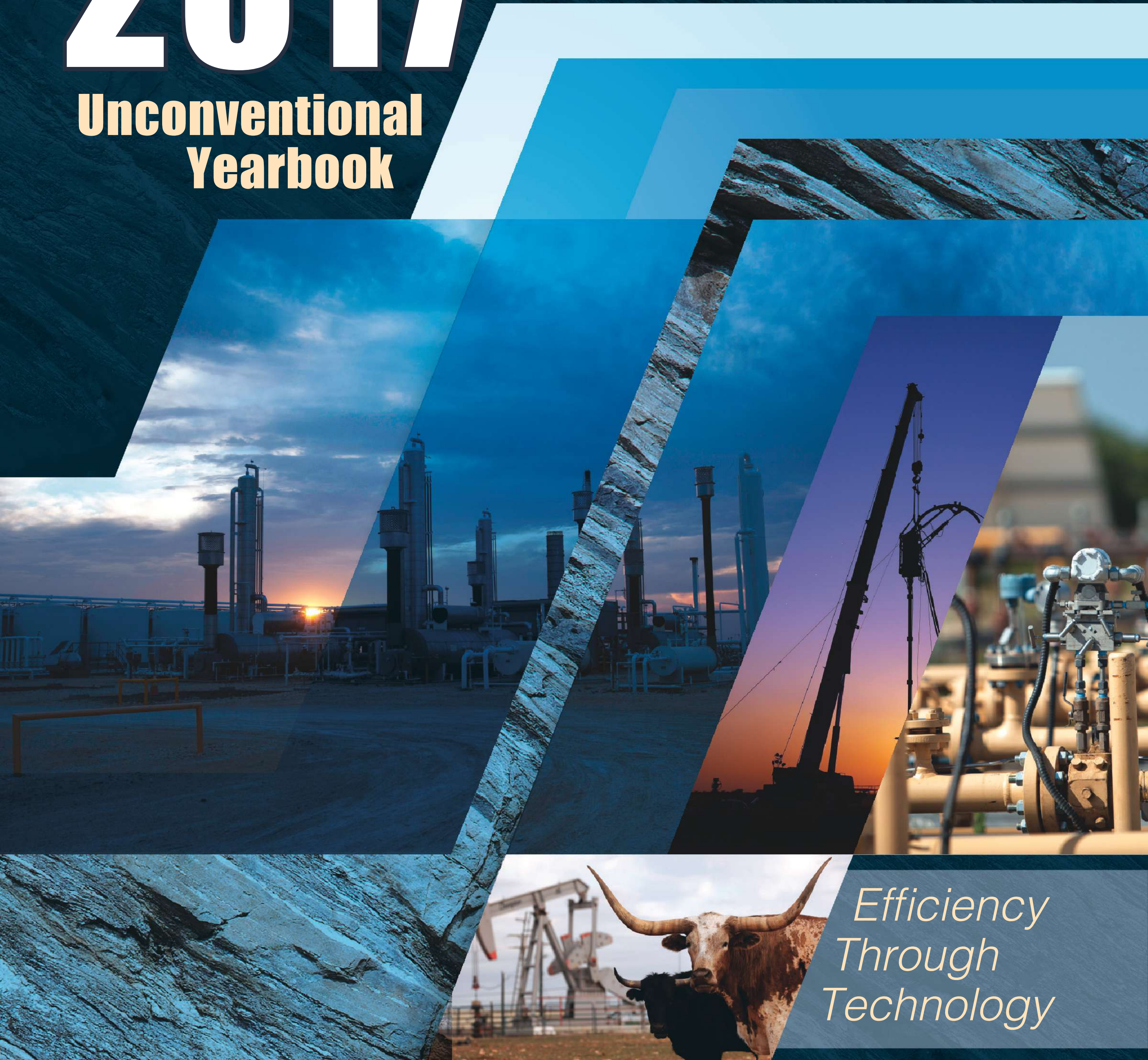
HARTENERGY

2017 Unconventional Yearbook



Efficiency Through Technology

A supplement to:

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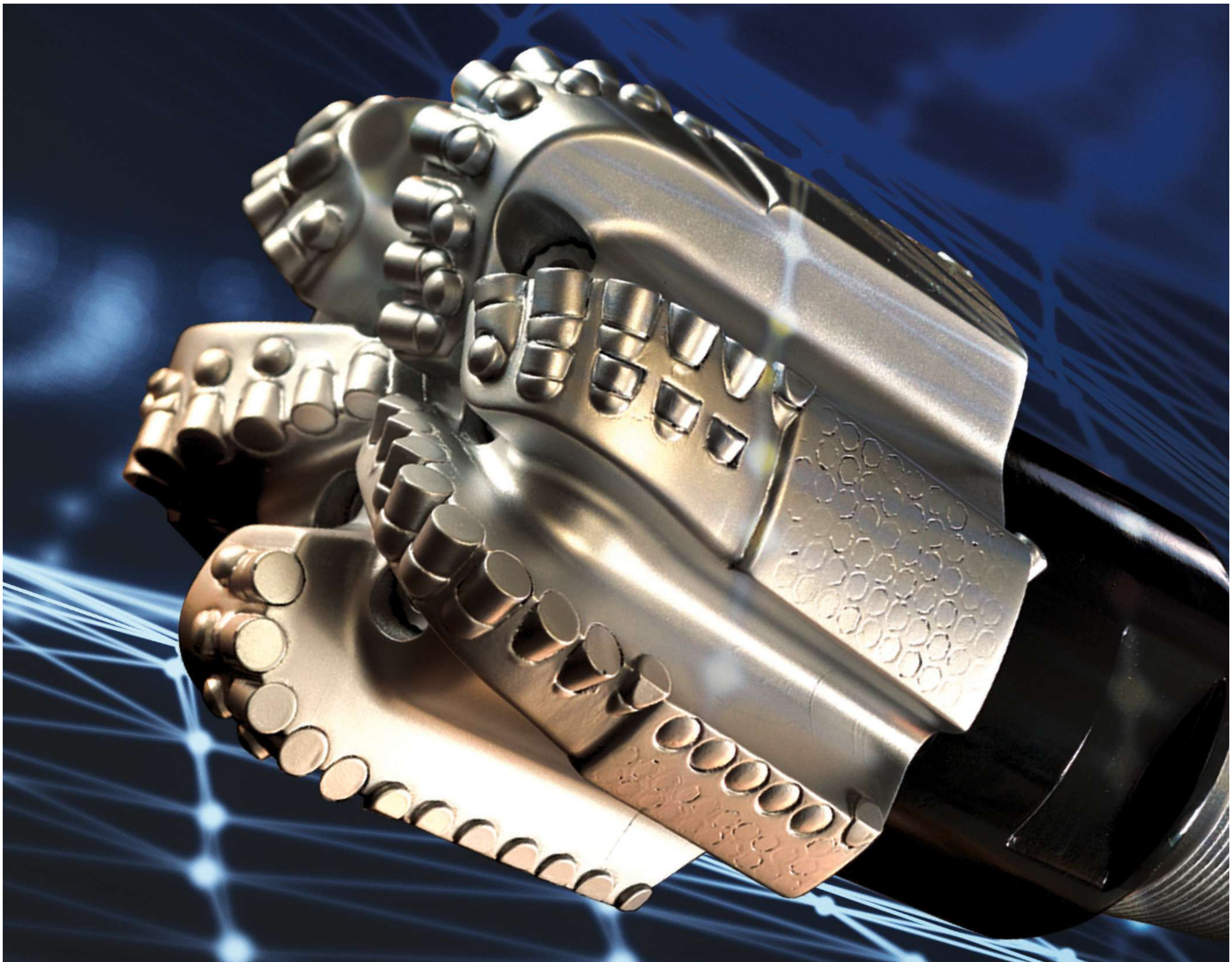

2017 Unconventional Yearbook

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2017 UNCONVENTIONAL YEARBOOK

In an extension of Hart Energy's unconventional resources playbook series, known for its in-depth coverage of the most compelling shale plays in North America, the 2017 Unconventional Yearbook presents the most important facts and figures on the top U.S. resource plays. This seventh in an annual series of yearbooks provides an overview of current activity in the regional plays, profiles of key players, a review of advances in technology, as well as economic analysis and data. Like the playbooks, this yearbook includes a full-color map. To learn more, visit ***ugcenter.com/subscribe***.

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Cover photos, courtesy of Hart Energy's *Oil and Gas Investor*, (clockwise from left): Sanchez Production Partners' central processing facility "D" in the Eagle Ford, photo by Mieko Mahi; Carrizo Oil & Gas Inc.'s coiled tubing operation on Bear Clause Ranch 54H in Lasalle County, Texas, photo by Tom Fox; monitoring production at Sanchez Production Partners' Western Catarina assets in the Eagle Ford Shale, photo by Mieko Mahi; and no mistaking this pumpjack's location in Texas' Permian Basin, photo by Tom Fox.

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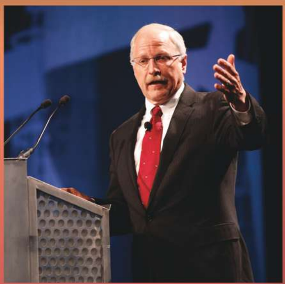

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April 17-18
Austin, TX

MIDSTREAM TEXAS
May 23-24
Midland, TX

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150,00+
Attendees in
10 Years

(Photo by Tom Fox, courtesy of Hart Energy's Oil and Gas Investor*)*

Disruptive Resources

By **Rhonda Duey**, Executive Editor

Unconventional development has been going strong for almost 15 years now. Three experts discuss the amazing transformation the industry has seen during that time.

Every once in a while a new technology or idea comes along that stands the oil and gas industry on its ear. The unconventional revolution has impacted not only North America but the global industry as well since commodity prices dropped due to the U.S.'s ability to increase its production 1 MMb/d in a single year.

In September 2001 *E&P* interviewed Steve Holditch, then a Schlumberger fellow, professor of engineering at Texas A&M and incoming president of the Society of Petroleum Engineers, about the potential for unconventional resources to be commercially developed. His insights were quite prescient. It seemed fitting that the introduction to Hart's 2017 Unconventional Yearbook revisit Holditch as well as unconventional pundits Mike Bahorich and George King to take a look back—and a look forward.

E&P: ***How has our understanding/knowledge about unconventional reservoirs evolved?***

Bahorich: Our thinking has changed substantially in the last decade or so. Years ago I remember fielding a question about the Barnett—would it be the only economic shale play? Of course, this was before liquids and oil in particular were generally thought of as even possible for shale plays.

Also, what we considered a good-sized frack job at that time is absolutely minuscule today. In the early days I asked (Apache's) Canadian vice president to put a big frack on this new shale that we were testing, which became the Horn River Basin. We had the first producing well in the basin, and he said, 'Oh, we put an enormous frack on that.' I looked at it later, and it was tiny.

In terms of what we look for in the subsurface, that has changed as well. We have learned that pressure, fluids and geology are very significant. Overpressure is a significant factor, although it can be more expensive to drill wells in high-pressure areas. And, of course, there is the importance of finding the right fluid mix. Dead oil is not as productive as light volatile oil.

We now realize that 3-D geological models can help better characterize the reservoir and fracture patterns. Companies like Sigma Cubed are doing that very effectively on the service side.

King: Evolution of knowledge, like any other practical science, be it medicine, aircraft development, bridge construction, space exploration, etc., proceeds by field trials, contemplative 'retro-engineering' and retrial—fancy words meaning trial and error. Shales and other unconventional resources have been opened almost exclusively by independent producers, all without research centers or formal research budgets but willing to take a large gamble. The majors came later to buy reserves and improve efficiencies, but after the independents had largely cracked the code by their trial and error methods. The secrecy around this knowledge evolution formed both a competitive edge and a learning debacle as many companies made common mistakes in resource recovery attempts. However, thanks to people movements between companies, new startups and the always-productive networking sessions at presentations or in bars, the lessons

Opposite page: The shale revolution was a result of trial, error and lessons learned and shared.

Operational efficiency has helped shale players tough out low commodity prices.
(Photo courtesy of Cameron)

of technology still made it out into the light of day.

As George Mitchell is said to have remarked, the Barnett was a '17-year overnight success.' We're still advancing, but now on many more fronts. Shale gas recoveries, once as low as 1% to 2% of original gas in place (OGIP) in the 1990s, is now from 20% to more than 40%, depending on the specifics (and understanding) of the individual play (and note that some experiments have recovered more than 50% of OGIP). Recoveries from liquid-rich shales still lag that of gas, probably because many are still insisting on using conventional stimulation and production techniques on unconventional reservoirs. We'll solve this problem, too—it's what we do.

Holditch: The level of understanding the industry has in 2017 compared to 2001 is remarkably better in almost every aspect of oil and gas development. In 2001 many companies were looking at unconventional gas and drilling vertical wells looking for 'sweet spots,' sometimes using 3-D seismic to locate wells. However, most wells were drilled on a pattern to hold acreage, and the sweet spots were found by just drilling more wells. It was also believed that we could mainly produce natural gas from shale reservoirs because crude oil was too viscous to flow from the shale matrix into the fracture and then into the wellbore.

In 2017 most companies developing shale reservoirs are

actively targeting oil in the shale formations and creating their own flow paths from the matrix into the hydraulic fractures by creating a network of fractures and opening natural fractures by pumping 20 to 30 or more large-volume fracture treatments down a long horizontal wellbore.

Companies are also using 3-D seismic and 3-D earth models to better understand the layers in the formations that are the most productive and the layers that control fracture height growth. Companies use the 3-D information to place the horizontal wells into targeted layers. The companies are also using microseismic information to better understand where and how induced fractures grow and interact with the layers.

E&P: ***Was the level of difficulty in recovering resources from unconventional reservoirs greater than the industry predicted or estimated? What has happened between 2001 and now that has surprised you or that you didn't expect?***

Bahorich: Many have been pleasantly surprised by the number of plays that have emerged. Even brilliant people like Mark Papa wondered if there would ever be another Eagle Ford, and if you look at what Mark is now doing in the Delaware Basin, you can argue that area produces returns as good as or better than the Eagle Ford.

I think there were many people that did not think that U.S. oil plays would literally drive the price of oil down, but that's exactly what happened. The industry had a level of success that took people by surprise, and if it didn't take them by surprise, then they sold their oil stocks, so good for them.

King: The most amazing thing about the grave-to-cradle rebirth of the American oil and gas industry was how each of the major challenges was chipped away by a thousand tiny cuts rather than a single huge 'aha' moment. That's really the story of this industry. When given the chance to excel and be rewarded, engineers, scientists and geologists are a formidable force, even if we continually make fun of each other. Was it a surprise that that it worked? No. But I sure crossed my fingers a time or two for luck.

Holditch: It was clear in 2001 that a lot of natural gas was trapped in tight gas sands, coalbed methane and shale reservoirs. Research into the distribution of natural resources clearly shows that we have more than 100 years of natural gas supply in unconventional reservoirs if the gas price is high enough and the infrastructure, such as pipelines and markets, exists near the gas deposits.

As the industry transitioned from drilling vertical wells in gas reservoirs like the Barnett Shale, Marcellus Shale and Haynesville Shale, and as the horizontal well lengths increased, the increase in gas flow rates and ultimate recovery was surprising. I do not believe anyone truly predicted what would happen with gas well productivity during 2001, but as the industry kept drilling and kept innovating, the results just seemed to keep getting better.

Even with the improvements in natural gas recovery in the mid-2000s, I do not think many people thought we could produce oil from these nano-Darcy reservoirs. To me, the most surprising result in the last 15 years is how much oil the industry is producing from the Bakken, the Eagle Ford and in the Permian Basin from shale formations. Many of these formations have long been considered the source rocks. In the 1970s and 1980s everyone knew the source rock for the Austin Chalk Formation was the Eagle Ford. No one that I knew could have predicted the Eagle Ford source rock would turn out to be such a productive reservoir.

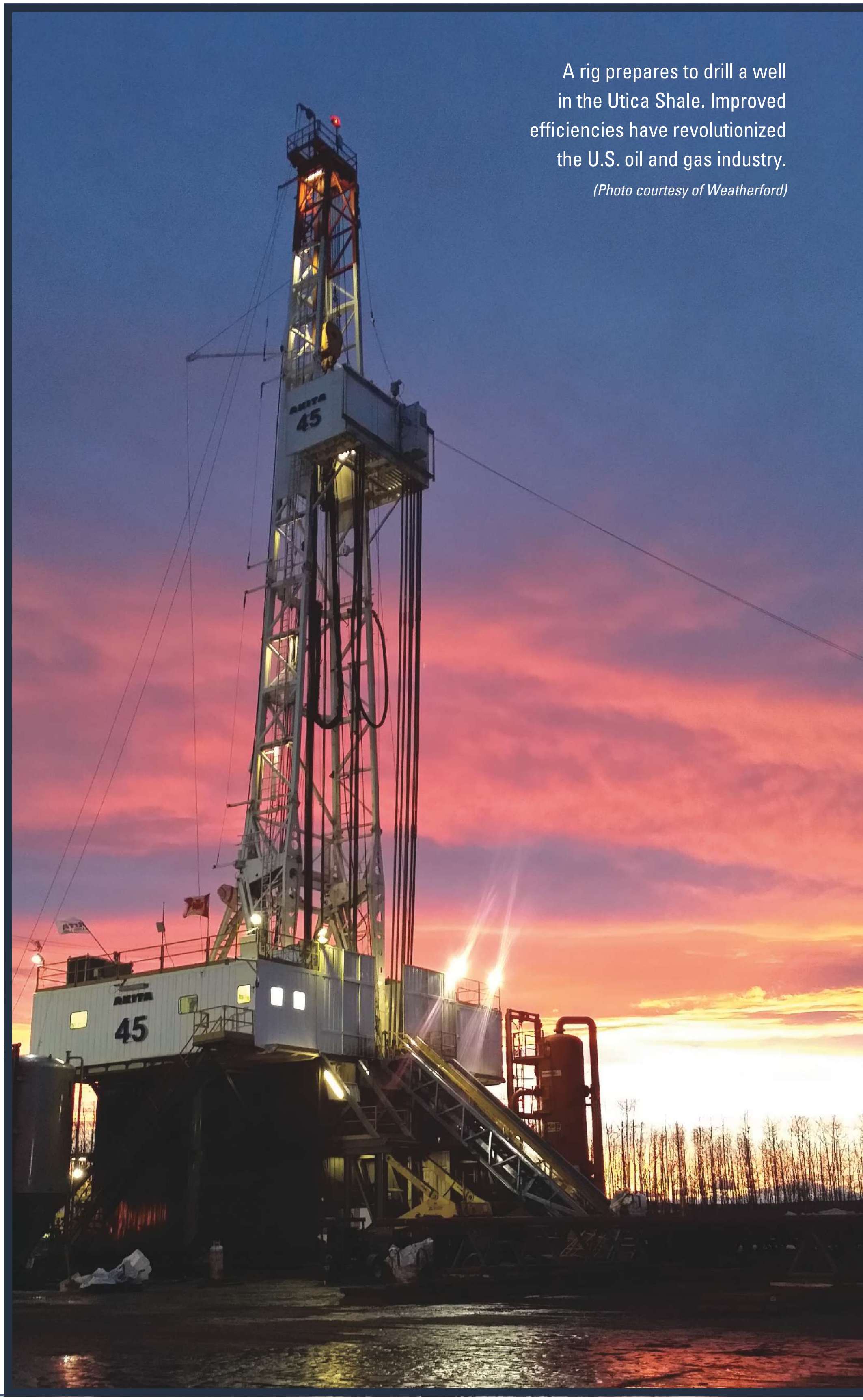
E&P: ***Did you anticipate just how crazy things were going to get in the unconventionals?***

Bahorich: I would say no. With higher prices, U.S. shale production was increasing by nearly 100,000 barrels per month while replacing the decline as well. I did not anticipate that shales would quickly increase supply by millions of barrels per day.

King: I don't think anyone really grasped how successful it could be. We were running full tilt even during early 2008 as the Barnett was literally ballooning at the seams, Fayetteville and Haynesville were coming online and Marcellus was beckoning—and all the while the gas volume in storage was soaring. The craziest thing was that we should have seen the gas surplus coming. We became a victim of our own success and a benefactor to the energy and product-using American industry.

Then the oil shale boom started, and we seemed to quickly forget the lesson we had just learned and literally launched into a frantic race for hydrocarbon liquids. Once again, we became a victim of our own success as the U.S. reversed a long trend of growing energy imports and became the No. 1 producing country, upsetting the apple cart of global market share. Even with this policy- and economics-driven downturn, the U.S. energy future is still solid, and land-based shale wells are here to stay. We are learning again how to be low-cost producers, although now we have the immense foundation of oil and gas resources in the shales—with a vast unexplored field of questions that can do nothing but improve our operations.

Holditch: No, I did not predict how 'crazy' things would get in the development of unconventional reservoirs. However, the U.S. is the hotbed of entrepreneurship in the world. Our culture allows us to develop technology, develop business plans and take risks. So looking back, it is not surprising that hundreds of companies were formed or focused their business on developing shale reservoirs. My guess is some of the companies wish they had not



A rig prepares to drill a well in the Utica Shale. Improved efficiencies have revolutionized the U.S. oil and gas industry.
(Photo courtesy of Weatherford)

grown so fast and/or used less debt for growing their business.

E&P: ***What was the greatest/most difficult obstacle to overcome in recovering resources from unconventional reservoirs?***

Bahorich: Oil recovery factor is still a very substantial issue. Although average recovery from oil has been increasing each year, it remains very small. The current focus has been increasing the volumes of frack sand, water and stages. EOG and others have tried secondary recovery, but success has been limited.

King: The most difficult thing to overcome in nearly any industry is the status quo. The only person that likes change is a wet baby. We fall into a 'rut' of doing things one way and often don't recognize there is always a better way. Once upon a time, changes came slowly. Now a technology may not even get fully developed before a better one is knocking at the window. Slow-downs or slumps are a time to try another approach to get more economic and come out even more economic on the next rebound. Necessity may be a distant relative of invention, but desperation is its true mother.

Holditch: I am not sure there was a single obstacle to overcome but rather a series of obstacles that are interrelated. The key to success has been the ability to drill long horizontal wells and then to fracture-treat the wellbore with 20, 30 or more stages. To drill the long horizontal wells, we had to have improvements in rigs, drillbits, drilling mud, MWD, steel metallurgy and geosteering, to name just a few of the technologies. To fracture-treat these long horizontal wells, we had to build hundreds of new fleets of fracture treatment pumping equipment, develop techniques to isolate stages in the borehole, learn the best fluids to pump and develop new sand mines to keep up with demand.

The biggest obstacle might have been the logistics of organizing all the equipment and people required to support the hectic pace of the past 10 years.

E&P: ***What low-hanging fruit remains for technologists to pick when it comes to unconventional reservoirs?***

Bahorich: There are some very good ideas to further improve recovery factor. It is currently popular to use higher sand and water volumes, fine mesh sizes, less gel and more stages. Some companies have low-hanging fruit because they have not made use of technology that the early adopters have already proven. Artificial lift is still in the early days, and service companies that provide more efficient solutions will make lots of money.

Big data applications are showing promise not only for maintaining equipment but also for exploration, production and reserves. Q.Engineering is a new company that leverages big data to appraise assets and explore for oil and gas. These guys are building tools that stretch the capabilities of an engineer. They can analyze a 500-well acquisition within a few days for pennies on the dollar.

King: The most consistently available (and always ripe) low-hanging fruit is efficiency. Beating suppliers' prices down might help an operator survive (although it isn't a treat for the vendor), but understanding your operations and improving your efficiencies (note that efficiencies is plural) is not only a key to survival but also delivers a stronger economic return in the rebound. Strong leadership in cost control is the hallmark of surviving companies.

Holditch: The obvious target for low-hanging fruit is refracturing, but it is not really that easy to do. Sure, we can pump refracture treatments in existing wells and use particulates to try to divert the stages from one set of perforations to another. However, it is doubtful that a large refracturing campaign would be overwhelmingly profitable. A few wells may produce large increases in production, but most will not. The service companies need to develop new technology to isolate portions of the wellbore to be refractured so that the treatments can be targeted to specific locations. Once such technology is developed, then refracturing could be more

profitable. The key will be developing a 'tool' to isolate part of the wellbore and have it designed so it does not become stuck in the hole because of the proppant.

E&P: Will this unconventional drive eventually spread globally? Despite much talk of it in recent years, the activity internationally has been disappointingly sparse.

Bahorich: I had a discussion with a Pemex executive about the Eagle Ford play at the border. It is a testament to the value of free markets and proper incentives that are needed to help unconventionals expand globally. It is a shame to see countries importing LNG when they have shale gas available locally at a reasonable price.

> "I THINK THE DEVELOPMENT OF OIL AND GAS from shale formations is just beginning."
>
> –*Steve Holditch*

King: The major enabling drivers for shale oil and gas production are 1.) private ownership of minerals; 2.) a free enterprise system; 3.) an innovative workforce with strong, smart management; 4.) efficient, fit-for-purpose locally oriented regulations; and 5.) economies that require inexpensive, reliable and sustainable energy and raw materials. When one or more of these elements are missing, the ability to generate a shale revolution is lessened.

Holditch: There is no doubt in my mind that unconventional reservoirs containing enormous volumes of oil and gas exist in every oil and gas basin in the world. When a basin has produced a lot of oil and gas, it must have source rocks to have generated the oil and gas now trapped in the conventional rocks. In the U.S. we are essentially producing oil and gas from what we have always considered as source rocks. So every oil and gas basin in the world has source rocks that can be produced in the future.

Obviously, the key will be demand, price and infrastructure. The largest obstacle so far has been infrastructure. One has to have the markets, the legal structure, the pipelines/transportation, the rigs, the fracturing equipment and the people who know what they are doing for the successful development of an unconventional reservoir, even after the productivity of the reservoir has been established.

E&P: Where do you think the shale industry will be in another 15 years?

Bahorich: U.S. shales will be much more mature by then. A majority of the U.S. resources will have been discovered and partially developed. Internationally, we will have seen some success by that time, but the U.S. will remain way out front.

King: Probably in transition to the next unconventional energy source but building on a very firm foundation of shale energy resources.

