HARTENERGY

2018 Unconventional Yearbook

Targeting Full-Field Development

Oil and Gas Investor

E&P

MIDSTREAM Business

The Face of Cutter Technology Has Changed

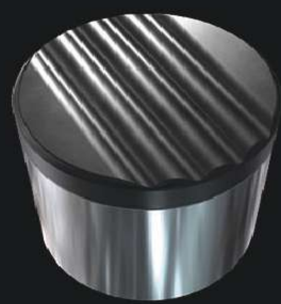
INTRODUCING GEOMETRIX™ 4D SHAPED CUTTERS

With recent advancements in manufacturing technology, we have taken cutter development to the next level. Unlike flat, cylindrical PDC cutters that rely on material properties alone, the Geometrix™ cutters incorporate complex shapes and geometries, customized to address application-specific challenges such as abrasion resistance, impact resistance, and geometrical thermal efficiency. With the largest range of shapes for the widest range of drilling environments, it's just another way we help you increase drilling efficiency and lower your cost per BOE. Contact your local Halliburton DatCI™ (Design at the Customer Interface service) team to learn more.

halliburton.com/geometrix

Chisel™ Plowed Scribe Cutter

Chopper™ Plowed Cylindrical Cutter



Dagger™ Multi-Plowed Cutter

Machete™ Optimized Tip Geometry Cutter

HALLIBURTON | Drill Bits & Services

2018 Unconventional Yearbook

HART ENERGY
1616 S. Voss, Suite 1000 | Houston, Texas 77057
Tel: +1 (713) 260-6400 | Fax: +1 (713) 840-8585
hartenergy.com

Director Unconventional Resources **PEGGY WILLIAMS**
Group Managing Editor, *E&P* **JO ANN DAVY**
Executive Editor **JENNIFER PRESLEY** *E&P*
Editor-in-Chief **STEVE TOON** *Oil and Gas Investor*
Editor-in-Chief **PAUL HART** *Midstream Business*
Associate Editor **BRIAN WALZEL** *E&P*
Contributing Editors **STEPHEN G. BECK**, **GREGORY DL MORRIS**, **SCOTT WEEDEN**
Associate Managing Editor **ARIANA BENAVIDEZ**

Corporate Art Director **ALEXA SANDERS**
Marketing Art Director **MELISSA RITCHIE**
Oil and Gas Investor Art Director **ROBERT AVILA**
Senior Graphic Designer **MAX GUILLORY**
Production Manager **SHARON COCHRAN**
Marketing Director **GREG SALERNO**

For additional copies of this publication, contact Customer Service +1 (713) 260-6442.

Vice President – Publishing **RUSSELL LAAS**
Vice President – Publishing **SHELLEY LAMB**
Publisher *Midstream Business* **DARRIN WEST**

HARTENERGY
MEDIA | RESEARCH | DATA

Editorial Director **PEGGY WILLIAMS**
Chief Financial Officer **CHRIS ARNDT**
Chief Executive Officer **RICHARD A. EICHLER**

2018 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 2018 Unconventional Yearbook presents the most important facts and figures on the top U.S. resource plays. This eighth 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***.

Table of Contents

Cover photos, courtesy of Hart Energy's *Oil and Gas Investor*, (clockwise from left): Cactus Drilling Co.'s Rig 148 drilled for Cimarex Energy Co. in Culberson County, Texas, photo by Tom Fox; H&P floor hands Justin Hill (left) and Matthew Hertenstein put a slip in place to hold the drilling pipe on Headrick 14-11 HC No. 2-AH well at Comstock Resources' gas drilling operations in the Haynesville Shale, photo by Tom Fox; and overseeing Ensign 160 operations on West Branch Pad O for Seneca Resources in McKean County, Pa., photo by Glenn Kulbako.

Booming activity keeps rigs and pumpjacks working side by side in the Permian Basin. *(Photo by Ricardo Merendoni, courtesy of Halliburton and Hart Energy's* Oil and Gas Investor*)*

2018 Looks Increasingly Positive for U.S. Oil and Gas

By **Stephen G. Beck**, Senior Director, Upstream, Stratas Advisors

OPEC-plus Russia remains willing to accommodate market conditions that support stability and range-bound prices.

Market participants appear prepared to play nice in 2018. OPEC production and the outlook for extending current production cuts is all but a done deal as of press time, higher oil prices provide much needed breathing room for many U.S. shale producers, and oilfield services are finally getting some relief from extreme margin pressures. Let's review 2017 themes before discussing each factor and the role each plays in our outlook.

While OPEC-plus Russia have not made an official statement as of press time, recent commentary suggests an extension to production cuts is almost certain. The key question is "for how long?" Let's brush that aside for now. The key takeaway is that OPEC-plus Russia remains willing to accommodate market conditions that support stability and range-bound prices. This is an important backdrop for U.S. shale.

Higher oil prices in recent months opened doors for U.S. independents to lock in hedges despite the shape of the curve, thus reducing risk exposures should spot prices fall in 2018 and 2019. Higher oil prices coupled with an extension of OPEC-plus production cuts through at least mid-2018 support activity in the best areas of all major U.S. shales through the end of 2018.

In 2017, watercooler chatter in oil and gas circles fixated heavily on the Permian Basin. Whether it was field hands in West Texas or energy investors in New York, oil and gas talk gravitated to the Permian. Topics discussed ranged from rising valuations per acre, lateral lengths and the impact from combining higher proppant loads with these bigger wells, last-mile challenges, type curves and remaining barrels of resource in place.

2018 will largely be a continuation of 2017 chatter … with a twist. Permian talk will still dominate the watercooler landscape. However, other plays like the Scoop/Stack, Eagle Ford and Bakken are already grabbing more attention and giving people things to talk about. The revelation that the Permian goose may not always produce golden eggs opened the door for other plays to re-enter the discussion. Hence, expect the Permian to share more of the stage with these plays in 2018.

So, what does all this mean for U.S. shale production? Unconventional oil production is projected to rise to 6.1 MMbbl/d by December 2018, up from 5.2 MMbbl/d in 2017. Rising Permian production is the primary growth driver of this 17% increase, further supported by a strong showing in the Eagle Ford. Other key shale contributors for oil include the Bakken, the Niobrara in the Rockies, and the Woodford Shale and related opportunities in the Midcontinent. These views assume OPEC-plus production cuts are extended until at least mid-2018 and cost pressures, especially for completions, do not overwhelm expected spending plans.

Looking at natural gas, unconventional production is projected to reach 69 Bcf per day by December 2018, an increase of 9 Bcf/d, or 15%, versus 2017. This outlook is grounded on two key pillars: associated gas and the Marcellus Shale. Notably, associated gas is driven almost entirely on oil economics. In contrast, Marcellus gas is driven largely by gas demand east of the Rockies coupled with natural gas prices. The Haynesville, another major shale gas resource, stands ready to inject substantial quantities of gas at competitive prices should consumption outstrip our current expectations.

Gazers of short-term oil and gas historically set their sights on permits, well spuds and rig counts. While these data remain important inputs to forecasting oil and gas production, the manner and use of early data types is changing due to differences in processes employed in shale. A shining example revolves around the whole discussion on drilled but uncompleted wells or DUCs.

HIGHER OIL PRICES COUPLED WITH AN EXTENSION OF OPEC-PLUS PRODUCTION CUTS through at least mid-2018 support activity in the best areas of all major U.S. shales through the end of 2018.

Before opining on DUCs, a review of drilling rigs seems in order. After all, rig activity is still the most crucial of input variables available for prognosticating on future production in shale. It comes as no surprise that the Permian Basin is expected to attract the lion's share of activity, followed by the Eagle Ford. Relatively stable rig counts are projected in the other major shale oil resource areas.

It is important to keep in mind that while rig counts and activity are projected to remain robust, the high number of "young" wells added in 2017 translates to a steeper base decline in 2018. A steeper base decline makes it more difficult to grow production as a greater share of "new source" production, which is production from wells added in the current year, replenishes production declines in the base wells. Base wells are wells that began their productive life prior to the current year.

In recent years, much has been made about efficiencies in drilling and completions. Truth be said, it is far easier to lay claim to consistently improving cycle times when working with the best crews and the best equipment. Unfortunately, not all crews nor all equipment can be best at all times. As increasing numbers of crews were called back and assigned to second-tier equipment, cycle times showed some slippage. Stratas does not anticipate large-scale degradation in cycle times, however; the pace of improvements witnessed in recent years is not expected to continue.

DUCs have been another topic *du jour*. The evolution of DUCs on the scale seen today is a product of pad drilling, batch processes to minimize damage and disruptions, and infrastructure planning. Observations of data reveal two important insights. First, the number of "steady state" DUCs moves in tandem with rig counts. As rig counts climb, the natural number of DUCs that are a normal and constant part of the accounting also climbs. We can see clear evidence of this in the Permian. In tracking DUCs, Stratas advises in netting out these "steady state" DUCs from the gross number. This ensures proper timing of production additions over the forecast horizon. It also ensures proper timing of well retirements in the long term. The second insight is that DUC inventories typically adhere to a first-in, first-out inventory model. Observations show that most wells are completed in a range of 120 to 210 days after drilling. As one might expect, precision in forecasting, especially in oil and gas, is enhanced when considering such details.

Shifting our gaze to the longer horizon, range-bound prices through the next several years will continue to support growing production of both commodities from shale while containing the industry from falling victim to the side-effects from over-exuberant development. OPEC-plus production curtailments will end. The timing is, of course, unknown. However, it is important to recognize that shale has proven its ability to compete effectively in today's market, and it is here to stay for the long term. Given the allocation of economic shale and tight resources in North America and ongoing efforts by industry to enhance competence in developing these resources, Stratas projects growing oil and gas production from shale and other tight rock formations through most, if not all, of the forecast period. ■

Editor's Note: For a detailed production forecast please see the article beginning on page 96.

This drilling rig in Southwest Appalachia is where Southwestern Energy has about 321,563 net acres. *(Photo by Ken Childress, courtesy of Southwestern Energy)*

Companies Focus on Strong Profits, Driving Down Costs

By **Ariana Benavidez**, Associate Managing Editor

These players see a bright future.

The U.S. Energy Information Administration (EIA) estimated that about 4.25 MMbbl/d of crude oil were produced directly from tight oil resources in the U.S. in 2016, equal to about 48% of total U.S. crude oil production in 2016.

According to a July 2017 Wood Mackenzie report, "The tight oil sector has struggled to generate positive cash flow since 2010—last year, only one company in the sector posted positive cash flow. But there is light at the end of the tunnel." The report estimates that the five largest tight oil players—Continental, Devon, EOG, Newfield and Pioneer—could become cash-flow positive by 2020.

In the following section, Hart Energy profiles 40 of the most active companies in the U.S.

Anadarko Petroleum Corp.

- About 580,000 gross acres in the Delaware Basin
- About 400,000 net acres in the D-J Basin

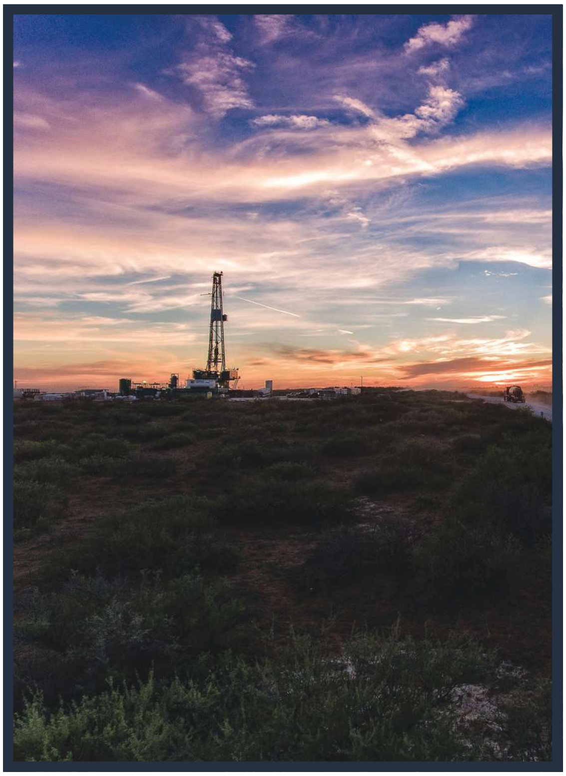
Headquartered in The Woodlands, Texas, Anadarko has onshore U.S. operations in Colorado, Texas, Utah and Wyoming. The company is among the world's largest independent oil and natural gas E&P companies, with 1.72 Bboe of proved reserves at year-end 2016, the company stated on its website.

Since 2015 Anadarko has sold nearly $7.5 billion of noncore assets "to reposition and focus its business to deliver better returns across commodity cycles," an October 2017 press release stated.

"Anadarko ended the third quarter of 2017 with $5.25 billion of cash on hand. This substantial cash balance enables flexibility in managing through the lower commodity price environment," the company said.

In the Delaware Basin Anadarko has about 580,000 gross acres (about 235,000 net) and 10,000-plus drilling locations, according to the company's 2016 "Texas Fact Sheet."

Anadarko averaged 16 operated rigs drilling during third-quarter 2017, and the company reported



In the Delaware Basin Anadarko has about 580,000 gross acres (about 235,000 net) and 10,000-plus drilling locations. *(Photo courtesy of Anadarko Petroleum Corp.)*

upstream capital investments of $314 million and production of 63 Mboe/d with oil volume averaging 37 Mbbl/d in the Delaware Basin that quarter, according to its third-quarter 2017 operations report.

In addition, "Anadarko is building long-term value in the Delaware Basin through its material infrastructure buildout and operatorship capture program," the report stated. "During the third quarter, the company completed land trades with various basin operators for more than 5,000 acres, which has added about 13 sections worth of extended-lateral opportunities."

In the Denver-Julesburg (D-J) Basin, Anadarko holds about 400,000 net acres in the basin's development area and estimates it holds more than 2 Bboe of recoverable resources on its acreage, the company said on its website. Anadarko averaged six operated rigs drilling at the end of the third quarter and reported capital investments of $269 million and production of 232 Mboe/d in the D-J Basin during the same period, according to the report.

Additionally, Anadarko is the largest natural gas producer in Utah with primary operations in the Greater Natural Buttes area of the Uinta Basin, according to the company's website.

Antero Resources

- **Formed in 2002**
- **485,000 net acres in the Marcellus Shale**

Antero Resources is an independent E&P company engaged in the exploitation, development and acquisition of natural gas, NGL and oil properties located in the Appalachia Basin. The Denver-based company holds more than 485,000 net acres in the southwestern core of the Marcellus Shale and more than 151,000 net acres of leasehold in the Utica Shale, according to Antero's website.

In June 2017 Antero acquired 10,300 net acres in the Marcellus primarily located in Doddridge and Wetzel counties in West Virginia for about $130 million, a company report stated. The acquisition included about 17 MMcfe/d of net equivalent production, 15 drilled but uncompleted wells with an average lateral length of 8,200 ft and one undeveloped drilling pad.

In the Marcellus Shale Antero is operating four drilling rigs in West Virginia. The company's production in the Marcellus averaged 1,813 MMcfe/d in second-quarter 2017, according to the company's website. The net production figure includes about 88,490 bbl/d of NGL and oil. According to the company, Antero has drilled and completed 571 horizontal Marcellus Shale wells, all of which were online as of Oct. 13, 2017.

Of the 54 wells Antero completed in the Marcellus from January to August 2017, 46 (85%) have used greater than 1,750 lb of proppant per foot and have generated aggregate production in excess of the company's 2 Bcf per 1,000-ft type curve target through 180 days, according to the company's second-quarter 2017 report.

Antero also is constructing its own gathering facilities in Doddridge, Tyler and Ritchie counties in West Virginia to connect its wells to compression facilities and processing, according to the company's website. Antero is processing more than 1.4 Bcf/d of rich gas production from the Marcellus Shale through MarkWest's Sherwood complex. Markwest is constructing an eighth and ninth 200-MMcf/d plant, Sherwood 8 and 9, which were scheduled to be placed into service in third-quarter 2017 and first-quarter 2018, respectively.

In the Utica Shale Antero has drilled and completed 155 horizontal Utica Shale wells in its core area, all of which were online as of Oct. 13. The company is operating two drilling rigs in the Utica Shale and reported production averaging 387 MMcfe/d in second-quarter 2017. The net production figure includes about 14,280 bbl/d of NGL and oil, according to the company's website.

Apache Corp.

- **Significant Alpine High discovery in Delaware Basin**
- **Second-quarter 2017 Permian production averaged 146 Mboe/d**

In the U.S. Apache has operations in the Permian Basin and Midcontinent region.

The company's Permian Basin acreage totals more than 3.1 million gross acres with exposure

to numerous plays focused primarily in the Midland Basin, Central Basin Platform/Northwest Shelf and Delaware Basin, the company said on its website. In first-quarter 2017 Apache reported production results of 75,210 bbl/d of oil, 109,492 of total liquids, 227,654 Mcf/d of natural gas and 147,534 boe/d in the Permian, according to the company's website.

These "grain bin" style tanks are used for recycling produced water in the Ketchum Mountain area in Texas. *(Photo courtesy of Apache Corp.)*

In second-quarter 2017, North American production was 244,000 boe/d, and Apache averaged 18 rigs and drilled and completed 36 gross-operated wells. Apache reported that "oil and gas capital investment was $738 million during the quarter, with two-thirds focused on the Permian Basin," according to the company's second-quarter 2017 results. Permian production averaged 146,000 boe/d, and Apache operated an average of 17 rigs during the second quarter, according to the company's second-quarter 2017 results.

In September 2016 Apache confirmed the discovery of a significant new resource play—Alpine High. Apache's Alpine High acreage lies in the southern portion of the Delaware Basin, primarily in Reeves County, Texas. The company estimated hydrocarbons in place on its acreage position are 75 Tcf of rich gas (more than 1,300 Btu) and 3 Bbbl of oil in the Barnett and Woodford formations alone, according to a company press release. Apache also expects significant oil potential in the shallower Pennsylvanian, Bone Springs and Wolfcamp formations. The company's 2017 plans included significantly increasing activity in the Permian region, while continuing to balance capital investments between its larger development project at Alpine High and focused exploration and development programs on other core assets in its Permian region, according to the company's website. During 2017 the company expected to average 15 drilling rigs in the Permian Basin and drill about 250 wells, which includes a four- to six-rig delineation drilling program at Alpine High. The company planned to allocate about two-thirds of its 2017 capital budget to the Permian region.

Apache's Midcontinent/Gulf Coast region includes the Granite Wash, Tonkawa, Canyon Lime, Marmaton and Cleveland formations of the West Anadarko Basin; the Woodford-Scoop and Stack plays located in central Oklahoma; and the Eagle Ford Shale in southeast Texas. The region includes 2.6 million gross acres and more than 3,200 producing wells primarily in western Oklahoma, the Texas Panhandle and South Texas, the company stated on its website. In 2017 Apache planned to run a targeted program, drilling four wells in the Woodford-Scoop play.

In first-quarter 2017 Apache reported production results of 11,142 bbl/d of oil, 24,327 bbl/d of total liquids, 123,501 Mcf/d of natural gas and 48,093 boe/d in the Midcontinent/Gulf Coast regions, according to the company's website.

In second-quarter 2017 in the Midland Basin Apache averaged six rigs and focused primarily on multiwell pad drilling in the Wolfcamp and Spraberry formations. During the quarter, the company brought online the nine-well Schrock 34 pad in Glasscock County with "very strong results," the company's second-quarter release stated.

BP

- **Ranked No. 12 on the 2017 list of *Fortune* Global 500 companies**
- **Brought online a Mancos Shale natural gas well**

BP is a global producer of oil and gas with operations in more than 70 countries. Over the past 10 years BP has invested $90 billion in the U.S.—more than any other energy company, according to BP.

BP's U.S. Lower 48 onshore operations span Colorado, New Mexico, Oklahoma, Texas and Wyoming as well as seven oil and gas basins. BP's Lower


Imagine energy independence for your children
At AECOM, we work with leading oil and gas producers to design, build, finance and maintain the infrastructure that delivers raw product to end consumers. From wellhead to gas tank, from crude oil to recyclable plastic water bottle, we're meeting the challenge. See how we deliver what others can only dream about at **aecom.com**.
AECOM
Imagine it.
Delivered.

48 unit is one of the largest producers in the San Juan Basin of New Mexico and Colorado, where the company operates about 3,900 wells, according to the company.

In August 2017 BP brought online a highly productive natural gas well in the Mancos Shale, according to a press release. "Early production rates at the NEBU 602 Com 1H well in San Juan County are the highest achieved in the past 14 years within the San Juan Basin, a large oil and gas producing area spanning southwest Colorado and northwest New Mexico that includes the Mancos Shale," the release stated. "The successful well test took place on assets BP acquired in late 2015." The well achieved an average 30-day IP rate of 12.9 MMcf/d.

For 2017 BP expected to start up seven major projects outside the U.S. in 2017, "making it one of the most significant years for commissioning new projects in our history," BP stated on its website. "Together with the projects already brought online in 2016, these new projects will make a huge contribution to the 800,000 barrels of oil equivalent per day of new production by 2020."

Carrizo Oil & Gas Inc.

- **104,000 net acres in the Eagle Ford Shale**
- **Second-quarter 2017 crude oil production of 33,629 bbl/d**

Houston-based Carrizo Oil & Gas Inc. is an energy company actively engaged in the exploration, development and production of oil and gas from resource plays in the U.S. The company operates in the Eagle Ford Shale in South Texas, Delaware Basin in West Texas and Niobrara Formation in Colorado.

In third-quarter 2017 Carrizo reported crude oil production of 34,903 bbl/d, a 43% increase from a year earlier, and total production of 55,224 boe/d, a 35% increase from a year earlier, according to the company's third-quarter 2017 report.

"Drilling and completion capital expenditures for the third quarter of 2017 were $165 million. Approximately 75% of the third-quarter drilling and completion spending was in the Eagle Ford Shale, while more than 20% was in the Delaware Basin. Land and seismic expenditures (excluding the ExL acquisition) during the quarter were $11.8 million and were primarily focused in the Permian Basin and Eagle Ford Shale," the company stated in the report.

In the Delaware Basin Carrizo has 42,500 net acres, 400-plus net undrilled locations and 12 MMboe of proved reserves, according to the company's website. The company's 2017 plans included a three-rig program, drilling 10 gross (8 net) wells and completing 16 gross (13 net) wells. In the second quarter Carrizo completed two operated wells, and crude oil production from the play was more than 900 bbl/d for the quarter, according to the company's second-quarter 2017 report.

In August 2017 Carrizo acquired about 16,508 net acres located in the Delaware Basin in Reeves and Ward counties in Texas from ExL Petroleum Management LLC and ExL Petroleum Operating Inc., a press release stated.

In the Eagle Ford Shale Carrizo has 104,000 net acres, 1,200-plus net undrilled locations and 162 MMboe of proved reserves, according to the company's website. The company's 2017 plans included a two- to three-rig program, drilling 93 gross (80 net) wells and completing 93 gross (84 net) wells. In the second quarter Carrizo drilled 23 gross (21.2 net) operated wells and completed 26 gross (21.6 net) wells, and crude oil production from the play was more than 30,600 bbl/d for the quarter, according to the company's second-quarter 2017 report.

In the Niobrara Formation Carrizo has 30,700 net acres, 640-plus net undrilled locations and 3 MMboe of proved reserves, according to the company's website. The company did not have drilling or completion activity planned in the Niobrara for 2017.

Carrizo planned to sell its Denver-Julesburg Basin assets for up to $155 million to an undisclosed buyer, according to a November 2017 press release. The transaction is expected to close in January 2018.

In November 2017 Carrizo sold substantially all of its assets in the Utica Shale, located primarily in Guernsey County, Ohio, for $62 million in cash, a press release stated. In the Utica Carrizo had 25,900 net acres, 130-plus net undrilled locations and 2 MMboe of proved reserves, according to the company's website. The company did not

Carrizo reported 162 MMboe of proved reserves in the Eagle Ford Shale. *(Photo courtesy of Carrizo Oil & Gas Inc.)*

have drilling or completion activity planned in the Utica for 2017.

In October 2017 Carrizo also sold its Marcellus Shale assets to a subsidiary of Kalnin Ventures LLC for $84 million in cash, according to a press release. "Net production from the assets averaged more than 40 MMcf/d of natural gas over the first nine months of 2017," the release stated. The transaction closed at the end of November.

Centennial Resource Development Inc.

- **About 88,000 net acres in the Delaware Basin**
- **Acquired about 11,860 net acres in Lea County, N.M.**

Independent oil producer Centennial Resource Development has about 88,000 net acres and 2,206-plus drilling locations (about 57% oil) in the Delaware Basin in Reeves County, Texas, and Lea County, N.M.

The company reported second-quarter 2017 total daily production of 29,664 boe and 17,435 bbl of oil, an increase of 61% and 66%, respectively, compared to first-quarter 2017, according to the company's second-quarter 2017 results.

In May 2017 Centennial acquired about 11,860 net acres in Lea County from GMT Exploration Co. for about $350 million, a press release stated.

In the second quarter Centennial reported strong wells from the Upper Wolfcamp A in Reeves County. Centennial completed its best well to date with the Stephens 2H (100% WI). The well achieved a 30-day IP rate of 1,953 boe/d (77% oil), according to the company's second-quarter report. The well had an effective lateral of about 4,190 ft with a 30-day IP rate of 359 bbl/d of oil per 1,000 ft of lateral. The Russell 6H (100% WI) was drilled with an about 4,185-ft effective lateral and produced 1,750 boe/d (86% oil) for the 30-day IP period, according to the report. On a per lateral foot basis, the well delivered a 30-day IP rate of 359 bbl/d per 1,000 ft of lateral.

"Since inception, one of our goals was to become the technical leader in shale oil extraction among the mid-cap E&P [companies]. The Stephens 2H and Russell 6H are the most productive wells drilled to date, evidence that we have achieved this goal," said Chairman and CEO Mark G. Papa in the second-quarter 2017 report.

Centennial added a sixth drilling rig in Reeves County during the second quarter. "Due to efficiency gains, Centennial expects to continue operating its current six-rig drilling program for the remainder of 2017. This compares to Centennial's previous plan to add a seventh operated rig during third-quarter 2017," the company stated

in the report. "Plans are to move one rig to Lea County, N.M, during the third quarter to begin development activity on its recently acquired GMT acreage."

Centennial also expected to drill and complete 65 to 75 gross wells during 2017.

Chesapeake Energy Corp.

- **About 870,000 net acres in The Wedge Play in the Midcontinent**
- **About 270,000 net acres in the Eagle Ford Shale**

Chesapeake Energy has operations in Louisiana, Ohio, Oklahoma, Pennsylvania, Texas and Wyoming.

"Chesapeake is currently utilizing 14 drilling rigs (below the third-quarter 2017 average of 17) across its operating areas, five of which are located in the Eagle Ford Shale, one in the Midcontinent area, three in the Haynesville Shale, three in the Powder River Basin [PRB] and two in Northeast Appalachia," according to the company's third-quarter 2017 results. Chesapeake expected to average 14 rigs in fourth-quarter 2017 and to place on production about 20 fewer gross operated wells in 2017.

As of first-quarter 2017 the company had three rigs and three fracture crews in the Haynesville Shale in western Louisiana. In 2016 improved completions designs led to a more than 250% increase in 90-day production. Chesapeake's Haynesville position is 100% HBP and only 25% developed, according to the company's website. In third-quarter 2017 the company reported 134 Mboe/d net production in the Haynesville, according to Chesapeake's third-quarter results. Chesapeake expected to place on production up to 23 wells in the Haynesville Shale in second-half 2017, compared to 17 wells in the first half, according to the company's second-quarter 2017 results report.

In the Eagle Ford Shale Chesapeake has about 270,000 net acres and expected to run three to four active rigs in 2017. Eagle Ford production consists of 56% oil, 19% NGL and 25% natural gas, according to the company's website. As of first-quarter 2017 the company has six rigs and three fracture crews in the Eagle Ford. In third-quarter 2017 the company

Chesapeake Energy's Faith Ranch wells achieved peak production of about 18,000 boe/d in third-quarter 2017. *(Photo courtesy of Chesapeake Energy Corp.)*

reported 93 Mboe/d net production in the Eagle Ford, according to Chesapeake's third-quarter results. Chesapeake expected to place on production up to 73 wells in South Texas in fourth-quarter 2017, compared to 31 wells in the third quarter, according to the third-quarter 2017 results report.

In the Northeast Appalachia, which includes the Utica Shale and Marcellus Shale, Chesapeake's operations include two rigs and two fracture crews, as of third-quarter 2017. In the Utica, with 70% of locations remaining in development, Chesapeake planned to run one to two active rigs in 2017. About 93% of the company's dry gas in the Utica Shale is sent to Gulf markets, according to the company's website. In third-quarter 2017 the company reported 120 Mboe/d net production in the Utica, according to Chesapeake's third-quarter results.

In the Marcellus Shale the company has about 11.2 Tcf of net recoverable resources and 2,900 undrilled locations in the Marcellus. In third-quarter 2017 the company reported 126 Mboe/d net production in the Marcellus, according to Chesapeake's third-quarter results. Chesapeake expected to place on production up to 17 wells in the Marcellus Shale in fourth-quarter 2017, compared to 25 wells in the third quarter, according to the third-quarter 2017 results report.

In the Midcontinent Chesapeake's operations include one rig and one fracture crew, as of third-quarter 2017. The company has about 870,000 net acres in The Wedge Play, with 1,400 additional upside locations, and about 1.5 million net acres in the entire Midcontinent region, according to the company's website. In third-quarter 2017 the company reported 56 Mboe/d net production in the Midcontinent, according to Chesapeake's third-quarter results.

