I knew we had to do something to make the market work," Hamm told Hart Energy in an exclusive interview.

Hamm marshaled his forces and became a founding member of the American GulfCoast Select Best Practices Task Force Association. For two months, the group has been talking to large producers, traders, midstream companies, refiners, consultants, the companies that publish commodity benchmark prices and the commodity exchanges—Intercontinental Exchange and Nymex.

The result—American GulfCoast Select (AGS)—was introduced by Platts on June 26. A unit of S&P Global, Platts publishes daily energy news and benchmark prices for commodity markets around the world; its prices are referenced by producers, buyers, refineries and traders in their daily work.

Global commodity pricing agency Argus also launched its own price assessment index for the U.S. Gulf Coast—Argus AGS—in close consultation with market participants, including Hamm-led American GulfCoast Select Best Practices Task Force Association.

The task force goal was to establish a new benchmark, a new mechanism, to more accurately and reliably price U.S. light, sweet crude oil, believing a waterborne benchmark is necessary to competitively market America's growing crude oil supply.

AGS is the new benchmark for light, sweet crude with API gravity between 38 to 41 degrees, meant for export on the Gulf Coast from facilities anywhere from Corpus Christi, Tex-

Platts American GulfCoast Select (AGS) At-A-Glance

Load Ports: Platts AGS reflects typical ports used for loading Aframax vessels along the Gulf Coast including Corpus Christi, Texas City, Houston, Beaumont and Nederland, with the assessment reflecting the most competitive location.

Laycan: Platts AGS reflects cargoes loading in a 15 to 45 day window from the day of the assessment. This means that the June 26 assessment will reflect cargoes loading from July 11 to August 10. Bids, offers and trades reported to Platts for inclusion in the assessment should specify at least a five-day loading period.

Cargo Size: Platts AGS assessment reflects typical cargo size of 700,000 bbl with a range of 550,000 bbl to 800,000 bbl included for the assessment.

as, to St. James, La. Production will come initially from the Permian Basin, then from the Bakken and the Eagle Ford shales.

"It's very exciting and transformative," Hamm said. "This is a real bright spot that helps every producer in America. Being a part of the global market is what it's all about. So, we're glad that Platts took the initiative to publish this, effective June 26."

The last new crude benchmark, North Sea Brent, was introduced in 2010.

"This [AGS] is not a replacement for WTI," Hamm noted. "It should have occurred right after exports began in 2015."

The new benchmark reflects dramatic changes in U.S. crude flows over the past few years as shale output grew exponentially and exports began, with increasing flows to, and storage in, the Gulf Coast region.

Horizontal drilling has enabled U.S. producers to bring on huge new quantities of light, sweet crude. However, most U.S. refineries could not handle these barrels. Hence, that crude was looking for new markets and had to be exported to other refineries around the world.

"The market has shifted," Hamm said. "There is so much oil now that never touches Cushing, coming from the Eagle Ford and much of the Permian. You've got a vast amount of new infrastructure along the Gulf Coast … spent on expanding dock space and loading facilities. So, we needed to develop a benchmark on the Gulf Coast. All of the major markets in the world are waterborne, not landlocked. If you sit back and take a 40,000-foot view, you see the need; you see what the logistics are."

The inflow of daily volumes of light, sweet crude oil into the Gulf Coast eclipses the Cushing, Okla., market. Storage in Cushing, exempting line fill, is 76 MMbbl, while storage on the U.S. Gulf Coast is nearing 391 MMbbl, the task force association said.

"This [the new benchmark] is happening, and it's been very well received around the world," Hamm said. "What this is all about is having the best competitive market in the world. Who wouldn't want to be associated with that?"

Hamm, also the chairman and founder of DEPA (Domestic Energy Producers Alliance), has historically been proactive in defending the U.S. producer.

Previously, he was instrumental in persuading the federal government to lift the crude export ban in 2015. Since then, the U.S. had been exporting as much as 5 MMbbl/d before the COVID-19 pandemic reduced global demand. That number has more recently fallen to about 3.3 MMbbl/d, "still strong despite the pandemic," Hamm said, and indicative of the power of American natural resources and producers' ability to manage them during a severe price downturn.

Hamm has also asked the Commodity Futures Trading Commission (CFTC) to investigate why the price of crude fell to a negative $37/bbl on April 20. He and others believe the event was not handled correctly.

AGS has to be traded widely, not narrowly, he added, and needs to be driven by those who would use it. He said the task force recognized early on that "producers were the tail of the dog" and that downstream companies and crude buyers have to be involved. □

DATAWING GLOBAL

The new AGS crude standard will hopefully help Gulf Coast producers better access waterborne markets across the world.

STAYING FOCUSED

Despite ongoing headwinds facing the battered oil and gas industry, reducing emissions remains a goal.

ARTICLE BY
VELDA ADDISON

When the dust settles from one of the most devastating downturns the oil and gas industry has seen in recent years, the push toward reducing emissions will still be there.

Fortunately, industry players are maintaining their commitment to reduce emissions along the entire supply chain as industry groups bring companies together to achieve common goals, and while regulators aim to bring order and checks to the process.

Upstream oil and gas companies participating in The Environmental Partnership recently welcomed the midstream sector, more than tripling its membership to 83 participants. Working with API, the partnership comprises companies of all sizes across the U.S. each aiming to lower emissions of methane and volatile organic compounds (VOCs). Their efforts, some of which are required by existing regulations, have included stepping up monitoring, implementing leak detection and repair programs, and replacing high-bleed pneumatic controllers.

"Using EPA [Environmental Protection Agency] estimates, we know that finding and fixing leaks can achieve a 60% emission reduction, and replacing high-bleed controllers is at least a similar cut in emissions—60%—and likely significantly greater based on recent emissions studies at investigating controller emissions," Matthew Todd, director of The Environmental Partnership, said on a media call July 15. "Many of the actions taken by the companies, removing gas-driven controllers from operations, are eliminating emissions entirely."

Data show efforts demonstrated by participating companies are working, he added.

Companies taking part in the partnership's Leak Detection and Repair Program in 2019 carried out more than 184,000 leak surveys at more than 87,000 production sites. The work included an estimated 116 million inspections of components such as valves, flanges and connectors—typically places where leaks can occur.

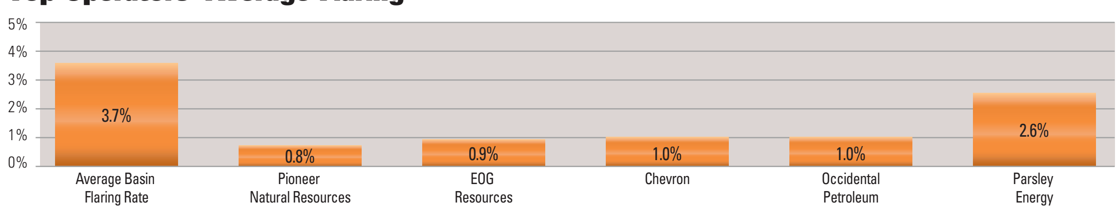
"Of these components, operators identified a leak occurrence rate of just 0.08%," Todd said, explaining that is less than one leak for every 1,000 components. That was an improvement from about two leaks for every 1,000 components in 2018.

Other results, which were shared in an annual report, included replacing, retrofitting or removing from service more than 3,300 high-bleed pneumatic controllers, removing from service more than 10,500 additional gas-driven controllers and installing more than 2,800 zero-emitting controllers.

"Similar to our current environmental performance programs and informed by EPA reporting data, midstream companies will take additional steps to further reduce emissions associated with pipeline blowdowns and compressor operations," said Vanessa Ryan, manager of the carbon reduction team at Chevron Corp. and chair of The Environmental Partnership.

The work is underway as the industry continues to endure unfavorable market conditions, massive spending cuts and widespread layoffs. The COVID-19 pandemic, which has slowed demand, also adds uncertainty.

Top Operators' Average Flaring



Source: Gaffney, Cline & Associates

"Of course, unforeseen public health and economic challenges have presented new hurdles to America's natural gas and oil industry. But nothing has moved energy operators away from their continued commitment to leading the world in energy development and environmental performance," said Mike Sommers, president and CEO of API. "In fact, the pandemic has brought a new level of urgency to operationalize our mission to learn, collaborate and take action to responsibly develop our nation's essential energy resources."

Their efforts also target flaring, and they are not the only ones on a mission.

Texas tackles flaring

A matrix identifying when flaring is necessary with a shortened time line for administrative action, best practices and new reports to provide greater accountability are among the suggestions from a coalition of oil and gas industry groups to help reduce flaring in Texas.

The report by the Texas Methane & Flaring Coalition was discussed in June during the Railroad Commission of Texas (RRC) meeting. It came as commissioners reached out to oil and gas industry players, environmental groups and other stakeholders as they sought ways to lessen the amount of natural gas flared from Texas oil fields.

Rising levels of flared gas have been driven mainly by higher oil production as operators drilled new wells prior to the latest downturn. Lower oil prices in recent months may have reduced production, bringing down flaring; however, concerns remain.

While flaring is needed at times for safety reasons, some companies routinely flare gas more than others when economics or other factors are at play. Texas law prohibits flaring of associated gas from initial completion beyond 10 producing days. Companies may request exemptions.

Certain operators have made it a priority to reduce flaring, putting gas to use, utilizing technology and making sure infrastructure is in place before bringing a well online.

The matrix, seen as a key component of the plan, gives companies several options based on their situations, guiding the application of Statewide Rule 32. The rule prohibits flaring of associated gas from initial completion beyond 10 producing days.

"The point is that operations are different and operators are different. But these steps will lead to reduced flaring," Todd Staples, president of the Texas Oil and Gas Association (TxOGA), told commissioners. "Importantly, a part of that is to embrace emerging technology. We believe that innovation and technology is what has made Texas the energy capital of the world, and we think that will drive environmental progress in everything that we do."

The coalition also recommended

- Changes to the Statewide Rule 32 dataset to improve commission oversight and data collection;
- A proposed new report to follow up on the duration and actual volumes of flared gas, providing the commission with clear and usable data; and
- Adding another code in production report forms for flaring to enable operators to better account for flared and vented gas.

Among the best practices are setting reduction goals and continuous gas capturing planning, working with midstream, assessing facility designs to enhance gas-oil separation, improving gas quality for pipeline specifications and evaluating potentially beneficial technologies—all aimed to reduce flared volumes.

When flaring is necessary, recommended best practices are to minimize emissions via auto igniters, remote or onsite monitoring, automation, redundant ignition and maintenance programs, according to the report.

"We believe that we can get to the end of routine flaring," Staples said. "We believe that more data are better data. It will enable the commission to do its job easier and more efficiently."

He added that technology and innovation should be part of the process, pointing out companies that have seen positive results.

RRC Chairman Wayne Christian sees the need for a place for new technology ideas at the commission. He mentioned a program in North Dakota in which new technologies and techniques are pitched with the most promising ones getting state funding that are matched by the industry.

"This is [an] opportune time to implement meaningful reforms to reduce flaring before oil and gas production climbs back to previous highs," Christian said.

Kirk Edwards, president of Latigo Petroleum, suggested commissioners study limiting production in areas without plant capacity to take gas from newly drilled wells.

"This allowable mechanism would last until the plant has room," for the gas wells, he said, noting this would apply to operators not drilling the first well on a new field.

GB HART/SHUTTERSTOCK.COM

Burning excess natural gas is a common practice among some operators when prices deem it uneconomic to transport gas to market. A flare is shown between two rigs in a West Texas oil field.

For new wells drilled in an existing field with no immediate gas plant access, Edwards proposed commissioners allow the operator to flare natural gas production for no more than 90 days. No extensions would be given.

"The operator must then shut in the well until an adequate market is found for the well to produce into," he said.

Wells permitted before July 1, and those completed and producing before Oct. 1, would be grandfathered to flare as current statutes allow, he added.

Setting, reaching goals

Environmental groups also had ideas to share. The Environmental Defense Fund (EDF) urged commissioners to develop a plan to eliminate routine flaring in Texas by 2025.

"We know this can be done because many of the leading operators are either already doing it or quickly working to achieve it," said Colin Leyden, director of regulatory and legislative affairs with EDF.

Parsley Energy Inc. flared less than 3% of its total produced volumes in 2019. That dropped to less than 1% of its pro forma produced volumes in June following the acquisition of a company that had been flaring about 20% of its volumes, according to Stephanie Reed, senior vice president of corporate development, land and midstream with Parsley.

"This did not happen by accident, but rather it required a methodical approach to reduce the flared volumes, including spending millions of dollars in necessary infrastructure," she said.

Parsley's road map includes an "aggressive corporate goal" tied to corporate compensation, reports detailing incidents to increase transparency and securing takeaway capacity before new wells start production.

Occidental Petroleum Corp. aims to have no routine flaring by 2030.

"The process to reduce flaring requires executive commitment and employee buy-in and ownership to reach our goal," said Mike Starrett, vice president of HSE with Occidental's domestic oil and gas operations.

Occidental's approach involves site-specific planning, including identifying and evaluating gas takeaway and facility design options; routine surveillance, maintenance and repair of well operations, and emissions control equipment; training for engineers and operations personnel, and accurate and timely reporting of flare events.

Sharing, using best practices

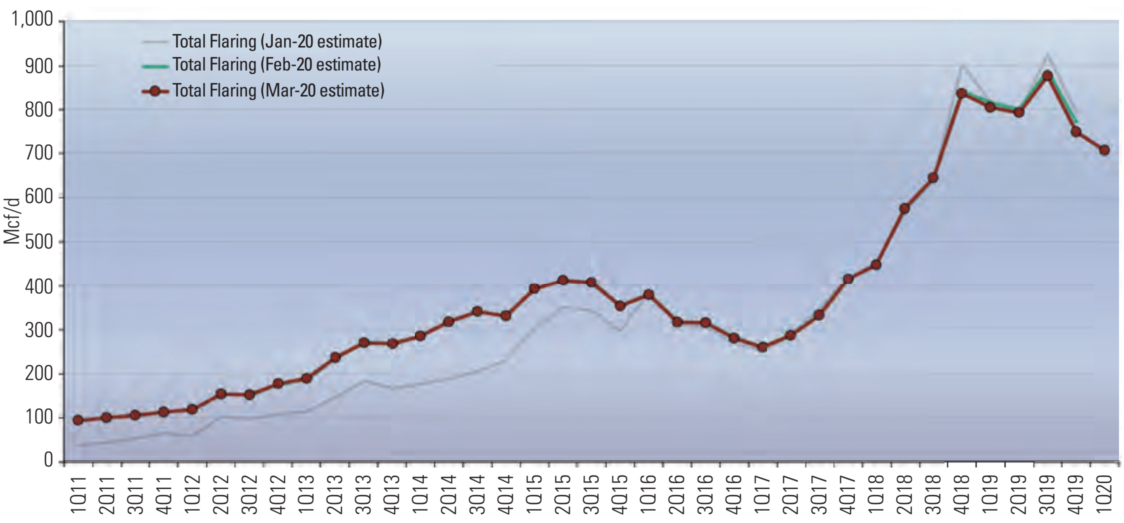
Parsley and Occidental are among the companies known for putting best practices to use. Their efforts—alongside Chevron Corp., EOG Resources Inc. and Pioneer Natural Resources Co.—were highlighted in research on how leading Permian Basin operators are keeping flaring levels in check, prepared on behalf of the EDF in a study by Gaffney, Cline & Associates. The companies have natural gas flaring rates ranging from less than 1% to 2.6% in the Permian Basin, which is below the basin's average of 3.7%.

Neither size, geographical footprint nor classification as an independent or integrated matter when it comes to reducing the amount of natural gas flared. It comes down to governance and leadership from the boardroom to the field, commitment and best-in-class practices, according to the study.

"The silver bullet is to sell your gas. If your gas is going to sales, the dilemma on how to manage flaring goes away," said Jennifer Stewart, carbon management strategy and policy lead with Gaffney Cline. "That's not a one-and-done situation. That's not an easy strategic leadership decision to make. It takes a lot of work and a lot of commitment. But these five companies have done it."

The words, spoken during a mid-June webinar hosted by Rice University's Baker Institute, came as natural gas flaring from the biggest oil field in the U.S. dips as operators slow activity amid weak prices. In recent years, the Permian has become notorious for its high flaring rates, which increased as producers—seeking oil—drove production to highs.

Permian Natural Gas Flaring By Quarter



Source: Gaffney, Cline & Associates

Reducing flaring requires commitment by companies to hook up gas wells only when infrastructure takeaway is in place; however, there must also be a willingness to shut in wells when infrastructure is not available, Stewart said.

Among the best operating practices shared by participating companies is using vapor recovery units on pad sites aiming to maximize emissions capture, frequently checking flares to ensure they are functioning properly, incorporating emissions monitors on facilities design and taking a strategic approach to manage operational upsets.

Common Flaring And Emissions Controls Practices

Daily AVO (auditory, visual, olfactory) observation of flare stacks	Monthly preventive maintenance	High pressure alarms on production separators
Remote observation of tank batteries by integrated operations centers	Thermocouples (temperature integrated operation centers sensors) to ensure pilot stays lit	Designing flares to handle wide range of production rates
Continual flare vs auto-ignite to prevent foul out ignition issues	Flares designed at correct velocity to ensure gas flow does not cause pilot light to extinguish	Blower packages to introduce oxygen to efficiently combust high BTU gas
Dual tip flares (high pressure and low pressure) sized for maximum production flow in an emergency situation	Ensure that production levels stay below flare capacity to ensure combustion efficiency	Low level alarms to prevent gas blowby to tanks which prevents venting
Tie in to SCADA systems and programmable logic controllers ('PLCs') to monitor flare ignition	Flare failure alarms directed to technicians for immediate repairs	

Source: Gaffney, Cline & Associates

Nonroutine flaring is needed only when there are operational upsets, high gas line pressures or other safety reasons.

"There's no easy fix to this issue. It'll take a lot of work, but it is a fixable, manageable issue," said Jeff Gustavson, vice president of Chevron North America E&P's Midcontinent Business Unit. "Sharing best practices with all the operators is a great [and] easy step to take."

Chevron, which has a more than 2 million-acre position in the Permian Basin, planned to produce about 600,000 boe/d this year and up to 1 MMbb/d by 2024, though Gustavson said those plans are being worked out in light of the current environment.

Industrywide curtailments are helping bring down amounts of flared gas, and the downturn is giving infrastructure time to catch up to production levels, Gustavson said. He pointed out positive economic signals from improved differential between Waha and Gulf Coast prices.

Energy research firm Rystad Energy said in April total gas flaring in the Permian dropped to an estimated 700 MMcf/d in the first quarter of 2020.

Chevron aims to reduce its global flaring intensity by 25% to 30% from 2016 levels by 2023.

The environmental and economic impacts are real, Gustavson said, before focusing on the latter.

"You're burning a product that has value," although prices went temporarily negative a few times last year, he said. Plus, he noted the market is watching, and there is heightened scrutiny on not just individual operators but the entire industry.

"Capital flows are changing because of this. That has a real economic impact," he said.

Creating value

When JP Morgan Asset Management analyzes energy stocks, sustainability factors are among the areas evaluated, according to David Maccarrone, a managing director with JP Morgan. The firm, he said, supports policymakers developing regulation to deliver on nonroutine flaring objectives in the Permian.