Holditch: As long as the world population continues to increase and the people on planet Earth want a higher standard of living, we will need more energy. Western civilization is becoming more energy-efficient and is using more renewable energy. However, in most of the world there is a lack of energy for improving the standard of living. So I am assuming that the predictions that the demand for energy—and specifically oil and gas—will continue to increase for 40 years or more is a valid view of the future.

Given the assumption of an increase in global demand, then I believe the oil and gas industry will continue to find and develop the supply. If one looks at the 'new discoveries' in conventional reservoirs, it is clear that the oil we will need will not come from new discoveries in conventional reservoirs. The oil the world will need will come from unconventional reservoir development such as shale and even the heavy oil from Canada and Venezuela. However, I think the development of oil and gas from shale formations is just beginning, both in North America and elsewhere in the world. Never underestimate the entrepreneurial nature of those in the oil and gas business. ■

(Photo courtesy of Apache Corp.)

Rig Count, Oil Price Hit Bottom in 2016, Slow Rebound in Activity

By **Scott Weeden**, Contributing Editor

Fiscal discipline, reduced D&C costs and continued innovation are the mantras for companies working to survive the downturn.

Editor's note: Data are current as of Nov. 1, 2016.

With more than 100 bankruptcies of oil and gas companies since the beginning of 2015 and many operators selling assets to pay down debt, the industry had little margin for error.

The West Texas Intermediate oil price was hovering slightly more than $48 around Halloween, which could be pretty scary if oil prices decline again. With the forward curve above $60 operators were hedging production through 2016 and into 2017. That gave the companies some added financial flexibility for capital spending.

The Permian Basin remained the most active U.S. play with 212 rigs drilling, according to the Oct. 28 Baker Hughes rig count. Oil-rich shale plays lead the active rig counts: Cana-Woodford, 41 rigs; Eagle Ford, 33 rigs; and Williston Basin, 35 rigs. The Marcellus with 36 rigs and the Haynesville with 20 rigs are the leading gas-rich shales.

In preparation for 2017 operators were completing their inventories of drilled but uncompleted wells (DUCs). The cash flow from these wells could allow them to fund their drilling and completion activity as well as bolt-on acquisitions to create contiguous leases for longer laterals.

"We're preparing ourselves to maximize the benefits of the upturn," said Cesar Alvarez, head, Eagle Ford asset for Statoil, at the DUG Eagle Ford Conference on Sept. 13.

The biggest source of optimism in the plays was the number of companies that were planning to add drilling rigs during fourth-quarter 2016. Of course the caveat was that rigs will be added if the price of oil remains fairly steady in the $50 range.

Companies were becoming pure-play operators. Hart Energy reviewed U.S. unconventional operators with many multibillion acquisitions even in the downturn.

Anadarko Petroleum Corp.

- **Drilling program targeted Delaware Basin**
- **346,000 gross acres in the Eagle Ford**

The Southern and Appalachia Region for Anadarko Petroleum includes the Delaware Basin in West Texas, the Eagle Ford for South Texas, the Haynesville in East Texas and northern Louisiana and the Marcellus in Pennsylvania.

For its 2015 drilling program in the Delaware Basin Anadarko Petroleum targeted the Wolfcamp, Second Bone Spring and the Avalon Shale. Anadarko drilled 80 operated wells and participated in 49 unoperated wells. The company continued its delineation program, running eight rigs to further its understanding of both the vertical and areal potential across its 600,000-gross-acre position.

In the Delaware Basin the company is continuing to optimize spacing and completion design and test stacked oil potential. The company identified thousands of potential drilling locations in the Wolfcamp formation that are expected to provide future activity in the basin.

The company had Eagle Ford acreage of about 346,000 gross acres. In 2015, the company averaged four drilling rigs, drilled 183 wells, completed 179 wells and brought 201 wells online.

Opposite page: Apache drilled 19 wells on its 307,000 contiguous acres in its Alpine High play in the southern Delaware Basin in Reeves County, Texas.

In 2015 Anadarko drilled 24 operated horizontal wells with a one-rig program in the Eaglebine Shale. *(Photo courtesy of Anadarko Petroleum)*

In the Maverick Basin, the company brought 40 Eagle Ford wells online in second-quarter 2016 by capitalizing on existing infrastructure.

Anadarko held 156,000 gross acres in the Eaglebine Shale in southeast Texas, most of which was held by existing Austin Chalk production. In 2015 Anadarko continued to delineate and develop this acreage by drilling 24 operated horizontal wells with a one-rig program.

In its third-quarter 2016 report, the company said it signed an agreement to sell its Carthage Field (Haynesville) assets in East Texas for more than $1 billion.

The company also focused on its 223,000 gross acres in the Haynesville Shale. The company averaged 3.5 operated rigs and drilled 39 wells in the Haynesville and Cotton Valley formations.

The company holds 625,000 gross acres in the Marcellus Shale. In 2015 Anadarko drilled one operated horizontal well and participated in the drilling of 18 nonoperated horizontal wells.

In the DJ Basin, costs improved from the first quarter with drilling days reduced by 15% and lease operating expenses lowered to $1.29/boe, a 15% savings.

Antero Resources Corp.

- **Acquired 55,000 net acres in the Marcellus in 2016**
- **Completed 22 horizontal Marcellus wells**

On June 9, 2016, Antero Resources Corp. signed a definitive agreement with a third party to acquire approximately 55,000 net acres in the core of the Marcellus Shale for $450 million and was working with another party toward signing a definitive agreement, adding 13,000 net acres and about 3 MMcfe/d of net production to the acquisition for an additional $108 million.

The acquisition includes undeveloped properties primarily in Wetzel, Tyler and Doddridge counties, W. Va.


Sand Box
Sand Box
Sand Box
Sand Box

Antero estimated the undeveloped properties included 5.1 Tcfe of unaudited Marcellus 3P reserves plus 2.2 Tcf of dry Utica resource potential. The acquisition added 625 identified 3P locations.

The lateral length of the new or enhanced identified 3P locations averaged 9,300 ft. Current drilling and completion costs have declined to $900,000 per 1,000 ft of lateral in the Marcellus and $1.04 million per 1,000 ft of lateral in the Utica, each for a 9,000-ft lateral.

In second-quarter 2016 Antero completed and placed online 22 horizontal Marcellus wells with an average lateral length of 9,200 ft, according to a July 14 press report. The company was currently operating six drilling rigs and four completion crews in the Marcellus Shale play.

Antero completed and placed online nine horizontal Utica wells during second-quarter 2016 with an average lateral length of 8,400 ft. Of the nine wells completed five have been online for more than 30 days and had an average restricted 30-day rate of 16 MMcfe/d, while rejecting ethane (13% liquids). The company was operating one drilling rig and one completion crew in the Utica Shale play.

In the Utica, drilling days from spud to final rig release during the second quarter were reduced from 31 days in 2015 to 16 days in 2016. Stages completed per day increased from 3.7 to 4.4 stages.

Apache Corp.

- **Announced Alpine High discovery in September 2016**
- **39% of 2016 capital program allocated to Permian Basin**

When Apache Corp announced its Alpine High discovery in the southern Delaware Basin on Sept. 7, the company's capital budget was turned upside down. The discovery was mainly in Reeves County and contained an estimated 75 Tcf of natural gas and 3 Bbbl of oil.

Alpine High has 4,000 ft to 5,000 ft of stacked pay in the Bone Spring, Wolfcamp, Pennsylvanian, Barnett and Woodford formations, according to a Sept. 7 press release.

This is the culmination of more than two years of work. John Christmann IV, Apache's CEO and president, said, "We have thousands of low-risk locations in the Woodford and Barnett formations alone. We [will be] further delineating what we believe will be a significant number of oil-prone locations in the Pennsylvanian, Wolfcamp and Bone Spring."

The company adjusted its capital program in conjunction with the second-quarter 2016 results and allocated 39% of its 2016 capital program to the Permian Basin.

Apache's 2016 capital guidance was increased to about $2 billion, with more than 25% of its spending dedicated to the Alpine High play. The company expected to run a minimum retention program on its 307,000 contiguous net acres, consisting of 60 to 80 wells per year in the Woodford and Barnett formations only.

In 2017 the company planned to increase development activity in the Midland and Delaware basins while maintaining its budget based on conservative price assumptions, according to a presentation at Barclays CEO Energy-Power Conference on Sept. 7. Apache will fund its Woodford/South Central Oklahoma Oil Province (SCOOP), Montney and Duvernay activities as oil price and cash flows enable.

In the Woodford-SCOOP, the company placed on production two gross-operated wells, including the Truman 3-28H, which achieved a 30-day average rate of about 1,800 boe/d from a 4,400-ft lateral.

In the Midland Basin, Northwest Shelf and Central Basin Platform, the company placed on production 16 gross operated wells. The company added a rig in the Midland Basin.

BHP Billiton Ltd.

- **Eagle Ford is company's largest play**
- **93,000 net acres in the Permian**

With about 252,000 net acres, the Eagle Ford is BHP Billiton's largest play currently. "Although we refer to it as our gem right now, particularly in the Black Hawk Field in Karnes County, our real long view is in the Permian, where we think the Permian has just been touched," said Jon Krome, transformation executive and head of continuous improvement for BHP, at the DUG Eagle Ford Conference Sept. 14.

The company operated about 500 wells in the Eagle Ford in DeWitt, Karnes, McMullen and LaSalle counties. The company's net working interest was about 64%.

In 2012 BHP was running 42 rigs. In 2016 Krome noted, "We have one or two rigs operating in Karnes and DeWitt counties. Our own work has diminished greatly because of the lower oil prices.

"In the end we believe we're well positioned for success in the Eagle Ford, where we are one of the bigger producers, and we want to stay that way. We've made some great progress in safely reducing costs. We are not satisfied yet. There is more to come. We want to get really, really profitable in a low-price environment," he continued.

"In shale we take a look at the unit cost. We did reduce our unit costs substantially in 2015 as well as our drilling costs in the prior two years by about 40% per year for each of those," he explained.

BHP's acreage in the Permian Basin consisted of 93,000 net acres. Its net working interest was about 91%.

In the Haynesville Shale production area BHP had 206,000 net acres with a net working interest of about 37%. Its Fayetteville Shale production operation consisted of 287,000 net acres with an average net working interest of about 22%.

The company's share of production in fiscal year 2016 was 108.9 MMboe, down from 125.7 MMboe, according to BHP's 2016 annual report.

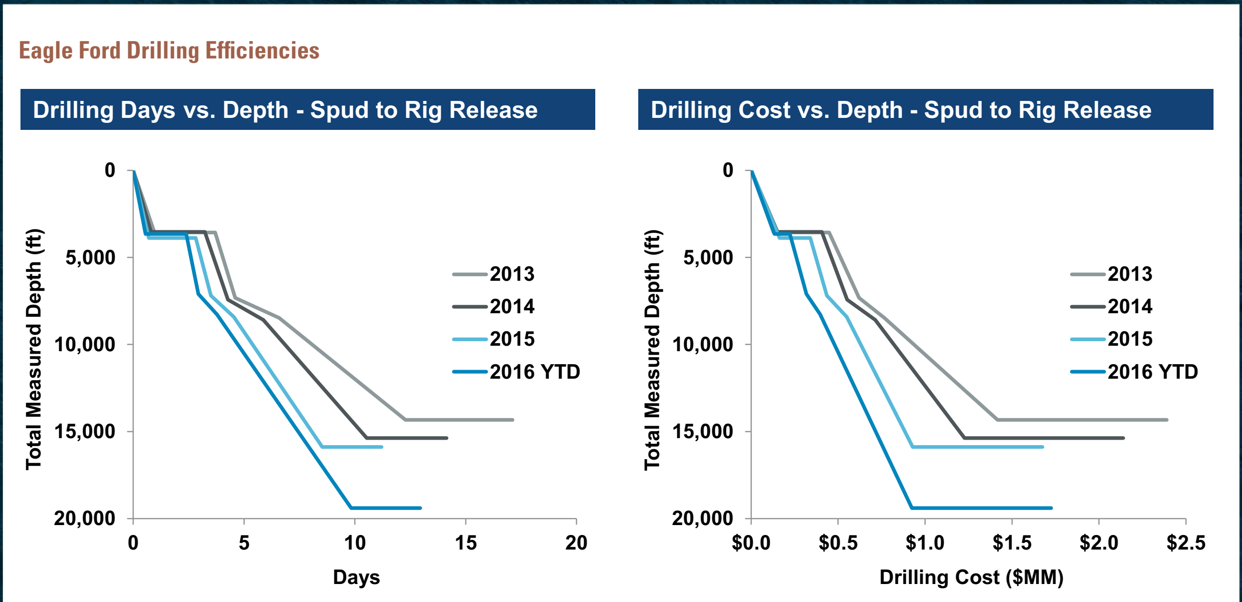
Cabot Oil & Gas Corp.

- **About 1,300 drilling locations in the Eagle Ford**
- **Drilled record lateral of 11,875 ft in 3Q 2016**

In the Eagle Ford Cabot Oil & Gas had about 85,500 net acres with about 75,000 net acres in the Buckhorn and 10,500 net acres in the Presidio. The company had about 1,300 drilling locations, according to a presentation at the Barclays CEO Energy-Power Conference on Sept. 8.

The company was operating one rig with three wells remaining in second-half 2016. Estimated

Cabot optimizes its bottomhole assembly, geosteering, rigs and process improvements to advance lateral drilling efficiency. *(Photo by Tom Fox, courtesy of Hart Energy's Oil and Gas Investor)*



(Source: Cabot Oil & Gas Corp. Nov. 17, 2016, company presentation)

activity for 2016 was about six net wells drilled and about 15 net wells completed. Those activity levels were predicated on meeting all mandatory near-term drilling and operating commitments necessary to maintain current leasehold positions. The company expected to have 14 drilled but uncompleted wells at year-end 2016. There were about 1,300 gross Eagle Ford locations.

Cabot continued to use optimization of its bottomhole assembly, effective geosteering, made-for-purpose rigs and general process improvements for drilling more lateral in less time. Drilling costs per lateral foot have decreased 56% since 2013. The company drilled a record lateral of 11,875 ft in the Eagle Ford in third-quarter 2016.

In the Marcellus Shale Cabot had about 200,000 net acres. For 2016 the company estimated about 26 net wells would be drilled and 55 to 60 net wells completed. In early September the company was operating one drilling rig and two completion crews.

"Cabot's reduction in drilling and completion activity in 2016 is predicated on lower anticipated natural gas price realizations throughout Appalachia as [the company awaits] the in-service of new takeaway capacity," the company said.

Marcellus well costs have declined to $5.7 million for a 7,000-ft lateral, driven by continued efficiency gains and lower service costs.

Success of recent downspacing tests between 700 ft and 800 ft (down from 1,000 ft) had resulted in a 15% increase in location count to about 3,450 net locations.

Carrizo Oil & Gas Inc.

- **1,825 potential drilling locations across all its plays**
- **Drilled and completed 19 Eagle Ford wells in 2Q 2016**

Focused on high-quality, low-cost oil and condensate resource plays, Carrizo Oil and Gas was active in the Eagle Ford Shale (88,000 net acres), Delaware Basin (22,200 net acres), Niobrara Formation (32,600 net acres), Marcellus Shale (19,300 net acres) and Utica Shale (26,300 net acres).

The company had about 1,825 potential drilling locations in all its plays. Carrizo had about 1,040 locations with a breakeven oil price of less than $40, about 445 locations at $40 to $50, about 90

Carrizo has updated drilling plans in the Eagle Ford due to higher oil prices. *(Photo from NeonLight/Shutterstock.com)*

locations at $50 to $60 and about 250 locations at more than $60, according to a presentation at the Wells Fargo West Coast Energy Conference on June 20-21, 2016.

Carrizo's initial capital program for 2016 was about $300 million with $245 million targeted for the Eagle Ford and $35 million in other plays, the company said.

However, with the increase in oil prices, the company changed its spending plans. "Given the improvement in the commodity price outlook since the beginning of the year, Carrizo has elected to eliminate the drilled and completed holidays it had originally scheduled for a portion of fourth-quarter 2016," the company said in its second-quarter 2016 report on Aug. 4.

In the Eagle Ford Shale, Carrizo drilled 19 gross operated wells during second-quarter 2016 and completed 19 gross wells. At the end of the quarter, Carrizo had 33 gross operated Eagle Ford drilled but uncompleted wells. The company was operating two rigs in the Eagle Ford.

According to the second-quarter 2016 report on Aug. 4, drilling and completion capex were $103.3 million.

Carrizo signed a deal Oct. 24 to acquire about 15,000 acres in the Eagle Ford Shale from Sanchez Energy Corp. for $181 million in cash for its Eastern Cotulla assets in LaSalle, Frio and McMullen counties, Texas.

The company temporarily added a second frack crew in the Eagle Ford during the third quarter.

Chesapeake Energy Corp.

- **Exited the Barnett Shale in 2016**
- **Increased ROR in the Eagle Ford to 65%**

As of Aug. 24, Chesapeake Energy Corp. had about $1 billion in proceeds from divestitures and expected to end the year with more than $2 billion in proceeds from asset sales.

The company exited the Barnett Shale by conveying its interests in the operating area to Saddle Barnett Resources LLC, a company backed by First Reserve, according to an Aug. 10 press release.

Properties in the transaction included about 215,000 net developed and undeveloped acres and about 2,800 operated wells.

In the Eagle Ford Chesapeake Energy increased its lateral length to 10,500 ft for its 2016 development program, increasing its rate of return (ROR) to 65%.

"We started the long-lateral technology a few years ago. It has taken a lot of work from our regulatory and land teams to start piecing together these long laterals. We expect the wells we spud in fourth-quarter 2016 to average 10,500 ft in length," said Jason Pigott, executive vice president, operations, Southern Division, Chesapeake, at the DUG Eagle Ford conference on Sept. 13.

As of Sept. 8, the company had 5,260 well locations in the Eagle Ford.

In the Haynesville the company acquired about 70,000 net acres for $87 million. The acreage was primarily within the company's existed operating units, allowing longer laterals. Completion optimization and extended laterals had increased significantly the company's ROR and net present value, according to a presentation at the 2016 Heikkinen Energy Conference on Aug. 24.

Chesapeake had about 1.5 million net acres in the Midcontinent region in Oklahoma in the Oswego, Pennsylvanian Sand, Mississippian and Woodford plays. The company had an inventory of about 850 locations at an ROR of more than 20% in the region.

The company also had operations in the Marcellus and Utica shales.

Chevron Corp.

- **Largest net acraeage holder in the Permian in 2016**
- **Planned 10 rigs in the Permian by year-end 2016**

Chevron Corp. was the largest net acreage holder in the Permian Basin with about 2 million net lease acres. Estimated potentially recoverable reserves were estimated at 9 Bboe in 2016. The company also had acreage in the Marcellus (600,000 acres), Utica (320,000 net acres) and the Antrim Shale in Michigan (370,000 net acres).

Capital spending on Chevron's exploration and development of its approximately 1.5 million net acres of shale and tight resources in the Midland and Delaware basins was focused on horizontal wells with multistage fracture stimulation.

With multiple stacked tight oil zones, the area is poised to deliver significant long-term growth for Chevron. The stacked plays enable efficient development and production from multiple zones and utilization of existing infrastructure.

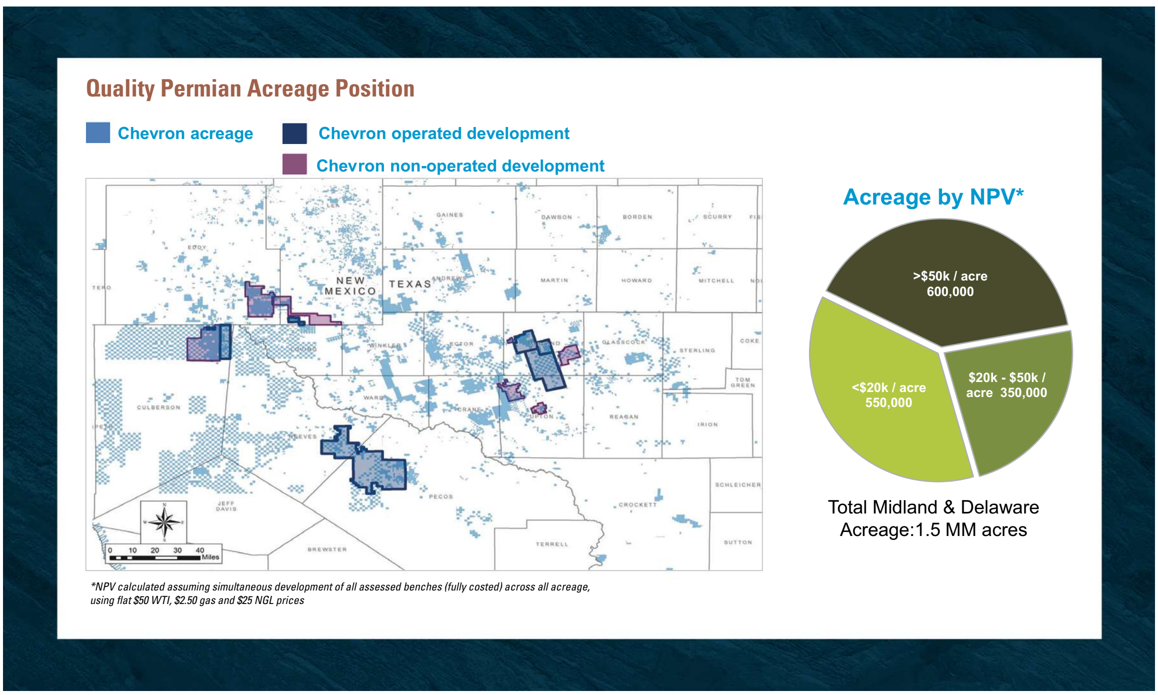
Daily production in the Permian Basin in 2015 averaged 96,000 bbl of crude oil, 320 MMcf of natural gas and 25,000 bbl of NGLs.

Spending was focused on the liquids-rich shale formations in the Permian Basin, the Vaca Muerta Shale in Argentina and the Duvernay Shale in Canada.

The company wanted to grow its Permian business, so it added a rig in August. Chevron expected to have a total of four additional rigs by the end of 2016, bringing the company's total to 10 rigs in the Permian.

"One of our primary benchmarking metrics for our Permian assets is development cost per barrel. Since second quarter [2015], we've reduced our unit development costs by approximately 30%," said Jay Johnson, Chevron's executive vice president, upstream. "We've been able to accelerate our performance improvements by incorporating industry-best practices and applying lessons learned from our joint ventures and contractors."

In its second-quarter 2016 report on July 29, Chevron noted its overall shale and tight-gas production increased by 50,000 bbl/d primarily due to growth in the Midland and Delaware basins in the Permian. The Marcellus in the U.S. Appalachian Basin, Vaca Muerta in Argentina and



(Source: Chevron Corp., November 2016 presentation)

Duvernay and Liard basins in Canada also reflected year-on-year growth.

Unconventional acreage was added in core areas of the Marcellus/Utica trend in the U.S. in 2015 and early 2016.

Cimarex Energy Co.

- **Considers the Wolfcamp its biggest opportunity**
- **$750 million capital investment planned for 2016**

The biggest opportunity for Cimarex Energy was in the Wolfcamp in the Delaware Basin. The company had about 230,000 net acres in the fairway in Culberson and Reeves counties.

About $314 million had been invested by Cimarex in exploration and development in first-half 2016. Capital investment for the year was expected to be $750 million. A portion of the additional capital was to be used to accelerate well completions in both the Permian Basin and the midcontinent region.

ABOUT $314 MILLION HAD BEEN INVESTED BY CIMAREX in exploration and development in first-half 2016. Capital investment for the year was expected to be $750 million.

The company increased its rig count to five rigs for the rest of 2016, according to its second-quarter 2016 report on Aug. 3. Three rigs were operating in the Delaware Basin. As of June 30, Cimarex had 26 gross (17 net) drilled but uncompleted wells in the Delaware Basin.

In the Culberson Wolfcamp area Cimarex had a joint development agreement with Chevron.

Cimarex completed and brought online 13 gross (nine net) wells in the Permian region during the second quarter.

Twenty long-lateral Lower Wolfcamp and 11 Wolfcamp wells are producing. The company had a six-well downspacing pilot with 7,500-ft laterals in a stacked and staggered well pattern. Wells were completed with 2,400 lbs of sand per foot at a well cost of $8.8 million.

Upsized hydraulic fracturing improved Cimarex's Second Bone Spring result in Eddy County, N.M. The frack program was increased from nine to 15 stages. There were 100 locations identified. The first 7,000-ft lateral had an average 30-day peak IP of 2,753 boe/d.

The company had 250 locations on about 13,700 net acres in Lea County, N.M. The company was drilling the Avalon and Leonard shales.

In its midcontinent area Cimarex had stacked targets in the Meramec and Woodford formations. The company had about 115,000 net prospective acres in the Meramec and 135,000 net undeveloped acres in the Woodford.

Concho Resources Inc.

- **17 rigs running in the Permian in 3Q 2016**
- **Avalon Shale is a key focus**

As of Sept. 1, 2016, Concho Resources, a pure-play company in the Permian Basin, planned to drill substantially all wells to about 10,000 ft in lateral length during 2016. The average lateral length for the 13 gross operated wells drilled in the Midland Basin during second-quarter 2016 was about 10,000 ft.

In early September, the company had 17 rigs running in the Permian, which was the largest program in the region. The company had more than 18,000 identified horizontal drilling locations.

The company expected to close in October on the acquisition of about 40,000 net acres to its core position in the Midland Basin from Reliance Energy for about $1.625 billion, according to an Oct. 4 press release. The acquired assets were in Andrews, Martin and Ector counties in Texas. Concho was running one rig on the acquired assets and planned to add a second rig in early 2017.

In its second-quarter 2016 report on Aug. 2, the company said it reduced per lease operating expenses by 20% year-over-year and quarter-over-quarter.

Tim Leach, Concho chairman, CEO and president, said, "Our updated 2016 outlook for annual production growth and lower cash opex

reflects the quality of our assets and our efforts to pursue sustainable efficiencies that enhance full-cycle returns.

"During second-quarter 2016, Concho averaged 13 rigs, compared to 10 rigs in first-quarter 2016. Concho started drilling or participating in a total of 55 gross wells (48 operated wells) and completed 55 gross wells during the second quarter," according to the press release.