In the PRB Chesapeake is one of the largest operators in the basin with gross recoverable resources potential of about 2.7 Bboe. The company's PRB operations include three rigs and one fracturing crew. In Wyoming's Southern PRB Chesapeake has multiple stacked and staggered liquids-rich formations underneath its consolidated leasehold position. This includes a dominant position in the Sussex Sandstone oil play, with about 200 undrilled locations, the company said on its website. In third-quarter 2017 the company reported 13 Mboe/d net production in the PRB, according to Chesapeake's third-quarter results. The company expected to place on production up to 11 wells in fourth-quarter 2017, compared to seven wells in the third quarter, according to the third-quarter results report.

Chevron

- **Ranked No. 45 on the 2017 list of *Fortune* Global 500 companies**
- **Largest net acreage holder in the Permian**

Chevron has operations in the shale and tight resources of the U.S. with major capital projects in the Marcellus and Utica, Permian Basin and the San Joaquin Valley.

In the Permian Basin Chevron has about 2 million net acres, making it the largest acreage holder in the basin, according to the company's website. The company reported 2016 production of 90,000 net bbl of crude oil, 327 MMcf of natural gas and 29,000 bbl of NGL in the basin as well as reserves of 9 Bbbl of oil and equivalent gas.

"Our development of oil and natural gas from tight rock and shale assets is focused on the Permian Basin in Texas and New Mexico, and the Duvernay Shale in Alberta, Canada. In other basins, such as the Marcellus Shale in Pennsylvania and West Virginia, and the Liard and Horn River basins in British Columbia, Canada, we are focused on identifying the areas most prospective for development and bringing those resources to production safely and cost effectively," the company stated on its website.

In addition, Chevron has had a presence in California's San Joaquin Valley for more than 100 years. San Joaquin Valley's heavy oil makes up about 86% of Chevron's production, according to the company's website. The company's San Joaquin Valley business unit has operations in several fields, including Coalinga, Cymric, Kern River, Lost Hills, McKittrick, Midway Sunset and San Ardo, and a non-operated joint venture in Elk Hills. With more than 16,000 wells in operation, Chevron ranks No. 1 in net daily oil equivalent production in California, according to the company.

Tap Into A Lower Total Cost Of Ownership With Allison

As The Oil Field Increases Pressure, So Does Allison Transmission. Our most recent addition to Allison's pressure pumping portfolio, the 9832 OFS™, enables our customers to increase their rig ratings to 2500 hp and beyond. For over 60 years, Allison has been a leader in oil field transmissions. With an industry leading space claim, the 9832 OFS™ can give you an edge, contact your Allison Authorized Distributor or Dealer to learn more. For the one nearest you, visit our website at **allisontransmission.com.**

allisontransmission.com

Allison Transmission®

Cimarex Energy Co.

- **Brought 85 gross MidCon wells online in first-half 2017**
- **Permian proved reserves of 372 Bcf of gas in 2016**

Cimarex Energy is an E&P company with operations mainly located in Oklahoma, Texas and New Mexico. Most of the company's drilling takes place in the Wolfcamp Shale and Bone Spring Sands in the Permian Basin and in the Woodford Shale in Western Oklahoma.

In the Midcontinent the company reported 2016 proved reserves of 1,095 Bcf of gas, 31,399 Mbbl of oil and 89,615 Mbbl of NGL, according to the company's website. The Midcontinent accounted for 63% of Cimarex's year-end 2016 proved reserves and 47% of total production.

In August 2017 Cimarex reported it had brought on 85 gross (18 net) wells in the Midcontinent in the first half of the year, according to the company's second-quarter 2017 report.

"Production from the Midcontinent averaged 509 MMcfe per day for the second quarter, up 10% vs. second-quarter 2016. Sequentially, crude oil volumes were up 8%, natural gas production grew 4% and NGL volumes increased 7%," the report stated. "In addition to its continued delineation in the Meramec play, the company recently began completion of an increased density pilot in the Woodford Formation. The project consists of eight wells that are testing both 16 and 20 Woodford wells per section. Results from this test are expected in the second half of 2017 and will help determine well spacing in upcoming Woodford developments."

In the Permian Basin the company reported 2016 proved reserves of 372 Bcf of gas, 74,295 Mbbl of oil and 40,977 Mbbl of NGL, according to the company's website. The Permian accounted for 37% of Cimarex's year-end 2016 proved reserves and 52% of total production.

In August 2017 Cimarex reported it had brought on 36 gross (26 net) wells in the Permian in the first half of the year, according to the company's second-quarter 2017 report. "Production from the Permian Basin averaged 644.7 MMcfe per day in the second quarter, a 27% increase from second-quarter 2016 and up 12% sequentially. Oil volumes represent 43% of the region's total production. Natural gas production increased 9% and NGL production was up 16%, sequentially," the report stated.

Concho Resources Inc.

- **No. 1 producer of oil in New Mexico**
- **A top 15 producer of oil in Texas**

Concho Resources has operations in the New Mexico Shelf, Delaware Basin and Midland Basin. Concho averaged 21 rigs in second-quarter 2017, and as of Aug. 2 the company was running 19 rigs and expected to average 17 rigs in second-half 2017, according to the company's second-quarter 2017 results report. During second-quarter 2017 Concho began drilling or participated in 87 gross wells (60 operated wells) and completed 76 gross wells, the report stated.

The independent company is the No. 1 producer of oil and No. 3 producer of natural gas in New Mexico with about 150,000 gross acres that are concentrated and largely HBP in the New Mexico Shelf, according to the company's website.

Concho has about 590,000 gross acres in the Delaware Basin. "Concho added 12 horizontal wells in the Northern Delaware Basin with at least 30 days of production during the second quarter of 2017 and an average lateral length of 6,045 ft. The average peak 30-day and 24-hour rates for these wells were 1,394 boe/d (66% oil) and 1,700 boe/d, respectively. The company currently [as of Aug. 2, 2017] has seven rigs drilling in the Northern Delaware Basin," the report stated.

"Concho added eight horizontal wells in the Southern Delaware Basin with at least 30 days of production during the second quarter of 2017. The average peak 30-day and 24-hour rates for these wells were 1,740 boe/d (77% oil) and 2,165 boe/d, respectively." The company had six rigs drilling in the Southern Delaware Basin as of Aug. 2, 2017.

The company has about 260,000 gross acres in the Midland Basin. "Concho added 31 horizontal wells in the Midland Basin with at least 30 days

of production during the second quarter of 2017 and an average lateral length of 9,995 ft. The average peak 30-day and 24-hour rates for these wells were 923 boe/d (87% oil) and 1,078 boe/d, respectively. The company currently [as of Aug. 2] has five rigs drilling in the Midland Basin," the report stated.

In July 2017 Concho acquired about 12,400 net acres with an average 100% working interest in Andrews and Martin counties, Texas, according to the company's second-quarter report. The acquired properties included about 3 Mboe/d (73% oil) of legacy production. The acreage is contiguous with the Mabee Ranch leasehold Concho acquired from Reliance in fourth-quarter 2016, according to the company.

Concho also boasts it is a top 15 producer of oil in Texas, according to a company fact sheet.

Concho expected production to average between 200 Mboe/d and 204 Mboe/d in fourth-quarter 2017.

ConocoPhillips

- **Ranked No. 339 on the 2017 list of *Fortune* Global 500 companies**
- **World's largest independent E&P company based on production and proved reserves**

ConocoPhillips has U.S. operations in the Lower 48 and Alaska. The company is the world's largest independent E&P company based on production and proved reserves.

In Alaska the company reported 2016 production of 179 Mboe/d and proved reserves of 1.3 Bboe, according to a March 2017 company fact sheet.

ConocoPhillips has ownership interests in two oil fields on Alaska's North Slope—Kuparuk, which the company operates with 55.3% interest, and Prudhoe Bay with 36.1% interest. Additionally, ConocoPhillips is the operator with 78% interest in two areas in the Alpine Field located on the Western North Slope—Alpine and Alpine Satellites.

"ConocoPhillips is pursuing several new developments and evaluating additional North Slope investments on its onshore acreage," according to the fact sheet.

In addition, "ConocoPhillips is Alaska's largest crude oil producer and one of the largest owners of state, federal and fee exploration leases, with approximately 0.5 million net undeveloped acres at year-end 2016."

In southern Alaska the company owns a 100% interest in the Kenai LNG facility. The Tyonek Platform in the North Cook Inlet Field and the Beluga River natural gas field located in the Cook Inlet were sold in 2016.

The company's Lower 48 segment consists of 12.3 million net acres, much of it HBP and includes three regions covering the Gulf Coast, Midcontinent and Rockies.

The company's major focus areas include the Eagle Ford, Bakken and Permian. In 2016 the company's Lower 48 production totaled 486 Mboe/d and proved reserves of 1.6 Bboe. During third-quarter 2017 ConocoPhillips had 12 operated drilling rigs running in the Eagle Ford, Bakken and the Permian Basin.

In June 2017 ConocoPhillips announced an agreement to sell its Barnett assets to an affiliate of Miller Thomson & Partners LLC. The transaction

ConocoPhillips has 78% interest in two areas in the Alpine Field located on the Western North Slope: Alpine and Alpine Satellites. *(Photo courtesy of ConocoPhillips)*

was expected to close in third-quarter 2017, according to a press release.

In July 2017 the company sold its San Juan Basin assets to an affiliate of Hilcorp Energy Co., a press release stated.

In September 2017 ConocoPhillips sold its Panhandle assets for $184 million to an undisclosed buyer, according to a company press release.

Continental Resources

- **Reported 112.4 Mboe/d in the Bakken in the second quarter**
- **Planned to exit 2017 with about 160 gross operated DUC Bakken wells**

Continental Resources operates in the Bakken in North Dakota and the Stack and Scoop plays in Oklahoma. The company reported year-end 2016 proved reserves of 1,275 MMboe, according to a company chart.

In second-quarter 2017 the company reported 112,397 boe/d in North Dakota's Bakken, 7,464 boe/d in Montana's Bakken, 61,107 boe/d in the Scoop and 31,934 boe/d in the Stack, according to Continental's second-quarter 2017 results report.

The company had 100 gross (38 net) operated and nonoperated Bakken wells completed during the second quarter and had 205 gross operated drilled but uncompleted (DUC) wells as of June 30. The company expected to exit 2017 with a DUC inventory in the Bakken of about 160 gross operated wells, including about 35 already stimulated with first production expected in 2018, according to the report.

The company had 36 gross (12 net) operated and nonoperated Stack wells completed during the second quarter, the report stated. By the end of August, the company expected to have nine operated rigs in the play, with seven rigs targeting the Meramec Formation and two targeting the Woodford Formation.

Continental also had 8 gross (2 net) operated and nonoperated wells completed during the second quarter. As of Aug. 8, 2017, the company had five operated drilling rigs working in the Scoop, targeting the Springer, Sycamore and Woodford formations, the report stated.

As of Aug. 8, 2017, Continental Resources had five operated drilling rigs working in the Scoop, targeting the Springer, Sycamore and Woodford formations. *(Photo courtesy of Continental Resources)*

In August 2017 the company signed two agreements with undisclosed buyers to sell 6,590 net acres of noncore leasehold in the oil window of the Stack in northern Blaine County, Okla., for $72.5 million, and 26,000 net acres of leasehold in the Arkoma Basin in Atoka, Coal, Hughes and Pittsburg counties, Okla., for $68 million, the second-quarter 2017 report stated. The leaseholds are nonstrategic and include minimal proved reserves, according to the company.

In October 2017 Continental Resources reported its first-ever sale of Bakken oil for delivery overseas to China. The company sold more than 1 MMbbl of Bakken crude oil for November delivery to Atlantic Trading and Marketing, a press release stated.

Devon Energy

- **Focused capital program in the Stack and Delaware Basin**
- **U.S. resources plays averaged 412,000 boe/d in the second quarter**

Devon Energy's U.S. operations include the Stack, Delaware Basin, Eagle Ford Shale, Barnett Shale and the Rockies. In the second quarter Devon's U.S. resources plays averaged 412,000 boe/d, according to the company's second-quarter 2017 report.

In the Delaware Basin the company reported year-end 2016 production of 60 Mboe/d (74% liquids) and reserves of 108 MMboe (75% liquids), according to Devon's website. In addition, in the Stack the company reported year-end 2016 production of 93 Mboe/d (48% liquids) and reserves of 393 MMboe (47% liquids). In the company's second-quarter 2017 report it stated, "Recent drilling activity from the company's U.S. operations was highlighted by nine high-rate development wells in the Stack and Delaware Basin that achieved initial 30-day rates averaging nearly 2,000 boe per day."

Additionally, Devon's Eagle Ford operations are located in DeWitt and Lavaca counties in Texas. The company reported year-end 2016 production of 76 Mboe/d (76% liquids) and reserves of 75 MMboe (76% liquids) in the Eagle Ford, according to Devon's website.

In the Barnett Shale Devon reported year-end 2016 production of 169 Mboe/d (27% liquids) and reserves of 895 MMboe (25% liquids), according to the company.

Devon's Rocky Mountain operations are focused on its oil opportunities in the Powder River Basin and the Wind River Basin. The company reported year-end 2016 production of 19 Mboe/d (79% liq-

This Stack production site is located in Canadian County, Okla. *(Photo courtesy of Devon Energy)*

uids) and reserves of 24 MMboe (64% liquids) in the Rockies, according to Devon's website.

According to Devon's second-quarter 2017 report, "Based on accelerated activity levels in the second half of 2017, the company projects U.S. oil production to exit the year at a rate of 18% to 23% higher than fourth-quarter 2016. This strong production growth over the remainder of 2017 is driven by the company's focused capital program in the Stack and Delaware Basin where 90% of its U.S. rig activity is allocated. Combined, these two franchise growth assets are expected to advance production by greater than 30% by the end of 2017 compared to the same period a year ago."

Diamondback Energy Inc.

- **191,000 net surface acres in the Permian**
- **Third-quarter 2017 production of 85 Mboe/d in the Permian**

Diamondback Energy's operations are focused solely in the Permian Basin within the Wolfcamp, Spraberry, Clearfork, Bone Spring and Cline formations. The independent company has 191,000 net surface acres with about 4,300 gross locations in the Permian, according to a September 2017 investor presentation.

The company reported third-quarter 2017 production of 85 Mboe/d (73% oil), an increase of more than 10% from the second-quarter 2017 average production of 77 Mboe/d, a press release stated. As of Oct. 2, 2017, Diamondback was running nine drilling rigs and four dedicated completion crews, and the company said it began operations with a fourth newbuild completion spread that has been executed as well as its three existing dedicated crews.

In February 2017 Diamondback acquired 80,185 net leasehold acres in Pecos and Reeves counties from Brigham Resources Operating LLC and Brigham Resources Midstream LLC for an aggregate purchase price of $2.55 billion, a press release stated.

In addition, Viper Energy Partners LP is a limited partnership formed by Diamondback to own, acquire and exploit oil and natural gas properties in North America, with a focus on oil-weighted basins primarily the Permian Basin. Viper reported third-quarter 2017 production of 12.6 Mboe/d (68% oil), according to a press release.

Encana Corp.

- **U.S. operations in the Permian, Eagle Ford and San Juan**
- **Sold its Piceance assets**

Encana's U.S. operations include the Permian Basin, Eagle Ford Shale and San Juan Basin.

In second-quarter 2017 Encana delivered a 20% increase in IP180 type curves and increased its premium return well inventory by 700 locations in the Permian, according to the company. Encana has 45 cube wells on production and aims to create additional upside through advanced completions design and new benches, according to the company's second-quarter 2017 report.

"With over 30 billion barrels of cumulative oil production, the Permian is a proven oil-rich resource play with multiple stacked horizontal targets. Encana believes the Permian's unconventional production potential will exceed the Eagle Ford and the Bakken combined," the company said on its website

In the Eagle Ford Encana delivered a 45% increase in average IP180 type curves and grew oil and condensate production by 30% from the previous quarter, according to the company's second-quarter 2017 report. The company also increased its premium return well inventory by 40 locations in the Eagle Ford.

Encana holds about 200,000 net acres in the San Juan, located almost exclusively in the oil window of the play. In 2017 the company had a six-well program. As of October 2017 all six were on production and evaluation of the results were underway to determine the course going forward.

In July 2017 Encana's wholly owned subsidiary, Encana Oil & Gas (USA) Inc., sold its Piceance natural gas assets located in northwestern Colorado to Caerus Oil and Gas LLC, a press release stated.

In addition, Encana Oil & Gas (USA) Inc. sold its Denver-Julesburg Basin assets in Colorado to Crestone Peak Resources in 2016, a press release stated.

Encana's RAB Davidson cube development pad is shown via a photo taken by a drone. *(Photo courtesy of Encana Corp.)*

Energen has identified 4,116 net engineered, unrisked potential drilling locations in horizontal plays in the Delaware and Midland basins. *(Photo courtesy of Energen)*

Energen

- **2.5 Bboe net undeveloped horizontal resource potential in Permian**
- **Proved reserves totaled 316 MMboe at year-end 2016**

Energen operates exclusively in the Permian Basin of West Texas and New Mexico. As of July 1, 2017, the oil-focused E&P company had identified 4,116 net engineered, unrisked potential drilling locations in horizontal plays in the Delaware and Midland basins with an estimated 2.5 Bboe net undeveloped resource potential, according to the company's website. Energen's proved reserves at year-end 2016 totaled 316 MMboe.

The independent company was scheduled to complete an estimated 111 net wells in 2017—36 in the Delaware Basin and 75 in the Midland Basin, according to Energen's September 2017 presentation. All 2017 completions feature the company's Gen 3 fracture design, and about 75% are pattern wells completed in batches at original reservoir pressure, the company said. As a result, Energen was on track at mid-year 2017 to generate 29% year-over-year growth in total production and 37% growth in Midland and Delaware production.

Energen expected to have 15 gross (14 net) drilled but uncompleted wells (DUCs) in the Midland Basin and 14 gross (12 net) DUCs in the Delaware Basin at year-end 2017, according to the presentation.

In addition, Energen is adding to its Permian footprint through acquisitions of unproved, bolt-on leasehold. In the 18 months ending June 30, 2017, Energen acquired about 19,000 net bolt-on acres for some $335 million, according to the company.

EOG Resources Inc.

- **2016 U.S. production of 181 MMboe**
- **Completed 51 wells in the second quarter in the Eagle Ford**

EOG operates in several basins across the U.S. The company reported 2016 U.S. production of 181 MMboe and year-end 2016 proved reserves of 2,088 MMboe, according to the company's website.

In the South Texas Eagle Ford EOG completed 51 wells in the second quarter with an average treated lateral length of 6,500 ft per well and average 30-day IP rates per well of 1,960 boe/d, or 1,520 bbl/d of oil, 225 bbl/d of NGL and 1.3 MMcf/d of natural gas, according to the company's second-quarter 2017 results report. In Karnes County, Texas, EOG completed a three-well pattern, the Lynch Unit 2H-4H, with an average treated lateral length of 5,800 ft per well and average 30-day IP rates per well of 3,245 boe/d, or 2,555 bbl/d of oil, 350 bbl/d of NGL and 2 MMcf/d of natural gas. In Gonzales County, Texas, EOG completed a four-well pattern, the Olympic A 1H–D 4H, with an average treated lateral length of 6,600 ft per well and average 30-day IP rates per well of 2,910 boe/d, or 2,160 bbl/d of oil, 380 bbl/d of NGL and 2.2 MMcf/d of natural gas, the report stated. And in DeWitt County, Texas, EOG completed a five-well pattern, the Dio Unit 11H-15H, with an average treated lateral length of 5,100 ft per well and average 30-day IP rates per well of 2,840 boe/d, or 2,135 bbl/d of oil, 355 bbl/d of NGL and 2.1 MMcf/d of natural gas, the report stated.

In the Delaware Basin Wolfcamp EOG completed 25 wells in the second quarter with an average treated lateral length of 6,500 ft per well and average 30-day IP rates per well of 3,010 boe/d, or 1,945 bbl/d of oil, 480 bbl/d of NGL and 3.5 MMcf/d of natural gas, according to the report.

In Lea County, N.M., EOG completed a four-well pattern, the Rattlesnake 28 Fed Com 706H-709H, with an average treated lateral length of 6,700 ft per well and average 30-day IP rates per well of 3,870 boe/d, or 2,545 bbl/d of oil, 600 bbl/d of NGL and 4.4 MMcf/d of natural gas.

In the Delaware Basin Bone Spring EOG completed 19 wells in the second quarter with an average treated lateral length of 5,600 ft per well and average 30-day IP rates per well of 2,130 boe/d, or 1,515 bbl/d of oil, 275 bbl/d of NGL and 2 MMcf/d of natural gas, according to the report. In Lea County EOG completed a three-well pattern, the Neptune 10 State Com 503H-505H, with an average treated lateral length of 9,700 ft per well and average 30-day IP rates per well of 3,620 boe/d, or 2,790 bbl/d of oil, 375 bbl/d of NGL and 2.7 MMcf/d of natural gas.

Additionally, in the Delaware Basin Leonard, EOG completed three wells in the second quarter.

In the North Dakota Bakken EOG completed 22 wells in the second quarter with an average treated lateral length of 8,400 ft per well and average 30-day IP rates per well of 1,450 boe/d, or 1,175 bbl/d of oil, 150 bbl/d of NGL and 0.7 MMcf/d of natural gas. Of particular note is a four-well pattern in the Antelope Field in McKenzie County, the Clarks Creek 73, 74, 75 and 110-0719H, completed with an average treated lateral length of 9,800 ft per well and average 30-day IP rates per well of 2,965 boe/d, or 2,075 bbl/d of oil, 500 bbl/d of NGL and 2.3 MMcf/d of natural gas, the report stated.

In addition, in the second quarter EOG completed nine wells in Karnes County in the South Texas Austin Chalk, eight wells in the Powder River Basin Turner area and 10 wells in the Denver-Julesburg Basin, according to the report.

EP Energy

- **173,110 net acres in the Uinta Basin**
- **91,675 net acres in the Eagle Ford**

EP Energy operates exclusively in the U.S. in the Altamont, Eagle Ford and Wolfcamp.

The company's operations in the Uinta Basin are focused on developing the Altamont Field, which includes the Altamont, Bluebell and Cedar Rim fields. EP Energy owns 173,110 net acres in Duchesne and Uinta counties.

"Our [Altamont] current activity is mainly focused on the development of our vertical inventory on 160-acre spacing. We have identified an inventory of 1,126 drilling locations, including 776 vertical locations and 350 horizontal locations. The industry is currently piloting 80-acre vertical downspacing programs in the Wasatch and Green River formations and horizontal development programs in the multiple shale and tight sand intervals," the company said on its website. "Because our acreage in the area is largely held by production, if these programs are successful, it will result in additional vertical and horizontal drilling opportunities that could be added to our inventory of drilling locations."

In second-quarter 2017 EP Energy completed five gross wells (three net wells) in its Altamont program and produced 12.6 Mbbl/d of oil, a 15% increase compared to the year prior, according to the company's second-quarter 2017 results report. Total equivalent production for second-quarter 2017 was 18 Mboe/d, up 16% from second-quarter 2016.

"EP Energy has two drilling rigs in Altamont and continues to benefit from its successful recompletion program," the company said in the report. During the second quarter, the company entered into a new 60-well drilling joint venture (JV) program. For second-half 2017, the company expected to run two JV drilling rigs and continue its recompletion program.

In the Eagle Ford EP Energy has 91,675 net acres, where it has identified 946 drilling locations. In the second quarter, EP Energy completed nine wells in its Eagle Ford program and produced 26.4 Mbbl/d of oil, a 3% decrease compared with second-quarter 2016, according to the report. However, volumes were up 10% from first-quarter 2017. Total equivalent production for second-quarter 2017 was 41.5 Mboe/d. As of Aug. 2, 2017, EP Energy had one drilling rig in the Eagle Ford and remained focused on continuing to improve program returns and operational efficiencies while running one drilling rig for the remainder of 2017, according to the report.

In the Wolfcamp EP Energy completed 21 gross wells (10.5 net wells) and produced 9.9 Mbbl/d of oil in the Wolfcamp in the second quarter, a 46% increase compared to the year prior. Total equivalent production for second-quarter 2017 was 25.4 Mboe/d, according to the report. As of Aug. 2, 2017, EP Energy had two drilling rigs in the Wolfcamp and expected to increase well completions and production in the second half of the year while maintaining two drilling rigs for the remainder of 2017.

EQT Corp.

- **3.6 million gross acres in the Marcellus**
- **Expected to drill about 207 Appalachian wells in 2017**

EQT has been a natural gas producer in the Appalachian Basin for nearly 130 years. EQT owns about 3.6 million gross acres including about 790,000

Operations take place at an EQT well pad in Morgan, Greene County, Pa. *(Photo courtesy of EQT Corp.)*

gross acres in the Marcellus play, more than 13,600 gross productive wells and 13.5 Tcf of proved natural gas, NGL and crude oil reserves.

In 2016 EQT drilled 135 wells, including 117 Marcellus wells, 13 Upper Devonian wells as well as four Utica wells.

"With a planned investment of approximately $1.3 billion for well development in 2017, EQT continues to be a formidable player in Appalachian Basin natural gas production," the company said in its 2017 operational forecast. "EQT plans to drill approximately 207 wells in 2017, including 119 Marcellus wells, 81 Upper Devonian wells and seven Utica wells."

EQT has secured the drilling rights to about 3.6 million acres of land across the Appalachian Basin and other basins, including property in Pennsylvania, West Virginia, Ohio, Kentucky, Texas and Virginia.

In February 2017 EQT, through its subsidiary EQT Production Co., won a bankruptcy auction to acquire 53,400 core net Marcellus acres, including drilling rights on 44,100 net acres in the Utica and current natural gas production of about 80 MMcfe/d, from Stone Energy Corp. for $527 million, a news release stated.

In November 2017 EQT acquired Rice Energy for $6.7 billion, according to a news release. "This transaction brings together two of the top Marcellus and Utica producers to form a natural gas operating position that will be unmatched in the industry," said EQT President and CEO Steve Schlotterbeck in the release.

In 2016 EQT acquired additional core Marcellus acreage, consisting of 42,600 net acres and current natural gas production of about 42 MMcfe/d from Trans Energy Inc. and entities affiliated with Republic Energy for an aggregate purchase price of $513 million as well as 17,000 net acres and current natural gas production of about 2 MMcfe/d from a third-party for $170 million. EQT also acquired 62,500 net Marcellus acres and current natural gas production of 50 MMcfe/d for $407 million in 2016 from Statoil USA Onshore Properties Inc.

Gulfport Energy Corp.

- **About 211,000 net acres in the Utica Shale**
- **About 87,700 net acres in the Scoop play**

Gulfport Energy Corp. has operations in the Utica Shale, Southern Louisiana and the Scoop play.

The independent company provided estimated 2017 production guidance of 1,065 MMcfe/d to 1,100 MMcfe/d, according to Gulfport's website, and the company produced 1,038.4 MMcfe/d in second-quarter 2017.

In the Utica Shale Gulfport has about 211,000 net acres (about 75% dry gas), and at year-end 2016 the company reported about 2.3 net Tcfe of proved reserves. The company also reported six gross operating rigs and 857.2 MMcfe/d production in second-quarter 2017. During second-quarter 2017 Utica production accounted for about 83% of Gulfport's total net production, according to the company's website. Gulfport planned to run about six operated rigs in 2017 in the Utica Shale. The company's 2017 planned operated activity included drilling 87 to 97 gross (67 to 74 net) wells and turn-to-sales 72 to 80 gross (61 to 67 net) wells in the Utica. The company's 2017 planned nonoperated activity included drilling 30 to 34 gross (10 to 11 net) wells and turn-to-sales 42 to 46 gross (9 to 10 net) wells in the Utica, Gulfport said on its website.

Gulfport's Scoop play has about 87,700 net acres, and in second-quarter 2017 the company reported four gross operating rigs and 162 MMcfe/d production of about 69% natural gas, about 21% NGL and about 10% oil. Gulfport planned to run about four operated rigs in 2017 in the Scoop. The company's 2017 planned operated activity included drilling 19 to 21 gross (16 to 18 net) wells and turn-to-sales 17 to 19 gross (14 to 16 net) wells in the Scoop. The company's 2017 planned nonoperated activity included drilling 10 to 12 gross (one to two net) wells and turn-to-sales 10 to 12 gross (one to two net) wells in the Scoop, Gulfport said on its website.

Gulfport's Southern Louisiana assets include its West Cote Blanche Bay and Hackberry fields. In Southern Louisiana the company has about 10,834 net acres, 2.6 net MMboe of proved reserves, 100-plus producing horizons and reported 3,022 boe/d production in second-quarter 2017, according to the company's website. During 2017 Gulfport planned to run one drilling rig and one recompletion rig at the fields.

Hess Corp.

- **About 554,000 net acres in the Bakken**
- **About 45,000 net acres in the Utica**

Hess Corp. operates in two U.S. shale plays—the North Dakota Bakken and Three Forks formations, where it produces shale oil and gas, and the Ohio Utica Basin, where the company primarily produce natural gas and NGL.

The Nabors B06 Rig operates in the Bakken in North Dakota. *(Photo courtesy of Hess)*

Through the application of Lean manufacturing techniques, Hess' wells continue to be among the lowest cost and most productive in the Bakken, according to the company. Hess has more drilling spacing units in the core of the play than any other operators and its IP rates continue to increase as the company has increased its standard well design to a 50-stage completion from the previous 35-stage completion. The company also has successfully tested tighter well spacing, which has allowed it to increase its net EUR from the Bakken to 1.6 Bboe from its previous estimate of 1.4 Bboe.

In third-quarter 2017, Hess reported Bakken production of 103,000 boe/d, according to the company's third-quarter 2017 earnings release. The company operated an average of four rigs in the third quarter, drilling 24 wells and bringing 13 new wells online.