"The reality is climate change needs to be high among companies' priorities because the world is changing," Maccarrone said. "These changes will drive company operations and stock valuations and for us. … it impacts our ability to create value for our clients."

EDF has been tracking flaring in the Permian Basin since the start of the shale boom. Its latest research revealed that some flares have major performance problems, contributing to methane emissions in the basin.

There is an incentive problem when it comes to flaring, said EDF's Leyden.

"You've got low gas prices, rush to bring production online, a lack of meaningful regulatory limits," he said. "That's all a recipe for excessive waste and pollution, and that's generally what we've seen in the Permian. Operators are primarily there for the liquids, and the dry gas can often end up essentially being a waste product."

He called flaring a "huge unforced error" and a "question mark hanging over the oil and gas industry's ability to compete in a low carbon economy."

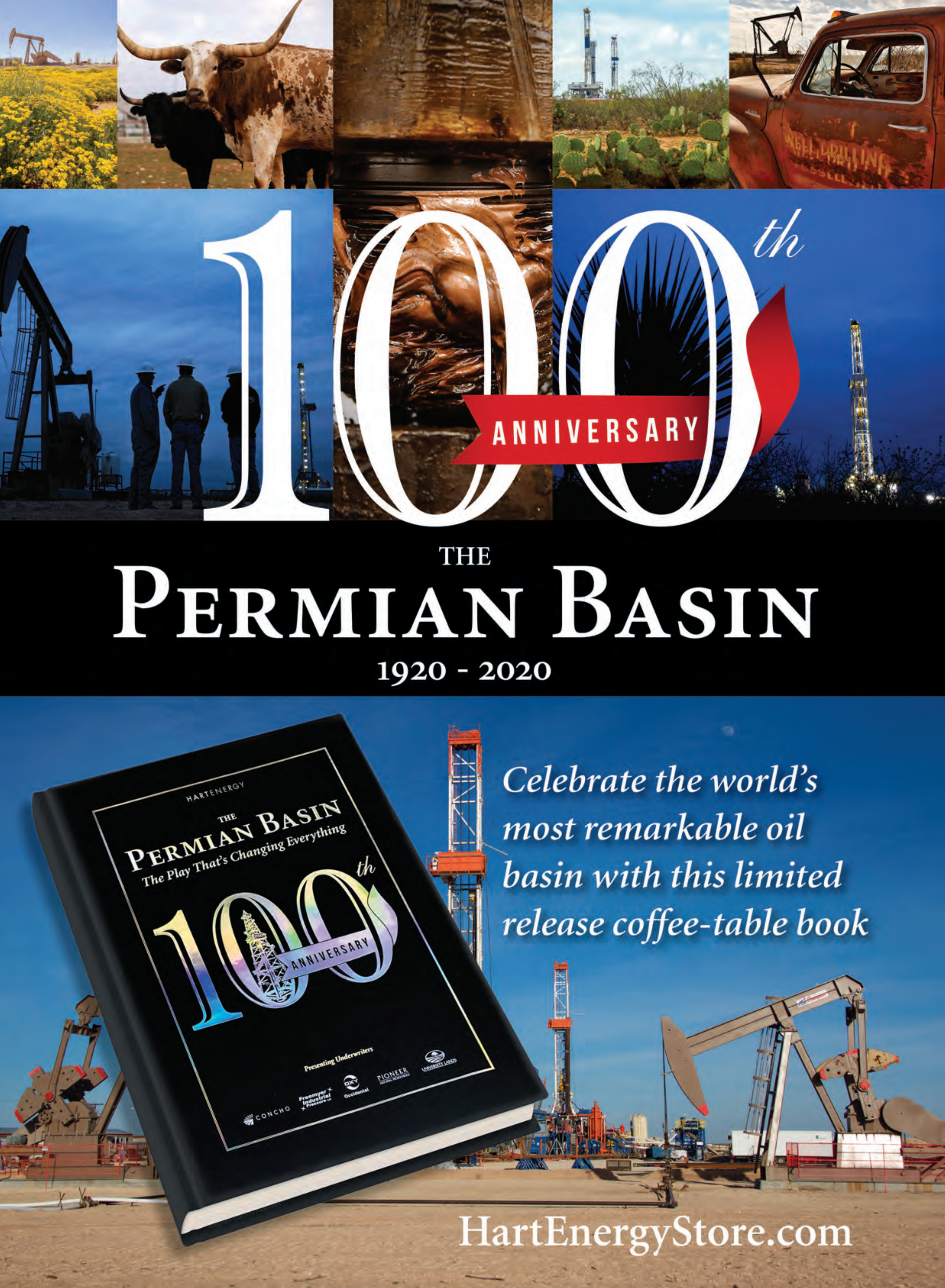
Hopes are for companies that routinely flare to be inspired by companies that don't and for regulators to enact rules to make that happen.

Besides companies highlighted in the Gaffney Cline report, others of various sizes have taken steps to reduce flaring without stricter regulations. The problem is not every company is doing so.

"There's an expression, 'If you aim for nothing, you'll hit it every time,'" Maccarrone said. "The voluntary operator actions we've seen have not delivered on the industrywide change we need to see in time, particularly in the Permian, given its size."

It also helps to have goals, which Stewart pointed out creates transparency to stakeholders and accountability within and outside the organization. Some companies, including Chevron, have tied compensation to flaring goals.

"It starts with that strong governance and strong leadership from the top," she said. □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NAVIGATING THE BATTLEGROUND STATE

The implementation of SB 181—Colorado's controversial new oil and gas law—poses significant challenges for the state's oil and gas industry. But savvy operators will continue to adapt to the regulatory landscape, as they have done successfully in the past.

ARTICLE BY
BEAU STARK,
FREDERICK R.
YARGER AND
GRAHAM VALENTA

Colorado is in the midst of a heated battle to determine the future of oil and gas development in the state, with proponents and opponents of the industry clashing in recent years at the ballot box, in the courtroom and in the Colorado General Assembly.

These clashes have intensified as significant increases in oil and gas production in Colorado, which has nearly quadrupled since 2010, continue alongside fast population growth in Denver and its surrounding suburbs. The increased proximity of Denver's residential areas to well pads has spawned attempts by industry opponents to curb oil and gas production through several different avenues, including:

- Proposition 112, a 2018 ballot initiative that would have required 2,500-ft setbacks for new wells across the state; and
- *Martinez v. Colorado Oil and Gas Conservation*, a lawsuit that, if successful, would have overturned more than a decade's worth of rulemaking by Colorado's primary oil and gas regulatory body, the Colorado Oil and Gas Conservation Commission (COGCC).

After the defeat of Proposition 112 in the fall of 2018, and after the Colorado Supreme Court maintained the regulatory status quo in its *Martinez* decision in early 2019, industry opponents shifted their focus to the legislative arena. In the 2018 elections, Democrats—many of them critics of the industry—gained simultaneous control of the governor's office and both houses of the Colorado General Assembly. Anti-industry activists capitalized on these majorities in the 2019 legislative session, immediately introducing Senate Bill 19-181 (SB 181), which was signed into law by Governor Jared Polis on April 16, 2019.

SB 181 mandates a host of changes to oil and gas regulation in Colorado, either through the bill itself or through the formal rulemaking processes at the COGCC and other state agencies, such as the Colorado Department of Public Health and Environment (CDPHE). SB 181 leaves the technical details to the COGCC and CDPHE, but the fundamental changes to Colorado's regulatory landscape are contained in SB 181 itself. Of those changes, two in particular have caught the industry's attention:

1. The shift in the COGCC's overall regulatory mission and priorities; and
2. The new ability of local governments to directly regulate oil and gas production and impose restrictions that are more stringent than those found in statewide laws and regulations.

While these changes appear daunting, Colorado's industry is accustomed to adapting to a changing regulatory landscape. In the years before SB 181, the state adopted dozens of precedent-setting regulations affecting all aspects of the production cycle, many of which were among the toughest in the country, and the industry continued to boom. As SB 181 is implemented at the state and local level, the industry will be required to stay engaged and nimble as rules are finalized and their operational impact becomes more clear.

COGCC mission change

SB 181 fundamentally transforms Colorado's approach to oil and gas regulation by revamping the mission of the COGCC. For decades, the primary goal of the COGCC was to "foster" the efficient development of oil and gas resources within Colorado in a manner consistent with various other considerations, including public HSE. The COGCC sought to balance these other considerations against the development of oil and gas resources where possible, but the COGCC's overall mission was clear: promote the efficient production of Colorado's oil and gas.

SB 181 recasts the COGCC's mission.

Rather than fostering oil and gas development—language that no longer appears in the statutory description of the COGCC's mission—the COGCC's primary goal is now to "regulate" oil and gas development "in a manner that protects public health, safety and welfare, including the protection of the environment and wildlife resources." This new mission puts greater emphasis on the protection of public HSE, backing away from the regulatory "balancing" that once defined the agency's work and is the standard approach to government regulation of industries with environmental impacts.

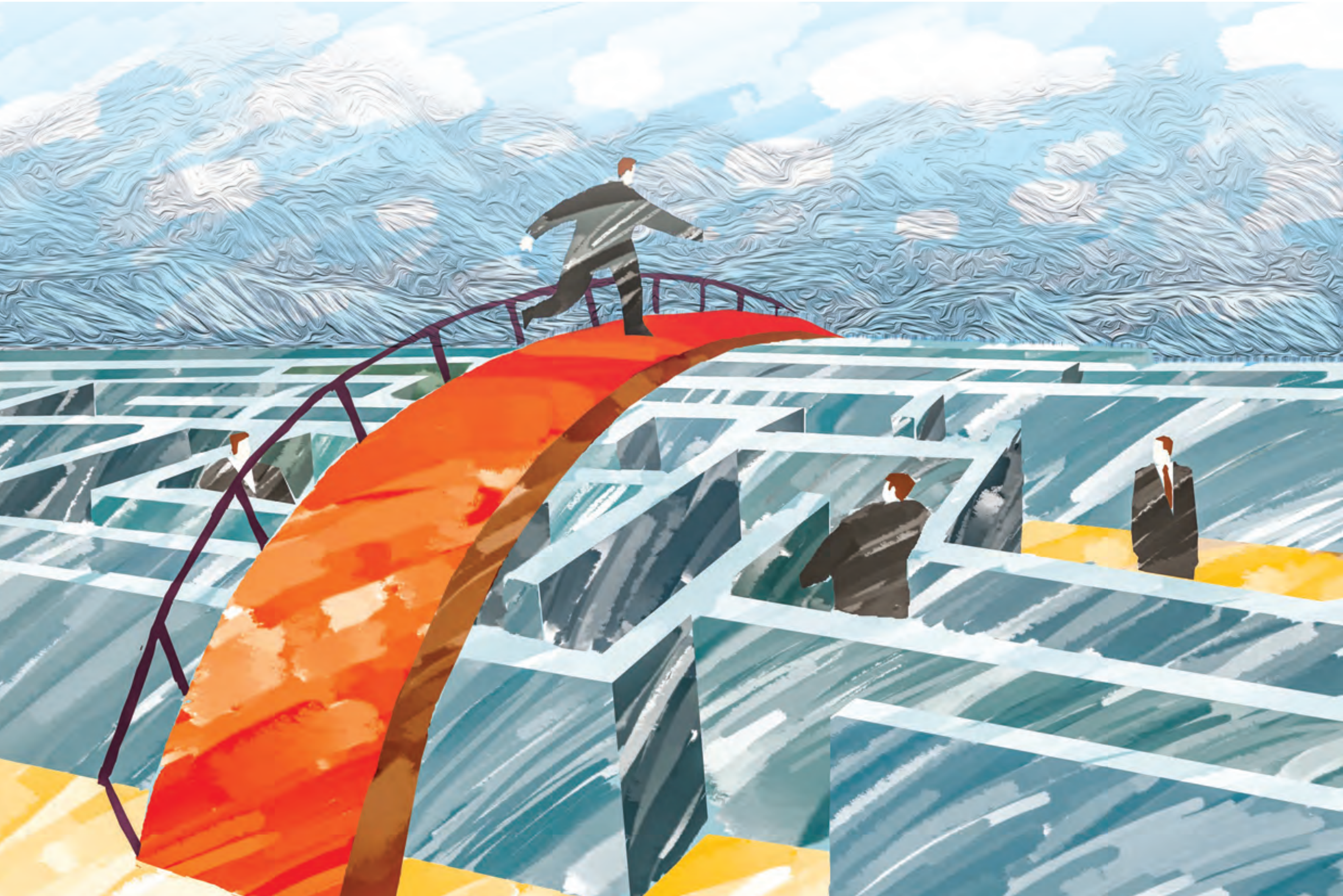
The COGCC's new mission is echoed in the restructuring and professionalization of the new-era COGCC mandated by SB 181. The COGCC was historically composed of nine volunteer commissioners, of whom at least three were required to have extensive experience in the oil and gas industry. As of July 1, 2020, the COGCC will have seven commissioners, each of whom will be a full-time state employee, and, in keeping with SB 181's de-emphasis of oil and gas development, only one commissioner will be required to have industry experience.

SB 181 also requires the COGCC to adopt regulations that reflect its new mission. The COGCC had intended to complete all of its rulemaking processes (including the mission change rulemaking process) prior to the COGCC's restructuring on July 1. However, these processes have suffered numerous delays since the adoption of SB 181. This is due in part to the contentious nature of rulemaking under the COGCC, which has grown increasingly heated since SB 181 was passed, and because of the COVID-19 pandemic, which prevented the COGCC from holding hearings that allowed members of the public to speak in person about the proposed rules. The COGCC's mission change rulemaking hearings are scheduled to take place in August and September of this year.

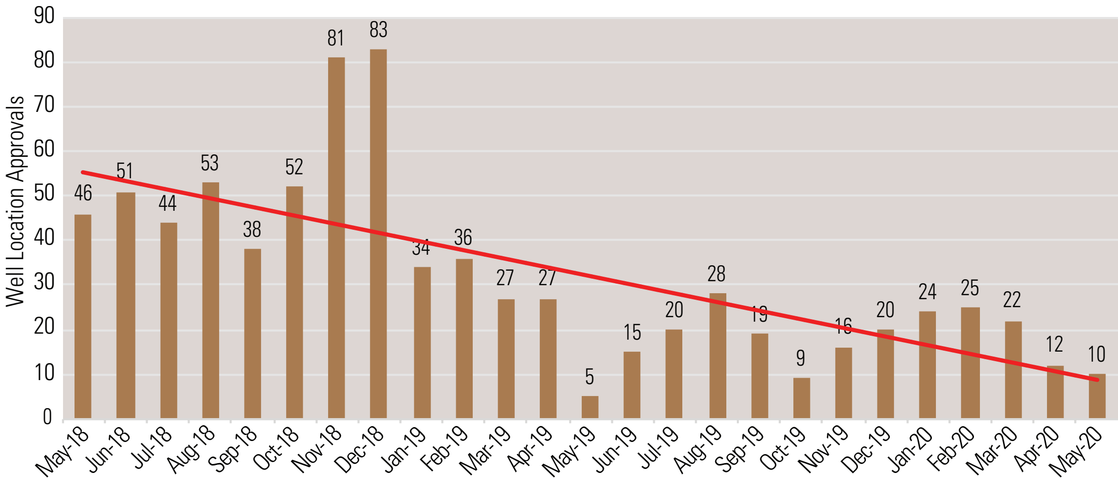
Local regulatory control

The other fundamental change ushered in by SB 181 is the new role local governments will play in industry regulation. Under SB 181, local governments can adopt their own oil and gas regulations for the first time, even when the COGCC or CDPHE enacts statewide regulations governing the same topics. If a municipality approves rules that are stricter than statewide counterparts, SB 181 allows the municipality's rules to override statewide rules. This new ability to preempt statewide rules gives local governments unprecedented power over oil and gas production within their territories and will require the industry to work with regulatory bodies at both the state and local levels.

Local control over oil and gas production is a historical break with Colorado's previous approach to oil and gas regulation, and it runs counter to the regulatory frameworks found in other states. For example, Texas passed a law



Colorado Well Approval Permits



Source: Colorado Oil and Gas Conservation Commission

in 2014 forbidding a municipality from passing ordinances regulating oil and gas in response to a ban on hydraulic fracturing passed by the city of Denton. The Texas law grew out of the concern that allowing municipalities to regulate oil and gas production would lead to an impractical patchwork of local regulations.

Before SB 181, Colorado lawmakers shared this concern, believing it would be difficult for oil and gas operators to juggle competing sets of local regulations. Under SB 181, however, Colorado's top priority is regulating oil and gas to ensure public health and safety, with significantly less emphasis placed on ensuring a uniform regulatory landscape. Local control over the industry is a natural consequence of Colorado's reordered regulatory priorities.

SB 181's effect on the industry

SB 181 was designed as a long-term solution to the state's oil and gas wars, but the full effect of the law has yet to be felt. SB 181 requires multiple extensive rulemaking processes, and full implementation of the law will take many more months to complete. However, in the year since SB 181 was signed into law, it has already affected the industry in critical ways.

Increased permitting scrutiny and permitting moratoria. One of SB 181's largest impacts has been a decline in permitting activity. Immediately after SB 181 was signed into law, the COGCC adopted interim guidelines imposing more stringent review of applications for drilling permits and well location permits. Because the purpose of these guidelines was to ensure that the COGCC's analysis of new permit applications complied with the new law's overall mandate, they offer a window into a world in which SB 181 is implemented in full.

At the same time, several cities and counties in Colorado enacted temporary permitting moratoria. These moratoria were designed to halt oil and gas activity while statewide and local regulations were finalized and to ensure that any permits granted post-SB 181 complied with the new regulations. However, the state and local rulemaking processes have suffered repeated delays, allowing municipalities to extend their permitting moratoria for nearly a year.

The combination of the COGCC's stringent review of permitting applications and local permitting moratoria has led to significantly fewer approved permits. In the 12 months after SB 181 was enacted, the COGCC's approval of well location permits was down by more than 50%. For example, the COGCC approved just 215 well location permits from May 2019 through April 2020, compared to the 442 and 572 well location permits approved by the COGCC over the same time periods in 2017 and 2018, respectively. Further, the decline in well location permitting in the 12 months after SB 181 cannot be attributed to one or two slow months—since SB 181 was signed into law, monthly approvals of new well locations have remained consistently lower compared to the previous 12 months.

Approvals for drilling permits are also down compared to previous years. According to a report by the University of Colorado's Leeds School of Business, the COGCC approved an average of 203 drilling permits per month through October 1, 2019, a decrease of about 54% compared to the 443 drilling permits per month approved over the same period in 2018. This trend has continued, with the COGCC approving an average of 144 drilling permits per month from November 2019 through May 2020.

It is not clear if the declines in permitting activity are only temporary or if they reflect a new normal after SB 181. Approval rates for drilling and well location permits may increase as the COGCC and local governments finalize their respective regulations and the various permitting moratoria expire. On the other hand, if permit approval rates remain low, the industry may have to revisit and reshape its current approach to permitting. As has always been the case, flexibility and engagement with regulators will be crucial.