The oil-rich Avalon Shale in Lea County, N.M., continued to be a key focus. The company delineated the multizone potential of the Avalon Shale with production data indicating that the upper and lower zones were distinct targets.

During first-half 2016, the company tested completion designs utilizing various sand concentrations.

ConocoPhillips

- **Shifting capital to Lower 48 unconventionals**
- **Has 2.6 million net acres of unconventional holdings**

In its third-quarter 2016 report on Oct. 27, ConocoPhillips said it was shifting capital from major projects to Lower 48 unconventionals.

"As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays," according to the 2015 annual report.

The company had about 2.6 million net acres in the Lower 48 of unconventional holdings in the following areas: 900,000 net acres in the San Juan Basin, 617,000 net acres in the Bakken, 216,000 net acres in the Eagle Ford, 109,000 net acres in the Niobrara, 102,000 net acres in the Permian, 61,000 net acres in the Barnett and 553,000 net acres in other unconventional exploration plays, according to the 2015 annual report.

The majority of ConocoPhillips 2015 onshore production originated from the Eagle Ford, San Juan, Permian and Bakken.

The Eagle Ford continued full-field development in 2015, with the majority of the development program being drilled on multiwell pads. The company operated six rigs on average in 2015, drilling 136 operated wells.

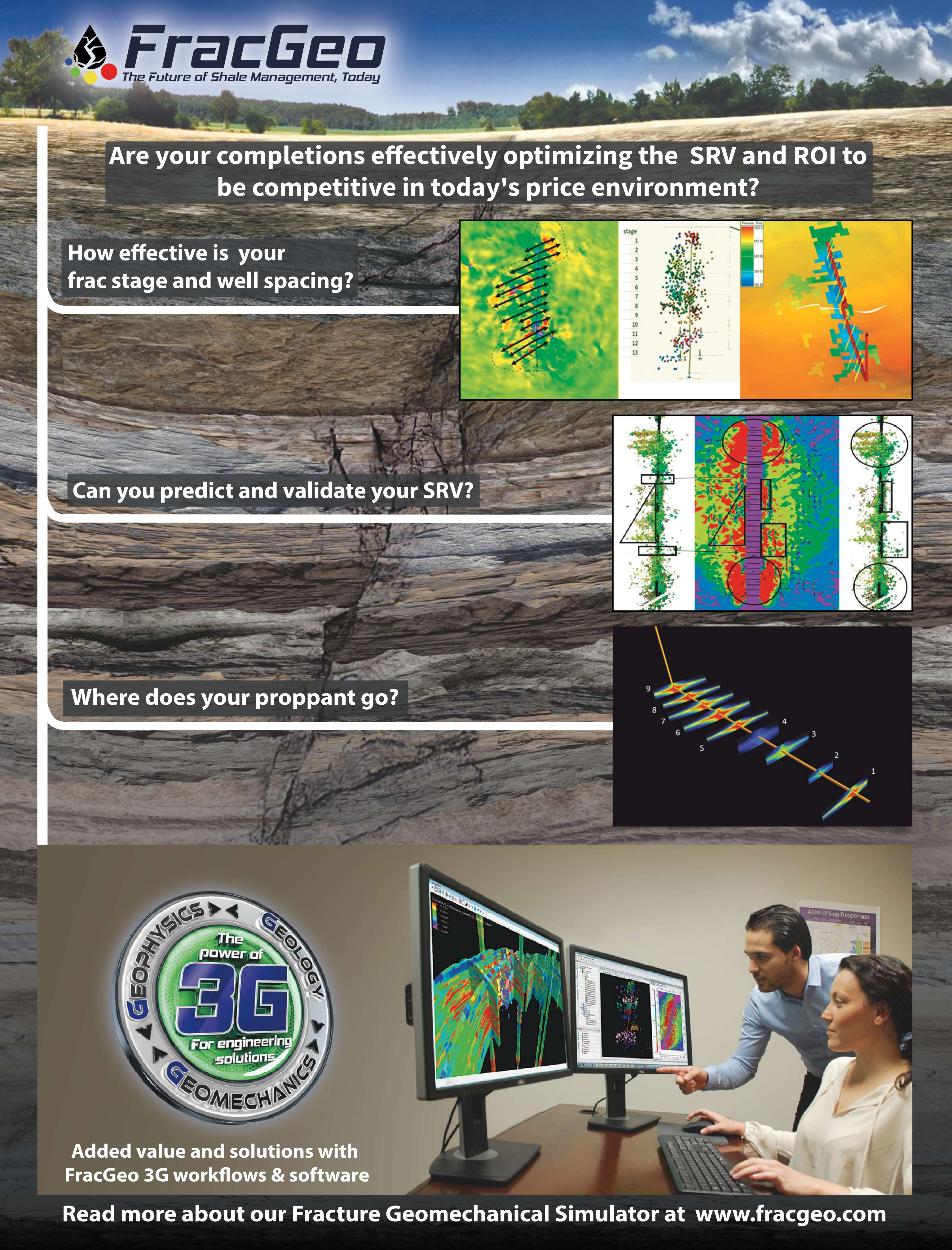
In the Bakken, the company operated five rigs on average throughout the year, drilling 89 operated wells and bringing 128 operated wells online.

The San Juan Basin included significant conventional gas production as well as the majority of its U.S. coalbed methane production.

The Permian Basin is another area where ConocoPhillips was leveraging new technology to improve the ultimate recovery and identify new, unconventional plays across the region.

(Photo courtesy of ConocoPhillips)

In 2015 ConocoPhillips continued full-field development in the Eagle Ford with the majority of the wells drilled on multi-well pads.


FracGeo
The Future of Shale Management, Today
Are your completions effectively optimizing the SRV and ROI to be competitive in today's price environment?
How effective is your frac stage and well spacing?
Can you predict and validate your SRV?
Where does your proppant go?
Geophysics Geology Geomechanics
The power of 3G For engineering solutions
Added value and solutions with FracGeo 3G workflows & software
Read more about our Fracture Geomechanical Simulator at www.fracgeo.com

In fourth-quarter 2015, the company completed the sale of certain non-core assets in East Texas and northern Louisiana and South Texas. Production from the assets sold was 33,000 boe/d, about 6% of the total Lower 48 segment production in 2015.

The company's 2015 drilling activity levels declined relative to 2014 due to reduced capital spending in the low commodity-price environment, according to the 2015 annual report.

Continental Resources Inc.

- **Sold non-strategic Bakken properties in 3Q 2016**
- **Six rigs drilling the STACK; five in the SCOOP**

On Aug. 18, 2016, Continental Resources said it signed a definitive purchase and sale agreement with an undisclosed buyer to sell non-strategic properties in North Dakota and Montana for $222 million. The sale included 68,000 net acres of leasehold primarily in western Williams County, N.D., and 12,000 net acres of leasehold in Roosevelt County, Mont.

"This is our third sale of non-strategic assets this year, with total expected proceeds of more than $600 million. We plan to apply proceeds to reduce debt and strengthen our balance sheet," said Harold Hamm, chairman and CEO in a press release.

In May 2016 the company sold about 132,000 net acres of leasehold in the Washakie Basin in Wyoming for $110 million. On Aug. 3, Continental had signed a definitive purchase and sale agreement with an undisclosed buyer to sell about 29,500 net acres of non-strategic leasehold in the eastern SCOOP play for $281 million.

In early September Continental had six rigs drilling the Sooner Trend, Anadarko Basin, Canadian and Kingfisher counties or "STACK" play in the Meramec and five rigs in the SCOOP Woodford. The company projected more than 1,200 potential net drilling locations in the two formations.

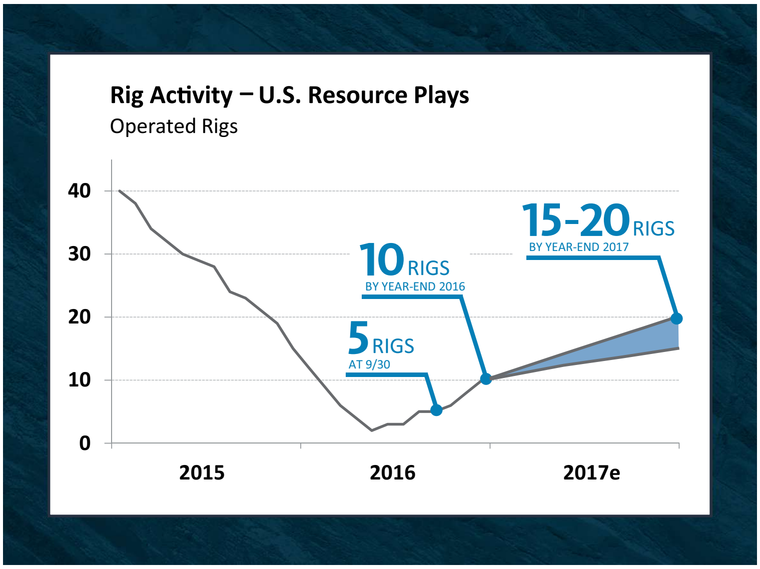
The company's leasehold in the Bakken totaled about 985,000 net acres. Continental had 384,000 net acres in the SCOOP Woodford and about 191,000 net acres in the SCOOP Springer after the sale. The company had about 183,000 net acres in the STACK play.

A statue of Roy V. Cashon of the 1st Oklahoma Volunteer U.S. Calvary stands in a downtown Hennessey, Oklahoma, park. The farming community of about 2,000 sits in the midst of the Stack oil play. *(Photo by Tom Fox, courtesy of Hart Energy's Oil and Gas Investor)*

Continental had about 215 gross operated drilled but uncompleted wells (DUCs) in inventory, of which approximately 165 were in the Bakken. The company expected the total to grow to about 240 gross operated DUCs at year-end 2016, with about 190 in the Bakken. The company said its Bakken DUCs have an average EUR of 850,000 boe per well and can be completed at an average cost of between $3 million to $3.5 million per well.

Devon Energy Corp.

- **Divested upstream assets in East Texas for $525 million**
- **Majority of leaseholding is in southeast New Mexico**



(Source: Devon Nov. 18, 2016, company presentation)

In an April 20, 2016, press release Devon Energy Corp. said it sold its non-core Mississippian assets in northern Oklahoma to White Star Petroleum LLC for $200 million. Then on June 6, the company entered into definitive agreements with undisclosed parties to monetize nearly $1 billion of non-core upstream assets.

The largest divestment was its upstream assets in East Texas for $525 million. In a separate transaction, the company agreed to sell its non-core position in the Anadarko Basin's Granite Wash area for $310 million.

In the northern Midland Basin, Devon agreed to sell its overriding royalty interest across 11,000 net acres for $139 million. The transaction did not include the company's working interest across 15,000 net acres in Martin County, Texas.

The majority of the company's leasehold is in the Delaware Basin in southeast New Mexico. Devon had 585,000 net risked acres by formation. Second-quarter net production was 65,000 boe/d. About 5,200 risked locations and more than 16,000 unrisked locations had been identified in the basin.

Devon resumed drilling operations in the Delaware Basin in September with one operated rig. The company planned to add up to two rigs during the fourth quarter. The company expected to run one frack crew in second-half 2016.

In the Eagle Ford Devon and its partner ran two rigs during the second quarter with activity focused on a staggered-lateral infill program in undeveloped portions of DeWitt County. About 50 staggered-lateral infill wells were drilled in first-half 2016.

The company expected to reduce its drilled but uncompleted wells inventory from about 100 wells in the third quarter to about 50 wells by year-end 2016.

The company expected to accelerate its activity in the STACK play by adding two operated rigs each in the third and fourth quarters. The company also expected to run three frack crews in second-half 2016.

Diamondback Energy Inc.

- **Pure play Permian Basin operator**
- **Had 20 DUCs at end of third-quarter 2016**

As another pure play Permian Basin operator Diamondback Energy had about 86,000 net acres in the northern Midland Basin with more than 2,700 gross drilling locations. In July 2016 the company entered into a purchase agreement for 19,180 net acres in the southern Delaware Basin in Ward and Reeves counties for $560 million.

With the Delaware Basin acreage, the company acquired 290 net identified potential horizontal drilling locations with an anticipated average lateral length of about 9,500 ft. One dedicated horizontal rig was expected to be added in 2017 in the Delaware.

The company had 20 drilled but uncompleted wells (DUCs) at the end of third-quarter 2016, according to an Oct. 10 press release. Diamondback was operating four drilling rigs with one more rig to be added by the end of the year and another rig in early 2017, assuming WTI price remains above $45/bbl. The company was operating two completion crews.

Diamondback planned to complete 90 to 120 gross wells in 2017 with an average lateral length of about 8,500 ft.

"Our existing asset base allows us to drive production growth within cash flow into 2017 and beyond at the current forward strip prices," said Travis Stice, Diamondback's CEO.

Diamondback had 1,852 gross identified potential drilling locations. The company's drilling, completion and equipment costs are below $6 million for a 10,000-ft lateral and below $5 million for a 7,500-ft lateral.

Viper Energy Partners LP, a Diamondback subsidiary, acquired mineral interests in 601 net royalty acres in the Midland Basin and 142 net royalty acres in the Delaware Basin, according to a July 25 press release.

Viper had pro forma 5,357 net royalty acres in the core of the Permian Basin. The company signed agreements to acquire mineral interests underlying 8,137 gross acres in the Midland and Delaware basins for about $111 million.

Encana Corp.

- Eagle Ford acreage in the Karnes Trough
- 10,000-well inventory in the Permian Basin

With an inventory of 130 premium drilling locations identified in the Eagle Ford and 2,750 premium drilling locations in the Permian Basin, Encana was derisking new zones and working to understand stacking and spacing of laterals.

The company's Eagle Ford mostly contiguous acreage was strategically positioned in the Karnes Trough. Stacked pay, infill spacing and Austin Chalk offered premium inventory upside. Encana had about 43,200 net acres in the Eagle Ford. Drilling and completion (D&C) costs were $3.9 million per well. The company also delivered a new pacesetter well at a cost of $3 million in the Eagle Ford.

The company was improving fracture effectiveness in the Eagle Ford with tighter cluster spacing, increased proppant concentration and greater fracture surface area.

Encana had a 10,000-well inventory in the Permian Basin and about 140,000 net acres. The company was derisking new zones and trying to understand the stacking and spacing of laterals. The company's D&C costs in the basin were down from more than $8 million to less than $5 million, according to an investors-day presentation on Oct. 5.

Large-scale pad development had led to $1.2 million in savings per well with shared wellsite facilities, minimized surface footprint, reduced nonproductive time and logistical efficiencies. Encana planned to eliminate future in-fill drilling by draining the basin without drilling through depleted reservoir.

The drivers for D&C cost reductions since 2014 included reduced drilling days (-25%), drilling design breakthroughs with simplified casing design and improved cementing (-20%), increased pumping time per day (-10%), completion design breakthroughs (-10%), streamlined logistics (-5%) and service cost reductions (-30%).

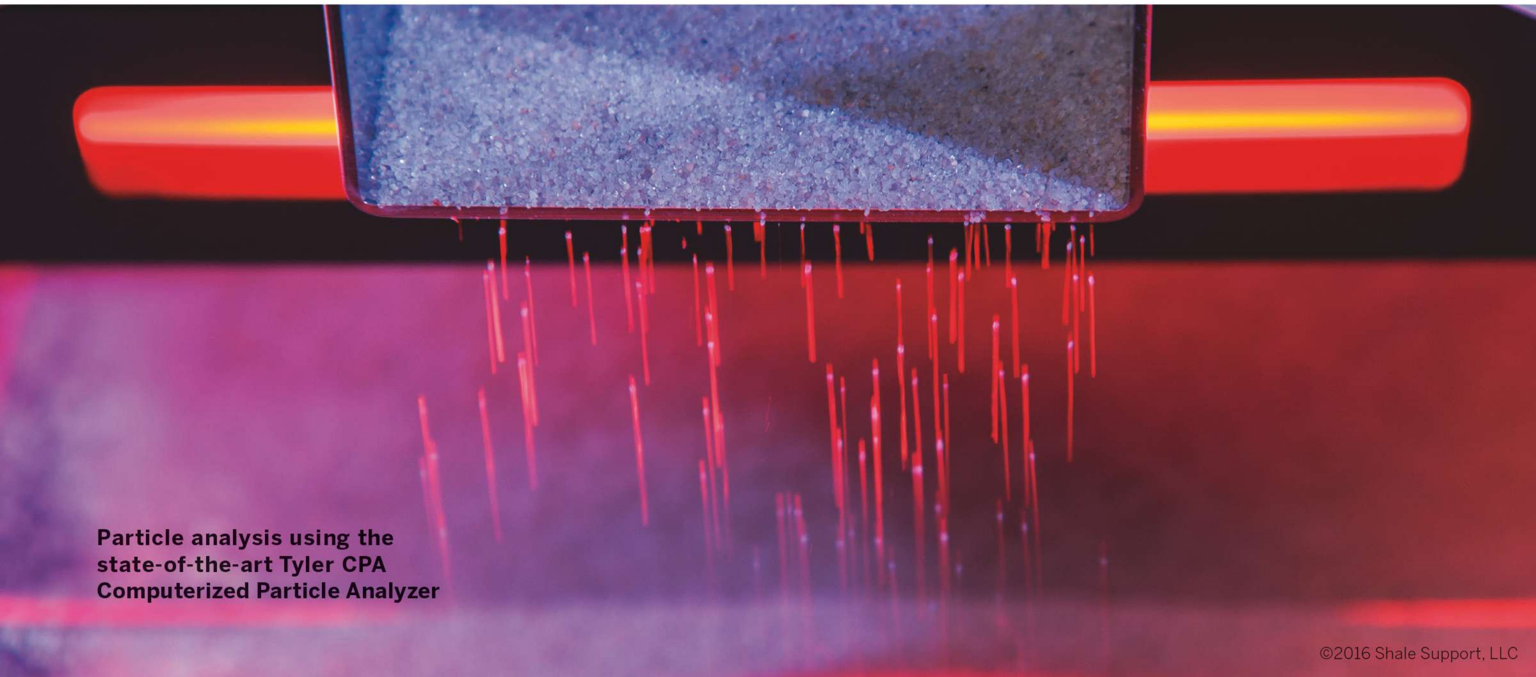
As of June 30, Encana had hedged about 78% of its remaining oil and condensate production at an average price of $55.91 and 86% of natural gas production at an average price of $2.63/Mcf.

Energen Corp.

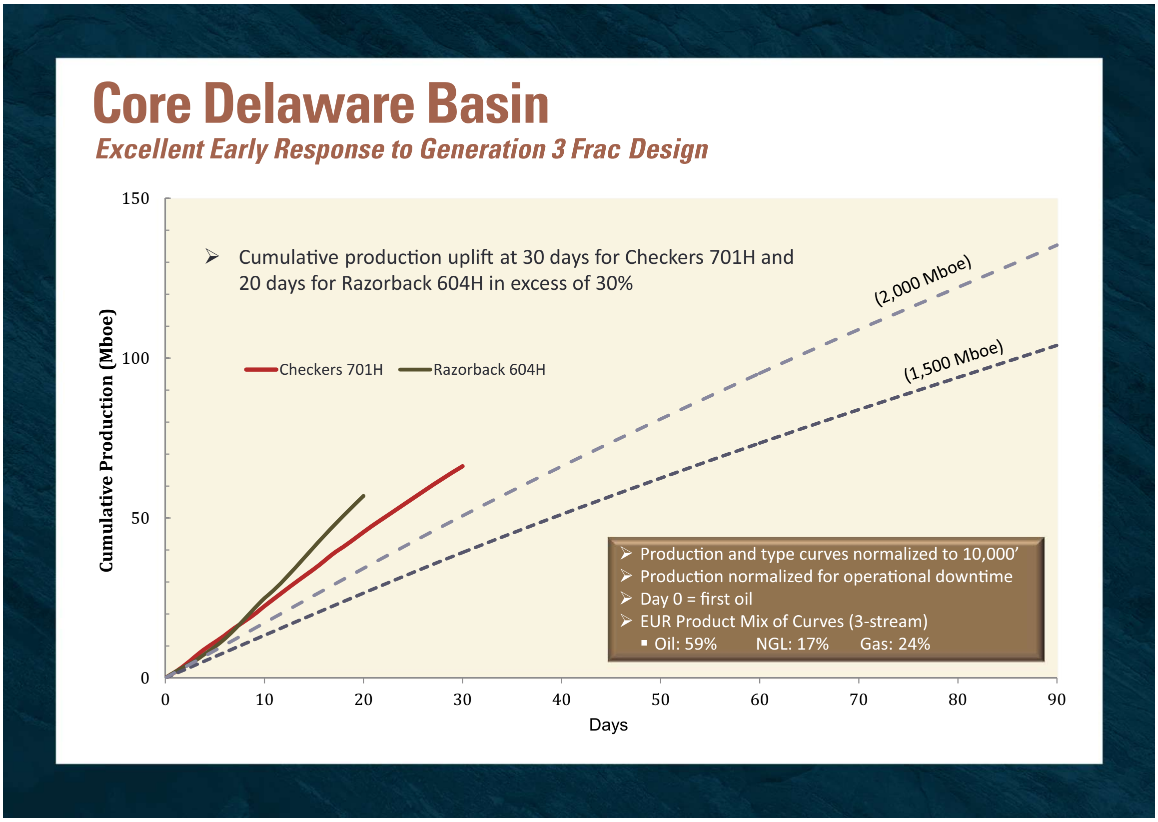
- Planned to drill 17 to 19 net DUCs in 2H 2016
- Completed transition to pure play Permian operator

With leading-edge drilled and completed designs, Energen completed a Delaware Basin well in Reeves County for $7.2 million and a Glasscock County well in the Midland Basin for $5.2 million.

The company drilled the Delaware Basin well with a 9,000-ft lateral in the Wolfcamp A in 22.4 days spud to total depth (TD). The well was completed using the company's Generation 3 frack design.



Particle analysis using the state-of-the-art Tyler CPA Computerized Particle Analyzer



(Source: Energen Nov. 16, 2016, company presentation)

The Midland Basin well was drilled with a 7,500-ft lateral in 13.1 days spud to TD. This well was also completed with a Generation 3 frack design.

"We are increasing our capital investment in 2016 to approximately $450 million to further build up our inventory of DUCs [drilled but uncompleted wells] at year-end [2016]," said James McManus, Energen's chairman and CEO, in the company's second-quarter 2016 report on Aug. 8. "Up to $130 million will now target the Delaware Basin, where we plan to drill 17 to 19 net DUCs in second-half 2016. In total, we now expect to end the year with approximately 54 to 58 net DUCs in the Permian Basin."

In a June 20 press release Energen stated it had closed or signed sales agreements for its non-core Delaware Basin and San Juan Basin assets for total gross proceeds of $551.7 million. In the Delaware Basin, there were about 55,000 net acres of non-core assets. With the sale of the rest of its San Juan Basin assets, Energen completed its transition to a pure Permian Basin operator.

In the core Midland Basin the company had 68,500 net acres with 2,546 net identified drilling locations in seven formations. After all the transactions have closed, Energen will have approximately 42,200 net acres in the Delaware Basin with 954 net identified locations in four Wolfcamp shale formations, according to a July 20 press release.

Estimated lease operating expenses per barrels of oil equivalent for the Midland Basin was $5.95 to $6.35, the Delaware Basin was $8.25 to $8.65 and the Central Basin Platform was $17.20 to $17.60.

EOG Resources Inc.

- **Acquired Yates Petroleum Corp.**
- **Increased Permian Basin acreage to 574,000 net acres**

With 1.6 million net acres in eight different basins, Yates Petroleum Corp. was an attractive acquisition for EOG Resources. EOG signed an agreement to combine with Yates Petroleum Corp. valued at $2.5 billion.

The acquisition increased EOG's Permian Basin acreage to 574,000 net acres and doubled its Powder River Basin covering 400,000 net acres. The added acreage enabled larger drilling units with longer laterals and concentrated development with scale.

"This transaction combines the companies' existing large, premier, stacked-pay acreage positions in the heart of the Delaware and Powder River basins, paving the way for years of high-return drilling and production growth," said Bill Thomas, EOG chairman and CEO, in a Sept. 6 press release.

The Yates transaction added 1,700 premium locations to EOG's Delaware Basin locations, which included 500 locations in the Wolfcamp and 600 locations each in the Second Bone Spring and Leonard Shale, which brought the company's total premium locations to 3,450 well sites as of September 2016.

In addition to the Permian and Powder River basins, Yates had acreage in the Williston, Green River, Denver-Julesburg, Uinta-Piceance, Paradox and San Juan basins.

EOG completed 60 wells in the Eagle Ford with an average treated lateral length of 4,800 ft and an average 30-day IP of 1,705 boe/d, according to a second-quarter 2016 report on Aug. 4.

The company increased its targeted number of well completions for 2016 from 270 to 350 net wells. Due to increased drilling productivity, the company expected to drill 250 net wells.

EOG expected to complete about 25 net wells in the Williston Basin in 2016. Its estimated resource potential was about 1 Bboe per 8,400-ft lateral for $7.2 million.

The company completed about 25 net Denver-Julesburg Basin and Rockies wells in second-quarter 2016.

EQT Corp.

- **Acquired 62,500 net acres in the Marcellus in 3Q 2016**
- **Has 3,680 undeveloped core Marcellus well locations**

An acquisition of 62,500 net acres in EQT Corp.'s core Marcellus development area of West Virginia in Wetzel, Tyler and Harrison counties for $407

Cholla cactus dot the Permian Basin landscape EOG acquired from Yates Petroleum in 2016. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

million was completed July 8 by the company from Statoil USA Onshore Properties Inc. Much of the acreage was contiguous with EQT's current acreage.

The lateral lengths of 106 existing EQT well locations can now be extended from 3,000 ft to an average of 6,500 ft. The company estimated it has 3,680 undeveloped core Marcellus well locations.

On Oct. 25 the company designed a definitive group to acquire 42,600 net acres in the Marcellus in West Virginia and Pennsylvania from Trans Energy and affiliates of private E&P Republic Energy and other parties.

EQT said May 2 that it signed an agreement to buy 62,500 net acres in the Marcellus Shale for $407 million. The assets were primarily located in Wetzel, Tyler and Harrison counties, W.Va., and added to EQT's core development area. Leases are either HBP or expire beyond 2018, EQT said.