In the Utica Shale play in eastern Ohio the company's acreage is in the heart of the wet gas window. Hess has 45,000 core net acres in Ohio and operates in Jefferson, Belmont, Harrison and Guernsey counties as part of a 50:50 joint venture with CONSOL Energy Inc. Hess benefits from a high net revenue interest and its wells are highly productive with significant liquids content, according to the company. Drilling and completion costs have been reduced by 30% by applying the same Lean manufacturing techniques used at its Bakken asset in North Dakota.

In June 2017 Hess entered into an agreement to sell its interests in EOR assets in the Permian Basin to Occidental Petroleum Corp. for a total consideration of $600 million, a press release stated.

Jagged Peak Energy

- **70,400 net acres in the Southern Delaware Basin**
- **$148.9 million capex for drilling and completion activities**

Jagged Peak Energy is an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Southern Delaware Basin. The company's acreage targets the oil-rich southern portion of the Delaware Basin located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos counties, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations, according to the company's operations webpage.

In second-quarter 2017 Jagged Peak reported production volumes of 14,714 boe/d (81% oil), an increase of 166% compared to second-quarter 2016 and an increase of 50% compared to first-quarter 2017, according to the company's second-quarter 2017 earnings release.

Jagged Peak drilled 13 gross operated horizontal wells and completed and put online 14 gross operated horizontal wells during the second quarter. For first-half 2017, the company drilled 23 gross operated horizontal wells and completed and put online 21 gross operated horizontal wells, the report stated. As of July 30, 2017, the company completed 46 horizontal wells in the Delaware Basin, according to the company's operations webpage.

As of June 30, 2017, the company's total leasehold position increased to about 70,400 net acres, with more than 1,400 future well locations identified in the Third Bone Spring, Wolfcamp A and Wolfcamp B formations, the second-quarter report stated.

In addition, capex for drilling and completion activities were $148.9 million; $9.8 million was spent on infrastructure; and $25.7 million was spent to add more than 1,800 net acres to the company's leasehold position during second-quarter 2017, according to the report.

Marathon Oil Corp.

- **Ranked No. 160 on the 2017 list of *Fortune* Global 500 companies**
- **365,000 net surface acres in Oklahoma resource basins**

Marathon Oil's U.S. operations cover the North Dakota, Northern Delaware, Oklahoma and Texas regions.

In the Bakken the independent E&P company had about 270,000 net acres as of year-end 2016, according to the company's operations webpage. The company's Bakken Shale acreage is located

Peace of mind

Delivered by reliable hydraulic fracturing equipment customized for your operation.

Backed by decades of engineering experience, our trusted brands **Rolligon™**, **Enerflow™**, **APPCO™** and **Anson™** bring field-proven, industry leading pressure pumping equipment to the toughest hydraulic fracturing operations.

To experience power, performance and reliability in a pumping solution made just for you, visit **nov.com/pressurepumping**.

Acidizing | Stimulation | Cementing | Coiled Tubing Support | Flowline | Sand Handling and Transport Systems

NOV Completion & Production Solutions

within the established Williston Basin in Dunn, Hettinger, McKenzie, McLean, Mountrail, Slope and Williams counties in North Dakota, and Richland, Roosevelt and Sheridan counties in Montana. In second-quarter 2017, Marathon Oil's Bakken production averaged 49,000 net boe/d, compared to 48,000 net boe/d in the prior quarter, according to the company's second-quarter 2017 results press release.

In June 2017 Marathon Oil acquired about 21,000 net surface acres in the Northern Delaware Basin of New Mexico from Black Mountain Oil & Gas and other private sellers for $700 million, excluding closing adjustments, according to a company press release. "Combined with the acquisition from BC Operating, which closed May 1, Marathon Oil's total position in the Permian Basin is 91,000 net surface acres," the release stated.

The company's Northern Delaware production averaged 4,000 net boe/d in second-quarter 2017, reflecting the May 1 closing of BC Operating assets and June 1 closing of Black Mountain assets, according to the company's second-quarter 2017 report.

In the Oklahoma resource basins Marathon Oil had about 365,000 net surface acres as of year-end 2016, which includes acreage acquired in August 2016 in the Stack Meramec play, according to the company's operations webpage. In the Scoop and Stack areas the company holds net acres with rights to the Woodford, Springer, Meramec, Osage, Oswego, Granite Wash and other Pennsylvanian and Mississippian plays. The company also has well-established production in Oklahoma from conventional operations in the Ammunition, Cement, Elk City, Huntley, Knox, Marlow, Rocky, Strong City, Watonga and Wheatland fields.

The company's unconventional Oklahoma production increased 11% to 49,000 net boe/d during second-quarter 2017, compared to 44,000 net boe/d in the prior quarter and up more than 80% from second-quarter 2016, according to Marathon Oil's second-quarter 2017 results press release.

In the Eagle Ford in South Texas Marathon Oil had about 145,000 net acres as of year-end 2016, according to the company's operations webpage. The company's acreage is located primarily within Atascosa, DeWitt, Frio, Gonzales and Karnes counties, with operated producing wells in the Eagle Ford, Austin Chalk and Pearsall formations.

Marathon Oil's production in the Eagle Ford averaged 100,000 net boe/d in second-quarter 2017, up from 99,000 net boe/d in the prior quarter, according to the company's second-quarter 2017 results press release. Marathon Oil brought 41 gross company-operated wells to sales in the second quarter, compared to 47 wells to sales in the previous quarter. The top 10 wells to sales had 30-day IP rates averaging 2,340 boe/d (69% oil). During the second quarter a new company record was set again for the fastest well drilled in the Eagle Ford at a rate of more than 4,200 ft per day, according to the release.

Mewbourne Oil Co.

- **Rated the No. 2 company in liquids production**
- **No. 5 producer by overall barrels of oil equivalent**

Mewbourne Oil Co., an independent oil and natural gas producer in the Anadarko and Permian basins of Texas, Oklahoma and New Mexico, operates more than 2,100 wells, according to Mewbourne's website.

According to 2017 production data for U.S.-based private E&P companies, Mewbourne is one of the top 10 liquids producers, sits at the No. 2 seat in liquids production and is the No. 5 producer by overall barrels of oil equivalent, according to industry analysts.

Mewbourne also ranks as the 15th largest operator by volume across the Permian Basin, according to a March 2017 report by Seeking Alpha.

In July 2017 IHS reported that Mewbourne completed two offsetting horizontal Wolfcamp gas wells in New Mexico's Purple Sage Field. The 1H Loving Townsite "21" W2PA Fee was tested flowing 2.7 MMcf of gas, 262 bbl of 55.6-degree condensate and 2,820 bbl of water per day after a 29-stage fracture-treatment. The company's 2H Loving Townsite "21" WOPA Fee was tested for 716 Mcf of gas, 217 bbl of condensate and 3,374 bbl of water per day from perforations at 9,890 ft to 14,480 ft following a 29-stage fracturing job, according to an IHS Markit report.

In August 2017 IHS reported that a Lower Bone Spring well in central Eddy County was completed by Mewbourne as the first horizontal producer in southeastern New Mexico's Avalon Field. The 1H Roscoe "6" B3AD Federal Com was tested for an initial daily potential of 231 bbl of crude, 527 Mcf of gas and 3,426 bbl of water through fracture-treated perforations at 8,761 ft to 13,275 ft.

IHS also reported that oil flowed at an initial rate of 360 bbl/d with 77 Mcf of gas and 976 bbl of water at a Mewbourne horizontal well completed in September 2017 6 miles south-southeast of Farnsworth, Texas. The M002CM Rifenburg is producing from a fracture-stimulated Marmaton lateral at 7,312 ft to 11,680 ft that was drilled south across the section to a bottomhole in A-1879.

In addition, Mewbourne opened a new regional headquarters office in June 2017 for operations in New Mexico's Permian Basin.

Newfield Exploration Co.

- **Average 159 Mboe/d net domestic production in third-quarter 2017**
- **New water recycling facility in the Stack play**

Newfield Exploration is focused on domestic, liquids-rich unconventional resource plays. The independent company's U.S. operations are located primarily in the Anadarko and Arkoma basins of Oklahoma, Williston Basin of North Dakota and Uinta Basin of Utah. About 98% of Newfield's proved reserves are located onshore U.S., according to the company's website.

By year-end 2017, Newfield expected its net domestic production to average about 168,000 boe/d. "Domestic net production was 159,000 boe/d (41% oil and 64% liquids), exceeding the mid-point guidance by approximately 4,650 boe/d [in the third quarter]. The better than expected results during the quarter were primarily related to higher volumes in Stack," the company stated in its third-quarter 2017 results report.

Newfield's Anadarko Basin production increased about 20% in the third quarter compared to the prior quarter, averaging about 105,000 boe/d during the third quarter, the report stated. The Anadarko Basin now comprises about two-thirds of total domestic production. Based on state records, Newfield is now the largest gross oil producer in Oklahoma, according to the company's report.

On Oct. 31, 2017, Newfield provided data on eight recent HBP wells in the Stack, including the play's "record-setting" Hoile well, which had the play's highest oil production per 1,000 ft of lateral over a 24-hr period. The Hoile recently commenced production with a 24-hr IP rate of 5,100 boe/d (67% oil) from a 7,140-ft lateral, the report stated.

In the Scoop play the company brought two developments online in the third quarter. "The

Newfield's Stark production facility is located outside of Okarche, Okla., in the Stack play of the Anadarko Basin. *(Photo courtesy of Newfield Exploration Co.)*

McClelland pad was our first development with eight infill wells drilled in the Woodford. The average 30-day rate for the eight infill wells was 1,966 boe/d (36% oil). The McClelland infill wells are performing in-line with Newfield's recent Tina development (second-quarter 2017 completions), where production per well has averaged 1,465 boe/d (41% oil) over the first 120 days," the report stated.

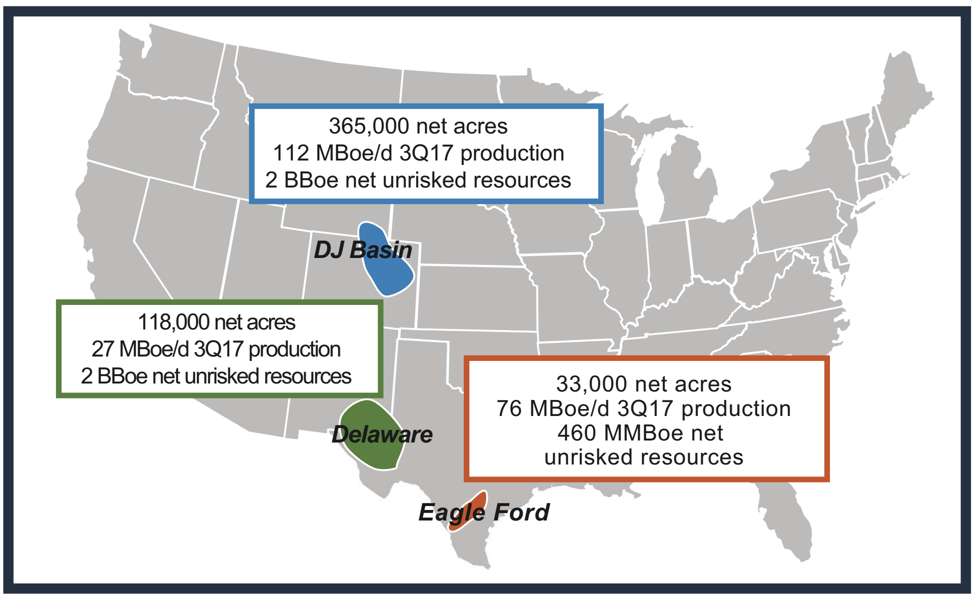
In March 2017 the company broke ground on a water recycling facility located in its Stack play in the Anadarko Basin in Kingfisher County, Okla., according to a news release. The Barton Water Recycle Facility is expected to process about 30,000 bbl/d of water. The recycling facility was completed in July and began operating at full capacity in August.

In addition, the company's production in the Williston Basin increased during the third quarter, averaging nearly 22,000 boe/d (about 65% oil).

Noble Energy Inc.

- **Acquired Clayton Williams Energy for $2.7 billion**
- **Drilled 49 U.S. wells in third-quarter 2017**

Noble Energy is an independent E&P company that has significant U.S. positions in the Denver-Julesburg (D-J) Basin, Delaware Basin and Eagle Ford Shale.



Noble Energy continued to high-grade its U.S. onshore portfolio in 2017. *(Data courtesy of Noble Energy)*

In January 2017 Noble Energy finalized the bolt-on transactions that added about 7,200 net acres to the company's Southern Delaware Basin position in Reeves County, Texas.

In April 2017 Noble Energy closed on the acquisition of Clayton Williams Energy for $2.7 billion, which increased Noble's core Delaware Basin position to nearly 120,000 net acres. Clayton Williams Energy became a wholly owned subsidiary of Noble Energy under the name NBL Permian LLC. Acquired assets included 71,000 highly contiguous net acres in the core of the Southern Delaware Basin adjacent to Noble Energy's original Reeves County holdings in Texas, an additional 100,000 net acres in other areas of the Permian Basin and more than 300 miles of oil, natural gas and produced water gathering pipelines.

In June 2017 Noble Energy divested its upstream assets in northern West Virginia and southern Pennsylvania to HG Energy II Appalachia LLC, a portfolio company of Quantum Energy Partners, for $1.125 billion. "The Marcellus has been a strong performer for Noble Energy over the last few years," Noble Energy Chairman, President and CEO David L. Stover said. "During the same time period, we have also significantly expanded the inventory of investment opportunities in our liquids-rich, higher-margin onshore assets, which has led us to now divest our Marcellus position. This enables us to further focus our organization on our highest-return areas."

In November 2017 Noble Energy signed a definitive agreement with SRC Energy Inc. to divest about 30,200 net acres from the company's noncore D-J Basin position in Weld County, Colo., for $608 million.

Noble Energy's third-quarter results report stated, "Third-quarter 2017 operating cash flow from the company's D-J Basin, Eagle Ford and Delaware Basin assets increased more than 40% as compared to the third quarter of last year. Total sales volumes across the company's U.S. onshore assets were 219 Mboe/d (42% oil, 25% NGL and 33% natural gas), at the high end of original guidance."

The company maintained an average of seven operated drilling rigs onshore during the third quarter (two in the D-J and five in the Delaware). During the third quarter Noble Energy drilled 49 wells (32 D-J and 17 Delaware) and reduced its long lateral drilling times in both basins, according to the report.

Occidental Petroleum Corp.

- **Largest operator and producer of oil in the Permian Basin**
- **5.4 million gross acres in the Permian Basin**

Occidental Petroleum Corp. (Oxy) is the largest operator, largest producer of oil and a leading acreage holder with nearly 5.4 million gross (2.5 million net) acres in the Permian Basin in West Texas and southeast New Mexico, according to the company's website. Oxy's Permian oil and gas production accounted for nearly 45% of 2016 total ongoing worldwide production, according to the company.

Oxy manages operations in the Permian Basin through two businesses: Permian Resources and Permian EOR.

Permian Resources reported that average production volumes improved from the second quarter by 1,000 boe/d to 139,000 boe/d in third-quarter 2017 due to increased drilling activity and well productivity, partially offset by the sale of noncore unconventional acreage in the third quarter and impact from Hurricane Harvey, according to Oxy's third-quarter 2017 results report. Permian Resources achieved record well results across multiple benches, the company said. Five New Mexico Third Bone Spring wells had an average 30-day rate of 3,780 boe/d. One New Mexico Second Bone Spring well had a 30-day rate of 4,500 boe/d.

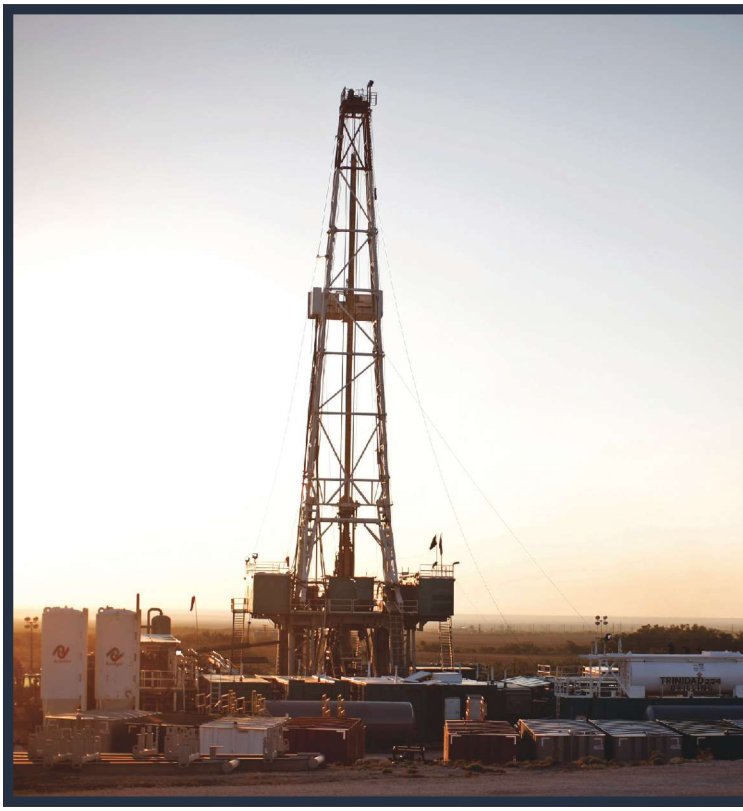
Average production for Permian EOR increased by 7,000 boe/d from the second quarter to 153,000 boe/d in third-quarter 2017, partially due to production from the EOR properties acquired in the third quarter, according to the report. Since gaining operatorship, average gross production increased 2,300 boe/d in the Seminole San Andres CO_2 unit.

In the Permian Basin Oxy's midstream operations own and operate a common-carrier oil pipeline and storage system with about 2,900 miles of pipeline and 7.1 MMbbl of storage capacity. The Oxy Ingleside Energy Center, located at the Port of Corpus Christi in Ingleside, Texas, is a crude oil storage and export terminal that provides access to international and domestic markets for the company's Permian Basin and third-party crude oil. The export terminal has about 2.1 MMbbl of total oil storage capacity and throughput capacity of 300 Mbbl/d.

Parsley Energy Inc.

- **Acquired Midland Basin assets from Double Eagle Energy Permian LLC**
- **Estimating 67.5 Mbbl/d of oil in 2018**

Parsley Energy focuses on the Permian Basin with operations in the Midland and Southern Delaware basins.



Parsley Energy operates on the Strain Ranch in Martin County, Texas. *(Photo courtesy of Parsley Energy)*

In April 2017 Parsley acquired undeveloped acreage and producing oil and gas properties in the Midland Basin from Double Eagle Energy Permian LLC for about $2.8 billion, a press release stated.

The company reported third-quarter 2017 net production of an average 71.5 Mboe/d, up 11% vs. second-quarter 2017 and 66% year-over-year, according to the company's third-quarter 2017 financial and operating results news release. In addition, daily net oil production increased 10% vs. second-quarter 2017 and 63% year-over-year.

"The company continues to execute acreage trades that optimize the development potential of its Midland Basin footprint. Net of acreage traded away, Parsley added more than 1.2 million net lateral feet to the company's horizontal drilling inventory through trades executed since its last quarterly update in August," the release stated.

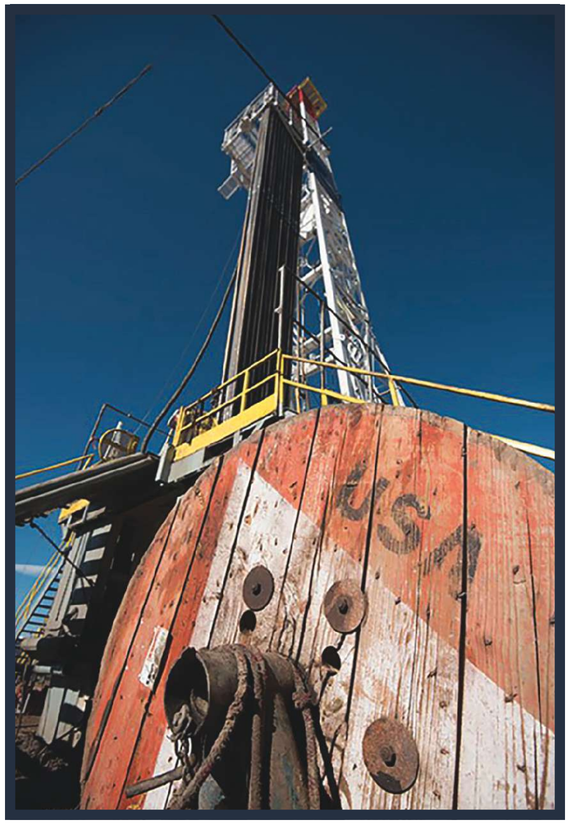
For 2018 Parsley Energy estimates capex of $1.35 billion to $1.55 billion would translate to oil production of 67.5 Bbbl/d to 72.5 Mbbl/d of oil, according to the third-quarter 2017 report. "While almost half of the wells Parsley has drilled and completed over the past four quarters have been located in new counties, targeted new formations and/or implemented new spacing arrangements, the company intends to focus on relatively established areas, formations and configurations in 2018," the report stated.

PDC Energy Inc.

- **Third-quarter 2017 production of 8.5 MMboe**
- **Planned to divest Utica Shale assets**

Independent E&P company PDC Energy has its primary operations in the Wattenberg Field in Colorado and the Delaware Basin in Reeves and Culberson counties in Texas. The company also has operations in the Utica Shale in Southeastern Ohio, but the company announced in April that it plans to divest those assets. PDC's operations are focused in the horizontal Niobrara and Codell plays in the Wattenberg Field and in the Wolfcamp zones in the Delaware Basin.

At year-end 2016, PDC closed the acquisition of about 4,500 net acres in Reeves and Culberson counties in Texas from Fortuna Resources Holdings LLC for about $118 million, according to a news release.



PDC Energy projected to deliver about 40% production growth to 32 MMboe to 33 MMboe in 2017. *(Photo by David Tejada Photography, courtesy of PDC Energy)*

The company's projected to deliver about 40% production growth to 32 MMboe to 33 MMboe in 2017, according to PDC's website.

In third-quarter 2017, the company reported production of 8.5 MMboe (about 92,500 boe/d), a 42% increase year-over-year; average daily production of about 92,500 boe; and oil production of 3.4 MMbbl, a 47% increase year-over-year, according to PDC's third-quarter 2017 results report.

In the Wattenberg Field PDC spud 46 wells and had 39 turn-in-lines in the third quarter with average production of about 77,580 boe/d. "Due to increased drilling efficiencies throughout the year, the company reduced its Wattenberg rig count from four to three early in November and plans to turn-in-line 22 operated wells in the fourth quarter of 2017," the report stated. "In addition, PDC has

entered into a cooperative arrangement to control the completion operations of certain drilled and uncompleted wells associated with its previously announced bolt-on acquisition with expected closing date in the fourth quarter of 2017. The company plans to turn-in-line 18 of these wells at approximately year-end 2017 with the completion costs expected to be treated as an increase to the purchase price."

In addition, Delaware Basin production averaged 12,845 boe/d in the third quarter, a 28% increase from the second quarter, the report stated. During the third quarter, PDC spud six wells and had four turn-in-lines.

Pioneer Natural Resources Co.

- **Third-quarter 2017 production of 276 Mboe/d**
- **Sold Martin County, Texas, acreage for $266 million**

Pioneer Natural Resources' operations are in the Permian Basin, Eagle Ford Shale, Rockies and the West Panhandle.

In March 2017 Pioneer signed a purchase and sale agreement with an undisclosed buyer to sell its acreage package in northeastern Martin County, Texas, for $266 million, according to a company news release. Net production was about 1,500 boe/d as of March 15.

Pioneer reported third-quarter production of 276 Mboe/d, an increase of 17 Mboe/d compared to the second quarter, and 162 Mbbl/d of oil, an increase of 15 Mbbl/d compared to the second quarter, according to the company's third-quarter 2017 financial and operating results news release.

"Third-quarter production was negatively impacted by 3,500 barrels oil equivalent per day due to Hurricane Harvey and unplanned downtime at a third-party gas processing facility; Production would have been at the top end of Pioneer's third-quarter guidance range of 274 Mboe/d to 279 Mboe/d without these negative impacts," the company stated in the release.

Third-quarter production growth was driven by the company's Spraberry/Wolfcamp horizontal drilling program. Pioneer increased Spraberry/Wolfcamp horizontal production by 22 Mboe/d compared to the second quarter, and horizontal oil production increased by 17 Mbbl/d quarter-over-quarter, according to the release.

In addition, Pioneer placed 61 horizontal wells on production in the Spraberry/Wolfcamp during the third quarter and expected to place about 70 wells on production in the area during the fourth quarter, totaling about 230 wells being placed on production during 2017, according to the release.

Other Pioneer highlights from the third quarter included drilling and completing 11 new wells and completing nine drilled but uncompleted wells (DUCs) in the Eagle Ford Shale during 2017 (Pioneer has a 46% working interest). Two new drills and nine DUCs were placed on production in the Eagle Ford Shale during the second and third quarters. The average cumulative production per well from the new drills and DUCs after about 80 days and 140 days of production, respectively, is more than double the average cumulative production per well for the same time period from all wells placed on production during 2015 and 2016, the company stated in the report. Two additional new drills were placed on production in early October.

QEP Resources Inc.

- **Third-quarter 2017 production of 14,124 Mboe**
- **Acquired Midland Basin assets**

QEP Resources operates in the Permian Basin, Williston Basin, Uinta Basin and Haynesville Shale. The company reported third-quarter 2017 production of 14,124 Mboe and year-end 2016 proved reserves of 731.4 MMboe, according to QEP's website.

In the Permian Basin QEP reported third-quarter 2017 production of 2,351.3 Mboe and year-end 2016 proved reserves of 147.8 MMboe. In October 2017 QEP acquired additional crude oil properties in the core of the northern Midland Basin. The properties include about 13,000 net acres with more than 730 potential horizontal drilling locations in four horizons—Middle Spraberry, Spraberry Shale, Wolfcamp A and Wolfcamp B—with


FRAC SHACK™
FracFueller™ Safe™
FRAC SHACK™
www.fracshack.com
CONFINED SPACE
AUTHORIZED PERSONNEL ONLY. PERMIT REQUIRED.
Bi-Fuel FracFueller™
Call Toll Free:
1-855-296-3722
Industry Leaders in
SAFETY AND EFFICIENCY
Visit us online:
fracshack.com
WELLEVATOR™
BY FRAC SHACK™

additional potential horizontal drilling locations in emerging prospective horizons, the company stated on its website. The company will acquire the acreage, which almost doubles QEP's Midland position, from JM Cox Resources LP and Alpine Oil Co. for $732 million, according to filings with the Securities and Exchange Commission.

In the Uinta Basin QEP reported third-quarter 2017 production of 905.3 Mboe and year-end 2016 proved reserves of 106.1 MMboe, according to the company's website. QEP has about 250,000 net acres in this basin, including 109,600 targeting the Lower Mesaverde Formation.

In September 2017 QEP sold its Pinedale Anticline Field assets in Sublette County, Wyo., a press release stated. "With the Pinedale divestiture and the pending Permian Basin acquisition [closed in October], we have made significant progress in repositioning the company for long-term success," said QEP Resources CEO Chuck Stanley in the release. "We have, however, experienced higher than anticipated production decline from a group of pilot wells that were completed in deeper benches of the Three Forks Formation in the Williston Basin and, as a result, we have modified our development plans going forward. Additionally, we also experienced some delays in our Permian Basin well completions as a result of the continuing evolution of our tank-style development methodology."

In the Williston Basin the company reported third-quarter 2017 production of 4,252.3 Mboe and year-end 2016 proved reserves of 160.2 MMboe. QEP has about 115,500 total net acres of crude oil development properties in this basin.

In the Haynesville Shale the company reported third-quarter 2017 production of 3,321.2 Mboe and year-end 2016 proved reserves of 144.3 MMboe. The company has interests in about 48,900 net acres in and around the Haynesville Shale.

Range Resources Corp.

- **About 900,000 net acres in the Marcellus**
- **About 220,000 net acres in Northern Louisiana**

U.S. independent producer Range Resources has operations in the Marcellus, Midcontinent and North Louisiana. As of year-end 2016, Range had 12.1 Tcfe of proved reserves, according to the company's website.

Range has about 900,000 net acres in the Marcellus, and the majority of the company's 2017 capital budget was directed toward the Marcellus. The company reported third-quarter 2017 net production in the Marcellus of 1.6 Bcfe/d and Marcellus and Upper Devonian unrisked unproved resource potential of 93 Tcfe, according to Range's website.

The company has about 190,000 net acres in the Midcontinent and reported third-quarter 2017 net production in the region of about 27 MMcfe/d, according to statistics on the company's website.

Range also has about 220,000 net acres in Northern Louisiana. The company reported third-quarter 2017 net production of about 360 MMcfe/d and unrisked unproved resources potential of 6.7 Tcfe in Northern Louisiana.