A potential patchwork of local regulations. Although the rulemaking process is not complete, so far some local governments in

Colorado have used their newfound powers under SB 181 to adopt regulations different from those of their neighbors, creating the regulatory patchwork feared by Colorado's oil and gas industry. The neighboring counties of Weld and Boulder, for example, have taken diametrically opposed approaches. Weld County, which accounted for nearly 88% of Colorado's aggregate oil production in 2019, has expedited new production in the county, going as far as attempting to create its own permitting department that would bypass the statewide permitting system. Boulder County, on the other hand, enacted a moratorium and is seeking to strengthen its existing oil and gas regulations and expand its regulatory authority. Indeed, activists have filed a lawsuit asking the Boulder County District Court to give its stamp of approval to the notion that the county can impose fracking bans and permanent drilling moratoria that under prior state law would have been preempted by state law.

The differences among regulations adopted by other counties are likely to be less extreme than the divide between Weld and Boulder. Even so, producers with leases, wells or other mineral interests in more than one county will need to stay on top of competing sets of local regulations, in addition to statewide regulations adopted by the COGCC and CDPHE. Compounding these difficulties are the different speeds at which cities and counties have adopted these regulations, with certain municipalities finalizing regulations within months after SB 181 was passed and others yet to enact final regulations. Even when state and local regulations are finalized, court challenges to the new rules are likely. While it may take some time before the state and local regulatory landscape is settled, the industry can take comfort in the fact that the vast majority of Colorado's crude oil production is located in possibly the most industry-friendly county in the state: Weld County.

Under SB 181, Colorado's top priority is regulating oil and gas to ensure public health and safety, with significantly less emphasis placed on ensuring a uniform regulatory landscape.

Looking ahead

SB 181 represents a significant departure from the regulatory scheme that had existed in the state for decades. For the industry itself, SB 181 has brought new regulatory and legal challenges that will continue to evolve as the law is implemented statewide. But this is not the first time Colorado has seen significant changes to the way in which the industry operates. In this environment, success will require the industry to remain nimble and engaged, at both the state and local level. The key will be to understand the details of the new regulations and the political forces behind them—an increased desire by regulators and affected communities to protect public health and environment while maintaining responsible access to the state's energy resources. ☐

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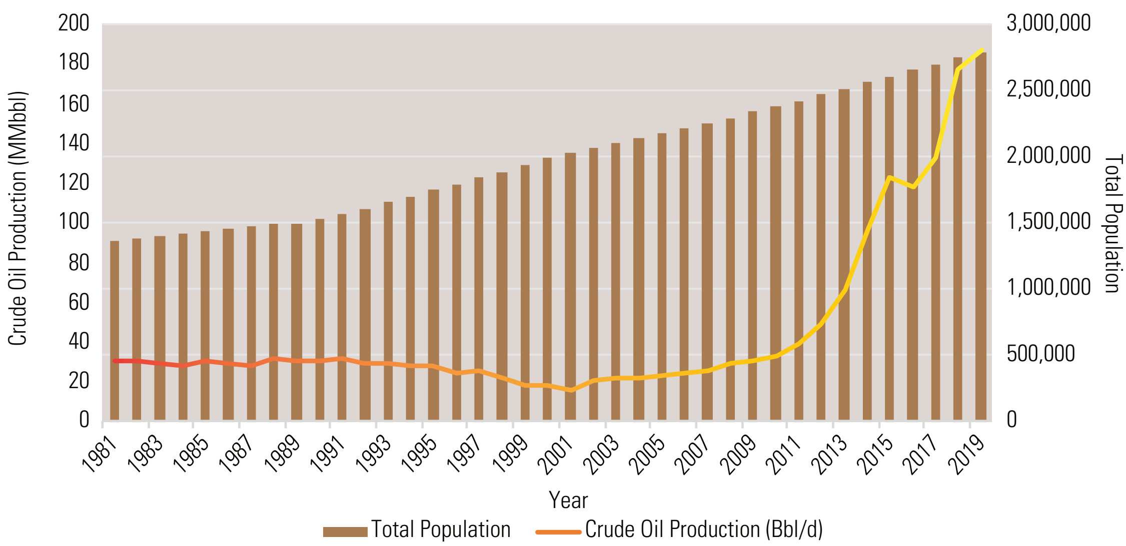
Annual Colorado Crude Oil Production And Denver Metro Area Population Growth



Source: U.S. Energy Information Administration, macrotrends.net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Chevron Buys Out Noble Energy For $13B


NOBLE ENERGY

CHEVRON CORP. agreed on July 20 to a buyout of Houston-based independent E&P company Noble Energy Inc. in an all-stock transaction valued at $5 billion. The total enterprise value, including debt, of the transaction is $13 billion, according to Chevron.

The San Ramon, Calif.-based oil major said in a statement the acquisition of Noble Energy provides Chevron with low-cost proved reserves and attractive undeveloped resources to enhance an "already advantaged upstream portfolio."

"Our strong balance sheet and financial discipline gives us the flexibility to be a buyer of quality assets during these challenging times," said Chevron Chairman and CEO Michael Wirth.

Founded more than 85 years ago, Noble Energy today operates a portfolio of U.S. shale assets, including in the prolific Permian Basin, plus international assets offshore Israel in the Eastern Mediterranean Sea as well as offshore West Africa.

Wirth said the Permian acreage is a "targeted bolt-on" to Chevron's acreage, adding 92,000 net acres in the core of the Delaware Basin adjacent to its existing footprint. The deal also complements Chevron's assets in Colorado and the Eagle Ford Shale.

"These assets play to Chevron's operational strengths, and the transaction underscores our commitment to capital discipline," Wirth continued in his statement.

Wirth added Chevron expects the combination to generate annual run-rate cost synergies of approximately $300 million before tax, and it is expected to be accretive to free cash flow, earnings and book returns one year after close.

The transaction comes roughly a year after Chevron's failed takeover of **Anadarko Petroleum Corp.** due to a bidding war launched by **Occidental Petroleum Corp.** over the independent E&P company.

Although on a smaller scale than its proposed $50 billion bid for Anadarko, Tom Ellacott, senior vice president of corporate analysis at **Wood Mackenzie**, said the acquisition of Noble will go "further in reducing the concentration of Chevron's upstream portfolio around core anchor positions in the Permian, Australian LNG, Kazakhstan and the U.S. Gulf of Mexico."

Additionally, much of Noble's upstream value comes from its positions in Israel and Cyprus, according to Jean-Baptiste Bouzard, from WoodMac's upstream research team.

"Noble's position in Israel is the company's crown jewel. Israel will provide Chevron with a new core international geography that will rebalance the portfolio towards gas and provide a springboard to capture further upside potential in the region," Bouzard said.

Ellacott also noted the Noble transaction marks the first large-scale corporate acquisition of the current downturn.

"Chevron was our top pick to lead bottom-of-the-cycle corporate consolidation arising from the oil price collapse and the COVID-19 pandemic," he said.

Further, Chevron's acquisition of Noble could lay out the blueprint for what post-COVID consolidation will likely need to look like with all-stock consideration, a moderate premium, and asset fit and synergies that are an easy and natural story to tell investors, according to Andrew Dittmar, senior M&A analyst for market research at **Enverus**.

"For Noble shareholders, Chevron equity likely looks like a fine landing spot, even absent a cash sweetener, given Chevron's operational experience for the assets, balance sheet strength and ability to fund dividends even in a tough market," Dittmar said.

The acquisition consideration for the Noble transaction is structured with 100% stock. Upon closing, expected fourth-quarter 2020, Chevron will issue approximately 58 million shares of stock. Noble Energy shareholders will receive 0.1191 shares of Chevron for each Noble Energy share and are expected to own approximately 3% of the combined company.

"Being able to use equity as currency in a corporate acquisition like this is one of the advantages held by companies like Chevron, whose stock is likely viewed as a relatively safe haven," Dittmar continued in his statement.

The transaction price represents a premium of nearly 12% on a 10-day average based on closing stock prices on July 17, according to the Chevron release.

Credit Suisse Securities (USA) LLC is financial adviser to Chevron for the transaction. **Paul, Weiss, Rifkind, Wharton & Garrison LLP** is acting as the company's legal adviser. For Noble Energy, **J.P. Morgan Securities LLC** serves as financial adviser, and **Vinson & Elkins LLP** as legal adviser.

—Emily Patsy

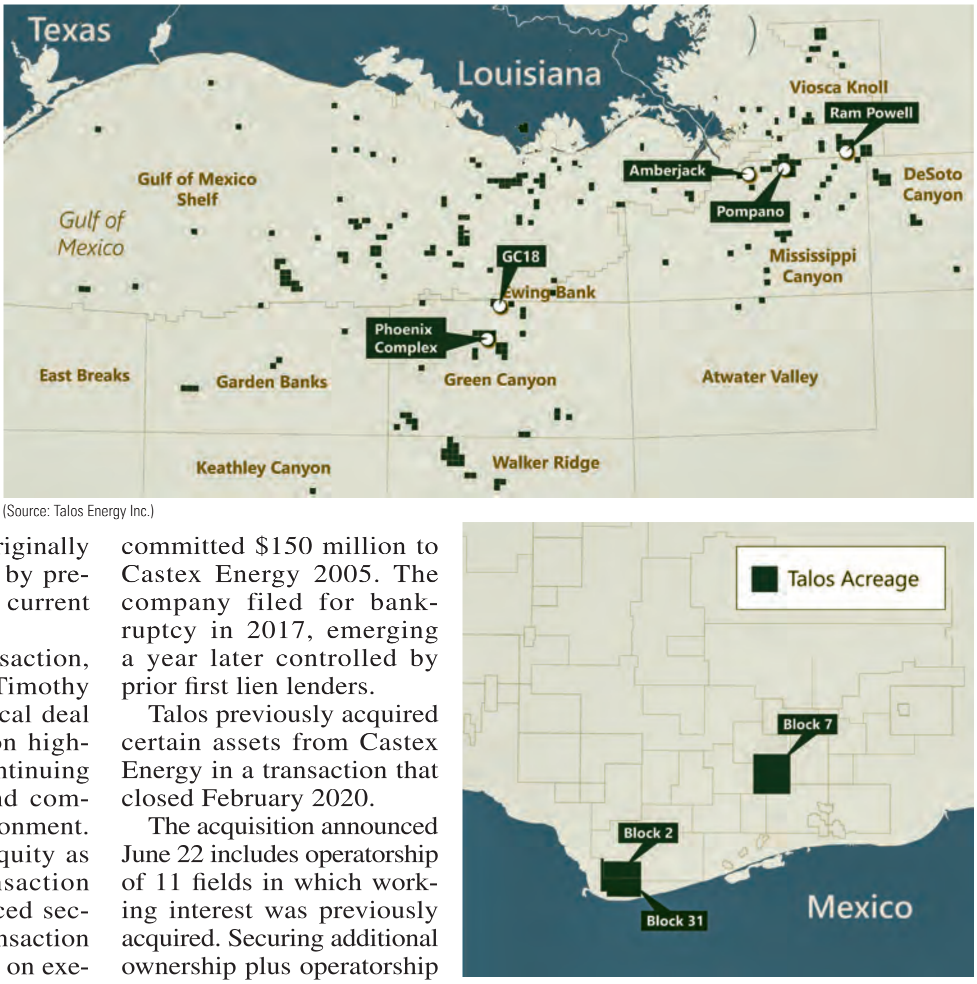
Talos Energy Adds 'Tactical' Bolt-on

TALOS ENERGY INC. tacked on additional assets located in its U.S. Gulf of Mexico (GoM) shelf core area through a bolt-on acquisition on June 22.

In a release from the Houston-based company, Talos said it had agreed to pay $65 million for 16 selected assets from affiliates of **Castex Energy 2005**. The purchase price will be funded through the issuance of approximately 4.95 million Talos common shares at closing and $6.5 million cash.

Among the acquired assets are multiple prolific, producing fields that were originally discovered and/or operated by predecessor companies led by current Talos management.

Talos Energy GoM Shelf Asset Map



(Source: Talos Energy Inc.)

Commenting on the transaction, Talos president and CEO Timothy S. Duncan said, "This tactical deal with a compelling valuation highlights the importance of continuing to remain opportunistic and commercial in the current environment. The ability to utilize our equity as consideration in this transaction and the previously announced second lien notes exchange transaction demonstrates both our focus on executing value accretive transactions for our shareholders as well as our commitment to protecting our strong credit profile, both of which better position us to continue to evaluate further opportunities."

Castex Energy is a private oil and gas company focused on exploration and development in South Louisiana and the GoM Shelf.

In December 2014, private-equity firm **Riverstone Holdings LLC** committed $150 million to Castex Energy 2005. The company filed for bankruptcy in 2017, emerging a year later controlled by prior first lien lenders.

Timothy S. Duncan

Talos previously acquired certain assets from Castex Energy in a transaction that closed February 2020.

The acquisition announced June 22 includes operatorship of 11 fields in which working interest was previously acquired. Securing additional ownership plus operatorship for the majority of the assets provides Talos with greater control moving forward, Duncan added in his statement.

The acquired assets generate an average production of about 6,400 boe/d, comprising roughly 15% oil and 85% natural gas. As of April 1, the assets had proved reserves of approximately 17.6 MMboe, with more than 66% classified as proved developed reserves.

Talos said it plans to hedge a significant portion of total volumes from the acquired assets through 2022 to secure "favorable long-term commodity pricing, supporting underlying transaction economics."

For the 12-month period that ended March 31, the assets generated operating cash flow of approximately $31.2 million, according to the Talos release.

In the release, Talos said it had executed the definite agreement to acquire the select assets from affiliates of Castex Energy 2005 on June 19. The effective date of the transaction is April 1, with closing expected in third-quarter 2020.

Intrepid Partners LLC advised Castex Energy 2005 in the transaction. **Vinson & Elkins** advised an affiliate of Talos Energy in connection with the acquisition.

Separately, Talos said its borrowing base had been reduced by 14% to $985 million following its semiannual redetermination process. Pro forma for the redetermination, Talos had approximately $121 million of cash on hand and $650 million drawn under its credit facility as of May 31.

"We are very pleased with the continuing strong support we've received from our bank group considering the historic dislocation in our industry in recent months," Duncan said. "As we look forward to the second half of 2020, we're highly confident in the financial strength of the company and believe we are well positioned for continued growth."

—*Emily Patsy*

Harvest Oil & Gas To Sell Remaining Assets

HARVEST OIL & GAS CORP. landed an agreement on July 8 to sell its remaining assets, as the Houston-based independent E&P and former affiliate of **EnerVest Ltd.** aims to begin the process of winding up and returning capital to its shareholders.

The divestiture includes the sale of 713,401 net Appalachian Basin acres, which Harvest said in a statement will represent "substantially all of the assets of the company."

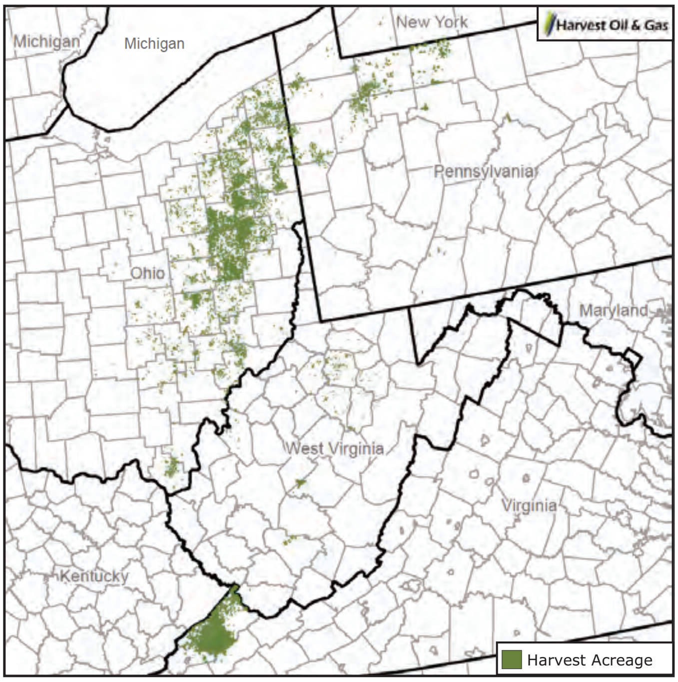
Harvest agreed to sell the assets to an unaffiliated third party in exchange for $20.5 million, comprising $14.5 million of cash and a $6 million note. The majority holders of Harvest common stock approved the transaction, according to the company's release

Harvest's Appalachian Basin portfolio includes 916,832 gross and 713,401 net acres. In May, Harvest voluntarily deregistered its common stock, which had been trading on OTC Market's OTCQX U.S. Premier Marketplace.

Harvest is a successor company of **EV Energy Partners LP**, a former affiliate of EnerVest that emerged from bankruptcy in June 2018. EnerVest was not a part of its affiliate's bankruptcy filing.

From the restructuring, Harvest inherited a multibasin portfolio including positions in the Permian Basin and Midcontinent region, which it has since sold off, piece by piece. Most recently, the company entered an agreement in March to sell all of its oil and natural gas properties in Michigan for a purchase price of $4.8 million. The transaction was expected to close during the second quarter.

Harvest Oil & Gas Appalachian Acreage



Source: Harvest Oil & Gas Corp.

Following closing of the Appalachian Basin asset sale, expected in August, the company said it "intends to evaluate the process of winding up and of returning capital to its shareholders." Harvest added the evaluation will be dependent upon an analysis of the net cash available for distribution to its stockholders and the amount of net cash that must be retained to satisfy its ongoing liabilities during the winding-up process.

The Appalachian Basin asset transaction has an effective date of July 1. The definitive agreement contains various representations, warranties, covenants and indemnification obligations of the company and the buyer that are customary in transactions of this type, the company release said.

—Emily Patsy

Sabine, Align Midstream Create JV

SABINE OIL & GAS recently formed a joint venture (JV) with **Align Midstream Partners II LLC** in a partnership that advances its strategy to capture value from "wellhead to burner tip," according to CEO Doug Krenek.

Headquartered in Houston, Sabine operates in the Haynesville Shale and Cotton Valley plays in East Texas. The formerly publicly traded E&P was acquired by Japan-based **Osaka Gas Co. Ltd.** last year.

The JV transaction marks Osaka Gas' first acquisition in the midstream business in the U.S. and also follows the completion of the TOPS pipeline in East Texas by Align II.

"Given the long-term view of Sabine and its parent Osaka, the TOPS investment is another step in vertically integrating Sabine and advancing our strategy of capturing value from the wellhead to the burner tip for our East Texas assets," Krenek said in a statement on June 29.

The TOPS pipeline is a 30-mile, 16-inch diameter gas gathering pipeline in the Carthage area with interconnections to key downstream takeaway markets, said Align CEO Fritz Brinkman.

"The TOPS Pipeline will bolster our existing East Texas footprint and enhance our ability to serve the growing Haynesville production, providing our customers with greater access to a number of attractive markets across the Carthage hub," Brinkman said.

Backed by private-equity firm **Tailwater Capital LLC**, Align has gathering, processing and treating assets across the Haynesville and Cotton Valley plays. In November 2019, Align II announced the combination of its assets with **Elevate Midstream LLC**, expanding Align II's footprint in East Texas.