As of Sept. 30, EQT had 816 wells online, 32 wells completed but not online and 101 drilled but uncompleted wells.

In the Marcellus, the company had 660,000 net acres with 7.8 Tcfe of proved reserves as of July 8, according to an Oct. 13 analyst presentation.

EQT had about 450,000 net acres in the Utica with 3,400 drilling locations.

The company's Upper Devonian play was being developed in conjunction with its core Marcellus. There were 70,000 core near-term development acres with about 600 core locations. Thirty wells were drilled in 2016 at a cost of $5.7 million per well.

ExxonMobil/XTO

- **Near-term focus on Permian and Bakken liquids plays**
- **Enhancing position through trades and farm-ins**

The large inventory of short-cycle opportunities, primarily onshore U.S. in the Bakken, Permian Basin and Ardmore/Marietta (Oklahoma) unconventional plays was being progressed by ExxonMobil. The company also added attractive acreage, according to the company's 2015 annual report.

The company's near-term focus was on its Permian and Bakken liquids plays with its 2.1 million net acres and 230,000 boe/d net production. ExxonMobil was enhancing its position through trades and farm-ins.

Two agreements were signed by ExxonMobil to obtain horizontal development rights on 48,000 acres in the core of the Midland Basin that included an acquisition and farm-in adjoining XTO's existing acreage position in Martin and Midland counties. The acreage was to be operated by XTO.

The agreements included an acquisition and farm-in adjoining XTO's existing acreage position in Martin and Midland counties, providing rights to all intervals within the basin.

"We are continuing to grow our position in a prolific area of the Permian Basin," said Randy Cleveland, president, XTO Energy, in an Aug. 6 press release. "The recent emergence of strong Lower Spraberry results, combined with the established Wolfcamp intervals, demonstrates the significant potential of the stacked pays in the Midland Basin core."

"We are encouraged by the horizontal well productivity and cost reductions we have achieved to date," Cleveland said. "We expect to drive continued improvements in productivity and cost as we develop our substantial inventory of wells across the multiple stacked pays."

XTO was operating 11 horizontal and four vertical rigs across its Permian Basin leasehold. Its net oil-equivalent production exceeded 115,000 bbl/d, according to a March 1 press release.

"We've reduced drilling time in our West Texas horizontal Wolfcamp by 40% since 2014, despite a 20% increase in average well depth," Cleveland said.

Hess Corp.

- **Significant drilling inventory in the Utica Shale**
- **2,850 future drilling locations in the Bakken**

With 577,000 net acres in the Middle Bakken and Three Forks formations and 50,000 net acres in the Utica Shale, Hess had significant drilling inventory. The company had 2,850 future operated drilling locations in the Bakken, according to a presentation at the Barclays CEO Energy-Power Conference on Sept. 8, 2016.

The primary focus for Hess was the Bakken where net production was 107,000 boe/d in third-

Trucks form a line to deliver supplies to Permian Basin properties. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

quarter 2016, compared to 113,000 boe/d in the prior-year quarter, due to a reduced drilling program, the company said in its third-quarter 2016 report on Oct. 26.

Hess operated an average of three rigs in the quarter and brought 22 gross operated wells on production. Drilling and completion costs averaged $4.7 million per operated well in the third quarter, down 11% from the year-ago quarter, while increasing the standard well design to a 50-stage completion from the previous 35-stage design. The 50-stage completions delivered more than a 20% average increase in initial production (IP) for 30-, 60- and 90-day rates.

"As a result of the 50-stage completion trials and tighter well-spacing pilots conducted in 2015, estimated ultimate recovery from the Bakken increased to 1.6 Bboe from our previous estimate of 1.4 Bboe," according to the 2015 annual report.

Continued success testing tighter well spacing indicated that 500-ft spacing between wellbores was optimal, which became the new standard design. This improvement allowed four additional wells to be drilled per 1,280-acre drilling spacing unit compared to the previous 700-ft spacing.

In the Utica Shale play in eastern Ohio, where the company participates in a 50% joint venture with CONSOL Energy, net production increased to 24,000 boe/d in 2015 from 9,000 boe/d in 2014. In 2015, the joint venture operated an average of 1.5 rigs and brought online 32 new wells. No drilling was planned in the Utica after first-quarter 2016.

Marathon Oil Corp.

- **Bakken Shale is focus of unconventionals portfolio**
- **Accelerating STACK value as first capital allocation priority**

The Bakken Shale oil play was a centerpiece of Marathon Oil's unconventional resource portfolio. As of year-end 2015, Marathon held approximately 277,000 net acres in the Bakken oil play in North Dakota and eastern Montana,

At year-end 2015, Marathon held about 265,000 net surface acres in the SCOOP, STACK, Granite Wash and other Pennsylvanian and Mississippian sands plays. In the Eagle Ford Shale the company had approximately 153,000 net acres.

A second drilling rig was added in the company's STACK play in third-quarter 2016. Marathon had about 1,560 gross co-op locations. The company was accelerating its STACK value as its first capital allocation priority, said Lee Tillman, Marathon president and CEO, at the Barclays CEO Energy-Power Conference on Sept. 7.

Marathon signed an agreement to acquire PayRock Energy Holdings LLC, which is a portfolio company of EnCap Investments, for $888 million. PayRock had approximately 61,000 net surface acres and current production of 9,000 net boe/d in the STACK play in Oklahoma.

In an Oct. 3 press release Marathon said that it signed an agreement for the sale of certain non-operated CO_2 and waterflood assets in West Texas and New Mexico for $235 million. Since August 2015 the company has announced or closed non-core asset sales in excess of $1.5 billion.

At the DUG Eagle Ford Conference on Sept. 13, Dale Kokoski, regional vice president, Eagle Ford, for Marathon, said the company had reduced its average completed well cost to $4.2 million.

In 2015 and 2016 the company focused on innovation, automation and artificial lift on the production side. "We realized we needed to improve those run times, improve the performance of the lift systems. This year we managed to get our production efficiencies well over 97%," he said. That allowed Marathon to be economical even at a $45 price environment.

> "**PROCEEDS FROM THE SALE OF OUR TEXAS ASSETS WILL REPLENISH** our cash balance and position us for the timely acceleration of our STACK development."
>
> — ***Lee K. Boothby**, Newfield*

Newfield Exploration Co.

- **Sold Texas assets in 2016**
- **Positioning to accelerate STACK development**

The 2016 capital budget for Newfield Exploration was increased to $700 million to $750 million, which reflected about $40 million for two STACK pilots and $50 million for additional drilling activities on existing and acquired acreage, according to the second-quarter 2016 report.

Newfield closed on its transactions to sell its producing oil and gas properties and undeveloped acreage in the Eagle Ford Shale to Protégé Energy III LLC and its conventional natural gas assets in South and West Texas to an undisclosed party. Combined proceeds from the sales were approximately $380 million, according to a Sept. 27 press release.

The company planned to revise its full-year 2016 production expectations to reflect the sale of these assets.

Newfield Chairman and CEO Lee K. Boothby said, "Proceeds from the sale of our Texas assets will replenish our cash balance and position us for the timely acceleration of our STACK development."

On May 5 the company signed a definitive purchase and sale agreement with a subsidiary of Chesapeake Energy Corp. to acquire approximately 42,000 net acres in the Anadarko Basin STACK play for $470 million. Newfield's STACK footprint increased to about 265,000 net acres. There was significant overlap with its existing acreage in Kingfisher, Blaine, Dewey and Canadian counties.

The company's SCOOP play was in full-field development, and it was preparing to begin full-field STACK development in 2017, explained Boothby in a presentation at Barclays CEO Energy-Power Conference Sept. 7 and 8.

In its Raptor-X Pilot in the STACK play, Newfield was testing 880-ft spacing per interval and six wells per interval in the Upper and Lower Meramec. Its No. 2 Chlouber Pilot tested 1,050-ft spacing per interval, 175-ft vertical spacing and five wells per interval.

Noble Energy

- **Quality positions in the Eagle Ford and Delaware Basin**
- **Ended JV with CONSOL in Pennsylvania and West Virginia**

The primary leasehold positions for Noble Energy included 45,000 net acres in the Eagle Ford Shale

Introducing a new controlled optimization process for multistage completions

A well-to-well program made possible by consistent frac placement and measured downhole pressures and temperatures

Controlling key variables enables true optimization

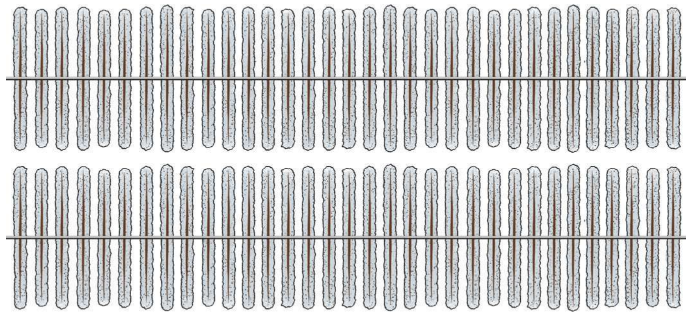
Plug-and-perf completions cannot be truly optimized, because the number of fracs, frac spacing, and propped volume are uncontrolled variables. The same is true for openhole packer/ball sleeve completions. Even if a completion is economically acceptable, there is no reliable, methodical way to improve the design, because frac placement is not repeatable from well to well.

With the Multistage Unlimited® pinpoint frac system, you know where fracs initiate and exactly how much proppant you put in each one. No matter what else you adjust—frac spacing, frac dimensions, proppant type and concentration, frac fluid, or injection rates—frac placement is predictable, verifiable, and repeatable, so you can clearly see the effects of your changes and adjust your design accordingly.

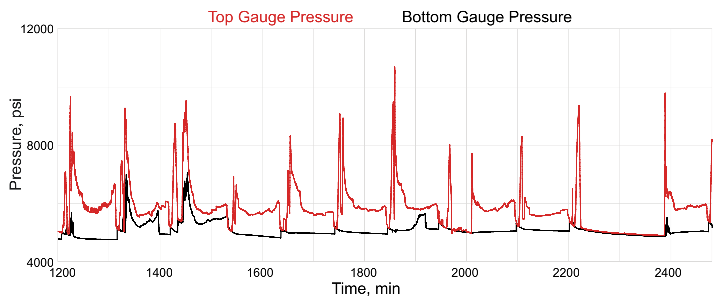
Recorded downhole data describes every frac

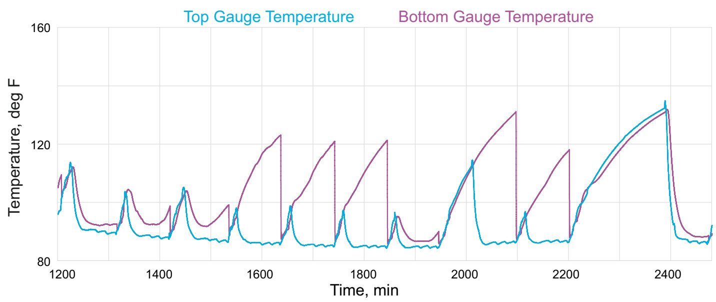
At every stage, the Multistage Unlimited frac-isolation system records pressures and temperatures at the frac zone and in the wellbore below (see charts at right). The data reveals the presence and type of any interzone communication (e.g., natural fractures or cement failure) and identifies the presence and source of near-wellbore restrictions. These stage-by-stage details provide critical insights operators are using to optimize frac design and frac spacing.

Consistent frac placement plus downhole data is your fastest route to truly optimized completions and field-development strategies. Learn more at ncsmultistage.com.



Predictable, verifiable, and repeatable frac spacing and propped volume facilitate formation-specific, well-to-well optimization across entire fields





Recorded pressure and temperature at and below the frac zone for ten stages. The data identifies any interstage communication and describes important frac and formation characteristics.

The Multistage Unlimited frac-isolation system is the world's leading coiled-tubing frac technology, with more than 137,000 stages completed.

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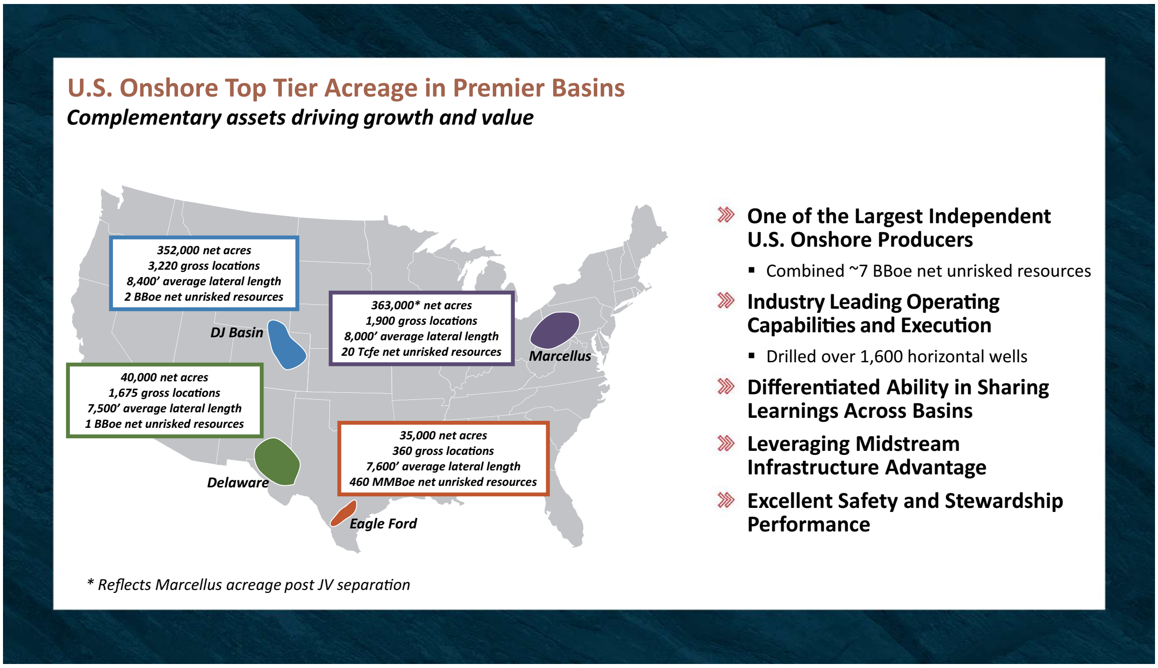


(Source: Noble Energy Nov. 16, 2016, company presentation)

primarily in Dimmit and Webb counties, 46,000 net acres in Reeves County and 9,000 acres in Gaines County in the Permian Basin, and about 360,000 net acres in the Denver-Julesburg (DJ) Basin.

"Recent performance of the Texas assets has been particularly encouraging and continues to demonstrate the high quality of our positions in both the Eagle Ford Shale and Delaware Basin," said David Stover, Noble's chairman, president and CEO, in the company's second-quarter 2016 results on Aug. 3.

Record quarterly sales volumes of 74,000 boe/d were achieved in the second quarter. Eagle Ford production represented 90% of the total and Permian Basin production the remaining 10%. At the end of the quarter there were 31 drilled but uncompleted wells (DUCs) in the Eagle Ford and 15 DUCs in the Delaware Basin.

Noble expected third-quarter capital spending to be between $400 million and $450 million, with about 80% of amount targeted to its U.S. onshore assets. For most of the third quarter and the rest of 2016, the company planned to operate two drilling rigs in the DJ Basin and one each in the Eagle Ford and Delaware Basin.

In the DJ Basin the company's average costs for normalized long laterals with enhanced completions were reduced to $2.6 million per well in its Wells Ranch Field. The company added about 11,700 net acres in Wells Ranch in exchange for about 13,500 net acres out of Noble's Bronco area. The company ended the quarter with 36 DUCs in the basin.

Sales volumes in the Marcellus in the second quarter averaged 546 MMcfe/d. The company exited the quarter with 79 DUCs in its joint venture, which provided options and flexibility for the company into 2017.

After five years of collaboration with CONSOL Energy Inc. in the Marcellus Shale, Noble Energy agreed on Oct. 31 to end their joint venture in Pennsylvania and West Virginia. Noble would pay CONSOL $205 million to eliminate its remaining carry-cost obligations.

Oasis Petroleum

- **Acquired about 55,000 net acres in Williston Basin**
- **Reduced lease operating expenses by 25%**

In third-quarter 2016, Oasis Petroleum completed and placed on production 17 gross (7.1 net) operated wells and had 80 gross drilled but uncompleted wells (DUCs) at the end of the quarter in the Williston Basin.

The company enhanced its pure play Williston Basin status on Oct. 17 by signing an agreement to acquire about 55,000 net acres and an estimated 226 gross operated drilling locations in the Williston Basin for about $785 million. The acquisition brought the company's leasehold to 539,745 net acres. The bolt-on acquisition had 34 operated drilling spacing units (DSUs) added to Oasis' 395 DSUs.

The acquisition added 130 gross core operated locations, bringing the Oasis total to 684 locations. The company's Red Banks, Painted Woods and South Cottonwood fields were key areas to add drilling rigs in a rising oil price environment.

The company began completing wells in Wild Basin Field in summer 2016, with the wells choked back until infrastructure was commissioned later in the year.

Oasis reduced its lease operating expenses by 25% over the past three years and achieved substantial improvements across all types of operating costs.

The company had been operating two drilling rigs during 2016. Its average spud-to-rig-release time declined by 2.1 days in second-quarter 2016 to 13.5 days.

On the completion side, Oasis was testing the latest technology, including diverters, higher sand loading, precision fracks, increased frack stage counts and proppant suspension.

The company had 83 gross operated DUCs as of June 30.

"The team continues to test the latest completion technologies. Our confidence is growing that increasing proppant loading and stage counts will continue to improve well performance as we are seeing production uplift in our own tests as well as tests done by other operators in similar operating areas," said Thomas Nusz, chairman and CEO for Oasis, in its preliminary third-quarter results on Oct. 17.

Occidental Petroleum

- **Looking to expand in Permian through asset acquisitions**
- **Decreased drilling costs per lateral foot by more than 20%**

Capital redeployed into Permian Resources by Occidental Petroleum was to be used "to add two drilling rigs by fourth-quarter 2016 to support production growth in 2017, while maintaining the flexibility necessary to maneuver through the uncertainty and volatility of this price environment," said Vicki Hollub, Oxy president and CEO, on the company's second-quarter 2016 call on Aug. 3.

The peaceful farmlands of Pennsylvania lie atop enormous Marcellus gas resources. *(Photo by Glenn Kulbako, courtesy of Hart Energy's* Oil and Gas Investor*)*

"On the merger and acquisition front, we also continue to look for ways to expand and further strengthen our position in the Permian through asset acquisitions," she continued.

"We slowed our Permian Resources drilling program as planned due to the severely depressed product prices in the beginning of 2016," said Jody Elliott, president, Oxy Domestic Oil and Gas, on the earnings call.

"In order to prepare for growth in 2017, we plan to add two drilling rigs in our resources business later this year. We will increase our operated rig count over second-half 2016 to seven to eight drilling rigs in the Permian. This is an increase from our previous guidance of four to five rigs," he continued.

Oxy had about 8,500 locations in its horizontal inventory, with 3,400 of those locations economic at less than $60/bbl. About 350 locations would be economic below $40/bbl.

Oxy had decreased its drilling costs per lateral foot by more than 20% since 2015. The drilling, completion and hookup cost in May was $5.9 million per well. The company expected to reduce costs to $5.5 million per well in second-half 2016.

The company's Delaware Basin well performance continued "to be strong despite reduced activity. We placed seven horizontal wells on production in the Wolfcamp A benches in the second quarter. We continue to increase well productivity by increasing contact with a reservoir near the well bore utilizing higher cluster density, higher proppant loading and drilling longer laterals," Elliott said.

Parsley Energy Inc.

- **Estimated savings of $1 million on a three-well pad**
- **Two land acquisitions completed**

The majority of 2016 wells for Parsley Energy were to be drilled from two-well or three-well pads in the Midland Basin. The transition to pads had amplified the downtrend in drilling and completion costs for the company.

Parsley estimated a cost savings of $1 million on a three-well pad vs. three single wells. At the same time the company was seeing uplifted productivity on pad wells with enhanced reservoir stimulation and "stress shadowing" vs. single wells, the company said in a May 2016 investor presentation.

The combination of reduced costs and increased productivity boosts project rate of return and net present value. The company expected to have ample running room with more than 1,100 Midland Basin Wolfcamp A and Wolfcamp B drilling locations alone. There was inventory upside from the upper Wolfcamp B flow unit in the Midland Basin and substantial downspacing potential relative to current spacing assumptions.

> **THE MAJORITY OF 2016 WELLS FOR PARSLEY ENERGY** were to be drilled from two-well or three-well pads in the Midland Basin.

There are more than 300 gross/net locations in the southern Delaware Basin based on just one flow unit in the upper Wolfcamp interval. Oil production throughout the Wolfcamp interval supports the possibility of multiple Wolfcamp flow units as well as the prospectivity of Bone Spring, Pennsylvanian, Mississippian and Woodford formations.

Two land acquisitions were completed by Parsley Energy subsequent to the end of second-quarter 2016. One acquisition was about 14,200 net acres in the southern Delaware Basin and the other was about 8,700 net acres in the Midland Basin, according to an Aug. 3 press release.

On Aug. 15 the company followed up with an agreement to acquire 9,140 net acres near existing Parsley acreage in Glasscock County for $400 million. There were 215 net horizontal drilling locations in the Lower Spraberry and Wolfcamp A and B based on 660-ft spacing and an estimated average lateral length of 7,500 ft.

The company expected to complete 80 to 90 horizontal wells in 2016.

PDC Energy Inc.

- **Plans to acquire two privately held companies**
- **$35 million capital plan in 2016 for its Utica program**

With about 57,000 net acres in the core Delaware Basin, about 65,000 net acres in the Utica Shale and about 96,000 net acres in the core Wattenberg, PDC Energy had a significantly expanded inventory of highly economic projects, optionality to allocate capital across its portfolio of two premier assets and visibility for material long-term, value-added growth, according to its October 2016 company update.

In one of the larger acquisitions in the Delaware Basin, PDC entered into definitive agreements to acquire two privately held companies managed by Kimmeridge Energy Management Co. for about $1.5 billion, according to an Aug. 23 press release, which marked PDC's entry into the Delaware Basin

The acreage included more than 700 gross estimated horizontal drilling locations targeting the Wolfcamp A, B and C with significant upside potential through downspacing and additional intervals, according to the release. Estimated well costs for a 5,280-ft lateral from a one-well pad were $6.5 million and from a four-well pad were $5.8 million.

There were multiple years of highly economic drilling in the core Wattenberg and core Delaware. The internal rates of return were extremely competitive even in a depressed commodity price environment, the company said.

The company started operating its first drilling rig in September in its core Delaware acreage and planned to operate two rigs by year-end 2016. There were 23 horizontal and seven vertical wells online with about 7,000 boe/d net production. PDC planned to complete two horizontal wells and operate two drilling rigs by year-end 2016.

In the Wattenberg area the company had 2,150 horizontal drilling locations with average lateral lengths of about 4,700 ft.

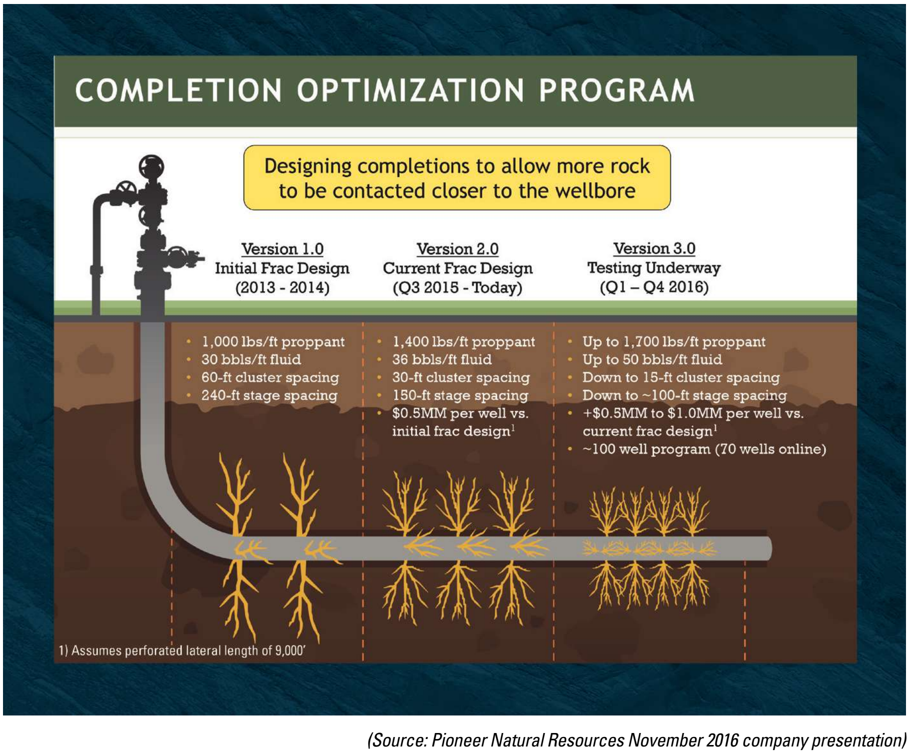
PDC had a $35 million capital plan in 2016 for its Utica program. The company was going to do well-orientation testing in late fourth-quarter 2016 or first-quarter 2017.

Pioneer Natural Resources

- **Largest acreage holder in the Wolfcamp play**
- **Plans to acquire 28,000 Midland Basin acres from Devon**

With about 600,000 gross acres in the northern portion of the Spraberry/Wolfcamp play and about 200,000 gross acres in the southern Wolfcamp joint venture area in the Midland Basin, Pioneer Natural Resources was the largest acreage holder in the play.

The company placed 69 horizontal wells on production during second-quarter 2016, with 37 wells benefiting from Pioneer's Version 3.0 completion optimization program, according to the company's second-quarter report on July 27.



(Source: Pioneer Natural Resources November 2016 company presentation)

Starting in the second quarter the company began testing its further enhanced completion design. Version 3.0 included larger proppant concentrations up to 1,700 lb/ft, larger fluid concentrations up to 50 bbl/ft, tighter cluster spacing down to 15 ft and shorter stage spacing down to 100 ft. The initial Version 3.0 is expected to be tested in about 80 wells during 2016.