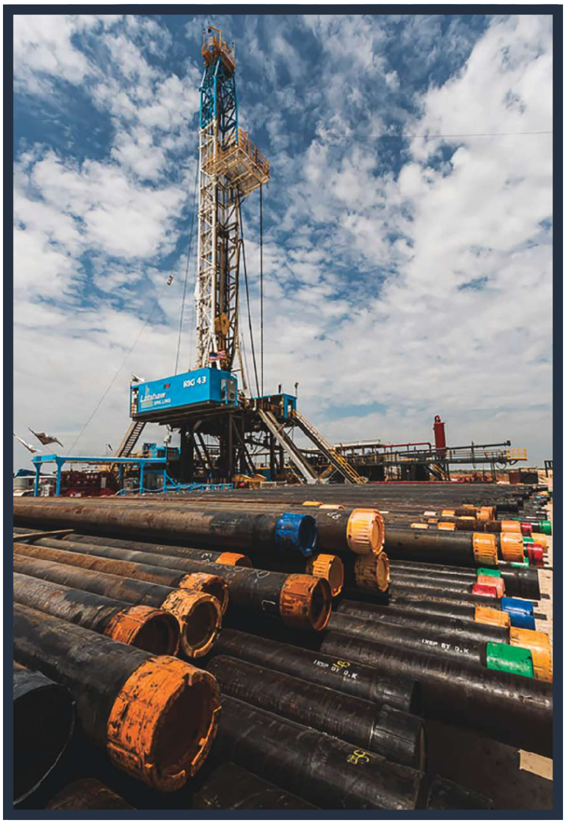
In 2016 Range and Memorial Resources Development Corp. (MRD) completed a merger agreement under which Range acquired all of the outstanding shares of common stock of MRD in an all-stock transaction valued at about $4.2 billion, including the assumption of MRD's net debt, a press release stated. The transaction increased Range's acreage positions in both the Appalachian Basin and Northern Louisiana.

RSP Permian

- **500,000-plus net effective horizontal acres in the Permian**
- **Acquired Silver Hill for $2.4 billion**

RSP is an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The company has 500,000-plus net effective horizontal acres and 4,200-plus net drilling locations in the Permian. RSP reported 283 MMboe pro forma 2016 proved reserves, according to statistics on the company's website.

Third-quarter 2017 production increased 98% to 58.9 Mboe/d (71% oil, 87% liquids), compared to



RSP is running seven rigs across its position, with a 2017 drilling program targeting four distinct target horizons in the Midland Basin and five in the Delaware Basin. *(Photo courtesy of RSP Permian Inc.)*

third-quarter 2016 and increased 8% compared to second-quarter 2017, according to the company's third-quarter 2017 results report.

RSP acquired $234.4 million of oil and gas properties in the Delaware Basin in the third quarter, acquiring about 5,800 net leasehold acres, 5,800 net royalty acres and 500 boe/d of production, according to the third-quarter 2017 report.

The company expected to spend $625 million to $700 million in development capital across its Midland and Delaware Basin assets in 2017, completing 80 to 85 gross operated horizontal wells and producing an estimated average of 53,000 to 57,000 boe/d for the year.

In addition, RSP Permian completed the acquisitions of Silver Hill Energy Partners LLC and Silver Hill E&P II LLC in November 2016 and March 2017, respectively, which added more than 68,000 gross acres to RSP's Permian assets.

In the third-quarter 2017 report, RSP Permian CEO Steve Gray said, "After closing our $2.4 billion acquisition of Silver Hill, 2017 has been all about execution. I am pleased to report that our buildout of infrastructure in the Delaware Basin has been completed on time and on budget, and we remain on track to deliver on our 2017 guidance."

The company planned to spend between $575 million and $625 million on drilling and completions in 2017, according to the report.

Shell

- **World's second largest energy company**
- **Ranked No. 7 on the 2017 list of *Fortune* Global 500 companies**

Shell produces heavy oil in California and oil and gas from shale in Pennsylvania, Texas and Louisiana. The company has significant shale acreage, focused in the Delaware Permian Basin in West Texas and in the Marcellus and Utica plays in Pennsylvania.

As a result of the BG Group Plc acquisition in 2016, Shell obtained a position in the Haynesville Shale gas formation in Northern Louisiana, which is operated by EXCO Resources Inc.

According to a February 2016 USA Today article, "Royal Dutch Shell is now the world's second largest energy company after completing its $53 billion acquisition of British giant BG Group. Shell's purchase of BG Group puts the company behind only Exxon Mobil on the list of largest energy companies by market capitalization."

According to Shell's 2016 interactive map on its website, the company has a Permian project under construction. The shale project started up in 2017 and peak production is reported at 54 Mboe/d. Shell also has a shale project underway in Canada called Fox Creek, which also started up in 2017. Peak production was reported at 26 Mboe/d, according to the map.

In California Shell has a 51.8% interest in Aera Energy LLC, which operates about 15,000 wells in the San Joaquin Valley in California, mostly producing heavy oil and associated gas.

Shell also has about 1,600 mineral leases in Canada, mainly in Alberta and British Columbia. The company produces and markets natural gas, NGL, synthetic crude oil and bitumen.

"We continued to develop fields in Alberta and British Columbia during 2016 through drilling programs and investment in infrastructure to facilitate new production," the company said in its 2016 annual report. "We own and operate natural gas processing and sulphur-extraction plants in Alberta and natural gas processing plants in British Columbia. Our investment focus remains on liquid-rich shale assets in Alberta. As part of that focus, we sold shale gas assets located in Deep Basin East and Gundy in November 2016."

Shell also has interests in Honduras.

SM Energy Co.

- **About 165,000 net acres in its operated Eagle Ford program**
- **About 89,000 net acres in the Midland Basin**

Founded in 1908, SM Energy has operations in the Rockies, Permian Basin and Eagle Ford Shale. Third-quarter 2017 production totaled 10.7 MMboe (32% oil, 45% natural gas and 23% NGL), according to the company's third-quarter 2017 results report.

In October and December 2016 SM Energy acquired oil and natural gas assets in Howard and Martin counties in Texas from Rock Oil Holdings LLC and QStar LLC and a related entity, respectively, for $2.6 billion, according to news releases.

In March 2017 SM Energy sold its third-party operated assets in the Eagle Ford, including ownership interest in midstream assets, for $800 million to Venado EF LP, an affiliate of KKR, a press release stated.

In the Eagle Ford Shale SM Energy reported average production of 112.6 Mboe/d and total proved reserves of 305.4 MMboe at year-end 2016 in this region, according to the company's website. Third-quarter 2017 production from SM Energy's Eagle Ford assets was 6.7 MMboe (60% natural gas, 35% NGL and 5% oil), according to the company's third-quarter 2017 report. SM Energy has about 165,000 net acres in its operated Eagle Ford program.

Third-quarter 2017 production from SM Energy's Eagle Ford assets was 6.7 MMboe. *(Photo by Jim Blecha, courtesy of SM Energy)*

In the Permian the company reported average production of 10.2 Mboe/d and total proved reserves of 53.8 MMboe at year-end 2016, according to SM Energy's website. Third-quarter 2017 production from the company's Midland Basin assets was 3 MMboe (78% oil), according to the company's third-quarter 2017 report. SM Energy has about 89,000 net acres in the Midland Basin, which includes about 5,000 net acres acquired year-to-date through acreage trades and other transactions.

Additionally, the company holds producing assets in the Rocky Mountain region including leaseholds primarily targeting the Bakken Formation in the Williston Basin of North Dakota and the Frontier and Shannon formations in the Powder River Basin of Wyoming. The company reported year-end 2016 average production of 28.2 Mboe/d and total proved reserves of 36.5 MMboe in this region, according to statistics on SM Energy's website. Third-quarter 2017 total production for this region was 1 MMboe, according to the company's third-quarter 2017 report.

Southwestern Energy

- **245,805 net acres in Northeast Appalachia**
- **321,563 net acres in Southwest Appalachia**

Southwestern Energy (SWN) is engaged in the E&P of natural gas, oil and NGL with current operations primarily focused on the Marcellus Shale in Pennsylvania and West Virginia and the Fayetteville Shale in Arkansas. During the first nine months of 2017, SWN invested about $921 million in the E&P business and participated in drilling 106 wells, completed 118 wells and placed 130 wells to sales, according to the company's third-quarter 2017 results report.

In Northeast Appalachia SWN has 245,805 net acres (as of year-end 2016). The company reported 2016 reserves of 1,574 Bcf and production of 350 Bcf, according to SWN's website. Third-quarter 2017 net production from Northeast Appalachia was 101 Bcfe, a 20% increase compared to the same quarter in 2016, according to the company's third-quarter 2017 results report. Northeast Appalachia also achieved record gross operated exit production rates of 1,408 MMcfe/d, a 35% increase compared to third-quarter 2016.

In Southwest Appalachia SWN has 321,563 net acres (as of year-end 2016). The company reported 2016 reserves of 677 Bcfe and production of 148 Bcfe, according to SWN's website. Third-quarter 2017 net production from Southwest Appalachia was 52 Bcfe, a 41% increase compared to the same quarter in 2016, according to the company's third-quarter 2017 results report. Southwest Appalachia achieved record gross operated exit production rates of 958 MMcfe/d, a 54% increase compared to third-quarter 2016.

In the Fayetteville Shale SWN has 918,535 net acres (as of year-end 2016). The company reported 2016 reserves of 2,997 Bcf and production of 375 Bcf, according to SWN's website.

Whiting Petroleum Corp.

- **691,880 gross acres in the Williston Basin**
- **157,513 gross acres at its Redtail Niobrara/Codell play**

Independent E&P company Whiting Petroleum produces crude oil in North Dakota and operates assets in northern Colorado. Whiting controls 691,880 gross (412,925 net) acres in the Williston Basin and 157,513 gross (131,763 net) acres at its Redtail Niobrara/Codell play in the Denver-Julesburg (D-J) Basin. Whiting had a full-year 2017 capital budget of $950 million.

In September 2017 Whiting sold its Fort Berthold Indian Reservation area assets located in Dunn and McLean counties in North Dakota to RimRock Oil & Gas Williston LLC for $500 million, a press release stated.

Whiting's third-quarter production totaled 10.5 MMboe (84% crude oil/NGL), according to the company's third-quarter 2017 results report. Third-quarter 2017 production averaged 114,350 boe/d, an increase from second-quarter 2017 production of 112,660 boe/d. The Bakken/Three Forks play in the Williston Basin averaged 102,015 boe/d. The Redtail Niobrara/Codell play in the D-J

Basin averaged 11,750 boe/d, a 78% increase over second-quarter 2017 levels.

During third-quarter 2017, Whiting completed 58 gross operated wells at its D-J Basin/Redtail area in Weld County, Colo., and 29 gross operated wells in its Bakken/Three Forks play in the Williston Basin, according to the report. Whiting plans to put 25 gross wells on production in its Redtail area and complete 32 gross wells in the Williston Basin in the fourth quarter. At year-end 2017 Whiting estimated it will have 39 drilled but uncompleted (DUC) wells at Redtail and 50 DUC wells waiting on completion in the Williston Basin, the report stated.

WildHorse Resource Development Corp.

- **About 385,000 net acres in the Eagle Ford**
- **Closed $594.4 million acquisition from Anadarko/KKR**

WildHorse Resource Development Corp. (WRD) has operations in the Eagle Ford Shale in East Texas and the overpressured Cotton Valley in North Louisiana. WRD has about 483,000 total net acres, with about 385,000 net acres in the Eagle Ford and about 98,000 net acres in North Louisiana.

WRD enhanced its acreage position with the June 2017 acquisition of about 111,000 net acres in the Eagle Ford from Anadarko Petroleum Corp. and affiliates of Kohlberg Kravis Roberts & Co. LP for $594.4 million. This acquisition followed WRD's December 2016 acquisition of about 158,000 net acres from Clayton Williams as well as a series of smaller bolt-on acquisitions earlier in 2017.

In 2017 WRD revitalized interest in the East Texas Eagle Ford with its Gen 3 completion design utilizing 3,700 lb of sand per foot in comparison to legacy Gen 1 designs with about 1,000 lb of sand per foot. The result of the higher intensity completions has been a considerable uplift in EURs to WRD's 91 boe per foot type curve.

As of Nov. 20, 2017, WRD had brought online 68 Gen 3 Eagle Ford wells through the third quarter of 2017 and plans to bring online another 30 to 35 gross Gen3 Eagle Ford wells, two gross Austin Chalk wells and six gross North Louisiana wells in fourth-quarter 2017.

Third-quarter 2017 production was 36.6 Mboe/d (62% oil), compared to 14.0 Mboe/d (35% oil) for third-quarter 2016, according to WRD's website.

WPX Energy Inc.

- **Oil production of 75,000 bbl/d as of Nov. 1**
- **100,000 net acres in the Permian's Delaware Basin**

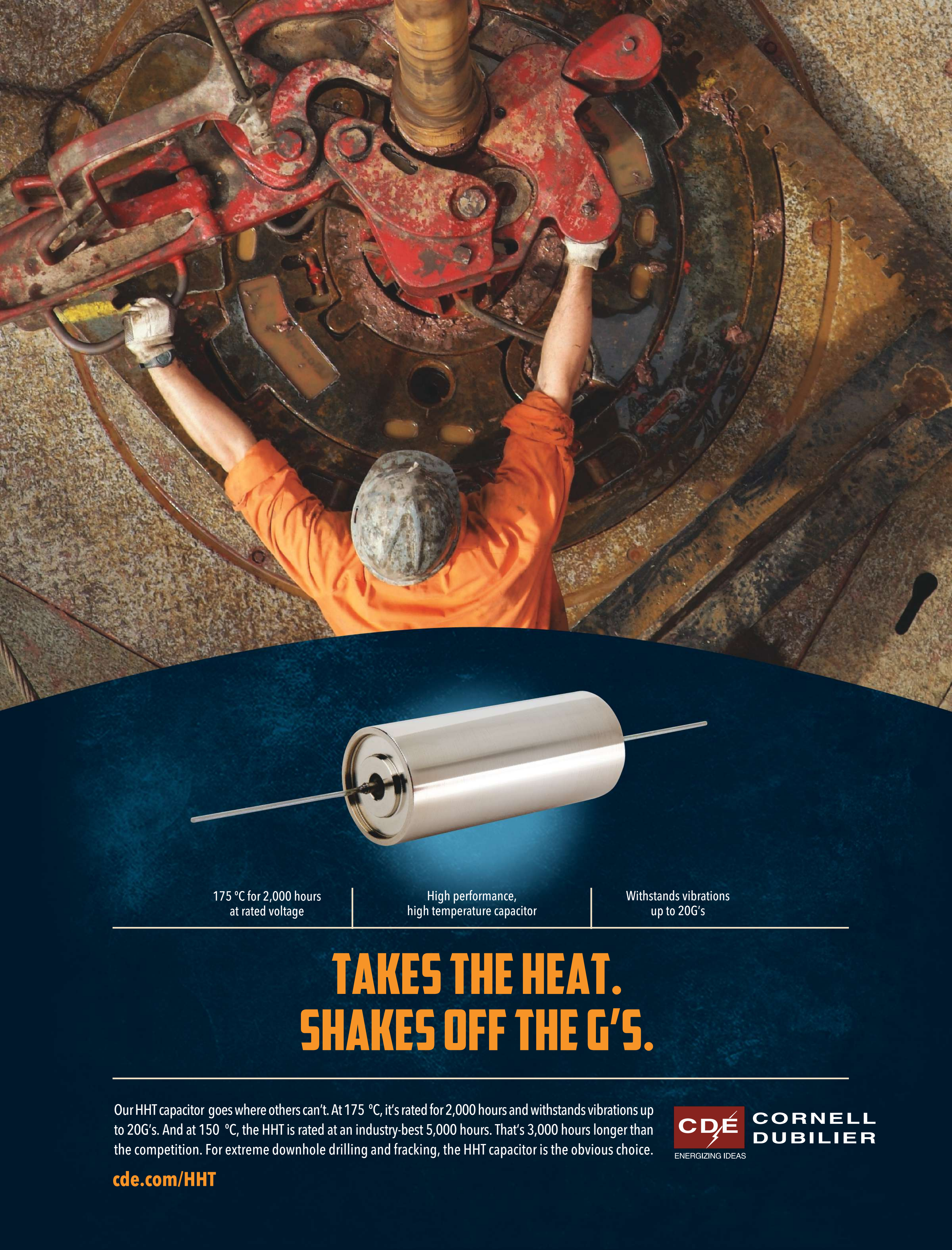
WPX Energy has operations in the Permian, Williston and San Juan basins. The company has 100,000 net acres in the Permian's Delaware Basin and 85,000 net acres on the Fort Berthold Indian Reservation in North Dakota.

In October 2017 WPX signed an agreement for the sale of its legacy natural gas position in the San Juan Basin for $169 million, according to the WPX's third-quarter 2017 report. The transaction included WPX's operated and non-operated gas properties in the basin. The parties expected to close the agreement prior to year-end 2017. WPX's oil operations in the San Juan Basin's Gallup oil play were not included in the sale.

In June 2017 WPX agreed to form a 50:50 joint venture (JV) with Howard Energy Partners to develop oil gathering and natural gas processing infrastructure in the Stateline area of the Permian's Delaware Basin, a company news release stated. The JV is designed to support WPX's drilling operations in the Stateline area, representing 50,000 net acres, or 37% of WPX's roughly 135,000 net acre position in the Delaware.

Third-quarter 2017 oil production of 64,800 bbl/d increased 11% vs. the second quarter and was up 67% vs. the year prior, according to the WPX's third-quarter 2017 report. Oil production was reported at about 75,000 bbl/d as of Nov. 1.

For fourth-quarter 2017 WPX expected oil production averaging about 75,000 bbl/d and equivalent production of about 125 Mboe/d to 135 Mboe/d, including the impact of the sale of WPX's dry gas assets in the San Juan Basin, according to the third-quarter 2017 report.


175 °C for 2,000 hours at rated voltage
High performance, high temperature capacitor
Withstands vibrations up to 20G's
TAKES THE HEAT.
SHAKES OFF THE G'S.
Our HHT capacitor goes where others can't. At 175 °C, it's rated for 2,000 hours and withstands vibrations up to 20G's. And at 150 °C, the HHT is rated at an industry-best 5,000 hours. That's 3,000 hours longer than the competition. For extreme downhole drilling and fracking, the HHT capacitor is the obvious choice.
cde.com/HHT
CDE
ENERGIZING IDEAS
CORNELL DUBILIER

Looking ahead, "WPX's 2018 total capital budget is $1.1 billion to $1.2 billion, including $60 million to $90 million for midstream costs. The budget is designed to fund an average of 9.5 rigs during the year ranging from eight to 11 based on the timing of activity, including six to seven in the Delaware Basin, two to three in the Williston Basin and zero to one in the San Juan Gallup oil play," the report stated.

The company's 2018 plan also includes completing an inventory of about 35 drilled but uncompleted wells expected at year-end 2017, according to the report. WPX also expects total production in 2018 ranging from 132 Mboe/d to 143 Mboe/d, including 82 Mbbl/d to 88 Mbbl/d of oil.

XTO Energy/Exxon Mobil Corp.

- **XTO has more than 3.9 million acres in 79 counties in Texas**
- **Exxon Mobil ranked No. 10 on the 2017 list of *Fortune* Global 500 companies**

XTO Energy, an Exxon Mobil subsidiary, operates in most of the major shales across the U.S. For the first nine months of 2017, Exxon Mobil reported 511 Mbbl/d net production in the U.S., according to the company's third-quarter 2017 results report.

In Texas XTO also holds more than 3.9 million acres in 79 counties and reported production of 83 Mbbl/d of oil and 1,860 MMcf/d of gas on its 2016 fact sheet. In September 2017 Exxon Mobil added 22,000 acres since May to its Permian Basin portfolio through a series of acquisitions and acreage trades, according to the company's third-quarter 2017 results report. Located in the Delaware and Midland basins, the new acreage adds more than 400 MMboe to the company's existing Permian Basin resource base of 6 Bboe. In addition, in February 2017 Exxon Mobil acquired 250,000 acres in the Delaware Basin from companies owned by the Bass family of Fort Worth, Texas.

XTO Energy also holds 713,061 acres in 15 counties in Arkansas and reported production of 324 MMcf/d on its 2017 fact sheet. In Colorado the company holds 553,392 acres in three counties and reported production of 130 MMcf/d of gas on its 2016 fact sheet. In Kansas the company holds 777,070 acres in seven counties and reported production of 4 MMcf/d of gas on its 2017 fact sheet. In Louisiana XTO also holds 661,152 acres in 13 parishes and reported production of 3 Mbbl/d of oil and 84 MMcf/d of gas on its 2016 fact sheet. In New Mexico the company holds 685,126 acres in four counties and reported production of 9 Mbbl/d of oil and 130 MMcf/d of gas on its 2016 fact sheet.

As of year-end 2015, XTO had more than 3.9 million acres in Texas. *(Source: XTO Energy)*

In addition, in North Dakota the company holds 486,198 acres in eight counties and reported production of 81 Mbbl/d of oil and 158 MMcf/d of gas on its 2017 fact sheet. In Ohio XTO holds 82,320 acres in two counties and reported production of 100 MMcf/d of gas on its 2016 fact sheet. In Oklahoma the company holds more than 1 million acres in 25 counties and reported production of 14 Mbbl/d of oil and 349 MMcf/d of gas on its 2017 fact sheet. In Pennsylvania the company holds 527,893 acres in 15 counties and reported production of 270 MMcf/d of gas on its 2016 fact sheet.

Moreover, XTO holds 381,409 acres in two counties in Utah and reported production of 46 MMcf/d of gas on its 2016 fact sheet. In West Virginia the company holds 158,794 acres in nine counties and reported production of 32 MMcf/d of gas on its 2016 fact sheet. In Wyoming XTO holds 135,240 acres in three counties and reported production of 14 MMcf/d of gas on its 2016 fact sheet. ■


VIKING
ENGINEERING
A GATE Energy Company
PASSION IS ENERGY
We have a Passion for Well Integrity
VIKING Engineering continues to provide the upstream oil and gas industry with the most thorough wellbore design and analysis solutions that meet customer's needs from initial pre-planning through abandonment.
We have worked with over 300 major and independent oil and gas operators around the globe on critical wells. We can help with HPHT, deepwater, shale, corrosive, or other challenging well designs and completions. From onshore to shelf and deepwater, our engineering expertise can ensure that your drilling and completion project works right the first time.
Petroleum Consulting
Multi-String Analysis
Material Selection
Well Construction
Failure Analysis
QA Vendor Surveillance/QA Audits
Training
www.vikingeng.net | 281.870.8455 | info@vikingeng.net

Operators are discovering that, unlike racking drill pipe, it is better to have more space between their wells. *(Photo by Glenn Kulbako, courtesy of Hart Energy's* Oil and Gas Investor*)*

Shifting Gears with Well Spacing

By **B. Robert Partain**, Contributing Editor

Operators strive to optimize well spacing and maximize well economics.

It was 1931 and Virgil Cottingham needed a bigger stick. He was weary of being ignored.

The huge East Texas Oil Field had emerged quickly and chaotically. Cottingham was chief petroleum engineer for the Texas Railroad Commission, which has historically regulated more oil and gas than railroads. He was a keeper of the rules, and East Texas was now a lawless land of crude oil thieves and skimmer refineries. In places like Kilgore, it seemed every available city lot was shadowed by a new drilling rig. Even then, operators knew that drilling a well too close to a neighbor could damage a conventional reservoir. Two wells—or three or four—also wouldn't extract any more hydrocarbons than a single well. East Texas overproduction was causing U.S. oil prices to crash by 80%. Locally, the race would go to the swiftest, or the best scoff-law, and every pharmacist and farm boy with a lease and a rig wanted to get in. Cottingham and others convinced Texas Governor Ross Sterling to order in the big guns–the National Guard. The Texas Railroad Commission, and the Army, finally enforced the field rules and established order, at least for a while.

Today's unconventional reservoirs could not be more different from the Woodbine sandstone of the East Texas Oil Field. Tight shales, horizontal wells and hydraulic fracturing have reinvented almost every aspect of hydrocarbon extraction.

Kicking off multiple horizontals from a superpad makes sense, especially as a way to push down costs and speed up operations. The question for operators now is how to fine-tune the spacing—both horizontally and vertically—to avoid interference and to maximize production and well economics.

"From a Wall Street perspective, it is not about identifying the resource. It is about converting that into cash flow in a timely manner," said Subash Chandra, managing director and senior equity analyst for Guggenheim Securities LLC. "We're really not sure what the optimal formula is. We get that it is NPV [net present value] per section, but does it mean we tolerate infill wells that are 30% worse than the parent well? Does it mean that average well productivity has peaked?"

Speaking at Hart Energy's DUG Midcon Conference last September, Chandra noted that companies with acquisitions debt are facing pressure from their financiers.

An acquisition package might have been "financed based on a location count premised on horizontal and lateral spacing between wells," Chandra said. "Now prove it. Not only prove it, but get it into development in a reasonable amount of time."

This is the fundamental goal of increased density and superpad drilling.

"It is not good enough to show a pyramid of 14 zones and say, 'Give us credit,'" Chandra said. "That was so 2016. 2018 is 'Get it, convert it and show us these locations actually exist.'"

Aggressive operators are already successfully meeting that challenge.

Encana Oil and Gas calls its tightly spaced 3-D development model "the cube." The Calgary and

Denver-based company exploits this model in the Permian Basin and in the Montney Formation of the Western Canadian Sedimentary Basin. Both plays have thousands of feet of stacked pay.

Encana uses field pilot tests, subsurface reservoir sampling via cores and electric logs, and reservoir modeling or simulation to help determine well spacing. Their first cube development involved 14 Permian Basin wells on a single pad in Midland County, Texas. "These wells were drilled into three benches across the Wolfcamp A & B," said Joel Fox, Encana's senior manager of drilling and completions. "The inter-well spacing was 385 ft. Next, we drilled a second Midland County pad with 12 wells. These wells were drilled into five benches across the Wolfcamp A & B and Lower Spraberry. The inter-well spacing was 450 ft. Our third cube development was a 'reoccupation' of the first pad, where we drilled an additional 19 wells in the opposite direction to the original. These wells were drilled into five benches across the Wolfcamp A & B and Lower Spraberry, with an inter-well range from 385 ft to 450 ft. These 45 dense cube development wells are significantly outperforming dense well development from the rest of the industry."

Encana has found that the more wells on a pad, the potential for longer cycle times. "We address this by using multiple drilling rigs and frack spreads running simultaneously on the same pad to eliminate expansion of cycle time," Fox said. "Additionally, we've found that having the same rigs drilling similar wells on the same pad is a powerful driver of innovation. The same is true for frack spreads. By having the crews, supervisors and engineers collaborate in real time, learning is accelerated and successive wells are drilled and completed faster at lower cost. With our cube development, we benefit directly from economies of scale."

Oklahoma City-based Devon Energy Corp., active in both the Midcontinent and in the Delaware Basin, is combining downspacing with other operating efficiencies, all aimed at a goal of better cashflow and EBITDA.

Devon's Chief Operating Officer Tony Vaughn reported 50 new wells in third-quarter 2017 with production averaging 2,100 boe/d. During the company's third-quarter 2017 earnings call Nov. 1, Vaughn credited low-risk multizone recovery as the major driver. That includes 55% improved drilling time, more repetitive operations, zipper fracks and debundled completions. "We're saving $1 million per well and have improved cycle time to 5.8 months from spud to production," Vaughn said.

Downspacing was part of the success of integrated teams securing supply chain improvements. "A recent example is locking in all our sand requirements through 2018 at below-market prices," Vaughn said. Devon is now sourcing sand from mines in the lower U.S., saving 30% on total delivery costs.

"A key driver of our operational momentum is the advancement of multizone development activity across our world-class Stack and Delaware Basin opportunities," said Dave Hager, Devon's president and CEO, in an Oct. 31 news release. "With several projects underway, this cutting-edge development technique will optimize per-section recoveries, while improving capital efficiencies by 20%."

Among Devon's downspacing pilots was the Alma test of the Upper Meramec in Kingfisher County, Okla. The results "suggested that lateral spacing in the overpressured oil of 1,000 ft and vertical spacing of just a couple hundred feet was just fine," Guggenheim's Subash Chandra said.

The Alma spacing pilot tested five wells per section across a single interval in the Upper Meramec, delivering 30-day production rates averaging 1,400 boe/d per well and a 60-day average rate of 1,300 boe/d per well.

Early flowback results from the Alma pilot indicated minimal interference between wells, suggesting potential for tighter spacing in the overpressured oil window. The Alma wells were drilled with 5,000-ft. laterals. "The Alma spacing pilot and record-setting Pony Express oil well are examples of the excellent results we are achieving in the Meramec Formation, which has quickly evolved into the best emerging development play in North America," Vaughn said in a July 18, 2016, news release. In an earlier Meramec test, the Born Free wells were spaced 400 ft apart and landed in two intervals in the Upper Meramec.

Devon followed the Alma with the Pump House spacing pilot, which tested a seven-well pat-

tern across a single-section interval in the Upper Meramec. Initial 15-day production rates averaged 2,200 boe/d per well (55% oil) and cost $6 million per well. The Pump House wells were drilled with 4,700-ft laterals and utilized a completion design that deployed 2,200 lb of proppant per lateral foot across 35 frack stages with perf clusters spaced 25 ft apart. The Pump House is three miles north of the Alma pilot.

and resource development. "When we utilize larger, more complex optimized completions," he said, "the parent well also sees increased oil production and a decrease in gas-oil ratio (GOR). The decrease in GOR ratio proves that these completions are reaching new rock."

In early 2017, Continental had 187 drilled but uncompleted wells (DUCs) in the Bakken and 90% of Bakken acreage held by production. The company was waiting for price recovery before tapping its considerable reserves. Using drilling and completion efficiencies, including downspacing, the harvest has begun. With breakeven prices falling to $20/bbl to $30/bbl based on improved technology, by the autumn of 2017 more than 100 DUCs were completed. Late in 2017, Continental also met a five-year goal of tripling its production to 300,000 boe/d, even in the face of lower oil prices.

Continental Resources Hawkinson Unit density drilling project is in the Bakken play in North Dakota. *(Photo courtesy of Continental Resources)*

Through August 2017, Continental Resources, already top leaseholder in North Dakota and Montana's Bakken play, moved up to top producer. Much of that progress came from scientific application of downspacing and other efficiencies. The Oklahoma City-based producer is also a major player in the Midcontinent Scoop and Stack plays.

Continental's downspaced Bakken wells are generational status climbers. The children are outperforming the parents, improving net asset values of the leases.