Align II marks the second partnership between the management team of Dallas-based Align and Tailwater, which currently manages more than $3.7 billion in committed capital, according to a company release.

Latham & Watkins LLP represented Sabine Oil & Gas in the midstream JV transaction with a Houston-based team led by partners Justin Stolte and Lauren Anderson, with associates Greg Sorensen and Ashley Nguyen.

—Hart Energy staff

Warren Buffett Company Buys Dominion Gas Business

Warren Buffet

BERKSHIRE HATHAWAY Inc., the conglomerate headed by famed investor Warren Buffett, agreed on July 5 to acquire the natural gas transmission and storage assets of **Dominion Energy Inc**.

The all-cash transaction has an enterprise value of approximately $9.7 billion including the assumption of $5.7 billion of debt, according to a Dominion release.

The deal reflects a strategic repositioning by Dominion on its regulated utility operations, according to CEO Thomas F. Farrell II, and it also follows the company's decision to cancel the Atlantic Coast Pipeline, a natural gas pipeline initially proposed in 2014.

"Today's announcement further reflects Dominion Energy's focus on its premier state-regulated, sustainability-focused utilities that operate in some of the most attractive regions in the country. ... This narrowing of focus will also allow us to increase our long-term earnings growth rate guidance by around 30%," Farrell said in a statement on July 5.

Analysts with **Tudor, Pickering, Holt & Co. (TPH)** noted the transaction likely signifies a broader shift away from midstream by the utilities sector.

"The transaction follows the buy-in of **Dominion Midstream** early last year and is likely indicative of a broader shift among regulated utilities to de-emphasize midstream operations as the sector's prior push toward unregulated growth opportunities comes full circle," TPH analysts wrote in a July 6 research note. "Recent transactions for midstream assets with a utility buyer have seen increased investor scrutiny centered on earnings quality [more concern on wellhead assets] and general decarbonization trends."

In his statement, Farrell added that the transaction will also align Dominion with its sustainability focus, which includes a net-zero target by 2050. He also noted Dominion's goal to invest up to $55 billion in emissions reduction technologies over the next 15 years and plans to retire more than four gigawatts of coal- and oil-fired electric generation by 2025.

In a news release, Buffett, chairman of Berkshire Hathaway, said he admires Farrell for his "exceptional leadership across the energy industry as well as within Dominion Energy. We are very proud to be adding such a great portfolio of natural gas assets to our already strong energy business."

Dominion's gas transmission and storage business includes more than 7,700 miles of natural gas transmission lines, with approximately 20.8 Bcf/d of transportation capacity and 900 Bcf of operated natural gas storage, with 364 Bcf of company-owned working storage capacity, and partial ownership of an LNG export, import and storage facility.

> "We are very proud to be adding such a great portfolio of natural gas assets to our already strong energy business."
> —Warren Buffett, Berkshire Hathaway chairman, on the company's nearly $10 billion acquisition of Dominion's pipe and storage arm

As part of the transaction, **Berkshire Hathaway Energy**, subsidiary of Berkshire Hathaway Inc., will acquire 100% of **Dominion Energy Transmission**, **Questar Pipeline** and **Carolina Gas Transmission** and 50% of Iroquois Gas Transmission System. The agreement does not include acquisition of the Atlantic Coast Pipeline.

Additionally, the company will acquire 25% of Cove Point LNG in Maryland—one of only six LNG export facilities in the U.S. Dominion Energy will continue to own 50% of Cove Point. **Brookfield Asset Management Inc.** will own the remaining 25% share, which it acquired from Dominion late last year for approximately $2.1 billion.

Berkshire Hathaway Energy will operate the Cove Point facility once the transaction closes, which is expected in fourth-quarter 2020.

In addition to assuming about $5.7 billion of existing debt related to Dominion Energy's gas transmission and storage segment, Berkshire Hathaway will make a cash payment of approximately $4 billion to Dominion Energy upon closing. Dominion Energy plans to use the proceeds to repurchase common shares.

Assuming a Cove Point valuation in-line with the sale to Brookfield in fourth-quarter 2019, TPH analysts estimate the Berkshire Hathaway transaction value implies a slightly lower multiple for Dominion's remaining pipeline assets, with primary natural gas midstream operators trading at a similar or higher multiple.

McGuireWoods LLP served as legal counsel to Dominion Energy for the transaction. **Barclays** was the company's lead financial adviser. **Morgan Stanley** also acted as financial adviser to the company.

—Emily Patsy

TRANSACTION HIGHLIGHTS

WILLISTON BASIN

■ **Northern Oil and Gas Inc.** agreed on June 10 to a bolt-on acquisition of properties operated by **WPX Energy Inc.** in the core of the Williston Basin.

The Minneapolis-based company, which touts itself as being the largest Williston Basin nonoperator, will pay an undisclosed seller $1.5 million in cash for the properties comprising about 320 acres. Since signing, Northern said it has received nine gross well proposals to fully develop the unit consisting of 2.1 net wells.

"We have consistently believed this environment would create opportunities for our shareholders in 2020 and beyond and budgeted for opportunities like this," Northern COO Adam Dirlam said in a news release about the acquisition. "This acquisition, while modest in size, is located in the heart of the core with one of the top operators in the Williston Basin and highlights Northern's competitive advantage as an actively managed nonoperator."

Further, he believes the deal to be materially accretive to cash flow in 2021, yet it represents no additional capital spending to Northern's stated 2020 budget.

The acquired assets are expected to produce 1,200 boe/d and produce an estimated $11.3 million of unhedged cash flow from operations in 2021 at the current commodity pricing strip as of June 5.

Northern expects approximately $12.5 million of development capital through 2020 and early 2021, with expected initial sales in first-quarter 2021. Inclusive of the development capital and acquisition costs, Northern expects a payback period of under 1.5 years.

All acquisition and associated development capital have already been accounted for in Northern's recent 2020 capital budget, according to the company release.

Northern expects to close the bolt-on acquisition on July 1.

ALASKA

■ **BP Plc** said it completed the sale of its Prudhoe Bay oil and gas producing properties to closely held **Hilcorp Energy Co.**, ending 60 years as a top Alaskan oil producer.

BP and other oil majors have reduced their production roles in the northernmost U.S. state as output slid and lower-cost fields emerged elsewhere. Hilcorp, known for buying up oil castoffs, acquired half of another BP Alaska project in 2014.

The $5.6 billion deal, including BP's stake in the Trans-Alaska Pipeline System that carries crude oil from Prudhoe Bay to Alaska's southern coast, should wrap up this quarter, both companies said in statements.

"We look forward to continuing to drive economic growth, create Alaskan jobs and contribute to local economies for decades to come," said Hilcorp CEO Greg Lalicker.

The agreement calls for Hilcorp to pay $4 billion to BP over an unspecified time, with the remaining $1.6 billion based on future earnings from the properties. Terms were revised and pushed back as Hilcorp sought to raise financing.

With the July 1 purchase, Texas-based Hilcorp becomes the state's second largest oil producer and reserves holder, behind ConocoPhillips Co. Hilcorp will nearly triple its workforce in Alaska to 1,450 employees with the acquisition, said Luke Miller, a Hilcorp spokesman.

MIDSTREAM

■ **Third Coast Midstream LLC** is unloading a portfolio of natural gas transmission assets through a sale to **Black Bear Transmission**, a Houston-based portfolio company of **Basalt Infrastructure Partners LLP**.

The terms of the transaction are not being disclosed. According to a Black Bear release on June 29, the assets are a natural extension to the Southeast U.S. natural gas transmission business that Basalt acquired from Third Coast Midstream in 2019 that resulted in its formation.

"We are pleased and excited about this follow-on sale of natural gas transmission assets to Black Bear," Matt Rowland, CEO of Third Coast Midstream, said in a statement. "We look forward to another successful transition with the Black Bear team following the sale of these assets, as Third Coast Midstream takes another step in its strategic repositioning to focus on its core Gulf of Mexico infrastructure platform."

The portfolio of natural gas transmission assets includes six intrastate natural gas pipelines spanning about 1,400 miles in Alabama, Louisiana and Mississippi. The system has total capacity of more than 800 MMcf/d.

"This investment expands our asset base of high-quality, demand-driven natural gas pipelines in the Southeastern United States," Rene Casadaban, CEO of Black Bear Transmission, said in a statement. "The NGT [natural gas transmission] assets are highly complementary to our existing Black Bear footprint and are strategically positioned to capture continued natural gas demand growth in the region."

Black Bear currently has eight regulated natural gas pipelines stretching more than 1,200 miles, with total delivery capacity of more than 1.8 Bcf/d. The pipelines are connected to 12 major long-haul pipelines, supplying gas to customers across Alabama, Arkansas, Louisiana, Mississippi, Missouri, Oklahoma and Tennessee.

The transaction is expected to close in the second half of 2020, subject to customary regulatory approvals and closing conditions.

Barclays is the exclusive financial adviser to Basalt, and **Vinson & Elkins** served as Basalt's legal adviser. **BMO Capital Markets** is the exclusive financial adviser to Third Coast Midstream, and **Orrick** served as its legal adviser.

APPALACHIA

■ Montage Resources Corp. is divesting gathering assets in its Ohio Utica condensate development area to an undisclosed international third-party.

In a company release on July 22, Montage said it entered into a non-binding letter of intent for the sale of its existing noncore Ohio Utica wellhead gas and liquids gathering infrastructure in exchange for a cash payment of $25 million. The transaction is expected to close fourth-quarter 2020.

Montage Resources CEO John Reinhart said in a statement, "We are extremely pleased to be working with this well-established third-party on the sale of these noncore assets and the proceeds will provide the company the ability to reduce leverage, enhance liquidity and maintain its already strong balance sheet."

Montage Resources is an E&P company based in Irving, Texas, with approximately 195,000 net effective

TRANSACTION HIGHLIGHTS

core undeveloped acres currently focused on the Utica and Marcellus shales of southeast Ohio, West Virginia and north-central Pennsylvania.

In preliminary second-quarter results announced on July 22, Montage anticipates its production for the quarter will be near the high end of the previously announced range of between 535 MMcfe/d and 555 MMcfe/d.

In April, the company shut-in low margin production in its liquids-rich producing areas, primarily impacting its Utica condensate production, due to the historic crash in oil prices. However, on July 22, Montage said substantially all production had been returned to sales by June 1.

MEDITERRANEAN

■ Italy's **Edison SpA** has agreed to reduce the value of the sale of its oil and gas operations to **Energean Plc** by two-thirds to $284 million after dropping the Algerian and Norwegian assets from the deal.

Mediterranean-focused Energean agreed to buy the oil and gas operations in 2019 for up to $850 million, but the parties agreed to revise the deal because of the amendments and a weaker outlook for oil and gas prices following the coronavirus crisis.

A unit of French state-controlled utility **EDF**, Edison said it would retain control of Edison Norge, which controls the group's upstream activities in Norway, until market conditions "allow a full valuation of its assets".

Energean entered talks with Edison to exclude the Norwegian subsidiary from the deal after Energean's plan to immediately sell on Edison's North Sea assets to **Neptune Energy** fell through.

ABU DHABI

■ **Abu Dhabi National Oil Co.** (ADNOC) said June 23 it had signed a $10-billion gas infrastructure deal with a consortium of investors, while its CEO told Reuters the company would keep a tight lid on costs amid low oil prices.

The mega pipeline deal is the world's single largest energy infrastructure investment this year, CEO Sultan al-Jaber said in a phone interview.

A consortium of **Global Infrastructure Partners** (GIP), **Brookfield Asset Management**, Singapore's sovereign wealth fund GIC, **Ontario Teachers' Pension Plan Board**, **NH Investment & Securities** and Italy's **Snam** will invest in select ADNOC gas pipeline assets valued at $20.7 billion, ADNOC said.

The venture will bring $10.1 billion in foreign direct investment to Abu Dhabi, where real gross domestic product is expected to contract by 7.5% this year, according to S&P Global Ratings.

The group of investors will acquire a 49% stake in newly formed subsidiary **ADNOC Gas Pipeline Assets**, while ADNOC will hold the remaining 51%. The deal comes as the world's top oil and gas companies, including ADNOC, scramble to control costs in response to the coronavirus crisis, which has hammered oil demand and prices.

EASTERN US

1 IHS Markit reported that ***Pioneer Oil Co.*** is drilling another deeper pool test in Illinois' White County. Located in Section 25-5s-8e in the west-central portion of the county, #1 Gunter has a planned depth of 4,550 ft and is targeting pays in Chouteau Lime (Lower Mississippian) and is in Turnbull Field. Pioneer Oil has permitted and drilled several tests in the area, including #1-36 Ackerman Trust about one-half mile to the southwest. The Chouteau Lime venture in Section 36-5s-8e was drilled in 2019 to an estimated depth of 4,550 ft and is currently holding for data. The company's offsetting #2-36 Ackerman Trust has a shallower Cypress Sand objective. Permitted in late 2019, the proposed total depth is 2,950 ft. White County's Trumbull Consolidated Field was opened in 1944. Reservoir production comes from a range of Mississippian pays, including Aux Vases at 3,170 ft; Ohara Lime at 3,230 ft; McClosky Lime at 3,290 ft and Ullin at 4,110 ft. Field production extends about 10 miles northeast of Pioneer Oil's program. To the southeast is Roland Consolidated Field. Similar to Trumbull Consolidated Field, the deepest wells in this field yield crude from the Ullin at 4,050 ft. Pioneer is based in Lawrenceville, Ill.

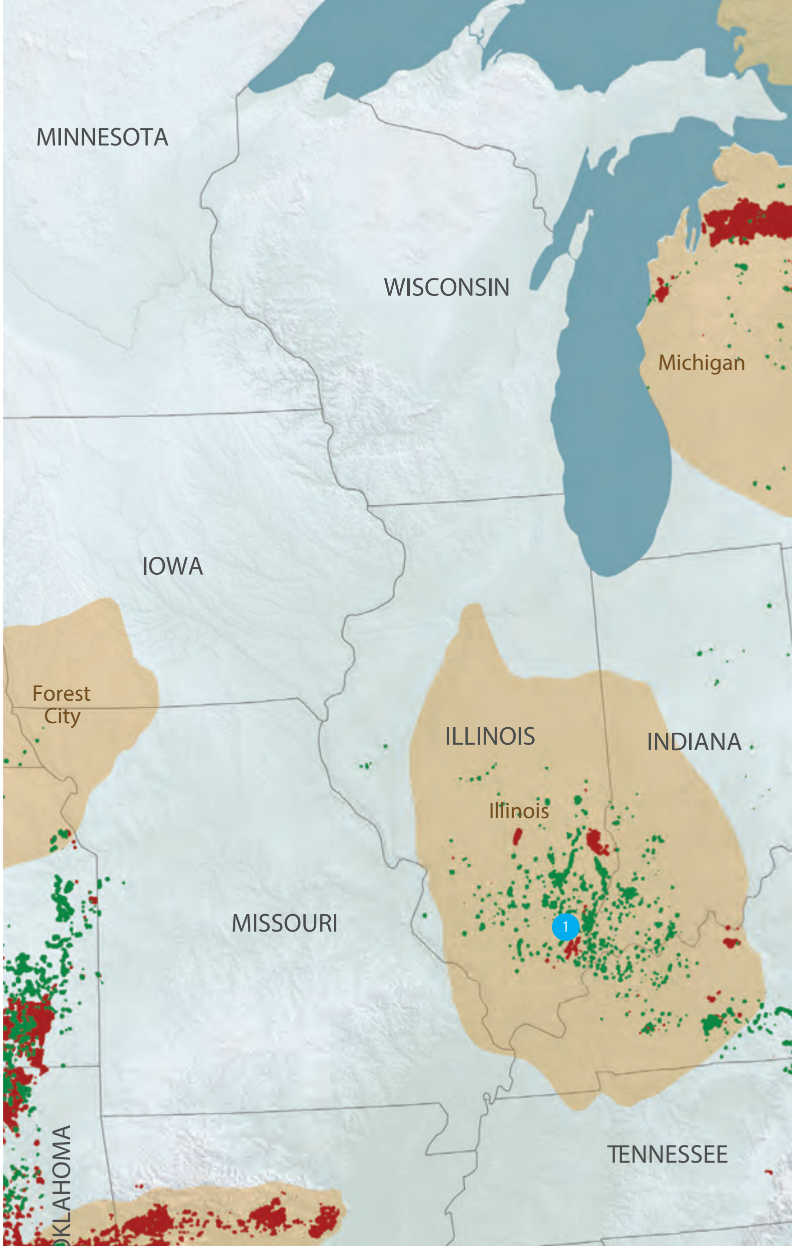
2 Results from two Conecuh County, Ala., wells were released by ***Pruet Production Co.*** The Smackover producers are in Brooklyn Field. The #1 Cedar Creek Land & Timber 28-13 s in Section 28-4n-13e was drilled to 11,775 ft. It was tested flowing 144 bbl of oil and 190 Mcf of gas per day from perforations at 11,415-28 ft. In nearby Section 32, #32-2 Cedar Creek Land & Timber initially flowed 67 bbl of oil with 164 Mcf of gas per day after acidizing. It was drilled to 11,959 ft and is producing from perforations at 11,598-11,624 ft. Pruet's headquarters are in Jackson, Miss.

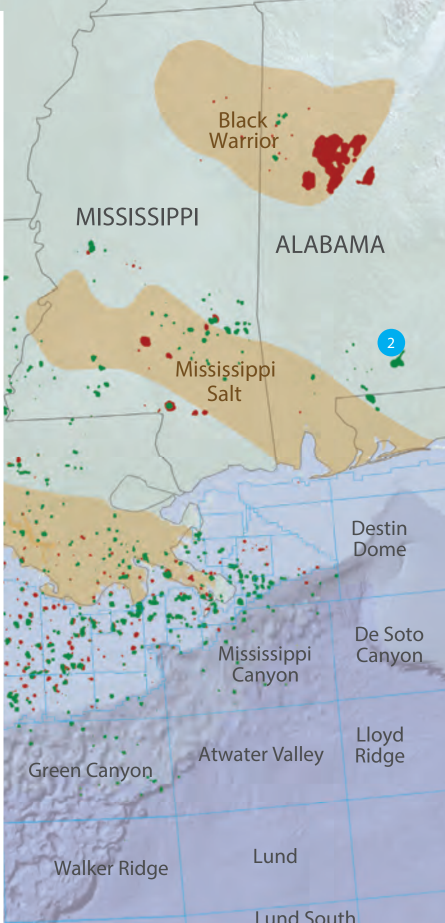
3 In Pennsylvania's Greene County, ***EQT Production Co.*** completed a Marcellus Shale well in New Freeport Field. The #12 Don Flamenco was drilled to 21,245 ft with a true vertical depth of 7,942 ft. It initially flowed 27.74 MMcf of gas from perforations between 8,662 and 21,123 ft. The venture is in Section 2, New Freeport 7.5 Quad, Richhill Township. EQT is based in Pittsburgh.