During the second quarter the company's horizontal drilling and completion costs averaged $7.2 million for the Wolfcamp B interval wells, $6.7 million for Wolfcamp A interval wells and $6.9 million for Lower Spraberry Shale interval wells.

For third-quarter 2016 Pioneer expected to place about 50 horizontal wells on production. The company also expected to place more wells on production using choke management to minimize the capital spent on water disposal infrastructure.

For its horizontal drilling program the company budgeted $1.54 billion for its northern Spraberry/Wolfcamp area, $45 million for the southern Wolfcamp and $30 million for its Eagle Ford area.

The company signed a purchase agreement for about 28,000 net acres in the Midland Basin with Devon Energy for $435 million, according to an Aug. 31 press release. The majority of the acreage was in the core of the Midland Basin with about 15,000 net acres in the Sale Ranch area in Martin County and northern Midland County. The company planned to increase its horizontal rig count from 12 to 17 rigs in the northern Spraberry/Wolfcamp during second-half 2016.

QEP Resources Inc.

- **74,400 net acres in the Permian**
- **Completed three wells at Ft. Berthold**

Five operated drilling rigs were planned for the remainder of 2016 by QEP Resources—three rigs in the Permian Basin and one each in the Williston Basin and Pinedale Field, according to the third-quarter 2016 report on Oct. 26.

For the first nine months of 2016 the company completed 25.6 net operated wells and 23 gross non-operated wells in the Williston Basin and 18 gross operated wells and nine gross nonoperated wells in the Haynesville/Cotton Valley.

During the third quarter the company continued its initial "wine rack" geometry well density test targeting in the Spraberry Shale A and C benches in the Permian Basin. QEP had 74,400 net acres in the Permian. Drilling and completion costs for a horizontal well were $4.9 million for a 7,500-ft lateral.

In the Williston Basin QEP completed three wells at Ft. Berthold using its modern completion design with 49 stages, sliding sleeves and 1,000 lb/ft of proppant. Drilling and completion costs for the wells averaged $5.5 million. The company had 117,000 net acres. There were 23 operated drilled but uncompleted wells (DUCs) and 12 gross non-operated DUCs in the basin as of Sept. 30.

Williston Basin net average production for the third quarter was 57,100 boe/d. The company completed and turned to sales six wells in the South Antelope Field and three wells at Ft. Berthold. QEP targeted the second and third benches of the Three Forks Formation.

For its Haynesville/Cotton Valley operations, the company's net production averaged 133 MMcfe/d, which was a 9% increase compared with third-quarter 2015. The increase was due primarily due to recent well workovers, changes in working interest, non-operated well completions and other production related adjustments. There were no rigs operating in the area in the third quarter.

Range Resources Corp.

- **Acquired Memorial Resource Development Corp.**
- **Sold its Bradford County non-operated assets**

In May 2016 Range and Memorial Resource Development Corp. (MRD) signed a definitive merger agreement under which Range will acquire all of the outstanding shares of common stock of MRD in an all-stock transaction valued at $4.4 billion, according to a May 16 press release.

With the closure of its merger with MRD, Range Resources Corp. on Sept. 16 expanded its shale operations in the Lower 48.

"Combining the northern Louisiana stacked-pay assets with our extensive Marcellus/Utica inventory makes Range a better and stronger company with geographic diversity," said Jeff Ventura, Range CEO, in the third-quarter 2016 report on Oct. 25.

The company's high-quality stacked-pay position included 515,000 net acres in the southwestern Marcellus, 100,000 net acres in the northeastern Marcellus, 220,000 net acres in northern Louisiana and 210,000 net acres in the Midcontinent.

Earlier in 2016 Range completed the sale of its Bradford County, Pa., non-operated assets for about $110 million of sales proceeds at the closing, according to a March 28 press release. Range sold an average working interest of 23% covering approximately 10,900 net acres.

The company's near-term focus on Marcellus development was in southwestern Pennsylvania where a significant inventory of more than 200 existing pads enhances future development. The pads could accommodate about 20 wells each with the flexibility to drill Marcellus, Utica or Upper Devonian formations.

In April Range sold certain assets located in central Oklahoma for $77.7 million. The assets consisted of about 9,200 net acres and about 5 MMcfe/d of net production from about 200 wells in Blaine, Canadian and Kingfisher counties. Following the closing of this sale, the company still owned about 19,000 net acres in central Oklahoma. The retained acreage was primarily HBP in the northern extension of the STACK play.

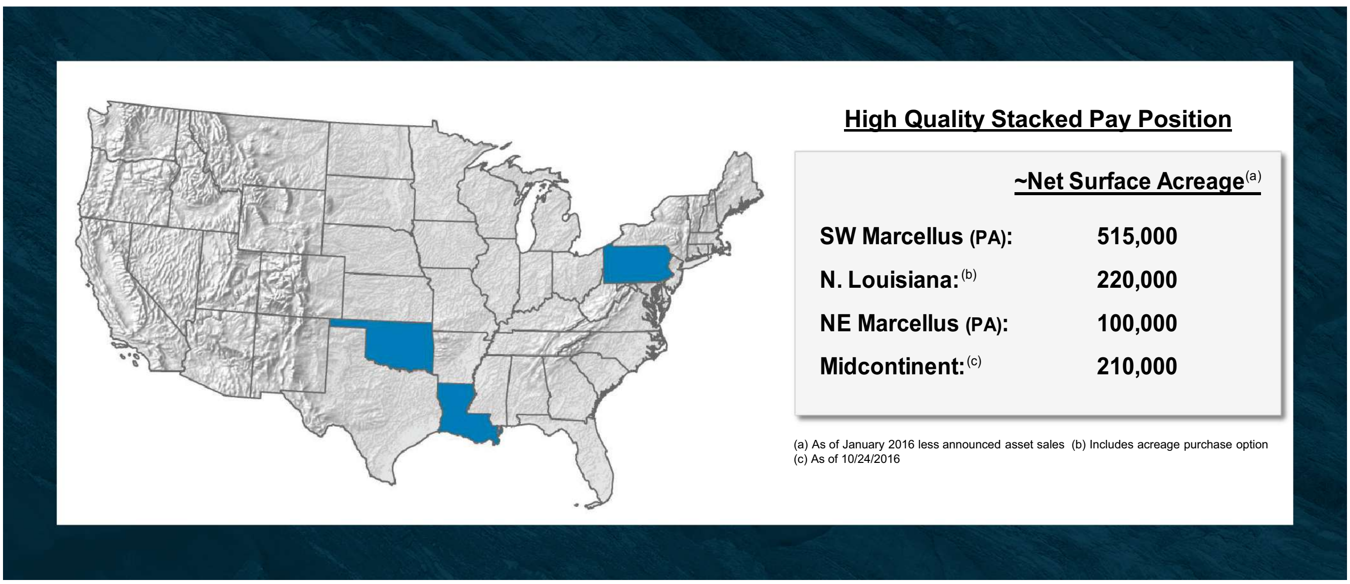
Shell

- **Leasehold of about 850,000 acres primarily in Pennsylvania**
- **Producing about 31,000 boe/d in Delaware Basin**

Shell's Appalachia operations are in the northern and western portions of Pennsylvania in the Marcellus and Utica formations. The company's leasehold was about 850,000 acres primarily in Pennsylvania with additional acreage in Ohio and New York.

In the Delaware Basin, Shell's primary focus was on the Wolfcamp, Bone Spring and Avalon formations. Shell had 300,000 net acres, of which 85% was considered core acreage, and was producing about 31,000 boe/d from about 400 Shell-operated wells. The company had identified more than 5,000 other possible well locations.

However, Shell minimized its spending in these plays and was working to reduce the economic breakeven point. The company was delineating the geological sweet spots, ahead of potentially



(Source: Range Resources November 2016 company presentation)

Casing pipe is stacked and ready for use in Marcellus Shale wells in Washington County, Pa. *(Photo by Glenn Kulbako, courtesy of Hart Energy's* Oil and Gas Investor*)*

more significant growth spending after 2020, according to Shell's 2015 investors' handbook.

The company had two central processing facilities at the end of 2015 and planned to develop additional facilities in 2016 and 2017. It also operated eight saltwater disposal facilities.

"We have significant tight-gas and liquids-rich shale acreage, centered on Pennsylvania in northeast U.S. and in the Delaware Basin in West Texas," stated the 2015 annual report.

SM Energy Co.

- **Acquired 24,783 net acres from Rock Oil Holdings LLC**
- **Purchased 35,700 net acres in Howard Co. from QStar LLC**

With about 245,000 net acres in the Williston Basin, about 161,000 operated net acres in the Eagle Ford and 82,450 net acres in the Midland Basin, SM Energy was in position to take advantage of its Midland Basin and Eagle Ford assets.

An acquisition of 24,783 net acres in Howard County was closed by SM Energy Co. from Rock Oil Holdings LLC for $980 million, according to an Oct. 5 press release.

The company followed that acquisition on Oct. 18 by entering into a purchase agreement for 35,700 net acres in Howard Co. from QStar LLC for $1.1 billion. The acquisition brought SM Energy's Midland Basin footprint to 82,450 net acres. At the same time, the company entered into an agreement to sell its Williston Basin assets outside of Divide County, which included the Raven/Bear Den acreage, to Oasis Petroleum Inc. for $785 million.

"Our preliminary plans for Midland Basin activity include adding a fourth rig during fourth-quarter 2016 and increasing to six rigs in early 2017," said Jay Ottoson, SM Energy's president and CEO.

The company was focused on Howard County because of significant stacked-pay potential, which includes the Middle and Lower Spraberry, Wolfcamp A, B and C, and the Wolfcamp D/Cline in the first acquisition. Original oil in place was estimated at 130 MMbbl per section. Up to 40 wells per section could be drilled.

As of June 30, the company had drilled 41 wells, completed 54 wells and had 151 drilled but uncompleted wells.

SM Energy also had about 161,000 operated and 36,000 non-operated net acres in the Eagle Ford. Nine net wells were completed.

Ottoson said, "We have outlined a simple strategy to focus on our Tier 1 assets in the Permian Basin and operated Eagle Ford."

Separately, the company closed on divestitures of assets located in New Mexico, North Dakota, Montana and Wyoming for about $186.7 million.

Southwestern Energy Co.

- **958,000 net acres in Fayetteville Shale**
- **Planned to have 55 to 65 DUC wells by year-end 2016**

With 370,000 net acres with stacked pays in the Marcellus, Utica and Devonian in West Virginia and southwestern Pennsylvania, Southwestern Energy was well positioned in a rapidly developing play, according to the company's August 2016 update.

The company also had 270,000 net acres and 423 producing operated horizontal wells in northeastern Pennsylvania as of Dec. 31, 2015. Southwestern planned to drill 37 to 40 wells and complete 35 to 38 wells in second-half 2106.

In the Fayetteville Shale the company had about 958,000 net acres and 3,724 producing operated horizontal wells as of Dec. 30, 2015. The company planned to drill seven to 10 wells and complete 36 to 39 wells in second-half 2016.

The company expected to end the year with 53 to 60 drilled but uncompleted wells (DUCs) in Appalachia and two to five DUCs in the Fayetteville.

For an assumed gas price of $3/Mcf the Fayetteville would have about 500 gross drilling locations remaining while Appalachia would have about 2,150 estimated drilling locations. If the price of gas was at $3.50, the company estimated 2,100 locations in the Fayetteville and 2,850 locations in Appalachia.

In its second-quarter 2016 report on July 21 Southwestern said it was in the process of restarting drilling and completion activity in each of its operating areas, and it planned to make incremental capital investments of up to $375 million by the end of the year. The company restarted drilling with its first rig in late July and planned to increase its rig count to five units by the end of the third quarter. Two rigs were to be drilling in northeastern Pennsylvania, two rigs in West Virginia and southwestern Pennsylvania and one rig in the Fayetteville.

The company also planned to complete 90 to 100 wells in second-half 2016, leaving its DUC inventory at 55 to 65 wells by year-end 2016.

Statoil

- **410,000 net acres in Marcellus Shale**
- **Divested West Virginia operated properties to EQT Corp.**

With about 410,000 net acres the Marcellus was Statoil's largest U.S. shale play, followed by the Bakken with about 249,000 net acres and the Eagle Ford with about 71,000 net acres.

At the DUG Eagle Ford conference Sept. 13, Cesar Alvarez, head, Eagle Ford asset, for Statoil, pointed out that Statoil optimizes its operations every day. "We're in the deepest, hottest, high-pressure area of the Eagle Ford. We are talking about a vertical depth of around 13,000 ft," he said.

> "**STATOIL HAS INCREASED EFFICIENCIES** by 30% and reduced costs by 20% worldwide since October 2013."
>
> — ***Cesar Alvarez**, Statoil*

To deal with these wells, the company devised its Perfect Well technique, where the company analyzes every activity related to drilling a well. This involved identifying best practices and applying them elsewhere and eliminating those things that don't work.

"We began applying this technique in the Eagle Ford. It has resulted in a 25% reduction in drilling days per well. Our best well was drilled in 10 days," he explained. "We also have achieved a 37% reduction in cost per foot."

Statoil was about to start its third cycle of the Perfect Well in the Eagle Ford. The technique was made part of its governing documentation. "Statoil has increased efficiencies by 30% and reduced costs by 20% worldwide since October 2013," Alvarez said.

In January 2015, a transaction with Southwestern Energy was closed. The agreement reduced Statoil's working interest in its non-operated U.S. southern Marcellus onshore asset from 29% to 23%.

Statoil agreed to divest its operated properties in West Virginia to EQT Corp. for $407 million in cash. This divestment of non-core assets comprised about 62,500 net acres. Statoil retained its operated properties in Ohio and its non-operated Marcellus positions.

As of April 1, Statoil was the sole operator in the Eagle Ford. Statoil had a 63% interest in the leasehold and Repsol had the remaining 37%. The company was operating one rig in the Eagle Ford.

Whiting Petroleum Corp.

- **443,125 net acres in Williston Basin**
- **Expected to have about 105 DUCs at year-end 2016**

In the Williston Basin Whiting Petroleum had 443,125 net acres with 99% of its acreage HBP. The company had 5,471 potential gross drilling locations as of Sept. 30, 2016.

"Our 13 new wells completed in [the Rolla Federal Unit] in McKenzie County tested at an average rate of 3,727 boe/d. Our leading-edge design with 10-plus million pound completions in Williams County are tracking a 1.5 million boe type curve," said James Volker, Whiting's chairman, president and CEO, in the company's third-quarter 2016 report on Oct. 26.

On July 27 Whiting closed the sale of its North Ward Estes Field in Ward and Winkler counties in Texas to a third party. The cash purchase price was $300 million. Whiting planned to operate the properties under a transition services agreement for three months after the closing date of July 27.

Whiting estimated the properties subject to the sale consisted of net daily production of about 8,600 boe/d in June 2016. This equates to a net cash price of about $34,900 per boe/d.

Whiting completed 48 wells in the Williston Basin with its enhanced completion, which consisted of 36 stages and 6.6 million pounds of sand. Whiting expected to have 22 drilled but uncompleted wells (DUCs) as of Dec. 31.

The company had two large-volume completions on wells in Williams County. One was completed with 13.6 million pounds and the other with 10.1 million pounds of sand.

The company also was developing the Niobrara A, B and C shales and the Codell/Ft. Hays formations in the Redtail Field in the Denver-Julesburg Basin in northeast Colorado. The company had 129,035 net acres in the prospect. The company expected to have about 105 DUCs at year-end 2016. ■

A tangle of transfer lines awaits deployment. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

(Photo courtesy of Cameron)

Completions Tech
Continues to Evolve

By **Jennifer Presley**, Senior Editor, Production

Upgrades in technology and innovative thinking continue to deliver effective well completion solutions.

Operational efficiencies and hydrocarbon recovery rates are two areas that operators, service companies and equipment manufacturers are focused on in this era of fiscal restraint. With hydraulic fracturing remaining the biggest big ticket item when it comes to drilling and completing a well, doing so safely and in a timely manner without breaking the bank are critical.

Be it big iron or megabytes, new technologies that can deliver results through optimum performance are key. These technologies, selected by the editors of *E&P* for their ability to deliver new solutions to tricky challenges, were showcased in 2016 as part of Hart Energy's DUG Conference and Exhibition events held across the county.

Confirm casing integrity

One example of how proven technology has been adapted to meet today's challenges is TAM International's PosiFrac Toe Sleeve (PTS). Winner of the 2016 Hart Energy's Special Meritorious Award for Engineering Innovation in Hydraulic Fracturing/Completions, the PTS is the industry's only flow-path initiation and stage-one stimulation tool to utilize field-proven valve technology to initiate actuation during the final bleed-down cycle following one or more successful casing integrity tests (CIT).

"The PTS offers a number of benefits that other tools on the market do not," Justin Bowersock, global product line manager, Cement Integrity and Completion Systems for TAM International told attendees of the DUG Permian Basin Technology Showcase held in May 2016. "We leveraged valving technologies that we've had for over 45 years to develop an innovative and unique solution."

There are, he noted, two types of conventional toe sleeve systems.

"The legacy systems, which are often referred to as burst disk subs, are essentially the grandfather of toe sleeve technology," he said. "These systems are simply one-shot tools that enable operators to establish injection so that stage-one perforating guns can be pumped to depth on wireline in lieu of being run in on coiled tubing, saving valuable time and money.

"However, to perform a valid CIT, the operator must first pump a dissolvable ball to an integral seat in the tool or a separate landing collar installed above the tool once injection has been established," he said. "This added operation requires a significant amount of water and time to pump the ball to bottom. At the conclusion of the CIT, the operator must then wait until the ball has dissolved enough to extrude through the landing collar or seat to reestablish injection through the open tool.

"The second type is a metered system that utilizes rupture disks and a metering valve. Once the disk has been burst, fluid is squeezed through an orifice at a predetermined rate until enough pressure has been transmitted to hydraulically shift a sleeve and open the tool. During this metering process, a CIT can be performed to validate casing integrity without the need to pump a dissolvable ball to bottom. However, in some instances temperature fluctuations and fluid volatility can

Opposite page: Continuous evolution in technologies are helping operators complete more wells in less time.

accelerate the metering process causing the tool to open prematurely. If this occurs before the duration of the CIT is complete, intervention operations will be required in order to perform a valid CIT."

The PTS enables operators to test the casing to maximum values for as long as necessary and subsequently establish communication with the reservoir without ever exceeding the validated CIT values or incorporating ancillary tools. The sleeve, once open, is held in place by a mechanical locking feature and via hydraulic forces, preventing it from closing at any time post-actuation, according to the company.

"The goal of the PTS was to give operators a means to utilize some of the key features and benefits of existing tools while also getting rid of some of the functional issues associated with those same tools," he said. "We can hold test pressures for any length of time necessary. The tool will not function until you've established a certain differential pressure between your maximum test pressure and a predetermined bleed-down threshold."

The PTS also has an extremely large inside diameter (ID), enabling the utilization of a variety of industry-standard wiper plugs. A number of other products have reduced IDs, requiring extremely costly specialized plug sets and landing collars to ensure adequate wiping efficiency is achieved, according to the company.

The sleeve is rated to perform in temperatures up to 350 F and pressures up to 20,000 psi. It features a debris-tolerant actuation system, a large flow area for high-rate stimulation treatments and an integral ball seat in the top sub for contingency pressure testing.

The PosiFrac Toe Sleeve is a flow-path initiation and stage-one stimulation tool. *(Image courtesy of TAM International)*

Efficient, safer stimulations

The QuickFRAC system offered by Packers Plus combines the efficiency of a ball-drop system with a cemented liner completion to help facilitate even fluid and proppant distribution throughout multiple entry points in a treatment zone. Because the stimulation treatment for the entire system is completed in one continuous pumping operation, completion time and costs are reduced, according to the company.

"Our QuickFRAC system integrates cemented liner design with the efficiencies of a ball-drop system," Josh Baker, manager of strategic marketing and sales support for Packers Plus, told attendees of the DUG Permian Basin Technology Showcase. "The system is a limited entry multistage completion system that's designed to be cemented in place, or it can be run in open hole, depending on your application. It's ball-actuated and uses injection ports to emulate the perforations from a plug-and-perf job but with much greater speed."

In addition, the system uses one ball to open multiple sleeves, and it eliminates the need to run perforating guns and plugs downhole. Pumping time and the volume of water used are two additional benefits of the systems, he added.

"This allows us to cut down on time and cost from running guns and removes the cost and risk of running wireline and coiled tubing from the job," he said.

The system is designed with very few moving parts. The ball travels downhole to activate the sleeves in the treatment zone. When the ball lands in the first QuickPORT IV sleeve in the treatment zone, pressure increases, and the sleeve shifts open. The ball then moves to the other sleeves in the zone, activating each sleeve, until it stops in the final sleeve. Incrementally larger diameter balls are dropped to activate sleeves in the subsequent treatment groups, according to the company.

"Generally, these sleeves are run in conjunction with one another," Baker said. "Two is the minimum, and we can go up to 10 or however many are needed to stimulate the well. However, we do see efficiencies fall off at a certain point. Generally we see them run in clusters of four."

Two common questions asked during a stimulation treatment are: Did the ball leave the surface,

and did the port shift and open? To answer these questions, Packers Plus developed ePLUS Retina, a system that provides real-time verification that these events did or did not occur, and the system operates independent of the data van.

"Retina provides an independent way to monitor everything that happens on the surface and downhole in your well during the stimulation. With this tool, we can tell you whether a ball has left the tree on the surface or it's landed on the seat or the seat has shifted," Baker said.

The system provides clear indication of the tool functions in real-time and does not interfere with the stimulation, according to the company.

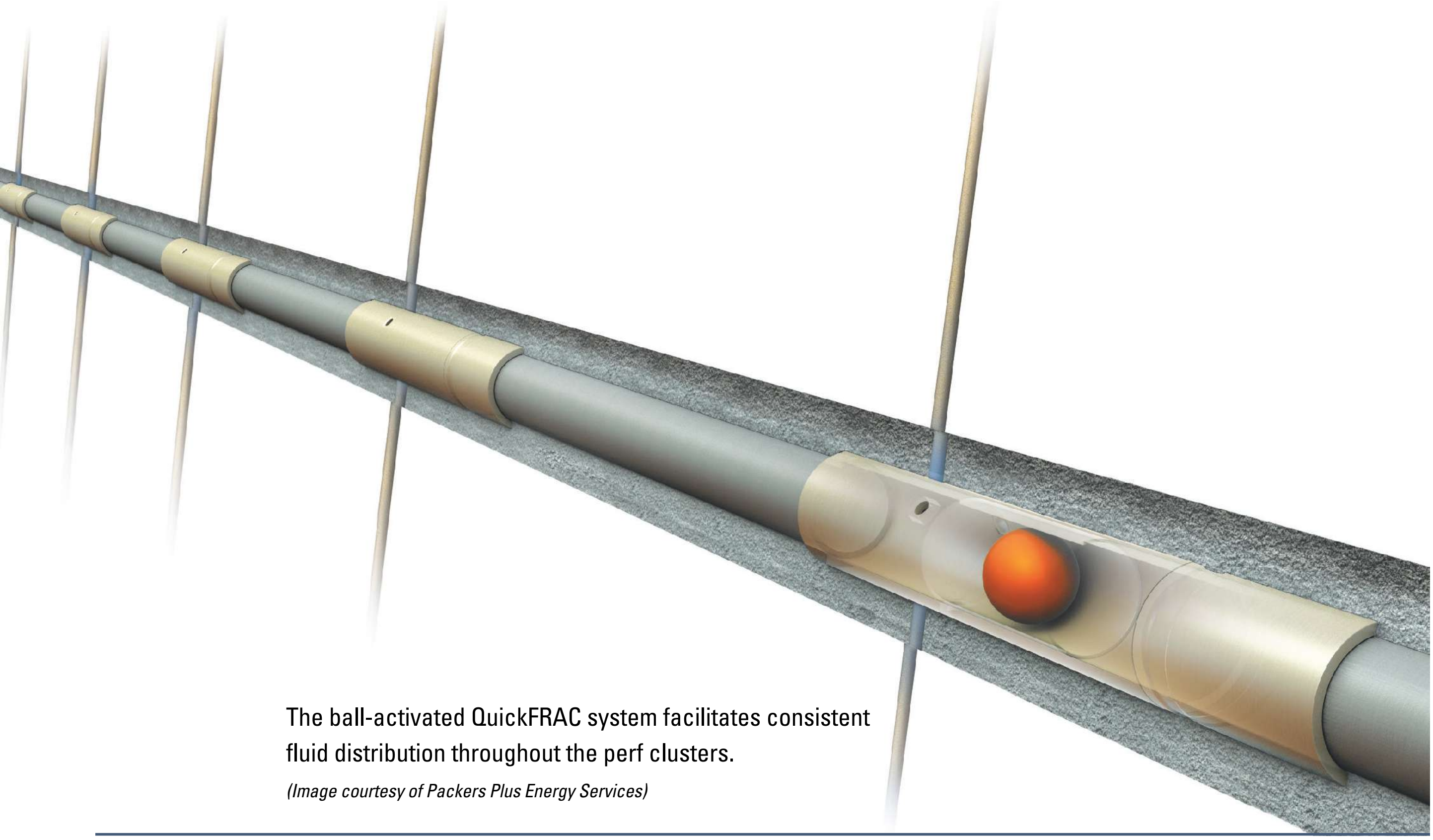
"Retina is highly effective in a couple of areas, particularly wells with low bottomhole pressure where we can't get good indications at surface that the ball has actually landed on seat," he said. "With limited entry systems like QuickFRAC, where one ball opens several sleeves, we need to know if all of those sleeves opened.

"The system can also be used in conjunction with automatic ball launchers. Not all ball launchers are created equal. Some are very good. Some are not quite so good, but all of them will eventually give you a problem. With Retina, we can tell whether the ball left or not conclusively."