"This is unique in the Bakken," said Gary Gould, Continental's senior vice president of production

All of Continental's 2017 Bakken wells have used optimized completions and the majority of them have been drilled on 660-ft spacing. Results are impressive. The 2017 wells have doubled the rate of return, from 40% to 80%, compared to the previous type curve EUR.

Continental also lowered its Bakken well payout period from 2.5 years to 15 months. "We're generating $2 million incremental cash flow per well in the first year—providing more profit to working interest owners, royalty owners and the state of North Dakota," Gould said. "Continental-operated oil production is up 35% in just the seven months from January to August this year. The average 24-hour IP for our 57 gross operated wells in third quarter is 1,750 boe/d, with 80% oil. That is a strong average in terms of both quality and quantity."

Gould said the unit development approach is pervasive. "We evaluate our operations, as well as our partners' and industry operations, in order to determine the optimum well density to maximize PV10 for unit development," he said. "We looked at well-by-well economics as we were broadening our acreage position a few years ago. Now that we are in the early stages of full development, we analyze economics by unit and develop all the wells at one time. So our question is, 'What is the optimum well density, completion and production design to maximize PV10 of the entire unit?'"

Continental completed three wells in third-quarter 2017, two in the Middle Bakken and one in Three Forks, that are in the all-time top 10 initial production rates for Bakken producers for their company. "They're spread out geographically and all of them used optimized completions," Gould said. Downspacing and other components of the company's optimized completions have built up Continental's operating inventory. "We estimate we now have over 4,000 gross operated locations remaining in the Bakken," Gould said. "We estimate that we could reasonably drill only about half of this inventory in the next decade, assuming an average rig count of eight to 10 rigs. We believe that this inventory could deliver a blended rate of return of 60% to 80%, assuming $50 to $55 WTI oil prices."

While tighter vertical and horizontal spacing is key to this resource management, there are other factors.

"The main characteristics of optimized completions are higher proppant loads averaging 1,000 pounds or more per foot, shorter stage lengths as short as 150 ft, and diverter technology to distribute the proppant during completion," Gould said. "On the production side, we're flowing back more aggressively and using electric submersible pump technology to generate higher production rates upfront." Continental went to slickwater fracks in 2014 and uses a variety of completion contractors. "Competition is a great way to reduce costs, increase operational efficiencies, and keep up with the latest technology," he said. "We also learn by monitoring our partners and other operators."

Continental Resources Ludwig Unit density drilling project is in the Stack play in Oklahoma. *(Photo courtesy of Continental Resources)*

Pat Bent, the company's senior vice president of drilling, points to design changes from rigs to bits that result in cost savings. "Compared to 2014, we cut our drilling time in half," Bent said. "We now average 10.5 days per well, spud to TD in the Bakken. Cycle time decreased dramatically through a combination of technology and teamwork. We have a command center on every well that includes engineering, geology and others co-located for real-time data decision making." Lateral drilling rates of 3,400 ft/d are common. "We've drilled 2-mile laterals in two days," Bent said. Continental maximizes use of its pad footprint, drilling as many as 25 wells from one location. "We've accessed reserves that were previously inaccessible, such as under a lake," Bent said.

In this early-stage density test environment, Continental is one of the pioneers in running pilot downspacing programs. Results in the Midcontinent Stack and Scoop are encouraging.

Continental's Compton unit tested the overpressured oil window of Stack. The 10-well density pilot included five new wells in the Upper Meramec and four new wells and one parent well in the Lower Meramec. Laterals averaged 10,200 ft per well. The 10 wells flowed at a combined peak 24-hour rate of 22,032 boe (75% oil) or 2,203 boe/d per well. Average completed well cost for the nine new Compton wells was approximately $9.2 million, down approximately 28% from the cost of the parent well. Spacing was about 1,000 ft.

Other pilots include the Sympson unit, a 2-mile long, dual-zone, 10-well pattern program with 14 wells. Two 1-mile parent wells and 12 children wells filled in a 1,280-acre unit pattern. This resulted in the equivalent of five wells in the Upper Woodford and five wells in the Lower Woodford. The 12 new wells produced at an average 24-hour peak production rate of 3,145 boe per day (11% oil) per well.

The company's Celesta unit is in the Scoop Springer, a six-well ongoing test that adds information learned from earlier programs.

One limit on spacing would seem to be production interference, but some interference is desired, and thick reservoirs require multiple layers of development.

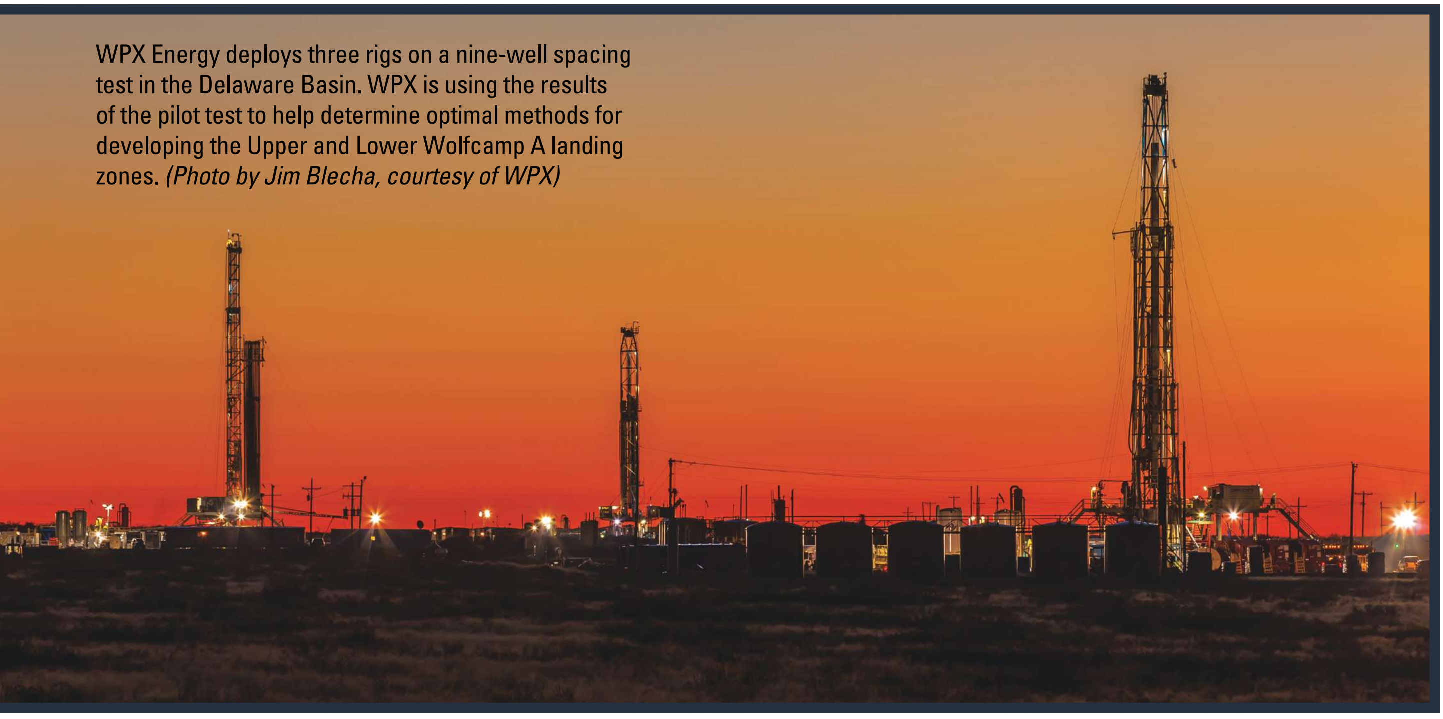
"If you don't see production interference at all, then your wells aren't close enough, and reserves in the unit are left behind," Gould said. "As far as layers go, we believe that thick geologic formations with over 250 ft of thickness, such as a large part of the Woodford in our Scoop acreage, will require developing two or more layers of wells in order to maximize the value of the units."

Tulsa-based WPX Energy's current oil production is approximately 75,000 bbl/d, a new company record. Downspacing is contributing to that total, and converting the company's balance to more oil than gas.

In the Delaware Basin, WPX's six-well Lindsay 10-15 pad scored big from the Wolfcamp A Formation, with three of the five 1.5-mile laterals hitting 24-hour highs exceeding 4,000 boe/d (52% oil). The strongest of the three tagged 4,221 boe/d.

The five long laterals on the Lindsay pad had 30-day production averaging nearly 3,100 Boe/d (54% oil) per well. The sixth well was a 1-mile lateral that had 30-day production averaging 1,593 Boe/d (53% oil).

Using the visual term "wine-rack" for its downspacing programs, WPX planned to continue



WPX Energy deploys three rigs on a nine-well spacing test in the Delaware Basin. WPX is using the results of the pilot test to help determine optimal methods for developing the Upper and Lower Wolfcamp A landing zones. *(Photo by Jim Blecha, courtesy of WPX)* concentrating on Delaware Basin targets in late 2017 and through 2018, blending wine-rack configuration with long laterals.

"WPX's CBR-22 pad in the Delaware Basin successfully tested nine wells at 15 wells-per-section in the Upper and Lower Wolfcamp A landing zones using wine-racked spacing," said Brad Musgrove, reservoir engineering manager for WPX's Permian Basin operations. "We believe it's the industry's most densely spaced test in the Delaware to date."

The nine wells had 30-day production averaging 1,538 boe/d (51% oil) per well during controlled flowback and 180-day production averaging production of 167,500 boe per well (50% oil).

WPX's CBR 6-7 five-well pad in the Delaware was completed late in the third quarter, including one well that didn't post first sales until after quarter close. This pad also focused on the Wolfcamp A Formation. Three of the five wells were 2-mile laterals, with two at peak rates of 3,210 boe/d (49% oil) and 3,024 (50% oil), respectively.

Musgrove doesn't believe the ultimate downspacing envelope has been approached yet.

"The majority of my experience at WPX is with the Upper Wolfcamp within a fairly specific PVT envelope. Personally, I haven't seen the limits in ideal conditions. For a single bench in the Upper Wolfcamp, 660-ft spacing seems safe and has been done. Will 500-ft spacing work? Probably, but we'd have to evaluate possible interference."

Musgrove said lateral spacing is affected by vertical spacing in adjacent benches and timing, if there's an offset parent well with significant cumulative production.

"In terms of wine-racked spacing, we have wells on our 2018 schedule at both 330-foot spacing and 440-foot spacing," he said. "We've already demonstrated that 330-foot spacing is feasible through our CBR-22 pilot test, but we want to keep gathering information on different approaches to optimize our long-term economic returns."

Geology can limit or assist in vertical spacing.

"For the Delaware, it depends on the complexity of deposition and the vertical heterogeneity we see in the Upper and Lower Wolfcamp," Musgrove said. "We often encounter carbonate stringers and debris flows that can deter fracture height growth. In this situation, we may get away with as little as 100 ft of vertical spacing on a wine-racked pattern. Absent those stringers, or other significant frack barriers, we probably need 200-plus feet. This remains to be quantified more precisely."

As in all hydrocarbon extraction, local variables have consequences.

"In the Delaware Wolfcamp, we're dealing with a very wide window of pore pressure gradient," Musgrove said. "It's not uncommon to have losses in some areas of depleted Delaware Mountain Group production that builds to overpressure in the Lower Bone Spring.

WPX is currently drilling 1.5- and 2-mile laterals both in its Stateline area and in the deeper part of the Delaware Basin in eastern Loving County.

This past year has set the pattern for 2018.

During a Nov. 2, 2017, earnings call, then senior vice president and COO Clay M. Gaspar revealed WPX's go-forward strategy. (Gaspar has since been named president of the company.) "We plan to drill 20% more lateral feet in 2018 versus 2017, with roughly a flat rig count," he said. "As an aside, on our current and anticipated efficiency gains, I'm betting on the over. The 20% is based on more pad drilling and focused on longer laterals. In 2018, about 75% of the wells will be 1.5-mile or 2-mile laterals. The average lateral length will be about 8,000 ft, which is 30% more than the average in 2017 and more than double the lateral length from when we acquired RKI back in 2015."

WPX will continue experimentation with well spacing, considering interference as a fact of life to monitor and control.

"I think it's not really a risk," Gaspar said. "It's reality. You want a little bit of well-to-well communication, both vertically and horizontally. We were very aggressive in our section 22 spacing test, with 330-ft spacing between Wolfcamp A wells on a wine-rack staggered pattern. We're now layering in the X/Y wells. We've designed that with the idea that there will be some communication. Early on, we didn't see any. We're roughly six months in and we're starting to see some correlation between the two, not like we've seen in other basins where you shut one well in, you have an immediate bump in the other wells that tells you that you really don't need as many wells as you planned. Ideally you'd probably plan for a 10% degradation from a parent to a child. That means you have properly spaced and properly capitalized that development. If there's no communication, then you really haven't drilled enough wells, or you haven't stimulated big enough."

In a Nov. 7, 2017, news release and third-quarter earnings presentation, Cimarex Energy reported a strong uptick in drilling and completions, including several downspacing tests in the Midcontinent. The Denver-based company is also active in the Permian's Delaware Basin. Overall, it has doubled both gross and net completions compared to the same period in 2016, with 198 gross completed wells in the first nine months of 2017, funded with a $900 million to $925 million drilling and completion budget.

With enhanced completion design and improved well performance, Cimarex is employing tighter development well spacing in all its tests. They announced five successful spacing pilots in 2017, including a 12-wells-per-section Upper Wolfcamp on production in Culberson County and a 14-wells-per-section Lower Wolfcamp test drilling nearby. Also drilling is an 18-wells-per-section Upper Wolfcamp project in Reeves County.

The Tim Tam infill development in Culberson County includes five 10,000-ft wells testing with six wells per section. Infills have surpassed parent wells in both landing zones. Tim Tam infill spacing is 1,756 ft laterally and 200 ft vertically. The Animal Kingdom infill testing has 14 wells per section. It is currently drilling eight wells with three landings. Animal Kingdom spacing is 1,216 ft horizontally and 225 ft vertically.

Culberson County Upper Wolfcamp pilots show similar per-well results with six, eight or 12 wells per section. The Seattle Slew pilot is testing 12 wells per section in a stack/stagger pattern. Seattle Slew spacing is 904 ft horizontally and 125 ft vertically.

In Reeves County, Cimarex has its Snowshoe, Wood State and Pagoda State projects targeting the Upper Wolfcamp. Currently 24 10,000-ft laterals are producing with an average 30-day peak IP of 1,728 boe/d (49% oil; 29% gas; 22% NGL). Two downspacing pilots are producing. Those include the Wood State (12 wells per section) and Pagoda State (16 wells per section). Wood State and Pagoda spacing is 680 ft horizontally and 340 ft vertically. The Snowshoe development will test 18 wells per section, seeking three landing zones. Snowshoe spacing is 880 ft horizontally and varies from 100 ft to 375 ft vertically.

In the Midcontinent, Cimarex is successfully exploiting Meramec and Woodford stacked targets, with 45 wells producing at an average lateral length of about 6,800 ft. Average 30-day IP is 1,591 boe/d (40% oil; 40% gas; 20% NGL). The company has brought on seven 10,000-ft lateral wells in 2017 YTD with average 30-day IP of 1,996 boe/d (46% oil, 36% gas, 18% NGL). Industry delineation continues with 24 downspacing pilots online or underway in the play. Cimarex has interest or data on all but four.

Cimarex's Woodford projects have tested both 16- and 20-well spacing per section. Preliminary results show no significant difference in well performance between the two spacing tests, indicating that Woodford wells can be drilled closer together in future infill projects than they have been historically.

The Leon Gundy is a stacked/staggered pilot with four Meramec wells testing 10 wells per section and four Woodford wells testing nine wells per section. Spacing is 1,065 ft horizontally and 200 ft vertically in the Meramec, and 578 ft horizontally in the Woodford, with 300 ft vertically.

The best Woodford returns in Cimerex's portfolio are from its Lone Rock activity. The Hines Federal #1H had a 30-day average peak production of 15.2 MMcfe/d (40% oil, 23% NGL, 37% gas). The company has about 16,000 net contiguous acres in the overpressured Woodford. Infill drilling is underway, with nine wells testing eight- and 11-well per section models. Spacing is 446 ft for an eight-well configuration and 637 ft for an 11-well spacing.

From the days when Barnett Shale operators were drilling horizontally mainly to avoid the Ellenberger, to the cubes, wine-racks and optimized completions of today, the evolution of unconventional oil and gas development continues.

As one oil executive remarked, technology and teamwork are "unleashing the true potential of our superior geological assets." ■

Nabors M-43 rig is drilling Chaparral Energy's High Valley well in Kingfisher County, just north of Dover, Okla. The company's Rigtelligent operating system has been implemented on 95 of its rigs in the Lower 48. *(Photo by Edward DeCroce, courtesy of Hart Energy's* Oil and Gas Investor*)*

Delivering Downhole Data to the Surface

By **Scott Weeden**, Contributing Editor

The uniqueness of each control system has inhibited large-scale automation projects because of the need to establish different communication protocols for each company.

The drive for wells with longer laterals in the U.S. and internationally efficiently drilled from multiple-well pads has created a demand for high-horsepower, modern AC rigs that can minimize time between each well, according to an Aug. 17, 2017, report from Westwood Global Energy Group.

Those ultra-long laterals are prime targets for automation, where being able to drill "gun barrel" wellbores makes well construction much easier.

Energent, a Westwood Global Energy Group company, breaks down drilling and completion expenditures. The company takes information from 42 different resources. Todd Bush, Energent principal, estimated oil prices would be $58 by the end of 2018. "We capture 17 expenditure categories on the drilling side, but I don't believe we're breaking out automation," he said. "It seems like automation is happening right now. Directional drilling seems to be one area we continue to hear is the first step in automation. The second step is getting to the point where operators are applying the data and models for drilling at the rig instead of at the office.

"The next step change is being able to control the rig and bits and to understand basin-by-basin what needs to be done," he added.

One example is a project underway in the Bakken with Nabors Industries Ltd. and a leading independent operator focused on automating the directional drilling decision-making workflow and the implementation of decisions at the rig.

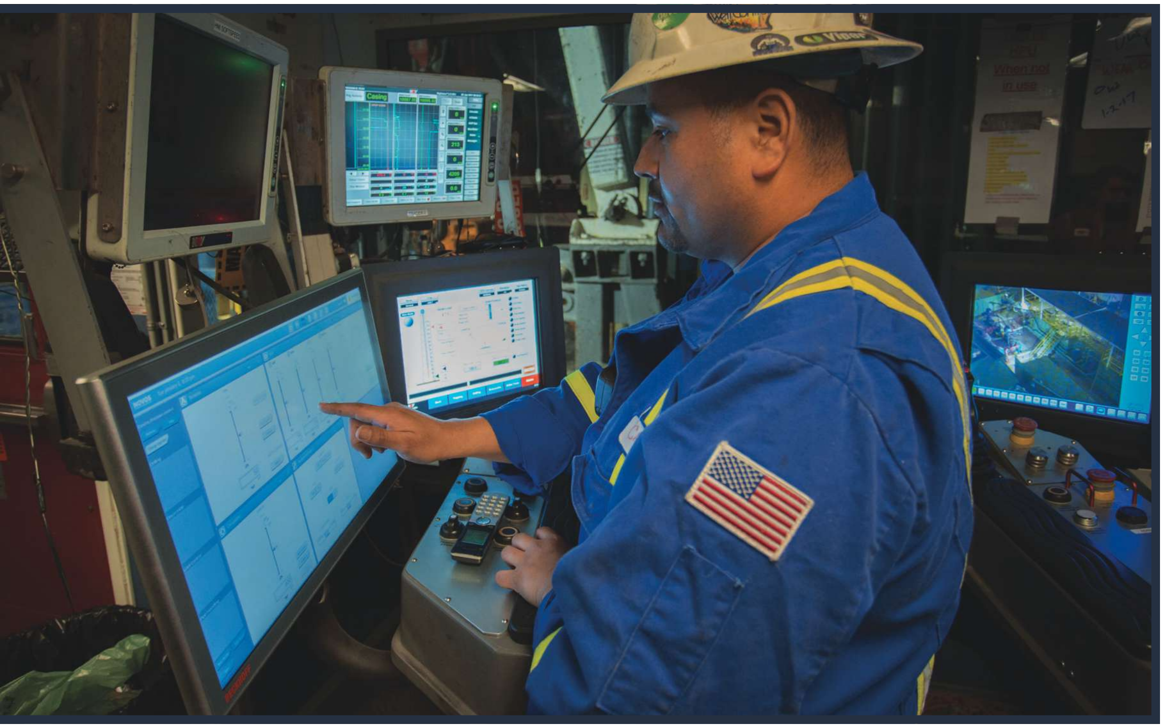
Nabors made a presentation on the project at the SPE Annual Technical Conference and Exhibition in San Antonio in October 2017 that referenced the project and the approach using the software system Rigwatch Navigator. "Nabors was basically presenting full automation from the desk to the rig, including controlling, steering and auto-correcting functionality that it is trialing in the Bakken," Bush explained.

Nabors started in the Bakken because it feels like it has a good handle on the geology and best practices, he said. "The company is working with the leading operator, and it basically has stated publicly, I think, that about 90% of the drilling instructions produced by Navigator were validated by the driller. I haven't seen that level of automation from too many companies," he emphasized.

Although that might be one of the more advanced efforts, other companies are also tackling automation. Many of those efforts are aimed at moving decision-making to the rigs, except for directional drilling, which is headed to consolidating operations in a central location.

What's driving drilling rig automation?

"The drilling industry is continually striving to become more efficient and has made great progress over the last 10 to15 years," said Duane Cuku, vice president, sales, rig technology, Precision Drilling. "The first step was retooling the fleet with modern AC rigs that are highly mobile and have very sophisticated control systems. Simply put, we built a bigger and better hammer. This, along with better drill bit and drilling fluid technology, has helped to significantly reduce overall drilling times. Since the low-hanging fruit has been picked, the next step is to refine the repeatable tasks that a machine can do as well as the best driller but far more consistently. This step required additional software, which was only developed for the drilling industry in the last few years.



A driller on Precision Drilling's Rig 601 in the Permian Basin manipulates the settings of a pre-programmed automation routine. *(Photo courtesy of Precision Drilling)*

"The interesting thing about automation is that as long as the rig has a sophisticated control system, the size or particular characteristics of the equipment don't matter since generally the same steps to drill a well are required regardless of depth and/or lateral length," he continued. "Automation can make an impact from the surface to total depth."

Katy Holst, vice president, technical services, Patterson-UTI, noted that each company has a different definition of automation depending on what it is focused on. Some people think automation is for specific sequences or processes. "I think what we're interested in is how we've been communicating with downhole tools and developing software that can execute consistent process decisions on the fly to really maximize performance and—ultimately—to reduce wellbore tortuosity, improve overall well placement accuracy and continue to increase the slope of days vs. depth curves. Improvements in survey management techniques will allow longer laterals, tighter well placement on pad sites and greater efficiencies in hydrocarbon recovery," she said.

Bret Barre, MWD technical director, MS Energy, a Patterson-UTI company, added, "I think for automation it is being able to drill the well better than we're doing right now. We can do it better if we can get enough data to drill the well more consistently. It is all contingent on the data we can get to the surface."

"People are excited to see where technology will take us in this area," added Holst. "It is a tremendous opportunity, but it can be a challenge. As different companies are trying to work together, we are having to establish different communication protocols for each company. Patterson-UTI now has an advantage in its ability to collaborate with its subsidiaries to fast-track the development of the drilling automation process."

Closed-loop drilling control

With Patterson-UTI's recent acquisition of MS Energy Services, the company is in a unique position to collaborate with a directional services company to close the loop on directional drilling control, Holst said.

"MS Energy has been working on developing high-speed electromagnetic (EM) telemetry and software that more accurately surveys the wellbore in real time. The next steps in joint development may include inputting survey and environmental data into the rig control system and allowing the rig's controls to automatically steer the well," she continued.


VAREL
OIL & GAS DRILL BITS
SLIPSTREAM
Eatin' Frac Plugs like Candy
Small Cuttings, Big Results.
A Plugs Worst Nightmare.
Record Setter.
Headquarters: Dallas Texas • varelintl.com • 1.800.827.3526 • 1.972.242.1160

More than anything else, closing the drilling control loop is about the communications interface. After acquiring MS Energy "we've broken down IP hurdles that may have been in place previously, and we are able to jump directly into ensuring that we have the right communication interface. We are able to begin developing technology that allows downhole tools to communicate directly with rig and surface control systems," she emphasized.

Along with the communication interface must come more speed in moving data. "One of the hardest things I see in front of us is getting data fast enough. Whether it is standard mud pulse telemetry or even the fastest EM, we're still getting data slowly from downhole," Barre said.

There is a lag already in getting data to the surface, analyzing it and acting upon that information. The company is looking forward to improvements in data speed. "We are looking at staying with mud pulse telemetry and EM or some integration of the two. In addition, we'll potentially be exploring opportunities with acoustic technologies," Barre added.

Holst said that, realistically, the completion of field trials for the closed-loop drilling control system won't happen until 2019. "We will be releasing our automation solution in a strategically phased approach," she said. "We're not field-testing right now."

Regarding the future of automation in drilling rigs, she noted, "It is exciting to see other companies moving forward in the same direction. There is a lot of momentum that is driving technological development in this area right now."

MS Energy will continue as a subsidiary to provide services for other drilling contractors, she explained. As MS Energy completes directional jobs on Patterson-UTI rigs it is now able to import its downhole data into the company's PTEN+ Performance Center. "The center utilizes Big Data technology in the way we're able to assemble data from multiple sources and very efficiently analyze and visualize that data to help us at this stage in research and development," Holst said.

Barre emphasized that it "goes beyond the drilling. When you do get that cleaner well, the production side becomes more convenient and more predictable."

Beta testing for process automation control

Precision Drilling has taken the point of view that many of the processes that a driller performs on a day-to-day basis throughout the construction of a well can be automated, including adding a joint of pipe, moving back into the formation, engaging the rock, directional drilling, power management and optimizing ROP.

"There are many things the driller does today that require him to modify or intervene in the actual processes being performed. We can automate a great majority of those processes such that he can focus his attention on the actual construction of the well and the safety and performance of his crew," Cuku said.

In its Oct. 27 third-quarter report Kevin Neveu, Precision's president and CEO, said, "During the third quarter we continued to demonstrate the 'next tier' of drilling efficiency improvement with process automation control (PAC) and other technology initiatives we are implementing in our beta-testing program.

"Precision has drilled approximately 70 wells utilizing PAC technology, which is currently installed on 20 Super Triple rigs. The results continue to show improved efficiency, consistency and repeatability. Precision along with its partner has made significant strides towards making Precision's PAC a commercial success in 2018," he added.

The PAC is basically a controller that sits on top of the main rig control system. "We standardized the interface so we have the ability to write algorithms and applications that run across the platform trying to make those routine," Cuku explained.

"One of the challenges in the industry that has really inhibited large-scale automation projects is the uniqueness of each control system. Think of a standard interface for each application or routine you want to install on the drilling rig. It would have to be a custom install, requiring service technicians and programmers on location. However, once we've standardized the interface with a base platform—in Precision's case, NOV's Amphion control system—we can effectively write the application once and push it across the entire fleet," he continued.

Vallourec casing.
Run.
Succeed.
Repeat.
Get the superior reliability and repeatability you need for the best performance in your unconventional operations. Vallourec Star provides **custom-engineered**, as well as API sizes ranging from 2 3/8" – 10 3/4". The casing and tubing tight tolerances, and high steel grades deliver the quality you need, every time. Vallourec Star; the capacity, infrastructure and support for the most competitive to the most complex wells.
vallourec
SMART TUBULAR SOLUTIONS
+1 713 479 3200 • www.vallourec.com/countries/usa
We Make Shale Possible.

Precision Drilling Rig 579 drills in Oklahoma's Scoop play. *(Photo courtesy of Precision Drilling)*

Precision chose an open source version of its platform. "Anyone can write applications to take over some of the set points and execution of operations. We have several very engaged customers in the process. We are actually looking to the future for them to be able to develop their own applications for the platform to optimize their profits and performance of the rig based on their own models that they've developed internally yet have not had a means to deploy to the field," he said.

The company is moving through the beta phase of the rollout of the platform. "We're moving them out to the field in development to get it to the point of full commercialization in 2018. We have industry partners as we typically do to jointly develop this platform and roll it out to the market," Cuku explained.

The PAC is laid on top of NOV's Amphion control system. "We have approximately 106 rigs with Amphion," he said. "There is a great deal of leverage across our fleet in North America as well as a few rigs in the Middle East as we make the product commercial."

Automation for better well placement

According to Westwood, "The drive, both in the U.S. and internationally, for wells with longer laterals and multiple wells [that are] efficiently drilled from larger pads creates demand for high-horsepower modern AC rigs that can minimize time between each well."

There is "a much smaller number of top-tier contractors [that] compete on the basis of having the best rigs, the best crews and significant scale, improving their ability to meet client requirements. This premium segment competes less on cost and more on value of the high-spec rigs with industry-leading equipment and technology," Westwood added.

Cuku explained, "From a length-of-lateral standpoint, if you can drill a higher quality wellbore that's better positioned, I think the laterals will have the ability to push out farther and farther."

"To reach some of those longer laterals, the discussions are around what some companies call wellbore placement and other companies call lateral science. I think companies will improve the ability to drill straight vertical sections and have the kickoff point heel-to-toe, essentially with the toe up. There is still a lot of debate about that at least from the people we talk to as far as the right techniques," Bush said.

"There is more technology that is required to really understand what's happening in the lateral and how the sensors, automation equipment or any of the new data sources can help with the drilling angles and completing the well," he continued.

TRIPOINT

Tri-Point is an oil and gas production and processing equipment company that brings together high-performing products, engineered solutions and turnkey services to support an integrated system approach from the wellhead through the pipeline.