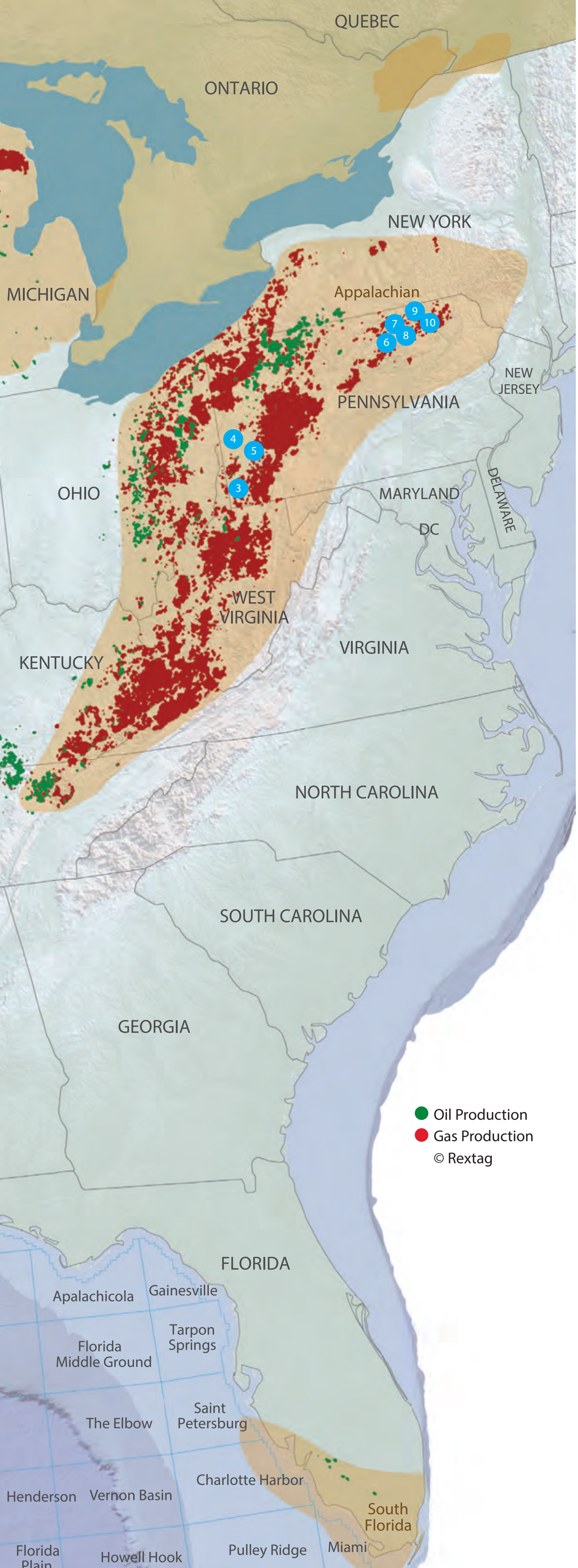
4 Two Beaver County, Pa., wells were completed by Fort Worth-based ***Range Resources.*** The Marcellus Shale discoveries were drilled from a pad in Section 7, Aliquippa 7.5 Quad, Independence Township. The #11H Jodikinos Carol 11380 Unit was drilled to 18,797 ft, 5,715 ft true vertical. It produced 15.01 MMcf of gas per day from perforations at 6,330-18,434 ft. Tested on an unreported choke size, the shut-in casing pressure was 1,031 psi. The offsetting #10H Jodikinos Carol 11380 Unit was drilled to 17,802 ft with a true vertical depth of 5,246 ft. It initially flowed 17.84 MMcf of gas per day from perforations between 5,891 and 17,716 ft. The shut-in casing pressure was 1,002 psi.

5 ***Range Resources*** announced results from two Marcellus Shale wells recently completed in Washington County, Pa. The Hickory Field ventures were drilled from a pad in Section 9, Midway 7.5 Quad, Chartiers Township. The #3H Pawlosky Anthony 12123 Unit was tested flowing 18.43 MMcf of gas per day from Marcellus Shale perforations between 6,700 and 19,487 ft. It was drilled to 19,529 ft with a true vertical depth of 6,320 ft. Production is from perforations between 6,700 and 19,487 ft with a shut-in casing pressure of 3,150 psi. The #1H Pawlosky Anthony 12123 Unit produced 12.984 MMcf of gas from perforations at 7,479-22,706 ft. It was drilled to 22,780 ft, and the true vertical depth is 6,255. Tested on an unreported choke size, the shut-in casing pressure was 2,100 psi.

6 ***Chesapeake Operating Inc.*** announced results from two Sullivan County, Pa., Marcellus Shale discoveries in Mehoopany Field that were drilled from a pad in Section 6, Colley 7.5 Quad, Colley Township. The #6H Pond Family was tested flowing 25.339 MMcf of gas from a fractured and perforated zone at 8,514-16,234 ft. It was drilled to 16,259 ft, and the true vertical depth is 8,863 ft. The shut-in casing pressure was 3,901 psi. The #104H Pond Family was drilled to 16,695 ft, 8,837 ft true vertical. It produced 25.399 MMcf of gas from a fractured and perforated zone at 8,693-16,664 ft and had a shut-in casing pressure of 3,232 psi. Chesapeake is based in Oklahoma City.

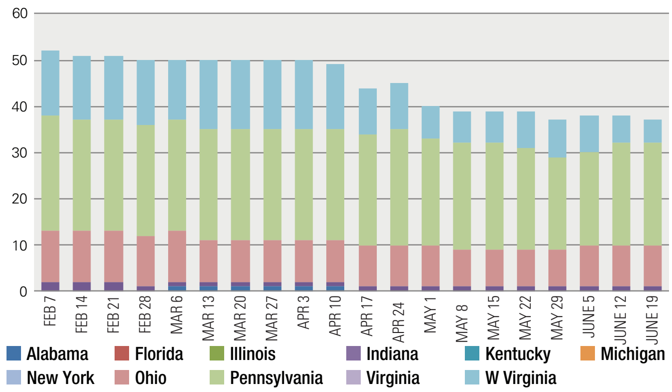






Eastern US Rig Count

Feb. 7, 2020-June 19, 2020



Source: Baker Hughes Co.

7 A Jessup Field-Marcellus Shale completion was tested flowing 46.787 MMcf of gas per day. ***Chesapeake Operating Inc.***'s #1HC Przybyszewski was drilled to 20,840 ft, 6,463 ft true vertical in Section 1, Auburn Center 7.5 Quad, Auburn Township in Susquehanna County, Pa. Production is from a fractured and perforated zone between 7,350 and 20,823 ft, and the shut-in casing pressure was 2,425 psi.

8 Three Susquehanna County Pa., Marcellus Shale producers were drilled at a drillpad in Section 6, Auburn Center 7.5 Quad, Auburn Township by ***Chesapeake Operating Inc***. The #105H Hooker flowed 32.503 MMcf of gas per day. Production is from acidized and fractured perforations at 7,406-12,448 ft, and the shut-in casing pressure was 3,987 psi. The offsetting #104HC Hooker flowed 38.915 MMcf of gas per day with a shut-in casing pressure of 3,633 psi. It was drilled to 19,528 ft with a true vertical depth of 7,594 ft. The #6H Hooker produced 32.548 MMcf of gas daily with a shut-in casing pressure of 3,642 psi. It was drilled to 12,522 ft, 7,320 ft true vertical. The wells are in Silver Lake Field.

9 ***Cabot Oil & Gas Corp.*** reported results from two Susquehanna County, Pa., Dimock Field-Marcellus Shale wells drilled in Section 4, Montrose East 7.5 Quad, Bridgewater Township. The #18 Greenwood R was tested flowing 24.5 MMcf of gas from perforations at 7,358-17,484 ft with a shut-in casing pressure of 1.075 psi. It was drilled to 17,549 ft, and the true vertical depth is 6,619 ft. About 20 ft to the north, #17 Greenwood R produced 23.9 MMcf of gas from a perforated zone at 7,025-18,132 ft and had a shut-in casing pressure of 1,000 psi. It was drilled to 18,314 ft with a true vertical depth of 7,050 ft. Cabot's headquarters are in Houston.

10 Five Susquehanna County, Pa., Marcellus wells were completed at a Dimock Field drillpad in Section 4, Montrose East 7.5 Quad, Bridgewater Township by Houston-based ***Cabot Oil & Gas***. The #10 Greenwood R was drilled to 16,824 (6,699 ft true vertical). It produced 26.2 MMcf of gas per day from perforations at 7,734-16,760 ft with a shut-in casing pressure of 1,100 psi. The #13 Greenwood R was drilled to 18,901 ft (7,026 ft true vertical). It flowed 20.3 MMcf of gas per day from perforations at 7,700-18,830 ft, and the shut-in casing pressure was 925 psi. The #15H Greenwood R was drilled to 11,803 ft (7,075 ft true vertical). It produced 22.9 MMcf of gas from perforations at 7,336-11736 ft with a shut-in casing pressure of 1,000 psi. The #11 Greenwood R was drilled to 13,004 ft (7,073 ft true vertical). It produced 21.7 MMcf of gas from perforations at 7,872-12,938 ft, and the shut-in casing pressure was 900 psi. The #22 Greenwood R was drilled to 16,959 ft (6,724 ft true vertical). It was tested flowing 21.6 MMcf of gas from perforations at 7,872-12,938 ft, and the shut-in casing pressure was 950 psi.

GULF COAST

1 An Austin Chalk completion was reported in Webb County (RRC Dist. 4), Texas, by Katy, Texas-based ***Escondido Resources***. The #1H Stokes-Krueger Unit AC is in Hawkville Field and was drilled to a projected depth of 10,555 ft in Section 643, BS&F Survey, A-27. It flowed 520 Mcf of gas and 95 bbl of water daily from perforations at 10,261-10,488 ft. The venture was tested on an 18/64-in. choke with a flowing tubing pressure of 615 psi and a shut-in casing pressure of 4,165 psi.

2 ***Chesapeake Operating Inc.***, based in Oklahoma City, tested an Eagle Ford well in Eagleville Field that produced 1.226 Mbbl of 39.4-degree-gravity oil with 287 Mcf of gas and 544 Mbbl of water per day. The La Salle County (RRC Dist. 1), Texas, completion, #3H B D and & Co HC4, was drilled to 16,702 ft, 7,716 ft true vertical, from a surface location in Section 26, Block 4, I&GN RR CO Survey, A-352. Production is from perforations at 8,047-16,663 ft. Gauged on a 27/64-in. choke, the flowing tubing pressure was 331 psi.

3 ***Marathon Oil Corp.*** announced results from two Eagleville Field wells that were completed in Karnes County (RRC Dist. 2), Texas. The discoveries were drilled from a surface location in Henry Brown Survey, S A-32. The #1H Turnbull Unit E was drilled to 18,682 ft (11,724 ft true vertical). It was tested flowing 2.4652 Mbbl of 43-degree-gravity oil, 2.595 MMcf of gas and 1.241 Mbbl of water daily from a perforated zone at 11,412-18,562 ft. Gauged on a 28/64-in. choke, the flowing casing pressure was 3,180 psi. The offsetting #2H Turnbull Unit E was drilled to 18,652 ft (11,697 ft true vertical). It was tested flowing 2.333 Mbbl of 49-degree-gravity oil, 2.11 MMcf of gas and 1,741 Mbbl of water per day from perforations at 11,474-18,536 ft. It was tested on a 28/64-in. choke, and the flowing casing pressure was 2,984 psi.

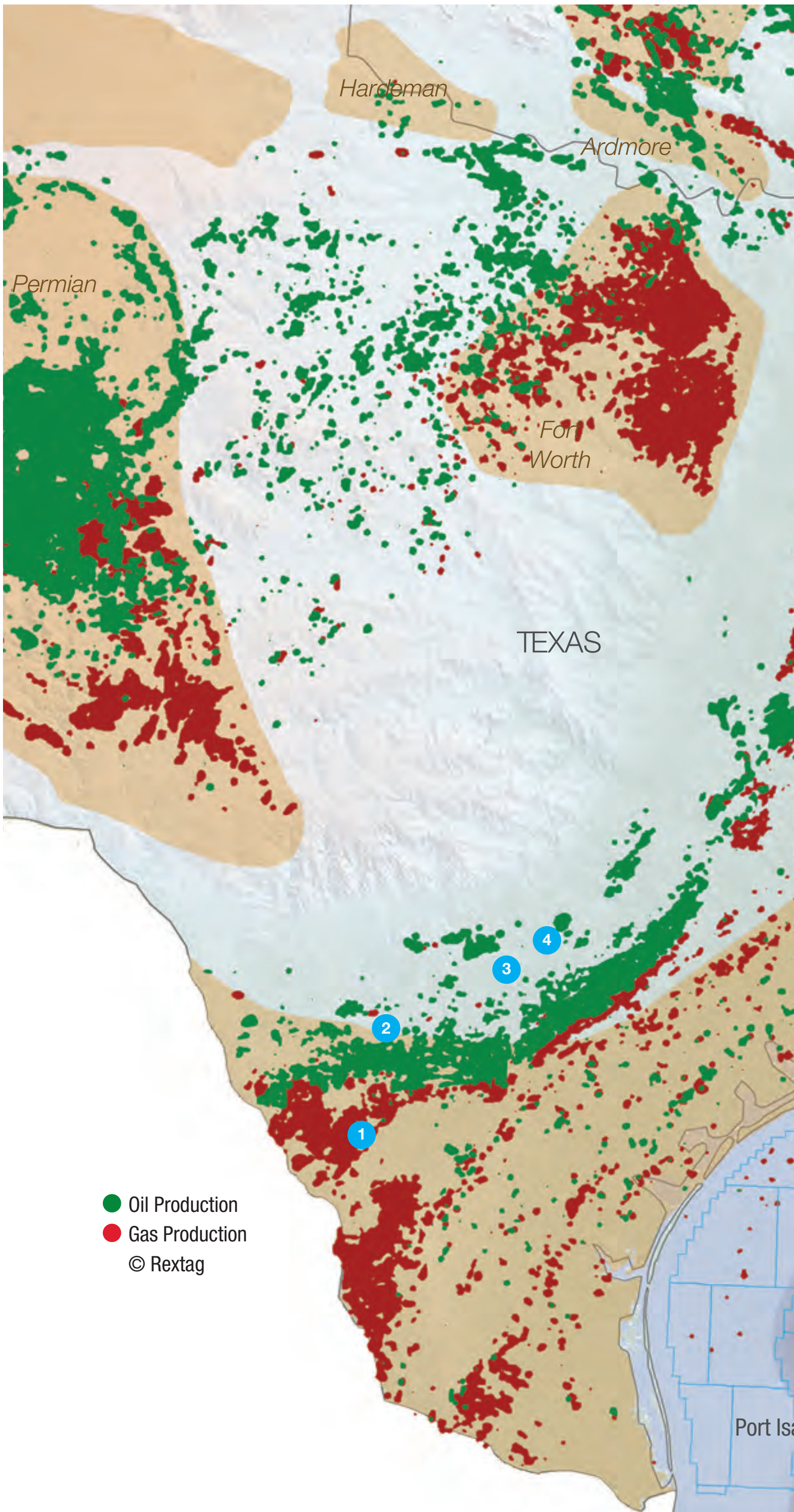
4 ***Devon Energy Corp.*** completed an Eagleville Field-Eagle Ford Shale well. The Oklahoma City-based company's #4H Migura B-Caskey B SA 4 initially produced 1.417 Mbbl of 59-degree-gravity condensate, 7.961 MMcf of gas and 731 bbl of water per day. The De Witt County (RRC Dist. 2), Texas, venture was drilled in James Wharton Survey, A-475. The total depth is 19,453 ft, and the true vertical depth is 13,449 ft. It was tested on a 22/64-in. choke with a flowing casing pressure of 6,237 psi and a shut-in casing pressure of 7,947 psi. Production is from perforations at 14,157-18,663 ft.

5 Houston-based ***Shell Oil. Co.*** has permitted the first Lower Tertiary exploratory test on a five-block prospect in the southern part of the Alaminos Canyon area. According to IHS Markit, #1 OCS G34771 is scheduled to be drilled in Alaminos Canyon Block 691. Water depth in the area is 6,800 ft. Known as the company's Leopard prospect, as many as 18 tests are planned for various surface locations across five blocks. Tracts in the prospect include Alaminos Canyon Block 647 (OCS G36105); Block 690 (OCS G34770); Block 691, Block 734 (OCS G34776) and Block 735 (OCS G34777).

6 ***Rockcliff Energy*** announced results from a Panola County (RRC Dist. 6), Texas, well in Carthage Field. The company's #2H Pope Jean West HV Unit B flowed 18.433 MMcf of gas and 1.061 Mbbl of water per day from Haynesville Shale. It was drilled to 22,626 ft (11,427 ft true vertical) in Alford Bissel Survey, A-89, and is producing from perforations between 11,841 and 22,445 ft. Tested on a 26/64-in. choke, the flowing casing pressure was 6,486 psi. Rockcliff's headquarters are in Houston.

7 ***Comstock Oil & Gas*** completed a De Soto Parish, La., Haynesville venture. The #1-Alt Shirey A 17-8 was tested flowing 28.797 MMcf of gas with 933 bbl of water per day from perforations between 11,840 and 21,725 ft. The well is in Section 20-13n-16w and was drilled to 23,000 with a true vertical depth of 13,000 ft. The Belle Bower Field completion was tested on a 30/64-in. choke, and the flowing casing pressure was 6,789 psi. Comstock is based in Frisco, Texas.

8 In Caddo Parish, La., ***Comstock Oil & Gas*** reported results from two Haynesville Shale discoveries. The Greenwood-Waskom Field completions were drilled from a pad in Section 2-16n-16w. The #1-Alt Hebert 2-11 HC was drilled to 20,960 ft with a true vertical depth of 11,182 ft. It was tested on a 34/64-in. choke flowing 32.125 MMcf of gas and 1.724 Mbbl of water per day. Production is from perforations at 11,445-20,850 ft., and the flowing casing pressure was 6,380 psi. The offsetting #2-Alt Hebert 2-11 HC was drilled to 16,909 ft, and the true vertical depth is 11,253 ft. The well flowed 22.07 MMcf of gas and 1.695 Mbbl of water daily, and production is from perforations between 11,343 ft and 16,793 ft. Tested on a 30/64-in. choke, the flowing casing pressure was 6,403 psi.



9 In Bossier Parish, La., ***GEP Haynesville LLC*** announced a Haynesville Shale completion in Sligo Field. The #2-Alt KHL Minerals 16-21H initially flowed 25.074 MMcf of gas and 861 bbl of water per day from a fracture-treated zone at 11,261-18,096 ft. Tested on a 30/64-in. choke, the flowing casing pressure was 6,191 psi. The horizontal sidetrack was drilled to 18,170 ft (11,141 ft true vertical) in Section 16-17n-12w and bottomed more than 1 mile to the south in Section 21. The original hole was junked and abandoned at 4,605 ft. GEP is based in The Woodlands, Texas.