Dissolvable disruptions

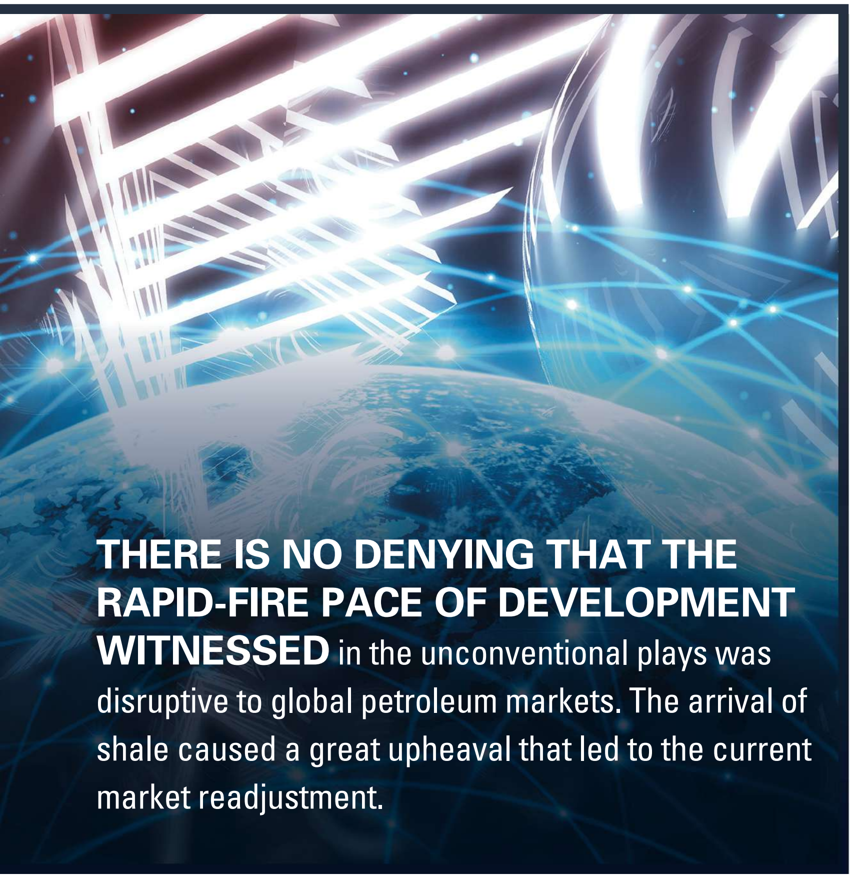
There is no denying that the rapid-fire pace of development witnessed in the unconventional plays was disruptive to global petroleum markets. The arrival of shale caused a great upheaval that led to the current market readjustment. Business as usual was no more. In time, the same could potentially be said about the use of dissolvable tools like frack balls and plugs. Like the unconventional wells they are used in, dissolvable balls and plugs are disruptive, according to Garrett Frazier, vice president of sales and marketing for Magnum Oil Tools.

"People tend to be impatient with new technology, preferring sustainable technologies as disruptive technologies tend to scare us. This applies to our industry," Frazier told attendees of the DUG Eagle Ford Technology Showcase held in September 2016. "We're comfortable with small improvements to existing technologies. Accepting disruptive technologies can be a hurdle to large companies.



The ball-activated QuickFRAC system facilitates consistent fluid distribution throughout the perf clusters.

(Image courtesy of Packers Plus Energy Services)



"With sustainable technologies, we rely on small incremental improvements to an already established technology. Think about some of the first composite plugs ever run in our industry, back in the early to mid-90s. Here we are today in 2016, some 20 years later, and we're still trying to perfect that product.

"Disruptive technology lacks the refinement and often has performance problems because it's new. It appeals to a limited audience and may not yet have the proven practical application. For example, Alexander Graham Bell's electrical speech machine was a disruptive technology. Dissolvable technology is disruptive. It's not the way we've always done things.

"It's changing the way well completions are being performed. Let's reel back. Let's think about the history of dissolvable technology. We're only looking at a couple of years here. The first dissolvable product used was the dissolvable ball—a simple sphere used in sliding sleeve technology."

The way that wells were being completed was to use a metal or composite ball that had to be removed or drilled out because it would get stuck on the seat and impede production. Dissolvable technology eliminated the need for well intervention to remove those metal or composite balls.

"Ten to 15% of the wells that are completed use sliding sleeves technology," he said. "Plug and perf is king, as it is the preferred method to complete wells not only in the U.S. but elsewhere. As lateral lengths increase and stage spacing decreases, dissolvable technologies such as the Magnum Vanishing Plug [MVP] have become a more a viable option in well completions today. But there are challenges."

One is the increased use of sand in stimulation treatments, per stage and per well.

"In well completions, if a ball seat is left behind, sand is going to pile up and cause an obstruction to your production. That is the reason for the push for a 100% dissolvable frack plug," Frazier said.

For example, in February 2016 an operator in the South Central Oklahoma Oil Province was looking to improve well economics and efficiencies in an 18-stage horizontal well where the effective reach of coiled tubing was limited. The MVP was selected for this job to eliminate well intervention and get to production faster rather than using composite plugs for wellbore isolation and coiled tubing for removal operations, a Magnum-issued case study stated. The well was put on production faster and without drilling out a single plug or needing to conduct a cleanout run with coiled tubing. The operator reduced its time to production by 90%.

The environment of the wellbore is the second challenge. It dictates the success of the dissolvable technology.

"The majority of products out there use a magnesium-based material, which requires a specific chloride content in the wellbore fluid. Certain parameters within the environment are needed for that magnesium to dissolve properly," he said. "At Magnum we use a thermoplastic material that is subject to the well temperature. Without the right well temperatures, the plugs will not dissolve at the rate needed. That is a challenge we've been working on and have now overcome."

The thermoplastic material used is the same material surgeons use for dissolvable stitches that are eventually absorbed by the body, Frazier noted.

"It is the same material we use in our dissolvable frack plugs. It turns into a liquid," he said. "With other frack plugs, the entire plug is made up with magnesium. It will crumble and eventually turn to a powder with the right amount of time, temperature, pressure and the proper chlorides."

The economics of well completions is the third and most important challenge, according to Frazier.

"In today's environment, the price of coiled tubing, the price of intervention, the three-digit price of composite plugs is so low that it's almost at a breakeven point with dissolvable technology," he said. "However, as we move forward and look into the future as to how dissolvable technology will be relevant in our industry, like with all disruptive technologies, the industry is working hard to figure out these challenges.

"Composite plugs are still used in nearly 90% of the wells today, and they are still being perfected. Dissolvable technologies also are still being perfected, and we're positive that they are not going away."

Optimized fracture treatments

Field experience has shown that when attempting to fracture multiple perforation clusters using limited-entry techniques, most of the proppant goes into one or two major fractures. When this occurs, it can potentially leave a large portion of the formation unstimulated and part of the fracture network without proppant, according to a Halliburton press release.

"Diversion technology has been one of the fastest growing technologies in unconventional history, and there's a good a reason for that," William Ruhle, completions engineer for Halliburton, told attendees at the DUG Rockies Technology Showcase held in March 2016.

"Our stimulation job volumes have increased dramatically over the past few years. In the same time the pressure drop created by limited-entry techniques only lasts for a small portion of the treatment," he said.

Empirical tests and scientific data suggest that a single perforation tunnel can erode to a near zero pressure drop within about 2,000 lb of proppant passing through it, he noted.

"Pinnacle, our subsurface diagnostics business unit, has monitored more than 400 frack stages across the U.S. using fiber-optic technologies. The aggregate of all these individual projects suggests that, on average, less than 60% of our clusters are being effectively stimulated and contributing to production," he said.

To address this issue, the company developed its AccessFrac stimulation service. The service was designed to optimize fracturing treatments by assuring that each perforation cluster in each interval receives the designated amount of proppant, according to the company.

"AccessFrac increases the surface contact area of the stimulation treatment by repeatedly constraining and redistributing the flow of fluid across the entire treatment interval," Ruhle said. "A properly engineered AccessFrac design will consist of a high intensity of proppant and diversion cycles repeated throughout the same stimulation treatment. These frack designs are designed to divert the fluid flow from dominant fractures during a treatment and initiate new fractures in the same treatment in parts of the reservoir that previously weren't getting stimulated."

According to a case study, the AccessFrac system and the company's RapidStage Multistage Frac Sleeve system were used to assist operators in the Bakken and Three Forks formations to increase compartmentalization in their wellbores by adding more fracturing stages to achieve more fracture surface area per lateral foot. The end goal was to access more productive reserves while also minimizing completion time to bring wells on production sooner.

The combination of the two systems along with the Swellpacker isolation system enabled up to 55 individual ball-drop stages for efficient openhole completions. The RapidBall DM dissolving ball technology eliminated to the need for post-stimulation intervention to ensure well production, according to the company.

As a result, production was brought online an average of three days faster and the number of effective fractures doubled without additional completion equipment or intervention procedures, according to the case study. The enhanced stimulation process improved the overall fracture quality. ■

(Photo by Tom Fox, courtesy of Hart Energy's Oil and Gas Investor*)*

Solving the Production Puzzle

By **Jennifer Presley**, Senior Editor, Production

Adaptation, collaboration and innovation lead to better insights into the effective and efficient production of hydrocarbons from unconventional reservoirs.

When faced with the challenge of assembling a thousand-piece jigsaw puzzle, the easiest pieces to start with are the edges. Set those first and then begin to work in, adding and removing pieces, rotating them this way and that, and before long the puzzle is complete. Unconventional reservoirs are the puzzles that have sat at the top of the industry's hydrocarbon resource development closet for years. Over a decade has passed since a man named Mitchell connected the right pieces in the Barnett Shale that set operators, service companies and equipment manufacturers scrambling to play across North America.

Edges now set

Technology advancements in seismic acquisition and interpretation increased knowledge of reservoir dynamics, leading to better placement and design of wells. Multiple wells drilled, combined with longer laterals that contacted more of the reservoir, provided for increased drilling efficiencies and increased recoveries.

The downturn in the market shifted development focus from drilling and completing more wells to producing more hydrocarbons from operating wells. New technologies and the adaptation of old ones are delivering solutions for production challenges that are oftentimes present in unconventional wells. Some of these technologies were showcased this year as part of Hart Energy's DUG Conference and Exhibition events held across the country. Selected by the editors of *E&P*, these technologies are helping operators continue to fill in the development puzzle.

Jet-powered cleanup

An added complexity found in producing unconventional wells is the staggering amount of sand pumped downhole during hydraulic fracturing operations. For example, a mid-June 2016 Hart Energy *Heard in the Field* survey reported that natural sand was the most common proppant used in the Permian Basin, averaging about 12.5 million pounds of sand per well. This number is up from 8.8 million pounds of sand per well reported in March.

Operators are embracing hydraulic jet lift systems to assist in cleaning up the well after it has been completed.

"We've seen an absolute boom in the amount of installations of hydraulic jet lift in the Eagle Ford, primarily for flowback and frack recovery," Scott Campbell, vice president of global sales and marketing, Artificial Lift Systems, for Weatherford told attendees at the DUG Eagle Ford Technology Showcase held in September. "We estimate that across the industry there are about 400 jet pumps running in the Eagle Ford today."

Strengths of a hydraulic jet pump include its ability to move large volumes of sand, solids and liquids quickly. In an Eagle Ford well, it is possible to see frack flowback rates as high as 2,000 b/d to 3,000 b/d initially, Campbell noted.

"Jet pumps are absolutely perfect for frack flowback applications to manage the dirty, sandy conditions of the well cleanup and keeping it on afterwards as a long-term lift solution," he said.

Hydraulic jet pumps also offer a rigless intervention solution.

Opposite page: Advances in artificial lift could lead to the eventual abandoning of pumpjacks, like this one seen at work in the field where an old rusty Chevrolet 6100 truck fades into time.

"Once the initial tubing installation is in the ground and the bottomhole assembly is set up correctly, the pump can be simply serviced by reverse-circulating the pump from surface by turning two valves," he said.

"We've seen flowing bottomhole pressures down to about 350 psi. That's substantial. A lot of people are surprised by that. They have not experienced that with hydraulic jet pumps before."

Hydraulic jet lift systems are being installed as an alternative to reciprocating rod lift in deviated wells.

"We're installing these systems in wells with severe deviations," he said. "Severe deviations in the well can prevent conventional rods from staying in the hole. While we're not suggesting that jet pumps replace all conventional rod-lift systems, we're having great success with jet pumps in that application."

Bridging the gap

Installing an artificial lift system is the next step when the natural flow of a well is expended. Each type of lift system has its own merits and drawbacks. By combining the strengths of gas lift and plunger lift, a hybrid lift method called gas-assisted plunger lift (GAPL) provides a cost-effective solution in bridging the gap between the two systems.

"With a typical gas-lift well you're always going to have high-pressure gas at surface. That gas is injected down the annulus between the tubing and casing of the well, making its way into the tubing through one gas-lift valve at the deepest point possible. As that gas enters the tubing, it actually decreases the density of the fluid, which lightens the fluid, making it easier to lift," said Todd Thrash, Mid-Con regional manager for Priority Artificial Lift, at the DUG Permian Basin Technology Showcase held in May.

"We incorporate a plunger lift system into an existing gas-lift system to operate a GAPL application," he said. To make the switch, a lubricator is installed onto the wellhead that receives the plunger at surface. This also allows for easier inspection and maintenance. A control box is installed along with a plunger arrival sensor that, according to Thrash, work together as the "brain of the system."

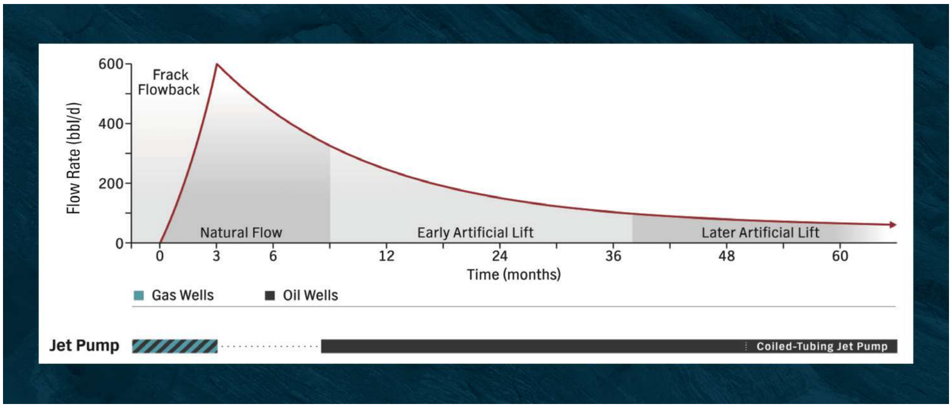
"As your plunger brings fluid to surface, unloading the fluid through the flow line and then onto the separator, it passes by the arrival sensor located on the lubricator. The arrival sensor sends a signal to the controller that the plunger has arrived and to switch the mode of operation to the next part of the cycle."

A plunger is installed downhole to increase the sealing efficiency between the gas and water interface. It also works to ensure that the inner diameter of the tubing is cleaned and maintained, Thrash noted. A downhole bumper spring is installed to prevent the plunger from falling past a certain point in the production string. "In a typical Eagle Ford or Wolfcamp well, we're looking at anywhere from a 20-degree to a 45-degree deviation," said Thrash. "An important design consideration is the proper placement of the bumper spring.

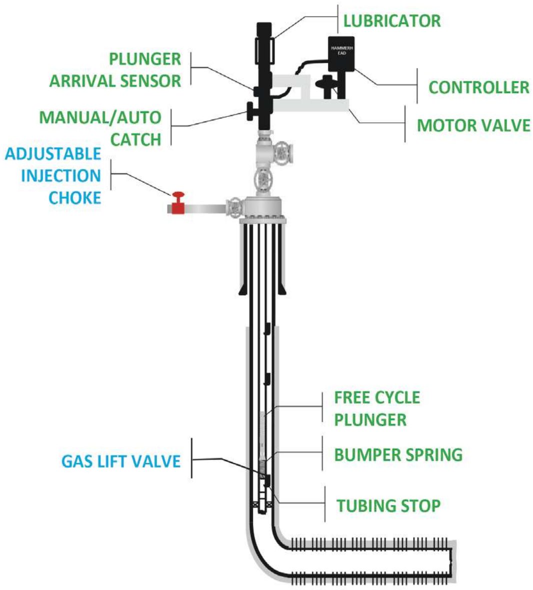
"We need to understand where our current point of injection is so that we can get as close to that point of injection as possible when we set the bumper spring. Doing so creates a more efficient seal throughout as much of the tubing string as possible, creating more drawdown and increased production."

The two systems working together flatten the decline curve, ultimately prolonging the requirement for more costly types of artificial lift, he added.

"We're lowering lifting costs. As bottomhole pressures decline in existing gas-lift wells, so does production," said Thrash. "We tend to



Hydraulic jet pumps are capable of handling the dirty, sandy conditions of the frack flowback stage in the early stages of a well's life as seen here on this decline curve for the Eagle Ford Shale. *(Image courtesy of Weatherford)*



GAPL is a hybrid lift method that uses both gas lift (in blue) and plunger lift (in green) to artificially produce gas and/or oil wells. *(Image courtesy of Priority Energy)*

see gas breaking through the fluid column and fluid falling back along the tubing walls and onto the formation, creating unnecessary back pressure," he said.

"The plunger effectively reduces the amount of fluid falling back on the formation, creating drawdown and maximizing production. The more efficient seal that a plunger and a GAPL application create actually allows us to lift the same amount or same volume of fluid with less injection gas."

Injection gas can be tapered off in most cases, he added, with the application eventually moving into a single-stage plunger earlier than if there had not been a GAPL system in place.

"An operator in the Permian Basin had the goal of reducing its injection gas and keeping the tubing clean. The operator determined prior to the workover that it would install 2-3/8-in. tubing along with a GAPL system," said Thrash. "Once the well was put back online, there was a significant increase in gas production. The increase actually allowed for close to a 50% reduction in gas-lift injection gas. As production stabilized, they were actually able to taper off their injection gas, and this well was put on free-cycle plunger lift alone. The operator's return on investment occurred in less than one week."

Associated costs from hot oil treatments or chemical treatments are also reduced since GAPL is an effective method for paraffin and scale control, he added.

"Paraffin control is really what brought GAPL to the game in areas like the Texas Panhandle, the Permian Basin and the Eagle Ford," he said. "In one example, an operator in the Permian had the primary goal of controlling paraffin and reducing associated costs. Like many operators in the Permian, the operator was already utilizing a gas lift system. Transitioning to the GAPL system involved the installation of a low-cost plunger lift system. Following the installation of GAPL, results showed that lease operating expenses were lowered as we essentially did away with the hot oiling required to control the paraffin. We also more than doubled the gas and oil production."

Fewer slugs, more lift

It is only fitting that an unconventional approach would be found to smooth out flow in unconventional horizontal wells. Through trial and error, Production Plus Energy Services developed a system that does just that.

"For many years we battled production issues in our horizontal wells. Poor run time and the inability to draw the well down were just two," Jeff Saponja, the company's CEO, told attendees at the DUG Rockies Technology Showcase held in March.

In the end, the company realized that all the challenges they were experiencing were actually symptoms of a root issue that was not being addressed.

"We studied the flow behavior in our horizontal wells and correlated down time and pump failures to production interruptions," he said. "For example, we found that any time we had a power failure in the field, we'd have pump failures and major pump gas interference events upon restarting the pumpjack. We discovered that the root issue is that horizontal wellbores, by their very nature, are great separators. As a result, the flow coming out of the horizontal wellbore to where a pump is placed is actually very inconsistent. It became obvious that no pump likes inconsistent flow."

Studying slug flow behavior in multiple wells, the company found that some wells were "sluggier" than others.

"Why did some wells slug so badly?" he asked. "It turns out that how the wells were drilled matters."

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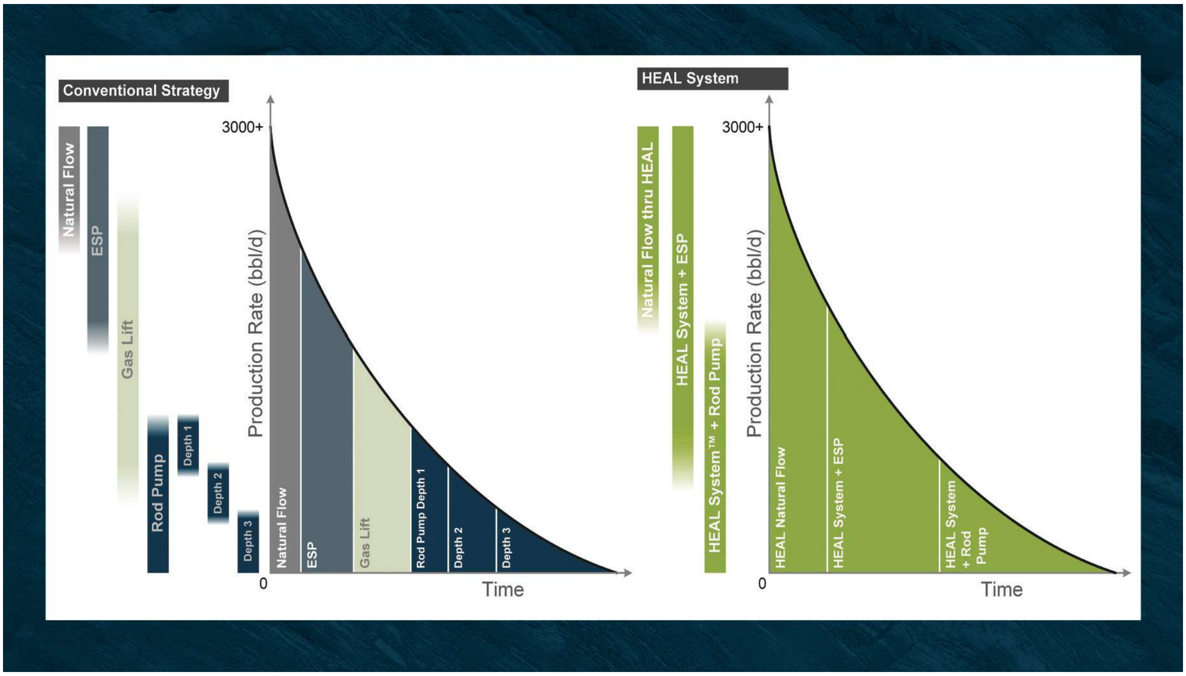


The HEAL System bridges the gap between natural flow and expensive intermediate lifting solutions to significantly reduce the cost per barrel of oil. *(Image courtesy of Production Plus)*

The more the wellbore undulates or is "toe-up," he explained, the worse the slugging.

"Toe-up horizontals have the most severe slugging. In the toe-up wellbore case, a large gas bubble forms in the toe of the well, and eventually the bubble becomes unstable and releases in a very violent manner. That's what can kill the pump or greatly reduce its performance," he said.

According to the company, conventional artificial lift systems struggle with horizontal wells that present rapidly fluctuating fluid rates and surges, solids issues, and gas interference. In looking for a fix, the company hypothesized that eliminating slugs by flow conditioning would deliver the results it was looking for: reliable maximization of drawdown.

To accomplish this, the company developed the patent-pending Horizontal Enhanced Artificial Lift System (HEAL). The system, comprised of a seal, a sized-regulating string and a vortex separator, settles the inconsistencies of horizontal flow and as well as reducing fluid density to lift the fluids up to the vertical where the pump can operate efficiently.

"Conventional artificial lift systems are designed for the vertical, so we said let's leave those in the vertical," he said. "We focused on smoothing the flow and lifting from the horizontal around the bend up to the vertical. We condition-flow from the horizontal to the vertical using what we call a sized-regulating string or SRS. Inside the string are custom designed liners. The internal diameters of the liners are varied to dampen and condition the flow, so the downhole separator and pump see a consistent rate," Saponja said.

"We took surface separator technology and brought in cyclonic vortex technology downhole, which greatly enhanced downhole separation of gas and solids. Gas and solids are separated out, protecting and giving the pump what it wants: smooth liquid and solids-free and gas-free flow. Our pump efficiencies went from 40% to 90%, with considerable extension in pump run life. We also found that our pumpjack sizes were now too big. Instead of a 640 jack, we might have 320 because of all the efficiency gains, reducing our capital costs in the artificial lift systems."

The company also found that drawdown could be simultaneously maximized, which increases production rate and reserves.

According to the company, the HEAL System can enhance the effectiveness of a variety of artificial lift systems, including sucker rod, electric submersible, progressive cavity and plunger lift pumps.

"The HEAL system makes the artificial lift system 'think' it's in a sumped vertical well. And so you operate it like a vertical well. This has reduced our operating cost by 30% or more," Saponja said.

The HEAL System has been installed in more than 125 wells across North America.

Lessons learned

Sand and gas in the flow present a unique set of challenges to artificially lifting a well. Where gas can choke a pump, sand abrades it over time. Solutions are similar to those used in conventional vertical wells but with modifications.

"Unconventionals have taught us a lot," Charlie Fowler, vice president of technology for Dover Artificial Lift, told attendees at the DUG Permian Basin Technology Showcase. "These wells have accelerated improvements to all forms of artificial lift for handling sand and gas."

Some of the key lessons include an acceptance that there is no one perfect solution and that each well is unique, Fowler noted. However, the preferred solutions share the primary goal of keeping sand and gas from entering the pump.

For gas removal, slowing the flow is critical to encourage natural separation while performing a directional change to break the gas out of solution and, using geometries in the pump configuration, direct the gas out to the annulus, he noted.

"For sand removal, we take a different approach. In some cases we speed the fluid up and use centrifugal separation. We can then reverse the flow to get the sand to fall out and deposit either into a rathole or additional joints of tubing," he said.

To accomplish this in the field, the company's SPIRIT Hybrid-X separator uses cyclonic motion for sand removal and internal baffling for gas removal.

"We've had particular success with this separator in rod lift applications," said Fowler. "You've got gravity working against the sand and buoyancy working against the gas. By using those physics, we're able to get that separation."

In situations where the gas and sand can't be prevented from entering pumps, there are solutions available. "Most of the time the sand causes more problems with abrasive wear between running surfaces than it does from just pure erosion," he said. "It's those tight clearances in the pumps where sand gives us trouble. There are two approaches we can take.

"One is to make pump materials are harder than the sand. You can use harder base materials or, in most cases with pumps, use a coating or plating."