The company has the expertise and capabilities to deliver high quality, tailored solutions to meet customer needs across the upstream and midstream markets in all major U.S. basins.

WWW.TRI-POINTLLC.COM

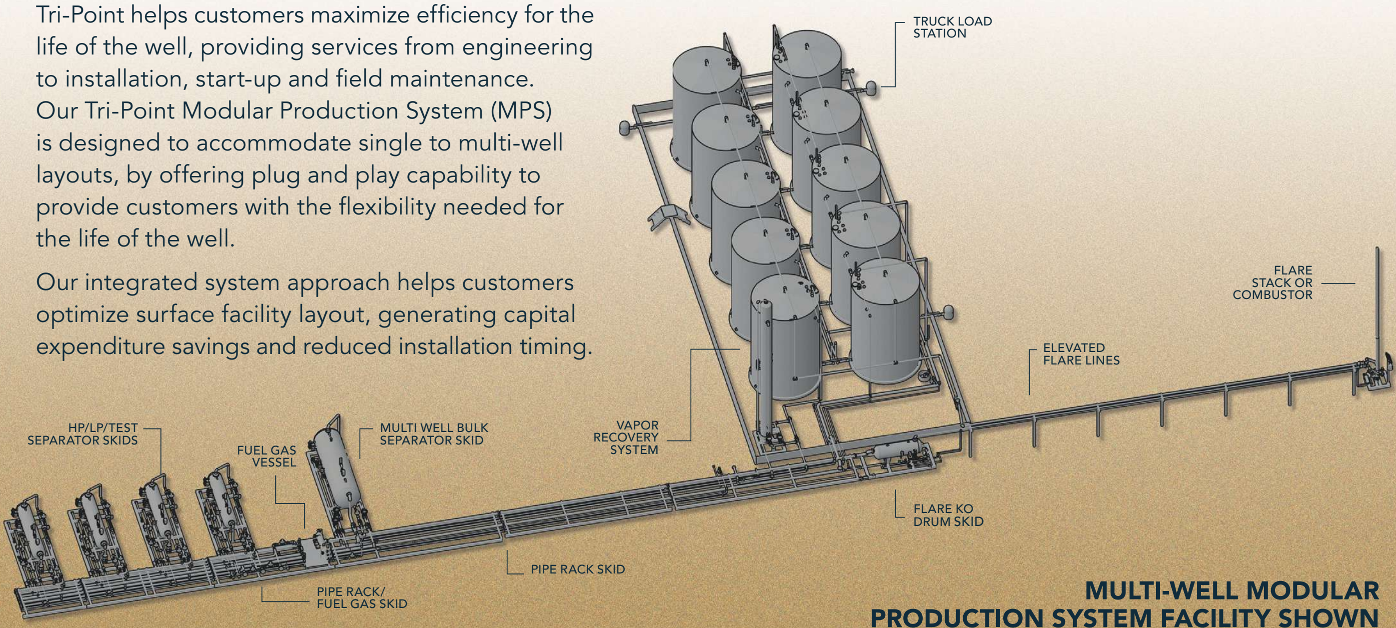
TRI-POINT BRANDS

CROSSFIRE SALES & SERVICE · EDGE MANUFACTURING & TECHNOLOGY · LEED FABRICATION · SFI · Streamline

INTEGRATED SYSTEM APPROACH

Tri-Point helps customers maximize efficiency for the life of the well, providing services from engineering to installation, start-up and field maintenance. Our Tri-Point Modular Production System (MPS) is designed to accommodate single to multi-well layouts, by offering plug and play capability to provide customers with the flexibility needed for the life of the well.

Our integrated system approach helps customers optimize surface facility layout, generating capital expenditure savings and reduced installation timing.



MULTI-WELL MODULAR PRODUCTION SYSTEM FACILITY SHOWN

Oxy, for example, is adding different sensors and MWD to get drillers to begin using the software and tools they're putting together. "They're trying to bring [techniques] to the drilling rigs [so] that they can make corrections now instead of calling a day later with those corrections," he said.

Fully automatic directional drilling system

In its Oct. 24 third-quarter report Anthony Petrello, Nabors Industries chairman, president and CEO, said, "Our Rigtelligent operating system has now been implemented on 95 of our rigs in the Lower 48 and is performing in line with our expectations.

"In our services portfolio we conducted initial field-testing of our ROCKit AutoPilot fully automatic directional drilling system. In these tests we successfully completed five horizontal wells in a timeframe consistent with our best-in-class directional drillers. One of these wells set a new record for this operator in this particular field. Our iRacker and robotic pipe handling systems are also close to commercial deployment."

In early September Nabors acquired the Norwegian company Robotic Drilling Systems, which provides robotic drill floor systems for both land and offshore rig applications.

The APEX-XK 1500 is Patterson-UTI's multifunctional rig design equipped with the latest AC drilling technology. *(Photo courtesy of Patterson-UTI)*

High-spec drilling rig demand

The APEX-XK 1500 rig is the newest design from Patterson-UTI, with an advanced operating and control system that offers a platform for drilling automation.

"We continue to see growing demand for super-spec rigs. Four of the previously announced seven APEX-XK upgrades have been delivered, and the remaining three rigs are under contract. We also have contracts to upgrade two additional rigs to APEX-PK rigs with a box-on-box substructure and integrated walking system for enhanced performance on a multiwell pad, both of which are expected to be delivered in the first half of 2018," said Andy Hendricks, Patterson-UTI's CEO, in the company's Oct. 26, 2017, third-quarter report.

"Based on contracts currently in place, we expect an average of 87 rigs operating under term contracts during the fourth quarter and an average of 53 rigs operating under term contracts during the 12 months ending Sept. 30, 2018," he added.

In the third quarter Precision reported a modest reduction in its active rig count, with 55 rigs active. Utilization in the high-spec rig market is expected to remain tight and pricing to remain firm. Overall demand for its Pad Walking Super Triple rigs has remained strong.

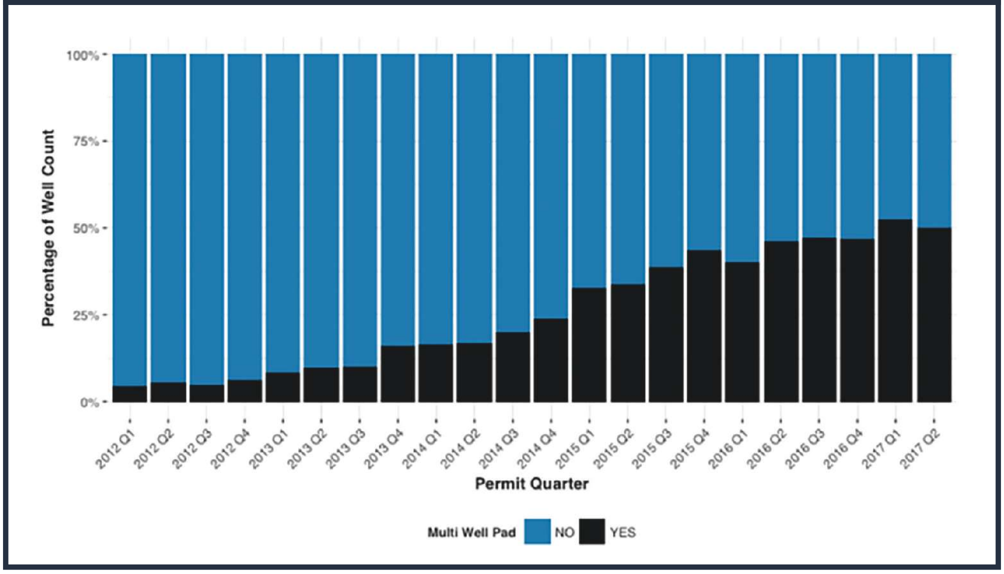
"As our customers across the U.S. and Canada have learned to operate in a 'lower-for-longer' commodity price environment, they have focused on drilling and completion efficiency utilizing long or extended-reach horizontal wells and adopted large-scale industrialization techniques such as multiwell pads and high-efficiency rig systems. Precision's Super Triple rigs are configured to optimize long-reach drilling performance combined with pad walking capability and are active in virtually every resource play in North America," said Neveu.

Petrello noted that Nabors' PACE-X800 and PACE-M800 rigs "continued to be fully utilized. We also deployed our first Quad PACE-X800 rig into the South Texas market. The Lower 48 operation increased by seven average rigs working during the third quarter, including the deployment of its first of two Quad rigs in late July. This upgrade capability is unique to the company's PACE-X800 rigs.

"The Quad configuration incorporates the ability to rack and handle four joints of drill pipe in a single stand," he said. "This yields higher racking capacity and speeds up the tripping of pipe in and out of the well. It also allows casing to be racked and run in double lengths, which significantly reduces the time required for installation of the casing into the well. The second Quad rig configuration is expected to soon commence operations in West Texas.

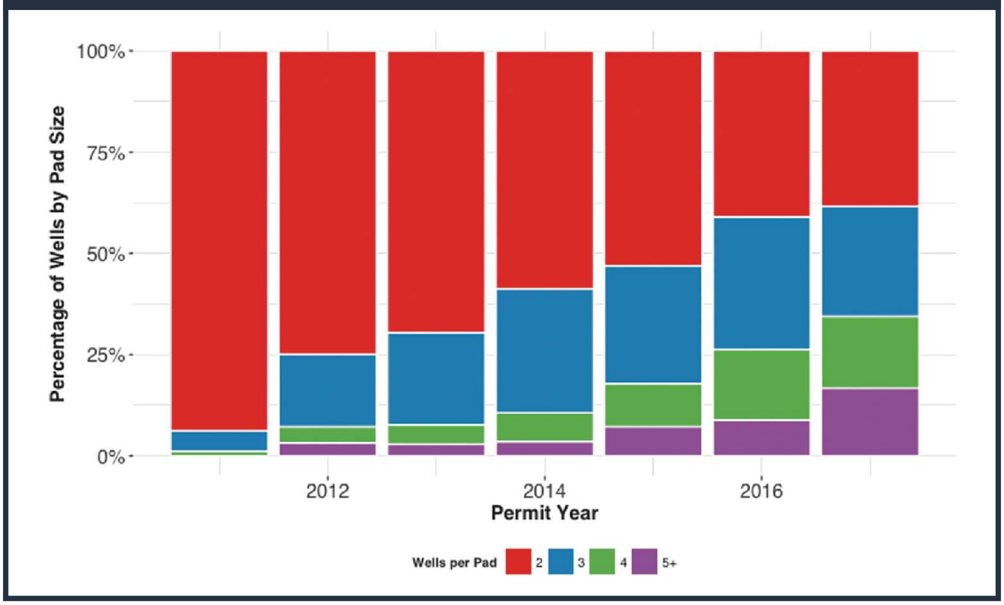
"Results should also benefit from the expected deployment before year-end [2017] of the first two of the company's PACE-M1000 newbuild SmartRig units that are currently under construction. This rig features pad capabilities equivalent to the PACE-X800 rig but with 1 million pounds of hookload and higher racking capacity," he said. ■

Permian Single-well versus Multiwell Pads by Percentage



The number of wells drilled per quarter from multiwell pads in the Permian Basin has risen steadily and topped 50% in first-quarter 2017. *(Source: Energent Group)*

Permian Wells by Pad Size



In the Permian Basin more than 60% of the wells since 2011 have been drilled on multiwell pads, with about 15% of the pads with five or more wells. *(Source: Energent Group)*

Trends in well completion strategies are enabling operators like Parsley Energy to enhance their production capabilities through longer laterals and higher counts of fracture stages. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

Enhanced Completions

Drive Production Gains

By **Brian Walzel**, Associate Editor

Innovations in spacing, lateral lengths and proppant usage are leading to more oil.

Well completions have come a long way since the days when the process of getting a well ready for production consisted of running a steel pipe down the wellbore, casing it in cement and hooking up the surface pump fixtures for delivery of the oil into a pipeline or truck to be delivered to a refinery. Today, the economic success of a producing well is largely dependent upon how the well is completed.

When the cost of completing a well ranges from $6 million to $9 million per well—sometimes up to 60% of the total cost of the well, according to Encana's 2016 fourth-quarter investor presentation—operators are often reluctant to move too far away from proven technologies and systems. The incremental improvements companies have leveraged have resulted in substantial advances in efficiency.

The variability among wellbores leads to well completions being as much art as science and engineering. The process is not as simple as product assembly lines—the end product may all be the same, but the means of getting there vary for each instance. One size does not fit all.

Optimized well completions are becoming a key strategy for operators looking to drive down costs and increase well recoveries. Longer laterals, decreased distances between stage spacing, higher fracturing stage counts and tons more proppant—these are the hallmarks of leading-edge completion designs. Well completion strategies are evolving quickly, and they are proving to be a key component in the matrix in offsetting low commodity prices.

"The pace of learning and change is moving briskly, and the evolution will be ongoing when you consider the investments in land, softer commodity prices, investor expectations and the emphasis on technical excellence," said Rich Downey, vice president of drilling and completions at WPX.

A market forecast by Westwood Global Energy Group issued in October predicted expenditures in the oilfield services market could reach $55 billion by 2022, with spending on completions accounting for the largest portion of that amount. The report focused on expected spending activity forecasts for six unconventional oil and gas plays in North America: the Denver-Julesburg Niobrara (DJ-Niobrara), Eagle Ford, Haynesville, Midcontinent, Permian and Williston basins.

"Importantly for OFS [oilfield services] companies it sees future expenditure weighted heavily toward equipment and services at the completions end of the market," Westwood reported. "For instance, in the DJ-Niobrara the average lateral length has increased 31% to 8,114 ft over 2014-2017."

Westwood also reported that completions expenditures accounted for 64% of overall Permian spending in 2017, up from 42% in 2014. Steve Robertson, head of OFS research at Westwood Global Energy Group, said in a press release that the results of the study indicated a change in the perception of the state of the oil and gas industry.

"It's time to re-think how we measure OFS industry activity in North America," Robertson said. "This report shows that the rig count is becoming less relevant and where we should focus our attention is well completions."

Lateral lengths and spacing

About two years ago, operators discovered the technologies and the economic benefit of drilling extended laterals, and today some of the longest wells reach as far as 17,000 ft or more. Eclipse Resources stated in its first-quarter 2017 earnings report that it completed a 19,300-ft lateral in the Utica Basin. Still, lateral lengths that extend 3 miles and more are the exception rather than the rule. Operators seem to have settled, at least for now, in the 7,000-ft range. According to BTU Analytics, the average lateral length in January 2013 was just more than 6,000 ft. By August 2017, that amount had increased to 7,000 ft. That doesn't mean operators aren't targeting longer laterals where they find the economic benefit and risks are minimal.

"We're trying wherever we can to drill 10,000-ft laterals," said Joel Fox, senior manager of drilling and completions for Encana. "We're being a bit cautious about going more than 10,000 ft. And the reason is, it's just the confidence you have in getting a good completion or managing any trouble once you get beyond 10,000 ft. We'll probably get there as an industry, but today, we don't think the risk is justified."

Stephen Ingram, vice president, technology solutions and innovation, North American operations at Halliburton, said the longest lateral in which Halliburton has been involved was a 4-mile fracturing operation in the Ohio Utica. But the biggest limitation to continued extended lateral lengths, he said, likely won't be technological ability but regulatory constraints.

"The primary barrier to extended laterals in all basins today is not the technology to do it nor the risk associated with longer laterals," he said. "The primary barrier is the actual acreage holding, or, depending on the state, the lease regulatory environment in which to put multiple sections together and drill an extra 5,000 ft of lateral. So today we feel the technical limits are longer than the longest wells drilled, and that the cost and risk is not a prohibiting factor. The primary factor prohibiting lateral lengths growing are lease acreage position and, in some states, the regulatory environment."

Independent completions consultant John Kumolski said, however, there may in fact be mechanical limitations on how long laterals could eventually go.

"If you're drilling a well and say you're going vertically 1 to 2 miles, and then you go horizontal, you have to be aware of what the limitations are on the rig," he said. "It may get to the point where you cannot put any more weight on the bit, and if you were drilling with a downhole motor, there may be a limitation on the pipe above it at the angles, and direction that you're running it might give you some limitations also."

In addition to extended laterals playing a key role in completion optimization, so too do spacing and proppant loading amounts. Operators are putting more wells on a pad, increasing the number of fracture stages and substantially increasing the amount of proppant they pump down their wells—all strategies that play a role in optimizing IP.

"The trend that we've seen over the last number of years is to closer wellbore spacing, and when you go to closer wellbore spacing you are really forced to understand the length of your hydraulic fracturing treatment," Ingram said. "So as we have observed closer wellbore spacing we have in parallel observed more perforation clusters per stage."

The result of that strategy, Ingram said, has been a decreased length of the hydraulic fracture away from the wellbore.

"What we are observing is denser hydraulic fracturing closer to each individual wellbore as a response to the cognizant decision to place wellbores closer together," he said. "So we are harvesting more hydrocarbons from each wellbore nearer the wellbore, which supports the ability to put wells closer together. You could not do this without the other. They are symbiotic."

Encana has deployed its cube well completion development strategy, which it says maximizes value from a multizone stacked development scheme. Encana's "cube development," the company reported in a 2017 investor relations presentation, minimizes inter-wellbore communication and eliminates parent-child in-fill drilling. According to the presentation, the evolution of the company's completion design has evolved from four wells per section in

2010 to 60 wells per section in 2017, systematically increasing wellbore density and recovery.

"Our Eagle Ford team pioneered these enhanced designs, based upon tighter cluster spacing and a thin fluids design with aggressive flowback," Fox said. "The advanced completion design produced strong results in new zones, increased our type curves and grew our premium return inventory and our margins."

Fox said the success of the design in the Eagle Ford has encouraged Encana to test its advanced completions model, which includes an analytics-based approach to completing a well, in the Montney, Duvernay and Permian basins as well.

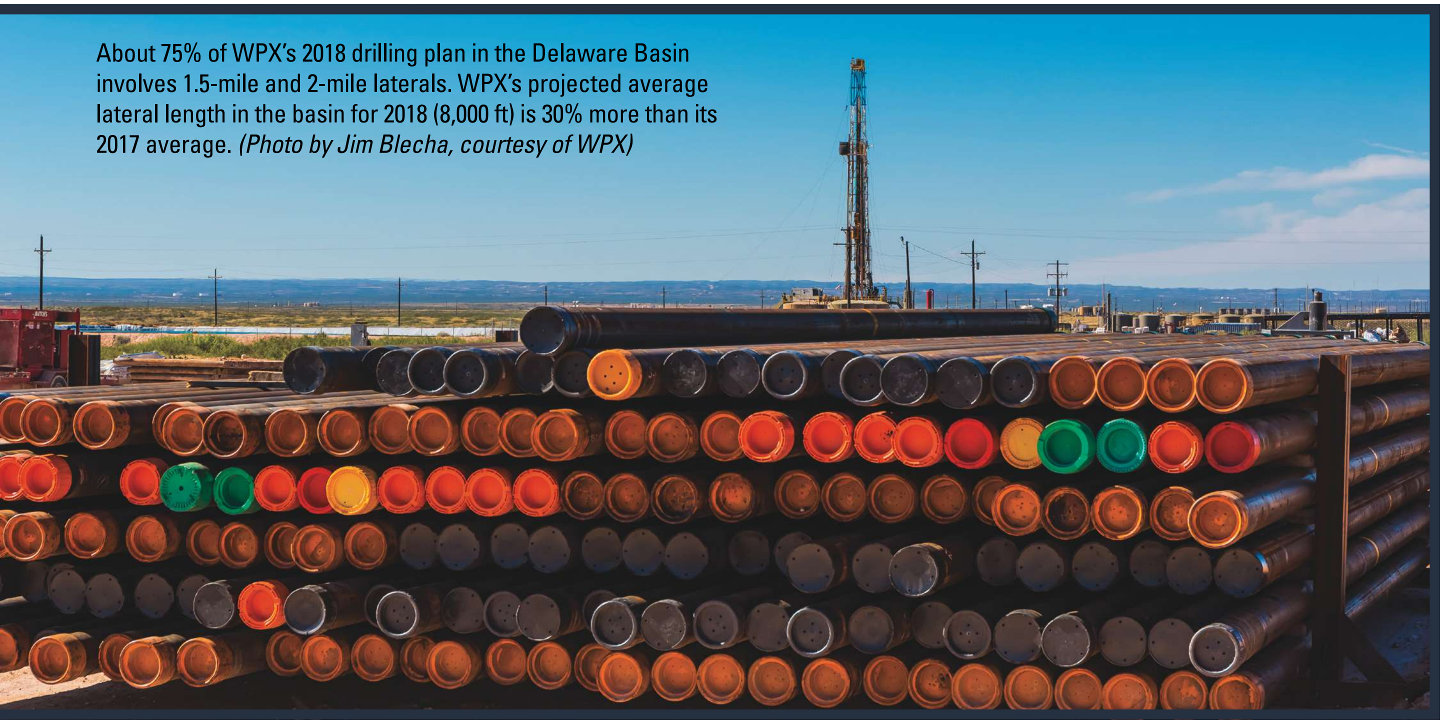
"Our approach is data-driven," Fox said. "In the Permian, for example, we studied and refined our development approach over several years after entering the basin. Our Vertical Optimization Experiment, or VOX well, drilled in Midland County in 2015, was equipped with 16 pressure gauges at various depths, along with 10 sliding sleeves across a 3,400-ft vertical section. It allowed for isolation and analysis of specific zones. These learnings were applied on the first 14 wells of the RAB Davidson cube development in early 2016. In turn, when we drilled the second phase of the RAB Davidson this year, we took the real-time data from those first 14 wells and evaluated the productivity of that pad and subsequent drawdown to drill 19 additional wells, including adding an additional layer and conducting a different style completion operation. Our approach with cube development is to create effective drawdown at the scale at which the reservoir exists from a single surface location."

According to its second-quarter 2017 report, WPX has tested multiple completion designs in the Williston Basin for its Caribou, Grizzly and Beaks pads. According to WPX, these pads varied in their number of stages—40 versus 60—and the number of clusters per stage—five versus 10. Their proppant loading ranged between 6 million pounds and 9 million pounds. The company reported that its 30-, 60- and 90-day cumulative oil production for its 60-stage completions exceeded its 40-stage wells.

WPX is actively testing its approach in the Permian as well, where it plans to complete 50% more lateral feet in 2018 on its Delaware Basin wells than it did in 2017.

Downey said the dynamics that dictate how WPX plans its laterals, spacing and stages are dependent upon that particular reservoir's characteristics.

"As with any reservoir, it comes down to the reservoir pressure, permeability and porosity," he said.



About 75% of WPX's 2018 drilling plan in the Delaware Basin involves 1.5-mile and 2-mile laterals. WPX's projected average lateral length in the basin for 2018 (8,000 ft) is 30% more than its 2017 average. *(Photo by Jim Blecha, courtesy of WPX)*

"Oil in place and recovery factors are also important. All unconventional plays are not created equal. You have to understand the reservoir to get the spacing and lateral length right. Unconventional plays are benefitting from all the continuous learning that's taking place. We want to learn as much as we can as quick as we can to eliminate over-spacing the wells and depletion and pressure drop issues within the reservoir."

In addition to reservoir pressure, Downey added that the length of a lateral typically comes down to the operator's ability to effectively stimulate the stage toward the toe of the well. He also said that lowering the cluster spacing maximizes the reservoir coverage along the lateral, while increasing the number of clusters per stage reduces the number of stages to be pumped.

According to its second-quarter 2017 earnings presentation, Energen Resources is deploying its Generation 3 well completion operation in the Delaware and Midland basins. The company's first iteration, Generation 1—implemented in the Delaware between 2012 and 2014—featured 1,000 lb/ft of proppant, 240-ft stage spacing, 39 bbls/ft of fluid and 50-ft cluster spacing. In the Midland Basin, Generation 1 completions featured 1,250 lb/ft to 1,400 lb/ft of proppant, 250-ft to 300-ft stage spacing and 65-ft to 75-ft cluster spacing.

By 2016 and into 2017, Energen had deployed its Generation 3 wells in the Midland and the Delaware basins. In the Delaware, those completions featured up to 2,400 lb/ft of proppant, 200-ft stage spacings, 40 bbls/ft of fluid and 33-ft cluster spacings. In the Midland, completions featured up to 2,000 lb/ft of proppant, 150-ft stage spacing, up to 45 bbls/ft of fluid and 30-ft cluster spacing.

According to its third-quarter 2017 earnings report, Continental Resources recently completed its third 10-well pattern density project in the Scoop Woodford condensate window, which set an Oklahoma record for an initial rate from a drilling spacing unit. The company's Sympson unit produced at a combined peak 24-hr rate of 41,701 boe/d. According to Continental, the Sympson unit is a 2-mile-long, dual zone, 10-well pattern that includes 14 wells. The 1,280-acre unit required a pair of 1-mile parent wells and 12 child wells to fill the 10-well pattern. The 12 new wells, which averaged lengths from 3,050 ft to 10,270 ft, produced at an average 24-hour peak production rate of 3,145 boe/d.

Operators in basins across all of North America are discovering these longer laterals are producing often record rates of IP. But Isaac Aviles, Schlumberger technical principal for multistage stimulation, said that increased lateral lengths and stage count should be weighed against their financial benefits.

"Depending on the basin, the additional operational process (and the increased cost) may not yield economic results," he said.

In a recent Schlumberger study in the Barnett, the relationship between lateral length and well performance was explored. From a production perspective using data analytics, no distinctive advantage was found for wells drilled with longer laterals. Furthermore, using engineering simulation for the basin, it was found that under certain conditions the linear relationship between production versus lateral length can be negatively affected when going beyond 10,000 ft to 12,000 ft. These findings complement a separate Schlumberger study of stage counts in the Bakken, aimed to determine if the economic limit—or stage count per lateral foot—had been reached. In some sections of the play, this was found to be the case.

"In these studies, lateral length and/or stage count were examined to gauge the production impact of spacing or extended reach," Aviles said. "It was found that in certain circumstances the associated cost of completions was not be financially compensated by the production gains. Analyses as such as the ones above need to be done on a regular basis to determine how the production and economic performance may change across the basin and over time."

Maintaining 'parent' well production

As operators drill and complete more wells on their wellpads with tighter spacing in North America's shale fields, older, more mature wells have come under risk of declining production. The issue of "frack hits" is on the rise as well spacing with infill wells becomes tighter, according to Highlands Natural Resources.

Highlands has developed a technology, DT Ultravert, which is designed to protect against well


TETRA Delivers Award-Winning, Technology-Driven, Engineered Solutions to the Oil & Gas Industry
COMPLETION FLUIDS, TOOLS & SERVICES
WATER MANAGEMENT
PRODUCTION TESTING & ENHANCEMENT
COMPRESSION SERVICES
OFFSHORE SERVICES
CLEAR BRINE FLUIDS MANUFACTURING
tetratec.com
TETRA Technologies, Inc. delivers unique, advanced completion technologies and innovative solutions that are dedicated to oil and gas operators through pioneering research focused on enhancing our customers' results. Look to TETRA for your Completion and Production Solutions, because our people make the difference.
TETRA®
© 2018 TETRA Technologies, Inc. All Rights Reserved.
TETRA and the TETRA logo are registered trademarks of TETRA Technologies, Inc.

bashing by preferentially pressurizing a portion of parent wells adjacent to planned child wells in advance of drilling the child well.

"In this way, DT Ultravert serves the dual purpose of protecting existing wells from bashing and enhancing child wells," the company stated in a press release.

WPX's Downey stressed understanding the difference between well communication and actual production issues when considering the potential impact a child well may have on its parent well.

"There's a fine line between well communication and actual production interference," he said. "Just because we're seeing pressure communication between wells doesn't mean the propped fracs are overlapping. Tracer technology and production analysis help us evaluate production sharing and interference."

Fox said that in some cases, Encana's cube completions design has resulted in the child wells outperforming its parent wells.

"In plays like the Permian and Montney, where there are thousands of feet of stacked pay, it has become evident that efficient exploitation of the resource requires a three-dimensional development model, where wells are not only tightly spaced side by side, but also above and below one another," he said. "Using our cube approach minimizes the risk of communication and enhances productivity by creating a more complex fracture network."

Fox said Encana works to minimize the risk of a child well's communication with the depleted reservoir which can make subsequent wells less effective.

"We enhance productivity by creating a more complex fracture network," he said. "We also improve our uptime by avoiding cleanouts due to offset frack hits."

Aviles said far-field diversion methods is a technology Schlumberger utilizes that helps reduce any negative impact on production from parent-child well interaction while fracturing.

"Engineered for tightly spaced wells, far-field diversion constrains fracture growth using particles to bridge only the fracture tip and thereby prevent excessive fracture length and height growth," he said. "The Broadband Shield fracture-geometry control service achieves this objective by minimizing the risk of communicating with neighboring wells or fracturing into undesirable zones while increasing fracture complexity."

Regarding parent-child well interactions (or infilled drilling programs), Halliburton's Ingram said that many reservoirs see a negative production impact in the parent well following the fracture of a child well, but not all do. He said that to deliver expected production from child wells, operators often turn to technologies designed to better understand fracture spacing and delivery such as downhole fiber optics, which can help an operator understand if a child wells' fracture treatment is impacting a parent well's production.

"We spend a lot of time thinking, designing and modeling around diversion technology and microproppant technologies that can alter how a fracture is being propagated and the length of the individual fracture treatment in this pressure-depleted environment," Ingram said. "Because that's really what the child/parent phenomenon is—treating the child wells in the presence of pressure depletion."

Consultant Kumolski said geologic and rock property modeling are key early steps to be taken to avoid fracture hits and well bashing. A better understanding of the reservoir's characteristics and how fractures are affecting those reservoirs could help avoid depleted production.