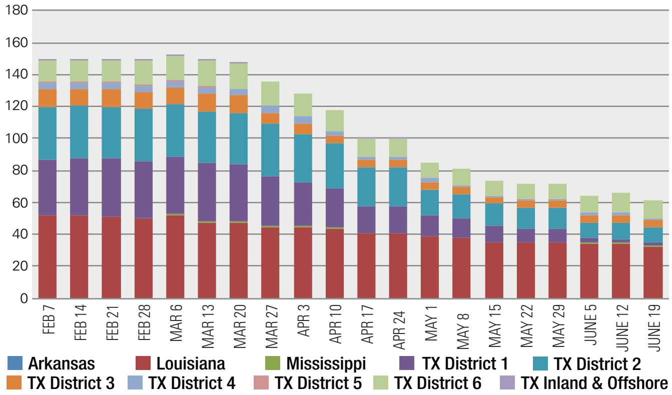
10 IHS Markit reported that ***Comstock Resources*** completed a Haynesville Shale well on the banks of Lake Bistineau in Webster Parish, La. The #1 Lindsay 36-25HZ, which extends Lake Bistineau Field into Webster Parish, was drilled in Section 36-17n-10w. It bottomed about 2 miles to the north in Section 25. The total depth is 21,274 ft, and the true vertical depth is 13,706 ft. It flowed 29.684 MMcf of gas and 893 bbl of water per day from an acid- and fracture-treated zone at 12,245-21,210 ft. Gauged on a 30/64-in. choke, the flowing casing pressure was 7,905 psi.

11 ***Beacon Offshore Energy*** has spud a development Mississippi Canyon Block 427 test south of La Femme Field. The #3SS OCS G31498 is in the southwestern portion of the block. La Femme Field was initially developed by ***LLOG Exploration*** in 2017 but is now majority owned by Houston-based Beacon. Reservoir production comes from three active wells. Field recovery totals 4.4 MMbbl of crude/condensate and 4.6 Bcf of gas from Miocene at 11,780-12,252 ft and 12,970-13,190 ft as well as a deeper Miocene zone at 19,280-19,340 ft. Just north of La Femme Field is ***BP***'s Kepler Field (Block 383), another Miocene oil reservoir.

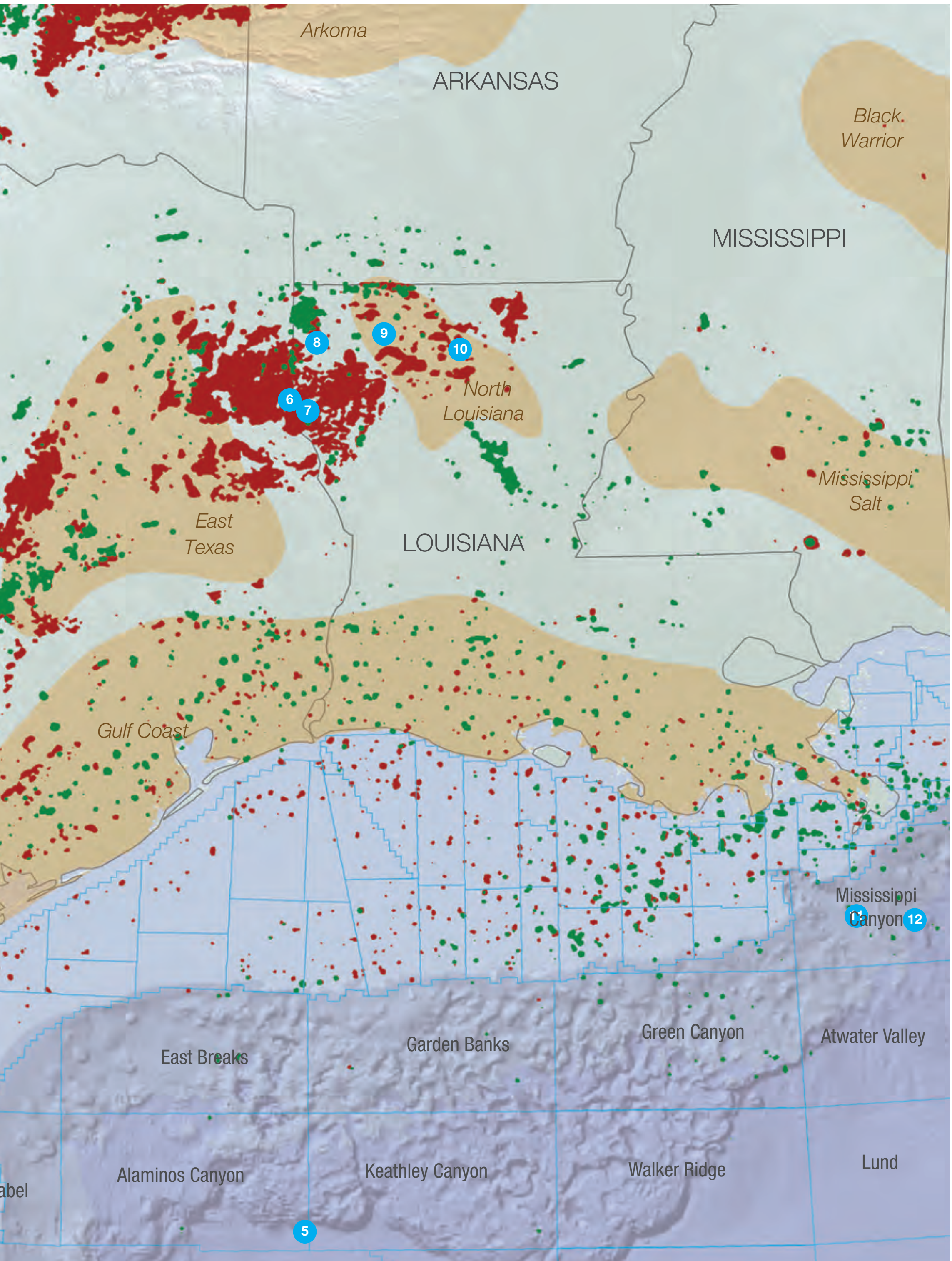
12 On ***BP***'s Galapagos Deep prospect on Mississippi Canyon Block 518, the London-based company is under way at #1 OCS G35828. According to the prospect's exploration plan, as many as six tests could be drilled on Block 518. Water depth in the area is 6,379 ft. The company has drilled numerous discoveries and brought several projects online, with activity centered around the company's Na Kika hub facility on Block 474. Fields adjacent to the Galapagos Deep prospect, Santiago and Isabela, make up BP's Galapagos development. Production from the fields comes from Miocene at 18,200-20,200 ft. BP remains operator of Isabela Field and ***Fieldwood Energy*** now owns Santiago Field.

Gulf Coast Rig Count

Feb. 7, 2020-June 19, 2020



Source: Baker Hughes Co.



MIDCONTINENT & PERMIAN BASIN

1 An Eddy County, N.M., discovery by ***Devon Energy Corp.*** produced 3.858 Mbbl of oil, 5.548 MMcf of gas and 3.233 Mbbl of water per day from Bone Spring. The #231H Maldives 15-27 Federal Com was drilled in Section 15-23s-31e and is in James Ranch Field. The 25,627-ft well has a true vertical depth of 10,222 ft, and it bottomed in Section 27. Production is from perforations between 10,388 and 25,604 ft. Devon is based in Oklahoma City.

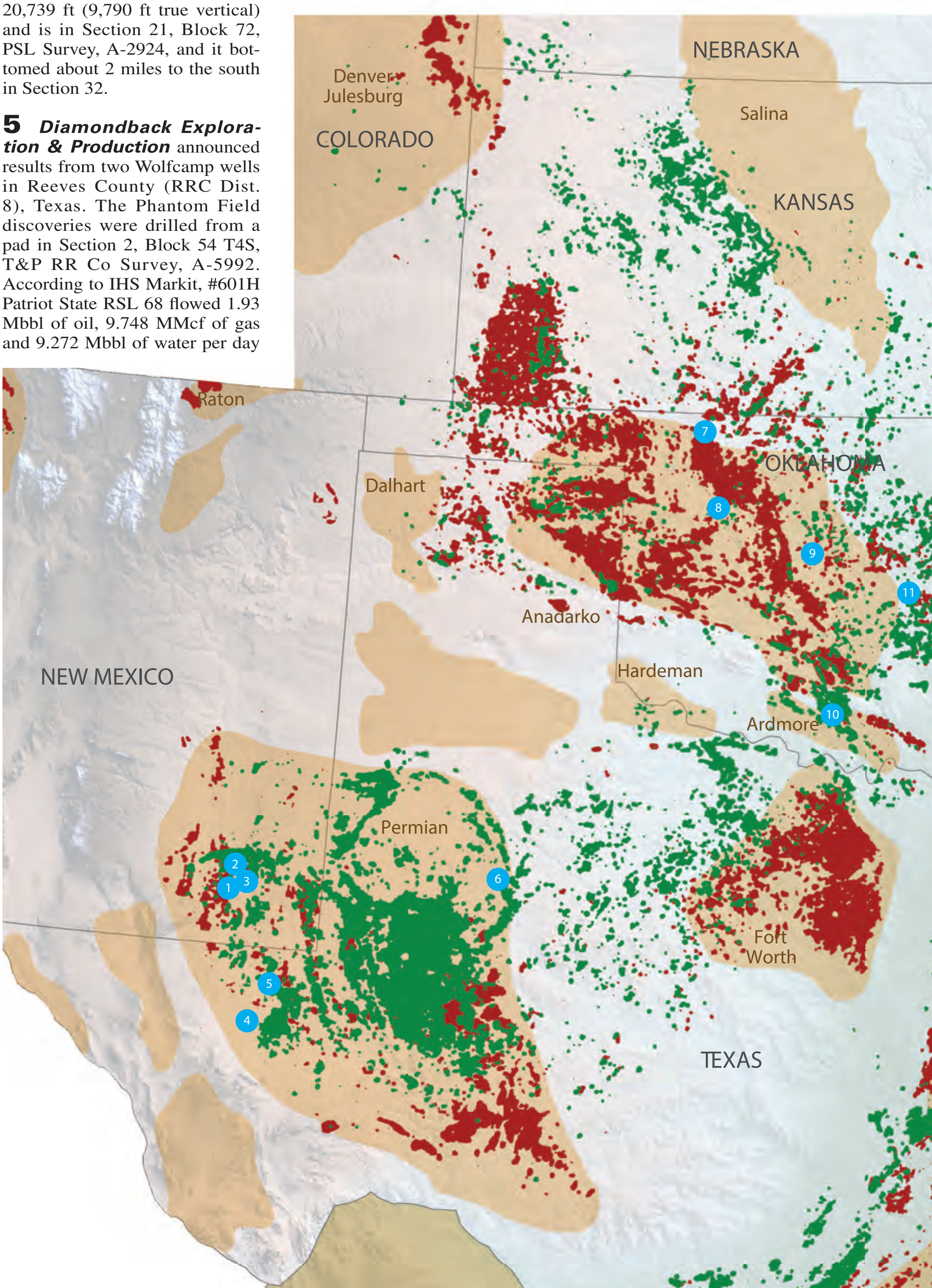
2 Two Eddy County, N.M., Wolfcamp wells were completed by ***Oxy USA*** in Purple Sage Field. The ventures were drilled from a pad in Section 33-23s-31e. The #177H Sterling Silver MDP1 33-4 Federal Com was drilled to 22,091 ft with a true vertical depth of 11,747 ft. It was tested flowing 3.231 Mbbl of oil with 6.171 MMcf of gas and 6.171 Mbbl of water per day from perforations at 11,878-21,980 ft after 42-stage fracturing. The #178H Sterling Silver MDP1 33-4 Federal Com produced 5.369 Mbbl of oil, 7.976 MMcf of gas and 5.367 Mbbl of water per day after 54-stage fracturing. It was drilled to 21,318 ft, and the true vertical depth is 10,779 ft. Oxy USA is based in Houston.

3 ***Devon Energy Corp.*** completed two Wolfcamp discoveries in Eddy County, N.M., in Ingle Wells Field. The #611H Tomb Raider 12-1 Federal was drilled to 21,962 ft (11,797 ft true vertical). It was tested after 50-stage fracturing flowing 4.022 Mbbl of oil, 11.475 MMcf of gas and 7.658 Mbbl of water per day. It was drilled in Section 12-23s-31e, and production is from perforations between 11,983 and 21,826 ft. About 1 mile to the north in nearby Section 1, #732H Tomb Raider 1-12 FED initially flowed 2.775 Mbbl of oil, 8.568 MMcf of gas and 5.418 bbl of water per day from perforations at 12,443-20,962 ft. It was drilled to 21.126 ft, 12,082 ft true vertical and tested after 43-stage fracturing.

4 A Phantom Field well in the Delaware Basin was completed by ***Luxe Operating LLC***. The Reeves County (RRC Dist. 8), Texas, well, #1H Michters State 21-26-32 Unit, produced 3.619 MMcf of gas, 585 bbl of 44.9-degree-gravity oil and 5.068 Mbbl of water daily from fracture-stimulated Wolfcamp perforations at 10,003-19,384 ft. Tested on a 1-in. choke, the flowing casing pressure was 808 psi, and the shut-in casing pressure was 1,070 psi. It was drilled to 20,739 ft (9,790 ft true vertical) and is in Section 21, Block 72, PSL Survey, A-2924, and it bottomed about 2 miles to the south in Section 32.

5 ***Diamondback Exploration & Production*** announced results from two Wolfcamp wells in Reeves County (RRC Dist. 8), Texas. The Phantom Field discoveries were drilled from a pad in Section 2, Block 54 T4S, T&P RR Co Survey, A-5992. According to IHS Markit, #601H Patriot State RSL 68 flowed 1.93 Mbbl of oil, 9.748 MMcf of gas and 9.272 Mbbl of water per day from acid- and fracture-treated perforations at 11,482-17,374 ft. The flowing casing pressure was 2,039 psi during testing on a 1-in. choke. It was drilled to 17,480 ft, 10,860 ft true vertical, and bottomed within 1.5 miles to the northeast in Section 68, R.S. Johnson Survey, A-3988. The offsetting and parallel #701H Patriot State RSL 68 produced 1.205 Mbbl of crude, 6.334 MMcf of gas and 8.731 Mbbl from perforations at 11,301-16,853 ft. Gauged on a 1-in. choke, flowing casing pressure was 1,624 psi. The lateral was drilled to 16,970 ft (11,115 ft true vertical) out of an 8,930-ft pilot hole. Diamondback's headquarters are in Oklahoma City.

6 In Howard County (RRC Dist. 8), Texas, two horizontal Midland Basin-Wolfcamp discoveries were reported by ***Bayswater Operating Co***. The ventures were drilled from a pad in Section 5, Block 30 T1N, T&P Survey, A-226. The parallel laterals bottomed about 2 miles to the southeast in Section 8. The #4W HW Wonderful Life 5-8 pumped 932 bbl of 38.6-degree-gravity crude, 514 Mcf of gas and 2.854 Mbbl of water per day from fracture-treated perforations at 6,748-16,808 ft. The Spraberry



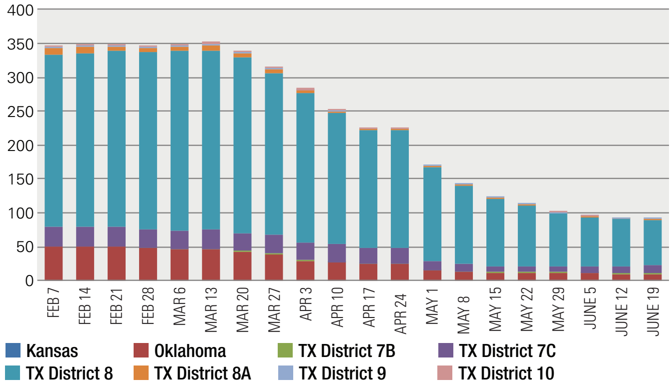
Trend well was drilled to 16,890 ft (6,636 ft true vertical). The offsetting #1W HW Bandolero 5-8 flowed at a daily rate of 959 bbl of 43.2-degree-gravity oil, 824 Mcf of gas and 2.185 Mbbl of water. Acid- and fracture-stimulated perforations are at 8,537-17,954 ft in Wolfcamp. It was drilled to 18,037 ft, and the true vertical depth is 7,975 ft. Bayswater Operating is based in Denver.

7 IHS Markit announced that Oklahoma City-based ***BCE-Mach LLC*** has completed a second Mississippian Lime well from a pad in Oklahoma's Avard Northwest Field. The Woods County discovery, #2H Hester 9-27-17, was tested on gas lift flowing 120 bbl of 25-degree-gravity crude, 1.306 MMcf of gas and 1.772 Mbbl of water per day. The Anadarko Basin well was completed in an openhole acid- and fracture-treated zone at 6,155-10,995 ft. The horizontal oil well was drilled in Section 17-27n-17w and bottomed about 1 mile to the north-northeast in Section 9. Drilled to 10,995 ft, the true vertical depth is 5,689 ft.

8 A Mississippian discovery was completed in Dewey County Okla., by ***Tapstone Energy LLC***. The Seiling Northeast Field well, #2H Deena 15/10-19-17, is in Section 22-19n-17w. It was tested flowing 94 bbl of 41-degree-gravity oil, with 4.116 MMcf of gas and 1,62 Mbbl of water per day. The venture was drilled to 21,187 ft, and the true vertical depth is 19,293 ft. It was tested on a 46/64-n. choke, and the flowing tubing pressure was 883 psi. Tapstone is based in Oklahoma City.