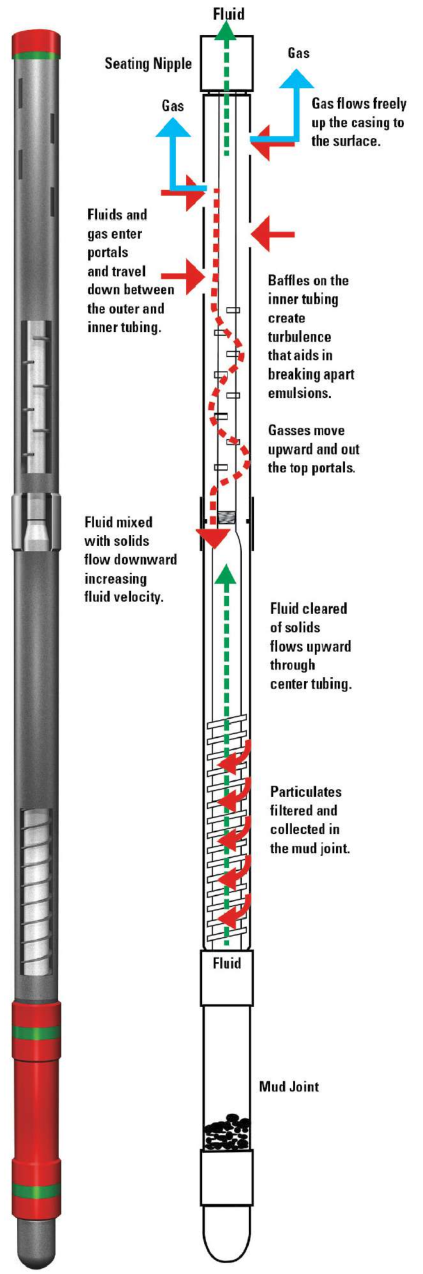
The second is through design. "Work with the geometry of the pump to keep the sand away from critical interface areas such as the area where the plunger and barrel meet in a rod pump. One successful technology is a sand flush plunger, where the fluid is ported in such a way that it flushes sand away from the critical interface between plunger and barrel to prevent the sand from getting trapped."

For unconventional wells, slugging causes considerable disruption in operations.

"If we're designing for a steady state of gas flow or gas concentration, that would be one thing, but when you get the slugging, then you really have to think about the technology involved. One of the things Dover offers is what we call our variable slippage pump," he said.

According to Fowler, the key technology in the pump is the tapered barrel that allows a bit of separation of the gas.

"Like many technologies, you've really got to work with your application and people and dial these things in. One of the things we found with this pump is that you really have to pay attention to your application. You just can't put it in there and hope it works. You've got to pay attention to where you place the plunger relative to the barrel and take some time to optimize it." ■



Dover's Spirit Hybrid-X Separator helps keep gas, sands and solids from reducing oil production. *(Image courtesy of Dover Artificial Lift)*

The sun sets on the West Texas horizon as a thunderstorm approaches.

(Photo by Tom Fox, photo courtesy of Hart Energy's Oil and Gas Investor*)*

New Technologies

Deliver Cleaner Air, More Water Options

By **Jennifer Presley**, Senior Editor, Production

Innovative solutions help operators keep costs low in an environmentally friendly manner.

There are many areas under construction within the puzzle of unconventional resource development. One is protecting the air quality surrounding fracturing operations. The other is the safe and efficient management of water, be it sourcing, treatment, transport or disposal.

The downturn in oil markets lead to the redoubling of efforts to trim expenses and deliver cost savings where ever possible. The use of field gas to power fracturing fleets helps keep fuel costs low and is just one area where operators are finding savings. The other is water reuse and using smart technologies like automation to advance their water management practices. Some of these technologies were showcased in 2016 as part of Hart Energy's DUG conferences held across the nation. These technologies, selected by the editors of *E&P*, have demonstrated their ability to help operators do more with less.

Quiet fracturing

Dirty and loud are two of the more common complaints lodged by the public against hydraulic fracturing operations. However, operations are whisper-quiet and the air is cleaner when electric-powered fracturing fleets like those offered by U.S. Well Services are in use. The company's Clean Fleet system incorporates existing industry equipment configured to provide fracturing services with enhanced safety features, smaller physical and environmental footprints as well as reduced noise levels at a lower cost relative to traditional fracturing equipment. The system is a fully mobile, fully electric hydraulic fracturing system fueled entirely by natural gas.

Electric motors have replaced the conventional diesel engines. Emissions were decreased by 99% compared to diesel-powered fleets. The reduction was achieved through the use of electric motors powered by natural gas turbine generators.

"We use field gas with a little bit of conditioning ourselves," Jared Oehring, vice president of technology for U.S. Well Services told attendees at the DUG East Technology Showcase held in June. "We can also run on CNG [compressed natural gas] or LNG. CNG is a little bit easier if you have less than about 35 miles to 50 miles of transportation. We connect the CNG feed to our current line and if the pressure drops below a certain rate, the CNG will automatically kick in and continue to feeding the system with gas."

The system uses between 3 MMcf/d to 4 MMcf/d and the turbines are equipped with high-quality injectors and nozzles so the system can accept a high variety of fuel value, he noted.

The Clean Fleet Whisper Technology was designed for low-noise impact hydraulic fracturing by reducing noise pollution, making the workplace safer and less disturbing to surrounding communities.

"Because we're using a turbine, we're able to reduce over 13 decibels which ends up being about a 95% reduction in low frequency noise, which is one of the top complaints received from the public about fracturing operations," he said.

Other benefits of the system include reduced downtime and maintenance costs along with longer a lifespan.

"On the electric motors we use the first major service interval is 30,000 hours," he said. "At that point, we need to replace the bearings. The first units made, the 'parents' for the motor that we're now using, were built 20 years ago and are still in use in the field now. Our turbines have operated everywhere, from the Arctic to the Sinai Desert. They can handle extreme applications and last significantly longer than diesel equipment."

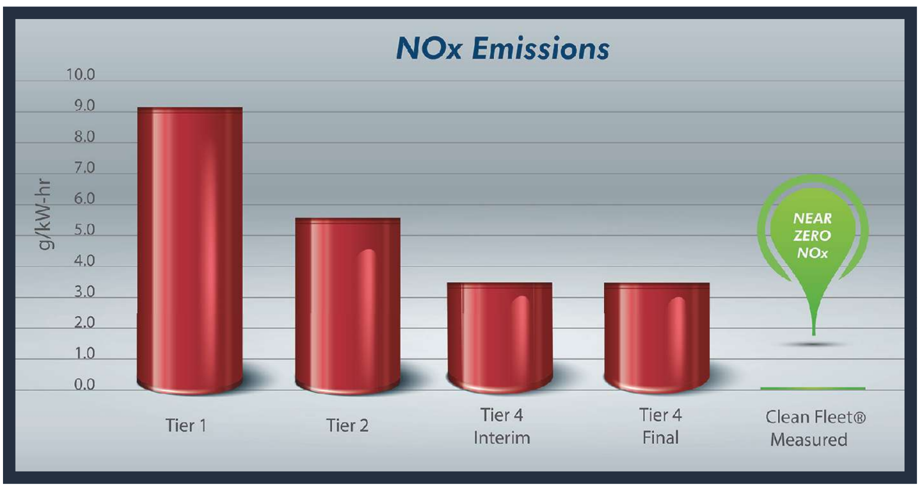
Reducing operating emissions is one of the primary reasons cited for the company going all-electric with its fracturing fleet, according to Oehring.

"Industry is moving to Tier Four with diesel engines. That's 3.5 grams per kilowatt hour," he said. "On our electric fleets, our NO_x [nitrogen oxide] emissions, we're at 0.036 grams per kilowatt hour. We're getting to near elimination of emissions."

In addition to reduced emissions, the company also has seen a reduction in fire risks.

"A huge hazard we see is the potential for a fracturing fleet to catch on fire," he said. "When you do not have a diesel engine, there is no turbo to spill hydraulic fluid onto and catch fire. The fire risks are significantly reduced with the Clean Fleet."

Emissions are reduced up to 99% for a Clean Fleet site. *(Image courtesy of U.S. Well Services)*



Freshwater alternative

Mounting concerns about freshwater deficits, growing transportation costs and more are driving demand to reduce the volumes of freshwater required for fracturing operations.

"Over three billion barrels of freshwater were used by the industry for hydraulic fracturing activities in recent years," Bridget Todd, an environmental manager for Baker Hughes told attendees at the DUG Permian Basin Technology Showcase in May. "In using freshwater, you have significant acquisition, storage, transportation and logistics costs. On the other end, you have disposal costs.

"Over 25 billion barrels of water have been produced from wells in the last year. That's a lot of excess sitting there. It's costing our industry quite a bit of money, with $23 billion holistically spent in acquisition, storage and disposal over the last year and a half," she said.

"Only 2% of this produced water is being reused. That's quite a bit that we're throwing away that could potentially be reused. Reusing our produced water not only offsets resource competition for freshwater, it also saves us money as an industry."

The shift in the use of freshwater to the reuse of flowback or produced water in fracturing operations has been made possible through the petroleum industry's research and development efforts.

One such solution is the Baker Hughes family of BrineCare fracturing fluid systems that transform former waste streams into cost-saving alternatives to freshwater systems.

According to the company, BrineCare provides an effective solution that delivers predictable performance by engineering robust product suites that are capable of performing when combined with produced water containing high total dissolved solids (TDS) as part of the fracturing fluid solution.

"We have engineered components of the BrineCare system to work with a variety of conditions. By testing local waters in different basins against different product combinations within our system, a metric of product offerings based on varying TDS levels and temperature thresholds," said Todd. "These are off-the-shelf solutions that can be customized specific to a customer's water."

When the BrineCare system is requested, the company works with the operator to gather data, like bottomhole temperatures, and also collects a water sample to verify TDS. All of this is screened to ensure to that the proposed treatment will work.

BrineCare systems offer easy-to-deploy fracturing fluids engineered to ensure reliable performance across a range of TDS and water temperatures. *(Photo courtesy of Baker Hughes)*

"By having done a lot of the testing on the backend in our labs, we are able to do a quick turn on providing an option to the operator. There is no long wait time for results because we have already completed a large portion of the analysis in advance," she said. "We've already determined which products we know will work well together and how they will perform in different TDS and temperature environments. By completing a thorough analysis of basin water conditions, we also know which products work best in the Permian vs. the Marcellus, for example."

This efficient screening process also identifies whether any treatment of the produced water, such as filtering, is required prior to application to deliver a minimally treated fluid solution.

"One example of where we saved some significant money for an operator in its water costs in a 10-stage frack in New Mexico," she said. "The bottomhole temperature was 155 degrees Fahrenheit with a TDS of 300,000 ppm with hardness levels of 50,000 ppm. For this customer, we saved more than $350,000 for this particular well by reusing water."

Water flexible fracturing fluid

Schlumberger's xWATER Integrated Water Flexible Fracturing Fluid Delivery Service allows operators to reuse up to 100% of produced water. The service, developed to mitigate water management challenges, reduces or eliminates costs associated with water acquisition, conveyance, treatment and disposal, according to the company.

"The xWATER service was developed to mitigate the economic and environmental burden that the freshwater sourcing, transport, storage and disposal carries on fracturing jobs," Juan Miguel Perez Rincon, fracturing fluids global product champion for Schlumberger, told attendees at the DUG Permian Basin Technology Showcase held in May.

According to Rincon, the service enables operators to engineer a specific fracturing fluid, customized for their specific source water's characteristics.

"The fracturing fluid is developed specifically to be compatible with any given water source quality," he said. "We're fitting the fracturing fluid to the water rather than the fitting the water into the fracturing fluid through extensive treatment."

This flexibility allows operators to use flowback or produced water from previous hydraulic fracturing jobs or nearby water sources, including brackish groundwater or seawater. The ability to reuse produced water by adding tailored fluids improves reservoir integrity and maximizes production as compared to freshwater, according to the company.

Fitting the fracturing fluid to the alternative water poses some inherent challenges, like water quality variation, Rincon noted.

"We need consistent fracturing fluid performance during the whole fracture treatment. Formation damage risk has to be prevented and mitigated," he said. "For this, we developed a set of salt tolerant chemistries that are able to handle a wide range of water chemistries along with a novel scaling model that allow us to identify and protect against the scale risks posed by the water/fracturing-fluid/reservoir mixing."

The most complex water with the greatest variation is produced water, he noted, as it mainly consists of soft salts and minerals, hydrocarbons, solids, bacteria, fracture fluid residue and more, all posing a big challenge for operators.

"To address this, the service was developed to be an economical and viable approach to handling this type of water. Especially for cross-linked gels, which have shown to be more difficult to formulate due to their more challenging or complicated chemistries than some conventional treatments such as slickwater or linear gel treatments," Rincon said.

xWATER service uses a cost-effective polysaccharide gelling agent and a proprietary metal crosslinker

xWATER service (shown in blue) cuts the traditional water management cycle in half, reducing or eliminating the costs associated with water storage, transportation, and treatment, and completely eliminating produced water transportation and disposal.

to formulate a "water-flexible" fluid able to handle listed challenges in waters with TDS in excess of 300 kppm. This approach certainly offers a cost-effective alternative to crosslinked gels made out of costly guar derivatives, according to the company. An operator in the Bakken Shale found significant savings through its use of the service in its hydraulic fracturing operations.

"In the Bakken Shale, we see high TDS in the water and it traditionally requires either treating the water or blending it with freshwater," Rincon said. "In one case, we implemented the service and developed a customized fracturing fluid that used 100% produced water without the need to perform any additional water treatment. We eliminated the disposal of about 7 million gallons of produced water, or about 600 tanker trucks per well."

Automated water monitoring

Meeting water needs can be a bit of a Catch-22 situation for operators and service companies. Too much, one runs the risk of overflowing storage pits. Too little creates operational downtime waiting for the water to arrive. Both situations create additional costs in transportation and logistical headaches.

Select Energy Services AquaView system balances out the too much vs. too little water debate by providing real-time visibility of water assets through automated monitoring and tracking, according to the company. It is a system that integrates technology and operational knowledge to optimize water management while reducing labor and storage.

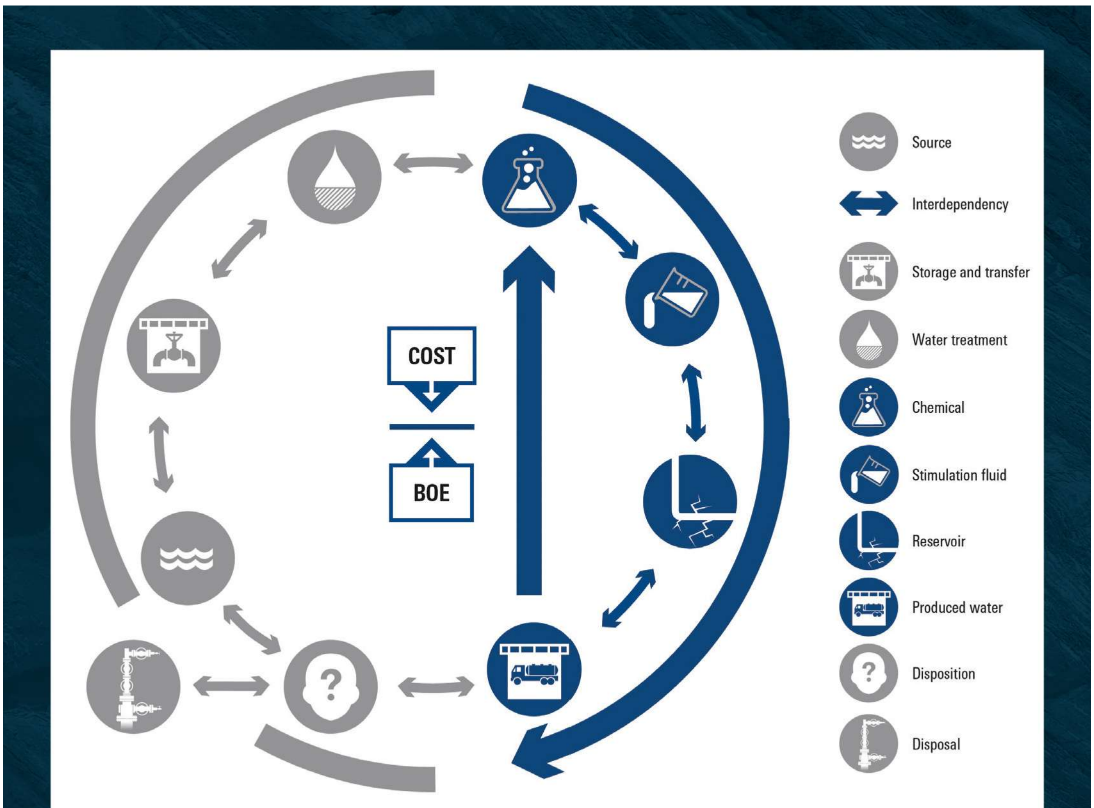
The system offers mapping, monitoring and reporting to gain real-time data through precise and accurate volumetric analysis of storage pits and aboveground storage tanks. This is accomplished through the use of hydrographic mapping vessels (HMV).

"The HMVs create a high-resolution, sonar-based bathymetric map that shows the actual volume of the storage pit or tank," Clay Maugans, water technology manager for Select Energy Services, shared with attendees at the DUG Permian Basin Technology Showcase.

"For example, we mapped a pit that the engineering drawings showed to be an 80,000-barrel pit. It turned out to be a 50,000-barrel pit," he said. "That's 31% less capacity than what everybody thought the pit was.

"The motivation behind the AquaView system is to provide accurate measure, monitoring and tracking. It's the difference between hoping the fracture operation has enough water to complete the job and knowing."

In addition to the HMVs, the AquaView suite includes a full array of auto-



(Image courtesy of Schlumberger. Source: IHS and internal Whiting database as of 12/31/2014)

mated monitoring systems, including remote operation functionality.

"The HMVs are tied into a solar-powered telemetry system that monitors in real time how much water is in the pit or storage tank," he said. "The system is easy to use and features plug-and-play capabilities, so if there is something else you'd like to monitor, say the pH of the water, then we can do it."

The system sends alarms when water gets too high or too low in the pit.

"It will also alert when the water levels are changing too rapidly," he said. "For example, illegal dumping of water into pits has been discovered. Say you have a freshwater pit and all of sudden there's a 2,000 spike in conductivity, you'll know that somebody has backed up a truck in the middle of night and dumped a load of produced water into your pit."

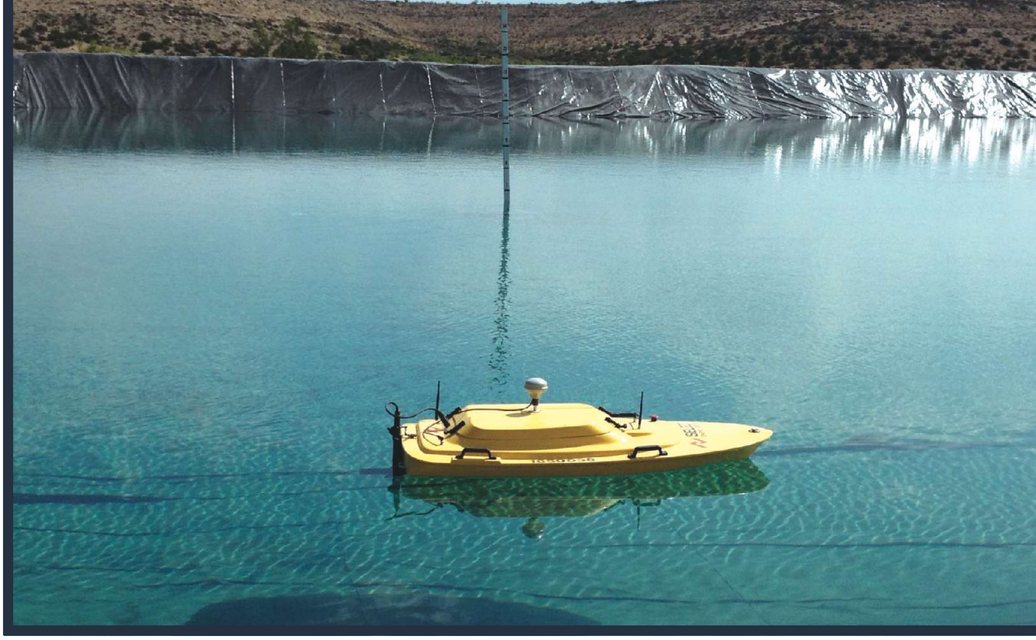
For aboveground storage tanks the system is equipped with leak detection system that is comprised of an entire array of sensors underneath the primary liner.

"This way, you'll know where and when the leak occurs as the system sends you an alarm," he said. "The sensors will automatically reset, so if the leak comes back, the sensors will trip the alarms again."

The telemetry system is tied into its AquaLogic suite of automated water transfer solutions.

"AquaView gives our customers the ability to monitor and track their water; AquaLogic allows them to automate the movement of water and conduct operations closer to their physical limits while maintaining strict safety standards," said Nate Banda, director of operational technology for Select, in a press release.

According to the release, the AquaLogic water transfer pumps use sensors and programming to operate and maintain desired water flow rates by modulating pressure within the system. The pumps remotely and automatically transfer water by raising and lowering pump rpm based on incoming and discharge water datapoints that are collected and shared throughout the system.



HMVs are equipped with sonar, GNSS and compass technology to deliver a complete view of water assets. They are strong and nimble enough to navigate environments ranging from flowback pits to tight tree-filled water sources. *(Photo courtesy of Select Energy Services)*

The automatic proportioning system is the second element of the AquaLogic suite. The system consists of a large manifold equipped with a programmable logic controller and sensors. Operators using the system can combine two fluid streams, such as produced water, heavy brine, flowback water and freshwater, to extend the life of water sources and reduce dependence on saltwater disposal wells.

AquaLogic combines both streams based on operator specifications and can maintain flow rates up to 100 bbl/min. In addition, the system directly integrates with the AquaView system to provide real-time monitoring of the water asset. ■

The APS enables energy producers to combine flowback or produced water volumes into a freshwater transfer. *(Photo courtesy of Select Energy Services)*

Shale Remains Resilient Through Market Downturn

A **Stratas Advisors** Staff Report

Driving down well costs while increasing production and recovery rates have contributed to an enhanced outlook.

Crude oil prices stumbled into 2016 trending downward after OPEC's final meeting in December 2015 that resulted in no action involving the maintenance of production rates. However, the price of crude has made somewhat of a comeback and has been hovering at about \$45/bbl to \$50/bbl through the second and third quarters of 2016. Sentiment has still been uneasy, prompting OPEC to announce a willingness to strike a deal with member countries around cutting back production for most members. Whether the cuts are respected, or even sufficient, leaves operators still a bit unsure about strategy. But activity was clearly increasing through third-quarter 2016, indicating at least a thawing of intentions and therefore capital spending.

Part of the enhanced outlook revolves around what many perceive to be "permanent" improvements in capital and operational efficiencies. "Resiliency" was the word often used to describe those in both exploration and service sectors. Company efforts to lower per-unit well costs, while still drilling longer laterals and using more proppants, played a vital role for companies to hold strong amid low revenues. Long gone are the days of 2014 when companies were drilling wells as quickly as possible and testing out whatever plays might seem even reasonable. Today, operators are focused exclusively on high-graded acreage and have been deploying proven and cost-effective completion techniques. These approaches have helped companies sustain operations by driving down well costs while increasing production and recovery rates.

Rig counts and drilling activity

According to the Energy Information Administration (EIA) Drilling Productivity Report in October 2016, rig counts for all major basins have been following the same trend since January 2014 and have been in decline, which has ultimately mirrored oil prices, albeit at a slight lag. The average rig count declined about 135% in 2015. This same downward trend bled into first-half 2016, resulting in an average decline of another 37% through May. At that point, the average rig count was at its lowest level, which was not that surprising given that this was just 3 months after oil prices were closing at about \$26/bbl. However, in the most recent months, rig activity has steadily climbed upward in all of the major basins on the belief and hope that price volatility has subsided.

One notable outlier to the rig count trend can be found in the Permian, which has seemingly experienced quicker reactions to the market swings than other basins, as shown in Figure 1. Clearly, activity has dropped considerably since the price drop of 2014, but activity seems to follow the gyrations in price more than in other plays. Furthermore, the rig count in the Permian has been on the upswing since May 2016, after hitting what many consider to be its low point of 139 active rigs. As of Oct. 28, the Permian had 187 rigs employed in the basin. According to the most recent EIA reports, the Permian has experienced output growth between 5% and 6% through 2016, and Stratas Advisors expected this trend to hold through year-end 2016, with the growth percentage increasing into 2017 as market conditions improve.

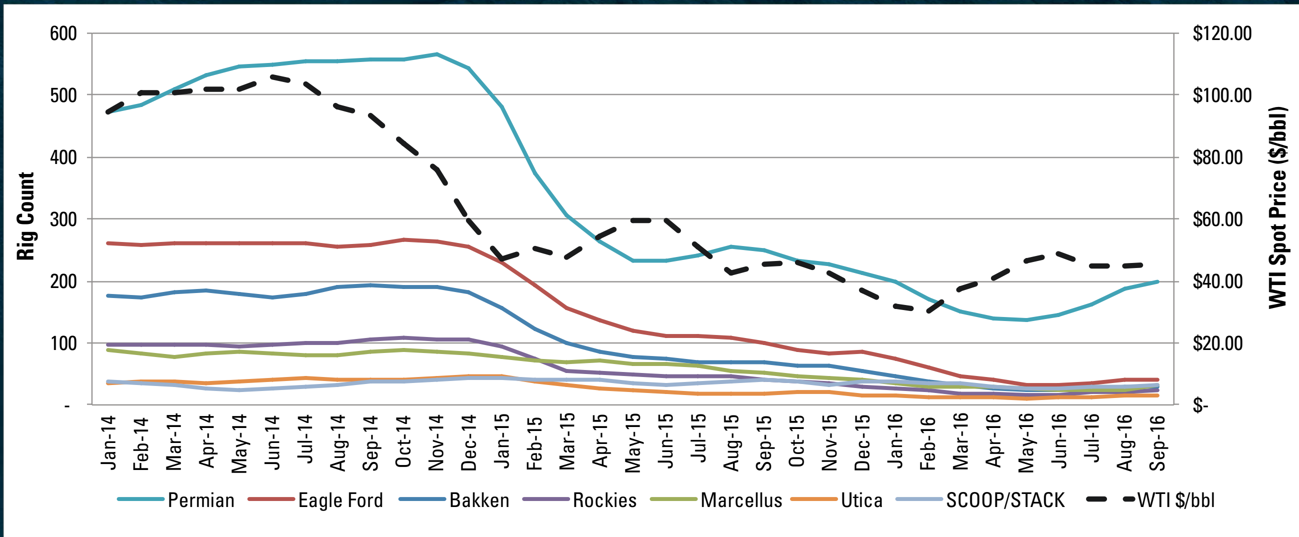


FIGURE 1. Monthly rig count data are shown with WTI price trends. *(Source: EIA, Baker Hughes)*

Although drilling activity has slowed, the most active companies in each basin have grown their drilled but uncompleted (DUC) well inventories, in part to fulfill lease and drilling obligations, as shown in Figure 2. These DUC wells will prove to play a major role in future activity levels, production forecasts and various companies' abilities to remain financially flexible in today's tighter market.