"Whenever you go into child wells have a better understanding of where some of the fractures have gone," he said. "Once you start fracking the child wells, you start affecting the parent wells. Put together some better geological models, then go back and design on what the volumes of sand, what stages you want to perforate and what you'd want to fracture."

Jeff Dutton, vice president of Longfellow Energy, said some operators increase pressures at the parent well prior to fracturing the child wells to maintain parent well production.

In a study first discussed at the Unconventional Resources Technology Conference in 2017, Schlumberger evaluated the impact of well spacing and interference on production performance in the Permian Basin Avalon Shale play. As part of its study, Schlumberger leveraged the Kinetix stimulation software suite for design, optimization, execution and evaluation for stimulation operations.

Slik-Vis™ - The Original and Still the Leader

High Performance Slickwater Fluid System

DCS
Downhole Chemical Solutions

Why Slik-Vis™

With over 16,000 stages successfully pumped in basins across the United States, Slik-Vis™ is the proven leader in high performance, enhanced viscosity slickwater fluids.

Contact us today for your free trial. DCS will provide new clients with two stages of chemicals at no cost and no obligation. See for yourself why E&P companies across the country are making the switch to Slik-Vis™.

- 99% Regain Conductivity
- High Proppant Transport Capability
- 10 - 15% Lower Treating Pressures
- Lower Cost
- On The Fly Adjustments and Ease of Use
- Fewer Chemicals on Location
- Broad Range of Water Conditions

One Cowboys Way Suite 572 - Frisco, TX 75034 - 469.466.1100 - www.stimchems.com

Aviles said that a 24% reduction in cumulative production over five years was discovered at the Avalon when the spacing between parent and child wells was 660 ft.

"To avoid [negative production interference], two solutions were proposed for this particular study," Aviles said. "[First], keep the well spacing at a minimum of 1,320 ft, where little to no production interference was observed. [Second], if possible, land the child wells 150 ft deeper, which allows 660-ft spacing while affecting the cumulative production by less than 10% over five years."

The optimal well spacing and completion design is critical to maintain and/or increase hydrocarbon production and maximize economic returns.

Trends in proppants

Proppant loading amounts have increased substantially during the past four years, as companies fracture more stages and drill longer wells.

According to Emerge Energy Services (EMES), proppant consumption reached its peak in about the first half of 2015, when the Eagle Ford was consuming more than 4.5 million tons of proppant and operators in the Permian were using 3 million tons. By the first half of 2016, those amounts declined to about 1.7 million tons in the Eagle Ford and 1.4 million tons in the Permian. But, according to EMES, the most substantial gains since then have been realized on a per-well basis.

For example, proppant consumption more than doubled in the Northeast basins from 3 million tons per well at the end of 2015 to more than 6 million tons per well by the end of 2016.

The Eagle Ford (more than 4 million tons), Permian (5 million tons), Bakken (3 million tons) and Midcontinent (4 million tons) all saw record amounts of proppant consumption per horizontal well, according to EMES.

Taso Melisaris, product director for Fairmount Santrol, said he expects the proppant market to continue its growth trajectory into this year and that demand for proppant will grow "very substantially."

According to Fairmount Santrol, raw fracture sand prices are expected to increase \$7 to \$9 per ton on average.

Melisaris said that although some 2018 projections put sand demand at 90 billion tons, and some

Sand producers are expecting the demand for hydraulic fracturing sand to be about 100 billion tons across unconventional plays in North America in 2018. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)* at 147 billion tons, Fairmount Santrol is expecting demand this year to be about 100 billion tons, up from 75 billion tons in 2017. Driving the increase, he said, is demand for 100-mesh sand.

Although the primary growth driver in the sand market will be of the 100-mesh variety, Melisaris said operators are beginning to demand 40/70 sand because they value its conductivity.

"Customers believe they need the extra conductivity they get from the 40/70, although some other operators tell me they prefer 100-mesh sand because of the better proppant transfer in slickwater and that they may be creating complex microfractures," he said.

Fox said the completions plan at Encana takes into account several factors in addition to proppant volumes that have improved the company's well performances.

"Rather than focus on proppant intensity or pounds per foot, we work to optimize fracture complexity, along with the grain size of the proppant, the distance between and design of perforation clusters, and the proportions and rate of the fluid and proppant in the pumping schedule," Fox said. "These factors are interdependent and, by increasing the surface area impacted, we improve well performance. We have tests underway of several technologies including self-suspending proppant, improved perforation design, diverters for improved cluster efficiency, and nanoparticles; these tests are underway now and results are pending—some results will be held confidential."

At WPX, Downey said the company first identifies optimum cluster spacing and the number of clusters needed per stage before it focuses on optimizing its sand volumes. He said it's "extremely important" to emphasize long-term production when planning a sand strategy, and that more sand has more of an impact on a slower decline rate and a reservoir's EUR.

"Long-term production and EUR performance will lead us to the best answers around sand type and volumes," he said. "One of the variables impacting the lateral length is the ability to get the rates and pressures to effectively stimulate the well at the toe."

Companies looking for a more bespoke approach to proppant loading are turning to specialty designs such as resin-coated proppants.

Hexion's AquaBond proppant helps the production of formation water. *(Photo courtesy of Hexion)*

Their properties have the ability to enhance oil flow depending on the characteristics of a reservoir's rocks. Jerry Kurinsky, senior vice president and general manager at Hexion, said resin-coated proppants are often the choice of operators seeking to enhance EUR, rather than focus on high IP rates that traditional sand usually offers.

"We're seeing a positive trend in the uptake of resin-coated proppant, so if you look at the trends of the wells that are actually using that technology, it's grown significantly over the last year, which is a signal that the operators are starting to take a little bit of a longer view on the performance of their assets," Kurinsky said.

During the commodities downturn, he said, companies often focused on reducing their short-term costs at the expense of the long-term performance of their assets, including their investments in proppants. But as prices slowly recover, operators are finding value in advanced proppant technologies, even if they cost more. Hexion's AquaBond resin-coated proppant helps reduce the amount of produced water from a well, and, as Kurinsky explained, saving money on produced water handling offsets the costs of specialty proppant products.

"[Operators are] going to spend a bit more up front on the completions, but they will save more money as they produce," he said.

Pinpoint and PNP fracturing

By nearly every measure, operators continue to rely on traditional plug-and-perf (PNP) systems that use slickwater to fracture their wells. But the most common alternative to PNP is the sliding sleeves method that utilizes coiled tubing (CT) operations and offers pinpoint fracturing capabilities.

Although PNP dominates the fracturing market, sliding sleeves have their place, such as in Encana's operations in the Midland Permian.

"Slickwater is both low viscosity, which minimizes the net pressure of the reservoir and also is very clean, minimizing the impact on the reservoir," Downey said. "Even though slickwater is not very effective in proppant transport, the velocity of the fluids carries the proppant at low-prop concentrations. Sliding sleeve technology is operationally very efficient. It takes away from the lateral coverage of the high number of clusters and perforations, which enhances the reservoir coverage and stimulation."

Damon Aucoin, U.S. sales manager for NCS Multistage, which provides a CT sliding sleeve system, said NCS recently assisted with several high-intensity well completions that combined longer laterals with more stages and higher proppant loading.

"Operators are testing the value of higher intensity completions," Aucoin said. "These completions demonstrate that CT fracturing can deliver the performance needed."

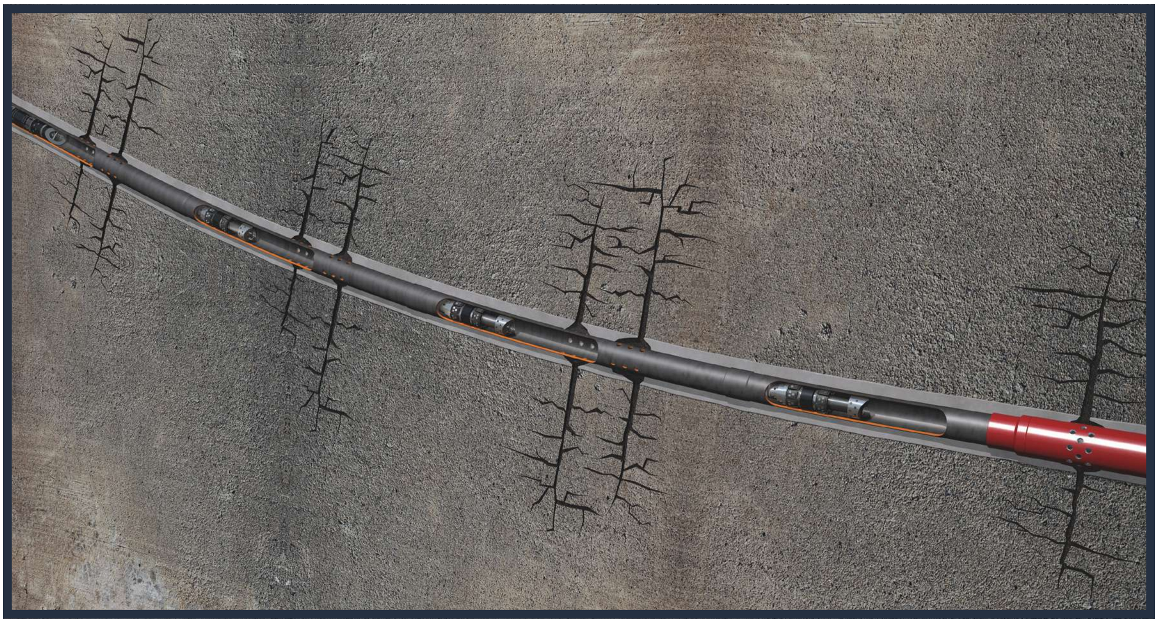
However, Ingram said Halliburton, which also offers sliding sleeve completions to its operators, still sees PNP operations as the go-to method in unconventional completions.

"We see a niche application having existed and continuing to exist on or about its same scale today for about the last many years," Ingram said. "Pinpoint, or sleeve, technology really reduced in application about five years ago as we saw the movement to tighter wellbore spacing and we saw a cost-prohibitive technology being offered in the industry."

Indicative of that trend is Longfellow Energy's evolution of well completions from 2012 to 2017. According to information presented at Hart Energy's DUG Midcontinent Conference in September, in 2012 Longfellow utilized packers and sleeves for its 64 wells completed at its Stack Nemaha play. Those completions included an average of 17 fracture stages, 237-ft well spacing and 614 lb/ft of proppant loading. By 2017, Longfellow had switched to a PNP completion operation with high-velocity slickwater, 141-ft stage spacing and more than 1,700 lb/ft of proppant.

Ingram said that operators faced concerns with pinpoint fracturing methods about the risk associated with premature screenouts and leaving wellbores full of sand. He added that the cost of some sliding sleeve technologies have come down and trials are being run in major basins in North America.

"However, what we still see in the big picture is over 98% of all treatments placed being plug-and-perf," he said.



Halliburton's Obsidian fracture plug is designed to isolate perforated intervals or portions of a wellbore. *(Image courtesy of Halliburton)*

When BroadBand Shield service is used to stimulate an infill well (light green), far-field diversion (yellow) limits fracture growth outside of the designed fracture area, preventing communication with neighboring wells and increasing fracture complexity. *(Image courtesy of Schlumberger)*

Aucoin said CT sliding sleeve systems deliver enhanced control for infill drilling, where operators are increasingly concerned about frack hits, and that PNP methods typically cannot reliably control how long a frack is going to be—what NCS Multistage calls "runaway fracks" and others call "super clusters."

"If one cluster out of five or six takes all the fluid and proppant pumped for that stage, that fracture will probably propagate beyond the designed frack length and communicate with nearby producing wells," Aucoin said. "The advantage that pinpoint fracturing with CT offers is the operator fractures only one cluster at a time, so they have complete control over how much proppant and how much fluid is pumped into that fracture."

A related challenge with PNP completions operations, Aucoin said, is that they aren't repeatable from well to well because the number of fractures, fracture spacing and propped volume are uncontrolled variables.

"For infill development, operators really need repeatable, consistent completions that maximize stimulated reservoir volume without impairing their production," Aucoin said. "Pinpoint fracturing control allows them to design and execute aggressive infill completions that match their well-spacing strategies, while minimizing the risk of communicating with parent wells."

Aviles said that, depending on the reservoir needs, CT sliding sleeves may allow operators to stimulate reservoirs at a lower rate to limit fracturing heights.

"Although hydraulic fracture length (un-propped length) may be affected when compared to PNP, the net or effective fracture length (propped length) can be similar," he said. "In such scenarios, Schlumberger implements the Broadband Precision integrated completion service, which fractures every intended entry-point along the lateral, while improving proppant transport to increase hydrocarbon production."

The end game

Continuously evolving completion strategies—longer laterals, tighter well spacing, more fracture stages, ever-increasing proppant loads—are leading to enhanced productions, at least in a reservoir's early stages. A depressed pricing environment has forced operators to get creative while also not giving up on their role of producing oil and gas. In a $50/bbl environment, oil and gas companies needed to cut costs, and necessity is the mother of invention. The result has been innovative approaches to well completions. WPX's Downey cautioned, however, that as costs to complete a well may rise with production rates, maximizing productivity is still the end game for completion design advances.

"We need to make sure we prioritize finding the very best completion first and not give up on the quality of the completion just because of inflation," he said. "The No. 1 priority is to maximize productivity." ■

The sun sets on one of Enable's sites in North Dakota. *(Photo courtesy of Enable Midstream)*

Staying Current with Modest Growth in Shale Production

By **Gregory DL Morris**, Contributing Editor

Even with the clamps on capex, production creeps higher; pipelines and processing are keeping pace.

During the boom days of the shale bonanza, midstream operators and even investors were scrambling to keep pace. Once the crash came at the end of 2014, the midstream was able to catch its breath, but found that money was tight even to finish projects underway. The theme for 2018 could be "Return of the Jedi" as modest increases in production keep bubbling out everywhere. The Permian is productive as ever, and the current hot plays in the Midcontinent are newly productive. But old friends such as the Haynesville and the Bakken need new gathering, processing and transportation.

There is often talk about the realignment of the North American midstream as a result of the shale bonanza but Enable Midstream Partners recently took that to a literal level when it closed its $300-million acquisition of Align Midstream in October 2017.

Align had gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin. The Align acquisition included about 190 miles of gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana, as well as a cryogenic natural gas processing plant in Panola, Texas, with a capacity of 100 MMcf/d. These assets are underpinned with long-term, fee-based contracts, including approximately 100,000 gross acres of dedication from producer customers.

Enable owns, operates and develops gas and crude infrastructure, including more than 13,000 miles of gathering lines, 2.6 Bcf/d of processing capacity and an extensive 7,800 miles of interstate pipelines. That includes the Southeast Supply Header, of which Enable owns half. The portfolio also includes about 2,200 miles of intrastate pipe and eight storage facilities comprising 85 Bcf of capacity.

"We have been around M&A for a while and have always tried to be smart," said Craig Harris, chief commercial officer, Enable Midstream. "The Align 190 miles of pipe and 100-million-cubic-foot-per-day plant in the Haynesville/Cotton Valley area is actually a good alignment with our existing plant and NGL infrastructure in the area. We are very pleased with the integration."

When producers or midstream operators mention the hot basins around North America the Haynesville is not usually among them. Indeed there was a time not so long ago when the play was the poster child for dry gas as in "Well, at *that* price per mcf even the Haynesville is profitable."

While no one is ready to declare the Haynesville the next Permian, Harris said "we are seeing a lot of activity in that play and in the Cotton Valley. Wells continue to improve across the footprint. It is an advantage to be so close to the major LNG export terminals, but the well profiles all by themselves are very encouraging. There is a great deal of positive momentum in the area—a good mix of wet and dry. We are actually seeing a fair amount of rich-gas drilling."

Stacking the deck

Enable has several projects in various stages of development, but two major projects coming online in 2018 are the Wildcat and the Cana and Stack Expansion (CaSE) projects in the Anadarko

Basin. Despite its name, Wildcat is anything but a risky venture. Quite to the contrary, it is an efficient application of existing but underused assets.

"We contracted with Energy Transfer Partners for 400 million a day of capacity at their processing plant at Godley, Texas," Harris explained. "We tie that in from our Super Header in Oklahoma, and the residual gas hits the Texas intrastate system through the NorTex Tolar Hub. We see it as a creative way to move gas from the Stack into North Texas while being very efficient with our capital dollars. It actually uses infrastructure that was built for the Barnett and is now underutilized. We gain 400 million a day of processing and access to a new market for our shippers, without having to build a plant and minimizing our pipe buildout."

In the lower-for-longer reality, smart is the new rich. "For us it makes sense to make the most of existing assets rather than build new ones," Harris said. "That also keeps costs lower and improves netbacks to our producers. They like that, and that enables them to drill more. We continue to look for options that are not so obvious."

The same applies for contracts. It has been mentioned by some acquisitive producers that legacy midstream contacts can be an impediment to upstream acquisition and divestiture activity. But Harris said that far from an opportunity to make a quick buck, a change in production ownership is an opportunity to make a new friend.

"If a contract is in place there is certainty for both sides," Harris said. "We like that dedicated acreage to remain dedicated at known rates and terms of service. Especially if a large producer is selling non-core assets, it does not make sense for us to try to make big changes. The benefit to us is for the acreage to become productive sooner. Some private-equity-backed producers prefer to have their own gathering and processing rather than contract for it, but in the cases where the acreage is dedicated to Enable we like to think the opportunity is more than offset by Enable's reliability and market access."

Toward the end of 2018 Enable will bring into service another example of making use of under-capacity assets. The CaSE project will bring 205 MMcf/d of residual-gas takeaway through inter- and intrastate pipe for Newfield Exploration in the Anadarko Basin. "We will be looping existing pipe and adding compression," Harris said, "so it provides relatively quick access to market for the shipper."

Rushing to Cushing

Elsewhere in the Stack, Scoop and related Midcontinent plays there has been a significant increase in crude liftings, noted Greg Haas, director, Stratas Advisors, a sister company of Hart Energy. "Meaningful midstream expansion is needed there, and it is happening." Notably there is the Glass Mountain Pipeline to Cushing, Okla. Construction on a 44-mile pipeline extension of the pipeline is expected to be complete by year-end 2017 and operational by first-quarter 2018. Sem Group had been leading the project, and, in early November 2017, sold its half of the system to an affiliate of Black Rock. There is also a 50:50 joint venture expansion by Plains All American and Phillips 66 into Cushing that was completed in November 2017.

That project, called simply the Stack Pipeline, moves crude from the Sooner Trend, Anadarko Basin, Canadian and Kingfisher (Stack) counties in northwestern Oklahoma to Cushing. Plains contributed an existing terminal at Cashion, Okla., with 200 Mbbl of crude storage and a 55-mile crude pipeline with a current capacity of 100 Mbbl/d. The system's connection to Cushing also provides another source of feedstock to Phillips 66's Ponca City refinery.

"Combined those extensions and expansions are adding significant transportation capacity out of these plays," said Haas. "They are also moving deeper into the western parts and connecting more of the regional plays. What is currently being planned will likely be sufficient mainline, long-haul capacity for the near term."

That said, Haas cautioned that an old problem is rearing its head again: not getting barrels out of the basins and over to Cushing but getting out of Cushing and on to a consuming market. "There is a bottleneck developing similar to what we saw in the early part of the decade. Already a differential is re-emerging between WTI and Brent or LLS because of the pipeline constraints from Cushing to the refiners and export terminals of the Gulf Coast."

In early November 2017 those differentials were running about $7/bbl, and Stratas forecasts that any differential will remain no larger than the high single digits. That is in contrast to 2013 when the differential soared to four times the November rate, close to $30/bbl. "Overall crude production has outpaced pipeline construction," Haas said. "Even Niobrara and Uinta production is pushing into Cushing with insufficient capacity out."

Two other projects are underway to help alleviate the bottleneck and the differential. Interestingly, they are designed to move crude north to domestic refining markets, rather than to tidewater for export. MPLX's Ozark line expansion will move 115 Mbbl/d from Cushing to St. Louis; the Diamond Pipeline will take 200 Mbbl/d from Cushing to Memphis.

MPLX acquired the Ozark line in February 2017 from Enbridge for $220 million. It runs from Cushing to Wood River, Ill., on the Mississippi River where Phillips 66 has a refinery. The expansion is due to be completed by the middle of 2018 and will take the line's capacity from 230 Mbbl/d to about 350 Mbbl/d.

Plains All American planned to start operations on its Diamond crude line at the end of 2017. In its November 2017 earnings call Plains reported that construction on Diamond had been completed at the end of October, and that commissioning had begun. Commercial operations were to begin during December, with the normal ramp up to capacity through the early part of 2018.

There are two other crude lines that reckon into the situation. MPLX has announced an open season to judge shipper interest in reversing the Capline, and the Dakota Access Pipeline that feeds into the Energy Transfer Crude Oil pipeline to Texas. All are likely to turn Patoka into an important hub, "like a Cushing North for the nation's inland crudes," said Haas. Back in Texas, Plains All-American's Permian Express will take 140 Mbbl/d from the Permian region to tidewater rather than into Cushing.

In July 2017 Oneok revealed plans to double its Canadian Valley gas processing plant in the Stack to 400 MMcf/d "to support increasing production growth" in the region. The Canadian Valley II project is to be completed by the end of 2018

Surfeit of Ethane Revives Appalachian Chemical Industry

Early in November 2017 Shell Chemical began construction on a $6 billion olefins complex in Potter Township, Pa., northwest of Pittsburgh. The steam cracker at the heart of the plant will use the overabundant Marcellus and Utica ethane and natural gas for feedstock and fuel to make primarily ethylene. That monomer in turn will be used to make polymers for regional manufacturing as well as export.

The Shell complex includes the cracker and three polyethylene trains, as well as a 250-MW gas-fired power plant to provide electricity and steam to the cracker. Total capacity of the polymer units is projected at 1.6 MMmt/year. Shell has noted that almost three- quarters of the North American manufacturing industry that uses polyethylene is less than a thousand miles from Pittsburgh. Construction is expected to take at least three years.

Steel in the ground is the culmination of years of planning that came after decades of speculation. While Shell is first off the mark, it is not likely to be the only game in town. As long as there has been talk of a Marcellus cracker there has been the realization there have to be at least two.

Operationally polymer plants tend to be steady-on types of units, while steam crackers, not unlike catalytic cracking units in a refinery, are more temperamental. For a polymer operation to be a reliable supplier, it has to have an alternate source of feedstock if its primary cracker goes down. The Houston area has multiple olefins plants, as well as cavern storage of ethylene. Neither exists in Pennsylvania. As a global polymer producer Shell would easily be able to divert polymer shipments to replace an outage at Potter Township. Still chemical industry sources say it would be best if there were at least one other cracker.

Jim Justice, governor of West Virginia, has been a booster for several proposals for olefins plants in that state, just over the border from the Shell project. Brazilian company Braskem, and its subsidiary Odebrecht, revealed plans for a cracker at Wood River, W.Va., about three years ago. Recently, Braskem took over the project entirely, but no investment commitment has been made. There are other ideas for a West Virginia cracker, as well as at least one plan for an olefins unit in Ohio. ■

—Gregory Morris

at a cost of $160 million. The company said at the time of the announcement that the expansion "is supported by more than 200,000 acres of dedication, primarily fee-based contracts and minimum-volume commitments."

The expansion of Canadian Valley, in conjunction with the previously announced 200 MMcf/d firm offload agreement to a third-party processor, will take Oneok's total processing capacity in Oklahoma to 1.1 Bcf/d by 2019. Further, NGLs produced from the expansion are expected to add 20 Mbbl/d of additional volumes to the company's existing Oklahoma liquids gathering system.

Party like it's 2012

It's back to the future in the Permian, where midstream operators are racing to keep up with burgeoning production as if it were 2012. Brazos Midstream will bring its 200-MMcf/d Comanche II cryogenic gas processing plant in Reeves County, Texas, online in January 2018, a full month ahead of schedule. Comanche I, at 60 MMcf/d was brought into service at the end of 2016, and Comanche III, a twin of II, is now due to be started before the end of 2018. That also will be early.

Separately, Lucid Energy Group planned to bring its 200 MMcf/d Roadrunner cryogenic plant in Eddy County, N.M., into service in December, a month ahead of schedule. The company is also considering placing its next gas plant there, a possible change from the original plan to locate it adjacent to the Red Hills II plant, also a 200 MMcf/d, which was put into service in May in Lea County, N.M.

It almost seems as if the play itself is playing with producers. At a time when domestic development budgets are being held to minimums, and global supply economics are still in surplus, producers have hardly been fostering higher production. Yet the Permian takes its moniker seriously: the gift that keeps on giving.

"Speed is the critical consideration for us and for our producer counterparties," said Mike Latchem, president and CEO of Lucid. "That is all related to the success of the wells in northern Delaware, including the Wolfcamp, the Bone Springs and the Avalon. They are coming on so much stronger than the producers anticipated. That is a great problem to have."

San Mateo, a joint venture of Five Point and producer Matador Resources, has plans to bring on a 200 MMcf/d processing plant early next year. "There is an incredible amount of wet gas in the Delaware," said David Capobianco, CEO and managing partner of Five Point. "The pace of production is not currently well understood, but it seems every new window and every new bench has great crude and massive gas. So much that in some zones it's hard to call it 'associated' gas."

Regional oil refining demand, together with out-of-basin transportation come to about 2.6 MMbbl/d. Crude production is expected to outpace existing takeaway capacity in 2018, but there is currently one pipe planned to be brought into service in the near term. Enterprise Products' Midland-to-Sealy line is expected to add an initial 300 Mbbl/d of new capacity by the middle of 2018. That line could be expanded by about half again as much with incremental debottlenecks. The same could be done on other existing lines, adding a further 300 Mbbl/d to 400 Mbbl/d of crude transportation.

Another essential project for the Permian is Enterprise Product Partners LP's Midland-to-Sealy line that will move 450 Mbbl/d to Houston's doorstep, and also the Cactus line that will take 140 Mbbl/d to Corpus Christi. "In total there is about three quarters of a million barrels a day of new capacity to move Permian crude to Gulf Coast refiners or exporters. That should handle most of the growth. Cactus will also take Eagle Ford crude on its run from Gardendale, Texas, to Corpus Christi. That plus crude-by-rail should suffice for the Eagle Ford," Haas said.

So close and yet so far

The Appalachian regional midstream industry is a "conundrum," Haas at Stratas noted dryly. "There is the massive market in the Northeast and middle-Atlantic states, and virtually on their doorstep is the largest gas supply basin in North America. The trouble is that pipeline construction, even expansion of existing lines, is extremely difficult and expensive in densely developed areas. It is even more difficult for lines that cross multiple state lines."

Still, there are expansions, if only in fits and starts, Haas added. He stressed the need to under-

stand there are two problems in Appalachia. One is how to get Marcellus and Utica gas out of the basin and to market. The other is the largest and closest metropolitan markets, the ones currently paying the greatest differential, are the most difficult to reach with meaningful new volumes.

While the answer to the second is also a partial answer to the first, there are answers to the first that head in another direction and do not solve the second. Notably that is moving Appalachian gas south, either to new power generation in the formerly coal-dependent Southeast, or all the way to the Gulf Coast.

"One piece of good news for Appalachian producers," Haas said, "is that Kinder Morgan has opened a season on the Utica Marcellus to Texas proposal that seeks to serve NGL producers and processors. This is something of a zombie plan that was first proposed in 2012 and is now being brought back to life."

More help for Appalachian producers is home grown. Shell Chemical has broken ground on its long-contemplated olefins and polymers complex. The idea of a "Marcellus cracker" has been around ever since the liquids-rich window of the play overwhelmed first local then regional markets for NGLs (see sidebar).

"There have also been at least two different possible collaborations on a second such olefins plant in the region," added Haas.

It is too soon to tell if any of that will come to fruition. The set of possible partner companies seems to be in flux and may be for some time. The memorandum of understanding signed by China Energy Investment Corp. and the State of West Virginia offers an amazing possibility of $84 billion in shale and petrochemical manufacturing investment in the state over the next two decades. But Haas anticipates that only a few firm decisions may be made by the end of 2018 to positively affect the Appalachian region in the short term.

Eagle Ford in 'later innings'

Erik Holt, vice president of business development and land with Teal Natural Resources, noted how different conditions are in the Eagle Ford in contrast to those in the Permian for both producers upstream as well as for operators in the midstream. "I was with an operator in the Delaware Basin relatively early in that development," he recalled. "There was such intense competition for undeveloped assets at the time. We don't have nearly the same velocity in the Eagle Ford these days."

By Holt's account the South Texas play is "in the later innings. We saw billions of capital invested upstream and midstream before the recent commodity downturn. After 2014 there has been so much production come down from a crude takeaway perspective that it is not economical to build new pipe, or even for us as a shipper in some cases to ship by pipe," he said.

On the gas side, "Whoever has a set footprint and assets in operation is who is going to be competing," in Holt's assessment. "I have not heard anything about anyone hurting. The economics are not bad; they are different than they were just a few years ago."

That situation has led to consolidation, as highlighted by the $815 million deal by American Midstream to acquire South Cross announced this past Nov. 13.

Prior to the acquisition American Midstream had about 4,000 miles of interstate and intrastate pipelines in the Gulf of Mexico, Permian Basin, East Texas and elsewhere. When the Southcross assets are fully integrated the combined operation will include 10 processing plants and more than 8,000 miles of crude, natural gas and NGL pipelines.

Holt also noted that "some of our gas is high in hydrogen sulfide, so if a producer does not treat gas on the lease then there are more limited midstream take-and-treat options than there are for sweet gas."

It also bears mentioning that the midstream took the brunt of the hit that Hurricane Harvey delivered to South Texas. "Upstream we and most other producers were able to shut wells in advance of the storm, and then bring them back with minimal effects. There was more disruption downstream. It is not that operators were not able to turn wells back on but that the bottleneck was midstream operations being out of service. I don't think many of them suffered serious damage, it was more a matter that they took longer to bring back into service." ■

Atlas Sand

A Brigham Company

Rendering of Plant Under Construction

Premium Permian Sand

Atlas Sand provides the highest quality source of in-basin Frac Sand.