Midcontinent & Permian Basin Rig Count

Feb. 7, 2020-June 19, 2020

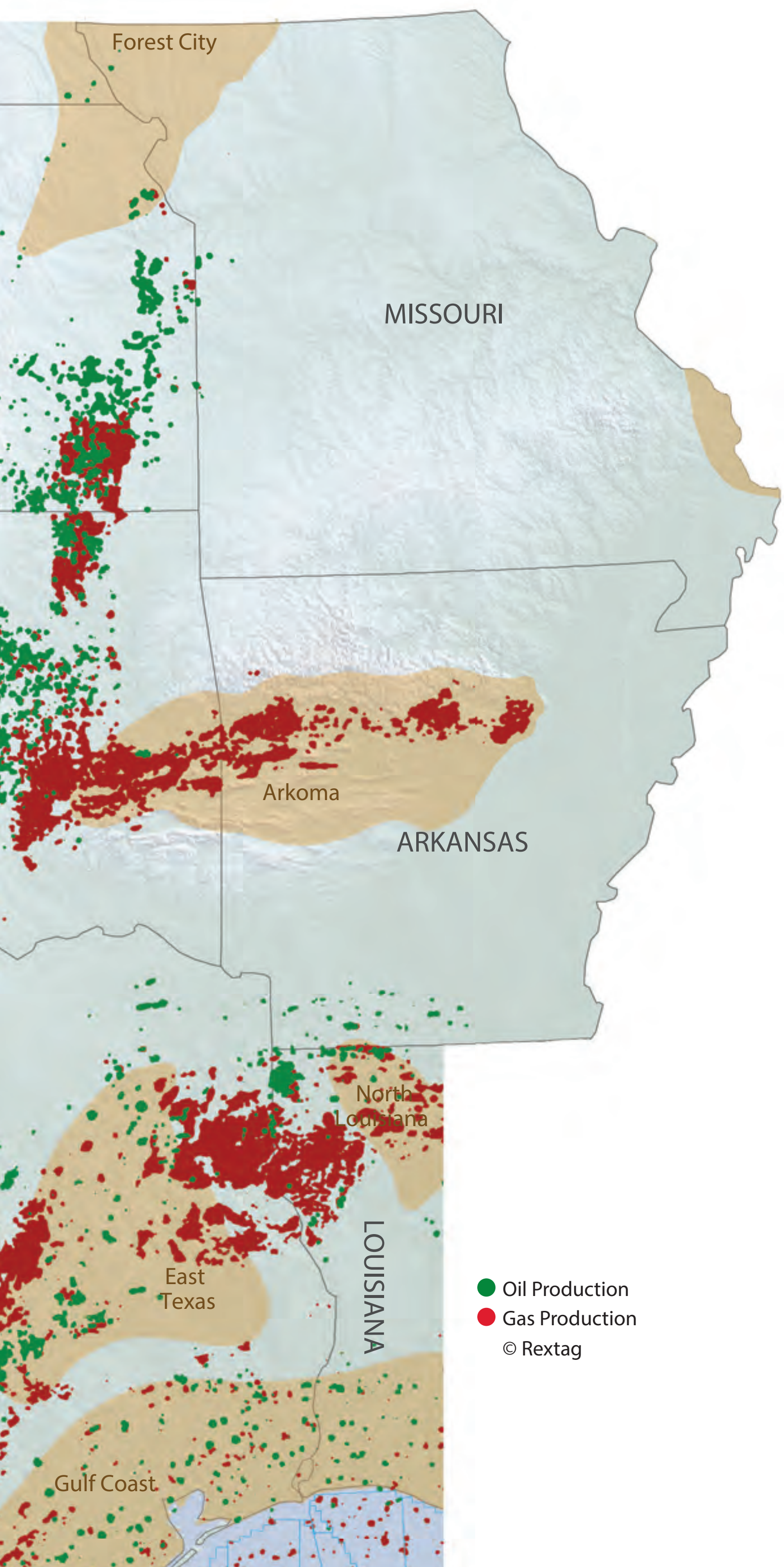


Source: Baker Hughes Co.

9 A Mississippi Lime discovery was announced by ***Camino Natural Resources*** in Canadian County, Okla. The #1MXH Johnny Bench 1108 11-14 is in Union City Field and was drilled in Section 11-11n-8w. It produced 323 bbl of 52-degree-gravity condensate, 4.211 MMcf of gas and 2.539 Mbbl of water per day from a perforated zone at 10,854-18,388 ft. Drilled to 18,458 ft (11,068 ft true vertical), it was tested on a 32/64-in. choke, and the flowing tubing pressure was 2,118 psi. Camino's headquarters are in Denver.

10 ***Blue Devil Exploration LLC*** has completed a horizontal Marietta Basin well in Oklahoma's Jefferson County. The Cornish West Field well, #1H-8 Wilson, was tested pumping 156 bbl of 27-degree-gravity crude and 1.676 Mbbl of water per day. Production is from acid- and fracture-treated perforations in Viola. It was drilled to 14,385 ft and is in Section 9-5s-4w. The lateral bottomed within 1.5 miles to the northwest in Section 8-5s-4w with a true vertical depth of 7,497 ft. Blue Devil is based in Tulsa.

11 ***Calyx Energy III LLC***, based in Tulsa, completed three horizontal Arkoma Basin gas producers at a pad in Section 14-8n-12e, Hughes County, Okla. The #2-14-2WH Hamilton flowed 9.359 MMcf of gas and 3.047 Mbbl of water per day from Mayes/Woodford at 5,106-15,163 ft. The perforated interval was acidized and fracture-stimulated, and the flowing tubing pressure was 349 psi. The horizontal Carson Field well was drilled to 12,251 ft (4,501 ft true vertical) and bottomed about 2 miles to the north-northeast in Section 2-8n-12e. The parallel #3-14-2WH Hamilton produced 9.009 MMcf of gas from Mayes/Woodford. It was drilled to 15,538 ft (4,492 ft true vertical) and perforated at 5,062-15,439 ft. The #4-14-2WH Hamilton flowed 9.843 MMcf of gas per day from Woodford perforations at 5,143-15,296 ft and was drilled to 15,395 ft (4,504 ft true vertical).



WESTERN US

1 In Sublette County, Wyo., ***Jonah Energy*** announced results from a Jonah Field discovery in Section 12-29n-108w. The #101X-12 Stud Horse Butte initially flowed 10 bbl of oil, 3.415 Mcf of gas and 233 bbl of water per day. Production is from commingled perforations in Fort Union (9,105-9,821) and Mesaverde (9,865-13,260 ft). It was drilled to 13,652 ft (13,575 ft true vertical) and was fractured in 10 stages. Gauged on a 48/64-in. choke, the shut-in casing pressure was 756 psi. Jonah's headquarters are in Denver.

2 In western Colorado's Garfield County, ***TEP Rocky Mountain*** announced results from two Rulison Field completions in Section 12-6s-94w. The #432-11 Federal RWF was drilled to 9,165 ft with a true vertical depth of 8,741 ft. It was tested after 13-stage fracturing flowing 1.129 MMcf of gas from commingled Williams Fork (5,645-8,284 ft) and Cameo (8,303-8,589 ft). Gauged on a 28/64-in. choke, the flowing tubing pressure was 1,205 psi, and the flowing casing pressure was 1,451 psi. About 25 ft to the north, #443-11 Federal RWF was drilled to a projected depth of 9,272 ft and a projected true vertical depth of 8,693 ft. It was tested after 14-stage fracturing flowing 1.574 Mcf of gas per day from commingled Williams Fork (5,730-8,293 ft) and Cameo (8,311-8,980 ft). It was tested on a 28/64-in. choke with a flowing tubing pressure of 977 psi and a flowing casing pressure of 1,400 psi. Both completions by the Denver-based company are holding for data.

3 A Gallup producer on the Venado Canyon Unit in the San Juan Basin was completed by Denver-based ***DJR Operating***. The well was drilled in Section 12-22n-6w, Sandoval County, N.M. The #203H Venado Canyon Unit initially produced 573 bbl of oil, 1.05 MMcf of gas and 264 bbl of water per day. Production is from a lateral in Gallup drilled to the northwest to 11,812 ft (5,368 ft true vertical) at a bottom-hole location in Section 11-22n-6w. It was tested following 39-stage fracturing between 5,950 and 11,739 ft. The Venado Canyon Unit now contains six horizontal Gallup producers and has produced 376.2 Mbbl of oil, 1.22 Bcf of gas from Gallup since ***Encana Corp.*** completed the unit's first well in early 2015.

4 ***Impact Exploration & Production LLC*** has completed a horizontal Frontier producer in Wyoming's Fly Draw Field from a multiwell pad in northwestern Converse County. The #447 5-32H Baccus was tested flowing 1.024 Mbbl of 42-degree-gravity crude, 1.221 MMcf of gas and 2.453 Mbbl of water per day. Acid- and fracture-treated perforations are at 13,113-23,076 ft. The well was drilled in Section 8-37n-75w to 23,173 ft. The horizontal leg bottomed 2 miles to the north in Section 32-37n-75w, and the true vertical depth is 12,869 ft. Impact is based in Denver.

5 A Shannon producer was completed in Converse County, Wyo., by ***Samson Resources Co***. The discovery, #4075-3625 1SH Spearhead Federal, was drilled in Section 35-40n-75w and was tested flowing 1.466 Mbbl of 39-degree-gravity oil, 703 Mcf of gas and 1.277 Mbbl of water per day. The Hornbuckle Field well was drilled to 21,010 ft with a true vertical depth of 10,906 ft, and production is from perforations at 11,162-20,903 ft. Gauged on a 22/64-in. choke, the flowing tubing pressure was 1,513 psi, and the shut-in casing pressure was 2,165 psi. Samson's headquarters are in Oklahoma City.

6 ***EOG Resources Inc.*** completed a Campbell County, Wyo., Niobrara discovery. The #2833-02H Telluride was drilled in Section 28-42n-73w to 20,495 ft with a true vertical depth of 10,538 ft. It was tested flowing at a daily rate of 1.199 Mbbl of 57.6-degree-gravity condensate with 1.958 MMcf of gas and 3.08 Mbbl of water after 36-stage fracturing. It was drilled to 20,485 ft, and the true vertical depth is 10,538 ft. Tested on a 22/64-in. choke, the flowing casing pressure was 2,795 psi. Production is from perforations between 10,706 and 20,391 ft. EOG is based in Houston.

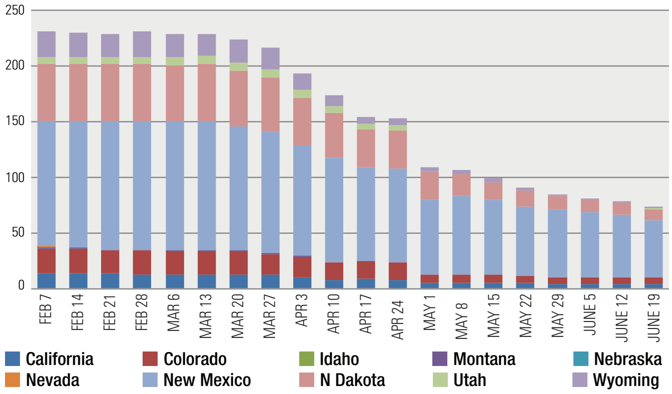
7 According to IHS Markit, a third horizontal Turner sand oil well was completed by ***Devon Energy Corp.*** at a pad in Converse County, Wyo. The #06-313971-1XTUH CWDU T-55 Fed flowed 1.547 Mbbl of 39.5-degree-gravity crude, 1.161 MMcf of gas and 1.030 Mbbl of water per day after 30-stage fracturing. Production is from perforations are at 11,560-21,180 ft. The well was drilled from a surface location in Section 7-38n-71w and bottomed 2 miles to the

north in Section 31-39n-71w. The total depth is 21,378 ft, and the true vertical depth is 10,817 ft. It was tested on a 38/64-in. choke, and the flowing tubing pressure of 435 psi. Devon is based in Oklahoma City.

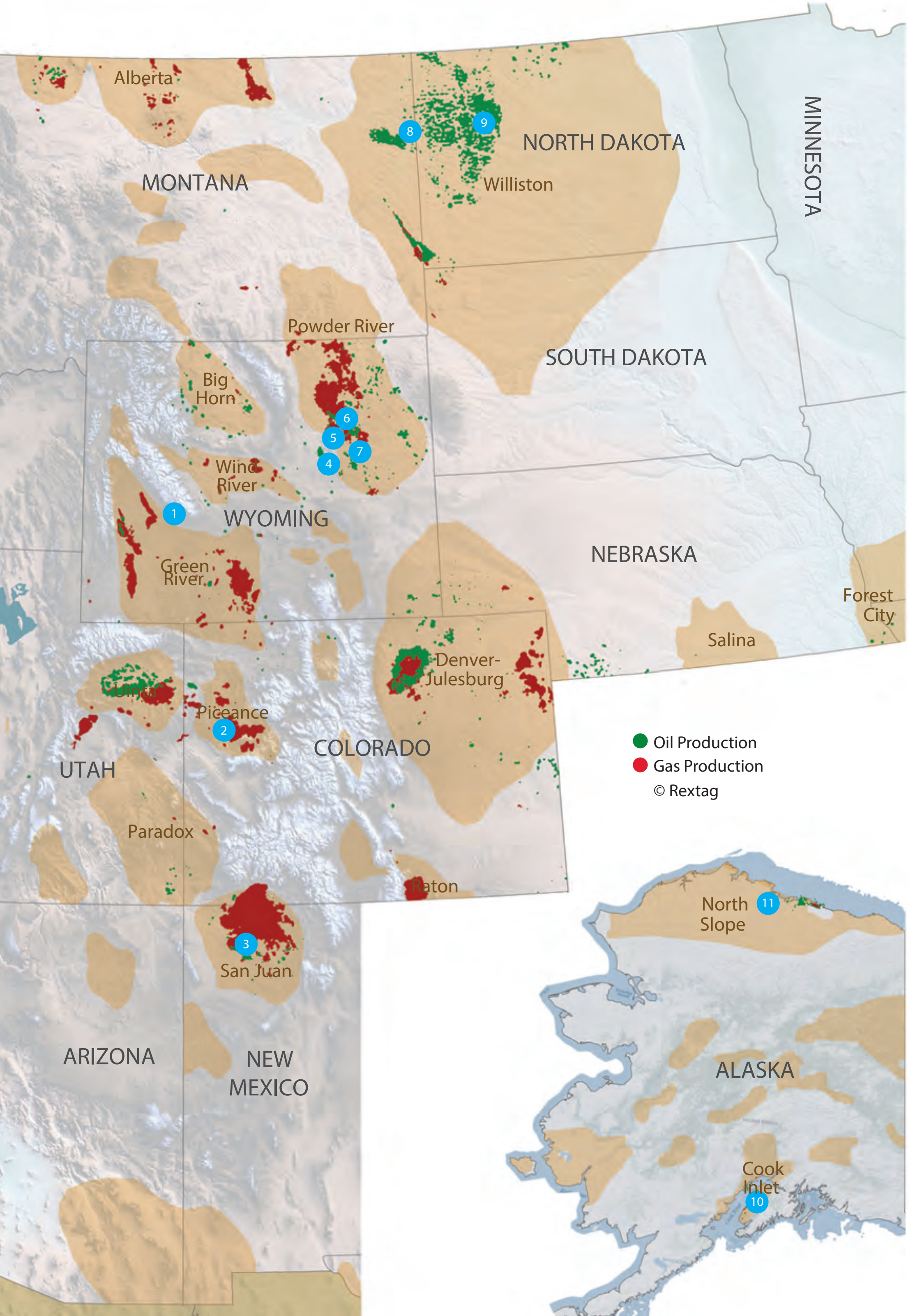
8 Completion details have been released by Houston-based ***Kraken Operating*** on two horizontal Middle Bakken wells drilled from a Nohly South pad in Richland County, Mont. IHS Markit reported that #12-13-1H Lonestar flowed 1.125 Mbbl of oil, 882 Mcf of gas and 2.606 Mbbl of water per day from acid- and fracture-treated perforations at 10,725-20,755 ft. The flowing tubing pressure was 460 psi, and the well was drilled to 20,815 ft (10,303 ft true vertical). The offsetting #12-13-2H Lonestar produced 995 bbl of crude, 712 Mcf of gas and 2.67 Mbbl of water per day. It is producing from acidized and fracture-stimulated perforations at 10,503-19,417 ft. The flowing tubing pressure was gauged at 320 psi, and the venture was drilled to 19,475 ft (10,311 ft true vertical). The parallel laterals for both wells bottomed about 2 miles to the south in Section 13.

Western US Rig Count

Feb. 7, 2020-June 19, 2020



Source: Baker Hughes Co.



9 A Four Bears Field discovery by Houston-based ***Marathon Oil Corp.*** initially flowed 5.946 Mbbl of 41-degree-gravity oil, with 6.185 MMcf of gas and 4.651 Mbbl of water per day from Three Forks. The #12-16TFH Perkins USA is in Section 17-152n-93w in North Dakota's McKenzie County. Drilled to 22,136 ft, the true vertical depth is 10,338 ft, and it was tested after 45-stage fracturing. Production is from fracture-treated perforations between 12,280 and 21,997 ft.

10 On Alaska's Kenai Peninsula, ***Hilcorp Energy*** completed a Ninilchik Field well in Section 7-1s-13w. The #6 Kalotsa Ninilchik Unit initially flowed 2.798 MMcf of gas per day from Tyonek perforations at 5,624-82 ft. The discovery was drilled to 5,745 ft, and the true vertical depth is 3,644 ft. It was tested on an unreported choke size with a flowing casing pressure of 186 psi. Hilcorp's headquarters are in Houston.

11 ***88 Energy*** reported that it hit more than 280 ft of net pay in Seabee, Torok and Kuparuk at an Alaska wildcat on the North Slope. The #1 Charlie is in Section 21-4n-9e in Umiat Meridian. The Project Icewine discovery was directionally drilled to 11,112 ft (11,109 ft true vertical) in Kuparuk. Additional lab work is planned to confirm rock properties and saturations. The well is 1 mile north of ***BP***'s #1 Malguk, an 11,375-ft venture that was abandoned in 1991 despite shows of oil in Seabee. The Charlie prospect is on state lease ADL 393380, 30 miles west of the Franklin Bluffs pad. 88 Energy is based in Perth, Australia.

INTERNATIONAL HIGHLIGHTS

In the International Energy Agency's latest "Oil Market Report," global oil demand for 2020 is expected to fall by 8.1 MMbbl/d, the biggest one-year drop in history. The report also says that there will be a rebound in demand of 5.7 MMbbl/d in 2021.

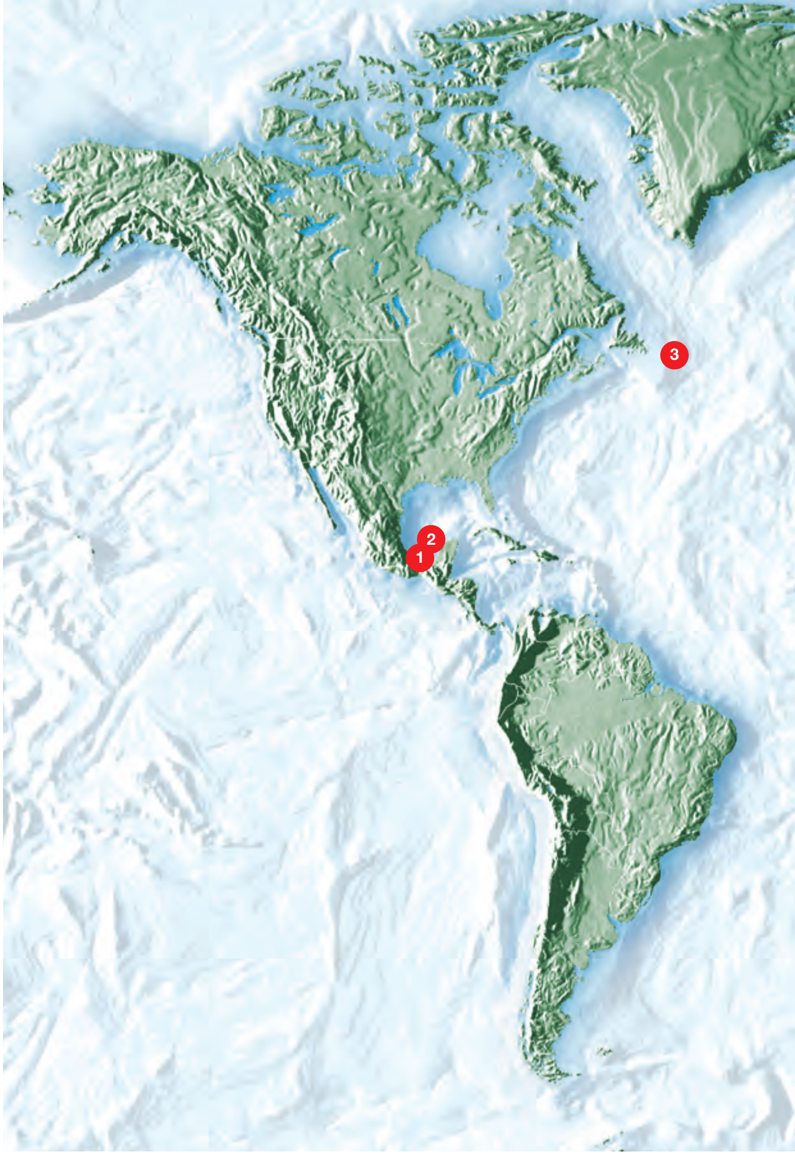
Increased demand in the March-May period provided support for the predictions, noting China's strong exit from the COVID-19 lockdown—April demand is near the levels of April 2019. A strong rebound also took place in India in May, although demand is still well below the levels seen during 2019.