Completion activity

Throughout each major basin operators have made significant efforts to use longer laterals in new wells, and they also shifted back to primarily using slickwater fluids for the type of fracture. The average proppant mass in each fracture also has increased over the last several quarters. Operators have implemented these changes to techniques in an effort to optimize recovery relative to their capital expenses. Interestingly, much of it has led to groundbreaking operational efficiency as well as to sustained increases in production and reserves.

PERMIAN

Operators in the Permian reflected much of this emphasis on the utilization of slickwater fluids for completions, and many also significantly increased the overall volume of proppants used in their fractures. The average proppant mass jumped by an astounding 430% between January of 2014 and October 2016. Before the fall in prices, an average fracture used about 2.3 million pounds. By July 2016 that figure jumped to about 12.5 million pounds. By that time slick water had represented about 50% of the total completions. As previously noted, lateral lengths have increased in the Permian, averaging about 7,500 ft in July 2016, up from an average of 5,500 ft at the beginning of 2014. These changes have proven to be major contributors to increasing EURs by an average of 311 Mboe per well in 2015.

EAGLE FORD

Completions inside the Eagle Ford vary by operator, but the general trend reported throughout 2016 was increasing the number of fracture stages as well as the volume of sand being used. More recent completions indicate an average of about 1,000 lb/ft to 2,000 lb/ft of sand. Lateral lengths have been increasing but not to the same degree as was witnessed in the Permian. By mid-2016, horizontal lengths averaged about 6,000 ft per well, up about 9% from about 5,500 ft in 2014. This relatively small change underscores the fact that more proppant is being used per fracture. The increase in proppant per lateral foot confirms that shorter stages and increased sand volumes are being implemented throughout the region, and this technique has helped to generate improved EURs on a per well basis.

ROCKIES

The Rockies region has seen major activity drops in outlying basins such as the Uinta, Piceance, San Juan and Powder River. The Denver-Julesburg (DJ) Basin, which is most closely associated with Niobrara production, is absorbing the majority of the remaining capital. This area is still relatively active, mainly due to a few select companies, including Anadarko, Noble and PDC. Drilling operations in the DJ Basin are being split between short, medium and extended-lateral programs, which vary from company to company. Most of the designs are medium or extended laterals, which can be as long as 9,500 ft, according to Bill Barrett Corp. As seen across numerous shale basins, the majority of the companies in the Rockies also have begun implementing new completion designs by introducing larger volumes of proppant and tighter stages. Operational efficiencies have enabled these companies to decrease their drilling times and drive down well costs to between $2.5 million and $4.5 million, depending of the lateral length drilled.

BAKKEN

The Bakken play experienced one the more drastic downturns of the North American shale production areas. This drop was most impactful given the fact that when oil was hovering at about $100/bbl, the Bakken gained recognition as one of the most prolific basins in North America. Top producers Continental and Whiting have managed to maintain their operations by decreasing the average days to drill but also boosting the number of stages. As of Oct. 28, 2016, these companies were still targeting about 900 Mboe EURs per each new well drilled. New enhanced completion designs will be the driving factor to bring the area back to prosperity. The areas average well costs are between $6 million and $7 million, which represents some of the higher well costs in the U.S.

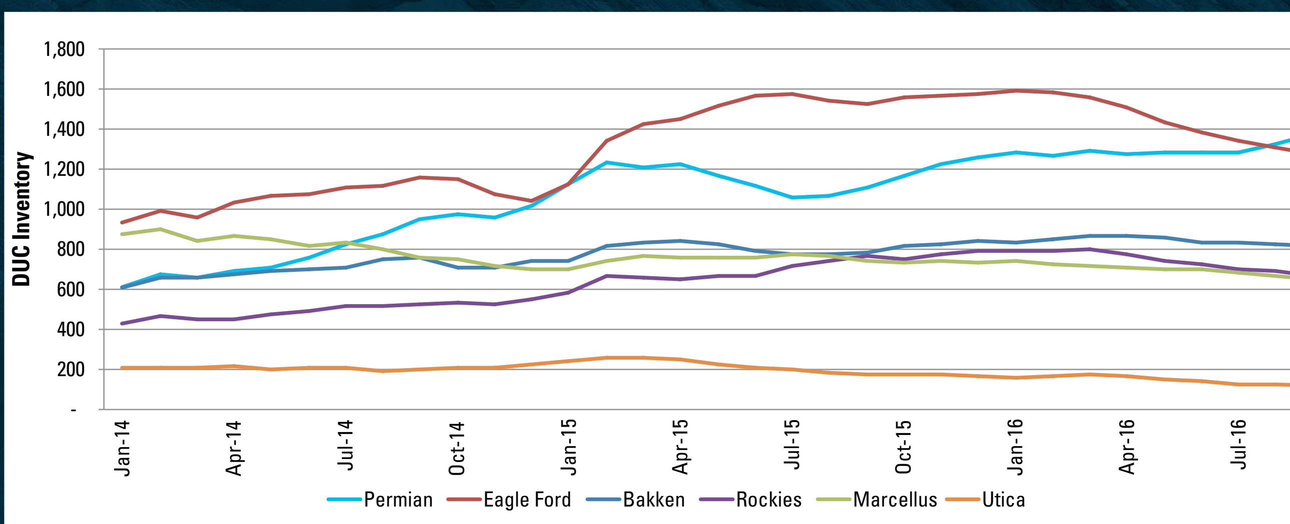
MIDCONTINENT

The SCOOP and STACK regions of the Anadarko Basin are still relatively young when compared to other shale and tight oil plays in North America. Completion strategies in these basins continue to be tested, which is illustrated by the relatively even distribution of fracturing fluids that are being used. Slick water still claims the majority share of completions, though only by a thin margin. Crosslink, crosslink-linear gel hybrids and slickwater-linear gel hybrids each claimed about 20% of fracturing jobs in first-half 2016.

APPALACHIA

Activity in the Marcellus and Utica plays is much more dependent on natural gas prices rather than the price of oil. However, activity in the region has suffered over the last couple of years.

FIGURE 2. Monthly DUC inventories vary for each major basin. *(Source: EIA)*




Visit us at Marcellus Utica Midstream,
Booth #412 in Pittsburgh
January 24-26!

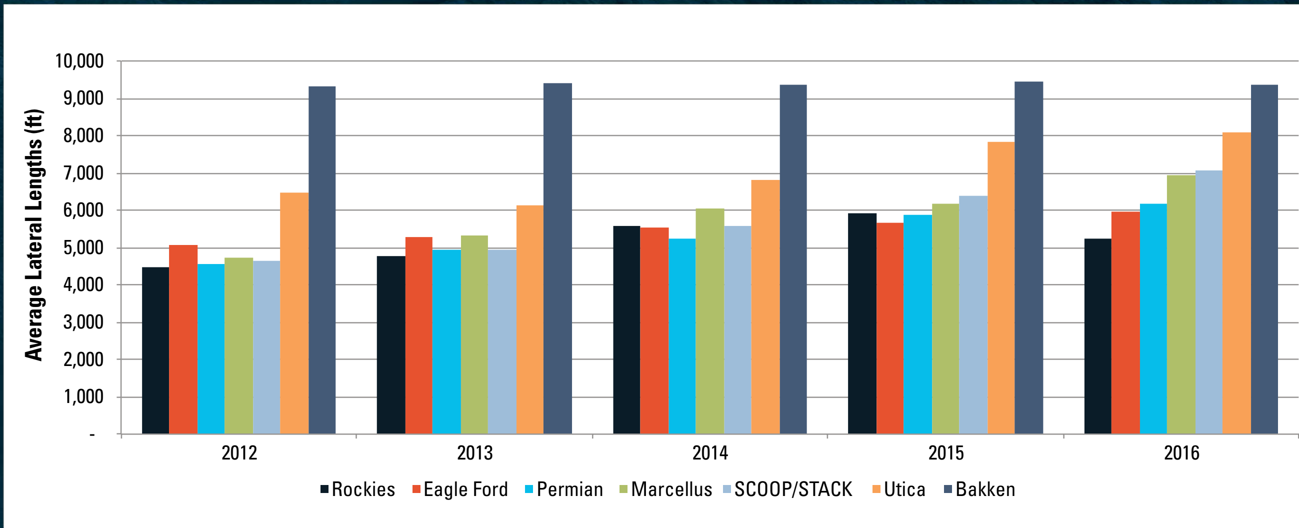


FIGURE 3. The average lateral lengths since 2012 are shown. *(Source: NavPort)*

Looking at the region as a whole, the Marcellus and Utica have been following suit with other major plays throughout North America in terms of completion techniques by tightening stages and increasing proppant loading per foot. Lateral lengths have been steadily increasing since 2012 in the Utica and Marcellus. Both plays averaged about the same lateral length in 2012 at 4,800 ft, but the Utica has since experienced bigger increases year over year with lateral lengths averaging more than 8,000 ft in 2015 vs. 6,000 ft in the Marcellus. However, there have been multiple wells that have surpassed 10,000 ft in both plays, with the record lateral length in the Utica of about 18,500 ft that was drilled and completed in early 2016 by Eclipse Resources.

Figure 3 illustrates how lateral lengths have changed over the last several years for the major plays. The Marcellus and Utica sit at the bottom of the DUC inventory list, which means the return of drilling activity could be more prevalent in the region due to less wells currently waiting on completion.

High-grading acreage

Operators across the U.S. have redirected their focus to high-competency areas or areas that have been heavily delineated and are respectively considered proved (1P) reserves. These areas typically have better production results and more favorable economics. This high-grading trend has been made apparent due to highly concentrated activity levels in regions that provide the best returns and well results. This movement is seen between plays, such as activity moving into the Permian and SCOOP/STACK away from other plays as well as within plays where companies are moving into the most promising counties.

APPALACHIA

One of the most noticeable regions where these high-grading trends can be seen is the northeast in the Marcellus and Utica basins. The Marcellus is classified as having two core areas: one in northeastern Pennsylvania and the other in southwestern Pennsylvania that extends into northern West Virginia. Activity levels in the southwest have surpassed the northeast, which has seen companies like Anadarko temporarily leave the basin to focus on their assets in the Rockies, where they boast some of the lowest breakeven costs in that region. Most of the acreage associated with the Marcellus also relates to the underlying Utica Shale. This play is more costly to develop, but it generates similar, if not better, EURs when compared against the Marcellus. The Utica is still in the exploration stages for the majority of operators in the region, which is causing many to focus on developing the Marcellus until prices increase.

PERMIAN

While the core of the Midland Basin continues to achieve exemplary production results in the premier acreage of Martin, Ector, Midland and Upton counties, many operators are shifting their focus to the stacked pay potential of the Wolfcamp and Bone Spring formations in the Delaware Basin. The core of the Delaware (mainly Reeves, Loving, Ward, and most currently, Culberson counties) is producing well results that are on par, if not more favorable than those of its Midland counterpart. This fact can be accredited in large part to improved drilling and completion capital efficiency. Other companies such as EOG Resources, which recently acquired Yates Petroleum, looks to capitalize on assets located in the New Mexico Shelf, further delineating these prospects and adding value to many locations that already were HBP by Yates.

EAGLE FORD

Although the Eagle Ford is commonly divided by three different windows (oil, wet gas/condensate and dry gas), most of the activity that has occurred in the region over the last couple of years has been focused around the oil and wet gas/condensate regions. The top five most active counties lie within the oil window boundaries, within the counties of Karnes, Dimmit, LaSalle, DeWitt and McMullen. These five counties have hosted more than 60% of total Eagle Ford completions since 2014, while Webb, Gonzales and Atascosa make up about 20% of completions. Operators, such as Marathon, also are downspacing in these areas, yielding EURs above the overall play's average and further adding proved drilling locations.

MIDCONTINENT

There are some core areas that are producing particularly impressive results within the SCOOP and STACK. In the STACK the majority of development continues to occur in Blaine, Kingfisher and Canadian counties, as companies like Devon and Newfield continue to capitalize on their prime positions within the overpressured oil window. The SCOOP continues to show favorable production results in Carter, Grady and Garvin counties. However, some top operators in the play are transitioning resources to newly acquired STACK assets. Continental has increased its STACK footprint by about 27,000 acres since year-end 2015, with the majority of its acreage lying in the overpressured window of the play. Additionally, Marathon Oil recently acquired PayRock Energy, which contributes 60,000 STACK acres to Marathon's portfolio. This acquisition increased the operator's production by about 9 Mboe/d. Upon closing, Marathon expected to immediately ramp up activity in its new STACK resources during third-quarter 2016, while also continuing development in its already delineated SCOOP position.

High-grading strategies are different around the U.S., as strategy also depends on the company profile and what is best for their portfolio. However, the ultimate goal is the same, and this strategy has been fundamental to companies' ability to survive in an unfavorable market.

Play production outlook

Thus far in 2016, most shale basins in the U.S. have experienced considerable declines in production, with the exception of a few key basins that remain economic within their core during the prolonged period of repressed market conditions.

PERMIAN

With the constant advancements being made to drilling and completion efficiencies, coupled with new discoveries and abundant land acquisitions from operators looking to strengthen their positions, output rates continue to grow within the Permian Basin. According to most recent EIA reports, Permian production has grown by 5% thus far in 2016 relative to 2015, which is a much smaller margin when compared against the 14% growth realized in 2015 relative to 2014. The Permian has nevertheless continued to show growth in production and development during a time when many other North American plays have substantially scaled back. Stratas Advisors expected Permian production to hold at a growth rate of 5% to 6% through year-end 2016, as West Texas Intermediate (WTI) remains close to $50/bbl. Stratas Advisors expected 2016 would post an average rate of production of just under 3,200 Mboe/d. As global demand for oil and gas continues to equalize with the current oversupply, Stratas Advisors believes that Permian output will continue to grow throughout 2017 at an annualized rate of up to 8%.

EAGLE FORD

Major operators in the Eagle Ford are experiencing higher production rates on new drills, where more production is expected on a per rig basis. Although 2016 production levels have shown notable declines, higher rig efficiency will ultimately facilitate the region one day reaching its historically high levels of production but while utilizing fewer rigs. Given the downward trend in drilled and completed wells, Stratas Advisors estimated a decline rate of 20% for the Eagle Ford in 2016, reflecting an exit rate of more than 2,200 Mboe/d.

> Major operators in the Eagle Ford are experiencing **HIGHER PRODUCTION RATES ON NEW DRILLS ...**

Moving forward, the incremental increase in production experienced per rig will aid in mitigating this decline, and the region should begin to benefit from a slower decline rate of about 15% in 2017. This rate of change would push production below 2,000 Mboe/d for the first time since 2013. Stratas Advisors believes operators will turn back to the play in 2018, and the region will see an influx of capital. At that point, Stratas Advisors expects more diversified operators, who possibly left for more profitable plays, will start returning to the Eagle Ford.

By 2018, Stratas Advisors predicts the price of WTI will reach $60/bbl, which is much closer to the majority of breakevens experienced within this play. Overall production decline is expected to be cut in half to 8% in 2018. Thereafter, Stratas Advisors forecast an upward, more gradual growth for the foreseeable producing years. Companies that have remained active during the downturn could step out and begin to test 2P reserve locations, which could become more profitable with the return of higher commodity prices.

ROCKIES

Recent EIA data suggest that the Rockies experienced a 6% decline in 2016, averaging just under 1,200 Mboe/d. Although average rig counts have plummeted 80% since 2014, production on a per rig basis is experiencing increases due to technical efficiencies driven by larger operators in the region. Increased production rates on a per well basis are anticipated to be the "new normal," and it is expected to get better with market stability. Budgets in 2017 are expected to remain lower than 2014 levels, and Stratas Advisors believes that this trend will carry into 2018. At that point, Stratas Advisors sees smaller operators beginning to add rigs or enter into nonoperating agreements, depending on acreage locations, and the region as a whole will begin to experience a rebound.

BAKKEN

The Bakken experienced an 8% decline in 2016 on a barrels of oil equivalent basis and about an 11% decline on an oil basis. Moving forward, drilling activity is expected to remain within the core counties of Mountrail, McKenzie, Williams and Dunn counties, where top tier companies are continuing to downspace acreage. Although completed well costs have become more favorable, they are still some of the highest in the U.S. due to the Bakken's depth and high-transportation costs. Stratas Advisors anticipates the Bakken to decline in 2017 at the same 2016 pace of between 8% and 10%. As oil prices continue to make a steady comeback in 2018 and push toward $60/bbl, operators are likely to move back into this area as operations become more economical.

MIDCONTINENT

On the production front, SCOOP/STACK playwide output continued to decrease modestly through 2016 by about 6%; however, the highly active operators such as Devon, Newfield, Continental and Cimarex have helped to cushion declines by remaining relatively active and averaging 5% to 6% growth. With the major players in the STACK expecting to reach full delineation by mid- to late 2017 and SCOOP operators continuing to develop and use enhanced drilling and completion efficiencies, Stratas Advisors expects output to remain at

current levels of about 430 Mboe/d in 2017. As commodity prices gradually improve moving into 2018 and WTI is expected to approach $60/bbl, Stratas Advisors projects that positive growth will return to the SCOOP/STACK region increasing 5% to abour 450 Mboe/d in 2018.

Economics

Across all major U.S. basins, operators have been relentlessly attempting to enhance development strategies to adapt to current market conditions, making the drilling and completion processes more efficient on a per well basis, and ultimately achieving well costs that are remarkably lower than pre-crash levels. Additionally, service companies have implemented material discounts, which have helped considerably with many operators' bottom lines. All of these cost contributions have allowed operators to stay active in many shale plays inside the Lower 48.

PERMIAN

The Delaware Basin's current EUR per well is about 870 Mboe, and the Midland Basin shows an average of about 890 Mboe. Each of these basins has increased by more than 70% from the previous year's calculated averages. Capital efficiencies in the Permian continue to improve as the range in cost per completed well dropped to $3.5 million per well to $7.5 million per well in 2016 from $5 million per well to $7.5 million per well in 2014, representing a 30% reduction on the lower bound over this time frame. Based on these EUR and capex data, the estimated breakeven prices being achieved in the Delaware and Midland come in at about $35/bbl and $40/bbl, respectively. With the continued advancements in drilling and completion technology, quicker spud-to-rig release times and continued pressure on well service companies, operator sentiment suggests breakevens could improve even further moving into 2017.

EAGLE FORD

Economics in the Eagle Ford are still favorable with DeWitt, Karnes and Webb counties all maintaining average breakeven prices below $40/bbl, when using an average drilling and completion cost of $4.5 million. The Eagle Ford is experiencing increases in EURs year over year, with the latest comparison between 2014 and 2015 showing a 45% increase from about 500 Mboe to more than 730 Mboe per well. The top counties previously noted all experienced the same trends, yielding EUR increases in 2015 of between 40% and 60% over 2014. This result propelled DeWitt and Webb county averages to more than 1,000 Mboe per well. These results translate to 25% to 45% higher EURs in the top counties compared to the overall play. Further reduction in well costs are still expected to continue as operators in the area are benefiting from lower service costs, decreasing drilling cycles and completing wells more efficiently.

MIDCONTINENT

EUR estimates calculated from the SCOOP and STACK have remained flat year over year at roughly 550 Mboe per well due to the combined effects of continued well testing with various lateral lengths and completion techniques. Many believe that for production to show any substantial increase WTI needs to be closer to the $60/bbl threshold. Stratas Advisors calculates an average breakeven of about $52/bbl in the STACK and $61/bbl in the SCOOP. Well costs are ranging anywhere from $4 million per well to $9 million per well in the region, with upside potential to decrease these figures once operators begin to converge on optimal drilling and completion parameters.

APPALACHIA

The Utica and Marcellus have each seen EURs climb significantly in recent years. The Utica has surpassed the Marcellus in terms of ultimate recovery potential, though well costs and ease of extraction continue to be a detriment to full-scale Utica production. EUR estimates in 2015 were calculated to be just over 3,000 Mboe in the Utica and 1,325 Mboe in the Marcellus. These results help lead to breakevens of a little over $3/Mcf in each play. These results are relatively favorable but still tight when compared to market prices. The results are primarily attributable to controlled well costs. Reported well costs in 2014 in the Marcellus ranged between $7 million and $11 million, which are quite high when compared to average 2016 well costs of between $5 million and $8 million. Similarly in the Utica, drilling and

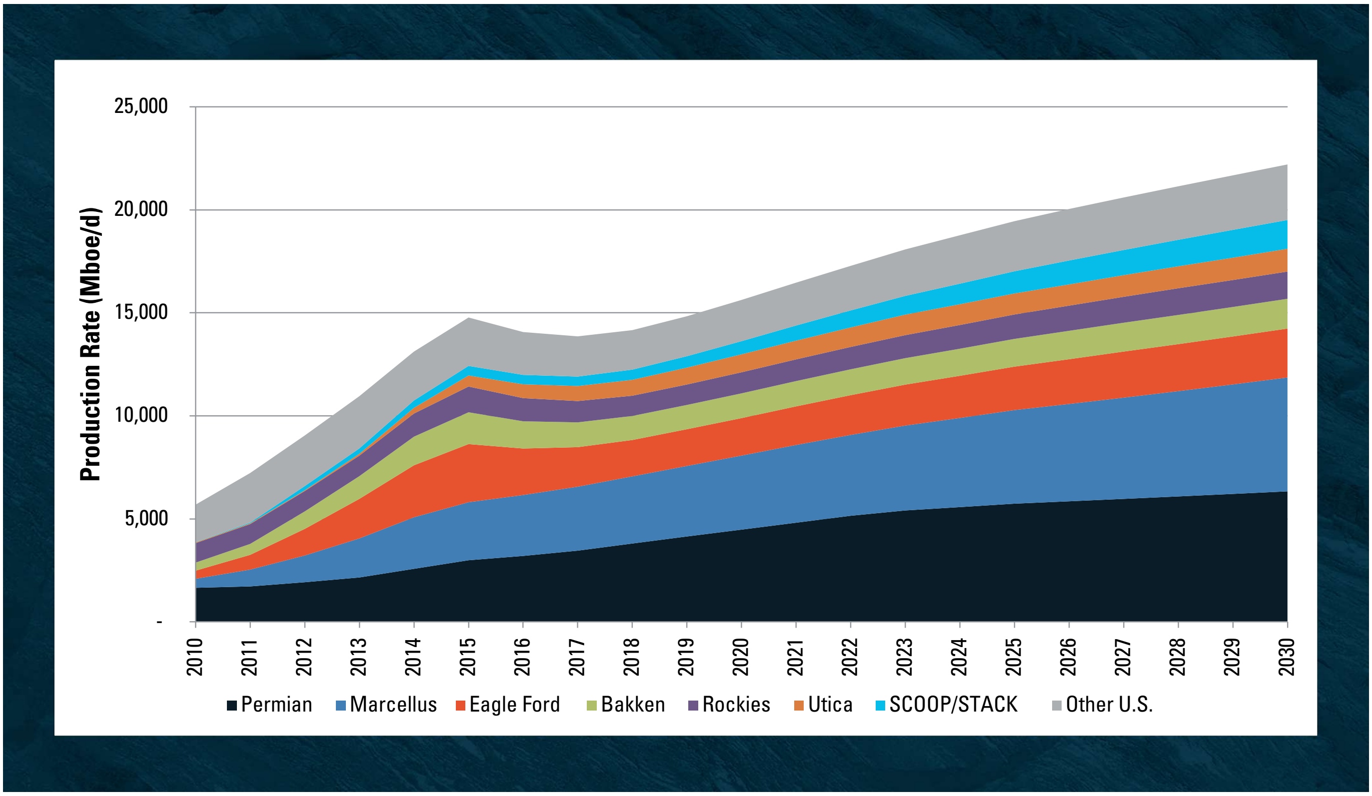


FIGURE 4. The North American outlook is positive as production rates increase across the U.S. *(Source: Stratas Advisors)*

completion costs have been reduced by about 30% to about $9 million in 2016, down from the 2014 average of $13 million.

North America outlook

As activity in the majority of U.S. shale plays has retracted during 2016, due in large part to unforeseen "lower for longer" commodity prices, five of the seven major U.S. basins have experienced production decreases (Figure 4). Overall U.S. daily production is expected to decrease roughly 3.5% in 2016, totaling just under 12,000 Mboe/d. With current projections suggesting the price environment will improve modestly in 2017 to between $50/bbl and $56/bbl at WTI, total production is forecasted to decrease minimally to about 11,900 Mboe/d, representing a slight decrease of 0.7% from 2016 exit rates. Production isn't expected to rebound until 2018 when prices are expected to reach $60/bbl. In 2018 Stratas Advisors forecasts production to increase by about 340 Mboe/d over 2017, a nearly 3% increase year over year.

What has kept production from the unconventional plays of North America from completely plummeting over the course of the depressed market in recent years is the resiliency of core areas within the Permian and, to a lesser extent, the Marcellus. If not for the sustained development efforts of operators in these areas to continue improvements in cost efficiency and continuing to produce economic wells in premier regions, it would be safe to assume that overall production from U.S. shale would have decreased by a much higher order of magnitude.

Looking forward into 2017, economic conditions are expected to allow production rates to level off. Stratas Advisors believes that while the Permian and Appalachian regions are estimated to continue growth at a modest rate through 2017, the majority of other plays will gradually steady their declining production rates and begin showing signs of positive growth starting in 2018. ■

Stratas Advisors, a Hart Energy company, is a global consulting and advisory firm that provides data, analysis and insight across all sectors of the energy industry. For more information visit stratasadvisors.com *or call +1 713.260.6426.*