We offer a premium product including Permian 40/70 and Permian 100 Mesh.

Atlas Sand is mined in the Kermit and Monahans dunes and then refined for Permian Basin use, it is logistically advantaged to dependably support operators there.

About Atlas Sand

Atlas Sand was founded by successful oil and gas entrepreneur Bud Brigham along with other Permian Basin operators. It is led by an experienced team of E&P and Frac Sand industry leaders. Atlas Sand has the largest and highest quality Frac Sand reserves in West Texas which are logistically advantaged to reliably serve the oil and gas industry.

www.AtlasSand.com

Market analysts see 2018 to be a year of "ups" for unconventional oil and gas producers. *(Photo by Tom Fox, image courtesy of Hart Energy's* Oil and Gas Investor*)*

In the Shale Spotlight

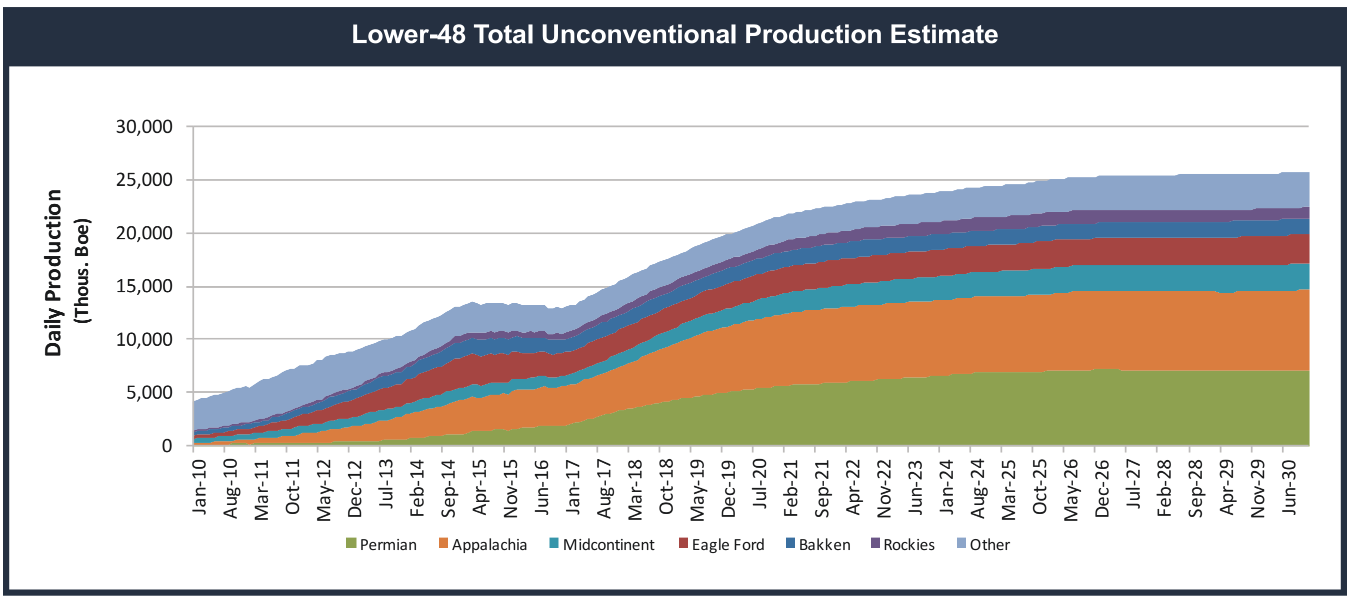
By **Stephen G. Beck**, Senior Director, Upstream, Stratas Advisors

The Permian Basin is expected to maintain a firm hold on the industry's focus in 2018.

It is common knowledge that the renaissance in U.S. oil and gas is due to success in developing unconventional resources economically. Not known as widely is that solutions for arriving at economically viable results vary greatly across and within plays. Much credit goes to the entrepreneurial spirit of the independent E&P and the oilfield service sector and the thousands of people who work with them for achieving the unthinkable. Looking at our forecast, we are reminded that innovation and experimentation remain key if our prognostications are to have any chance of becoming reality. Without further adieu, let us turn to this year's forecast.

Annual average production from Lower 48 unconventional sources is projected to grow by 18% versus 2017, averaging 16.6 MMboe per day. Accelerating growth in the Permian is the driving force behind this rapid growth. Stratas estimates total unconventional production from the Permian will average about 3.7 MMboe/d in 2018, up from 2.5 MMboe/d in 2017.

So, what makes the Permian special? In our opinion, it has much to do about options. Operators have many options in the Permian due to "stacked" pays. Stacked pay is one of the buzzwords to take over watercooler discussions in recent years. The term simply refers to an area having many lay-



(All data and images courtesy of Stratas Advisors) ers of hydrocarbon-prone resources primed for production. And no place epitomizes this more than the Permian Basin, with some industry experts saying there could upwards of 40 formations available for eventual production, the most prolific of which is the Wolfcamp Shale.

The Wolfcamp Shale

The Wolfcamp is comprised of multiple productive zones within what are commonly referred to as the A, B, C and D benches. The formation consists of interbedded organic-rich siliceous and calcareous mudstones, fine-grained limestone and organic-poor muds high in clay content. In other words, present is a mix of different stuff that just happens to include oil and/or gas. Operators have been focusing on the A and B benches where clay volumes tend to be lower, ranging from 10% to 36%, with relatively equal amounts of silica and carbonate, which makes it brittle and easier to fracture. Breakeven prices for Delaware Basin Wolfcamp wells have been some of the best in the Permian. Top wells can post breakeven prices well below \$50/bbl. Meanwhile, improvements in the Midland Basin Wolfcamp have led to a "most improved" status. Midland Basin Wolfcamp wells are increasingly competitive with other top wells.

Two other unconventional resources in the Permian remain on our radar—the Bone Spring and Alpine High—both of which have attractive aspects as well as detractions.

Beginning with the Bone Spring, solid economics and attractive breakeven prices are likely for operators sitting on good acreage. The second and third Bone Spring formations remain the go-to opportunities. Unfortunately, the Bone Spring encompasses a relatively small areal extent encompassing approximately 1,800 sq miles. As such, Stratas believes the economic opportunities are likely to be fully developed by the early- to mid-2020s.

The Alpine High has all the trappings of an early lifecycle play. Little production history on few wells leaves a lot of risk on the table. It also leaves a lot of upside. The other factor that raises some concern is the few operators participating in the play. History has shown that successful shales tend to begin with many operators conducting parallel "experiments" until the "code" is cracked. While we have great respect for Apache's capabilities, we would welcome more "scientists" to this experiment.

The Eagle Ford

Turning our attention to the Eagle Ford, operators have arrested declining production by putting about twice the number of rigs to work in the play since the trough of mid-2016. While the Eagle Ford boasts some of the best economics in North America shale, large swaths of the play are densely developed, which is both good and bad. On the good side, highly predictable results are had with operators having a keen understanding of the play and its opportunities. On the bad side, keen knowledge of the play means that there is limited upside potential. With an average thickness of about 150 ft, multizone development opportunities in the Eagle Ford are limited. However, sweet spots in thick sections of the overpressured oil window along the northeast-southwest trend will continue to produce great results. In recent years, the Eagle Ford has produced the largest share of highly economic wells in shale with well over half its wells posting breakeven prices below \$50/bbl. Despite this, Stratas projects slower Eagle Ford production growth for several years as operators increasingly view the play as an asset to harvest.

As a harvest asset, the Eagle Ford remains a good prize. Geologically, the Eagle Ford Shale is calcareous (carbonate rich) and organic rich, making it conducive to enhanced production from hydraulically induced fractures. Average lateral lengths in the Eagle Ford play ranged from 5,800 ft to 6,000 ft in recent years. As in other plays, operators have been experimenting with extended length laterals. Chesapeake Energy drilled a record 16,926-ft lateral in the play with improved projected production. Ongoing experimentation with laterals and completion designs should bode well for the Eagle Ford longer term.

The Scoop/Stack

Tracking north, the Scoop and Stack plays have quickly become some of the most interesting plays in the U.S. Targets include the Woodford, Osage, Sycamore, Meramec and Springer reservoirs. In the Stack, overpressured, liquids-rich Meramec and Woodford tend to have highest production rates. Hence, most attention in the Stack continues to center on the Meramec and Woodford formations where top performing wells can post breakeven economics well below $50/bbl, assuming a 10% return to investors. Operators continue to report higher production associated with longer laterals and larger fracture jobs. Earlier this year, Devon Energy reported a 10,000-ft lateral in the overpressured Upper Meramec that produced a peak 24-hour IP of 6 Mboe/d with a 50% oil mix and potential for multizone development across separate intervals. In the Scoop, Woodford prospects remain a top priority. Highly prospective opportunities may be relatively limited geographically in the Midcontinent; hence, Stratas will be monitoring developments closely.

In the Rockies, the Niobrara reigns supreme among shales and tight rock resources. Most Niobrara activity remains entrenched in the Wattenberg area where Anadarko Corp. and Noble Energy are the most active operators. Economics in large portions of the Niobrara are advantaged due to mineral fee aspects of the acreage dating back to the transcontinental railroad. Outside Wattenberg, the prospects look brightest in the Powder River Basin.

The Bakken

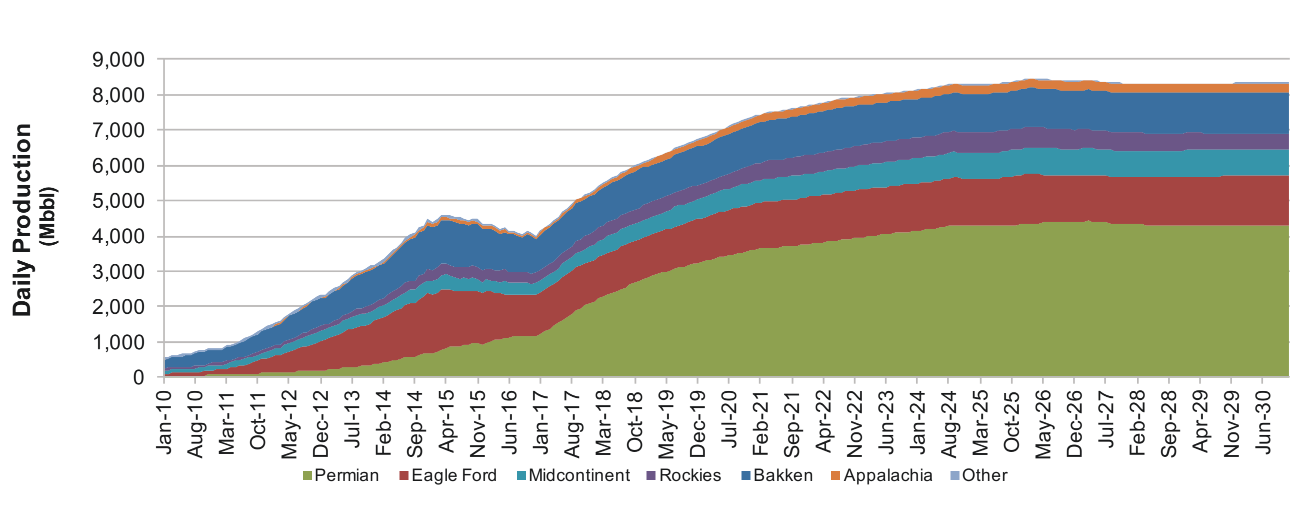
Moving to the Bakken, the play is the most mature unconventional liquids play in North America. As such, development in the sweet spots is dense in many areas. That said, good opportunities remain in the gassier portions of the play along the Missouri River, east of the Nessen Anticline. Top wells in this part of the play can still generate breakeven prices well below $50/bbl. How long until the Bakken goes into steady decline hinges on the loss of its depletion drive. Expanding gas used to evacuate oil will continue to lose energy as reservoir pressure decreases and GOR increases.

Geologically, the Devonian Bakken is composed of black, organic-rich shale and quartz-rich limestone and siltstone. The Upper Bakken generally has very low matrix permeability, and is less productive than the lower unit, but it does produce where overpressured and naturally fractured. For this reason, we believe the Bakken will reach resource location exhaustion in the early- to -mid-2020s.

Modeling Lower 48 natural gas production

Turning to natural gas, Stratas projects unconventional gas production will average 65 Bcf/d in 2018, an increase of 9 Bcf/d, or 16%, versus 2017. This outlook is largely based on two key resources: associated gas and the Marcellus Shale. Before pro-

Lower 48 Unconventional Liquids Production Estimate



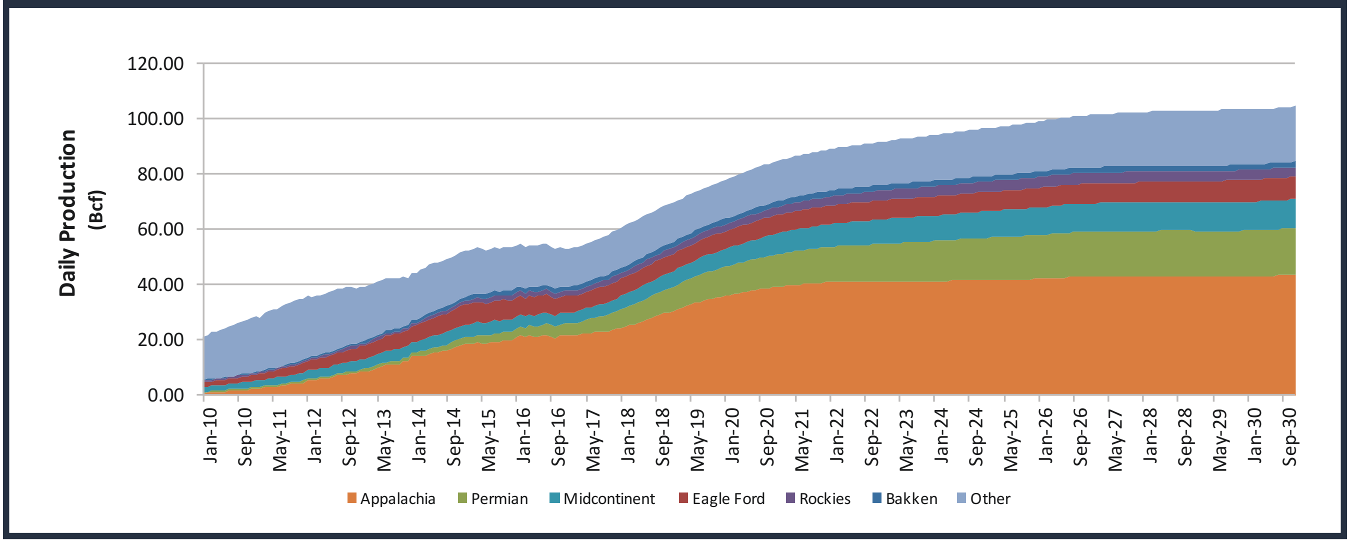
ceeding further, it seems appropriate to introduce our model for Lower 48 natural gas production. Natural gas production in the Lower 48 is akin to a four-legged chair, with associated gas, Appalachia unconventional gas, non-Appalachia unconventional gas and Gulf of Mexico (GoM) offshore each representing a leg on the chair.

Associated gas is the first leg on the chair. Being oil-driven, associated gas is indifferent to Henry Hub and NYMEX gas prices. Associated gas is expected to grow by 21%, driven by accelerated activity in the Wolfcamp Shale of the Permian. Associated gas currently represents about 35% of total unconventional gas in the Lower 48, and that share is not expected to change as growth in Permian is met with growth in the Marcellus and Utica of Appalachia. Attractive breakeven oil prices for the best areas of the Wolfcamp and Bone Spring provide a clear runway for many years. Consequently, the Permian will continue to attract a disproportionate share of rigs for years to come.

Appalachia dry gas is the second leg on our chair. Appalachia activity is highly correlated to gas prices and to infrastructure projects. Appalachia gas is primarily Marcellus gas and assisted with contributions from the Utica/Point Pleasant formations. Gas demand east of the Rockies sets the call on domestic production greater than the "base" supplies (associated gas) provided from "liquids" wells. In periods when Appalachia gas falls short of demand, mostly due to infrastructure constraints, the Haynesville stands ready to inject substantial quantities of gas at competitive prices, making the Haynesville an important "swing" producer for North America.

Delving deeper into the Marcellus, we find that understanding the mineral composition is key to understanding the play and the areas prone for creating a dense, connected network of induced fractures. The Marcellus is generally laminated, with silica-content up to 60% and clay content up to 49% in some areas. Where clay content is greater than about 40%, the rock is more ductile, inhibiting effective fracture stimulation. Most Marcellus production occurs in the central and eastern portions of the formation's extent, as the northern and western portion is both immature and thinner, with limited results. Depths can be up to 9,900 ft; free and adsorbed gas in the pore space help to increase Marcellus reservoir pore pressure to an average 6,000 psi. We expect the Marcellus to remain a top contributor through at least the end of the next decade.

Lower 48 Shale and Tight Gas Production Estimate



Staying in Appalachia, the Utica Shale is composed of organic-rich, black shale interbedded with limestone during the Ordovician period. It generally contains 25% carbonate and 10% to 51% clays, with up to 70% clay in parts of Ohio. This increased clay volume decreases the ability of proppant and induced fractures to effectively propagate, decreasing connectivity and well production.

Annual average production from Lower 48 unconventional sources is **PROJECTED TO GROW BY 18% VERSUS 2017, AVERAGING 16.6 MMBOE PER DAY**. Accelerating growth in the Permian is the driving force behind this rapid growth.

The Point Pleasant Formation underlies the Utica and comprises interbedded dark shales, siltstones and limestones. It is organic-rich and occurs as a transition zone between the argillaceous (clay-rich) Utica above and the calcareous (carbonate-rich) Lexington/Trenton formations below. Oil and gas operators have increased lateral lengths in the play, seeking to understand optimal completion designs. Eclipse Resources recently reported the successful completion of a "super-lateral" measuring 19,300 ft of "completable" lateral well length in the Utica, with expected production in the first quarter of 2018. The geographic extent of these larger well completions may be restricted to more carbonate-rich, basal sections of the Utica and the Point Pleasant. Stratas will be monitoring these wells and neighbors to evaluate the repeatability of this approach.

Non-Appalachia dry gas is the third leg on the chair. Within this category, the Haynesville stands out. The Haynesville Shale is a Late Jurassic, carbonate- and organic-rich mudstone, which is overpressured due to rapid deposition and hydrocarbon generation during and after the Cretaceous period. This overpressured reservoir regime is a key factor in its higher porosity, permeability and free gas measures. However, these same factors also cause production declines of about 80% in the first year. Haynesville dry gas production is attributed to high thermal maturity and reservoir temperatures. Additionally, the Haynesville contains significant silica content, such as quartz and feldspars, which leads to improved fracture propagation during hydraulic fracturing. Recent progress with longer laterals and new completion designs has led to strong improvements in well level economics. The key question for 2018 and 2019 centers on how much running room the play has for these bigger wells. Stratas views the Haynesville as the ideal asset to assume the swing producer role for Lower 48 natural gas.

Finally, the GoM is the fourth leg on the chair. Historically, the GoM was a major contributor to domestic gas volumes. However, that is no longer the case in the shale era. Instead, gas production from the GoM is mostly sourced from existing wells that are already in decline.

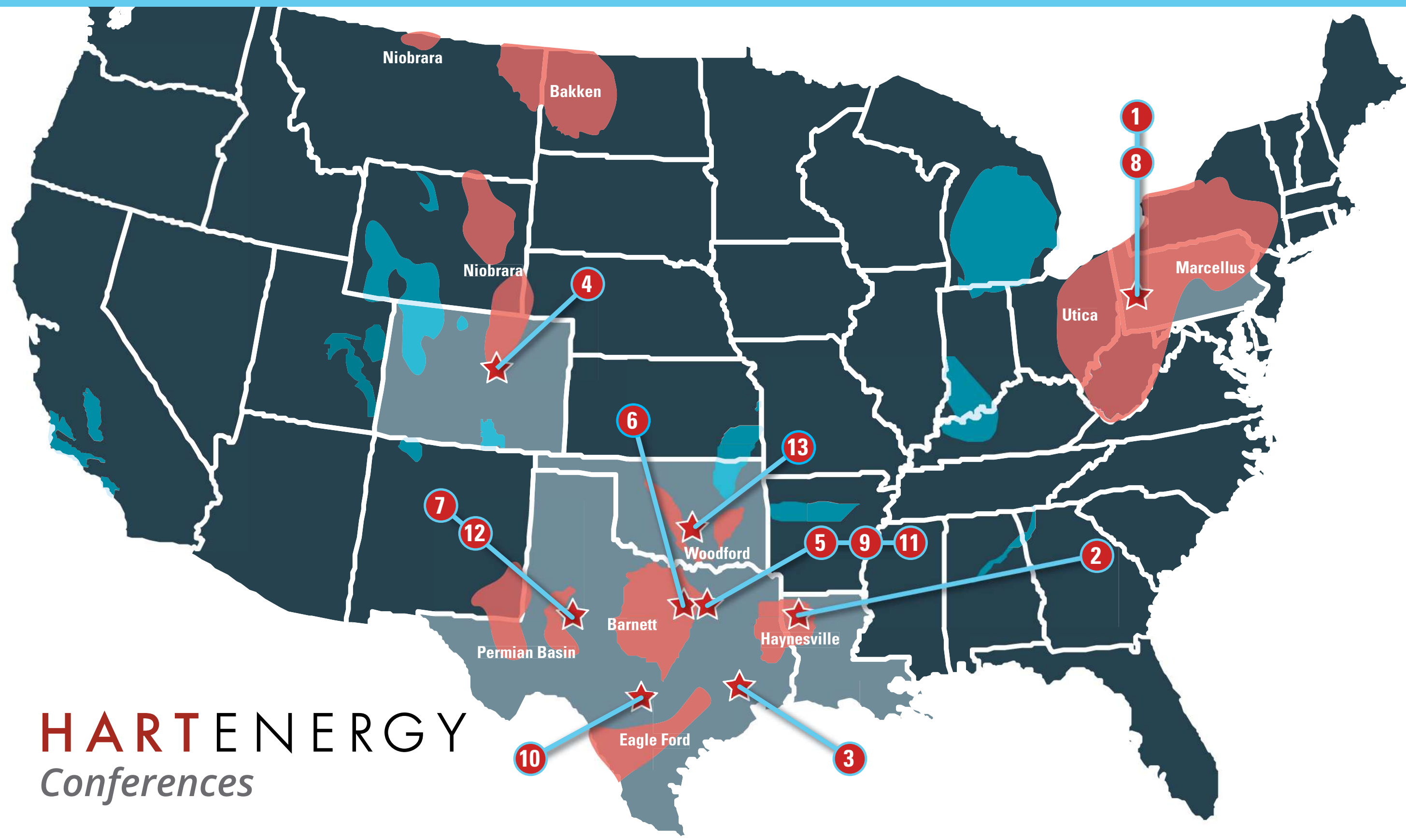
Growth will be harder to come by in 2018. While rig counts and activity are projected to remain robust, the high number of "young" wells added in 2017 translates to a steeper base decline in 2018. A steeper base decline makes it more difficult to grow production as a greater share of "new source" production, or production from wells added in the current year, replenishes production declines in the base wells. Base wells are wells that began their productive life prior to the current year.

Forecasting growth

Well spuds remain the most critical independent variable to forecasting growth in oil and gas production. In recent years, much has been made about efficiencies in drilling and completions. Truth be said, it is far easier to lay claim to consistently improving cycle times when working with the best crews and the best equipment. Unfortunately, not all crews nor all equipment can be best at all times. As increasing numbers of crews were called back and assigned to second-tier equipment, cycle times showed some slippage. Stratas does not anticipate large-scale degradation in cycle times, however; the pace of improvements witnessed in recent years is not expected to continue.

2018 Hart Energy Conferences

Where Business Meets Opportunity

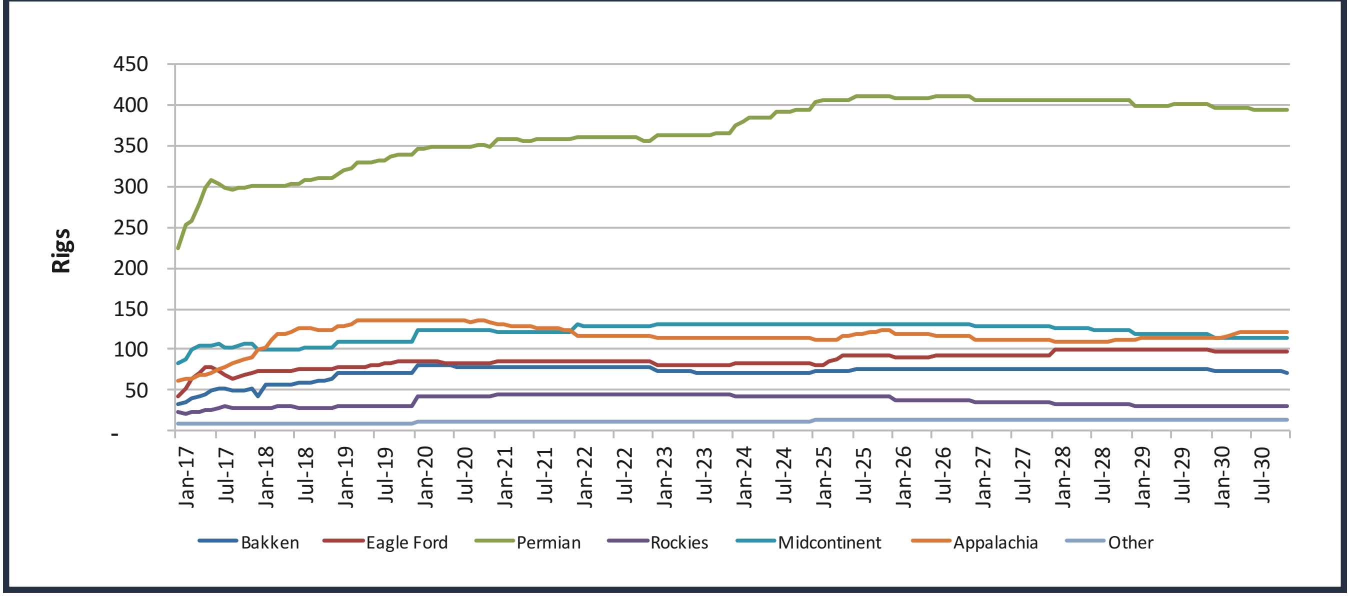


HARTENERGY
Conferences

1. MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION — **Jan. 30 – Feb. 1**, Pittsburgh, PA
2. DUG HAYNESVILLE — **Feb. 20 – 21**, Shreveport, LA — NEW IN 2018
3. DUG EXECUTIVE — **Feb. 26**, Houston, TX — NEW IN 2018
4. DUG ROCKIES — **April 24 – 25**, Denver, CO
5. energycapital CONFERENCE — **May 7**, Dallas, TX
6. DUG PERMIAN BASIN — **May 21 – 23**, Fort Worth, TX
7. MIDSTREAM TEXAS — **June 5 – 6**, Midland, TX
8. DUG EAST — **June 19 – 21**, Pittsburgh, PA
9. A&D STRATEGIES AND OPPORTUNITIES Conference & Workshop — **Sept. 5 – 6**, Dallas, TX
10. DUG EAGLE FORD — **Sept. 19 – 21**, San Antonio, TX
11. MIDSTREAM FINANCE CONFERENCE — **Oct. 22 – 23**, Dallas, TX — NEW IN 2018
12. EXECUTIVE OIL CONFERENCE — **Nov. 5 – 7**, Midland, TX
13. DUG MIDCONTINENT — **Nov. 13 – 15**, Oklahoma City, OK

For more information, visit ***HartEnergyConferences.com***

Shale and Tight Resource Rig Activity



One aspect Stratas does expect to change is cost. Oilfield service companies appear to be gaining some pricing power with higher utilization rates, especially for the most in-demand services in prime locations. Further fueling these increases are demands for select consumables and services, particularly those used in completions. Consequently, Stratas is modeling double-digit cost increases on average for U.S. shales in 2018.

Drilled but uncompleted wells (DUCs) remain an important but secondary consideration for 2018. The evolution of DUCs on the scale seen today is a byproduct of pad drilling, batch processes to minimize damage and disruptions, and infrastructure planning. Observations of data reveal two important insights.

First, the number of "steady-state" DUCs moves in tandem with rig counts. Steady state refers to DUCs that are a result of normal business practices. A good rule-of-thumb for estimating the steady-state DUC count is:

Steady-state DUCs = Rigs * wells per month per rig * 3 months

As rig counts climb, the steady-state DUC count also climbs. Clear evidence of this can be found in the Permian today. In tracking DUCs and their potential impact on production, Stratas advises in netting out these steady-state DUCs from the gross number. This ensures proper timing of production additions over the forecast horizon. It also ensures proper timing of well retirements in the long term. The second insight is that DUC inventories typically adhere to a first-in, first-out inventory model. Observations show that most wells are completed in a range of 120 to 220 days after drilling. As one might expect, precision in forecasting, especially in oil and gas, is enhanced when considering such details.

Shifting our gaze to the longer horizon, range-bound prices through the next several years will continue to support growing production of both commodities from shale while containing the industry from falling victim to the side effects from over-exuberant development. OPEC-plus production curtailments will end. The timing is, of course, unknown. However, it is important to recognize that shale has proven its ability to compete effectively in today's market, and it is here to stay for the long term. Given the allocation of economic shale and tight resources in North America and ongoing efforts by industry to enhance competence in developing these resources, Stratas projects growing oil and gas production from shale and other tight rock formations through most, if not all, of the forecast period. ■