Data from the International Air Transport Association indicate that airline passenger traffic in 2020 will be nearly 55% lower than in 2019 and traffic will be slow through 2021.

The combination of the pandemic and an exceptionally mild winter in the northern hemisphere has put global demand for natural gas on course for its largest annual decline in history. Global gas demand is expected to fall by 4%, (150 Bcm), double the drop following the 2008 global financial crisis.

Gas demand is expected to recover over the next two years, but the pandemic is expected to have a lasting impact on future market developments and growth.

—Larry Prado

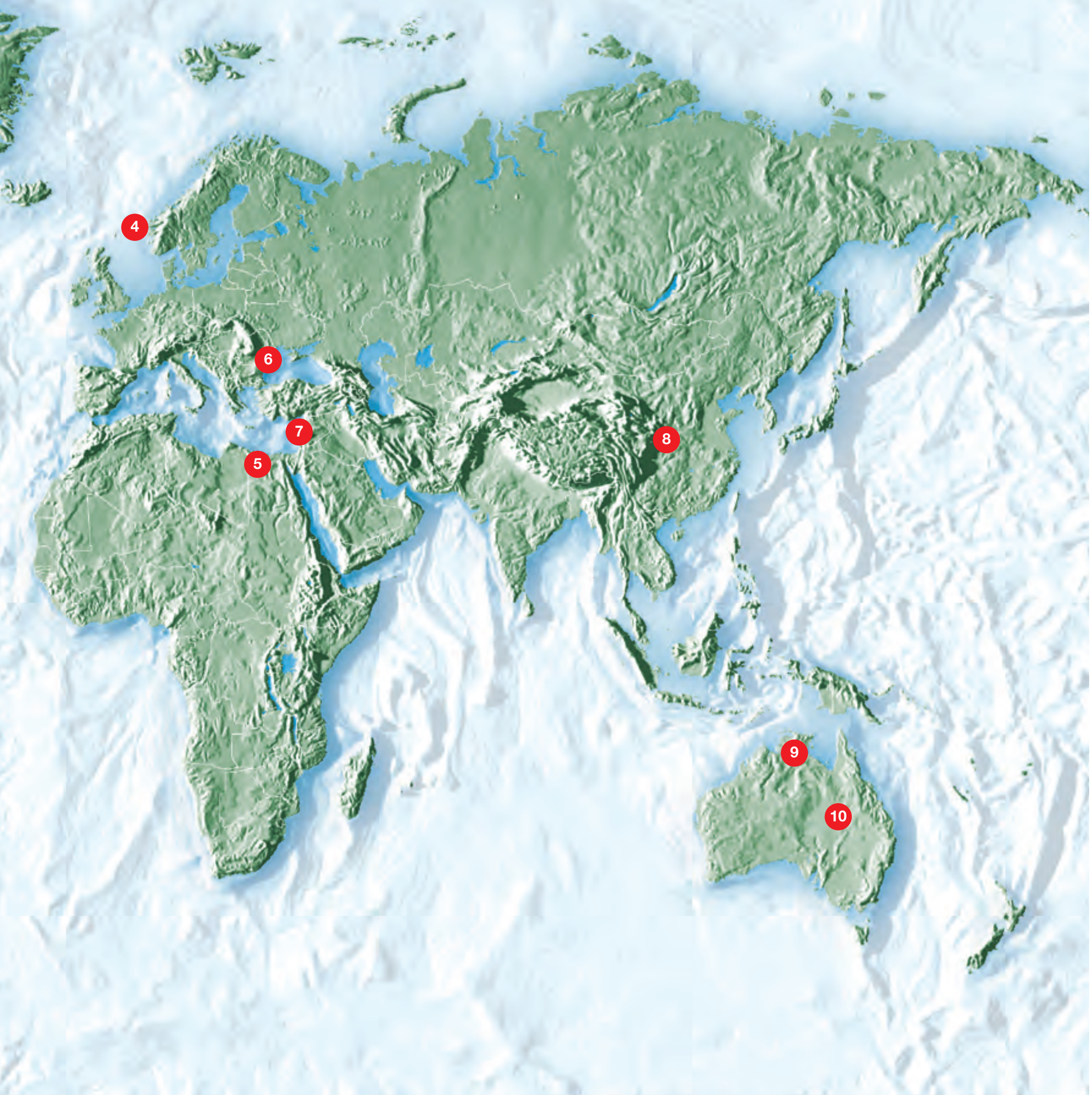


1 Mexico
Plans have been approved to drill two exploration wells on the Uchukil Field in the Mexican sector of the Gulf of Mexico in the Bay of Campeche. The ***Pemex***-operated wells, #1EXP Camatl and #1EXP-Chi, will be in the shallow water field (AE-0148-Uchukil). Area water depth is about 27 m. The Camati prospect is estimated to have 53 MMboe of recoverable hydrocarbons. Pemex is based in Mexico City.

2 Mexico
At the Saasken Exploration Prospect in offshore Mexico's Block 10, Rome-based ***Eni*** announced a new discovery in Cuenca Salina in the Sureste Basin. According to preliminary estimates, the new discovery may contain between 200 and 300 MMbbl of oil in place. The discovery well, #1-Saasken NFW, is the sixth consecutive successful well drilled by Eni in the Sureste Basin. Area water depth is 340 m. The 3,830-m well encountered 80 m of net pay of good quality oil in Lower Pliocene and Upper Miocene sequences with excellent petrophysical properties in the reservoir. Current data indicates that the production capacity of the well is more than 10 Mbbl/d. The Block 10 partners are Eni (operator with a 65% stake), ***Lukoil*** (20%) and ***Capricorn*** (15%). Additional appraisal work is planned.

3 Canada
Equinor announced that exploration well #47-K Cappahayden is an oil discovery in the Bay du Nord region of offshore Canada's Flemish Pass. According to the Stavanger-based company, it is a potentially large oil reservoir. It was drilled in 974 m of water and is about 450 km east of St John's, Newfoundland, in the EL1156 Block. The well is close enough to the Bay du Nord Field to be connected to a proposed floating production, storage and offloading vessel that Equinor hopes to build for the project. If additional drilling indicates a sizeable reservoir, it could improve the economics of the project, which is currently estimated at 300 MMbbl of oil.

4 Norway
Neptune Energy has received a drilling permit for wildcat wells #34/4-15 S and #34/4-15 A in offshore Norway's production license PL 882. Both ventures will be drilled from the Yantai platform. Production license PL 882 was awarded in 2017—these are the first and second exploration wells to be drilled in the license area, which consists of parts of Blocks 33/6 and 34/4 and are about 10 km northwest of Snorre Field. Neptune Energy is the operator and holds 40% interest and partners are ***Concedo*** (20%), ***Petrolia NOCO*** (20%) and ***Idemitsu Petroleum*** (20%). Neptune Energy is based in London.



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5 Egypt

Kuwait Energy announced an oil discovery in the Abu Sennan concession in Egypt's El Salmiyah Field. The #5-El Salmiyah initially flowed 4.1 Mbbl of oil with 18 MMcf of gas per day. The venture encountered hydrocarbons in all of the targeted intervals, totaling more than 120 m. The well was targeting previously undrained reservoirs in the field, with the primary focus on Kharita, and secondary objectives in Abu Roash C and Abu Roash E. According to the Bahrain-based company, testing in Kharita indicated a larger than expected, undrained area updip of the existing wells in the field. The well was drilled to 4,400 m with a true vertical depth of 3,911 m. Additional drilling and testing is planned. Partners include ***United Oil & Gas***, 22%, ***Global Connect Limited***, 25%, and ***Dover Investments Limited***, 28%.

6 Belarus

Belorusneft announced that it discovered two new oil fields, Izbynskoye and North Omelkoviche, in the Khoiniki District of the Gomel region in Belarus. The initial estimate of reserves is 17.7 MMbbl, and the discovery increases the prospects and resource potential of the central structural zone of the Pripyat Trough. According to laboratory studies, oil from the newly discovered fields is light, sweet, low-viscosity oil. The Gomel, Belarus-based company announced that it will study the commercial potential of the central structural zone of the Pripyat Trough with seven exploration wells between 2020 and 2023.

7 Lebanon

Paris-based ***Total*** is planning to drill a second exploratory well in offshore Lebanon Block 9 territorial waters. The first test on nearby Block 4 at #16-1 Byblios did not find hydrocarbons. Block 9 also has a possible reserve in its carbonate limestone formations, similar in geology to offshore Egypt's Zohr Field and Cyprus's Calypso prospect. The Block 9 test is set to start by the end of 2020. Total is the operator of Block 9 with 40% interest in partnership with Eni holding 40% and ***Novatek*** with the remaining 20%.

8 China

PetroChina reported the discovery of a large gas belt with an estimated reserve of more than 35.3 Tcf in southwestern China's Sichuan Province. The gas belt discovery is in Tianbao Township, Daying County. It flowed 43.08 MMcf of gas per day. According to the Beijing-based company, the discovery will increase the province's production capacity, which is currently 529.72 Bcf of gas per year.

9 Australia

Denver-based ***Falcon Oil & Gas*** is nearing completion at appraisal well #117 N2-1H ST2 Kyalla in the Beetaloo Sub-Basin, Northern Territory, Australia, The venture was drilled to test the Lower Kyalla Shale play. The well was drilled to 3,809 m, including a 1,579-m lateral section in Lower Kyalla. Preparatory work, including the drilling of water impact monitoring bores, a new requirement of the Code of Practice for onshore petroleum activities in the Northern Territory, will begin this summer ahead of the next stage of operations. Falcon is currently examining and testing conventional cores, sidewall cores, diagnostic fracture injection testing and results from wireline logging.

10 Australia

Vintage Energy has received approval to fracture-stimulate the #1-Vali ST1 discovery in Queensland's ATP 2021 permit area. The plan currently calls for fracturing five stages in the Patchawarra section and one in the deeper Tirrawarra/Basal Patchawarra section. The gas saturated zones to be fracture stimulated are at depths of between 2,810 m and 3,140 m and will be followed by flow testing. According to the Goodwood, South Australia–based company, the Vali gas discovery has a net 2-C contingent resource of 18.9 Bcf. Vintage is the operator and holds 50% interest. Partners in the prospect are ***Metgasco*** (25%) and ***Bridgeport*** (25%).

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
East Resources Acquisition Co.	NASDAQ: ERESU	Boca Raton, Fla.	$300 million	Commenced IPO of 30 million units at a price of $10 per unit. Each unit issued will consist of one share of Class A common stock and one-half of one warrant, each whole warrant entitling the holder thereof to purchase one share of the Class A common stock at an exercise price of $11.50 per share. Company intends to grant underwriters a 45-day option to purchase up to an additional 4.5 million units. Proceeds will be used for the purpose of entering into a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses in the energy industry in North America. Wells Fargo Securities LLC is sole book-runner.

DEBT

Cheniere Energy Inc.	NYSE American: LNG	Houston	$2.5 billion	Obtained commitments from 17 financial institutions for a three-year delayed draw senior secured term loan. Proceeds from borrowings, along with cash on the balance sheet, are expected to be used to refinance convertible notes.
EQM Midstream Partners LP	NYSE: EQM	Canonsburg, Pa.	$1.6 billion	Priced an upsized offering of $700 million in aggregate principal amount of senior notes due 2025 and $900 million in notes due 2027. Proceeds will be used to partially repay outstanding borrowings under its $3 billion revolving credit facility and for general partnership purposes.
Canadian Natural Resources Ltd.	NYSE: CNQ	Calgary, Alberta	$1.1 billion	Priced unsecured notes due 2025 and 2030. Proceeds will be used primarily to refinance outstanding short-term indebtedness and for general corporate purposes. Any proceeds not utilized immediately may be invested in short-term marketable securities. J.P. Morgan Securities LLC, BofA Securities Inc. and MUFG Securities Americas Inc. are joint book-running managers. BMO Capital Markets Corp., Citigroup Global Markets Inc., RBC Capital Markets LLC, Scotia Capital (USA) Inc., TD Securities (USA) LLC, Mizuho Securities USA LLC, SMBC Nikko Securities America Inc., CIBC World Markets Corp., Wells Fargo Securities LLC, Barclays Capital Inc., Desjardins Securities Inc. and National Bank of Canada Financial Inc. are co-managers.
Comstock Resources Inc.	NYSE: CRK	Frisco, Texas	$500 million	Priced upsized public offering of 9.75% senior notes due 2026 at 90% of par. Proceeds will be used to repay borrowings outstanding under its bank credit facility. BofA Securities, BMO Capital Markets and Wells Fargo Securities are joint lead book-running managers. Fifth Third Securities, Mizuho Securities, Capital One Securities and SOCIETE GENERALE are joint book-running managers. Regions Securities LLC and KeyBanc Capital Markets are joint lead managers. Credit Agricole CIB, Citizens Capital Markets, Barclays, CIT Capital Securities and Goldman Sachs & Co. LLC are co-managers.
DCP Midstream LP	NYSE: DCP	Denver	$500 million	Priced an upsized offering of $500 million aggregate principal amount of 5.625% senior notes due 2027 at a price to the public of 100% of their face value. Proceeds will be used for general partnership purposes, including the repayment of indebtedness under its revolving credit facility and the funding of capex. BofA Securities Inc., Barclays Capital Inc., Wells Fargo Securities LLC, PNC Capital Markets LLC, SMBC Nikko, SunTrust Robinson Humphrey and US Bancorp are joint book-running managers. Regions Securities LLC is co-manager.
Rattler Midstream LP	NASDAQ: RTLR	Midland, Texas	$500 million	Proposed an offering, subject to market conditions and other factors, of senior notes due 2025 to qualified institutional buyers. Proceeds will be loaned to Rattler Midstream Operating LLC to repay outstanding borrowings under its revolving credit facility.
Whistler Pipeline LLC	N/A	Austin, Texas	$325 million	Closed sale of $400 million senior secured bullet notes to Global Infrastructure Partners. Proceeds will be used to fund construction of natural gas pipeline connecting the Permian Basin to the Agua Dulce hub near Corpus Christi, Texas, owned by a consortium consisting of MPLX LP, WhiteWater Midstream and a JV between Stonepeak Infrastructure Partners and West Texas Gas.

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THE GRAND RECKONING

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

During this historic summer, many Americans are sweating through the greatest, most difficult soul-searching exercise ever done. Should we follow recommendations from health authorities or not? Are these accurate, exaggerated or downright erroneous?

Should a statue be taken down? Or should it remain, but be enhanced with new contextual signage that would explain the complex historical choices that make the U.S. so interesting, so inspirational—and at times, so maddening?

The more we learn, the more information and data that come to light, the more uncertain we seem to be. Confusion and passion heat up the public square and blogosphere.

In similar fashion, the past and future of the U.S. oil and gas industry is being assessed from all angles—economics, politics and environment, and upstream, midstream and downstream.

We now hear some prominent CEOs and analysts say that U.S. shales, in retrospect, were an example of exuberant capitalism gone wild, with a mistaken focus on making money for a few but not for most.

Other observers cite negative environmental effects and call for a non-fossil-fuel future. One good sign is that the industry can respond. API announced The Environmental Partnership is booming. It now includes pipelines and has grown from 26 to 83 member companies. Further, an API study shows that methane emissions related to U.S. gas production fell more than 60% between 2011 and 2018, the most impressive such achievement in the world.

Today the largest oil and gas companies increasingly admit to their effects on the climate, have adopted tougher goals to reduce emissions and pledged to find alternatives to increase energy efficiencies.

So, the oil and gas industry has been the culprit at times and sometimes the hero.

What future do we now face? Some CEOs say we will never achieve peak shale oil production again such as we saw in late 2019. Others contend we should not invest to increase oil production, even if we can.

The Energy Information Administration says output from the seven main shale plays is at a two-year low already, with the largest decline seen in the Eagle Ford. It estimated U.S. production fell by 2.5 MMbbl/d from March to May.

For every step backward, there is another forward. On June 26, American GulfCoast Select (AGS) was introduced to great fanfare—some positive news in an otherwise gloomy summer. The reasoning behind this new oil benchmark is good, according to Matt Marshall, who runs the View Group for Aegis Energy, a risk management advisory firm. Platts and Argus have been reporting the new price mechanism. So far, AGS has been running $1.14 to $1.80/bbl below Brent—but more than $2 higher than landlocked WTI.

Furthermore, the new benchmark has a closer economic similarity to Brent—also a waterborne crude—than it does to WTI.

"If these price assessments are calculated based on trades on the water, then these prices would better reflect the economics of international trade," he said. "The price between a U.S. barrel and a Brent barrel would better represent the bid in the market for U.S. supply."

While for now, buyers may be scarce, when U.S. production of light, sweet crude starts to rise again, the U.S. cannot absorb it all. If international buyers take these barrels, they will get them via ocean tanker, so the new waterborne benchmark should provide more transparency as to what each barrel is worth, he said.

Marshall had one caution.

"In our experience, these new price markers only work well if the large physical shops (think BP, Shell, etc.) start using them as the pricing mechanism for their customers. When that happens, there is a reason for the forward markets to develop."

Note that other oil and gas markers introduced on Nymex in the past did not fare too well because the market never became liquid enough for adequate price discovery.

All summerlong, pros and cons about oil and gas have not cooled down. There is Joe Biden's pledge to reduce fossil fuel use, Trump's pledge to build pipelines, pipeliners canceling their projects, court battles and the Saudis' plan to increase oil production starting in August.

Brad Cornell, who teaches climate finance at UCLA, and Branko Terzic, former commissioner with the Federal Energy Regulatory Commission, both managing directors at the Berkeley Research Group, stated in an assessement, "The problem is not one of getting rid of 'bad' fossil fuel production companies ... the fossil fuel providers should be treated as partners who bring unique knowledge to the global effort to manage energy supply and use, not as independent agents who need to be shunned."


Oil and gas is here to stay.
And so are we.
The last few months have challenged everyone in extraordinary ways as a virus temporarily crushed demand. However, the world – as it begins to ramp back up – still needs oil and natural gas, especially the light, sweet crude and abundant, clean-burning natural gas our domestic producers provide. Recently, we joined with others in our industry to introduce a new benchmark named American GulfCoast Select (AGS). It's designed to better reflect the migration of our production and infrastructure to a waterborne marketplace. It's yet another example of the resiliency and agility of American oil and gas companies. At Continental, we know the country and the world need us to do our jobs and to continue to support a thriving export market. We are built to meet all challenges, big and small. You would expect nothing less from America's Oil Champion.
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